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STATE OF FLORIDA

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JACK SHREVE
PUBLIC COUNSEL

April 28, 1997

Ms. Blanca S. Bayó, Director
Division of Records and Reporting
Florida Public Service Commission
2540 Shumard Oak Boulevard
Tallahassee, FL 32399-0870

RE: Docket No. 970261-EI

Dear Ms. Bayó:

Enclosed are originals and fifteen copies each of the Direct Testimony of William R. Jacobs, Jr., Ph.D and Exhibits of William R. Jacobs, Jr., Ph.D, on behalf of the Office of Public Counsel for filing in the above referenced file.

Please indicate receipt of filing by date-stamping the attached copy of this letter and returning it to this office. Thank you for your assistance in this matter.

Sincerely,

John Roger Howe
Deputy Public Counsel

JRH/dsb
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Before the

Florida Public Service Commission

Docket No. 970261-EI

PRELIMINARY
CRYSTAL RIVER UNIT 3 OUTAGE REVIEW

Direct Testimony of

WILLIAM R. JACOBS, JR., Ph.D.

On Behalf of
THE FLORIDA OFFICE OF PUBLIC COUNSEL

April 28, 1997

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DIRECT TESTIMONY OF
WILLIAM R. JACOBS, JR.
CRYSTAL RIVER UNIT 3 OUTAGE REVIEW

I. INTRODUCTION

Q. PLEASE STATE YOUR NAME, TITLE AND BUSINESS ADDRESS.

A. My name is William R. Jacobs, Jr., Ph.D. I am a Principal of GDS Associates, Inc. My business address is 1850 Parkway Place, Suite 720, Marietta, Georgia, 30067.

Q. DR. JACOBS, PLEASE SUMMARIZE YOUR EDUCATIONAL BACKGROUND AND EXPERIENCE.

A. I received a Bachelor of Mechanical Engineering in 1968, a Master of Science in Nuclear Engineering in 1969 and a Ph.D. in Nuclear Engineering in 1971, all from the Georgia Institute of Technology. I am a registered professional engineer and a member of the American Nuclear Society. I have more than twenty-six years of experience in the nuclear power industry including more than twelve years of nuclear power plant construction and startup experience. I have participated in the construction and startup of seven nuclear plants in this country, including Crystal River 3 (CR-3), and overseas in management positions including startup manager and site manager. As a loaned employee at the Institute of Nuclear Power Operations (INPO), I participated in the Construction Project Evaluation Program, performed operating plant evaluations and assisted in development of the Outage Management Evaluation Program. Since joining GDS Associates, Inc. in 1986, I have been involved in evaluation and monitoring of nuclear plant construction and operation on behalf of non-operating owners. I have also participated in rate case and litigation support activities related to nuclear power plant construction, operation and decommissioning. I have evaluated the certification application of fossil fueled plants and have monitored the construction of gas turbine peaking plants for a state regulatory agency. My resume is included as Exhibit____(WRJ-1).

Q. **WHAT IS THE NATURE OF YOUR BUSINESS?**

A. GDS Associates, Inc. (GDS) is an engineering and consulting firm with offices in Marietta, Georgia and Austin, Texas. GDS provides a variety of services to the electric utility industry including power supply planning, generation support services, rates and regulatory consulting, financial analysis, load forecasting and statistical services. Generation support services provided by GDS include fossil and nuclear plant monitoring, plant ownership feasibility studies, plant management audits, production cost modeling and expert testimony on matters relating to plant management, construction, licensing and performance issues in technical litigation and regulatory proceedings.

Q. **ON WHOSE BEHALF ARE YOU TESTIFYING?**

A. I am presenting testimony on behalf of the State of Florida Office of Public Counsel.

Q. **WHAT WAS YOUR ASSIGNMENT IN THIS PROCEEDING?**

A. My assignment was to perform a preliminary evaluation of the current outage at Florida Power Corporation's (FPC) Crystal River Unit 3 that began on September 2, 1996. I was asked to investigate the causes of this outage and to evaluate the performance of

FPC management as it relates to the current outage. Finally, I was asked to prepare and present testimony presenting the results of my investigation and evaluation.

Q. WHY DO YOU CHARACTERIZE YOUR WORK AS A PRELIMINARY INVESTIGATION OF THE CRYSTAL RIVER OUTAGE?

A. I consider my investigation preliminary for several reasons. First, the outage is in progress. Neither the duration of the outage nor the outage critical path are known at this time. For this reason, any investigation and evaluation of the outage must be preliminary in nature. Secondly, the time frame allowed for my evaluation was exceedingly short. Due to the abbreviated time frame, less than one full round of discovery was possible before the filing date for my testimony. A complete investigation of a lengthy outage such as the current Crystal River outage can take six months to one year to complete and will typically involve many rounds of discovery. For these reasons, I believe that my investigation and findings are preliminary. I would hope that time will permit a more complete investigation of the outage once it is completed and the unit has been returned to service.

Q. PLEASE DESCRIBE THE METHODOLOGY USED IN THE CONDUCT OF YOUR INVESTIGATION.

A. In performing my preliminary review of the current outage at Crystal River Unit 3, I reviewed extensive records and documentation prepared by the Company. These documents include Florida Power Corporation's Preliminary Report on the Current Outage at Crystal River Unit 3 submitted to the Commission on March 19, 1997, a transcript of the Staff Workshop held on March 26, 1997, and testimony filed by the Company's witnesses. I also reviewed other publicly available documents such as NRC inspection reports. I developed interrogatories and document requests and reviewed the Company's partial production of documents, although the time available for this review was limited. I attended the depositions of Mr. P. M. Beard, Mr. Paul McKee and Mr. Fran Sullivan and participated in the development of questions for these depositions. In summary, I used all of the relevant sources of information that were available to develop an understanding of the circumstances that led to the current outage and of the work that is being performed during this outage.

Q. **DID YOU PLACE MORE WEIGHT ON ANY PARTICULAR SOURCE OF INFORMATION?**

A. In performing a retrospective analysis of an outage such as the current outage at Crystal River, I have found that the best sources of information are the contemporaneous documents that were generated at the time of the events under review or shortly thereafter. These documents would include routine working records such as the Modification Action Requests (MAR) and safety evaluations prepared for the modifications of interest, Company correspondence and presentations to the NRC explaining the facts and circumstances relevant to the outage, assessments and root cause analyses performed to determine the fundamental causes of the problems, and other contemporaneous documents prepared during the normal course of business.

Q. HOW DID YOU EVALUATE THE REASONABLENESS OF FLORIDA POWER CORPORATION'S MANAGEMENT ACTIONS IN YOUR REVIEW OF THE CRYSTAL RIVER OUTAGE.

A. I evaluated the decisions and actions by FPC management, employees and contractors in light of the facts that were known or reasonably should have been known at the time by a person possessing the proper qualifications. Thus, in evaluating the current Crystal River 3 outage, I have applied a "reasonable, properly qualified, person test" to the decisions and actions of FPC, evaluating these decisions and actions in light of what FPC knew or should have known without benefit of hindsight.

Q. IN YOUR OPINION, IS IT APPROPRIATE TO USE DOCUMENTS PRODUCED BY THE NUCLEAR REGULATORY COMMISSION, THE INSTITUTE OF NUCLEAR POWER OPERATION, OR OTHER REGULATORY AGENCIES IN AN EVALUATION OF THE PERFORMANCE OF THE MANAGEMENT OF A NUCLEAR POWER PLANT?

A. Yes, I believe that it is appropriate and valuable to use documents prepared by the NRC or INPO in performing an evaluation of the actions of nuclear plant management. It is not only appropriate and valuable to use these sources of information, but failure to do so would result in a less than complete investigation of the record and circumstances related to the outage or event under review. Documents prepared by the NRC or INPO contain the observations of a knowledgeable, third party investigator and often provide the best available contemporaneous compilation of the facts and circumstances surrounding a specific event. These documents are often the result of extensive investigations by teams of experts and are a source of information that should not be ignored. However, I agree with the 1982 decision of the Florida Supreme Court in which it considered the use of NRC reports in investigations of utility management and found:

> While the use of these documents are undoubtedly useful for numerous purposes, they should not serve as the primary source of evidence in a fault-finding determination.[1]

The NRC uses different criteria in performing its evaluations. Nevertheless, the facts and information contained in relevant regulatory documents are an important part of the record that often cannot be duplicated after the fact. These documents should be appropriately considered if an evaluation is to be thorough and complete.

Q. DOES THE COMPANY MANAGEMENT BELIEVE THAT NRC INSPECTION REPORTS AND OTHER DOCUMENTS ARE USEFUL IN IDENTIFYING PROBLEM AREAS AND EVALUATING THE OPERATION OF A NUCLEAR POWER PLANT?

A. Yes, they do. When Mr. Percy M. Beard, Jr., the recently retired Senior Vice President of Nuclear Operations, was asked in his deposition on April 22, 1997, how he familiarized himself with Crystal River 3 upon assuming the position of Senior Vice President Nuclear, the first two actions identified by Mr. Beard were to review the

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[1] Florida Power Corp. v. Public Service Commission, No. 60534, December 16, 1982, Fla., 424So.2d 745

NRC reports concerning the unit and to visit the NRC regional office in Atlanta to discuss the plant and identify current problem areas.[2]

Q. DOES THE COMPANY MAKE USE OF FINDINGS BY THE NRC IN ITS TESTIMONY?

A. Yes, the Company makes extensive use of NRC findings and reports when these findings and reports are supportive of their position. For example, in his testimony before the Commission during FPC's 1991 rate case, Mr. Beard went to great lengths to review the findings of the NRC's Systematic Appraisal of Licensee Performance (SALP) report for Crystal River 3 that were favorable.[3] The Company clearly believed that the NRC's SALP findings were appropriate for consideration by the Commission. In the Company's Preliminary Report on the Current Outage at Crystal River 3 , the Company repeatedly states that the NRC was aware of the modifications or that the modifications were made with the knowledge of the NRC[4]. Once again, in this case, the Company believes that the actions by the NRC should be considered by this Commission.

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[2] Deposition of Mr. P. M. Beard, Jr., dated April 22, 1997, page 35, lines 12 - 16

[3] Transcript of Hearing In Re: Petition for a Rate Increase by Florida Power Corporation, Florida Public Service Commission, Docket No. 910890-EI, July 15, 1992, Prefiled Testimony pages 8-11 corresponding to transcript pages 1373-1376.

[4] FPC Preliminary Report on the Cu..ent Outage at Crystal River Unit 3, dated March 19, 1997, page 11.

Q. WHAT DO YOU RECOMMEND CONCERNING THE USE OF NRC DOCUMENTS IN EVALUATING UTILITY MANAGEMENT?

A. I recommend that the Commission allow NRC documents to be used in evaluation of utility management. These documents should not be relied upon as the "primary source of evidence in a fault-finding determination," but the Commission should recognize them as valuable sources of information to be considered. The Company should not be allowed to have it both ways. That is, they should not be allowed to introduce and rely upon NRC documents when these documents support their position but be allowed to prevent the use of such documents when these documents are critical of their decisions or actions.

Q. PLEASE SUMMARIZE YOUR TESTIMONY.

A. My testimony presents the results of my preliminary review and evaluation of the ongoing outage at Crystal River 3. I refer to my review and evaluation as preliminary because the outage is still in progress and a final evaluation is not possible prior to completion of the outage. In addition, the abbreviated schedule available for this review did not allow for comprehensive discovery that will be necessary to perform a final evaluation of the outage. As a result of my review I have reached the following conclusions:

- FPC's management of CR-3 has been seriously deficient for several years prior to the current outage. These management deficiencies allowed the conditions to develop that ultimately resulted in the current outage.

- The outage was avoidable. If FPC had adequately evaluated the impact and the safety consequences of modifications to the emergency feedwater system, and submitted these modifications to the NRC for review and approval as required by NRC regulations, the current outage would not have been necessary.
- The root causes of the CR-3 management deficiencies are identified in the Company's Management Corrective Action Plan Phase II including:
  - Focusing more intensely on cost and production than safety;
  - Management not listening to or acting upon information available to them;
  - A strong sense of denial with regard to performance;
  - A family organizational culture rather than a self-critical team.
- FPC should bear the burden of additional costs resulting from this outage.

Based on these conclusions I make the following recommendations to the Commission:

1. Preclude the Company from collecting any funds as a result of this outage until a final evaluation of the outage has been performed and it has been determined whether the Company should be allowed to recover additional costs resulting from this outage;
2. At the conclusion of the outage, conduct a full and comprehensive evaluation of the causes and impacts of the outage;

3. Establish a schedule for the comprehensive outage review that provides adequate time for full discovery and analysis of the complex technical issues related involved.

II. OVERVIEW OF CR-3 MANAGEMENT PROBLEMS

Q. WHAT IS CONTAINED IN THIS SECTION OF YOUR TESTIMONY?

A. In this section of my testimony I provide an overview of the long standing management problems at Crystal River 3 that ultimately culminated in the current shutdown. This overview is primarily based on assessments, root cause analyses and corrective action plans developed by the Company.

Q. WHY IS AN UNDERSTANDING OF THE MANAGEMENT ISSUES AT CR-3 IMPORTANT TO THIS PROCEEDING?

A. It is important to put the current problems in context and for the Commission to understand that the problems that led to this outage are not isolated anomalies but are part of a broad picture of ineffective management that has existed at CR-3 for a long period of time.

Q. WHICH ASSESSMENT OF CR-3 MANAGEMENT WILL YOU DISCUSS FIRST?

A. I will first discuss the most recent corrective action plan, the Management Corrective Action Plan Phase II. In addition to containing corrective actions, this document identifies the root causes of many of the existing management problems at CR-3.

Q. WHAT IS PHASE II OF THE MANAGEMENT CORRECTIVE ACTION PLAN?

A. According to FPC, the Management Corrective Action Plan Phase II (MCAP II) "… charts the course for bringing CR-3 to the standards the owners, regulators, and public expect and deserve."[5] Areas identified as needing corrective actions are identified in MCAP II as:[6]

Leadership Oversight and Involvement
Configuration Management/Design Basis
Regulatory Compliance
Engineering Performance
Operations Performance

These areas encompass most of the major operational areas of the plant. Problems and difficulties of this magnitude and extent can only occur due to shortcomings and failures of management. FPC itself states that "… management was the key ingredient to the shortcomings."[7] In short, FPC had long standing, pervasive management problems that resulted in the major corrective actions that are currently

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[5] Crystal River Unit 3 - Management Corrective Action Plan Phase II (MCAP II), November 22, 1997, Opening Statement, page 1. (This document was transmitted to the NRC by FPC by letter on November 27, 1997 and is included as Item 4 in Appendix I to Florida Power Corporation's Preliminary Report on the Current Outage at Crystal River Unit 3, Docket No. 970261-E, March 19, 1997.)

[6] Crystal River Unit 3 - Management Corrective Action Plan Phase II (MCAP II), November 22, 1997, page 2.

[7] Crystal River Unit 3 - Management Corrective Action Plan Phase II (MCAP II), November 22, 1997, Opening Statement, page 1.

underway. These findings are emphasized even further by Revision 1 to the report which states:

> A specially designated subcommittee of the Nuclear General Review Committee (NGRC), chaired by the NGRC Chairman, reviewed Revision 0 of MCAP II. This group believed the focus prescribed in the five areas above was too narrow and did not address the four following fundamental root causes:
>
> - Focusing more intently on cost and production than safety.
> - Management not listening to or acting upon information available to them.
> - A strong sense of denial with regard to performance.
> - A family organizational culture rather than a self-critical team.[8]

These problems were identified not just by an internal group at FPC or by a small group of individuals. According to Mr. Beard:

> ... several assessments have been conducted over the last few months. These assessments were conducted by our staff, the Nuclear Regulatory Commission, as well as teams of highly-qualified, experienced, nuclear industry professionals. I have used these assessments to help me determine what needed to be fixed ...[9]

Mr. Beard goes on to state that:

> There is one area I particularly want to stress because it is so critical to the successful operation of a nuclear power plant ... oversight. At CR-3, as is the case at all nuclear plants, there are multiple

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8 Crystal River Unit 3 - Management Corrective Action Plan Phase II (MCAP II), November 22, 1997, page 2.

9 Crystal River Unit 3 - Management Corrective Action Plan Phase II (MCAP II), November 22, 1997, Opening Statement, page 1.

> groups that serve the purpose of monitoring all phases of the plant's performance. There is ... internal oversight such as QA [Quality Assurance], NGRC [Nuclear General Review Committee], PRC [Plant Review Committee], and NSAT [Nuclear Safety Assessment Team]. While those responsible for CR-3's internal oversight activities cannot be blamed for the plant's shortfalls in performance, they can be criticized for failure to recognize and help assure they were corrected. However, oversight organizations can not be effective if line management fails to respond appropriately to critical appraisals. There is some indication that this has occurred at CR-3.[10]

Once again, although there were oversight organizations which should have identified and assisted in alleviating the problems at CR-3, these organizations could not be effective due to the failures of line management.

MCAP was developed "with two fundamental principles in mind: (1) to identify the major issues and deficiencies in Crystal River 3's performance and to (2) direct action to resolve those deficiencies."[11] The effective implementation of the direct actions necessary to resolve the identified deficiencies has resulted in the current ongoing outage at CR-3. There is little doubt that these actions are necessary to restore CR-3 to a material and management condition that complies with the design basis and will enable future operation that is both safe and economical.

Q. HOW EXTENSIVE ARE THE PROBLEMS IDENTIFIED IN MCAP II?

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[10] Crystal River Unit 3 - Management Corrective Action Plan Phase II (MCAP II), November 22, 1997, Opening Statement, pages 1-2.

[11] Crystal River Unit 3 - Management Corrective Action Plan Phase II (MCAP II), November 22, 1997, page 2.

A. The material provided in the MCAP II document in addressing both of its concerns in a logical fashion has corrective actions interspersed with identification of deficiencies and problems. For purposes of implementing the needed corrective actions, this format is appropriate. However, for purposes of understanding the deficiencies and problems, it does not provide a clear picture of the extensive magnitude of the problems at CR-3. Excerpts from MCAP II are provided in Exhibit____(WRJ-2) which focus only on the problems identified. This exhibit delineates problem descriptions, root causes, contributing causes and (to the extent appropriate for discussion of the problems) CR-3's present condition. Taken in total, this set of excerpts makes it plain just how pervasive and widespread the problems were.

Q. HAS FLORIDA POWER CORPORATION IDENTIFIED THESE PROBLEMS OR SIMILAR PROBLEMS IN OTHER ASSESSMENTS PRESENTED BY FPC?

A. Yes. FPC made a presentation to the NRC in the January 24, 1997 Predecisional Enforcement Conference in which it discussed its internal management problems. To a large extent, that presentation amplified and discussed particular facets of MCAP II and concluded that MCAP II would resolve the problems. One indication of the long standing nature of the difficulties was FPC's statement that:

> FPC views the apparent violations as symptomatic of deficiencies that predate MCAP II:
> - 10CFR50.59 evaluations ...
> - Design control ...
> - Corrective action implementation ...

- Procedures ...[12]

Some indication of the pervasive nature of the problems in one area, that of conducting safety evaluations of design changes, is reflected in FPC's statement that in a preliminary review 12 of a sample of 44 safety evaluations required further review.[13]

In their presentation to the NRC, FPC noted with regard to the scope of the problem regarding design control process and procedures that it had been found that unverified electrical diesel case studies, hydraulic system case studies, and station blackout case studies had been used to support plant modifications.[14] Such practices are a clear violation of standard practices in the industry.

There were also earlier indications of management problems at CP-3.

Q. WHAT WERE THE EARLIER INDICATIONS THAT THERE WERE MANAGEMENT PROBLEMS AT FPC?

A. In 1994-1996, FPC experienced problems which resulted in identification of management problems. In particular, on September 4 and 5, 1994, two unauthorized tests (referred to as "evolutions" in most of the available documentation) were conducted on the Makeup Tank (MUT) by operators at CR-3. On September 13, 1994,

[12] FPC Presentation Notes (attached to the January 31, 1997 NRC letter to FPC documenting the January 24, 1997 Predecisional Enforcement Conference), page 7.

[13] *Ibid.*, page 21. Twelve of the reviewed safety evaluations involved the ASV-204 modifications. The remaining 32 were a sample over the period from 1990-1996.

[14] *Ibid.*, page 30.

other FPC personnel learned of the second unauthorized evolution which occurred on September 5, 1994 and notified the NRC. This began a series of investigations. Ultimately, as a result, in February 1995, the original MCAP was issued (consisting of 49 steps). It was not until July 13, 1995, however, that FPC management became aware of the first unauthorized evolution which occurred on September 4, 1994.[15]

As a result of learning of the September 4, 1994 event, in July 1995, FPC management chartered an investigation of the events involved to attempt to determine the facts and to make recommendations. The investigation was headed by Daniel C. Poole and his report came to be known as the "Poole Report." The bulk of the investigation revolved around the failure of the operators to disclose the first of the two unauthorized evolutions for ten months despite an active set of investigations conducted during that time. Portions of the opinions and conclusions reached, nevertheless, raised management concerns. The report states that:

> During the course of the investigation, an accumulation of facts and/or opinions have indicated that other issues needed to be investigated. These included ... What broke down in FPC's corrective action processes such that the September 4th evolution went undetected and unreported?[16]

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[15] The details in this paragraph were excerpted from the chronology presented by FPC to the NRC in the March 27, 1996 Predecisional Enforcement Conference. This material was attached to the NRC letter of April 2, 1996 to FPC documenting that meeting.

[16] Daniel C. Poole *et al*, Final Report on the Investigation of Possible Misconduct - Phase 1, September 6, 1995, page 18. This report was submitted to the NRC by an FPC letter dated April 22, 1996.

As a part of the earlier investigations, the Manager of Nuclear Power Operations (MNPO) had been directed to consider the issue of earlier evolutions. The Poole Report stated that "The MNPO does not appear to have regarded the issue of previous evolutions with much seriousness."[17] The report then goes on to state that:

> FPC management failed to perform a detailed event review and root cause analysis. This appeared to result from a failure to implement the basic corrective action process for human performance problems. The next logical step may seem to be a conclusion that this was motivated by attempts to "down play" the event. But, to the contrary, the failure to implement basic corrective processes appears to be more related to management's zeal to deal with the issue at a high level and with dispatch.[18]

In addition, with regard to selected issues, the report goes on to state that "The Team was left with a sense that insufficient communication was employed by management ... The Team was also left with a feeling that the issue of the plant's performance not following the [expected curve] wasn't resolved in a timely manner ..."[19] This portion of the report concludes that:

> The Team did not have the time or the resources to pursue these questions to adequately provide actionable answers to management. They are very important from a nuclear safety standpoint and are valid questions for FPC management to pursue.[20]

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[17] *Ibid.*, page 20.

[18] *Ibid.*, page 20.

[19] *Ibid.*, page 23.

[20] *Ibid.*, page 23.

In short, the Poole Report raised issues that should have alerted management to at least the potential for significant and pervasive problems. This appears not to have been acted on promptly.

Also, on December 2, 1994, FPC (i.e., Mr. Beard) convened a Management Review Panel (MRP) which was charged to review the concerns expressed by the NRC in November 1994 in response to the first notification of an unauthorized evolution. On December 31, 1994, Dan Poole, the Chairman of the MRP, responded in part:

> The MRP found sufficient examples in our review of documents pertaining to operations in the 1993 and 1994 time frame to justify the NRC's concerns ... [T]aken as a whole they represent evidence of some needed actions by FPC management to ensure the nuclear mission is met and to restore the NRC's confidence in our operation.
>
> The recommended actions can be summarized as:
>
> - Initiating an aggressive effort to improve, from the top down, internal communication of the safety culture ...
> - Expand existing management procedural initiatives, including additional emphasis on procedural adherence ...
> - Increase the management attention devoted to managing change. This includes configuration management, procedures and processes, and organizational change. Ineffective or incomplete management of changes was a significant contributor to many of the events or conditions reviewed by the MRP.
> - Enhance the current initiatives to improve the working relationship with the NRC, by development of a more comprehensive plan. This plan should address philosophy and expectations as well as mechanics. It should stress recognition of the value added by the regulator in each interaction. Once developed, thorough internal and external communication will be required for it to be effective.

> It should be emphasized that no single aspect of the recommendations would, by itself, be sufficient to accomplish the objectives of ensuring the mission statement can be met and restoring NRC confidence in our operations.[21]

In short, FPC has found evidence in prior years of the very kind of pervasive problems now being addressed by MCAP II. This occurred despite FPC's assurance to this Commission that configuration management was the subject of a substantial improvement effort that had been underway since 1989.[22]

Q. WHAT ROLE DID THE NRC PLAY IN IDENTIFICATION OF THESE EARLIER PROBLEMS.

A. The NRC played an active role of raising questions, conducting investigations, and issuing Inspection Reports. On March 27, 1996, the NRC conducted a Predecisional Enforcement Conference with FPC in which a series of violations and problems and the associated root causes were discussed. FPC made extensive statements in that meeting with regard to these matters. With regard to root causes and contributing factors underlying violations, FPC stated:

- There was insufficient day-to-day management presence in the control room (page 38)
- [The root cause was] Deficient shift supervisor leadership (page 21)
- Management was not successful in achieving consistent adherence to procedures by operators (page 21)

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21 Dan Poole, Management Review Panel, December 31, 1994.

22 Transcript of Hearing In Re: Petition for a Rate Increase by Florida Power Corporation, Florida Public Service Commission, Docket No. 910890-EI, July 15, 1992, Prefiled Testimony pages 16-17 corresponding to transcript pages 1381-1382.

- Management efforts to strengthen shift supervisor leadership not timely (page 22)
- Ineffective communication & interaction between Design & System Engineering (page 69)
- Inadequate Engineering involvement in operating procedure revisions (page 75)
- Ineffective communication between Engineering & Operations (page 75)
- Management did not assure calculation and operating procedure processes included interdepartmental reviews (page 75)[23]

FPC also cited and agreed with the NRC statement (with certain qualifications) that "Inadequate management oversight allowed recurrent challenges to and violations of operating curves that were intended to ensure that design basis limits were not exceeded."[24] In their explanation of their "agreement" with the NRC, FPC stated that management oversight had five elements of which only the following three were inadequate:

- Communicating operating standards, including training on these
- Establishing processes to identify deviations from standards
- Observing and self-assessing to ensure standards are met.[25]

FPC also agreed with the NRC's assessment that "... management did not work effectively with the engineering and operations staff to resolve a long standing operator

[23] Page numbers are from the FPC presentation to NRC in the March 27, 1996 Predecisional Enforcement Conference. This material was attached to the NRC letter of April 2, 1996 to FPC documenting that meeting.

[24] *Ibid.*, page 45.

[25] *Ibid.*, page 46.

concern. [emphasis in original]"[26] Once again, this agreement had certain reservations attached. FPC concluded, in part, that "There were deficiencies in some elements of management oversight in September 1994."[27]

These findings, both internally and by the NRC should have been sufficient to alert FPC management of the need for improvements and changes to meet the minimum standards appropriate for management of a nuclear unit.

Q. ARE THESE PROBLEMS SIMILAR IN ANY WAY TO PROBLEMS AT OTHER NUCLEAR POWER PLANTS IN THE UNITED STATES?

A. Yes. The most prominent case is the ongoing case involving Northeast Utilities and the Millstone nuclear units in which it is widely alleged that an inappropriate emphasis was placed on cost control and production at the expense of safety. The general similarity with regard to one of the suspected root causes is striking. However, the state regulatory authorities in the appropriate jurisdictions have not yet completed their determinations in that case, and it would be premature to conclude that the issues are precisely the same. In addition, the specifics at CR-3 are certainly different.

Q. SHOULD FPC HAVE BECOME AWARE OF THE EXTENT OF THEIR PROBLEMS ANY EARLIER THAN THEY DID?

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[26] *Ibid.*, page 79.

[27] *Ibid.*, page 82.

A. Yes. There were emerging indications of problems as discussed extensively in FPC's internal evaluations. These problems were apparently dealt with narrowly, probably due to what is now viewed by FPC as one of the root causes of their problems, namely management "denial."

Q. DOES THE NATURE OF THE PROBLEMS BEING EXPERIENCED BY FPC ARISE FROM NEW DEVELOPMENTS IN THE NUCLEAR INDUSTRY OR FROM CHANGES IN REGULATIONS?

A. No. As experience in the nuclear industry increases, there are evolutionary changes in the practices and in the interpretation of regulations (including some of the areas that are at issue in this proceeding). Those areas include configuration control and, in particular, keeping records of the current design and the basis for the design of the facility, as well as the required conduct of safety evaluations when changes are made in the design. FPC's practices in these areas did not meet good utility practices or existing nuclear industry practices. The Emergency Feedwater and the Emergency Diesel Generator problems discussed at length elsewhere in my testimony are only one example of this. Keeping track of the current design of the plant and conducting safety evaluations of design changes is and has been a regulatory requirement imposed by the NRC (and codified in the Code of Federal Regulations) and the practice in the nuclear industry since its inception.

III. HISTORY OF THE CURRENT OUTAGE

Q. WHAT WAS THE INITIATING EVENT FOR THE PRESENT OUTAGE?

A. On September 2, 1996, the unit experienced a failure of a pipe in the turbine lubricating oil system. Plant operators had received indications of a problem in the turbine lube oil system a few days earlier when low pressure caused the start of a back up bearing oil pump. On September 2, 1996, operators noticed a decreasing level in the main turbine lube oil reservoir and observed foaming of the oil in the tank. In response to these indications of a serious problem with the turbine lube oil, the unit was removed from service. Inspections the following day found a long crack in a turbine lube oil pipe. Additional inspections revealed a four and one half foot crack in the lube oil pipe and a blown gasket on a flanged pipe joint. Engineers also found a damaged pipe support and one missing pipe support.

Q. DO YOU AGREE WITH THE COMPANY'S DECISION TO REMOVE THE UNIT FROM SERVICE ON SEPTEMBER 2, 1996?

A. Yes. From the indications observed by the Company, it was apparent that a serious problem existed in the turbine lube oil system. Loss of lube oil when a turbine is in operation can cause catastrophic damage to the turbine resulting in a lengthy outage and millions of dollars of damage. I agree with the Company's decision to remove the unit from service. I have reached no conclusion, however, concerning the reasonableness of the Company's maintenance activity in this regard.

Q. IF THE TURBINE LUBE OIL PIPE FAILURE HAD BEEN THE ONLY PROBLEM, WHEN WOULD THE UNIT HAVE RETURNED TO SERVICE?

A. Company witness Mr. Paul McKee states in his testimony that by September 14, the repairs were completed and the tank was cleaned and refilled with oil. Mr. McKee estimates that the unit would have been ready to return to service on approximately September 21, 1996.[28]

Q. WHY WAS THE UNIT KEPT OUT OF SERVICE BEYOND SEPTEMBER 21, 1996?

A. During Refueling Outage 10 in early 1996, the Company had installed a modification in the Emergency Feedwater System designed to resolve concerns with the availability of emergency feedwater during all required accident scenarios and concerns with loading of the A Emergency Diesel Generator. These concerns and the resulting modifications are discussed in detail in the next section of this testimony. Throughout the summer of 1996, the NRC continued to raise questions about the modification and the adequacy of the Emergency Feedwater and Emergency Diesel Generator systems. By early September, the NRC had identified what it considered to be Unreviewed Safety Questions (USQs) with both systems. An Unreviewed Safety Question exists if the probability of occurrence or the consequences of an accident or equipment failure important to safety (as evaluated in the safety analysis report) may be increased or if

[28] Direct Testimony of Mr. Paul F. McKee in FPSC Docket No. 970261-EI, page 45, lines 17 - 22

the potential for an accident different than evaluated in the safety analysis report may be created. A USQ is also created if the margin of safety as defined in the basis for any technical specification is reduced.[29] If a USQ is created, the licensee must receive approval from the NRC by means of a license amendment prior to making the change. Initially, FPC did not agree with the NRC's conclusion that Unreviewed Safety Questions existed but FPC engineers continued to study and analyze the situation.

FPC's actions during this period were described in detail by Mr. Fran Sullivan, FPC Manager of Nuclear Operations Engineering, during his deposition on April 16, 1997. Mr. Sullivan described several days of intense study and review by an engineering task force trying to resolve the USQ issues raised by the NRC. At the end of this period, Mr. Sullivan stated that he requested a "Devil's Advocate" panel to review the conclusions of the group. A Devil's Advocate panel is a group of senior plant personnel assembled to question and challenge the decisions concerning complex technical issues. Mr. Sullivan described a very technical review meeting in which he took nearly three hours to describe the issues in great detail. Following his presentation, he responded to questions from the panel. One questioner asked if there were any other single failures (failures of a single piece of equipment) that he had not considered. At this point Mr. Sullivan described his realization that his group had been so focused on the particular failure scenario under review that they had failed to

[29] Title 10 Code of Federal regulation, Part 50.59 (a)(2).

consider other "single failures." Further analyses over the next few days identified other failures modes that had not been considered. At this point, Mr. Sullivan, the manager in charge of maintaining the design of Crystal River 3 (i.e., the person responsible for keeping the plant in compliance with design requirements), describes his actions as follows:

> So at that point in time, I went and talked to Mr. Boldt and Mr. Beard. I said, "As your design manager, I don't think I can support the startup of the unit," because, basically, at the time my words were, "I don't know where we are."[30]

Maintaining a nuclear power plant in compliance with its design basis, Technical Specifications and other regulatory requirements is one of the fundamental responsibilities of nuclear plant managers. To reach a condition in which "I don't know where we are" with important safety systems is a very serious situation. At this point, FPC management decided that they would keep the unit shut down until these issues could be resolved.

Q. **WHAT IS A SINGLE FAILURE AND WHY IS IDENTIFICATION OF ADDITIONAL SINGLE FAILURES SIGNIFICANT?**

A. Safety analyses of a nuclear power plant are based on event scenarios in which the plant experiences a Loss Of Coolant Accident (LOCA) coincident with a Loss of Offsite Power (LOOP). In addition, the failure of any single active component must be assumed. The plant must be able to withstand a LOOP/LOCA-single failure without

[30] Deposition of Francis X. Sullivan, April 16, 1997, page 129, lines 4 - 8

exceeding the design safety limits. Many different single failures must be evaluated to ensure that the worst-case single failure is identified and properly analyzed. It should be noted that this basis of being able to withstand a postulated accident at the same time that there is a loss of offsite power and a single active failure is a requirement of the NRC and the longstanding practice throughout the nuclear industry. The fact that this combination is, in itself, of very low probability is irrelevant to the design requirement. In this regard, low probability or low risk does not relieve the responsibility of designing to withstand the postulated situation.

Q. FPC STATES THAT THEY DECIDED TO KEEP THE UNIT SHUTDOWN. DID THEY HAVE ANY OTHER CHOICE ONCE THEY DETERMINED THAT THE PLANT DESIGN WAS IN A CONFIGURATION THAT WAS NOT IN COMPLIANCE WITH THE DESIGN BASIS?

A. No, they did not. Once it was decided the plant was not in compliance with its license requirements, FPC had no choice but to keep the plant shutdown until these issues were resolved.

Q. WHEN FPC NOTIFIED THE NRC THAT THEY WOULD NOT BE RESTARTING THE PLANT, WERE THE UNREVIEWED SAFETY QUESTIONS CONCERNING THE EMERGENCY FEEDWATER SYSTEM AND THE EMERGENCY DIESEL GENERATORS THE ONLY ISSUES THAT FPC COMMITTED TO RESOLVE PRIOR TO RESTART?

A. No, there were many issues that required resolution prior to restart. On October 28, 1996, FPC sent a letter to the NRC explaining their decision to keep the unit shutdown and identifying the issues that would be resolved and actions that would be performed prior to restarting the unit. A copy of this letter is included as Exhibit____(WRJ-3). FPC states that:

> Due to the EFW/EDG [Emergency Feedwater/Emergency Diesel Generator] issues, and some other design-related issues, FPC management made a decision to keep CR-3 shut down until these issues are adequately addressed.

Other design margin improvement issues identified by FPC requiring resolution were:

- High Pressure Injection (HPI) Pump Recirculation to the Makeup Tank
- HPI System Modifications to Improve SBLOCA Margins
- LPI [Low Pressure Injection] Pump Mission Time
- Reactor Building Spray Pump 1B NPSH [Net Positive Suction Head]
- Failure MODES and Effects of Loss of DC Power
- Generic Letter 96-06

In addition, FPC committed to establishing an internal "restart panel" similar to an NRC restart panel as describe in NRC Inspection Manual 0350. FPC indicated at in its October 28, 1996 letter that they expected the unit to remain shutdown until at least mid-January, 1997.

Q. SO, IN ADDITION TO THE EFW/EDG ISSUES, SEVERAL OTHER ISSUES WERE IDENTIFIED TO BE CORRECTED BEFORE RESTARTING THE UNIT?

A. That is correct, and the list of required restart items continued to grow as FPC performed its reviews. In fact the full scope of the outage is not known even at the time of this writing.

Q. PLEASE EXPLAIN WHAT YOU MEAN BY THE LIST OF REQUIRED RESTART ITEMS CONTINUED TO GROW.

A. On November 1, 1996, Mr. Stewart D. Ebneter, the NRC Regional Administrator formed an NRC Restart Panel to oversee the restart of Crystal River 3. In this letter to the members of the NRC restart panel, Mr. Ebneter identified a number of concerns with the management of the unit. The letter states in part:

> Since 1994, the staff has observed significant performance concerns at CR3 (e.g., unauthorized makeup tank test, non-conservative trip setpoints, missed surveillances and failure to follow procedures). Poor operator performance was highlighted by the September 1994 unauthorized test of the Makeup Tank (MUT). The staff also performed a root cause analysis of these adverse trends and determined the probable root cause, i.e. lack of management commitment. In response, the FPC initiated a Management Corrective Action Program (MCAP).
>
> FPC's MCAP has not been effective in reversing the declining performance trend. Since its implementation, the staff observed continued notable deficiencies in personnel performance in general, and more specifically in the area of engineering. The engineering issues include, among others, the inaccurate design basis curve for the MUT, service water system design, and persistent control room and Technical Support Center ventilation system issues, poor

> quality of engineering relating to the Steam Generator tube plugging criteria, inadequate assumptions in the emergency operating procedures, inadequate safety evaluations and implementation of modifications which compromised design basis limits. In April 1996, the staff identified five areas of concern: (1) inadequate management oversight and involvement, (2) configuration management and design basis issues, (3) lack of sensitivity to comply with regulations, (4) a marginally effective engineering organization and (5) poor operator performance. In July 1996, an IPAP [Integrated Performance Assessment Process] and SSFI [Safety System Functional Inspection] also confirmed the staff's concerns.

The NRC Restart panel met on November 13, 1996 and developed seven general areas under which restart issues would be grouped. These areas are:

1. Knowledge of design and licensing bases and adequacy of design margin
2. Regulatory knowledge and perspective
3. Operator performance and knowledge
4. Marginally effective engineering organization
5. Management oversight; including quality assurance, self assessment and corrective action
6. Corrective actions for NRC violations
7. Other

Under these seven general areas, the NRC developed an Issues Checklist that contained more than 150 individual items that required resolution before restart.

Q. DID FPC ALSO DEVELOP A LIST OF ACTIONS AND ISSUES REQUIRING RESOLUTION PRIOR TO RESTART?

A. Yes. On December 3, 1996, Mr. Beard established the Crystal River Unit 3 Restart Panel and initiated a program to identify required restart items and track them to completion. The FPC Restart Panel document contained a Restart Review List that identifies many areas to be analyzed for restart issues. The Restart Review List areas included 33 areas for review as shown below:

- Open precursor cards and problem reports
- Open NRC items:
  - Violations
  - Unresolved items (URI's)
  - Inspector follow-up items (IFI's)
- NRC Minutes of Crystal River Restart Panel First Meeting, November 13, 1996 - Attachment B, Crystal River 3 Issues Checklist
- IPAP action list and proposed violations
- Requests for engineering assistance (REA's)
- Independent design review panel (IDRP) action list
- Management corrective action plan (MCAP II) action list
- Maintenance items
- Key focus Item list
- Open PRC/NGRC issues
- Licensee event reports (LER's)
- NRC commitments (NOCS)
- B&W [Babcock & Wilcox] generic issues:
  - Decay heat dropline
  - LOCA [Loss of Coolant Accident] induced mechanical fuel loading
  - OTSG [Once Through Steam Generator] primary/secondary coupling - EFP [Emergency Feed Pump] steam supply
  - OTSG tube primary boundary integrity
  - RCP [Reactor Coolant Pump] bumping - recriticality
  - Wolf Creek sticking control rod applicability
  - Groove IGA [Inter-Granular Attack] applicability
- Surveillance procedure - status to operate until Refuel 11
- Organizational and Programmatic (O&P) issues:
  - Corrective action program
  - Root cause evaluation program
  - 10CFR50.59 evaluation program

- Design basis program
- Engineering calculation process
- FSAR review program
- OP/EOP/AP/SP changes [Operating Procedure/Emergency Operating Procedure/Abnormal Procedure/Surveillance Procedure]
- Amendments required:
    - Unresolved safety questions (USQ's)
    - Technical specification changes
    - License conditions
- Restart procedure (AI-256) completion

This is obviously an enormous list of areas to be reviewed, including many of the fundamental programs that are needed to ensure safe plant operation such as the Organizational and Programmatic issues. FPC continued to meet with the NRC to develop an agreed on list of issues to be resolved and actions required before restart. As of January 13, 1997, the NRC's Crystal River 3 Issues Checklist of items to be inspected by the NRC before restart had grown to nearly 200 items. It is clear that by December 1996, the scope of the outage had grown from resolution of items concerning the EFW/EDG issues, or the original 8 issues identified by FPC on October 28, 1996 to a massive review of essentially all aspects of FPC's operation of the Crystal River plant.

Q. WHY DID THE SCOPE OF THE OUTAGE GROW FROM RESOLUTION OF A RELATIVELY SMALL NUMBER OF TECHNICAL CONCERNS TO A MASSIVE REVIEW OF FPC'S NUCLEAR OPERATION?

A. I believe that the scope of the outage increased so dramatically because the NRC had serious concerns about FPC's ability to safely manage the plant. As previously discussed, the NRC had expressed concerns about FPC's management for several years. When it was discovered that FPC had restarted the unit following refueling outage 10 with the plant in violation of its design basis, the NRC decided that it was time to require a comprehensive evaluation of all aspects of FPC's management and formed a Restart Panel for this purpose. So the scope of the outage grew from a relatively few technical items to a comprehensive review of FPC's nuclear operation because of NRC concerns resulting from poor management performance for several years prior to the outage.

Q. WHAT IS THE SIGNIFICANCE OF THE FORMATION OF THE NRC RESTART PANEL?

A. An NRC Restart Panel is formed according to the NRC Inspection Manual for the purpose of establishing guidelines "for approving restart of a nuclear power plant after a voluntary or involuntary shutdown as a result of a significant event, complex hardware problem, or serious management deficiency."[31] The manual further states that:

> This manual chapter shall be followed when a power reactor licensee plans to restart the reactor after the plant has been shut down for one or more of the following reasons:
>
> - Serious NRC questions about licensee management effectiveness.

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[31] NRC Inspection Manual, Chapter 0350, "Staff Guidelines for Restart Approval," Section 0350-01.

- Identification of a complex hardware problem or a degradation of a structure, system, or component to the extent that it may not perform its intended safety function and requires comprehensive NRC evaluation before restart.

- A significant event, such as the one that fits the characteristics described in Inspection Manual Chapter 0325, "Augmented Inspection Teams," or a significant operational event that meets the description in NRC Management Directive 8.3, "NRC Incident Investigation Program."

- Possible damage to offsite support systems such as offsite power or emergency response capability as a result of a natural disaster, explosion, riot, or event with similar consequences.[32]

The first two items of the above list are clearly applicable to CR-3. Further, the manual goes on to state explicitly that:

> A licensed commercial nuclear power plant may be shut down, voluntarily or involuntarily, for a variety of reasons. When a plant is shut down for reasons stemming from license conditions or technical specifications, the licensee **normally** can develop a clearly defined corrective action plan and the plant restarts without special approval from the NRC. However, plants occasionally are shut down as **a result of safety concerns resulting from a significant event, complex hardware problem, or serious management deficiency. This manual chapter addresses these latter cases**. [emphasis added][33]

In other words, formation of a Restart Panel in accordance with this portion of the NRC Inspection Manual is <u>not</u> a routine matter, but a very serious situation requiring special extra attention from the NRC. A copy of this section of the NRC Inspection Manual

[32] *Ibid.*, Section 0350-03.

[33] *Ibid.*, Section 0350-05.

is attached to this testimony as Exhibit____(WRJ-4). It should also be noted that the appendix to the manual section contains a substantial generic restart checklist.

Q. IS NRC APPROVAL REQUIRED PRIOR TO RESTARTING CRYSTAL RIVER UNIT 3?

A. Yes, it is. On March 4, 1997, the NRC issued a Confirmatory Action Letter (CAL) detailing the requirements for FPC's restart of Crystal River Unit 3. In this letter, the NRC summarized FPC's planned corrective actions to address deficiencies in the engineering program and to assure FPC's readiness to restart the unit including:

1. Completion of a comprehensive restructuring of management;
2. Completion of in-depth reviews and corrective actions to ensure compliance with the licensing and design bases of the facility and,
3. Implementation of broad and in-depth engineering program changes.

A list of five specific actions was identified to be completed prior to restart. These five actions are:

1. Resolve the eight design issues delineated in FPC's letter of October 28, 1996;
2. Conduct extent of condition reviews to assure that safety-related systems are in compliance with the licensing and design bases of the facility;
3. Satisfactorily resolve any additional safety or licensing questions including those identified as a result of system and engineering reviews in item 2 above;

4. Meet with the NRC to discuss FPC's acceptance criteria for and achievement of satisfactory progress on the actions described in FPC's management Corrective Action Plan (MCAP), Phase II forwarded by FPC's letter of November 12, 1996;

5. Obtain concurrence in writing from the NRC Region II Regional Administrator prior to entering Mode 2 (meaning that the reactor is critical at low power -- one of the final steps before resuming power operations).

Q. WHAT IS THE PRESENT STATUS OF THE PLANT?

A. At this writing, the unit remains shutdown and FPC continues to work to resolve the many issues identified in the restart plan and to perform the required actions. The Company continues to review the status of safety related systems as required by the NRC.

Q. WHAT IS MEANT BY THE TERM "CRITICAL PATH" OF AN OUTAGE?

A. The term Critical Path of an Outage is commonly used terminology that refers to that sequence of events that determine the shortest possible duration of an outage. It is that sequence of tasks or activities that controls the duration of the outage. All other required tasks can be completed before completion of the critical path activities.

Q. WHAT IS THE CRITICAL PATH FOR THE PRESENT CRYSTAL RIVER 3 OUTAGE?

A. It is impossible to know the actual critical path of an outage until the outage is completed. For that reason, I cannot determine the critical path of the outage at this time. The Company states that the critical path is controlled by the Emergency

Feedwater and Emergency Diesel modifications.[34] They further state that the Company's response to the NRC's concerns is not expected to lengthen the shutdown.[35]

Q. DO YOU AGREE WITH THE COMPANY'S ASSESSMENT OF THE OUTAGE CRITICAL PATH?

A. No, I do not. First, as stated above, the actual critical path of the outage will not be known until the outage is completed. In addition, at this time, the Company continues to investigate issues and evaluate system readiness. In his deposition on April 16, 1997, Mr. Sullivan explained that several new issues are still under investigation. Concerning the current outage schedule Mr. Sullivan stated:[36]

> From my perspective on the modifications, it's pretty solid. We've got -- the major issues we're dealing with, the ones we've been talking about, I think we're very solid there. We are also in the process of looking elsewhere for other problems. We call this "extending condition." We are getting some new issues there that we just -- you know, we haven't had a chance to really put our arms around. So it's as solid as it could be considering that we're still looking for problems

Until all of the issues are known and identified, it is impossible to even make a reasonable estimate of the outage critical path. Also, as explained above, the NRC must approve of the corrective actions and resolution of issues by FPC. While the

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[34] Deposition of Mr. P. M. Beard, Jr., dated April 22, 1997, page 108, lines 16 - 20.

[35] FPC Preliminary Report on the Current Outage at Crystal River Unit 3, dated March 19, 1997, page 4.

[36] Deposition of Francis X. Sullivan, April 16, 1997, page 136, lines 1 - 10.

NRC will attempt to not delay the start up of the plant, neither will they be rushed in their review of FPC's actions. The nuclear industry has found on many occasions that receiving NRC approval can take longer than planned. Finally, I find the Company's assertions that resolution of the vast number of regulatory issues will have no impact on the outage unreasonable. Resolving these issues will demand extensive attention of utility management and staff. The subsequent startup will be much more involved than a normal plant startup. For example, the Company's Crystal River 3 Restart Plan provided in Appendix H of their preliminary report (and included in this testimony as Exhibit____(WRJ-5) for ease of reference) shows approximately five months of an activity described as System Lineups, Heatup and Testing. This activity should take at most one week to 10 days during a normal startup following a refueling outage. The five months shown by FPC is a clear indication of the impact of the regulatory proceedings on the duration of the outage.

Q. DID MR. BEARD ALSO ADDRESS THE OUTAGE CRITICAL PATH?

A. Yes, Mr. Beard addressed the outage critical path in his deposition on April 22, 1997. Mr. Beard reviewed Appendix H to the Company's Preliminary Report on the CR-3 outage. This Appendix is entitled "Critical Path Timeline Chart." Mr. Beard stated that he would need to depend on his knowledge about the outage to determine the critical path from this document.[37] Mr. Beard agreed that non-critical path activities and

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[37] Deposition of Mr. P. M. Beard, Jr., dated April 22, 1997, page 108, lines 6 - 13.

activities currently unknown could become critical path activities as the outage progressed. For example, he stated that the activity "Install R.B. Penetration MAR" could become a critical path item.[38]

Q. WHAT DO YOU CONCLUDE FROM MR. BEARD'S COMMENTS CONCERNING THE CRITICAL PATH OF THE CURRENT OUTAGE?

A. Mr. Beard's comments supported my belief that the actual critical path is not known at this time. Some other identified or, as yet, unidentified items may become the critical path during the outage. Other issues are being investigated that could impact the critical path. Mr. Beard also stated that the Company believed that the NRC Reviews would not delay startup. He further agreed, however, that the actions of the NRC are beyond control of the Company.[39]

IV. THE EMERGENCY FEEDWATER SYSTEM MODIFICATIONS

Q. PLEASE BRIEFLY DESCRIBE THE CIRCUMSTANCES THAT LED TO FPC'S DISCOVERY IN 1996 THAT CRYSTAL RIVER 3 WAS NOT IN COMPLIANCE WITH ITS DESIGN BASIS OR LICENSING REQUIREMENTS.

[38] Deposition of Mr. P. M. Beard, Jr., dated April 22, 1997, page 109, lines 12 - 18.

[39] Deposition of Mr. P. M. Beard, Jr., dated April 22, 1997, page 115, lines 3 - 6.

A. This is a rather lengthy series of events and decisions made by FPC that began with the Three Mile Island (TMI) accident in 1979. It involves a series of modifications made by FPC to compensate for increased loading on the A Emergency Diesel Generator (A EDG) that ultimately resulted in the present condition. I will describe the sequence of events very briefly and then I will discuss each modification in more detail.

In 1987, FPC made a modification designed to increase the margin in the A EDG, i.e., the rated electrical capacity of the generator versus emergency load. FPC made another modification in 1990 to further improve EDG margin. In 1996, they discovered that the 1987 modification resulted in the possibly of making both Emergency Feedwater Pumps inoperable so, during Refueling Outage 10, they reversed the 1987 modification. Unfortunately, FPC forgot or did not consider that the 1990 modification depended on the 1987 modification. The 1996 reversal of the 1987 modification resulted in a plant configuration in which the capability to cool the plant down at all times could not be assured. At this time, they are reinstating the 1987 modification along with some other modifications to fully resolve the problems.

Q. DID YOU DISCOVER A DOCUMENT THAT PROVIDES A BRIEF DESCRIPTION OF THE MANY CHANGES TO THE EMERGENCY FEEDWATER SYSTEM?

A. Yes. Attachment 4 to FPC's Root Cause Report RC96-059 entitled Historical Description of EFW System Changes provides a concise narrative describing the many changes to the EFW system. A copy of this report is provided as Exhibit____(WRJ-6).

This document briefly describes 9 different configurations of the EFW system since 1980. In addition a tenth configuration is being installed during the current outage. This historical description also contains an interesting observation. The document states:

> An observation which can be made from review of the various changes to the EFW system since 1980, is that **the majority (7 of 9) of the configurations introduced one or more problems or missed an opportunity to identify and resolve previous problems.** Several attempts to improve upon a weak design have not resolved certain long-standing issues. (emphasis added)

This is a rather amazing finding. Of the 9 changes to the EFW system since 1980, 7 either introduced more problems or missed an opportunity to identify and resolve previous problems. This observation by FPC provides an excellent example of the deficient modification activities at CR-3 that ultimately led to the current shutdown.

Q. PLEASE EXPLAIN HOW THIS SEQUENCE OF EVENTS WAS INITIATED BY THE THREE MILE ISLAND ACCIDENT.

A. Following the Three Mile Island accident in 1979, the nuclear industry realized that safety analyses in use at that time did not adequately cover the full spectrum of possible break sizes that would result in a loss of coolant accident (LOCA). Additional safety analyses demonstrated that emergency feedwater would be required to deal with some small-break LOCAs. The NRC issued a document, NUREG-0737, that contained actions that utilities were required to take to implement lessons learned from TMI. Some of these actions involved assurance of the availability of emergency feedwater.

electrical load of EFP-1 on the A EDG. Essentially, one of the valves that opened to provide steam to the EFP-2 turbine was changed from a B train valve to an A train valve. This valve is called ASV-204. This ensured that EFP-2 would be operating when either an A train signal or a B train signal called for emergency feedwater to be in operation. Thus, EFP-2 could be relied upon to provide some of the required EFW flow and the load on EFP-1 and A EDG would be reduced.

Q. DID THIS MODIFICATION INTRODUCE A POTENTIAL PROBLEM AT CRYSTAL RIVER 3?

A. Yes it did. Under certain conditions, namely failure of the B train battery, the flow control valves for EFP-2 would fail in the open position. This would result in EFP-2 operating at full flow along with EFP-1 also operating at relatively high flow rates as these pumps attempted to fill the steam generators.

Q. WHY IS THIS A PROBLEM?

A. Centrifugal pumps require a certain minimum pressure at their suction to ensure that the pumps do not cavitate. Cavitation occurs when the suction pressure, called the Net Positive Suction Head (NPSH) is too low and steam bubbles form in the impeller of the pump. Excessive flow due to both pumps running at high flow rates could result in the available NPSH being lower than the required NPSH and one or both pumps could be damaged due to cavitation.

Q. PLEASE BRIEFLY DESCRIBE THE RULES GOVERNING MODIFICATIONS TO A NUCLEAR POWER PLANT.

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Q. BEFORE GOING ANY FURTHER, PLEASE BRIEFLY DESCRIBE THE EMERGENCY FEEDWATER SYSTEM AT CRYSTAL RIVER 3.

A. Crystal River 3 has two Emergency Feedwater Pumps. One is driven by a motor and one is driven by a small steam turbine. The motor driven pump, called A Emergency Feedwater Pump (EFP) or EFP-1, is controlled and powered from the A train. Nuclear plants have two trains of emergency power and control, usually designated as the A and B trains. At the time of the TMI accident, EFP-1 was powered from the A safety train and could be connected to the A EDG if offsite power was lost. In 1979, this connection would be initiated manually by a plant operator. As a result of TMI, NUREG-0737 required that the connection of EFP-1 to the A EDG be made automatically, so FPC implemented a modification to automatically connect or load EFP-1 to A EDG in the early 1980's.

Q. DID THIS CREATE A PROBLEM?

A. After this modification in the early 1980's, the plant was still within its design basis but the automatic loading of the EFP-1 electrical load reduced the margin available for the A EDG and created an additional burden on the operator. This modification, in some circumstances, resulted in loading the EDG into a high load range in which the EDG could only operate for 30 minutes.

Q. WAS THE NRC CONCERNED ABOUT THIS SITUATION?

A. Yes. In his deposition, Mr. Paul McKee described how the NRC continued to press FPC to take steps to increase the EDG margin and decrease the burden on the operator.[40]

Q. WHAT DID FPC DO IN RESPONSE TO THE NRC'S CONCERNS?

A. FPC evaluated many options including installation of additional diesel generators and ultimately decided to implement the modification that was installed in 1987 to increase the EDG margin and reduce operator burden.

Q. PRIOR TO INSTALLATION OF THE 1987 MODIFICATION, DID THE EDG AND EMERGENCY FEEDWATER SYSTEM MEET THE DESIGN BASIS AND LICENSING REQUIREMENTS?

A. Yes, they did.

THE 1987 MODIFICATION

Q. PLEASE DESCRIBE THE MODIFICATION THAT WAS INSTALLED IN 1987.

A. The modification[41] installed in 1987 involved utilizing the turbine driven emergency feedwater pump, EFP-2, to share the hydraulic load on EFP-1 and thus reduce the

[40] Deposition of Mr. Paul F. McKee dated April 16, 1997 page 19, line 21 through page 20, line 21.

[41] Installed as a temporary modification in 1987 and changed to a permanent modification in March 1992.

A. NRC regulations contained in the Code of Federal Regulations, 10CFR50.59, require that operators of nuclear power plants perform safety analyses on modifications installed in their plants. In nuclear terminology these are called 50.59 evaluations. These evaluations should identify and analyze all possible safety hazards or failure modes that could result from a modification. If the modification results in increased risk or consequences of an accident, then the NRC must review the modification prior to installation.

Q. IN PERFORMING THE 50.59 EVALUATION FOR THE 1987 MODIFICATION TO THE EMERGENCY FEEDWATER SYSTEM, DID FPC IDENTIFY THE POTENTIAL CAVITATION PROBLEM AND HAVE IT REVIEWED BY THE NRC PRIOR TO INSTALLATION OF THE MODIFICATION?

A. I have reviewed the 50.59 evaluation for the 1987 modification and found no evidence that FPC considered the potential for cavitation in their safety analysis. They also did not submit this modification to the NRC for review as required by the regulations. The NRC also reached this conclusion as stated in NRC Inspection Report No. 50-302/96-19 which states:

> The inspectors noted that the 50.59 safety evaluations for the TMAR [Temporary Modification Action Request] and MAR did not address the potential hydraulic effects of this modification. Further, the inspectors concluded that the TMAR and MAR did increase the probability of malfunction of equipment important to safety (damage to EFP-2 due to insufficient NPSH) and thus introduced a potential USQ. In the event scenario that prompted

> PC 96-2197 and MAR 96-04-12-01, the plant design basis relied upon EFP-2 to share the EFW flow with EFP-1 in order to maintain the EDG within its loading limits. The 50.59 safety evaluations for TMAR T87-10-09-01 and MAR 87-10-09-01A were inadequate in that they failed to identify this potential USQ and the modification was installed without the required prior NRC review.[42]

Q. DID MR. BEARD EXPRESS AN OPINION ON THE FAILURE OF THE 50.59 EVALUATION FOR THE 1987 MODIFICATION TO ADDRESS THE POSSIBILITY OF PUMP CAVITATION?

A. Yes he did. Mr. Beard opined that the issue of pump cavitation might have been considered but the consideration was not recorded formally in the 50.59 evaluation.[43]

Q. WHEN QUESTIONED, WHERE DID MR. BEARD SAY THAT HE WOULD EXPECT TO FIND A DISCUSSION OF THE CAVITATION ISSUE IF HAD BEEN CONSIDERED?

A. Mr. Beard expressed his opinion that the cavitation issue would likely be discussed in the Modification Action Request (MAR) if it had been considered.[44]

Q. DID YOU REVIEW THE MAR FOR THE 1987 MODIFICATION?

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[42] NRC Inspection Report No. 50-302/96-19 dated January 7, 1997, page 6.

[43] Deposition of Mr. P. M. Beard, Jr., dated April 22, 1997, page 74, lines 6 - 9.

[44] Deposition of Mr. P. M. Beard, Jr., dated April 22, 1997, page 75, line 18 through page 76, line 4.

A. Yes, I reviewed the MAR for the 1987 modification and found no indication that cavitation of the emergency feedwater pumps had been considered. A copy of the MAR is provided as Exhibit ____(WRJ-7).

Q. **DID MR. BEARD EXPRESS AN OPINION ON THE INSTALLATION OF THE 1987 MODIFICATION IF THE POSSIBILITY OF PUMP CAVITATION HAD BEEN IDENTIFIED?**

A. Yes. Mr. Beard was asked if he would have approved installation of the modification if the possibility of cavitation had been identified and he responded that he would not have approved installation of this modification if the possibility of cavitation had been known.[45]

Q. **DID THE INSTALLATION OF THE 1987 MODIFICATION RESULT IN AN UNANALYZED CONDITION?**

A. Yes. In Licensee Event Report (LER) 97-001-00 revealingly entitled "Ineffective Change Management Results in Unrecognized NPSH Issue Affecting Emergency Feedwater Availability," FPC states that as a result of the modification that was installed in December 1987 (when ASV-204 was powered and received its open signal from the A train) until this signal was removed in May, 1996, during Refueling Outage 10, "CR-3 was in an unanalyzed condition which could render EFW incapable of

[45] Deposition of Mr. P. M. Beard, Jr., dated April 22, 1997, page 81, lines 1 - 2.

fulfilling its intended safety and accident mitigation functions."[46] This is clearly an unanalyzed condition and an unreviewed safety question that should have been reported to the NRC. LER 97-001-00 is included as Exhibit___(WRJ-8).

Q. IN YOUR OPINION, WITHOUT BENEFIT OF HINDSIGHT, SHOULD THE COMPANY HAVE IDENTIFIED AND EVALUATED THE POTENTIAL NPSH AND CAVITATION PROBLEM PRIOR TO INSTALLATION OF THE 1987 MODIFICATION?

A. Yes, they should have. Conduct of an adequate 50.59 evaluation would have identified the cavitation problem. Determination of adequate NPSH in all possible configurations is a fundamental principal in the hydraulic design of fluid systems. A fluid system designer must ask himself if the system provides adequate NPSH under all relevant conditions. In the case of safety related systems in a nuclear power plant, all single failures must be considered when analyzing the possible system configurations. In addition, if this modification had been submitted to the NRC for review as required by regulations, I believe that the NRC would have identified a concern with pump NPSH and cavitation in 1987, just as they did in 1996. In summary, I believe that FPC should have identified this problem in 1987.

[46] Crystal River 3 LER 97-001-00, page 2 of 8.

Q. IF THIS PROBLEM HAD BEEN IDENTIFIED PRIOR TO INSTALLATION OF THE 1987 MODIFICATION, WHAT WOULD BE THE IMPACT ON THE PRESENT OUTAGE?

A. If FPC had done a complete analysis of the potential hydraulic affects of the modification or had done an adequate 50.59 evaluation for the 1987 modification and identified the potential cavitation problem, the modification would not have been installed. FPC would either have selected another option for meeting their goals of increasing EDG margin and reducing operator burden, or the 1987 modification would have been changed to include the installation of flow limiting devices such as the cavitating venturis that FPC is installing during this outage to eliminate the cavitation problem. In either case, the present outage would not have been required to install the EFW and EDG modifications.

THE 1990 MODIFICATION

Q. PLEASE DESCRIBE THE MODIFICATION THAT WAS INSTALLED IN 1990.

A In 1990, in an effort to increase A EDG margin, FPC installed another modification. This modification was based on FPC's determination that analyses showed that because the 1987 modification would have EFP-2 in operation, it was not necessary to have both EFP-1 and the A Low Pressure Injection (LPI) pump, both powered by the A EDG, in operation at the same time. In order to reduce the electrical load on the A

EDG, the modification was installed to trip EFP-1 when reactor coolant pressure reached 500 psig (pounds per square inch gauge), the point at which the A LPI was automatically started. This modification relied on EFP-2 being in operation to provide cooling from 500 psig to approximately 185 psig at which point the LPI would be capable of injecting cooling water into the reactor coolant system.

Q. DID THIS MODIFICATION CREATE A PROBLEM?

A. This modification did not create a problem in 1990. However, a subsequent modification in 1996 made it a problem.

THE 1996 MODIFICATION

Q. PLEASE DESCRIBE THE 1996 MODIFICATION AND THE CIRCUMSTANCES SURROUNDING ITS IMPLEMENTATION.

A. In April 1996, as a result of ongoing procedure reviews, FPC engineers identified a concern with operation of EFP-2 at high flow rates that could exceed the NPSH limits. This situation would result from the loss of the B battery as previously described. FPC responded by initiation of MAR 96-04-12-01 that would essentiall; reverse the 1987 modification and remove the automatic opening of ASV-204 by an A train signal. This resolved the cavitation (or NPSH) problem because, with the reversal of the 1987 modification, EFP-2 would not start if the B battery was lost. However, reversal of the 1987 modification created other problems.

Q. WHAT PROBLEMS WERE CREAT"D BY THE 1996 MODIFICATION?

A. Unfortunately, FPC forgot, or did not recognize, that the modification installed in 1990 relied on operation of EFP-2 under all conditions. The A EDG Loading Evaluation supporting the 1990 modification assumed that EFP-2 was operating and would continue to operate after EFP-1 was tripped.[47] This is important because, if EFP-1 is tripped at 500 psig (as it was following the 1990 modification), no automatic means of cooling is available until the LPI pump begins injecting at 185 psig -- unless EFP-2 is in operation. If EFP-2 is not in operation, then the plant is without a source of cooling from 500 psig to 185 psig and is in an unanalyzed and unanticipated condition.

Q. FOLLOWING INSTALLATION OF THE 1996 MODIFICATION WAS THE PLANT RETURNED TO SERVICE?

A. Yes, the plant returned to service on May 17, 1996 following completion of Refueling Outage 10 and operated until the turbine lube oil line rupture on September 2, 1996.

Q. WAS CRYSTAL RIVER 3 OPERATING OUTSIDE ITS DESIGN BASIS FROM MAY 17, 1996 UNTIL IT WAS TAKEN OUT OF SERVICE ON SEPTEMBER 2, 1996?

A. That is correct. I believe that this is the event that resulted in the NRC concluding that the problems at CR-3 were so severe that a restart panel was required to determine if FPC management could safely operate the plant. This was the straw that broke the camel's back.

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[47] NRC Inspection Report No. 50-302/96-19 dated January 7, 1997, page 7.

V. CONCLUSIONS AND RECOMMENDATIONS

Q. PLEASE SUMMARIZE THE CURRENT OUTAGE.

A. The outage began on September 2, 1996 with the rupture of a turbine lube oil pipe. If this had been the only problem, the unit could have been returned to service in approximately three weeks. However, while the unit was down, the Company's analysis of several issues raised by the NRC identified that the plant had been operating out of compliance with its design basis and licensing requirements. By early October, the Company concluded it had significant problems and that the unit would be shutdown for an extended period. Given the serious and pervasive nature of the present problems the Company decided to form a restart panel to perform a comprehensive evaluation of the Company's readiness to return the plant to service. The Company developed a comprehensive list of issues to be resolved prior to restart. This list eventually grew to more than 200 items. At this time, the Company continues to investigate and evaluate issues and cannot predict definitively when the unit will be restarted.

Q. MR. BEARD STATED IN HIS TESTIMONY THAT IF THE COMPANY HAD CONCLUDED AT ANY TIME PRIOR TO OCTOBER 1996 THAT IT WOULD BE NECESSARY TO MAKE THE MODIFICATIONS NOW IN PROGRESS, THEN THIS WOULD HAVE REQUIRED THE SAME KIND OF OUTAGE AS

THE ONE NOW IN PROGRESS.[48] MR. BEARD FURTHER STATED IN HIS TESTIMONY THAT THERE WAS NO PRACTICAL WAY THAT THIS OUTAGE COULD HAVE BEEN AVOIDED.[49] DO YOU AGREE WITH MR. BEARD'S ASSERTIONS REGARDING THIS OUTAGE?

A. No I do not. This outage was clearly avoidable. If the Company had performed an adequate analysis and safety evaluation prior to the 1987 modification, using good engineering practices, and submitted the modification to the NRC for review as required by NRC regulations, I believe that the cavitation problem would have been identified, just as it was in 1996 when the Company and the NRC reviewed the modifications in detail. In 1987, before the modification, the plant was in compliance with its design basis and licensing requirements. It was not under a 72 hour time limit to resolve the problem. If the cavitation problem had been identified during development of the ASV-204 modification, the Company could have chosen another alternative to add additional margin to A EDG and lessen operator burden due to diesel loading. This alternative could have been implemented during subsequent refueling outages with little to no impact to plant availability. This conclusion is based on what the Company knew and should have known at the time of the 1987 modification without the benefit of hindsight.

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48 Testimony of P.M. Beard, FPSC Docket No. 970261-E1, page 23, lines 1 - 9 .

49 Testimony of P.M. Beard, FPSC Docket No. 970261-E1, page 25, lines 12 - 15.

Q. IN ITS PRELIMINARY REPORT ON THE CRYSTAL RIVER 3 OUTAGE SUBMITTED TO THE COMMISSION ON MARCH 19, 1997, THE COMPANY STATES THAT "THE COMPANY'S RESPONSE TO THE NRC'S CONCERNS IS NOT EXPECTED TO LENGTHEN THE SHUTDOWN."[50] DO YOU BELIEVE THIS STATEMENT BY THE COMPANY?

A. No, I do not. It is not reasonable to believe that the addition of some 200 issues requiring resolution and the need for NRC review and approval prior to startup will not lengthen this outage. The actual critical path of the outage will not be known until the outage is over. However, I believe that a review of the outage critical path when the outage is over will reveal a significant impact caused by the effort and time needed to resolve the issues required for restart.

Q. WHAT DO YOU BELIEVE TO BE THE ROOT CAUSES OF THE CURRENT CONDITION OF CRYSTAL RIVER 3?

A. The current outage is the result of long-standing deficiencies in FPC's operation and management of Crystal River 3. These deficiencies led to the current condition in which the unit is shut down due to a series of inadequately analyzed modifications installed without the required approval of the NRC that ultimately resulted in the unit not being in compliance with its design basis or licensing requirements. I believe that

[50] Florida Power Corporation's Preliminary Report on the Current Outage at Crystal River Unit 3 dated March 19, 1997, page 4.

FPC did a good job of identifying the root causes of these deficiencies in the MCAP Phase II corrective action plan. In particular, the four fundamental root causes identified by the special subcommittee of the Nuclear General Review Committee are particularly relevant. These four root causes are:[51]

- Focusing more intensely on cost and production than safety;
- Management not listening to or acting upon information available to them;
- A strong sense of denial with regard to performance;
- A family organizational culture rather than a self-critical team.

These four fundamental causes contributed strongly to the decline in regulatory performance and the inadequate engineering performance that led to the current condition of Crystal River 3.

Q. WHAT WAS THE ROOT CAUSE OF THE DEFICIENCIES WITHIN FPC'S ENGINEERING ORGANIZATION AT CRYSTAL RIVER 3?

A. Again, I believe that the MCAP Phase II identified the appropriate root cause. The MCAP report with regard to engineering performance states:

> An appropriate safety culture was not effectively emphasized. As a result, activities were not given a level of safety attention commensurate with that given to production or cost priorities. This led to design basis concerns being primarily resolved through analytical means in lieu of physical means (such as plant

[51] FPC Management Corrective Action Plan Phase II dated November 22, 1996, page 2.

modifications and equipment testing) directed at maintaining or improving design margins.

Q. DOES YOUR TESTIMONY PRESENT THE RESULTS OF A COMPLETE AND COMPREHENSIVE EVALUATION OF THE CRYSTAL RIVER 3 OUTAGE?

A. I would characterize my investigation of the CR-3 outage as preliminary for several reasons. First, the outage is still in progress. FPC personnel have stated that they are still evaluating new issues that have been identified. The full impact and the relevant facts concerning the outage cannot be known until the outage is over. Second, the time period available for my investigation was not sufficient to conduct what I would call a complete and comprehensive evaluation. The Company provided partial responses to one round of document requests made up of some 179 documents in 9 boxes. These were received less than two weeks prior to the submittal date for testimony. (Responses to the first set of interrogatories were received as this testimony was being finalized.) The first round of discovery responses is usually just a starting point for doing a comprehensive investigation and analysis of an outage. I believe that the Company's Preliminary Report, the Company's testimony, the discovery documents provided, the deposition of Company personnel, the relevant regulatory documents and my experience allow me to reach valid preliminary conclusions concerning this outage. However, given the length of the outage and the large financial burden that will be placed on the ratepayer if the Company's position is adopted, I believe that a full and complete investigation should be performed following completion of the outage.

Q. WHO SHOULD BEAR THE FINANCIAL BURDEN RESULTING FROM THE CURRENT OUTAGE?

A. In my opinion, this outage is the result of consistently poor management of the unit by FPC, particularly in the area of engineering and design. I believe that this outage could and should have been avoided if the Company had followed good engineering practices and complied with regulatory requirements, based on what it knew or should have known, concerning the modifications to the emergency feedwater system. Therefore, the Company should bear the financial costs associated with this outage.

Q. WHAT ACTION DO YOU RECOMMEND THAT THE COMMISSION SHOULD TAKE AT THIS TIME BASED ON YOUR PRELIMINARY REVIEW OF THE CRYSTAL RIVER 3 OUTAGE?

A. My recommendations for consideration by the Commission are as follows:

1. I recommend that the Commission preclude the Company from collecting any funds as a result of increased fuel costs due to the current outage until a comprehensive and thorough investigation of the outage has been completed and it has been determined whether the company should be allowed to recover such increased fuel costs.

2. At the conclusion of the outage, after the unit has been returned to service, I recommend that the Commission conduct a full and comprehensive

investigation of the causes and impact of the outage using all available and relevant information.

3. Finally I recommend that the Commission establish a procedural schedule for the comprehensive investigation that allows sufficient time for full discovery and a thorough investigation and analysis of the many complex technical issues related to this outage.

Q. DOES THAT CONCLUDE YOUR TESTIMONY?

A. Yes, it does.

CERTIFICATE OF SERVICE
DOCKET NO. 970261-EI

I HEREBY CERTIFY that a true and correct copy of the foregoing DIRECT TESTIMONY OF WILLIAM R. JACOBS, JR., Ph.D., and EXHIBITS OF WILLIAM R. JACOBS, JR., Ph.D, have been furnished by *Hand-delivery **Federal Express Delivery or by U.S. Mail to the following parties on this 28th day of April, 1997.

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Before the

Florida Public Service Commission

Docket No. 970261-EI

PRELIMINARY
CRYSTAL RIVER UNIT 3 OUTAGE REVIEW

Exhibits of

WILLIAM R. JACOBS, JR., Ph.D.

On Behalf of
THE FLORIDA OFFICE OF PUBLIC COUNSEL

April 28, 1997

Before the

Florida Public Service Commission

Docket No. 970261-EI

PRELIMINARY
CRYSTAL RIVER UNIT 3 OUTAGE REVIEW

Exhibits of

WILLIAM R. JACOBS, JR., Ph.D.

On Behalf of
THE FLORIDA OFFICE OF PUBLIC COUNSEL

April 28, 1997

LIST OF EXHIBITS

Exhibit WRJ - 1	Resume of William R. Jacobs, Jr., Ph.D.
Exhibit WRJ - 2	Excerpts from the Management Corrective Action Program Phase II
Exhibit WRJ - 3	FPC letter to NRC dated October 28, 1996
Exhibit WRJ - 4	NRC Inspection Manual
Exhibit WRJ - 5	Critical Path Timeline Chart - Crystal River Unit 3 Restart Plan
Exhibit WRJ - 6	Historical Description of EFW System Changes
Exhibit WRJ - 7	Modification Action Request (MAR) for 1987 ASV-204 Modification
Exhibit WRJ - 8	Licensee Event Report 97-001-00, Ineffective Change Management Results in Unrecognized NPSH Issue Affecting Emergency Feedwater Availability

Exhibit___(WRJ-1)

Resume of
William R. Jacobs, Jr., Ph.D.

EDUCATION: Ph.D., Nuclear Engineering, Georgia Tech 1971
MS, Nuclear Engineering, Georgia Tech 1969
BS, Mechanical Engineering, Georgia Tech 1968

ENGINEERING REGISTRATION: Registered Professional Engineer

PROFESSIONAL MEMBERSHIP: American Nuclear Society
National Society of Professional Engineers

EXPERIENCE:

Dr. Jacobs has over twenty-four years of experience in a wide range of activities in the electric power generation industry. He monitors nuclear plant operations for GDS clients and has provided testimony on nuclear plant operations and decommissioning in several jurisdictions. He has assisted the Georgia Public Service Commission staff in evaluation of applications for certification of three combustion turbine peaking projects and assists the staff in monitoring the construction of these projects. He has provided technical litigation support and expert testimony support in several complex law suits involving power generation facilities. Dr. Jacobs has provided testimony before the Georgia Public Service Commission, the Public Utility Commission of Texas, the North Carolina Utilities Commission, the South Carolina Public Service Commission, the Iowa State Utilities Board, the Louisiana Public Service Commission and the FERC.

Dr. Jacobs has extensive international experience in the nuclear power industry. He served as a startup engineer at three different domestic pressurized water reactors. He was a shift test director at Crystal River Unit 3. Dr. Jacobs was startup manager at nuclear plants in Yugoslavia and the Philippines. He established operating and maintenance programs and procedures as advisor to the Korea Electric Company. He was site manager in the Philippines for a 655 MW pressurized water reactor, responsible for all site activities including construction, startup, and site engineering. Dr. Jacobs has also worked with the Institute of Nuclear Power Operations, responsible for the inspection of nuclear plant outage activities across the United States.

<u>1986-Present</u> GDS Associates, Inc.

As Principal, Dr. Jacobs directs GDS' nuclear plant monitoring activities and has assisted clients in evaluation of management and technical issues related to nuclear power plant operation. Dr. Jacobs has evaluated nuclear plant operations and provided testimony in the areas of nuclear plant operation, construction prudence and decommissioning in five states. He has provided litigation support in complex law suits concerning the construction of nuclear power facilities. He has evaluated and testified on combustion turbine projects in certification hearings and has assisted the Georgia PSC in monitoring the construction of the combustion turbine projects.

1985-1986 Institute of Nuclear Power Operations (INPO)

Dr. Jacobs performed evaluations of operating nuclear power plants and nuclear power plant construction projects. He developed INPO Performance Objectives and Criteria for the INPO Outage Management Department. Dr. Jacobs performed Outage Management Evaluations at the following nuclear power plants:

- Connecticut Yankee - Connecticut Yankee Atomic Power Co.
- Callaway Unit I - Union Electric Co.
- Surry Unit I - Virginia Power Co.
- Ft. Calhoun - Omaha Public Power District
- Beaver Valley Unit 1 - Duquesne Light Co.

During these outage evaluations, he provided recommendations to senior utility management on techniques to improve outage performance and outage management effectiveness.

1979-1985 Westinghouse Electric Corporation

As site manager at Philippine Nuclear Power Plant Unit No. 1, a 655 MWe PWR located in Bataan, Philippines, Dr. Jacobs was responsible for all site activities during completion phase of the project. He had overall management responsibility for startup, site engineering, and plant completion departments. He managed workforce of approximately 50 expatriates and 1700 subcontractor personnel. Dr. Jacobs provided day-to-day direction of all site activities to ensure establishment of correct work priorities, prompt resolution of technical problems and on schedule plant completion.

Prior to being site manager, Dr. Jacobs was startup manager responsible for all startup activities including test procedure preparation, test performance and review and acceptance of test results. He established the system turnover program, resulting in a timely turnover of systems for startup testing.

As startup manager at the KRSKO Nuclear Power Plant, a 632 MWE PWR near Krsko, Yugoslavia, Dr. Jacobs' duties included development and review of startup test procedures, planning and coordination of all startup test activities, evaluation of test results and customer assistance with regulatory questions. He had overall responsibility for all startup testing from Hot Functional Testing through full power operation.

1973 - 1979 NUS Corporation

As Startup and Operations and Maintenance Advisor to Korea Electric Company during startup and commercial operation of Ko-Ri Unit 1, a 595 MWE PWR near

Pusan, South Korea, Dr. Jacobs advised KECO on all phases of startup testing and plant operations and maintenance through the first year of commercial operation. He assisted in establishment of administrative procedures for plant operation.

As Shift Test Director at Crystal River Unit 3, an 825 MWE PWR, Dr. Jacobs directed and performed many systems and integrated plant tests during startup of Crystal River Unit 3. He acted as data analysis engineer and shift test director during core loading, low power physics testing and power escalation program.

As Startup engineer at Kewaunee Nuclear Power Plant and Beaver Valley, Unit 1, Dr. Jacobs developed and performed preoperational tests and surveillance test procedures.

1971 - 1973 Southern Nuclear Engineering, Inc.

Dr. Jacobs performed engineering studies including analysis of the emergency core cooling system for an early PWR, analysis of pressure drop through a redesigned reactor core support structure and developed a computer model to determine tritium build up throughout the operating life of a large PWR.

SIGNIFICANT CONSULTING ASSIGNMENTS:

Louisiana Public Service Commission Staff - Evaluated management and operation of the River Bend Nuclear Plant. Submitted expert testimony before the LPSC in Docket No. U-19904.

U.S. Department of Justice - Provided expert testimony concerning the in-service date of the Harris Nuclear Plant on behalf of the Department of Justice U.S. District Court.

City of Houston - Conducted evaluation of a lengthy NRC required shutdown of the South Texas Project Nuclear Generating Station.

Georgia Public Service Commission Staff - Evaluated and provided testimony on Georgia Power Company's application for certification of the Intercession City Combustion Turbine Project - Docket No. 4895-U.

Seminole Electric Cooperative, Inc. - Evaluated and provided testimony on nuclear decommissioning and fossil plant dismantlement costs - FERC Docket Nos. ER93-465-000, et al.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the Robins Combustion Turbine Project by Georgia Power Company - Docket No 4311-U.

North Carolina Electric Membership Corporation - Conducted a detailed evaluation of Duke Power Company's plans and cost estimate for replacement of the Catawba Unit 1 Steam Generators.

Georgia Public Service Commission Staff - Evaluated and prepared testimony on application for certification of the McIntosh Combustion Turbine Project by Georgia Power Company and Savannah Electric Power Company - Docket No. 4133-U and 4136-U.

New Jersey Rate Counsel - Review of Public Service Electric & Gas Company nuclear and fossil capital additions in PSE&G general rate case.

Corn Belt Electric Cooperative/Central Iowa Power Electric Cooperative - Directs an operational monitoring program of the Duane Arnold Energy Center (565 Mwe BWR) on behalf of the non-operating owners.

Cities of Calvert and Kosse - Evaluated and submitted testimony of outages of the River Bend Nuclear Station - PUCT Docket No. 10894.

Iowa Office of Consumer Advocate - Evaluated and submitted testimony on the estimated decommissioning costs for the Cooper Nuclear Station - IUB Docket No. RPU-92-2.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Prepared testimony related to Vogtle and Hatch plant decommissioning costs in 1991 Georgia Power rate case - Docket No. 4007-U.

City of El Paso - Testified before the Public Utility Commission of Texas regarding Palo Verde Unit 3 construction prudence - Docket No. 9945.

City of Houston - Testified before Texas Public Utility Commission regarding South Texas Project nuclear plant outages - Docket No. 9850.

NUCOR Steel Company - Evaluated and submitted testimony on outages of Carolina Power and Light nuclear power facilities - SCPSC Docket No. 90-4-E.

Georgia Public Service Commission/Hicks, Maloof & Campbell - Assisted Georgia Public Service Commission staff and attorneys in many aspects of Georgia Power Company's 1989 rate case including nuclear operation and maintenance costs, nuclear performance incentive plan for Georgia and provided expert testimony on construction prudence of Vogtle Unit 2 and decommissioning costs of Vogtle and Hatch nuclear units - Docket No. 3840-U.

Swidler & Berlin/Niagara Mohawk - Provided technical litigation support to Swidler & Berlin in law suit concerning construction mismanagement of the Nine Mile 2 Nuclear Plant.

Long Island Lighting Company/Shea & Gould - Assisted in preparation of expert testimony on nuclear plant construction.

North Carolina Electric Membership Corporation - Prepared testimony concerning prudence of construction of Carolina Power & Light Company's Shearon Harris Station - NCUC Docket No. E-2, Sub537.

City of Austin, Texas - Prepared estimates of the final cost and schedule of the South Texas Project in support of litigation.

Tex-La Electric Cooperative/Brazos Electric Cooperative - Participated in performance of a construction and operational monitoring program for minority owners of Comanche Peak Nuclear Station.

Tex-La Electric Cooperative/Brazos Electric Cooperative/Texas Municipal Power Authority (Attorneys - Burchette & Associates, Spiegel & McDiarmid, and Fulbright & Jaworski) - Assisted GDS personnel as consulting experts and litigation managers in all aspects of the lawsuit brought by Texas Utilities against the minority owners of Comanche Peak Nuclear Station.

Exhibit____(WRJ-2)

Excerpts from the
Management Corrective Action
Program Phase II

Excerpt
of
Problem Descriptions, Root Causes, Contributing Causes and Selected Other material
from
MCAP II

NOTE: These excerpts are directly from the MCAP II document provided as Item Number 4 of Appendix I to Florida Power Corporation's Preliminary Report on the Current Outage at Crystal River Unit 3 submitted to the Florida Public Service Commission, Docket No. 970261-E, dated March 19, 1997. The only material added is references to page numbers which are contained in square brackets and bold print.

[beginning on page 4]

SECTION A

I. Area of Concern ...

Leadership Oversight and Involvement

II. Problem Description:

Leadership oversight and involvement in plant issues has been inadequate in emphasizing its safety culture role. This has occurred in areas ranging from communication and reinforcement of core values and expectations to site processes and priorities. Further, where assessments have been conducted, they have neither focused on elements from the safety culture perspective, nor have they been sufficiently self-critical to enable assessment of root or apparent causes.

Root Cause 1 **[on page 5]**

Site leadership has not been effective in carrying out its safety culture role because it has not:

1. Clearly and consistently communicated and reinforced core values and expectations with emphasis on safety culture.
2. Implemented site processes with appropriate emphasis on safety culture.
3. Established site wide priorities with proper emphasis on safety culture.
4. Implemented balanced accountability with respect to safety.
5. Established constructive self criticism and self improvement as an integral way of doing business.
6. Fixed things that were wrong.

Root Cause 2 **[on page 8]**

Excessive and ineffective organizational and programmatic changes have increased human error rates.

Root Cause 3 **[on page 9]**

An inadequate root and common cause analysis process inhibits management from addressing the right issues in the right priority.

Contributing Cause 1: **[on page 10]**

Inadequate performance monitoring and trending which inhibits proactive identification of emerging issues and results in an excessive number of investigations with little value added.

Contributing Cause 2:

Inadequate analysis of performance monitors has resulted in ineffective detection of adverse trends related to site programs, processes, and procedures.

Contributing Cause 3: **[on page 11]**

An inadequate feedback process has resulted in self-assessments not being controlled by the corrective action process and consequently, missed opportunities to improve.

Contributing Cause 4:

Inadequate adjustments (corrective actions) have resulted in frequent ineffective changes that may cause additional problems.

Contributing Cause 5: **[on page 12]**

The quality Assurance process has not effectively communicated or followed up on issues.

beginning on page 14

SECTION B
ENGINEERING PERFORMANCE

I. Area of Concern ...

The engineering Department has not supported plant operations well, particularly in maintenance and application of the plant design basis.

II. Problem Description:

The focus of the concern in engineering is primarily on design and analytical work, configuration management, and teamwork with other departments. The systems engineering area is generally perceived to be satisfactory, although some performance problems have been noted here too.

Overall, the engineering department has had an inconsistent record of performance. Over the last several SALP period it was rated SALP 3, SALP 2, SALP 2 (and IMPROVING), and SALP 1 only to decline back to SALP 2 in 1995.

Although inspection reports identify some engineering strengths, they are overshadowed by weaknesses in the following areas: timeliness and accuracy of design and analytical support for plant operation, adequacy of regulatory correspondence quality of 10CFR50.59 evaluations, planning and prioritization of work load, and maintenance/communication of the plant design basis.

III. Present Condition:

The engineers were challenged to self-identify the key factors contributing to the problems described above. Their input is summarized below:

1. For the first eighteen years of plant operation there was a heavy reliance upon A/E, contractor, and NSSS resources for performance of design activities. Corporate engineering personnel served as project manager over these resources and were not intimately involved with the details. As a result, there was ineffective technology transfer from the external resources to CR3 engineers.

2. Ineffective management of change within the engineering organization had a negative affect on its performance. The combined effect of downsizing, relocation of corporate personnel to the Crystal River plan site, implementation of the business process improvement (BPI) recommendations to the design processes, and the reduction in reliance upon external engineering resources, negatively influenced productivity and product quality, frustrated personnel, and increased engineering work backlogs.

   The reduction in reliance in external resources, although recognized by all as a potentially positive move, was performed in a more aggressively than the FPC team was prepared to accommodate given the existing level of engineering knowledge and skills.

Root Cause 1 **[on page 15]**

An appropriate safety culture was not effectively emphasized. As a result, activities were not given a level of safety attention commensurate with that given to production or cost priorities. This led to design basis concerns being primarily resolved through analytical means in lieu of physical means (such as plant modifications and equipment testing) directed at maintaining or improving design margins.

Root Cause 2 **[on page 18]**

Insufficient communication of management expectations - particularly with respect to safety culture.

<u>Contributing Cause 1</u>: **[on page 19]**

Inadequate performance monitoring, trending, and self-assessment within engineering which precludes:

- Early identification of equipment reliability problems.
- Highlighting repeat failures.
- Identification of organizational and programmatic issues.

<u>Contributing Cause 2</u>: **[on page 20]**

Inadequate deviation analysis of performance indicators which results in ineffective detection of adverse trends related to O&P issues.

<u>Contributing Cause 3</u>:

Inadequate root and common cause analysis process precludes engineering from addressing the right issues in the correct priority.

<u>Contributing Cause 4</u>: **[on page 21]**

Inadequate communication among managers, supervisors, and engineering personnel which leads to:

- Lack of common awareness of problem extent,
- Expended effort to resolve problems at too low a level in the organization,
- Focus on inappropriate priorities,
- Denial, or rationalization, of problem existence.

[beginning on page 24]

SECTION C
CONFIGURATION MANAGEMENT AND DESIGN BASIS

I. Area of Concern ...

Weaknesses have existed in implementing programs for maintaining plant configuration consistent with design basis.

II. Problem Description:

The NRC's expectation, as contained in the commission's policy statement dated August 10, 1992, is "*...the licensee will have current design documents and adequate technical bases to demonstrate that the plant physical and functional characteristics are consistent with the design basis, the systems, structures and components can perform their intended functions, and the plant is being operated in a manner consistent with the design basis.*"

FPC has not fully met this expectation. Weakness that have been identified include:

- Discrepancies between the physical plant and design documentation.
- Inaccuracies in the technical content of design documents including incorrect assumptions and calculational errors.
- Discrepancies between operational configuration (procedures) and the supporting design documentation.
- Inconsistencies among design documents and between the design basis and licensing basis.

Examples of deficiencies in these areas have been documented by FPC and the NRC. Some of these deficiencies date back to the original design of the plant. We are concerned with the number and cumulative potential effect of these issues on continued safe plant operation. The identification and resolution of these issues has impacted the workload and priorities of the entire nuclear operations organization, and in particular on engineering, operations and licensing. FPC has had to operate in a reactionary mode to address these issues as they arose.

FPC's 10CFR50.59 process is also viewed as inconsistent and examples of weak 50.59 reviews have been cited in NRC inspection reports and PRC reviews. A quality 10CFR50.59 process is reliant on readily available, consistent and accurate design information.

... FPC remains challenged to complete focussed reviews of past design efforts (including the original plant design/basis). Some problems were also identified by the NRC IPAP team with more recent engineering work. This has indicated the FPC may have taken actions based on treating symptoms rather than the root cause(s) of the problems. **[this paragraph is from**

the last paragraph of Section III on page 25]

Root Cause 1 **[on page 25]**

Limited emphasis on nuclear safety culture in relation to more traditional production priorities, such as capacity and cost, resulting in:

- Inadequate design margins that have not been addressed.
- Limited definition, documentation, and on-site understanding of the plant design basis.
- Lack of comprehensive plant configuration controls.
- Lack of networking with other B&W plants to maintain consistent designs/design margins.

<u>Contributing Cause 1</u>: **[on page 27]**

Inadequate self assessment which precludes comprehensive, proactive identification and resolution of design basis issues.

[beginning on page 47]

SECTION D
REGULATORY COMPLIANCE

II. Problem Description:

Crystal River Unit 3 (CR-3) does not have a sufficient understanding of NRC regulations and does not assign full compliance with the intent of NRC regulations a sufficiently high priority. Also, there appears to be a perception that conservative decision making regarding regulatory issues is seen as secondary to plant availability.

This is supported by the following specific concerns:

A. Examples of failure to report or untimely reporting of events or conditions.

B. Examples of questionable interpretations of the regulations by both licensing and non-licensing personnel.

C. Examples of not meeting commitments made in licensing correspondence.

D. Examples of questionable or incorrect technical information provided in NRC submittals.

III. Present Condition

It is also apparent that he knowledge of regulations and of the general regulatory process is not to the necessary level in the other departments. **[this sentence is the opening sentence to the last paragraph on page 47]**

Root Cause 1 **[on page 48]**

Inadequate communication of management expectations and priorities with respect to safety culture regulatory compliance resulting in:

- FPC positions on some regulatory issues not meeting the safety intent of regulations.
- Regulatory compliance not being considered pro-actively and with high priority when dealing with site activities.
- A perception by personnel that regulatory requirements should be addressed only from perspective of minimum cost.
- Inadequate and inconsistent explanations of technical issues to the NRC.
- Imprecise or unclear commitments to the NRC.

Root Cause 2 **[on page 50]**

Inadequate performance monitoring and trending from a regulatory compliance perspective which precludes:

- Focussing on the right issues in the right priority.
- Obtaining first-had information on issue content and sensitivity.
- Obtaining real-time information on emerging issues.
- Effective implementation of the safety evaluation process.

Contributing Cause 1: **[on page 51]**

Inadequate root cause/common cause analysis process which precludes resolution of long term, high visibility regulatory issues.

[beginning on page 53]

SECTION E
0PERATIONS PERFORMANCE

II. Problem Description:

The Operations Department has not attained a level of performance equivalent to those measured as excellent by INPO and the NRC. Recent outside and internal audits have detailed several areas in need of improvement in order to attain operational excellence.

III. Present Condition

... some problem areas have not been successfully corrected as evidenced by:

- Component mispositioning events.
- Failure to follow procedure events.
- Inconsistent log keeping practices.
- Failure to properly self-identify mistakes with the problem reporting process.

Root Cause 1

Inadequate implementation of established standards. Supervision has not consistently reinforced operating standards and this has resulted in:

1. Challenges to plant safety.
2. Inadequate work practices.
3. Failure to follow operational and administrative procedures.

Contributing Cause 1: **[on page 54]**

Inadequate resources within Cperations.

Contributing Cause 2: **[on page 56]**

Vague and unclear operating expectations or standards have resulted in operating short falls.

Contributing Cause 3:

Inadequate root and common cause analysis resulting in management failure to address the right issues with proper priority.

Contributing Cause 4:

Inadequate performance monitoring and trending with precludes proactive identification of emerging issues.

Exhibit____(WRJ-3)

FPC letter to NRC
dated October 28, 1996

CR-3 Design Margin Improvement Outage Scope of Work

1. High Pressure Injection (HPI) Pump Recirculation to the Makeup Tank

Concern: The HPI pumps draw suction from the Borated Water Storage Tank (BWST) during the initial phase of emergency core cooling system (ECCS) injection. Once BWST level has reached a pre-determined level, suction is switched to the reactor building sump with the HPI pumps taking suction from the discharge of the low pressure injection (LPI) pumps (piggyback operation). During piggyback operation, LPI pump discharge pressure keeps the check valve in the suction line from the makeup tank (MUT) to the HPI pumps closed (MUV-65). During long term small break LOCA (SBLOCA) cooling, HPI flow may require throttling due to lower required ECCS flow. If throttling continues, procedures will eventually direct the operators to increase total HPI pump flow by opening the HPI recirculation valves at a pre-determined flow rate to divert some flow to the MUT. Since no flow is exiting the MUT, the tank could fill up with recirculation flow and lift the relief valves, dumping fluid onto the auxiliary building floor. This would result in the transfer of RB sump fluid to the auxiliary building sump, which reduces the amount of water available in the RB sump from which the LPI and reactor building spray pumps take suction during the later stages of core and containment cooling. This could also create a release path for post accident radioactive fluid outside containment.

Resolution: FPC is consulting with Framatome Technologies, Inc. (FTI) to confirm whether the scenario is valid and within the CR-3 design basis. Although the resolution of this issue is still undetermined at this time, preliminary indications are that opening of a high point vent valve may preclude the need to open the HPI recirculation valves in the SBLOCA scenarios of concern.

Schedule: This issue will be resolved prior to startup from the current outage.

2. HPI System Modifications to Improve SBLOCA Margins

Concern: The CR-3 HPI system currently meets all design and licensing basis functional requirements. However, the CR-3 configuration is not consistent with the designs at other Babcock and Wilcox (B&W) plants. As a result, HPI minimum and maximum flow limits are more restrictive and peak cladding temperatures for certain SBLOCA scenarios are higher. In addition, the reduced system design margin has created the need for several manual operator actions to ensure adequate core cooling. FPC intends to reduce the operator burden created by these actions and the system margin deficit through hardware modifications. These modifications would also make the CR-3 HPI system design more like other B&W plants.

Florida
Power
CORPORATION
Crystal River Unit 3
Docket No. [illegible]

October 28, 1996
3F1096-22

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555-0001

Subject: Crystal River Unit 3 Forced Outage

Dear Sir:

On September 2, 1996, Florida Power Corporation (FPC) shut down the Crystal River Unit 3 (CR-3) nuclear plant due to a leak in the turbine lube oil system. During this forced outage, FPC determined that a modification had been made to the plant during the Spring, 1996 Refuel 10 outage which created an Unreviewed Safety Question (USQ) regarding emergency diesel generator (EDG) loading. This USQ involved a reduction in the margin of safety described in portions of the Technical Specification Bases.

On October 4, 1996, while still shut down, FPC was preparing a submittal to request NRC approval of a license amendment to change the affected EDG Technical Specification Bases when additional questions arose regarding the change to the emergency feedwater (EFW) system which created the diesel loading USQ. These questions involved failure modes with the EFW system which needed to be evaluated to ensure the system could perform its safety function and reliance on the turbine-driven, "B" train emergency feedwater pump for "A" train EDG load management. Due to the EFW/EDG issues, and some other design-related issues, FPC management made a decision to keep CR-3 shut down until these issues are adequately addressed. The purpose of this letter is to inform the NRC of our plans to address these issues prior to restarting the plant.

CRYSTAL RIVER ENERGY COMPLEX: 15760 W. Power Line St • Crystal River, Florida 34428-6708 • (352) 795-6486
A F...ida Progress Company

The issues described in the attached list were identified through a review conducted by a multi-discipline team involved in reviewing the Emergency Operating Procedures (EOPs) and through design reviews by the engineering organization. The list was reviewed by CR-3 senior management and the items are considered necessary to ensure safety system operability or to increase design margins. Each issue has been documented in the CR-3 corrective action system and will be tracked to closure. Several of the issues have been determined to be reportable and Licensee Event Reports are being processed.

FPC will ensure the safety systems in question are capable of performing their design basis functions prior to restart from this outage. As an added level of assurance, FPC will be establishing an internal restart panel which will function similar to an NRC restart panel using NRC Inspection Manual 0350 as a guideline for conducting the restart readiness review. Upon completion of the work to resolve the issues, the panel will conduct a final review to confirm that all issues have been resolved adequately. When satisfied, restart of the unit will be recommended to the Senior Vice President, Nuclear Operations. In addition, the Nuclear General Review Committee (NGRC) will conduct an independent review prior to restart.

Project teams or individual lead responsibility have been established for each issue to support the design, licensing and installation activities necessary to complete the outage work scope. Final resolutions for some of the issues on the list have not yet been determined. Other resolutions require relatively long lead procurement activities. Therefore, an integrated outage schedule is not available at this time. However, we expect the unit to remain shutdown until at least mid-January, 1997. This will also likely move our next refueling outage, Refuel 11, to the fall of 1998 rather than the spring of 1998, as currently scheduled. The NRC will be kept abreast of the schedule and progress on these issues as the outage continues.

Sincerely,

P. M. Beard, Jr.
Senior Vice President
Nuclear Operations

PMB/BG

Attachment

xc: Regional Administrator, Region II
Senior Resident Inspector
NRR Project Manager

Resolution: At this time, the following modifications are being considered:

a. Installing cavitating venturis to limit flow through any single injection leg due to a postulated break in that leg.

b. Installing cross-tie piping downstream of the HPI injection control valves to deliver increased core cooling flow should a failure prevent one or more of the injection valves from opening.

c. Modifying the normal makeup line to ensure automatic isolation occurs upon ES actuation to eliminate the operator action now required to perform this function. This involves modifying the power supply to the existing isolation valve (MUV-27) and adding another isolation valve powered from the opposite train in series with MUV-27. (Note: the proposed installation of the cavitating venturis could preclude the need for this modification).

Schedule: Since the HPI system is fully capable of meeting its design function, these modifications are not considered necessary to complete during the current outage. However, FPC is developing the design packages and determining whether equipment can be procured in a time frame to install in the current outage given the schedules for other activities.

3. <u>LPI Pump Mission Time</u>

Concern: During the IPAP inspection, an issue was raised regarding the need to establish flow through the decay heat removal (DH) drop line to the decay heat removal (LPI) pumps as part of small break LOCA mitigation. CR-3 has two redundant, independent LPI trains which can take suction from the RB sump during long term recirculation core cooling. However, certain small break LOCAs could result in long-lasting, elevated RCS pressures such that the LPI pumps would have to operate in the piggyback mode at low flow rates for an extended period of time. As that period of time approaches the current low flow mission time for the LPI pumps, plant procedures direct the operators to trip one pump and open the DH drop line valves to the RB sump to provide additional flow through the remaining running LPI pump. There is only one DH drop line at CR-3 (and many other pressurized water reactors) which has three motor-operated valves in series. Failure of any one of the drop line valves to open would prevent flow through the line. If the DH drop line was necessary to fulfill the ECCS long term core cooling function for small break LOCA mitigation, this would violate the single failure design criterion.

Resolution: The concern described above is time-dependent. If the time frame is long enough after the event, opening of the DH drop line could be considered a long-term recovery action as opposed to an emergency core cooling function. FPC considers the long term recovery phase beyond the time frame implied by the regulations where applying the single failure design criterion is necessary. At the time of the

IPAP inspection, the low flow mission time for the LPI pumps was 72 hours, which was questionable from an ECCS versus long term recovery perspective. FPC is currently low-flow testing a pump which is identical to the CR-3 LPI pumps. The test flow rate is approximately 100 gallons per minute (gpm). The design flow rate of the LPI pumps is 3000 gpm. The results of this test are expected to prove that the pumps could run for an extended period at very low flows without damage. If the test is successful, procedures will be revised to characterize opening the DH drop line in this scenario as a long term recovery action rather than an ECCS function.

Schedule: This issue will be resolved before startup from the current outage. As of 3:30 p.m. on October 25, 1996, the pump had completed 18 days of continuous low-flow testing with no performance (head curve) degradation, no mechanical seal leakage, no indication of unexpected bearing wear, and all vibration parameters stable and well below the action levels specified in the surveillance procedure. The testing is continuing beyond 18 days.

4. Reactor Building Spray Pump 1B NPSH

Concern: During the long term recirculation phase of core and containment cooling, the reactor building spray pumps (BSPs) take suction from the reactor building sump. Calculations have shown BSP-1B to have little margin between required and available net positive suction head (NPSH) during this phase of operation. A recent revision of the calculation shows the margin to be approximately one foot of water. It is desired to increase this margin.

Resolution: FPC currently plans to conduct factory testing and/or modify the pump impeller to improve the margin between required and available NPSH.

Schedule: This issue will be resolved before startup from the current outage.

5. Emergency Feedwater System Upgrades and Diesel Generator Load Impact

Concern 5.1: The CR-3 EFW system is comprised of two 100% capacity trains, with the "A" train pump (EFP-1) being motor driven and the "B" train pump (EFP-2) being steam driven. The steam for the EFP-2 turbine driver is fed through redundant inlet valves (ASV-5 and ASV-204) to ensure the availability of steam given a failure of one of the inlet valves to open. Each pump feeds both steam generators. For a portion of the flow path from the emergency feedwater tank (EFT-2), the two pumps share a common suction line. Under certain accident scenarios, there are failure modes which can cause the calculated NPSH available to both pumps to be less than required. For example, a failure of the DC control power source for the injection control valves in one train of EFW can result in the pump in that train producing high flows which result in excessive friction head losses through the common suction line.

Concern 5.2: Motor-driven EFP-1 is powered from the "A" train ES bus and is connected to the "A" emergency diesel generator (EGDG-1A). EFP-2 is steam driven and therefore does not affect "B" train EDG loading. However, portions of the load management scheme for EGDG-1A depend on the availability of EFP-2 to: 1) limit the total flow produced by EFP-1 during the early stages of diesel loading and 2) permit EFP-1 to be shut down and the "A" train LPI pump (and other engineered safeguards features) to be started in the later stages of accident mitigation. Therefore, some postulated failure modes which cause EFP-2 to be unavailable invalidate assumptions made in EGDG-1A loading calculations and some accident analyses which may have taken credit for flow from EFP-2 after EFP-1 was shut down.

Resolution: At this time, the following modifications are being considered:

a. Installing cavitating venturis in the EFW pump discharge lines to limit flow during the postulated failures which result in the loss of flow control for an EFW train. This will eliminate the NPSH concern.

b. Re-enabling "A" train Emergency Feedwater Initiation and Control (EFIC) system actuation of EFP-2 via automatically opening steam turbine inlet valve ASV-204. This feature was disabled by a modification in Refuel 10 and will be restored to ensure EFP-2 auto-starts given a failure of the "B" side initiate logic or ASV-5.

c. Installing motor operators on cross-tie valves EFV-12 and EFV-13 to allow remote manual opening of these valves. Opening these valves establishes a flow path allowing the pump from one train to feed the steam generators through the injection lines of the other train. This is desirable to ensure the operators can maintain EFW flow control and indication in certain single failure scenarios without requiring local manual valve operation.

Schedule: This issue will be resolved before startup from the current outage. We expect this issue to require additional interaction with the NRC prior to restart.

6. <u>Emergency Diesel Generator Loading</u>

Concern: The rated capacity of EGDG-1A is challenged by the continuous, automatically connected loads as well as the loads that are manually connected in the later stages of accident mitigation. Three concerns were created by the Refuel 10 modification which removed the "A" train EFIC automatic actuation of ASV-204. Calculated peak transient diesel loads were above the 3500 kW maximum engine rating documented in the FSAR and the ITS basis background for LCO 3.8.1, "AC Sources"; calculated peak diesel load at one minute was above the 3100 kW rating discussed in the basis for Surveillance Requirement 3.8.1.11; and the highest single rejected diesel load

Exhibit___(WRJ-4)

NRC Inspection Manual

UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

NRC INSPECTION MANUAL

PIPB

MANUAL CHAPTER 0350

STAFF GUIDELINES FOR RESTART APPROVAL

0350-01 PURPOSE

01.01 To establish guidelines for approving restart of a nuclear power plant after a voluntary or involuntary shutdown as a result of a significant event, complex hardware problem, or serious management deficiency.

01.02 To provide a list of potential tasks and issues from which a plant-specific Restart Action Plan can be developed.

01.03 To provide for a record of major regulatory actions leading to approval for restart.

0350-02 OBJECTIVES

02.01 To ensure that NRC's restart review efforts are appropriate for the individual circumstances, are reviewed and approved by the appropriate NRC management levels, and provide objective measures of restart readiness.

02.02 To provide for effective coordination of NRC resources in determining restart readiness.

02.03 To clarify responsibilities for the actions necessary to approve restart.

02.04 To ensure that the Office of Nuclear Reactor Regulation (NRR) and regional management agree on the actions to be taken and provide a unified NRC position.

0350-03 APPLICABILITY

This manual chapter shall be followed when a power reactor licensee plans to restart the reactor after the plant has been shut down for one or more of the following reasons:

- Serious NRC questions about licensee management effectiveness.
- Identification of a complex hardware problem or a degradation of a structure, system, or component to the extent that it may not perform its intended safety function and requires comprehensive NRC evaluation before restart.
- A significant event, such as one that fits the characteristics described in Inspection Manual Chapter 0325, "Augmented Inspection Teams," or a significant operational event that meets the description in NRC

Management Directive 8.3, "NRC Incident Investigation Program."

- Possible damage to offsite support systems such as offsite power or emergency response capability as a result of a natural disaster, explosion, riot, or event with similar consequences.

This manual chapter applies only when a licensee plans to restart a reactor after a plant has been shut down. The events described above are not criteria for directing or requesting that a plant be shut down. This manual chapter and its appendix provide general guidance for NRC oversight of plant restart based on previous experience and should be used as a starting point for developing a plant-specific restart check list.

0350-04 RESPONSIBILITIES AND AUTHORITIES

04.01 Director, Office of Nuclear Reactor Regulation (NRR). Notifies the Executive Director for Operations (EDO) and the Commission, as appropriate, of the NRC actions taken concerning shutdown plants and the proposed followup plan.

04.02 Regional Administrator

a. Discusses with the Deputy Executive Director for Nuclear Reactor Regulation, Regional Operations and Research, the Office of Enforcement (OE), and NRR, as appropriate, the need for an order or confirmatory action letter (CAL) specifying the actions required of the licensee to receive NRC approval to restart the plant and the proposed followup plan.

b. Decides, in consultation with the NRR Associate Director for Projects, whether this manual chapter applies to a specific reactor restart.

c. In coordination with the NRR Associate Director for Projects, decides whether to establish a Restart Panel.

d. In coordination with the cognizant NRR Director, Division of Reactor Projects, develops a written Restart Action Plan, including a case-specific checklist, to assign responsibilities and schedules for restart actions and interactions with the licensee and outside organizations.

e. Coordinates and implements those actions prescribed in the Restart Action Plan that have been determined to be the regional office's responsibility. These include, when appropriate, interactions with State and local agencies and with regional offices of Federal agencies.

f. In conjunction with NRR, reviews and determines the acceptability of licensee's corrective action program.

g. Approves restart of the shutdown plant, following consultation with the EDO and the Director of NRR.

04.03 NRR Associate Director for Projects

a. Acts as the focal point for discussions within NRR to establish the appropriate followup actions for a plant that has been shut down.

04.04 NRR Reactor Projects Division Director

a. Coordinates participation in followup conference calls and management discussions to ensure that the Regional Administrator and the Director of NRR are directly involved, when appropriate, in followup action.

b. Coordinates and implements actions prescribed in the Restart Action Plan that have been determined to be NRR's responsibility. These include, where applicable, appropriate NRC Office or NRR Division interaction with other Federal agencies (e.g., Federal Emergency Management Agency (FEMA), Department of Justice (DOJ)) pursuant to any applicable Memoranda of Understanding.

0350-05 BACKGROUND AND INITIAL ACTIONS

05.01 Background

A licensed commercial nuclear power plant may be shut down, voluntarily or involuntarily, for a variety of reasons. When a plant is shut down for reasons stemming from license conditions or technical specifications, the licensee normally can develop and implement a clearly defined corrective action plan and the plant restarts without special approval from the NRC. However, plants occasionally are shut down as a result of safety concerns resulting from a significant event, complex hardware problem, or serious management deficiency. This manual chapter addresses these latter cases.

The guidelines in this chapter ensure that (1) NRR and the regional offices are appropriately involved in restart decisions for significant cases, (2) the NRC responds in an appropriate manner with a unified position to the licensees, and (3) restart activities are comprehensive and appropriate for the specific reason for the shutdown.

It is the intent of this manual chapter that for each NRC oversight of a plant restart a plant-specific restart plan be developed using this manual chapter as guidance. As such, the restart plan for a specific situation may include additional issues that are determined to be applicable to the situation and may omit issues discussed below if such issues are determined not to be applicable to the situation.

05.02 Initial Actions

When NRC staff members believe that a particular situation at a shutdown plant involves a significant event, complex hardware problem, or serious management deficiency warranting increased regulatory attention, NRR and the applicable regional office should promptly discuss the situation. The initial discussion is normally between the regional office Director of Reactor Projects and the cognizant NRR Division Director of Reactor Projects. For significant operating events, the Director, Division of Reactor Program Management (DRPM) also should be included. The discussion should include a description of the event or circumstances as well as the actions already taken by the regional office and those proposed for the future. The Regional Administrator and the NRR Associate Director for Projects should be informed of the circumstances and the significance of the situation to plant safety and operation.

NRC action may include the establishment of an incident investigation team (IIT), an augmented inspection team (AIT), or a special inspection team. Such action could further include, as appropriate, a CAL or an order. All of these specific actions should be conducted in accordance with appropriate office policies, procedures, and manual chapters.

Special circumstances involving a significant, rapidly occurring event may require that discussions be initiated directly at the level of the Regional Administrator, the Director of NRR, or the Deputy Executive Director for Nuclear Reactor Regulation, Regional Operations and Research.

0350-06 RESTART REVIEW ACTIVITIES

06.01 Restart Panel

a. Membership. For each plant restart subject to oversight consistent with this manual chapter, the Regional Administrator, in coordination with the NRR Associate Director for Projects, decides whether to establish a Restart Panel. The Regional Administrator normally establishes the composition of the panel and its responsibilities in writing. The panel will typically consist of the following individuals or those in similar positions:

- Director or Deputy Director, regional office Division of Reactor Projects (DRP) (Chairman)
- Director, responsible NRR Project Directorate (Vice Chairman)
- Responsible regional office DRP Branch Chief
- Regional office Division of Reactor Safety (DRS) Branch Chief
- Responsible Project Manager, NRR
- Responsible Senior Resident Inspector

Members can be added to or removed from the panel, as appropriate, depending on the specific details of the shutdown and the matters to be evaluated before restart is authorized. For long-term plant shutdowns, the panel may vary in composition and size over time depending on the corrective actions being performed. For short-term or less complex cases, a panel can consist of as few as two individuals - one from the regional office and one from NRR.

b. Responsibilities of the Restart Panel. Typical responsibilities of the panel are the following:

1. Review all available information related to the plant shutdown.
2. Develop the Restart Action Plan and modify it as needed to ensure that all issues that could affect plant restart are included as they are identified.
3. Review the licensee's corrective action or improvement program and ensure that it addresses identified problems and weaknesses.
4. Maintain an ongoing overview of licensee performance throughout the corrective action process to include periodic meetings among members of the panel.

5. Conduct periodic meetings with the licensee to discuss progress toward satisfactory completion of the program. Depending on the reason for the plant shutdown, meetings with the licensee may be held near the facility. The meetings with the licensee are usually open for public observation, but not participation. A public meeting may be scheduled after the formal meeting with the utility is closed. (See Section 07.04 for public participation guidance)

6. Provide oversight of NRC's followup activities. Review NRC inspection and assessment plans and findings and licensee performance. Identify areas where NRC inspection and technical review are needed.

7. Periodically provide assessment of licensee performance and corrective actions to NRC management.

8. Based on the satisfactory completion of the pre-startup portion of the licensee's restart program, provide a written recommendation and the basis for the recommendation to the Regional Administrator and Director of NRR for approval to restart.

06.02 <u>Restart Action Plan</u>

Appendix A contains guidelines for the development of a case-specific restart checklist. The generic restart checklist in Appendix A should only be used as a tickler to select those actions and issues applicable to the specific case. The Restart Panel should develop a case-specific restart checklist using the generic checklist as a starting point. The case-specific checklist shall provide the detailed list of actions and issues that should be considered prior to approving restart of the plant. The case-specific checklist shall be incorporated into the Restart Action Plan.

The Restart Action Plan should include all expected NRC actions that will be required to be taken before a plant is approved to restart, including those actions not directly related to the initiating event. The Restart Action Plan should also include an inspection plan to ensure an adequate inspection record is created to support the restart determination. The plan should define the following: (a) what must be accomplished by the NRC, as a minimum, to approve plant restart; (b) what issues are to be resolved before restart (i.e. restart issues); (c) who has lead responsibility for each action; and (d) who has responsibility for actual plant restart approval. The plan should establish a process for tracking the status of restart issues and for referencing documentation associated with the resolution of the restart issues. The Restart Action Plan shall be modified as necessary by the Restart Panel to address emergent issues that require use of NRC resources to evaluate or determine that the plant is ready for restart.

The Regional Administrator, in coordination with the Deputy Executive Director for Nuclear Reactor Regulation, Regional Operations and Research, and the Director of NRR, normally has the authority to approve restart. In some instances, Commission approval may be required. Lead responsibility for interactions with the Commission, Advisory Committee on Reactor Safeguards (ACRS), media, Federal agencies, and other public officials also should be established. Typically, NRR will take the lead in interactions with the Commission, ACRS, headquarters offices of Federal agencies, and Congress, and the regional office will typically deal with the local media and State and local officials and regional offices of Federal agencies.

0350-07 GUIDANCE

07.01 Coordination of Followup Actions

The focal point for working-level discussions within the NRC for followup actions will be the appropriate projects division director in the regional office and the NRR reactor projects division director. They will coordinate participation in conference calls, the Restart Panel, and management discussions to ensure that the Regional Administrator and the Director of NRR are directly involved, when appropriate, in important decisions. The project divisions will coordinate and implement the actions prescribed in the Restart Action Plan.

07.02 Commission Involvement

The Commission must be kept adequately informed of the staff's restart actions on a continuing basis. NRR will inform the Commission of the staff's and licensee's restart actions through Commission papers, or communications to the EDO. On the basis of these interactions between the staff and the Commission, the need for Commission briefings will be determined by the circumstances and the Commission's wishes.

For those plants requiring Commission approval for restart, the staff should anticipate Commission briefings with licensee participation (a) after a corrective plan is agreed to and (b) about a month before plant restart is anticipated. At the final briefing, the NRC staff should provide its basis for recommending or not recommending restart. The Commission may express its views concerning restart at any time during the process. A formal vote after the restart briefing may or may not be required.

07.03 Independent Review

The Advisory Committee on Reactor Safeguards (ACRS) may review the restart of plants to independently review NRC's and the utility's actions. ACRS will normally review the restart of plants that have been shut down for more than a year because of substantive deficiencies in equipment, systems, or management. If a plant has been shut down for less than a year, ACRS will consider whether or not to review restart issues of the plant on a case-by-case basis. The NRR staff will keep ACRS informed of NRC's actions involving plants shut down for more than a year and will coordinate briefings of the ACRS.

07.04 Public Participation

The need for public participation varies greatly from situation to situation and depends on the cause of the shutdown, interest of local citizens, interest of elected officials, and concerns of other government agencies. Public meetings have proven to be a valuable vehicle for public participation in the restart process. These meetings, which are often transcribed, are held to receive comments on licensee plans and to describe the results of the NRC review of licensee activities. The need for and level of public participation will be determined by NRC management on a case-by-case basis and will be incorporated into the actions necessary for restart. Public meetings in the local area should be considered to hear concerns and comments on the licensee's restart activities and to factor these concerns and comments into the restart review when these concerns and comments will contribute positively to the review.

07.05 Other Agencies and Government Organizations

At a minimum, the chairman of the Restart Panel should hold an open dialogue with local government officials and interested citizens when a formal public meeting is not deemed necessary. The Restart Panel Chairman shall ensure that inquiries from local and State Government agencies, other Federal agencies, or the public are promptly addressed. Appropriate caution shall be exercised to avoid the release of predecisional, proprietary, or safeguards information when responding to inquiries. In cases when interest extends to a foreign government (e.g., Canada), the Office of International Programs or its designee shall brief the foreign officials if the EDO deems it appropriate.

The decision to restart should include consideration of the need to involve staff from other Federal agencies, such as FEMA and DOJ, and State and local government representatives. Briefings with elected officials and observations of NRC inspections by State representatives have been an effective way of enhancing NRC communication regarding problem plants.

0350-08 RECORDS

It is important that the restart process be documented. The licensee and the NRC staff must understand the reasons for the plant shutdown and the necessary actions to be completed before restart. In addition, information related to NRC and licensee actions, as well as acceptance criteria and confirmatory actions by other agencies and government organizations, must be made available to the public. Generally, information on NRC and licensee actions related to plant restart should be attached to or included in NRC inspection reports. However, other forums, such as public correspondence between the licensee and the NRC or Commission papers, are acceptable. At a minimum, the record developed for the shutdown and restart process shall consists of the following:

a. Preliminary notifications, Commission information papers, and other documents describing the nature of the problem.

b. Confirmatory action letter (CAL) or order issued to the licensee specifying the actions to be taken.

c. Establishment of the Restart Panel and the specific Restart Action Plan.

d. Revisions to the Restart Action Plan that document changes in the scope of the plan or incorporate review of emergent issues.

e. Interim progress reports (e.g., Commission paper).

f. Topics of discussions and major decisions or conclusions from Restart Panel meetings and meetings between the NRC and licensee representatives to discuss the licensee's progress in taking necessary actions.

g. Inspection reports and related correspondence.

h. Safety evaluations.

i. Other agency and government actions communicated to NRC.

j. Documentation that describes the resolution of restart issues.

k. Documentation for the basis for restart approval and the written determination that restart is approved.

All documents relating to the restart process are to be included in the docket file and, to the extent permitted by 10 CFR 2.790, made public in accordance with NRC policy.

0350-09 · REFERENCES

Memorandum of November 23, 1988, from V. Stello, Jr., to office directors and regional administrators entitled "Staff Guidelines Concerning Plant Restart Approval" (DCS microfiche 47707/220).

Memorandum of August 17, 1989, from R. Fraley to J. Taylor, entitled "Proposed Plant Restart: Nine Mile Point Unit 1: (DCS microfiche 70006/326).

END

Appendix
A. Generic Restart Checklist

APPENDIX A

GENERIC RESTART CHECKLIST

A. GENERAL

A.1 PURPOSE

To provide a basis to plan and coordinate NRC review activities for nuclear power plant restart following a shutdown for one or more of the reasons provided in Section 0350-03 of this manual chapter.

A.2 OBJECTIVES

To ensure that NRC review efforts are consistently developed and implemented, specific guidance is provided to support the following:

a. Determining restart issues for review.

b. Identification of the basic tasks needed to review and approve a plant restart.

c. Coordination and tracking of restart review activities.

A.3 BACKGROUND

The implementation of this appendix assumes that there has been a nuclear power plant shutdown that merits a comprehensive NRC review of the restart process. The plant is assumed to be in a safe shutdown condition and measures are in place to physically maintain the plant in a safe shutdown condition.

Section B, "PROCESS," of this appendix describes generic tasks that support the Restart Action Plan described in Section 6.02 of this manual chapter.

Section C, "ISSUES," of this appendix contains potential issues, supplemental to Section B, for consideration during the Restart Review Activities described in this manual chapter.

A.4 ACTIVITIES

a. Develop Case-Specific Checklist. During development of the case-specific checklist (CSC), the issues in the generic checklist of this appendix should be reviewed to determine whether they are applicable to the specific case and should be included in the outline for NRC review of a commercial nuclear power plant restart. Some of the issues in the generic checklist may have previously been completed or are inappropriate for the situation and therefore do not have to be included in the CSC. The CSC should be developed as soon as practicable after a comprehensive restart review is deemed necessary. The CSC should become part of the Restart Action Plan and be used by a Restart Panel to coordinate actions. The CSC is a living document that shall be revised as emergent issues are identified that need to be evaluated, requiring a significant use of NRC. CSC development should contain the following elements:

(1) Section B, "PROCESS," should be reviewed and the applicable tasks needed to support the restart review should be selected on the basis of the known facts specific to the situation. If needed, tasks not included in Section B should be added. From this review, a specific task list should be developed.

(2) Section C, "ISSUES," should be reviewed and the issues that need inspection or verification should be selected on the basis of the

specific situation. Items not included in Section C should be added if necessary. From this review, a specific issue list should be developed.

(3) Items (1) and (2) above form the CSC. The Restart Panel should assign responsibility and a schedule for completion of CSC items. Previously planned inspections included on the Master Inspection Plan (MIP) may satisfy the required verifications and inspections and should be factored into the process. Note: Inspection time required to assess or verify licensee activities should be charged against the respective inspection procedure. CSC planning and maintenance time should be charged against a TAC number for the Restart Action Plan.

(4) The CSC should be incorporated into the Restart Action Plan.

b. CSC Maintenance. The Restart Panel should maintain and periodically review the CSC at a frequency consistent with the needs of the panel and the anticipated restart schedule. The panel should (1) determine review status, (2) verify that necessary tasks and items are complete for each phase of the review, and (3) ensure that review tasks and issues for assessment remain consistent with the known facts and status of the restart effort. The panel should review the generic lists in Sections B and C of this appendix when significant milestones are completed and before restart authorization to ensure that any emerging items are considered.

c. Issue Tracking. The CSC may be used to track the status of NRC actions, track the resolution of restart issues, and provide a central point to reference documentation associated with the resolution of restart issues.

d. After the restart process is complete, the CSC should be closed out in accordance with the Restart Action Plan. The closeout shall include a Restart Panel assessment of licensee readiness and provide a basis for NRC authorizing restart.

B. PROCESS

This section outlines the general NRC restart review process. The major process steps (i.e. initial response, initial notifications, etc.) are broken down into potential tasks provided in a menu format. Only applicable tasks should be selected for incorporation into the CSC. The short discussion before each major process step provides insight into the intended activity. An effort was made to place the major steps and tasks in the general order of performance; however, the exact sequence of events cannot be predicted in advance. Thus, many of the major process steps and the specific tasks are expected to be performed in parallel.

Where possible within the tables, the typical lead responsible organization is given in parentheses next to the task. Where an NRC action responsibility is not indicated, the Restart Panel will determine responsibility. The tables provide a column to mark applicability for the CSC.

B.1 INITIAL NRC RESPONSE

The facts, the causes, and their apparent impacts should be established early in the process. This information will assist the NRC in characterizing the problems, the safety significance, and the regulatory issues. Early management appraisal of the situation is also important to ensure the proper immediate actions are taken. The following items should have been completed or should be incorporated into the CSC as appropriate. Refer to Section 5.02 of this manual chapter for additional information.

TASK

a. Initial notification and NRC management discussion of known facts and issues (Region).

b. Identify/implement additional inspections (i.e. AIT, IIT, or Special) (Region).

c. Determine need for formal regulatory response (i.e. order or CAL).

d. Identify other parties involved (i.e., NRC Organizations, other Federal agencies, industry organizations).

B.2 NOTIFICATIONS

Initial notification of the event quickly communicates NRC's understanding of the event and its immediate response to the parties having an interest in the event. Notification to regional and headquarters offices of cognizant Federal agencies may be appropriate. As the review process continues, additional and continuing notifications may be required.

TASK

a. Issue Daily and Directors Highlight (NRR).

b. Issue preliminary notification (Region).

c. Conduct Commissioner assistants' briefing.

d. Issue Commission paper (NRR).

e. Cognizant Federal agencies notified (i.e., FEMA, EPA, DOJ).

f. State and local officials notified (Region).

g. Congressional notification (NRR).

B.3 ESTABLISH AND ORGANIZE THE NRC REVIEW PROCESS

It will be necessary to establish and organize the NRC restart review to ensure the effective coordination of resources in evaluating the restart process. Effective interactions within and outside the NRC are critical to properly identify and resolve the pertinent issues. Both regional and headquarters offices of cognizant Federal agencies should be considered. Refer to Sections 6 and 7 of this manual chapter for additional information.

TASK

a. Establish the Restart Panel.

b. Assess available information (i.e. inspection results, licensee self-assessments, industry reviews).

c. Obtain input from involved parties both within NRC and other Federal agencies such as FEMA, EPA, DOJ.

d. Conduct Regional Administrator briefing (Region).

e. Conduct NRR Executive Team briefing (NRR).

f. Develop the case-specific checklist (CSC).

g. Develop the Restart Action Plan.

h. Regional Administrator approves Restart Action Plan.

i. NRR Associate Director and/or NRR Director approves Restart Action Plan.

j. Implement Restart Action Plan.

k. Modify CAL or order as necessary.

B.4 REVIEW IMPLEMENTATION

The review can be accomplished by a variety of methods including inspections, testing, evaluation of licensee self-assessments, evaluation of licensee action plans, and regulatory actions (i.e., orders, CALs). Early establishment of the review areas will assist in defining the methods to perform the review. Once the licensee has developed its corrective action plan, the NRC shall review that plan to verify its completeness and adequacy. The NRC will also need to determine which corrective actions will be required to be implemented before restart and thus become restart issues and which can be deferred to some later date as long-term corrective actions. The discussions and issues provided in Section C of this appendix provide additional information to support the review activities described below.

B.4.1 Root Causes and Corrective Actions

TASK

a. Evaluate findings of AIT, IIT, or special team inspection.

b. Licensee performs root cause analysis and develops corrective action plan for root causes.

c. NRC evaluates licensee's root cause determination and corrective action plan.

B.4.2 Assessment of Equipment Damage

For events where equipment damage occurs, a thorough assessment of the extent of damage is necessary. A root cause determination will be necessary if the damage was the result of an internal event. The need for independent NRC assessment should be considered. The licensee will need to determine corrective actions to repair, test, inspect, and/or analyze affected systems and equipment. These actions are required to restore or verify that the equipment will perform to design requirements. Equipment modifications may also be required to ensure performance to design requirements.

Potential offsite emergency response impact for external events such as natural disasters, explosions, or riots should be considered. NRR should obtain information from FEMA headquarters reaffirming the adequacy of State and local offsite emergency plans and preparedness if an event raises reasonable doubts about emergency response capability.

TASK

a. Licensee assesses damage to systems and components.

b. NRC evaluates licensee damage assessment.

c. Licensee determines corrective actions.

d. NRC evaluates corrective actions.

B.4.3 Determine Restart Issues and Resolution

The establishment of the restart issues that require resolution before restart demands a clear understanding of the issues and the actions required to address those issues by both the NRC and the licensee. This section outlines steps to determine the restart issues and NRC's evaluation of their resolution.

TASK

a. Review/evaluate licensee generated restart issues.

b. Independent NRC identification of restart issues (consider sources external to NRC and licensee).

c. NRC/licensee agreement on restart issues.

d. Evaluate licensee's restart issues implementation process.

e. Evaluate licensee's implementation verification process.

B.4.4 Obtain Comments

Since some shutdowns involve a broad number of issues, solicitation of comments from diverse sources may be appropriate. The decision to solicit comments from a group and the level of participation should be made on a case-by-case basis. Input from these groups should be factored into the restart process when they contribute positively to the review. Note: If needed, comments concerning the adequacy of state and local emergency planning and preparedness must be obtained from FEMA headquarters through NRR.

TASK

a. Obtain public comments.

b. Obtain comments from State and Local Officials (Region).

c. Obtain comments from applicable Federal agencies.

B.4.5 Closeout Actions

When the actions to resolve the restart issues and significant concerns are substantially complete, closeout actions are needed to verify that planned inspections and verifications are complete. The licensee should certify that corrective actions required before restart are complete and that the plant is physically ready for restart. This section provides actions associated with completion of significant NRC reviews and preparations for restart.

TASK

a. Evaluate licensee's restart readiness self-assessment (Region).

b. NRC evaluation of applicable items from Section C "ISSUES" complete.

c. Restart issues closed.

d. Conduct NRC restart readiness team inspection (Region)*.

e. Issue augmented restart coverage inspection plan (Region).

f. Comments from other parties considered.

g. Determine that all conditions of the Order/CAL are satisfied.

h. Re-review of Generic Restart Checklist complete.

*NOTE: The restart inspection need not be as comprehensive as an NRC Operational Readiness Assessment Team (ORAT) inspection. However, the inspection shall be tailored to the restart issues under evaluation. The restart inspection should focus on an overall assessment of the licensee's readiness to restart and should provide a basis for concluding restart should be authorized.

B.5 RESTART AUTHORIZATION

When the restart review process has reached the point that the issues have been identified, corrected, and reviewed, a restart authorization process is begun. At this point the Restart Panel should think broadly and ask: "Are all actions substantially complete? Have we overlooked any items?"

TASK

a. Prepare restart authorization document and basis for restart (Region).

b. NRC Restart Panel approves Restart Authorization.

c. No restart objections from other applicable HQ offices.

d. No restart objections from applicable Federal agencies.

e. Regional Administrator concurs in Restart Authorization.

f. NRR Associate Director and/or NRR Director concurs in Restart Authorization (NRR).

g. EDO concurs in Restart Authorization when required.

h. Conduct ACRS briefing when requested (NRR).

i. Conduct Commission briefing when requested (NRR).

j. Commission concurs In Restart Authorization when required.

k. Regional Administrator authorizes restart.

B.6 RESTART AUTHORIZATION NOTIFICATION

Notify the applicable parties of the restart authorization. Notifications should generally be made using a memorandum or other format consistent with the level of formality required. Communication of planned actions is important at this stage to ensure that NRC intentions are clearly understood.

TASK

a. Commission (if the Commission did not concur in the Restart Authorization or as requested) (NRR).

b. EDO (if the EDO did not concur in the Restart Authorization or as requested) (NRR).

c. Congressional Affairs (NRR).

d. ACRS (a briefing may be substituted for the written notification if the ACRS requests a briefing) (NRR).

e. Applicable Federal agencies (NRR).

f. Public Affairs (Region).

g. State and local officials (Region).

h. Citizens or groups that expressed interest during the restart approval process (Region).

i. International Programs for sites whose emergency planning zones cross international boundaries (NRR).

C. ISSUES

Restart review actions for specific situations may address additional issues or may omit issues discussed below if such issues are determined not to be applicable to the situation. The following sections contain items for consideration by the Restart Panel during the restart review. These items are based on issues found during other restart reviews. The experience is primarily based on plant shutdowns due to management deficiencies, hardware issues, or a combination. External events such as natural disasters, explosions, or riots may require development of a unique set of specific issues. A column is provided to mark whether or not an item is applicable.

C.1 ASSESSMENT OF ROOT CAUSE IDENTIFICATION AND CORRECTION

The root cause(s) of the event or the conditions requiring the shutdown should be identified and corrected. A comprehensive licensee corrective action plan should be developed that addresses the root cause(s) and all applicable issues including corrective action, implementation, and verification. The licensee should revise its corrective action plan as necessary to ensure emergent issues are addressed and resolved. The Restart Panel should ensure that emergent issues identified by the NRC are promptly conveyed to the licensee for incorporation into the licensee's corrective action plan. The corrective action plan should also include sufficient measures to prevent recurrence of problems. The NRC shall review the licensee's corrective action plan to verify its completeness and adequacy and to determine which corrective actions will be required to be implemented before restart and which can be deferred to some later date as long-term corrective actions.

The NRC will review the licensee's corrective action activities and use the tools available in the regulatory program to determine the acceptability of these actions with respect to safe operations. These tools include staff reviews; the systematic assessment of licensee performance (SALP); inspections, including special team inspections; requests under 10 CFR 50.54(f); senior management meetings; enforcement conferences; and a Restart Panel. The results of the staff's reviews will be documented by safety evaluations, license amendments, orders, confirmatory action letters, inspection reports, Commission meeting transcripts, and enforcement documents.

C.1.1 Root Cause Assessment

ISSUES

a. Conditions requiring the shutdown are clearly understood.

b. Root causes of the conditions requiring the shutdown are clearly understood.

c. Root causes of other significant problems are clearly understood.

d. Effectiveness of the root cause analysis program.

C.1.2 Damage Assessment

ISSUES

a. Damage assessment was thorough and comprehensive.

b. Corrective actions clearly restored systems and equipment or verified they can perform as designed.

C.1.3 Corrective Actions

ISSUES

a. Thoroughness of the corrective action plan.

b. Completeness of corrective action programs for specific root causes.

c. Control of corrective action item tracking.

d. Effective corrective actions for the conditions requiring the shutdown have been implemented.

e. Effective corrective actions for other significant problems have been implemented.

f. Control of long-term corrective actions.

g. Effectiveness of the corrective action verification process.

C.1.4 Self-Assessment Capability

The occurrence of an event may be indicative of potential weaknesses in the licensee's self-assessment capability. A strong self-assessment capability creates an environment where problems are readily identified, prioritized, and tracked. Effective corrective actions require problem root cause identification, solutions to correct the cause, and verification methods that ensure the issue is resolved. Senior licensee management effectiveness in ensuring effective self-assessment is treated separately.

ISSUES

a. Effectiveness of Quality Assurance Program.

b. Effectiveness of Industry Experience Review Program.

c. Effectiveness of licensee's Independent Review Groups.

d. Effectiveness of deficiency reporting system.

e. Staff willingness to raise concerns.

f. Effectiveness of PRA usage.

g. Effectiveness of commitment tracking program.

h. External audit (i.e. INPO) capability.

i. Quality of 10 CFR 50.72 and 50.73 reports.

C.2 ASSESSMENT OF LICENSEE MANAGEMENT EFFECTIVENESS

The NRC staff should evaluate the effectiveness of the licensee's management in assessing, evaluating, and resolving the problems and the associated root causes that resulted in the plant shutdown and contributing problems. The effectiveness of licensee's management in addressing the problems and root causes of the plant shutdown should be measured against the results achieved by the licensee. The results should demonstrate a coordinated and integrated approach to resolving the problems and developing corrective actions, the problems and corrective actions should be effectively communicated to the licensee's staff, and the corrective actions should be assigned priority consistent with their safety significance. Licensee's management must demonstrate an ability to recognize safety problems, develop and implement adequate corrective actions, and verify the effectiveness of the corrective actions in a timely manner.

C.2.1 Management Oversight and Effectiveness

ISSUES

a. Goals/expectations communicated to the staff.

b. Demonstrated expectation of adherence to procedures.

c. Management involvement in self-assessment and independent self-assessment capability.

d. Effectiveness of management review committees.

e. Management's demonstrated awareness of day-to-day operational concerns.

f. Management's ability to identify and prioritize significant issues.

g. Management's ability to coordinate resolution of significant issues.

h. Management's ability to implement effective corrective actions.

C.2.2 Management Support

ISSUES

a. Impact of any management reorganization.

b. Effective and timely resolution of employee concerns.

c. Adequate engineering support as demonstrated by timely resolution of issues.

d. Adequate plant administrative procedures.

e. Effective information exchange with other utilities.

f. Participation in industry groups.

g. Effectiveness of Emergency Response Organization.

h. Coordination with offsite emergency planning officials.

C.3 ASSESSMENT OF PLANT AND CORPORATE STAFF EFFECTIVENESS

The licensee staff must be capable of recognizing and carrying out their responsibilities to ensure public health and safety. The effectiveness of the plant and corporate staff should be assessed on the basis of the results achieved by the licensee. A proactive attitude toward safety issues should be demonstrated in all aspects of operations. In this regard, the licensee staff should display attentiveness to duty, fitness for duty, a disciplined approach to activities, a sensitivity for trends in the plant, security awareness, an openness of communications, and a desire for teamwork that supports effective relations between different groups (e.g., management, operations, health physics, maintenance, engineering, security, and contractors).

C.3.1 Assessment of Staff

ISSUES

a. Demonstrated commitment to achieving improved performance.

b. Demonstrated safety consciousness.

c. Understanding of management's expectations and goals.

d. Understanding of plant issues and corrective actions.

e. Qualifications and training of the staff.

f. Staff's fitness for duty.

g. Attentiveness to duty.

h. Level of attention to detail.

i. Off-hour plant staffing.

j. Staff overtime usage.

k. Procedure usage/adherence.

l. Awareness of plant security.

m. Understanding of offsite emergency planning issues.

C.3.2 <u>Assessment of Corporate Support</u>

ISSUES

a. Corporate staff understanding of plant issues.

b. Corporate staff site specific knowledge.

c. Effectiveness of the corporate/plant interface meetings.

d. Corporate involvement with plant activities.

e. Effectiveness of corporate engineering support.

f. Effectiveness of corporate design modification process.

g. Effectiveness of licensing support.

h. Coordination with offsite emergency planning officials.

C.3.3 <u>Operator Issues</u>

ISSUES

a. Licensed operator staffing meets requirements and licensee goals.

b. Level of formality in the control room.

c. Effectiveness of control room simulator training.

d. Control room/plant operator awareness of equipment status.

e. Adequacy of plant operating procedures.

f. Procedure usage/adherence.

g. Log keeping practices.

C.4 ASSESSMENT OF PHYSICAL READINESS OF THE PLANT

The physical condition of the plant is of principal importance not only when a shutdown is the result of a physical event or a hardware deficiency but for other reasons as well, especially following prolonged outages.

The licensee should identify the causes of significant equipment problems and take appropriate corrective actions taken. Operational testing should verify that each significant equipment problem has been resolved. As appropriate, the complete spectrum of preoperational and startup testing programs may need to be expanded to cover the more complex types of problems or the effects on plants that have been shut down for extended periods.

The licensee must be able to demonstrate that all needed safety equipment is operational before restart. Systems and equipment need to be available and aligned. Surveillance tests should also be up to date. The maintenance backlog should be managed at controllable levels and should be evaluated for impact on safe operation. Maintenance personnel must also be capable of responding to equipment failures during startup and operation and should not be hindered by unresolved chronic problems with equipment readiness. Procedures should be adequate and up to date. The emergency preparedness function both onsite and offsite needs to be capable of protecting public health and safety.

ISSUES

a. Operability of technical specification systems.

b. Operability of required secondary and support systems.

c. Results of pre-startup testing.

d. Adequacy of system lineups.

e. Adequacy of surveillance tests/test program.

f. Significant hardware issues resolved (i.e. damaged equipment, equipment ageing, modifications).

g. Adequacy of the power ascension testing program.

h. Effectiveness of the plant maintenance program.

i. Maintenance backlog managed and impact on operation assessed.

j. Adequacy of plant housekeeping and equipment storage.

C.5 ASSESSMENT OF COMPLIANCE WITH REGULATORY REQUIREMENTS

The plant and its prospective operation must not be in conflict with any applicable regulations or requirements of any document authorizing restart (such as license amendments, orders, or CAL). Restart should not conflict with any ongoing matter such as an Atomic Safety and Licensing Board hearing.

ISSUES

a. Applicable license amendments have been issued.

b. Applicable exemptions have been granted.

c. Applicable reliefs have been granted.

d. Imposed Orders have been modified or rescinded.

e. Confirmatory Action Letter conditions have been satisfied.

f. Significant enforcement issues have been resolved.

g. Allegations have been appropriately addressed.

h. 10 CFR 2.206 Petitions have been appropriately addressed.

i. Atomic Safety and Licensing Board hearings have been completed.

C.6 COORDINATION WITH INTERESTED AGENCIES AND PARTIES

Coordination with other interested agencies and parties is important to ensure that concerns and requirements of these organizations are factored into the restart authorization.

ORGANIZATION

a. Federal Emergency Management Agency

b. Environmental Protection Agency

c. Department of Justice

d. Department of Labor

e. Appropriate State and local officials

f. Appropriate public interest groups

g. Local news media

END

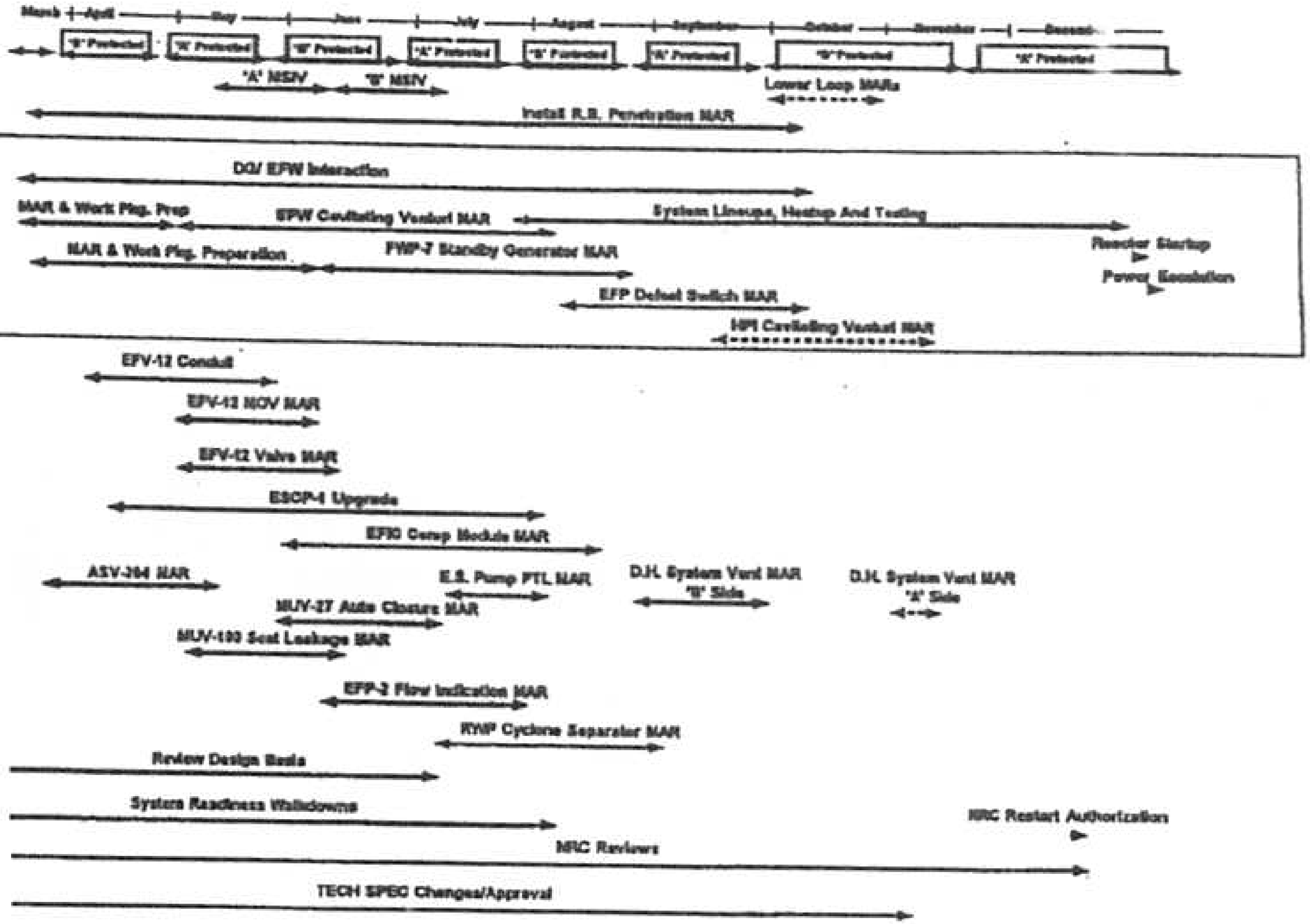
Exhibit____(WRJ-5)

Critical Path Timeline Chart
Crystal River Unit 3 Restart Plan

APPENDIX "H" TO FLORIDA POWER CORPORATION'S PRELIMINARY REPORT

Appendix "H" CRITICAL PATH TIMELINE CHART

Crystal River Unit #3 Restart Plan



Exhibit____(WRJ-6)

Historical Description of
EFW System Changes

Historical Description of EFW System Changes

There have been nine (9) different configurations of the Emergency Feedwater (EFW) system since 1980 when the "A" train EFW pump was automatically loaded to the "A" train Emergency Diesel Generator (EDG-A). The purpose of this section is to describe: (1) each of these configurations; (2) the problems which were addressed when changing from configuration to configuration; and (3) the problems which were created by these changes. Schematic diagrams included with this section show each of the major configurations since 1980. These diagrams show the changes made to the EFW system, why the changes were made, and what unresolved problems remained for each configuration.

The purpose of the following summary is to provide an overall description of how the EFW system evolved since 1980 so that the root cause evaluation results can be understood in the context of the history of the plant and EFW system. The root causes associated with human errors, inappropriate actions, organizational failures, and programmatic deficiencies are addressed elsewhere.

An observation which can be made from review of the various changes to the EFW system since 1980, is that the majority (7 of 9) of the configurations introduced one or more problems or missed an opportunity to identify and resolve previous problems. Several attempts to improve upon a weak design have not resolved certain long-standing issues.

Configuration #1: Pre-1980 Design of EFW System

The Emergency Feedwater (EFW) system was originally designed as a non-safety system to provide secondary coolant to the Once Through Steam Generators (OTSG) in the event that the main feedwater system (FW) became unable to perform this function or when either steam generator had less than 18 inches water. Two independent but interconnected trains were available, each of which was capable of supplying emergency feedwater to either or both OTSGs. Both EFW pumps, turbine and motor-driven, and the Condensate Storage Tank werc designed to Seismic Class 1 requirements. The motor-driven pump, EFP-1 received power from the "A" Engineered Safeguards (ES) 4160 V bus. Upon an AC power failure at the bus, EFP-1 would trip and could be manually loaded to the "A" EDG after completion of the block loading sequence.

The "B" train used a steam turbine-driven EFW pump (EFP-2) with steam supplied from either of the OTSGs.

Problem 1-1: Following TMI-2, enhanced reliability was considered necessary for the Emergency Feedwater System. Several concerns were identified requiring system upgrade to address weaknesses in single failures of pump suction valve, separation of EFW from the non-safety Integrated Control System, the need to automatically load EFP-1 onto the diesel generator, and flow control valve reconfiguration.

Configuration #2: EFW Pump EFP-1 Automatically Connected to EDG-A (July 1980)

Enhanced reliability of the Emergency Feedwater System was obtained by automatically block loading EFP-1 to the "A" train Emergency Diesel Generator (EDG-1A). This change was accomplished by Modification Approval Record (MAR) 79-11-82 by adding a fifth block to the EDG loading sequence.

This change introduced two problems:

Problem 2-1: Under some circumstances, the 30-minute load limit rating of EDG-1A was exceeded with EFP-1 connected. It was assumed that EDG-A could be operated in the overloaded condition up to the 30 minute limitation defined by the manufacturer, and then continue operation at a decreased load associated with the 200 or 2000 hour engine rating. An alarm was provided in the Control Room to indicate the EDG was operating in the 30-minute rating. In addition, an automatic trip of EFP-1 was provided at the end of the 30-minute rating. It may not have been understood that overloading the EDG up to its 30 minute load limit used up its reserve margin such that no reserve was left for operating at the 200 or 2000 hour engine ratings.

Problem 2-2: As discussed above, EFP-1 could be tripped after 30 minutes, thus relying upon EFW pump EFP-2 to supply feedwater to the OTSGs. The analysis used to support the reliance on EFP-2 did not consider that a single failure of EFP-2 or a loss of the "B" DC bus prior to the start of EFP-2, along with a Loss of Offsite Power (LOOP) and Loss of Coolant Accident (LOCA) could render the EFW system inoperable.

Configuration #3: Valve ASV-204 Installed Parallel to ASV-5 (March 1985)

ASV-204 was installed parallel to ASV-5 to increase the reliability of the EFW system to admit steam to EFP-2 (MAR 80-11-48-01 and MAR 80-11-48-02). Valve ASV-204 was connected to the "B" train DC power supply. Although this modification improved the reliability of EFP-2 associated with operation of ASV-5, it did not resolve EDG-1A overloading (Problem 2-1), or the reliance on both EFW trains under some circumstances (Problem 2-2). No new problems were generated by this configuration change; however, see Configuration #5 for additional changes made to ASV-204.

Configuration #4: EFIC System Added (August 1985)

The Emergency Feedwater Initiation and Control (EFIC) system was installed (MAR 80-10-66-1 through MAR 80-10-66-26A). This change automated many of the control functions associated with the operation of the EFW system, removed the manual regulating valves (FWV-161 and 162), and added individual control valves (EFV-55 through 58). However, it did not resolve the EDG-1A overloading (Problem 2-1) or the reliance on both EFW trains under some circumstances (Problem 2-2) as described in Configuration #2. Further, it added an additional problem, described below.

Problem 4-1: This modification did not address concerns identified by the AE/NSSS vendor regarding EFW pump runout. Under some circumstances (e.g., when the EFIC System is actuated with the secondary side of the OTSGs at low pressure), the flow to the OTSGs could be excessive and possibly cause cavitation of the EFW pumps, overcooling of the OTSGs, and damage to OTSG tubes due to excessive cross flow. It should be understood that EFW pumps were sized to enable certain flows at high OTSG pressures, thus creating the problem of excessive flows at low pressures.

Configuration #5: Switched Source of Power and Control for Valve ASV-204 to "A" Train (December 1987)

The EFW system was modified to power and control ASV-204 from the "A" train of the EFIC system instead of the "B" train (Temporary MAR T87-10-09-01). This was done so that EFW pump EFP-2 could be run in parallel with EFP-1 and supply part of the feedwater flow to the OTSGs. This was intended to reduce the load on the "A" EDG so that its load limits, as described in Problem 2-1, would not be exceeded. This modification was implemented as an alternative to increasing EDG capacity. This modification did not address the reliance on both EFW trains under some circumstances as described in Problem 2-2 (i.e., lack of redundancy to protect against single failure). Likewise, this modification did not address the EFW pump runout and potential excessive feedwater flow described in Problems 4-1 (potential cavitation of EFW pumps, overcooling of the OTSGs, and OTSG tube cross flow damage). In addition, this modification failed to address three other problems as described below.

Problem 5-1: Depending on both trains of EFW was now hardwired into the EFW system. Whenever the "A" train operated, the "B" train automatically operated in parallel. The ability of EDG-1A to supply all required loads was now dependent on the operation of the "B" train pump, EFP-2.

Problem 5-2: If "B" DC bus power is lost to flow control valves EFV-55 and 56 (EFP-2 flow control valves), feedwater flow from EFP-2 would be uncontrolled and quickly fill the OTSGs. The secondary side water level would have been limited only by the overfill protection circuit (part of EFIC) which uses block valves EFV-11 and EFV-32 (powered from the "A" DC train batteries) to isolate the "B" train of the EFW system. As water boiled off from the OTSG, the water level would drop below the overfill reset point and the isolation block valves would re-open, thus creating a "coarse" level controller. The unanticipated duty cycle of repeatedly opening and closing block valves EFV-11 and EFV-32 was not evaluated. However, it is likely that the relatively large difference between the overfill and overfill reset setpoints for the block valves provided sufficient "rest time" for these block valves.

Problem 5-3: TMAR 87-10-09-01 (powering ASV-204 from the "A" train) was designed in parallel with, and installed 4 days prior to the flow limiting MAR (86-05-25-01) discussed in Configuration #6. TMAR 87-10-09-01 negated the benefits of the flow limiting MAR since flow would not be limited during loss of "B" DC bus scenario.

Configuration #6: EFIC System Modified to Limit EFW Flow (December 1987)

The EFIC system was modified to include a flow limiting circuit which prevents EFW pump runout (under most circumstances) and the associated problems as discussed in Problem 4-1 (MAR 86-05-25-01). This modification implemented an electrical/control solution to correct the potential for excessive flow. Some B&W plants installed mechanical flow limiting devices (cavitating venturis) instead.

This modification did not fully address Problem 2-2 (single failure vulnerability), Problem 5-1 (cross-train dependency), and Problem 5-2 (cycling of block valves). Further, it did not consider all the failure modes where EFW pump EFP-2 could run out as described below.

Problem 6-1: Not all failure modes were considered in developing this modification to address Problem 4-1. If the EFW pump EFP-2 was operating (i.e., ASV-5 and/or ASV-204 was open) and power (e.g., the "B" battery) was lost, flow control valves EFV-55 and EFV-56, would fail completely open and allow EFP-2 to run out. Under some circumstances (e.g., when the pressure on the secondary side of the OTSGs is low), the EFW flow rate during pump runout could become excessive and cause the same problems described in Problem 4-1 (EFW pump cavitation, OTSG overcooling, OTSG tube damage) and in Problem 5-2 (reliance on cycling of block valves to control the water level in the OTSGs).

Configuration #7: EFP-1 Tripped When LPI Actuated (June 1990)

Since the "A" EDG did not have the capacity to support both the EFP-1 and the Low Pressure Injection (LPI) pumps, a modification was made to drop EFP-1 from EDG-1A and start the LPI pumps when the pressure in the Reactor Coolant System (RCS) dropped below the LPI setpoint of 500 psi (MAR 88-05-24-01). This scenario would occur during a postulated Loss of Offsite Power (LOOP) and a Small Break Loss of Coolant Accident (SBLOCA).

This modification was based on the assumption that emergency feedwater would continue to be supplied by EFP-2 after the primary side pressure dropped below 500 psi and EFP-1 was tripped. EFW flow is needed until the primary side pressure drops to less than about 200 psi, at which point the LPI pumps have sufficient shutoff head to allow water to be injected directly into the reactor coolant system for decay heat removal.

This modification did not fully address previous problems (2-1, 4-1, 5-1, 5-2, and 6-1). It introduced an additional cross-train dependency as described below.

Problem 7-1: This modification added another element of cross train dependency. During a SBLOCA and LOOP, EFP-1 would not be available when RCS pressure dropped below 500 psi. Addition of feedwater under these circumstances is dependent upon the "B" train of the EFW system assuming EDG "A" load margin is not available to support restarting EFP-1.

Configuration #8: Addition of Auxiliary Feedwater System (AFW) (April, 1993)

An auxiliary source of secondary cooling was installed in April, 1993 (MAR 88-07-05-01) by addition of Feedwater Pump FWP-7 with a rated capacity of 800 gpm. The purpose of this pump and associated components was to provide an additional, non-safety related source of secondary heat removal to the steam generators in emergency conditions only if main feedwater and emergency feedwater are unavailable. This satisfied NRC Generic Issue 124 and Standard Review Plan (SRP) Section 10.4.9 with respect to emergency feedwater reliability criterion. Auxiliary Feedwater is injected at the upper nozzles of each steam generator (same as EFW) and is independently regulated by pneumatic control valves. Flow is displayed in the control room. FWP-7 and its control valve may be manually operated from the control room, independent of EFIC or any other automatic actuation.

No new problems were introduced by this modification. However, it should be noted that previous EFW system problems (2-1, 4-1, 5-1, 5-2, 6-1, and 7-1) were not addressed.

Configuration #9: Disabled Automatic Opening of Valve ASV-204 (May 1996)

During an evaluation of Emergency Operating Procedures associated with the EFW system, FPC recognized that EFW pump EFP-2 could runout if flow control valves EFV-55 and EFV-56 failed fully open upon loss of "B" battery power (Problems 4-1 and 6-1) and possibly cause pump cavitation due to insufficient NPSH. There was also a concern that block valves EFV-11 and EFV-32 would cycle excessively while controlling flow to the OTSGs. This concern was an enhancement of the concern discussed in Problem 5-2 and was created by a 1995 calculation requiring the overfill and overfill reset setpoints to be set closer together, thus increasing the duty cycle of the block valves.

To prevent these identified problems, automatic opening of valve ASV-204 was disabled (MAR 96-04-12-01) so that EFP-2 would not automatically operate when the EFIC system signaled EFP-1 to operate. Since a number of upgrades to EDG-1A were made between 1988 and 1990 to provide additional loading margin, it was thought that EDG-1A could handle the load. Manual operation of ASV-204 was still possible. This modification to the EFW system solved several problems, namely:

- Eliminated the hardwired cross train dependencies (Problems 2-2, and 5-1)
- Prevented excessive feedwater flow due to pump runout under some circumstances (Problems 4-1, and 6-1)
- Prevented the need for cycling of block valves EFV-11 and EFV-32 under some circumstances (Problem 5-2)

This change, however, did not address all the problems associated with the EFW system. The problems which remained (or were re-introduced) from earlier configurations were as follows:

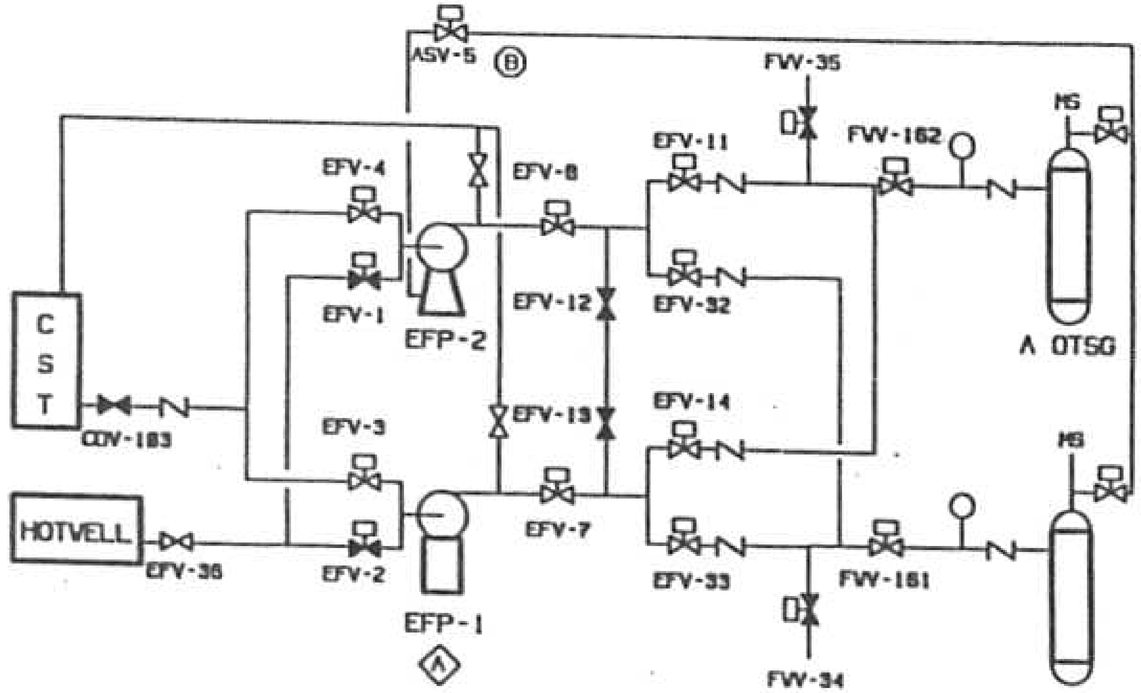
- Exceeded the EDG-1A load limits (Problem 2-1)
- Only one train of EFW was available at OTSG pressures below 500 psi during LOOP and SBLOCA (Problem 7-1)
- The potential single active failure which could result in uncontrolled EFW flow remained (Problem 6-1)

In addition, this change to the EFW system created the following additional problems:

Problem 9-1: This modification reduced the reliability of EFP-2 since ASV-204 was no longer automatically opened. Therefore, the probability of EFP-2 to start when needed was reduced.

Problem 9-2: This modification did not account for the fact that EFW may be needed below 500 psig during a LOOP when EFP-1 is tripped (see Configuration #7). This created an unanalyzed condition in that EFW would not be available for removal of decay heat below 500 psig.

Configuration #1 - Pre-1980 Design of EFW System



AC Power

(O) - Offsite Power

(A) - "A" EDG

DC Power

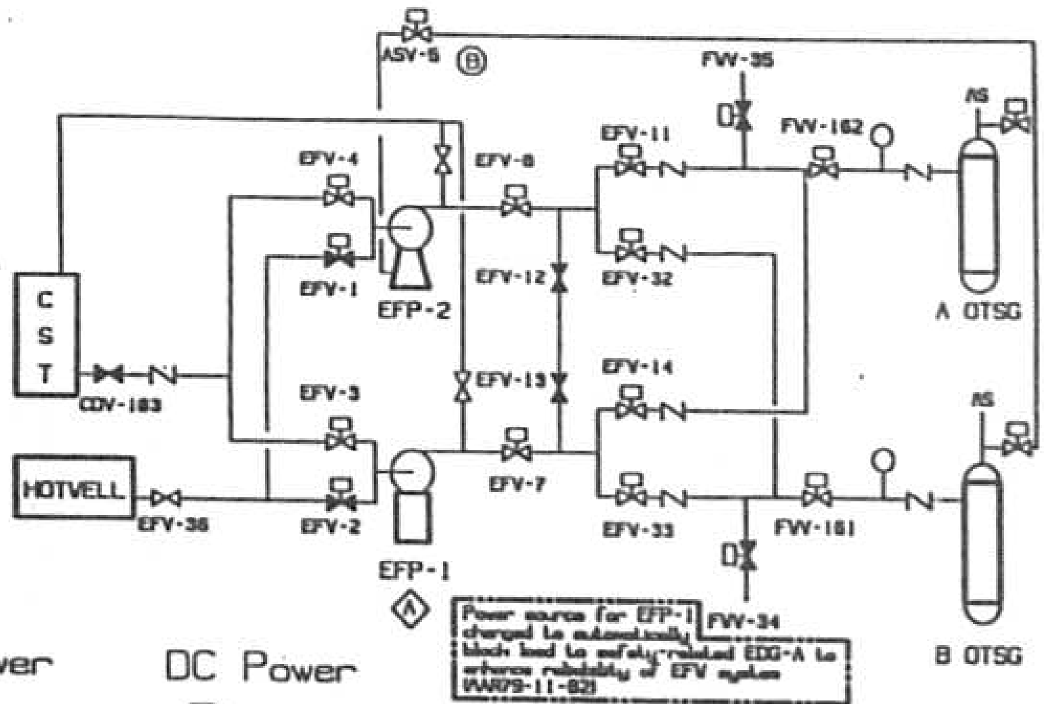
(A) - "A" Battery

(B) - "B" Battery

Unresolved Problems:

1-1 EFW required to be upgraded to safety related after TMI-2

Configuration #2 - EFP-1 Auto Connected to EDG-A (July 1980)



AC Power

- O - Offsite Power
- A - "A" EDG

DC Power

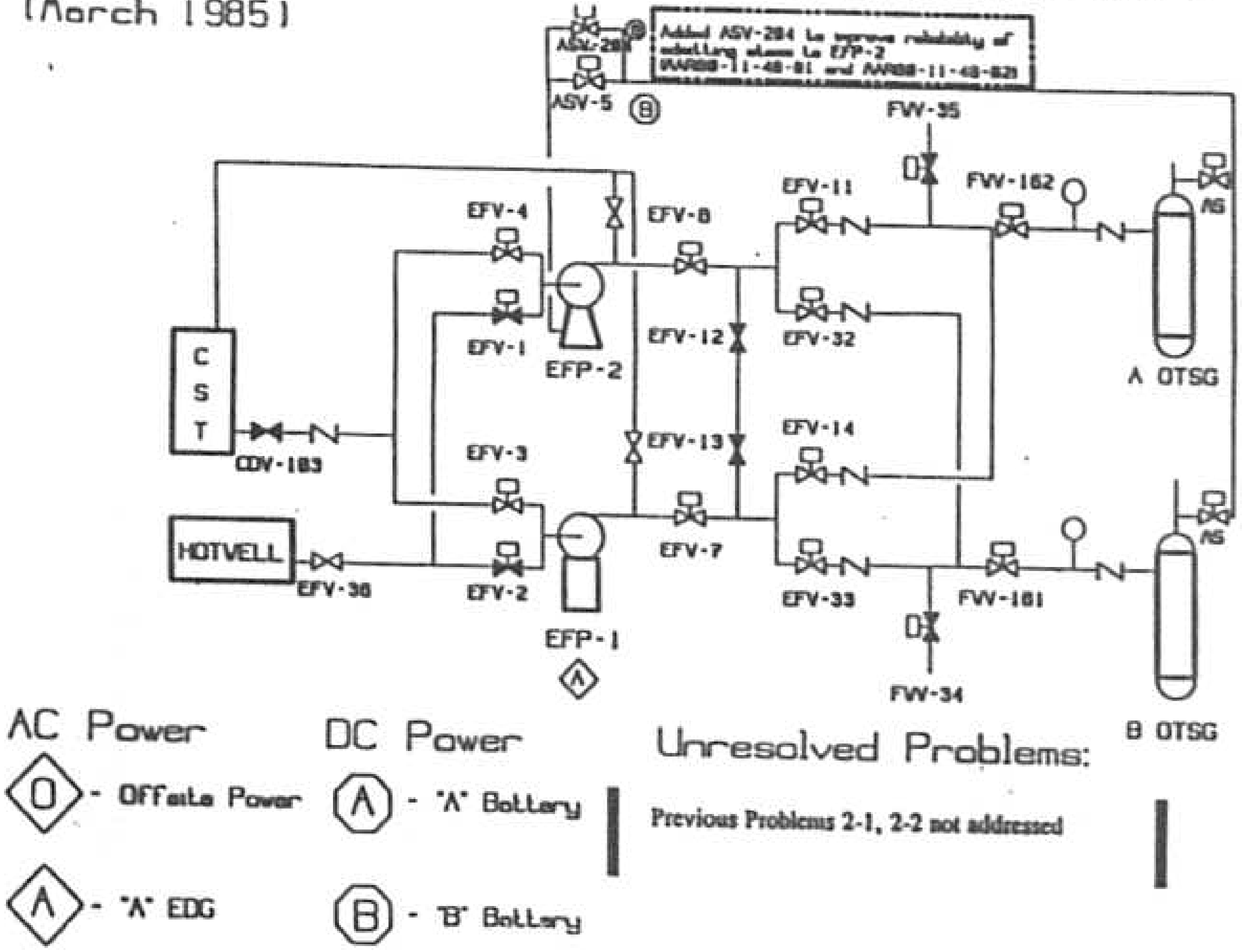
- A - "A" Battery
- B - "B" Battery

Unresolved Problems:

2-1 EDG-1A overloaded under some circumstances

2-2 Single failure vulnerability for EFP-2 with auto trip of EFP-1

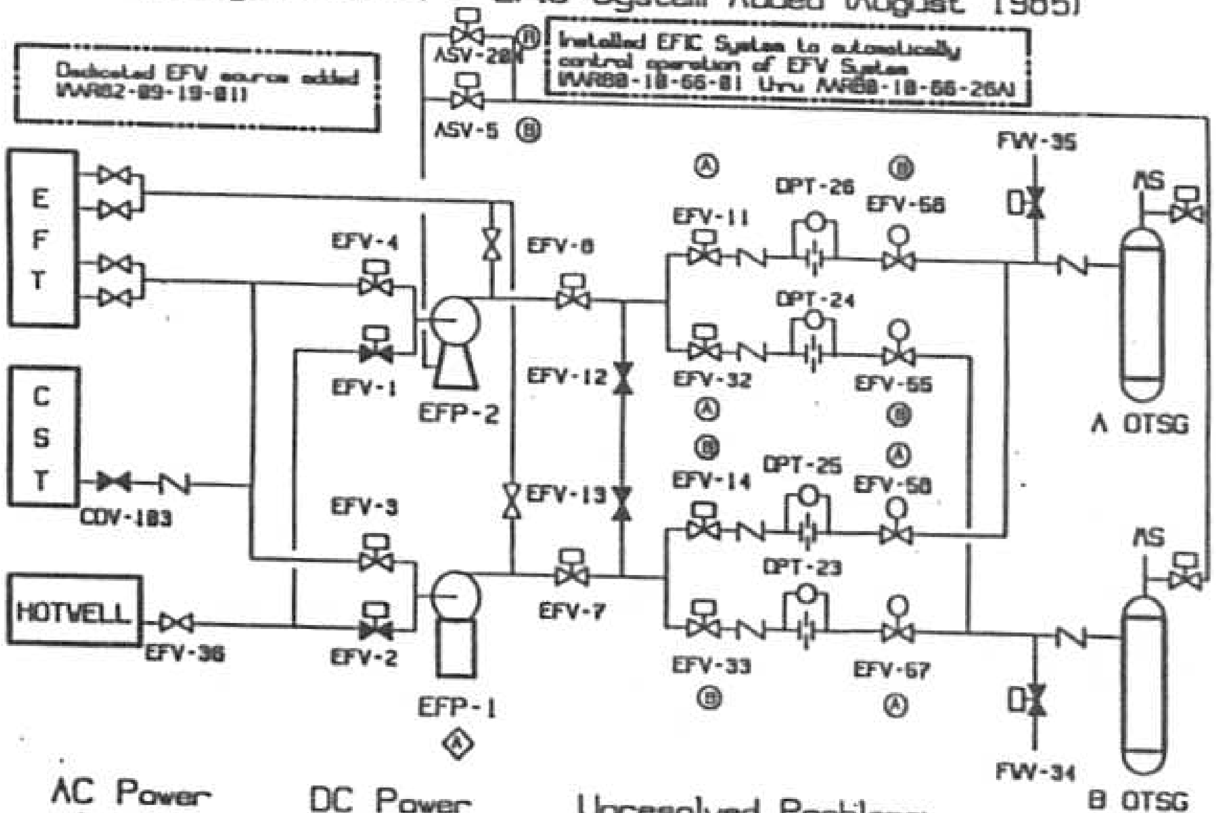
Configuration #3 - Valve ASV-204 Installed Parallel to ASV-5 (March 1985)



Unresolved Problems:

Previous Problems 2-1, 2-2 not addressed

Configuration #4 - EFIC System Added (August 1985)



AC Power

(O) - Offsite Power

(A) - 'A' EDG

DC Power

(A) - 'A' Battery

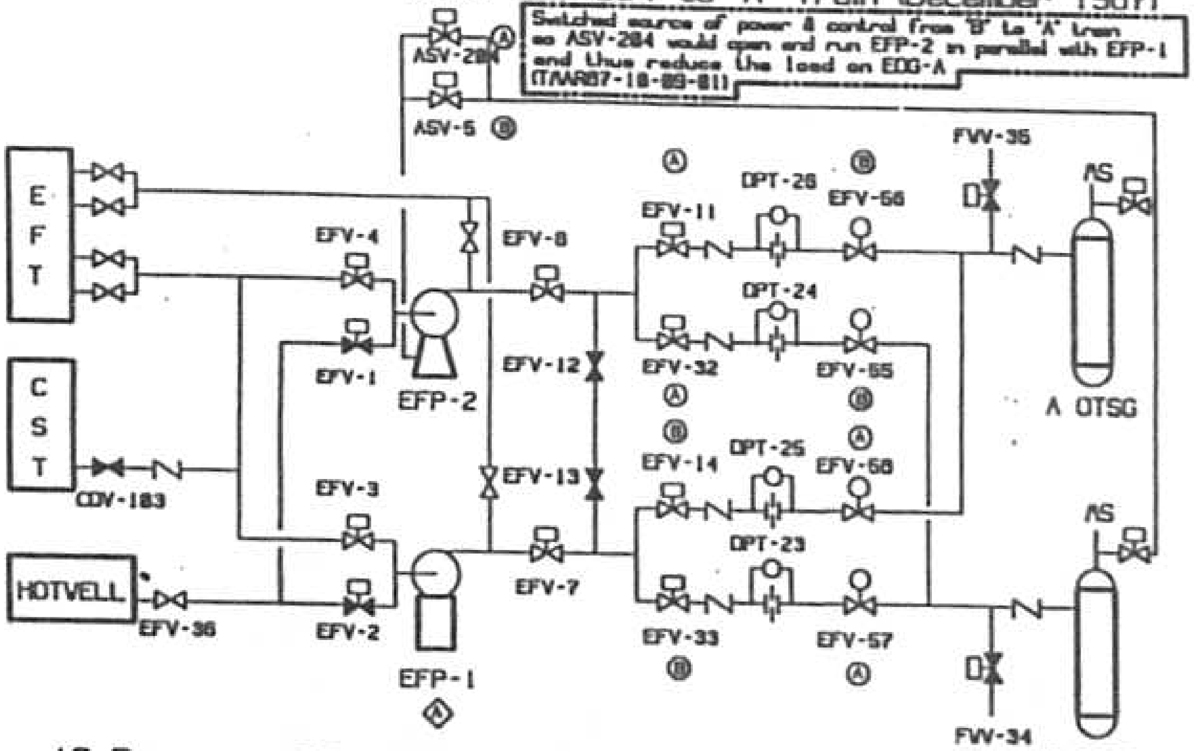
(B) - 'B' Battery

Unresolved Problems:

2-1, 2-2 Previous problems not addressed

4-1 EFW pump runout could cause cavitation, overcooling of OTSG and OTSG tube damage

Configuration #5 - Switched Source of Power & Control for Valve ASV-204 to "A" Train (December 1987)



AC Power

(O) - Offsite Power

(A) - "A" EDG

DC Power

(A) - "A" Battery

(B) - "B" Battery

Unresolved Problems:

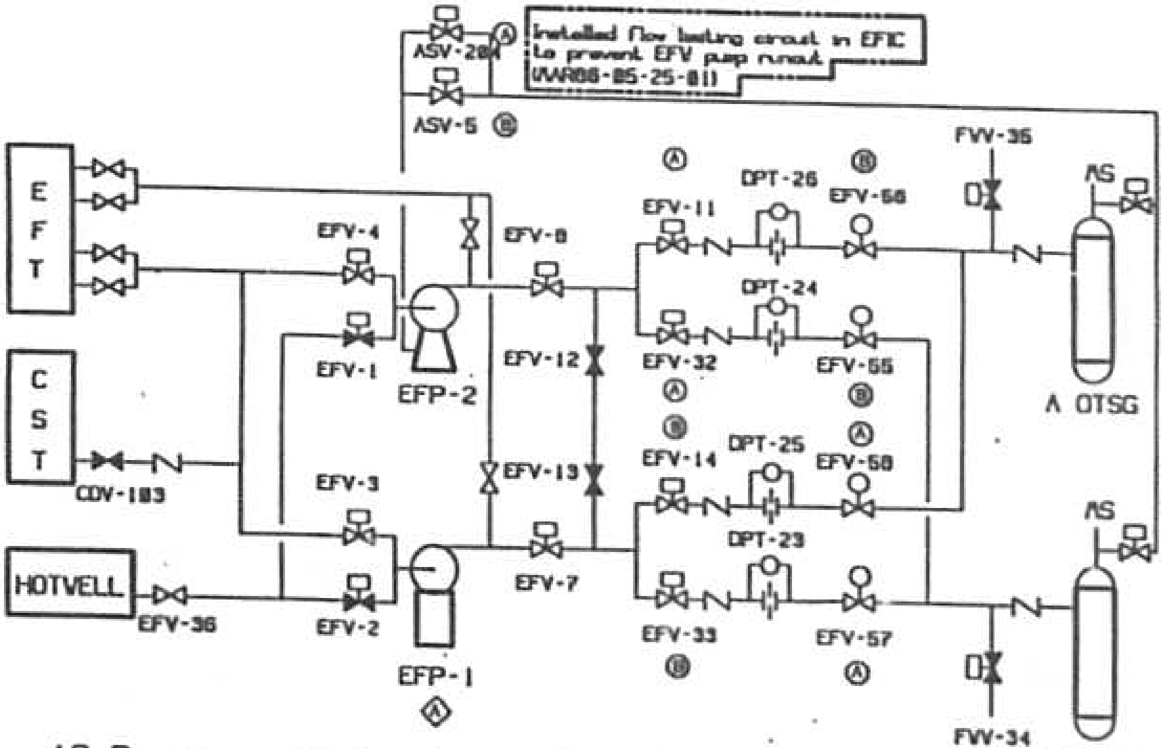
2-2, 4-1 Previous problems not addressed

5-1 Cross-train dependency

5-2 Cycling of block valves to control OTSG level

5-3 Benefits of flow limiting change in Conf #6 negated by this change

Configuration #6 - EFIC System Modified to Limit EFW Flow (December 1987)



AC Power

O - Offsite Power

A - 'A' EDG

DC Power

A - 'A' Battery

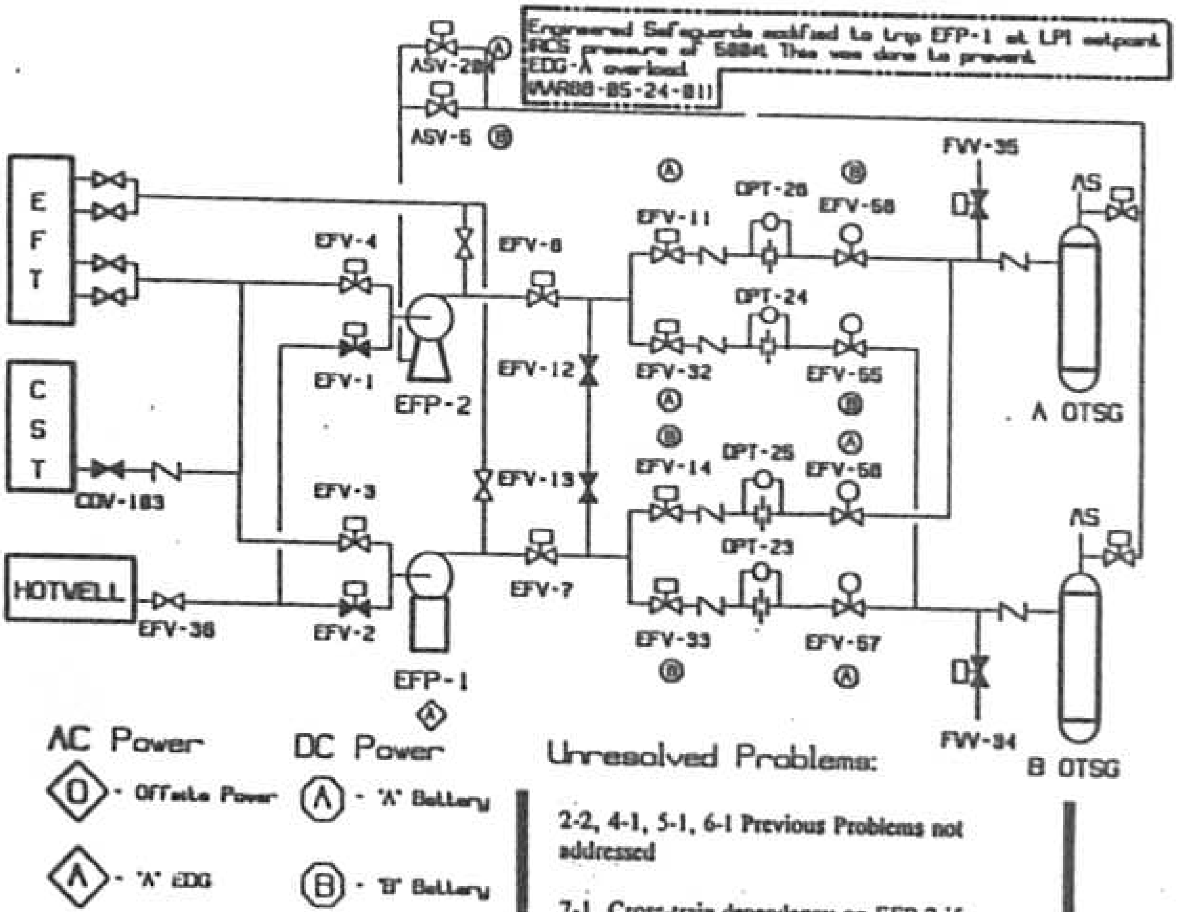
B - 'B' Battery

Unresolved Problems:

2-2, 5-1 Problems not addressed

6-1 Loss of "B" DC bus not considered regarding possible EFP-2 runout.

Configuration #7 - EFP-1 Tripped When LPI Pumps Auto Start
(June 1990)

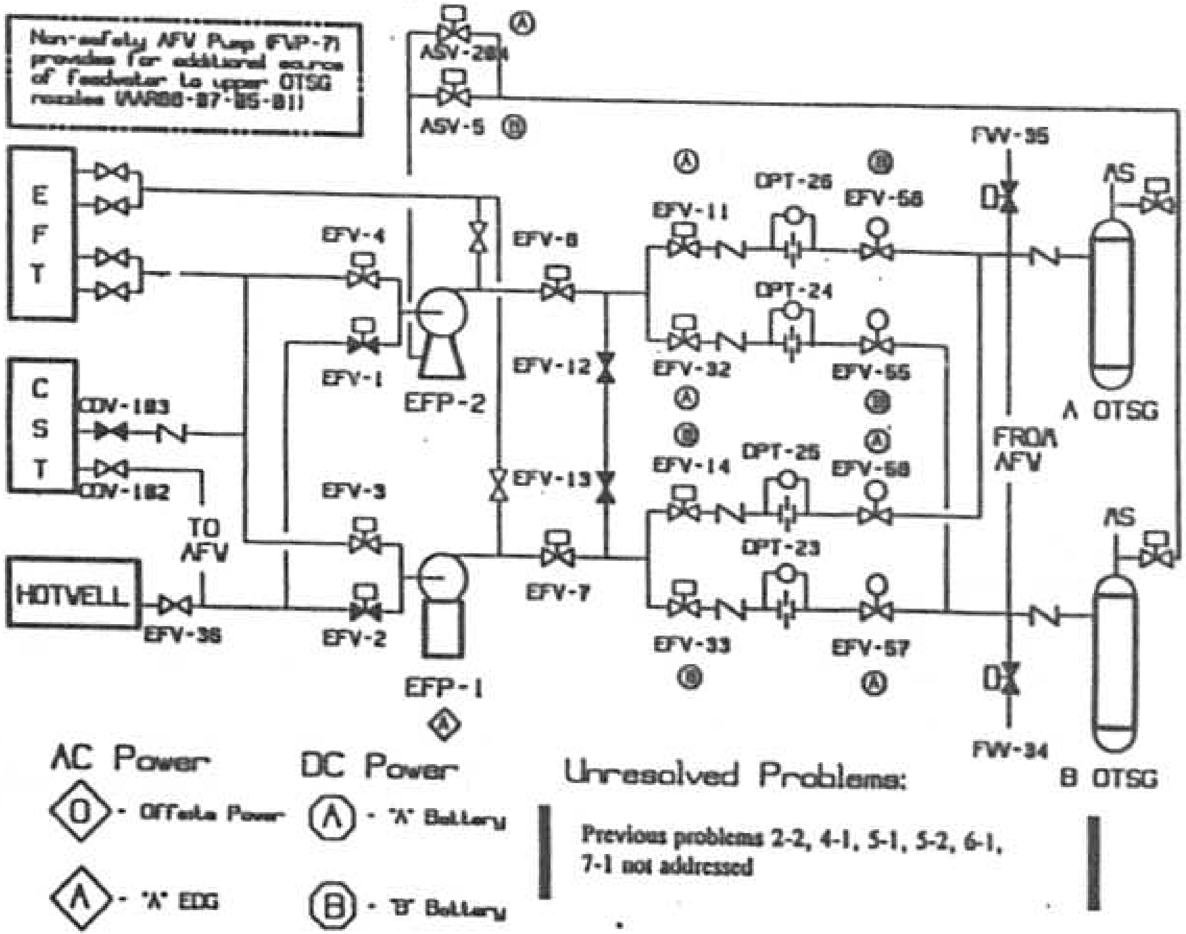


Unresolved Problems:

2-2, 4-1, 5-1, 6-1 Previous Problems not addressed

7-1 Cross-train dependency on EFP-2 if insufficient EDG-1A margin to restart EFP-1 when needed

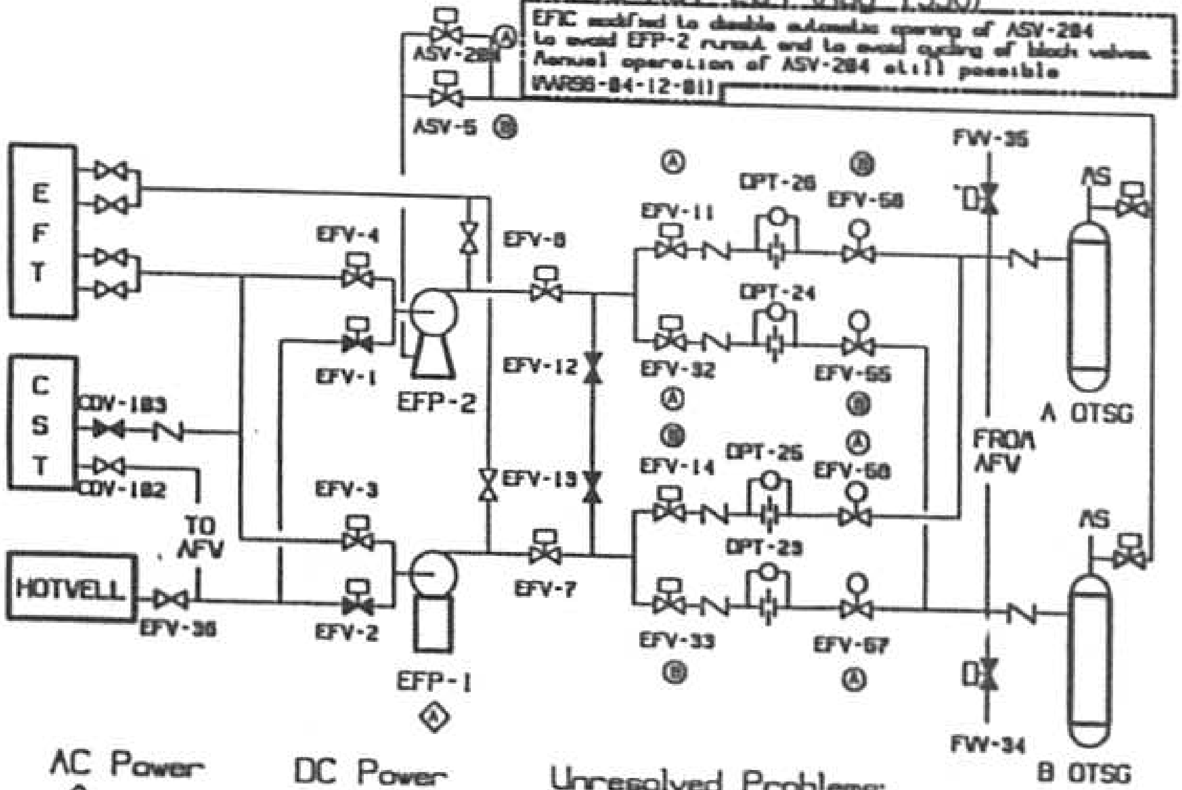
Configuration #8 - Addition of Auxiliary Feedwater System (AFW) (April 1993)



Unresolved Problems:

Previous problems 2-2, 4-1, 5-1, 5-2, 6-1, 7-1 not addressed

Configuration #9 - Disabled Auto Opening of Valve ASV-204 (May 1996)



AC Power

(O) - Offsite Power

(A) - 'A' EDG

DC Power

(A) - 'A' Battery

(B) - 'B' Battery

Unresolved Problems:

2-1, 6-1, 7-1 Problems not addressed

9-1 EFP-2 reliability reduced

9-2 Unanalyzed condition created with no EFW below 500 psig

CR3 082563

Exhibit___(WRJ-7)

Modification Action Report (MAR)
for 1987 ASV-204 Modification

MODIFICATION APPROVAL RECORD

Crystal River Unit 3

Modification Number	Work Request	Safety Related	Review Required
MAR T87-10-09-01	94907	X Yes ☐ No	☐ Yes X No

Project Name: AST-5/204 POWER SEPARATION

Systems Number	Priority Code	Cost Accounting Data
AS	X100	

Type of Modification

☐ Permanent X *Temporary Expiration Date: 10-1-88 *W.R. No. for Removal 94708

☐ Mechanical X Electrical ☐ I&C ☐ Structural ☐ Hanger

Description of Proposed Modification

See Attached Sheet 1 of 1 [illegible] 11/[illegible]

NOTE: Supplemental Information To Be Added

Reason for Modification

See Attached Sheet 1 of 1 [illegible]

ORIGINAL

Design Engineer	Date		Date
E.A. [illegible]	10/30/87	[signature]	10/30/87
		[signature]	10/30/87

	Signature	Date
Quality Programs Inspection Plan Review	[signature]	11-[illegible]-87
Meeting Number [illegible] Plant Review Committee (PRC)	[signature]	11-13-87
NGRC Review Required ☐ Yes X No NGRC Approval		
Installation Authorized	[signature] E [illegible] (On Call)	11/15/87
Cancellation		
Temporary Modification Removed	NA Made Permanent By MAR 87-10-09-01 A	
Installation and Test Complete and All Documentation Enclosed	[signature]	7/13/92

Florida Power Corporation

ANALYSIS / CALCULATION
Crystal River Unit 3

REI / MAR No.	MAR T87-10-09-01	Date	OCTOBER 28, 1987
Project:	ASV-5/204 POWER SEPARATION		

ATTACHMENT TO MODIFICATION APPROVAL RECORD

DESCRIPTION OF PROPOSED MODIFICATION

Electrically separate Motor Operated Valve ASV-204 from ASV-5 and assign a new power source for ASV-204 from the 250/125 Vdc ES 'A' power system. Install separate remote manual control and automatic EFIC interlocks for ASV-204.

REASON FOR MODIFICATION

Presently, ASV-204 and ASV-5 are electrically connected in parallel and powered from a common 250/125 Vdc ES 'B' power source, and operate via common manual and automatic control interlocks. ASV-204 is being repowered from a 250/125 Vdc ES 'A' power source and provided with separate controls in order to enable the Turbine Driven EFW Pump (EFP-2) to be operable with a failure of the 250/125 Vdc ES 'B' power system. With this capability, EFP-2 will be available to share the EFW flow requirements with the motor driven EFW pump and, thus, decrease the load on Emergency Diesel Generator EDG-1A for scenarios requiring EFW coincident with loss-of-offsite-power and failure of the 'B' power system.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
D.G. Rider	10/28/87	[illegible]	10/28/87	[illegible] for REV	10/28/87

MODIFICATION SAFETY EVALUATION

MAR NO. T87- 10. 09 - 01

SAFETY EVALUATION: Answer the following questions and provide specific justification (use attachment if necessary).

1. Is the probability of an occurrence or the consequence of an accident or malfunction of equipment important to safety as previously evaluated in the Final Safety Analysis Report, INCREASED? YES ___ NO X

   Because:

   See Attached Sheet

2. Is the possibility for an accident or malfunction of a different type than any previously evaluated in the Final Safety Analysis Report, CREATED? YES ___ NO X

   Because:

   See Attached Sheet

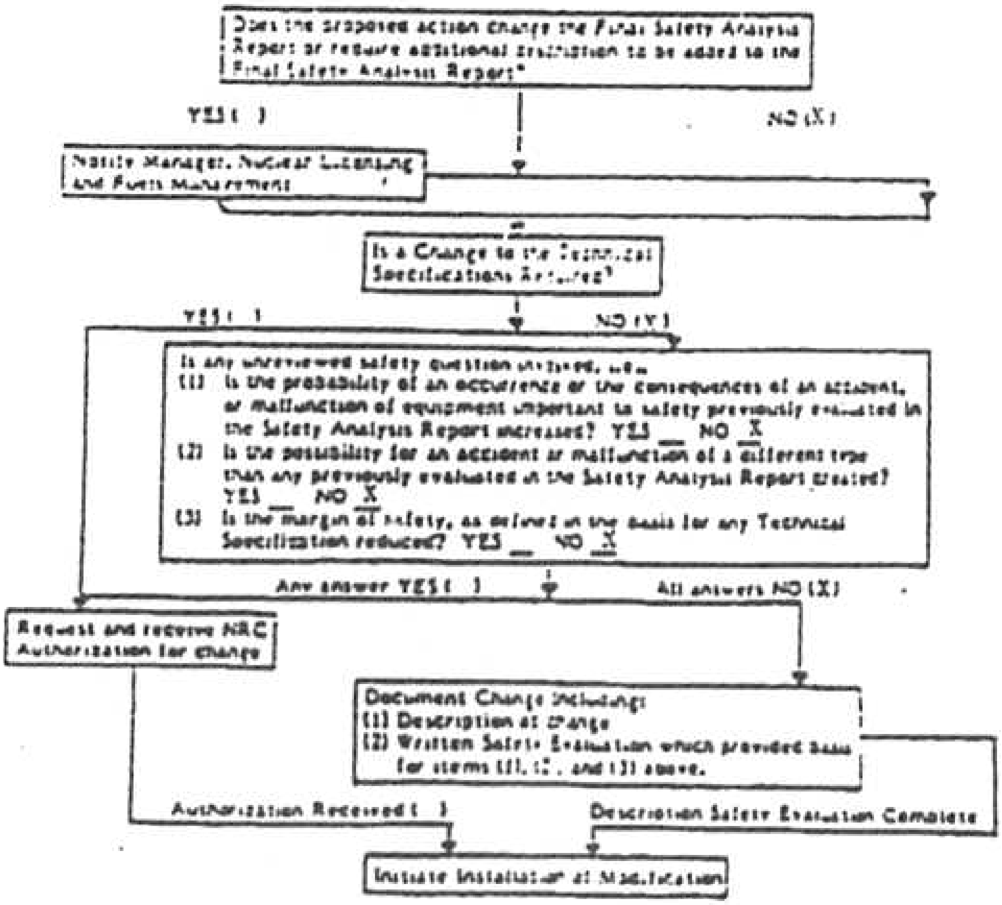
3. Is the margin of safety, as defined in the basis for any Technical Specification, REDUCED? YES ___ NO X

   Because:

   See Attached Sheet

LICENSE REVISION REQUIRED:			
	Final Safety Analysis Report:	YES ___	NO X
	Technical Specifications:	YES ___	NO X
	NRC Authorization for Change Required:	YES ___	NO X
	Semi-Annual Reporting to NRC Required:	YES ___	NO X

10CFR50.59 CHECKLIST



CR3 085376

*Required changes to Technical Specifications [illegible]

Prepared by: [illegible signature]

EI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 19, 1987
Project:	ASV-5/204 POWER SEPARATION		

ATTACHMENT TO MODIFICATION SAFETY EVALUATION

1. ASV-5 and ASV-204 are motor operated valves having identical functions of supplying steam to the turbine driven Emergency Feedwater Pump (EFP-2). Since EFP-2 is the ES "B" channel pump, ASV-5 and 204 were electrically connected in parallel to a common 250/125 VDC ES "B" channel power and control source. This modification electrically separates ASV 204 from ASV-5 and repowers ASV-204 from 250/125 VDC ES "A" channel power. Also, separate control room controls and separate "A" channel EFIC interlocks are being provided for ASV-204. Automatic control logic of ASV-204 has not changed. Therefore, the probability of an occurance or the consequences of an accident or malfunction of equipment important to safety as previously evaluated in the FSAR is not increased since the logic of automatically opening ASV-204 whenever the EFIC System calls for emergency feedwater has not been altered. The reliability of EFP-2 has actually been increased because with this modification either "A" or "B" train power will control and operate one of the steam inlet valves to EFP-2 as opposed to both valves being "B" train powered. FSAR Sections 7.2.4, 8.2.2.6 and 10.2.1.6 have been reviewed.

2. The electrical separation of ASV-204 from ASV-5 does not impact the design function of either valve to supply steam to the EFP-2 turbine. Power and control for ASV-5 is not affected by this modification and ASV-5 retains its automatic control logic, remote manual control, local manual control and remote shutdown isolation and control. ASV-204 is being powered from the redundant power channel, and will be provided with its own remote manual control and with separate EFIC interlocks for automatic operation. The type of remote manual control and automatic operation of ASV-204 is the same as for ASV-5. Therefore, based on the above, the possibility for an accident or malfunction of a different type than any previously evaluated in the FSAR is not created. FSAR Sections 7.2.4, 8.2.2.6, and 10.2.1.6 have been reviewed.

CR3 085377

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
G G Black	[illegible]	[illegible]	10/21/87	[illegible] LEV	10/20/87

Florida Power Corporation

ANALYSIS / CALCULATION
Crystal River Unit 3

SHEET 3 OF 3

REI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 19, 1987
Project:	ASV-5/204 POWER SEPARATION		

3. This modification enables the turbine driven Emergency Feedwater Pump (which is the "B" channel pump) to be operational even if a failure should occur on the "B" channel power system for which shutdown operation would be via the "A" channel systems. With this capability, the turbine driven EFW pump is able to operate and share the EFW requirements with the "A" channel motor driven EFW pump. This will reduce the electrical load on the "A" channel diesel generator for the condition of an ES actuation coincident with a loss-of-offsite-power and failure of the "B" channel power system. Consequently, with this modification the margin of safety, as defined in the basis for any Technical Specification, is not reduced. It is actually enhanced because of the increased availability of the turbine driven Emergency Feedwater Pump. Technical Specification Sections 3/4.7.1 and 3/4.8.1 have been reviewed.

CR3 085378

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
D. S. Black	10/24/87	[signature]	10/30/87	[signature] for KCV	10/31/87

ENCLOSURE 9

SAFETY EVALUATION REVIEW

TO: Nuclear Technical Specification Coordinator

A copy of NAR T87-15-0901 PCN ______________ is attached for your review of the NAR Safety Evaluation for Technical Specification Conformance and Unreviewed Safety Implications.

☒ ACCEPTABLE

☐ UNACCEPTABLE — Return immediately to the Nuclear Modification Supervisor for resolution

COMMENTS.

11/16/87

[illegible]

Return to Nuclear Modification Supervisor

CR3 085379

REGULATORY/ENVIRONMENTAL REVIEW
Crystal River Unit 3

DOCUMENT NUMBER

MAR T87-10-09-01

REF. NUCLEAR OPERATIONS DEPARTMENT PROCEDURE: NOD-11

1. **10 CFR 50.54 Reviews**

Does this modification or document revision change what is described in any of the following plans/programs? If unable to determine, contact responsible person designated below.

Quality Program Description (FSAR Section 1.7) Contact: Director, Quality Programs	☐ Yes	☑ No
Licensed Operator Requalification Program (FSAR Section 12.2.3.4 and Appendix 12 C) Contact: Manager, Nuclear Operations Training	☐ Yes	☑ No
Modified Amended Security Plan Contact: Manager, Nuclear Licensing	☐ Yes	☑ No
Safeguards Contingency Plan Contact: Nuc. Security & Special Project Superintendent	☐ Yes	☑ No
Security Guard Training and Qualification Plan Contact: Nuc. Security & Special Project Superintendent	☐ Yes	☑ No
Radiological Emergency Response Plan Contact: Manager, Site Nuclear Services	☐ Yes	☑ No

If any are "yes":

a. Contact appropriate responsible person identified above to perform the evaluation and attach. The evaluation must be approved by the Division Head responsible for the plan/program. — Evaluation ☐ Complete ☑ N/A

b. NRC approval received if needed and attach. — ☐ Complete ☑ N/A

2. **Environmental Protection Plan Review**

Could this change affect the environment in a non-radiological way? — ☐ Yes ☑ No

If "yes", contact the Manager, Nuclear Licensing — ☐ Complete ☑ N/A

3. **Review for change to Radioactive Waste System (10 CFR 50.34a and Appendix I / T. S. 6.18.1.1)**

Will this change to a radioactive waste system (liquid, gaseous or solid) result in an increase of radioactive material released to the environment? — ☐ Yes ☑ No

If "yes", submit change to Manager, Nuclear Licensing to evaluate the reporting requirements. — ☐ Submitted ☑ N/A

IF ALL OF ABOVE ARE CHECKED NO, NO FURTHER REVIEWS ARE REQUIRED.

PREPARED BY	DATE	APPROVED BY	DATE
R. S. Glason	11/10/87	J.W. [illegible] C B Doyle	11/13/87 11/11/87

Rev. 7/87

QS LOG # ______________

DOCUMENT # T-97-10-09-01 FCN — REV — CHANGE —

SAFETY RELATED: ✓ YES ___ NO

RELATED DOCUMENTS: ______________

QA REVIEW:

___ (1) APPROVED AS IS

✓ (2) APPROVED WITH ADMINISTRATIVE COMMENTS

___ (3) REJECTED
(Asterisked items must be resolved for approval. This rejection must be returned for subsequent reviews of the above document.)

INSPECTION REQUIREMENTS:

___ (1) INSPECTIONS REQUIRED

___ (2) NO INSPECTION REQUIRED

___ (3) NO CHANGE TO EXISTING INSPECTION

___ (4) EXISTING INSPECTION ARE REVISED

✓ (5) INSPECTION REQUIREMENTS TO BE DETERMINED AT THE WORK PACKAGE LEVEL

QUALITY INSPECTION PLAN # ______________

COMMENTS: 1) T-MAR does not comply with 10 CFR 50 Appendix B criteria VI and ANSI N18.7 para 5.2.15
2) T-MAR doesn't comply with SREP #6 para VB(2) removal instructions.

This document has been review by Quality Systems for Quality Assurance (QA) requirements and for the identification of inspections which are necessary to assure compliance with the engineering design and with the material, fabrication, assembly, erection, installation, and examination and test requirements.

NOTE: For definition of Hold Point, Witness Point, and Surveillance, refer to QAP No. 25, Section 4.0.

REVIEWED BY: [signature] DATE: 11-14-97

REV 7/87

CR3 085381

Florida Power Corporation

ENGINEERING INSTRUCTIONS
Crystal River Unit 3

MAR/EEI No.	Date
T87-10-09-01	10/24/87

Project: ASV-5/204 Power Separation

A. SUMMARY FUNCTIONAL DESCRIPTION

This modification electrically separates the turbine driven emergency feedwater pump steam inlet isolation valves ASV-5 and ASV-204 in that ASV-204 is being powered from the 250/125 VDC ESA power system. ASV-5 will remain powered from the 250/125 VDC ESB power system. ASV-204 will become an ES channel 'A' valve and will have its own control switch and position indicator lights on the ESA/EFIC section of the main control board. The control circuit for ASV-204 will also be provided with contacts from the EFIC 'A' channel logic for automatic operation. Auxiliary relays will be added to the control circuitry in order to provide alarm logic for alarms which are common to ASV-5 and ASV-204.

This modification will enable the turbine-driven emergency feedwater pump to be operable in the event of failure of the 250/125 VDC ESB power system.

B. ATTACHMENTS

1. Project Assignment Memo
2. Design Data Sheets (4)
3. Design Input Record [illegible]
3a. Safety Classification [illegible] with attachment Sketch [illegible] and page 2-15.
4. Verification Report
4a. [illegible] Design Verification Record (2)
5. Fire Protection Review — with [illegible] sheet.
6. Modification Safety Evaluation with sheets 2 + 3 of 3
7. Regulatory Environmental Review
8. Drawings:

Sketch 1 - Electrical Block Diagram

Sketch 2 - Electrical Conduit Layout, Intermediate Bldg. EL. 95-0

Sketch 3 - Electrical Conduit Layout, Intermediate Bldg. EL. 119-0

HWC 11/13/87

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D.A. Rhoads	10/24/87	[illegible]	10/30/87	[illegible]	10/30/87

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Sketch 4 - Electrical Conduit Layout, Complex EL. 108

Sketch 5 - Electrical Conduit Layout, Control Complex EL. 124-0

Sketch 6 - Electrical Conduit Layout, Control Complex EL. 134-0

Sketch 7 - Electrical Interconnection Wiring Diagram, ASV-5

Sketch 8 - Electrical Interconnection Wiring Diagram, Motor Starter for ASV-204

Sketch 9 - Electrical Interconnection Wiring Diagram, TB-AS-9

Sketch 10 - Electrical Interconnection Wiring Diagram, Motor Starter for ASV-5

Sketch 11 - Electrical Interconnection Wiring Diagram, ASV-204

Sketch 12 - Electrical Interconnection Wiring Diagram, TB-AS-01

Sketch 13 - Electrical Arrangement, DPDP-5A

Sketch 14 - Electrical Arrangement, ACDP-54

Sketch 15 - Electrical Arrangement, E.S. Aux. Relay Rack Assy. RR3A

Sketch 16 - Electrical Aux. Relay Rack 3A Internal Wiring

Sketch 17 - Electrical Aux. Relay Rack 3A Internal Wiring

Sketch 18 - Electrical Aux. Relay Rack 3A Terminal Boards

Sketch 19 - Electrical Aux. Relay Rack 3A Terminal Boards

Sketch 20 - Electrical Aux. Relay Rack RRSB1 Terminal Boards

Sketch 21 - Electrical Main Control Board Primary and Secondary Auxiliary Assembly

Sketch 22 - Escutcheon Plate Detail

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D.G. Rbowke	10/29/87	[illegible]	10/30/87	[illegible] for SEV	10/30/87

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Sketch 23 - Electrical Main Control Board PSA/EFIC Internal Wiring
Sketch 23A - Electrical Main Control Board PSA/EFIC Internal Wiring CBB 11/1/87
Sketch 24 - Electrical Main Control Board Primary and Secondary Aux. Terminal Boards

~~Sketch 25 - Electrical Main Control Board PSA/EFIC Internal Wiring~~ CBO 11/1/87 11/13/87

Sketch 26 - Electrical Main Control Board Primary and Secondary Aux. Terminal Boards 11/13/87

Sketch 27 - Electrical Elementary Wiring Diagram, ASV-204

Sketch 28 - Electrical Elementary Wiring Diagram, ASV-204

Sketch 29 - Electrical Elementary Wiring Diagram, ASV-204

Sketch 30 - Electrical Elementary Wiring Diagram, ASV-5

Sketch 31 - Electrical Elementary Wiring Diagram, ASV-5

Sketch 32 - Electrical Elementary Wiring Diagram, ASV-5

Sketch 33 - Electrical Elementary Wiring Diagram, ASV-5

Sketch 34 - Electrical Elementary Wiring Diagram, EFIC Matrix 'A' Control and EFW Actuation 'A'

Sketch 35 - Electrical Elementary Wiring Diagram, EFIC Matrix 'A' Control and EFW Actuation 'A'

Sketch 36 - Electrical Elementary Wiring Diagram, EFIC Matrix 'A' Control and EFW Actuation 'A'

E/I Sketch 'A' - Demolition Dwg., Intermediate Bldg. EL. 95-0

9. Bill of Material #1, Revision 0

10. Analysis Calculations

    a. DC-5510-126.0-EE, Rev. 0

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
G. G. Rhat	10/24/87	[signature]	10/31/87	[signature] for EEV	10/31/87

Rev 3/81

RET 25 Yr RESP: Nuc Eng 912241

CR3 085384

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b. DC-CR3-017-EE, pages 1, 2, 24, 29, 31, 32, 33, 34 and 40, all Rev. 1

c. DC-5510-126.1-EE, Rev. 0

11. Cable Pulling, Termination and Test Data Sheets for the following circuits:

ASE 27	ASE 30	ASE 34	ASE 37	ASK 1
ASE 28	ASE 31	ASE 35	ASF 31	ASK 29
ASE 29	ASE 33	ASE 36	ASF 32	ASK 30

12. ALARA Analysis/Calculation Sheet

C. REFERENCES

1. FCS-8915 dated 10/12/87

2. Telecon D. A. Rhoads/M. U. Rahman dated 10/16/87

3. Telecon K. Shirk/I. R. Pressley dated 10/22/87

4. Emergency Diesel Generator Loading Evaluation Report dated 10/23/87

D. MATERIALS

See attached Bill of Material number 1.

E. INSTALLATION INSTRUCTIONS

1. Charge all time and materials to Work Request #94907 for installation and to Work Request #94708 for removal.

2. All cable pulling, termination, splicing, and conduit installation shall be in accordance with applicable FPC maintenance procedures.

3. Conduit Installation at ASV-204.

*a. Install the following aluminum conduits safeguards 'A' Red per Sketch No. 2 and detailed conduit routing sketches.

ASE 34 - 2"
ASE 33 - 1"
ASE 36 - 2"

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D. A. Rhoads	10/24/87	H. D. Shreff	10/24/87	Martin for TDV	10-24-87

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*b. Install the following aluminum conduit non-safeguards 'X" White per Sketch Nos. 2 and 3 and detailed conduit routing sketches.

ASF 32 - 1"

4. Conduit Installation at DPDP-8A.

*a. Install the following aluminum conduit safeguards 'A' Red per Sketch No. 4 and detailed conduit routing sketches.

ASE 34-2"

5. Conduit Installation at RR3A and RR5B1.

*a. Install the following aluminum conduit non-safeguards 'X' White per Sketch No. 5 and detailed conduit routing sketches.

ASK 30-3/4"

6. Conduit installation at floor opening 67A to Main Control Board Section PSA.

*a. Install the following aluminum conduit safeguards 'A' Red per Sketch No. 6 and detailed conduit routing sketches.

ASE 36-2"

*Note: Detailed conduit routing sketches to be issued per subsequent FCNs to this MAR.

7. Instructions for MOV ASV-5.

a. Determinate circuit ASK1 as follows and as indicated on Sketch No. 7.

Wire Color/Wire Mark	Terminal
Black (1)/100AL	13A
White(2)/100AL1	13
Shield / ---	Floating

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
G.G. Rhodes	10/26/87	H. J. Thuff	10/31/87	[illegible] for EB	11/3/87

Rev 1/83

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b. Retag wires in ASV-5 as follows:

CKT	Wire Color/Wire Mark	To Wire Mark
EFK42	Red (3)/100 AL1	100 AL2
	Green (4)/100 AL	100 AL1

c. Pull cable out of conduit ASK1-3/4" to cable tray #302. Pull cable back (east) in tray #302 to conduit ASE36-2" and coil in tray to be re-routed in E/I Step 8.

8. Pull the following cables as indicated on the applicable cable pulling data sheets:

ASK 1 (Pulled back in Tray 302)
ASE 34
ASE 35
ASF 32
ASE 36
ASE 37
ASE 33
ASK 29
ASK 30

9. Wiring Instructions for Motor Starter for MOV ASV-5, Sketch No. 10:

a. Open breaker #20 in ACDP-12

b. Pull fuse #5 in DPDP-8B

c. Pull fuse #6 in DPDP-8B

d. Determinate the following circuits (circuits to be deleted):

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASF 31	Black (1)/26	3L1
	White (2)/27	3L2
	Red (3)/Spare	---

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
E G P Booker	10/29/87	[signature]	10/27/87	[signature] for LSV	10/30/87

Rev. 7/87 RETAIN 5 Yr. RESP: Nuc Eng 912273

CR3 085387

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASE 27	Black (1)/1 (P)	1L1
	White (2)/6 (N)	1L2
	Red (3)/7	C1

10. Wiring instructions for Terminal Box AS-01, Sketch No. 12.

   a. Determinate the following circuit (circuit to be deleted):

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASE 30	Black (1)/Spare	---
	White (2)/Spare	---
	Red (3)/8	TBB-3
	Green (4)/7	TBB-1
	Orange (5)/15	TBB-9
	Blue (6)/18	TBB-10
	White/Black (7)/20	TBB-11
	Red/Black (8)/22	TBB-12
	Green/Black (9)/36	TBA-7

11. Wiring instructions for motor starter for MOV ASV-204, Sketch No. 8.

   a. Determinate the following circuits (circuits to be deleted):

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASF 31	Black (1)/26	3L1
	White (2)/27	3L2
	Red (3)/-	---
ASE 27	Black (1)/1(P)	1L1
	White (2)/6 (N)	1L2
	Red (3)/7	2L1
ASE 28	Black (1)/38	C2
	White (2)/8	2L2
	Red (3)/50	C4

   b. Remove resistors R1, R2, and R3 and save to be reused later this MAR.

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D. A. Klaack	10/29/87	H. J. Shaff	10/31/87	[illegible] for [illegible]	10/31/87

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c. Terminate the following cables:

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASF 32	Black (1)/21	3L1
	White (3)/22	3L2
*ASZ 34	Black (1)/1 (P)	1L1
	White (3)/ 2 (N)	1L2
*ASE 35	Black (1)/8	2L1
	White (2)/9	2L2
ASE 33	Black (1)/8	2L1
	White (2)/9	2L2
	Red (3)/12	C2
	Green (4)/14	C4
	Orange (5)/Spare	---

* Tape end of cables safeguard 'A' Red.

d. Tape the end of the cable ASE 31 safeguard "A" Red and revise wire marks as follows:

From Wire Mark	To Wire Mark
24	5
25	6
23	3
33	4
28	7

12. Wiring instructions for terminal Box AS-9. Sketch No. 9.

a. Determinate the following circuits:

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASE 29	Black (1)/7	TBA-2
	White (2)/Spare	—
	Red (3)/15	TBA-3

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D.A. R[illegible]	10/29/87	[illegible]	10/30/87	[illegible]	10/30/87

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Circuit No.	Wire Color/Wire Mark	Terminal Number
ASE 29 (cont.)	Green (4)/30	TBA-9
	Orange (5)/18	TBA-4
	Blue (6)/20	TBA-5
	White/Black (7)/22	TBA-6
	Red/Black (8)/38	TBA-8
	Green/Black (9)/36	TBA-7

(This ckt. to be reterminated later this MAR)

ASE 28	Black (1)/38	TBA-8
	White (2)/8	TBA-1
	Red (3)/30	TBA-9

(This ckt. to be deleted)

ASE 30	Black (1), Spare	---
	White (2)/Spare	---
	Red (3)/8	TBA-1
	Green (4)/7	TBA-2
	Orange (5)/15	TBA-3
	Blue (6)/18	TBA-4
	White/Black (7)/20	TBA-5
	Red/black (8)/22	TBA-6
	Green/Black (9)/36	TBA-7

(This ckt to be deleted)

EFK 42	Red (3)/100AL1	TBB-5
	Green (4)/100AL	TBB-4

(Wires to be re-terminated later this MAR)

EFK 43	Red (3)/100AL1	TBB-5

(Wire to be reterminated later this MAR)

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D.O. Rhonde	10/30/87	[signature]	10/31/87	[signature] for REV	11/3/87

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REV 25 Yr. RESP., Nuc Eng 9/1/81

CR3 085390

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b. Install Zener Diodes as follows:

	From Terminal	To Terminal
ZD-1	TBA-8	TBA-12
ZD-2	TBA-8	TBA-10
ZD-3	TBA-8	TBA-11

c. Install resistors as follows (Previously removed from motor starter for ASV-204):

	From Terminal	To Terminal
R1	TBA-10	TBB-10
R2	TBA-11	TBB-11
R3	TBA-12	TBB-12

d. Install #14, AWG SIS Red jumper wire as follows:

From Terminal	To Terminal
TBA-2	TBA-8

e. Terminate circuits as follows:

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASE 29	Black (1)/8	TBA-1
(Was	White (2)/Spare	---
determinated	Red (3)/13	TBA-6
earlier	Green (4)/14	TBA-7
this MAR.)	Orange (5)/15	TBB-10
	Blue (6)/17	TBB-11
	White/Black (7)/19	TBB-12
	Red/Black (8)/12	TBA-5
	Green/Black (9)/11	TBA-4

(Tape end of cable safeguard 'A' Red)

Design Engineer	Date	Verification Engineer	Date	Manager Nuclear Engineering	Date
R.A. Rhode	10/26/87	[signature]	10/30/87	[signature] for CEV	10/30/87

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Circuit No.	Wire Color/Wire Mark	Terminal Number
ASE 33	Black (1)/8	TBA-1
	White (2)/9	TBA-2
	Red (3)/12	TBA-5
	Green (4)/14	TBA-7
	Orange (5)/Spare	---
ASE 36	Black (1)/8	TBA-1
	White (2)/9	TBA-2
	Red (3)/13	TBA-6
	Green (4)/10	TBA-3
	Orange (5)/16	TBA-10
	Blue (6)/18	TBA-11
	White/Black (7)/20	TBA-12
	Red/Black (8)/Spare	---
	Green/Black (9)/Spare	---
ASE 37	Black (1)/8	TBA-1
	White (2)/11	TBA-4
	Red (3)/13	TBA-6
	Green (4)/10	TBA-3
	Orange (5)/Spare	---
EFK 43	Red (3)/100 AL2	TBB-6
EFK 42	Red (3)/100 AL2	TBB-6
	Green (4)/100 AL1	TBB-5
ASK 1	Black (1)/100 AL	TBB-4
	White (2)/100 AL1	TBB-5
	Shield/---	Float

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D.A. R[illegible]	10/24/87	H.J. Shauff	10/30/87	[illegible] for [illegible]	10/30/87

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RET 25 Yr RESP. Nuc Eng [illegible]

CR3 065392

Florida Power Corporation

ENGINEERING INSTRUCTIONS
Crystal River Unit 3

MAR/EEI No. T87-10-09-01	Date 10/24/87

Project: ASV-5/204 Power Separation

13. Wiring instructions MOV ASV-204, Sketch No. 11.

    a. Retag the following wire marks as follows:

From Wire Mark	To Wire Mark
33	4 (2 places)
24	5
25	6
23	3
28	7
36	11 (2 places)
38	12 (2 places)
50	14
7	8 (2 places)
20	17
22	19
15	13
18	16
100 AL1	100 AL2

    b. Tape the ends of cables ASE 29 and ASE 13 safeguard 'A' Red.

14. Wiring instructions for DPDP-8A, Sketch No. 13.

    a. Terminate the following circuits as follows:

Circuit No.	Wire Color/Wire Mark	Fuse Terminal
ASE 35	Black (1)/8 (PN)	15-(PN)
	White (2)/9 (N)	15-(N)

(Tape ends of cable safeguard "A" red)

Circuit No.	Wire Color/Wire Mark	Fuse Terminal
ASE 34	Black (1)/1 (P)	17-(P)
	White (2)/2 (N)	17-(N)

(Tape ends of cable safeguard 'A' Red)

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D. Q. R[illegible]	10-24-87	[signature]	10/31/87	[signature] for RFV	10/31/87

Rev. 1/83

REF: 25 Yr RESP Nuc Eng 912243

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15. Wiring instructions for ACDP-54, Sketch No. 14:

   a. Terminate the following circuit as follows:

Circuit No.	Wire Color/Wire Mark	Breaker
ASF 32	Black (1)/21	4
	White (2)/22	4

16. Wiring instructions for Relay Rack RR3A, Sketch Nos. 15, 16, 17, 18, 19.

   NOTE: Reference MAR T87-10-96-01 which removes relays from the spaces where relays are being added via this MAR.

   a. Install relays TMA and TMB as indicated on Sketch 15.

   b. Install #14 AWG SIS Red wires as follows:

From	To
AR-1-Sketch 17	TMA-1-Sketch 16
BA-1-Sketch 17	TMB-1-Sketch 16
BA-2-Sketch 17	TMB-2-Sketch 16
AR-3-Sketch 17	TB14-21-Sketch 18
AR-4-Sketch 17	TB14-22-Sketch 18
TMA-2-Sketch 16	TMB-2-Sketch 16

   c. Convert contact ~~BA~~ AR-3/4 from N.O. to N.C.

   d. Install #14 AWG SIS Gray wires as follows:

From	To
TMA-3-Sketch 16	TB13-12-Sketch 19
TMA-4-Sketch 16	TB13-13-Sketch 19
TMB-3-Sketch 16	TB13-10-Sketch 19
TMB-4-Sketch 16	TB13-11-Sketch 19

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
E. O. [signature]	10/26/87	[signature]	10/30/87	[signature] for LEV	10/30/87

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MAR/SEI No.	T87-10-09-01	Date	10/24/87
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e. Terminate circuits as follows:

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASK 29	Black (1)/1706AL3 White (2)/1706AL4 Shield/ --	TB13-10-Sketch 19 TB13-11-Sketch 19 Float
ASK 30	Black (1)/100K White (2)/100AL Shield/ --	TB13-12-Sketch 19 TB13-13-Sketch 19 Float
ASE 37	Black (1)/8 White (2)/11 Red (3)/13 Green (4)/10 Orange (5)/Spare	TB14-19-Sketch 18 TB14-22-Sketch 18 TB14-20-Sketch 18 TB14-21-Sketch 18 ---

17. Wiring instructions for RR5B1, Sketch No. 20.

a. Terminate circuit ASK 30 as follows:

Wire Color/Wire Mark	Terminal Number
Black (1)/100K	TB12-27
White (2)/100 AL1	TB12-28
Shield/---	Float

18. Installation instructions for MCB Section PSA/EFIC, Sketch Nos. 21 and 22.
19 KSJ 11/11/87 11/11/87 CGD 11/11/87

NOTE: Reference MAR T87-10-04-01 which removes existing 'AD' push button. plate

KSL 11/10/87 a. Install ~~three holes for items TM1, TM2, and TM3 on the main control board per Sketch No. 21~~ Blank ~~plate~~ over "AD" and remove blank plate from spared switch and lights per sketch 21.

11/11/87 b. Fabricate escutcheon plate per Sketch No. 22.

CGD 11/11/87 c. Install escutcheon plate and panel items TM1, TM2, TM3, and TM4 per Sketch No. 21.

d. Engrave and install nameplate per Sketch Nos. 21 and 22.

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D.C. Rhoads	10/24/87	[signature]	10/30/87	[signature] for LCV	10/30/87

Rev 1/82

RET T1 -- RESP, Nuc Eng. 912243

CR3 065395

Florida Power Corporation

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Date 10/24/87

Project: ASV-5/204 Power Separation

INSERT PAGE 15A ~~Install demarcation boarders (Reference B/M Item No. 81) per Sketch No. 24.~~ CBP 11/1/87

19. Wiring Instructions for MCB Section PSA/EFIC, Sketch Nos. 23, 24, 23A, and 26.

a. Install #18 AWG SIS red wiring as follows:

From	To
TM1-1-Sketch 23	TB59-14-Sketch 24
TM1-2-Sketch 23	TB56-1-Sketch 24
TM1-2-Sketch 23	TM2-2-Sketch 23
TM2-?-Sketch 23	TM3-2-Sketch 23
TM2-1-Sketch 23	TB59-2?-Sketch 24
TM3-1-Sketch 23	TB59-2?-Sketch 24

b. Install #14 AWG SIS red wiring as follows:

From	To
TM4-3-Sketch 23	TB56-2-Sketch 24
TM4-3-Sketch 23	TM4-7-Sketch 23
TM4-4-Sketch 23	TB59-15-Sketch 24
TM4-8-Sketch 23	TB59-3-Sketch 24

c. Remove #14 AWG SIS green wire as follows:

RLC 11/13/87 CBP 11/13/87 C 11/13/87

From	To
AE4-11-Sketch ~~26~~ 23A	TB40-3-Sketch 26
AE4-9-Sketch ~~25~~ 23A	TB40-2-Sketch 26
AE4-10-Sketch ~~26~~ 23A	TB40-1-Sketch 26

d. Install #14 AWG SIS gray wire as follows:

From	To
TB40-5-Sketch 26	TM4-1-Sketch 23
TM4-2-Sketch 23	AE4-11-Sketch ~~26~~ 23A

CBP 11/13/87 11/13/87

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
D.A. Rhodes	10/24/87		11/3/87	for REV	10/30/87

Rev. 1/87

RET: 25 Yr. RESP: Nuc Eng. 912141

CR3 085396

Florida Power

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Request No.	Date
T87-10-09-01	11/13/87

Project: ASV-5/204 POWER SEPARATION

18. e. DETERMINATE THE SWITCHBOARD WIRING FROM DEVICES AE1, AE2, AE3 (AS NECESSARY) AQ, AP, AN AND AM. REMOVE THESE DEVICES ~~[illegible]~~ FROM THE MAIN CONTROL BOARD. RETAIN THEM FOR REINSTALLATION IN STEP 18 K.

f. FABRICATE A COVER PLATE FOR THE AFFECTED AREA OUT OF #10 GAGE STEEL PLATE. THE PLATE SHALL BE 3.5 ± 0.1 IN HIGH AND 3.5 ± 0.1 IN WIDE.

g. LOCATE THE PLATE ON THE MAIN CONTROL BOARD PER AE4, SKETCH 21. LOCATE AND PUNCH HOLES FOR DEVICES AE1, AE2, AE3, AQ, AP, AN AND AM PER SKETCH 21. THE SWITCH FOR ASV 5 SHALL BE VERTICALLY ALIGNED WITH THE SWITCH FOR ASV-204. THE EFIC CH B TO EFP-2 START LOGIC LIGHTS SHALL BE VERTICALLY ALIGNED TO THE SIMILAR LIGHTS ABOVE FOR CHANNEL A. HORIZONTAL LOCATIONS SHOULD BE APPROXIMATELY AS SHOWN.

h. USING THE PREPARED COVER PLATE AS A TEMPLATE, CUT OR DRILL HOLES IN THE MAIN CONTROL BOARD TO MATCH.

i. PAINT THE COVER PLATE TO MATCH THE MAIN CONTROL BOARD. SEE THE PAINT SPECIFICATION IN MAR 80-08-10-11.

j. INSTALL THE COVER PLATE ON THE PANEL USING INSTRUCTIONS FOUND IN THE NOTES OF DRAWING E-201-334, REV 1.

K. INSTALL DEVICES AE1, AE2, AE3, AE4, AQ, AP, AN AND AM AND RETERMINATE THE WIRING PER SKETCH 23A

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
C. B. Doyle	11/13/87	[signature]	11/13/87	[signature]	11/13/87

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Project:	ASV-5/204 Power Separation		

e. Terminate circuit ASE 36 as follows:

Circuit No.	Wire Color/Wire Mark	Terminal Number
ASE 36	Black (1)/8	TB56-2-Sketch 24
	White (2)/9	TB56-1-Sketch 24
	Red (3)/13	TB59-8-Sketch 24
	Green (4)/10	TB59-15-Sketch 24
	Orange (5)/16	TB59-16-Sketch 24
	Blue (6)/18	TB59-26-Sketch 24
	White/Black (7)/20	TB59-27-Sketch 24
	Red/Black (8)/ --	Spare
	Green/Black (9)/ --	Spare

20. Demolition of cable and conduit for ASV-5 and ASV-204

a. Remove the following cables per E/I Sketch A and their respective cable pulling data sheets.

ASE 30
ASE 28
ASF 31
ASE 27

b. Remove the following conduits per E/I Sketch A

ASK 1-1/2"
ASE 28-3/4"
ASE 27-1"
ASF 31-1"
ASE 30-1 1/2"

c. Plug all holes in motor starter ASV-204, Terminal Box AS-1, Terminal Box AS-9, motor starter ASV-5 and MOV ASV-5.

21. REMOVAL INSTRUCTIONS FOR THIS TEMPORARY MAR TO BE ISSUED WHEN THE MAR IS ISSUED FOR THE PERMANENT SOLUTION TO THE DIESEL PROBLEM. GGD 11/13/87

[illegible] 11/13/87

Design Engineer	Date	Verification Engineer	Date	Supervisor Nuclear Engineering	Date
D.A. Rhoda	10/29/87	[signature]	10/30/87	[signature] for RSV	10/30/87

Florida Power Corporation

ENGINEERING INSTRUCTIONS
Crystal River Unit 3

MAR/REI No.	T87-10-09-01	Date	10/24/87
Project:	ASV-5/204 Power Separation		

F. EXAMINATION

Visually inspect component installations and wiring terminations to assure proper installation and termination in accordance with the MAR sketches and maintenance procedures.

G. TESTING

Upon completion of this modification, motor operated valves ASV-204 and ASV-5 shall be functionally tested to assure proper valve operation, and all limit switch functions (i.e., indicator lights, alarms, interlocks) shall be monitored to assure that the valve control logic has not been altered by this modification. After installation, all wiring shall be tested for continuity and insulation integrity, as applicable, in accordance with FPC standard procedures.

H. IN-SERVICE INSPECTION

Not applicable.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
G C Roberts	10/29/87	[signature]	10/30/87	[signature]	10/30/87

Rev. 2/81 RET 25 Yr RESP. Nuc. Eng 912241

Florida Power CORPORATION

PROJECT ASSIGNMENT
Nuclear Engineering

REVMAR NUMBER

MAR T87-10-09-01

PROJECT TITLE

ASV-5/204 POWER SEPARATION

The below listed personnel are assigned the responsibility for the subject project

DESIGN ENGINEER(S)

C/C I (Lead)

R. E. Clawson.

VERIFICATION ENGINEER(S)

/C I.

C. Juachow

COMMENTS

SUPERVISOR NUCLEAR ENGINEERING

C B Doyle

DATE

11/11/87

Original: Lead Design Engineer
cc: Other Design/Verification Engineers
File: REVMAR Number
Supervisor (w/REVMAR form only)

REF Life of Plant REMR Nuclear Eng

CR3 085400

DESIGN DATA SHEET
Crystal River Unit 3

Florida Power

SHEET 1 OF 2

NO / MAR NUMBER	DATE
T87-10-09-01	OCTOBER 14, 1987

PROJECT	SYSTEM
ASV-5/204 POWER SEPARATION	AS

SAFETY CRITERIA: ☒ Safety Listing Rev. 24 Dated 7-10-87 Page I-15
☒ Safety Classification Review Form (attach copy)

SAFETY RELATED: ☒ Yes ☐ No

	YES	NO	APPLICABLE DESIGN INPUT REQUIREMENTS
1.	☒	☐	Basic Functions of each structure, system and component.
2.	☒	☐	Performance requirements such as capacity, rating, system output.
3.	☒	☐	Codes, standards, and regulatory requirements including the applicable issue and/or addenda.
4.	☒	☐	Design conditions such as pressure, temperature, fluid chemistry and voltage.
5.	☒	☐	Loads such as seismic, wind, thermal and dynamic.
6.	☒	☐	Environmental conditions anticipated during storage, construction and operation such as pressure, temperature, humidity, corrosiveness, site elevation, wind direction, nuclear radiation, electromagnetic radiation and duration of exposure. 10CFR50.49 applicability — For electrical equipment only, reference above Safety Listing page or attach copy of Environmental Qualification Requirements form.
7.	☒	☐	Interface requirements including definition of the functional and physical interfaces involving structures, systems and components.
8.	☒	☐	Material requirements including such items as compatibility, electrical insulation properties, protective coating and corrosion resistance.
9.	☐	☒	Mechanical requirements such as vibration, stress, shock and reaction forces.
10.	☐	☒	Structural requirements covering such items as equipment foundations and pipe supports.
11.	☐	☒	Hydraulic requirements such as pump net positive suction heads (NPSH), allowable pressure drops, and allowable fluid velocities.
12.	☐	☒	Chemistry requirements such as provisions for sampling and limitations on water chemistry.
13.	☒	☐	Electrical requirements such as source of power, voltage, raceway requirements, electrical insulation and motor requirements.
14.	☒	☐	Layout and arrangement requirements, to include potential adverse affects of non-seismically qualified masonry walls.
15.	☒	☐	Operational requirements under various conditions such as plant startup, normal plant operation, plant shutdown, plant emergency operation, special or infrequent operation, and system abnormal or emergency operation.
16.	☒	☐	Instrumentation and control requirements including indicating instruments, controls and alarms required for operation, testing, and maintenance. Other requirements such as the type of instrument, installed spares, range of measurement, and location of indication should also be included.
17.	☐	☒	Access and administrative control requirements for plant security.
18.	☒	☐	Redundancy, diversity and separation requirements of structures, systems and components.
19.	☒	☐	Failure effects requirements of structures, systems and components, including a definition of those events and accidents which they must be designed to withstand.
20.	☒	☐	Test requirements including in-plant tests and the conditions under which they will be performed.
21.	☐	☒	Accessibility, maintenance, repair and inservice inspection requirements for the plant including the conditions under which these will be performed.

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	SUPERVISOR, NUCLEAR ENGINEERING	DATE
[illegible signature]	[illegible]	[signature]	10/13/87	[signature] for [illegible]	[illegible]

CR3 085401

DESIGN DATA SHEET
Crystal River Unit 3

Florida Power

T87-10-09-01	DATE OCTOBER 14, 1987
PROJECT ASV-3/204 POWER SEPARATION	SYSTEM AS

YES NO **APPLICABLE DESIGN INPUT REQUIREMENTS: (Continued)**

22. ☒ ☐ Personnel requirements and limitations including the qualification and number of personnel available for plant operation, maintenance, testing and inspection and permissible personnel radiation exposures for specified areas and conditions. (ALARA)
23. ☐ ☒ Transportability requirements such as size and shipping weight, limitations, I.C.C. regulations.
24. ☐ ☒ Fire protection or resistance requirements: (Check applicable letter)
    - ☐ a. Changes or additions/deletion of fire detection suppression systems or equipment.
    - ☐ b. Changes or additions to the plant configuration that change the effectiveness of existing fire detection/suppression systems.
25. ☐ ☒ Handling, storage and shipping requirements.
26. ☐ ☒ Other requirements to prevent undue risk to the health and safety of the public.
27. ☒ ☐ Materials, processes, parts and equipment suitable for application.
28. ☒ ☐ Safety requirements for preventing personnel injury including such items as radiation hazards, restricting the use of dangerous materials, escape provisions from enclosures, and grounding of electrical systems.
29. ☐ ☒ Addition or relocation of safe shutdown equipment, systems, components, or circuits that require compliance with the separation criteria stated in 10CFR50, Appendix R.
30. ☐ ☒ The modification will modify an item that: (Check applicable letter(s))
    - ☐ a. was originally procured and installed in an unmodified state and for which spare parts are stocked; or,
    - ☐ b. is being procured as a part of this modification and will be modified after receipt; or,
    - ☐ c. is currently in inventory (FIMIS) in an unmodified state and will be modified prior to installation and/or restocking
    - ☐ d. will be completely or partially replaced by an item of different design or materials.

    If "Yes" to any of the criteria, forward a completed copy of the Design Data Sheet, Design Input Record, Engineering Instructions, PR/BOM/material specifications (as applicable) and other applicable supporting documentation (Instruction Manuals, Vendor Drawings, FPC Drawings, Sketches, Figures, etc.) to Site Nuclear Procurement Engineering
31. ☒ ☐ The modification adds or relocates control room equipment entailing operator interface that requires Human Factors design review per the criteria stated in NUREG-0700 (Ref: FPC Specification SP-5145)

CR3 085402

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	SUPERVISOR NUCLEAR ENGINEERING	DATE
[illegible]	[illegible]	[signature]	10/20/87	[signature] for [illegible]	10/20/87

[illegible]

Florida Power Corporation

DESIGN INPUT RECORD
Crystal River Unit 3

REI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 14, 1987
Project:	ASV-5/204 POWER SEPARATION		

1. The function of this modification is to assure that the turbine driven emergency feedwater pump EFP-2 will be operable in the event of a failure of the ESB 250/125V DC system coincident with loss-of-offsite-power and an ES actuation. Under this scenario EFP-2 will be relied upon to share the emergency feedwater load with the motor driven emergency feedwater pump in order to decrease the electrical load on diesel generator EDG-1A. In order to assure that EFP-2 is operable for the above condition, this modification removes the 250/125VDC ES "B" power from ASV-204 and repowers it from 250/125VDC ES "A" power. This involves separating the ASV-5 and ASV-204 power and control circuits which are presently wired in parallel, and providing a separate control switch, indicator lights, and EFIC interlocks for ASV-204.

2. The capacity and rating of ASV-204 will not be changed by this modification. However, it will not be required to comply to the separation requirements of 10CFR50, Appendix R, because ASV-5 will remain in compliance. Therefore, remote shutdown isolation will not be required for ASV-204 circuitry.

3. IEEE-323-1974

   IEEE-344-1975

   IEEE-383-1974

   10CFR50, Appendix R

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
D.C. Blanda	10/20/87	[signature]	10/21/87	[signature] for KEV	10/21/87

Rev. 7/87

REF: Site Ot Plant RESP: Nuclear Engineering

CR3 085403

Florida Power Corporation

DESIGN INPUT RECORD
Crystal River Unit 3

REI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 14, 1987
Project:	ASV-5/204 POWER SEPARATION		

4. Power and control voltage to ASV-204 shall remain at 250/125 VDC.

5. New circuits which will be classified as safety related shall be routed in seismically qualified raceway. Relay racks and the main control board shall be reviewed for seismic integrity to account for the addition of any new components.

6. This modification involves wiring changes at ASV-204 and ASV-5 (Environmental Zone 14), adds a control switch and indicator lights in the main Control Room and adds two relays in the Relay Room (Environmental Zones 13 and 58, respectively). The zone environmental data sheets defining the environmental parameter requirements for the above zones are attached.

7. The control circuit for ASV-204 shall interface with the EFIC System as follows:

   a. A normally open EFIC actuation contact shall be wired in parallel with the control switch contact in the valve "opening" circuit to provide automatic opening of ASV-204 when EFIC is actuated.

   b. A normally closed EFIC actuation contact shall be wired in series with the control switch contact in the valve "closing" circuit to interrupt the closing of ASV-204 when EFIC is actuated.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
E G Parks	10/20/87	[signature] Graff	10/30/87	[signature] for [illegible]	10/30/87

Rev. 1/87

REF: Life Of Plant RESP. Nuclear Engineering [illegible]

Florida Power Corporation

DESIGN INPUT RECORD
Crystal River Unit 3

REI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 14, 1987
Project:	ASY-5/204 POWER SEPARATION		

8. Safety related electrical cables shall meet the requirements of IEEE-383-1974. New components required for this modification such as relays, and control switches shall be qualified for the application in which they are to be used.

13. Power for ASV-204 shall be 250 VDC ES Channel "A" power for the motor operator and 125 VDC ES Channel "A" power for the valve control circuit. The circuits shall be routed in accordance with CR3 ES Channel Separation Criteria. The motor starter space heater for ASV-204 is presently powered in parallel with the starter space heater for ASV-5 from a common non-1E 120 VAC power source. Although space heaters are non-1E, in order to avoid any circuitry common to the starters for ASV-5 and ASV-204, the ASV-204 starter space heater shall be powered from a separate non-1E 120 VAC source.

14. The control switch and indicator lights for ASV-204 shall be located on the PSA/EFIC Section of the Main Control Board in a existing spared switch cutout. ~~the space where pushbutton switch "AD2" is mounted.~~ Switch "AD2" is being removed via MAR T87-10-~~08~~19-01, and a new blanked [illegible]

15. With this modification, ASV-204 is required to be operational for a loss-of-power condition coincident with an ES actuation and a single failure of the 125 VDC ES Channel "B" power system.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
[signature]	10/29/87	[signature]	10/30/87	[signature] for [illegible]	10/30/87

Rev. 7/87

RET: Life Of Plant RESP: Nuclear Engineering 912247

CR3 085405

Florida Power Corporation

DESIGN INPUT RECORD
Crystal River Unit 3

REI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 14, 1987
Project:	ASV-5/204 POWER SEPARATION		

16. Remote manual control and indication shall be provided from the main control room via a control switch and red, green, and amber position indicator lights. The manual control shall be such that the control switch must be held in the open or close position to permit valve travel. Automatic control of ASV-204 shall be as described in item 7 above. Existing alarms utilizing ASV-204 and ASV-5 control logic shall be maintained. Auxiliary relays shall be used, as required, to provide the alarm logic from ASV-204.

18. Reference DIR items 7 and 13 above.

19. The failures and events that this modification is to be designed to withstand are as described in DIR items 5 and 15 above.

20. Manual and automatic operation of ASV-204 and ASV-5 including alarms and indicator lights (and remote shutdown operation of ASV-5) shall be tested upon completion of this modification.

22. Cable routing design and component location shall consider maintaining doses ALARA.

27. Cables, relays, controls, indicator lights, and any other components to be installed by this modification shall be qualified to the seismic and/or environmental criteria applicable to the equipment or areas in which they are to be installed.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
D.A. P. Bowie	10/29/87	[signature]	10/30/87	[signature] for CPV	10/30/87

Florida Power Corporation

DESIGN INPUT RECORD
Crystal River Unit 3

REI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 14, 1987
Project:	ASV-5/204 POWER SEPARATION		

30. Existing plant electrical grounding procedures shall apply.

31. With the implementation of this modification, there will be separate control switches and indicator lights for valves ASV-5 and ASV-204 in lieu of just one common switch and lights that presently exists for both valves. The new switch and indicator lights for ASV-204 shall be located per Specification SP-5145, Human Factors Design Conventions.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
A. O. Ehrck	10/29/87	[signature]	10/30/87	[signature] for RJV	[illegible]

Florida Power

SAFETY CLASSIFICATION REVIEW
Crystal River Unit 3

ITEM	COMPONENT
Valve Motor Operator ASV-204	Turbine Driven Emergency Feedwater Pump Inlet Isolation Valve

Generic ☐ Yes ☒ No Application

SYSTEM	REG. NO.	P & ID NO.	[illegible] NO.
AS	N/A	N/A	N/A

Answer each question:

1. Does the item/service assure the integrity of the reactor coolant system boundary (i.e., "Pressure-retaining" as defined in ASME Boiler and Pressure Vessel Code)? Yes ☐ No ☐

Justification: (Answer the following questions - If both are Yes, check "Yes" above, otherwise check "No".

	Yes	No
• Is the item/service a part of reactor coolant system?	☐	☐
• Is the item/service pressure-retaining per Code?	☐	☐

Comments: N/A

2. Does the item/service assure the capability to shut down the reactor and to maintain in a safe shut-down condition? Yes ☐ No ☐

Justification: N/A

3. Does the item/service assure the capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in 10CFR100.11? Yes ☐ No ☐

Justification: N/A

Is the answer to any question above "Yes"?

☐ Yes → Item/Service is Safety-related

☐ No → Item/Service is non Safety-related

NOTE:
If item is considered to be electrical equipment, the Environmental Qualification Requirements Review form must be completed to determine 10CFR50.49 applicability.

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	SUPERVISOR NUCLEAR ENGINEERING	DATE
D. O. Rhode	10/20/87	[signature]	10/30/87	[signature]	10/[illegible]

CR3 085408

Florida Power Corporation

ANALYSIS / CALCULATION
Crystal River Unit 3

SHEET ___ OF 1

REI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 14, 1987
Project:	ASV-5/204 POWER SEPARATION		

ATTACHMENT TO "SAFETY CLASSIFICATION REVIEW"
FOR VALVE MOTOR OPERATOR ASV-204

Safety Listing Revision 24, Page 1-15 lists valve motor operator ASV-204 as Safety Channel B. The modification of MAR T87-10-09-01 will change the motor and control power to ASV-204 from ES "B" 250/125 VDC to ES "A" 250/125 VDC. Consequently, the channel designation for ASV-204 on Page 1-15 of the Safety Listing must be changed from "B" to "A".

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
D O Rhoads	10/20/87	[illegible]	10/22/87	[illegible] for EV	10/2[illegible]

CR3 085409

VERIFICATION REPORT
Crystal River Unit 3

Florida Power

T87-10-09-01 | Date: 10/29/87

PROJECT: ASV-5/204 Power Separation

VERIFICATION METHOD: ☑ Design Review (use checklist below) ☐ Alternate Calculations (attach analysis calculation sheet)
☐ Qualification Testing (use attachments as necessary)

	YES	NO	N/A	
1.	☑	☐		Were the inputs correctly selected and incorporated into design?
2.	☑	☐	☐	Are assumptions necessary to perform the design activity adequately described and reasonable? Where necessary, are the assumptions identified for subsequent reverifications when the detailed design activities are completed?
3	☑	☐		Are the appropriate quality and quality assurance requirements specified?
4	☑	☐		Are the applicable codes, standards and regulatory requirements including issue and addenda properly identified and are their requirements for design met?
5	☑	☐	☐	Have applicable construction and operating experience been considered?
6.	☑	☐	☐	Have the design interface requirements been satisfied?
7	☑	☐		Was an appropriate design method used?
8.	☑	☐		Is the output reasonable compared to inputs?
9.	☑	☐	☐	Are the specified parts, equipment, and processes suitable for the required application?
10	☑	☐	☐	Are the specified materials compatible with each other and the design environmental conditions to which the material will be exposed?
11	☑	☐	☐	Have adequate maintenance features and requirements been specified?
12	☑	☐	☐	Are accessibility and other design provisions adequate for performance of needed maintenance and repair?
13	☐	☐	☑	Has adequate accessibility been provided to perform the in-service inspection expected to be required during the plant life?
14	☑	☐	☐	Has the design properly considered radiation exposure to the public and plant personnel?
15	☑	☐	☐	Are the acceptance criteria incorporated in the design documents sufficient to allow verification that design requirements have been satisfactorily accomplished?
16	☑	☐	☐	Have adequate pre-operational and subsequent periodic test requirements been appropriately specified?
17	☑	☐	☐	Are adequate handling, storage, cleaning and shipping requirements specified?
18	☑	☐	☐	Are adequate identification requirements specified?
19.	☑	☐	☐	Are requirements for record preparation review, approval, retention, etc. adequately specified?
20	☑	☐	☐	Has seismic adequacy been considered and evaluated and are the results acceptable?
21	☑	☐	☐	Have fire protection considerations been adequately addressed?

I have performed a verification on the subject MAR design package and find the results
☑ acceptable ☐ unacceptable

COMMENTS

Verifier Signature	Date	Supervisor, Nuclear Engineering	Date
[signature]	10/30/87	[signature]	10/30/87

Gilbert Commonwealth Companies

POWER AND INDUSTRIAL SYSTEMS DIVISION – READING
DESIGN VERIFICATION RECORD

PAGE 1 OF

A PROJECT: CRYSTAL RIVER UNIT 3 MAR T87-10-09-01

SUBJECT: ASV-5/204 Power Separation ID # DV-5510-126-EE

SECTION NAME AND NUMBER: Elect. Engr. / 0421

W.O.: 04-5510-126

D. A. Rhoads — ORIGINATOR

R. P. Cronk — PROJECT ENGINEER

THIS DOCUMENT CONTAINS PRELIMINARY DATA/ASSUMPTIONS:

NO ✓ YES ______ PAGE(S) ______

A COMPUTER PROGRAM WAS:

✓ NOT USED ______ USED (CERTIFIED PER CAM) ______ USED (NOT CERTIFIED—TO BE VERIFIED WITH CALCULATION)

PROGRAM SYSTEM NAME	REV.		REV.
(1)		(4)	
(2)		(5)	
(3)		(6)	

VERIFICATION PACKAGE (IDENTIFY EACH ITEM)

DOCUMENTS TO BE VERIFIED	REV.		REV.
(1) Cwr Sc- MAR T87-10-09-01		(4)	
(2)		(5)	
(3)		(6)	

SUPPORTING DOCUMENTS	REV.		REV.
(1) As listed in Section C		(7)	
(2) of Engineering Instructions		(8)	
(3)		(9)	
(4)		(10)	
(5)		(11)	
(6)		(12)	

D. A. Rhoads — ORIGINATOR'S SIGNATURE   10/24/87 — DATE

B NO VERIFICATION REQUIRED PER DCP 2.05:

REASON: ______

VERIFICATION REQUIRED (CHECK METHOD(S)):

DESIGN REVIEW ✓ ALTERNATE CALCULATION ______ QUALIFICATION TESTING ______

IDENTIFICATION OF VERIFIER/~~VERIFICATION TEAM~~ H. I. Gonzalez

[signature] — PROJECT ENGINEER'S SIGNATURE   10/30/87 — DATE

C. CONCURRENCE WITH SELECTION OF VERIFIER(S):

SECTION MANAGER'S SIGNATURE

11/20/87
DATE

D. EXTENT OF VERIFICATION:

Documents were verified for conformance to FPC SRDP's and G/C, Inc. DCP's and that the modification meets the design intent. Documents were reviewed for adequacy of inputs and correct design methodology.

RESULTS OF VERIFICATION:

Inputs were correctly selected and applied and design methodology is reasonable and applicable 10/21/87 appropriate. Applicable operating conditions have been considered in the design. Outputs are reasonable compared to the inputs. The final product meets the intent of the design. Verification comments have been resolved with the originator. Results are acceptable.

BACK SIDE OF
PREVIOUS DOCUMENT

ATTESTATION:

THIS DESIGN VERIFICATION WAS PERFORMED IN ACCORDANCE WITH DCP 3.3.

VERIFIER'S SIGNATURE

10/30/87
DATE

E. COMPLETION OF VERIFICATION:

PROJECT ENGINEER'S SIGNATURE

11/30/87
DATE

FIRE PROTECTION REVIEW
Crystal River Unit 3

Florida Power

MAR NUMBER	DATE
MAR T87-10-09-01	OCTOBER 28, 1987
PROJECT	**SYSTEM**
ASV-5/204 POWER SEPARATION	AS

YES NO

1\. Does the design/design change involve the modification, addition, removal, or relocation of any of the following? If yes, explain in space provided.

- [X] YES [ ] NO a. Combustibles (oil, hydraulic fluid, grease, wood-based materials, cloth, charcoal, PVC, cable insulation, carpet, etc.)

  See Attached Sheet

- [ ] YES [X] NO b. Available Fire Protection (detectors, fire extinguishers, hose stations, sprinklers, halon system, CO_2 system, etc.)

- [ ] YES [X] NO c. Equipment, components, or cables that would interfere with the operation of existing fire detection, emergency lighting, or other fire protection features.

- [X] YES [ ] NO d. Penetrations, penetration seals, or conduit seals. (If yes, update Penetration Seals List if applicable)

  See Attached Sheet

- [ ] YES [X] NO e. Space Separators (walls, ceilings, floors, doors, curbs, dampers, etc.)

- [X] YES [ ] NO f. Fireproofing, exposure fire protection, cable tray covers/wrapping, conduit wrapping, etc.

  See Attached Sheet

2\. [ ] YES [X] NO Will this design/design change require a revision to the Fire Hazards Analysis? Reference EG-4, Sect. V.C.

3\. [ ] YES [X] NO Does this design/design change deviate from any applicable NFPA Fire Code requirement in safety-related or safe shutdown areas/zone? If yes, explain below and obtain Fire Protection Engineer review and concurrence.

GCa 10/22/87

DESIGN ENGINEER	DATE	FIRE PROTECTION ENGINEER (if concurrence required by item 3)	DATE
D. A. Rhodes	10/24/87		

CR3 006440

Florida Power Corporation

ANALYSIS / CALCULATION
Crystal River Unit 3

REI / MAR No.	MAR T87-10-09-01	Date	OCTOBER 28, 1987
Project:	ASV-5/204 POWER SEPARATION		

ATTACHMENT TO FIRE PROTECTION REVIEW

Item 1.a.

This modification involves the installation of an approximate total of 3,200 feet of various power, control and instrumentation cable. Most of this cable is routed either in conduit or fire protected cable tray and, thus, does not contribute to the combustible load in the respective fire areas. The only fire areas where some of the above cable is routed in open cable trays are the Cable Spreading Room and the Relay Room. In the Cable Spreading Room, most of the cable tray route is in tray less than 50% full. Since the Fire Hazard Analysis is based on trays 50% filled, the additional cables do not affect the overall combustible load in this area. The cables in the Relay Room are very short runs where as they penetrate the ceiling and drop into the relay racks. The cables consist of a 5/C #14 control cable and two 2/C #16 instrument cables. The amount of combustible load contributed by these cables is considered insignificant.

Item 1.d.

This modification requires a conduit penetration through the Intermediate Building EL-119 floor, which requires resealing to the equivalent rating of the floor. Cables will penetrate through existing sealed penetrations in the following fire barriers:

Intermediate Building Floor EL-119
Control Complex West Wall On EL-134
Control Complex Floors EL-134 And 145

Upon completion of cable installation, these penetrations shall be resealed to the equivalent fire rating of the respective fire barriers.

Item 1.f.

Fire protected cable trays that need to be opened to accommodate cable installation shall be resealed to the required fire rating of the respective trays.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
D. A. P[illegible]	10/28/87	H. D. Graeff	11/3/87	[illegible]	[illegible]

MODIFICATION SAFETY EVALUATION

MAR NO. T87- 10- 09 - 01

SAFETY EVALUATION: Answer the following questions and provide specific justification (use attachment if necessary).

1. Is the probability of an occurrence or the consequence of an accident or malfunction of equipment important to safety as previously evaluated in the Final Safety Analysis Report, INCREASED? YES ___ NO X
Because:

See Attached Sheet

2. Is the possibility for an accident or malfunction of a different type than any previously evaluated in the Final Safety Analysis Report, CREATED? YES ___ NO X
Because:

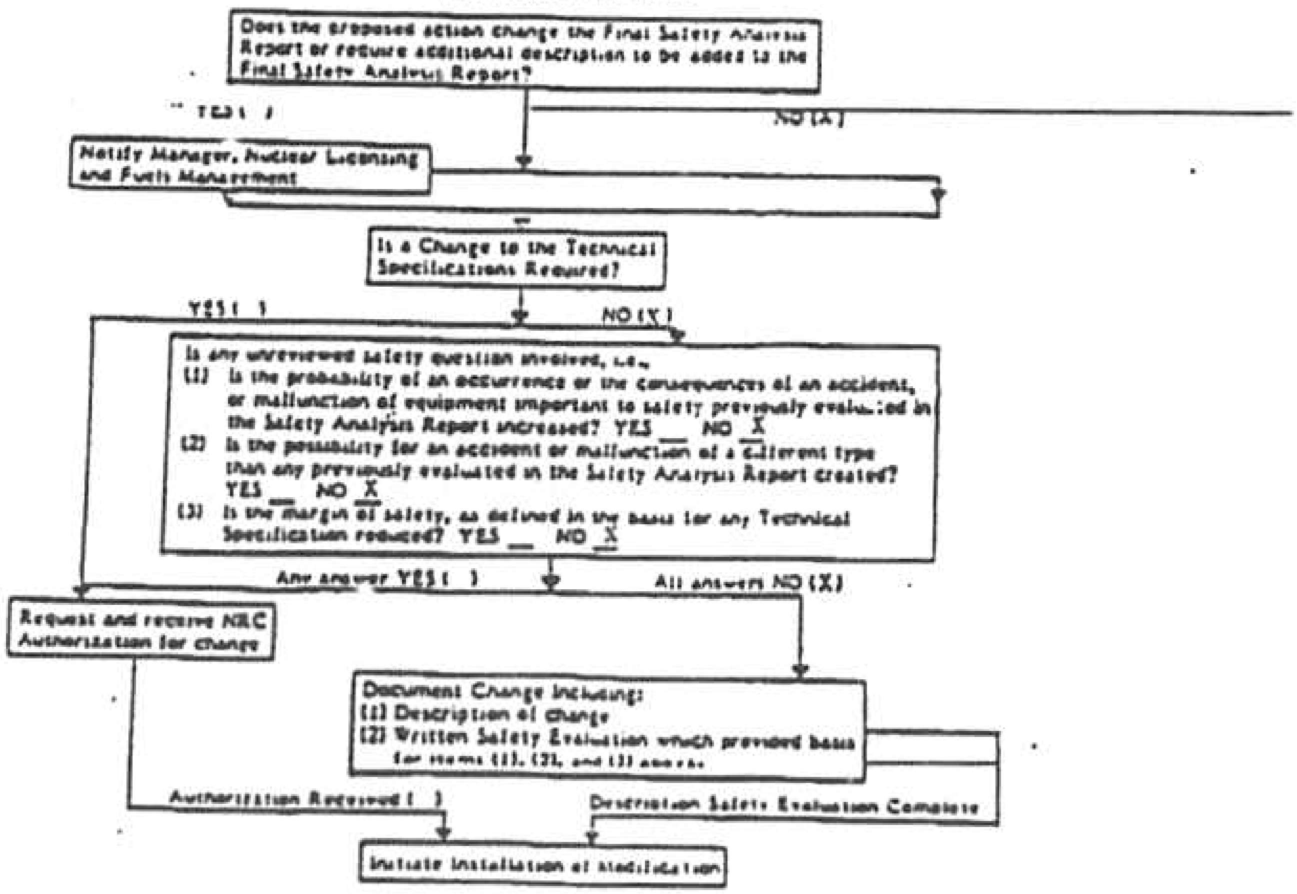
See Attached Sheet

3. Is the margin of safety, as defined in the basis for any Technical Specification, REDUCED? YES ___ NO X
Because:

See Attached Sheet

LICENSE REVISION REQUIRED:		
Final Safety Analysis Report:	YES ___	NO X
Technical Specification:	YES ___	NO X
NRC Authorization for Change Required:	YES ___	NO X
Semi-Annual Reporting to NRC Required:	YES ___	NO X

10CFR50.59 CHECKLIST



Florida Power Corporation	ANALYSIS / CALCULATION Crystal River Unit 3	SHEET 2 OF 3
[illegible] MAK T87-10-09-01		[illegible]
Project: ASV-5/204 POWER SEPARATION		

ATTACHMENT TO MODIFICATION SAFETY EVALUATION

1. ASV-5 and ASV-204 are motor operated valves having identical functions of supplying steam to the turbine driven Emergency Feedwater Pump (EFP-2). Since EFP-2 is the ES "B" channel pump, ASV-5 and 204 were electrically connected in parallel to a common 250/125 VDC ES "B" channel power and control source. This modification electrically separates ASV-204 from ASV-5 and repowers ASV-204 from 250/125 VDC ES "A" channel power. Also, separate control room controls and separate "A" channel EFIC interlocks are being provided for ASV-204. Automatic control logic of ASV-204 has not changed. Therefore, the probability of an occurance or the consequences of an accident or malfunction of equipment important to safety as previously evaluated in the FSAR is not increased since the logic of automatically opening ASV-204 whenever the EFIC System calls for emergency feedwater has not been altered. The reliability of EFP-2 has actually been increased because with this modification either "A" or "B" train power will control and operate one of the steam inlet valves to EFP-2 as opposed to both valves being "B" train powered. FSAR Sections 7.2.4, 8.2.2.6 and 10.2.1.6 have been reviewed.

2. The electrical separation of ASV-204 from ASV-5 does not impact the design function of either valve to supply steam to the EFP-2 turbine. Power and control for ASV-5 is not affected by this modification and ASV-5 retains its automatic control logic, remote manual control, local manual control and remote shutdown isolation and control. ASV-204 is being powered from the redundant power channel, and will be provided with its own remote manual control and with separate EFIC interlocks for automatic operation. The type of remote manual control and automatic operation of ASV-204 is the same as for ASV-5. Therefore, based on the above, the possibility for an accident or malfunction of a different type than any previously evaluated in the FSAR is not created. FSAR Sections 7.2.4, 8.2.2.6, and 10.2.1.6 have been reviewed.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
[illegible]	[illegible]	[illegible]	10/23/87	[illegible]	[illegible]

Florida Power Corporation

ANALYSIS / CALCULATION
Crystal River Unit 3

REI/MAR No.	MAR T87-10-09-01	Date	OCTOBER 19, 1987
Project:	ASY-3/204 POWER SEPARATION		

3. This modification enables the turbine driven Emergency Feedwater Pump (which is the "B" channel pump) to be operational even if a failure should occur on the "B" channel power system for which shutdown operation would be via the "A" channel systems. With this capability, the turbine driven EFW pump is able to operate and share the EFW requirements with the "A" channel motor driven EFW pump. This will reduce the electrical load on the "A" channel diesel generator for the condition of an ES actuation coincident with a loss-of-offsite-power and failure of the "B" channel power system. Consequently, with this modification the margin of safety, as defined in the basis for any Technical Specification, is not reduced. It is actually enhanced because of the increased availability of the turbine driven Emergency Feedwater Pump. Technical Specification Sections 3/4.7.1 and 3/4.8.1 have been reviewed.

Design Engineer	Date	Verification Engineer	Date	Supervisor, Nuclear Engineering	Date
N G Plonk	10/20/87	[signature]	10/31/87	[signature]	11/3/87

Florida Power

REGULATORY/ENVIRONMENTAL REVIEW
Crystal River Unit 3

DOCUMENT NUMBER

MAR T87-10-09-01

REF. NUCLEAR OPERATIONS DEPARTMENT PROCEDURE: NOD-14

1. **10 CFR 50.54 Reviews**

   Does this modification or document revision change what is described in any of the following plans/programs? If unable to determine, contact responsible person designated below.

Quality Program Description (FSAR Section 1.7) Contact: Director, Quality Programs	☐ Yes	☑ No
Licensed Operator Requalification Program (FSAR Section 12.2.1.4 and Appendix 12 C) Contact: Manager, Nuclear Operations Training	☐ Yes	☑ No
Modified Amended Security Plan Contact: Manager, Nuclear Licensing	☐ Yes	☑ No
Safeguards Contingency Plan Contact: Nuc. Security & Special Project Superintendent	☐ Yes	☑ No
Security Guard Training and Qualification Plan Contact: Nuc. Security & Special Project Superintendent	☐ Yes	☑ No
Radiological Emergency Response Plan Contact: Manager, Site Nuclear Services	☐ Yes	☑ No

   If any are "yes":

   a. Contact appropriate responsible person identified above to perform the evaluation and attach. The evaluation must be approved by the Division Head responsible for the plan/program. — Evaluation ☐ Complete ☑ N/A

   b. NRC approval received if needed and attach. — ☐ Complete ☑ N/A

2. **Environmental Protection Plan Review**

   Could this change affect the environment in a non-radiological way? — ☐ Yes ☑ No

   If "yes", contact the Manager, Nuclear Licensing — ☐ Complete ☑ N/A

3. **Review for change to Radioactive Waste System (10 CFR 50.34a and Appendix I / T. S. 6.16.1.1)**

   Will this change to a radioactive waste system (liquid, gaseous or solid) result in an increase of radioactive material released to the environment? — ☐ Yes ☑ No

   If "yes", submit change to Manager, Nuclear Licensing to evaluate the reporting requirements. — ☐ Submitted ☑ N/A

IF ALL OF ABOVE ARE CHECKED NO, NO FURTHER REVIEWS ARE REQUIRED.

PREPARED BY	DATE	APPROVED BY	DATE
R. S. [signature]	11/10/87	[signature] / C. S. [signature]	11/13/87 / 11/11/87

Gilbert Commonwealth Companies

POWER AND INDUSTRIAL SYSTEMS DIVISION – READING
DESIGN VERIFICATION RECORD

A PROJECT: CRYSTAL RIVER UNIT 3 ~~DC-5510-126EE~~

SUBJECT: ADDITION OF ASV-204 TO DPDP-8A

SECTION NAME AND NUMBER: Elect. Engr. /0421

W.O. 04-5510-126

D. A. Rhoads — ORIGINATOR

R. P. Crank — PROJECT ENGINEER

THIS DOCUMENT CONTAINS PRELIMINARY DATA/ASSUMPTIONS:

NO ✓ YES ____ PAGE(S) ____

A COMPUTER PROGRAM WAS:

✓ NOT USED ____ USED (CERTIFIED PER CAM) ____ USED (NOT CERTIFIED–TO BE VERIFIED WITH CALCULATION)

PROGRAM SYSTEM NAME	REV.		REV.
(1)		(4)	
(2)		(5)	
(3)		(6)	

VERIFICATION PACKAGE (IDENTIFY EACH ITEM)

DOCUMENTS TO BE VERIFIED	REV.		REV.
(1) DC-5510-126-EE	0	(4)	
(2)		(5)	
(3)		(6)	

SUPPORTING DOCUMENTS	REV.		REV.
(1) As listed in 'Design Inpt'		(7)	
(2) of DC-5510-126-EE		(8)	
(3)		(9)	
(4)		(10)	
(5)		(11)	
(6)		(12)	

D. A. Rhoads — ORIGINATOR'S SIGNATURE — 10/24/87 DATE

B NO VERIFICATION REQUIRED PER DCP 2.05:

REASON: ____

VERIFICATION REQUIRED (CHECK METHOD(S)):

DESIGN REVIEW ✓ ALTERNATE CALCULATION ____ QUALIFICATION TESTING ____

IDENTIFICATION OF VERIFIER/~~VERIFICATION TEAM~~ H. T Greer

[signature] — PROJECT ENGINEER'S SIGNATURE — 10/24/87 DATE

CR3 085440

Gilbert/Commonwealth CALCULATION	SUBJECT: CRYSTAL RIVER UNIT 3 ADDITION OF ASV-204 TO DPDP-8A	IDENTIFIER: DC-5510-[illegible]26.0-EE	PAGE 3 of 4
	REV. 0		
	ORIGINATOR: P. A. [illegible]		
	DATE: 10/20/87		

1. PURPOSE

Review the 250/125VDC ES 'A' power distribution system to verify that sufficient capacity is available to power motor operated valve ASV-204 from distribution panel DPDP-8A.

2. DESIGN INPUTS

A. Scope Document FCS-8915 dated 10/12/87
B. Calculation DC-CR3-017-EE, Rev. 0
C. Calculation DC-5079-275.0-EE, Rev. 0
D. Motor Data Sheet for ASV-5

3. COMPUTER PROGRAMS USED

None

4. ASSUMPTIONS

None

5. CALCULATION

Per D.I. 2.C above, the electrical requirements of ASV-204 are identical to ASV-5. The motor data sheet for ASV-5 indicates a full load current of 2.9 amps and a locked rotor current of 16.2 amps.

ASV-204 is being powered from distribution panel DPDP-8A.

Per page 29 of 40 of Calculation DC-CR3-017-EE, Rev. 0 (D.I. 2.B) the load on DPDP-8A (without ASV-204) is 94.5 amps for the first minute of the battery duty cycle and 4.5 amps after the first minute.

Gilbert/Commonwealth CALCULATION	SUBJECT CRYSTAL RIVER UNIT 3 ADDITION OF ASV-204 TO DPDP-8A		IDENTIFIER DC-3510-1260-EE		PAGE 4 OF 4 PAGES
	REV. 0	1	2	3	
	MICROFILMED				
	ORIGINATOR D.A. Rhoads				
	DATE 10/20/87			-	

Allowing one amp for control circuit power and conservatively assuming that the motor current for the first minute is equal to the LRA value, the addition of ASV-204 (which will operate during the first minute of the battery duty cycle) increases the load on DPDP-8A to 111.7 amps for the first minute and 5.5 amps after the first minute. This is well within the 400 amp continuous rating of DPDP-8A.

Per page 34 of Rev 0 of Calculation DC-CR3-017-EE, Rev. 0 (D.I.2.B) the total Ampere-Hour load on the 250/125 VDC ESA system is 1111 A-H without the addition of ASV-204. With the addition of ASV-204 to DPDP-8A the total Ampere-Hours becomes 1113 A-H (Ref. DC-CR3-017-EE, Rev 1). The rating of the 250/125 VDC ESA battery is 1580 A-H.

6. CONCLUSION

Based on the above analysis the new total load on the 250/125 VDC ESA system with the addition of ASV-204 to DPDP-8A is well within the system capacity.

POWER AND INDUSTRIAL SYSTEMS DIVISION — READING
DESIGN VERIFICATION RECORD

PAGE 1 OF 4

Gilbert Commonwealth Companies

A PROJECT: CRYSTAL RIVER UNIT 3 — DC-5510-126.1-EE

SUBJECT: ASV-5/208 Power Separation Qualification Review

SECTION NAME AND NUMBER: Elect. Engr. / 04121

W.O.: 08-5510-126

D. A. Rhoads — ORIGINATOR

R. P. Cronk — PROJECT ENGINEER

THIS DOCUMENT CONTAINS PRELIMINARY DATA/ASSUMPTIONS:

NO ✓ YES ______ PAGE(S) ______

A COMPUTER PROGRAM WAS:

✓ NOT USED ______ USED (CERTIFIED PER CAM) ______ USED (NOT CERTIFIED—TO BE VERIFIED WITH CALCULATION)

PROGRAM SYSTEM NAME	REV.		REV.
(1)		(4)	
(2)		(5)	
(3)		(6)	

VERIFICATION PACKAGE (IDENTIFY EACH ITEM)

DOCUMENTS TO BE VERIFIED	REV.		REV.
(1) DC-5510-126.1-EE	0	(4)	
(2)		(5)	
(3)		(6)	

SUPPORTING DOCUMENTS	REV.		REV.
(1) As listed in "DESIGN INPUTS"		(7)	
(2) on page 3 of 4		(8)	
(3)		(9)	
(4)		(10)	
(5)		(11)	
(6)		(12)	

D. A. Rhoads — ORIGINATOR'S SIGNATURE   10/29/87 — DATE

B NO VERIFICATION REQUIRED PER DCP 2.05:

REASON: ______

VERIFICATION REQUIRED (CHECK METHOD(S)):

DESIGN REVIEW ✓ ALTERNATE CALCULATION ______ QUALIFICATION TESTING ______

IDENTIFICATION OF VERIFIER/~~VERIFICATION TEAM~~ T. D. Riss

[signature] — PROJECT ENGINEER'S SIGNATURE   10/29/87 — DATE

POWER AND INDUSTRIAL SYSTEMS DIVISION — READING
DESIGN VERIFICATION RECORD

A) PROJECT: CRYSTAL RIVER UNIT 3 ID = DC-CR3-017-EE

SUBJECT: BATTERY 3A SIZE VERIFICATION

SECTION NAME AND NUMBER: Elect. Engr. / 0421 W.O. 04-5510-126

D. A. Rhoads — ORIGINATOR

R. P. Corrit — PROJECT ENGINEER

THIS DOCUMENT CONTAINS PRELIMINARY DATA/ASSUMPTIONS:

NO ✓ YES ____ PAGE(S) ____

A COMPUTER PROGRAM WAS:

✓ NOT USED ____ USED (CERTIFIED PER CAM) ____ USED (NOT CERTIFIED—TO BE VERIFIED WITH CALCULATION)

PROGRAM SYSTEM NAME	REV.		REV.
(1)		(4)	
(2)		(5)	
(3)		(6)	

VERIFICATION PACKAGE (IDENTIFY EACH ITEM)

DOCUMENTS TO BE VERIFIED	REV.		REV.
(1) DC-CR3-017-EE, Pages	1	(4)	
(2) 24, 29, 31-34, 40		(5)	
(3)		(6)	

SUPPORTING DOCUMENTS	REV.		REV.
(1) DC-5510-126-EE	0	(7)	
(2)		(8)	
(3)		(9)	
(4)		(10)	
(5)		(11)	
(6)		(12)	

D. A. Rhoads — ORIGINATOR'S SIGNATURE 10/24/87 — DATE

B) NO VERIFICATION REQUIRED PER DCP 2.05:

REASON:

VERIFICATION REQUIRED (CHECK METHOD(S)):

DESIGN REVIEW ✓ ALTERNATE CALCULATION ____ QUALIFICATION TESTING ____

IDENTIFICATION OF VERIFIER ~~/QUALIFICATION TERMS~~ H. T. Graeff

[signature] — PROJECT ENGINEER'S SIGNATURE 10/24/87 — DATE

QUALITY PROGRAMS INSPECTION PLAN REVIEW

Florida Power

FIELD CHANGE NOTICE

Crystal River Unit 3

PLANT REVIEW COMMITTEE APPROVAL

☑ To Be Added at W.P. Level ☐ Revised & Issued W/Working Copy ☐ Revised & Attached

MAR NUMBER	FCN NUMBER	SAFETY RELATED		IP REVIEW REQUIRED	
T87-10-09-01	1A	☒ Yes	☐ No	☐ Yes	☒ No

PROJECT NAME: RV-5 & RV-2A Power Separation

SAFETY EVALUATION REQUIRED	REGULATORY ENVIRONMENTAL REVIEW REQUIRED	PRC REVIEW REQUIRED
☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No

DRAWINGS AFFECTED

SEE SHEET # 2

DESCRIPTION OF FIELD CHANGE AND ADDITIONAL SHEETS IF REQUIRED

THIS FCN PROVIDES THE CONDUIT ROUTING AND SEISMIC CONDUIT SUPPORT WEIGHT CALC SHEETS FOR RV-5 & RV-2A POWER SEPARATION AS REQUIRED FOR THE ADDITION OF CONDUIT IN THE SUBJECT MAR.

ORIGINAL

FOR ATTACHMENTS ADDED, SEE SHEET #3.

REASON FOR FIELD CHANGE AND ADDITIONAL SHEETS IF REQUIRED

ADDITIONAL CONDUIT ROUTING IS REQUIRED PER INSTALLATION INSTRUCTIONS 3A, 3B, 4A, 5A, AND 6A ON SHEETS 4 AND 5 OF 17 OF THE ENGINEERING INSTRUCTIONS OF THE SUBJECT MAR.

TECHNICAL JUSTIFICATION: EACH CONDUIT SUPPORT HAS AN ACTUAL LOAD WITHIN ITS CALCULATED ALLOWABLE AS SHOWN IN INDIVIDUAL SUPPORT CALCULATION PACKAGES.

NUCLEAR ENGINEERING APPROVAL

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	
Jürgen F. Emhardt	11/16/87	E. O. F.	11/16/87	☐ Yes ☐ No ☒ N/A
		ENGINEERING SUPERVISOR: G. E. Colley	11-16-87	

QUALITY PROGRAMS INSPECTION PLAN REVIEW

REVIEWER	DATE	INSPECTION PLAN FOR ADVANCED FCN
Steve Broad	11-17-87	☑ To Be Added at W.P. Level ☐ No Change ☐ Revised & Issued W/Working Copy ☐ Revised & Attached

PLANT REVIEW COMMITTEE APPROVAL

PRC APPROVAL BY PRC CHAIRMAN	DATE	MEETING NUMBER
N/A		N/A
INSTALLATION AUTHORIZED BY	DATE	
N/A	N/A	

NUCLEAR PLANNER VERIFICATION

THIS FCN HAS BEEN INCORPORATED INTO THE MAR PACKAGE BY	POSITION
MICHAEL K. WILSON	NPS
COMPANY NAME	DATE
FPC	7/13/92

CR3 085424

Florida Power

FIELD CHANGE NOTICE

Crystal River Unit 3

To be Applied at W.P. Level ☐ Revised & Issued W/Working Copy ☐ Revised 8

Sheet 1 of 2

WAR NUMBER	FCN NUMBER	SAFETY RELATED		LE REVIEW REQUIRED	
T87-10-09-01	F 2A	☒ Yes	☐ No	☐ Yes	☒ No

PROJECT NAME
ASV-5/204 Power Separation

SAFETY EVALUATION REQUIRED		REGULATORY ENVIRONMENTAL REVIEW REQUIRED		PRC REVIEW REQUIRED	
☐ Yes	☒ No	☐ Yes	☒ No	☐ Yes	☒ No

DRAWINGS AFFECTED
Ref EC-209-008 AS-6

DESCRIPTION OF FIELD CHANGE (Use Additional Sheets if Necessary)

1. Revised Safety Listing To ~~include~~ revise Channel on AS4 Term. Box And ASV-204 Starter
2. Added Note Identifying Channel Change of ASV-204 Motor Starter from Green To Red
3. Revised Wiring To assist field in installation.
4. Corrected Typographical error.

FCN Attachment - BIM - Attachment 1

REASON FOR FIELD CHANGE (Use Additional Sheets if Necessary)

This FCN is written to assist the field in wiring Changes To ASV-204, and corrects omissions to the safety listing.

ORIGINAL

NUCLEAR ENGINEERING APPROVAL

DESIGN ENGINEER	DATE	VERIFYING ENGINEER	DATE	CONCUR WITH APPLICABLE FOR
[signature]	11/23/87	R. S. Kramer	11/23/87	☒ Yes ☐ No ☐ N/A
		ENGINEERING SUPERVISOR	DATE	
		[signature]	11-23-87	

QUALITY PROGRAMS INSPECTION PLAN REVIEW

APPROVED	DATE	INSPECTION PLAN FOR APPROVED FCN
[signature]	11-27-87	☒ To Be Applied at W.P. Level ☐ No Change ☐ Revised & Issued W/Working Copy ☐ Revised & Attached

PLANT REVIEW COMMITTEE APPROVAL (Required if checked YES ...)

PRC APPROVAL BY PRC Chairman	DATE	MEETING NUMBER
N/A		N/A
INSTALLATION AUTHORIZED BY Plant Manager	DATE	
N/A		

NUCLEAR PLANNER VERIFICATION

THIS FCN HAS BEEN INCORPORATED INTO THE WAR PACKAGE	PRINT NAME
MICHAEL K. WILSON	NPS
COMPANY NAME	DATE
FPC	7/13/92

CR3 085425

Florida Power

FIELD CHANGE NOTICE

Crystal River Unit 3

Sheet 1 of 1

T87-10-09-01/A	3A	☒ Yes ☐ No	☐ Yes ☒ No

PROJECT NAME: ASV-5/204 Power Separation

SAFETY EVALUATION REQUIRED	REGULATORY ENVIRONMENTAL REVIEW REQUIRED	PRC REVIEW REQUIRED
☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No

DRAWINGS AFFECTED: None

DESCRIPTION OF FIELD CHANGE (Use Additional Sheets if Necessary)

Add note to Clarify use of Brand Rex Wire B/M Item 23 in Equipment Located in a Harsh Environment.

ORIGINAL

REASON FOR FIELD CHANGE (Use Additional Sheets if Necessary)

Brand Rex 218 wire is the only qualified jumper wire for use in a harsh environment

NUCLEAR ENGINEERING APPROVAL

	DATE		DATE
[signature]	11/29/87	Larry R. McDougal [signature]	☒ Yes ☐ No ☐ N/A
		ENGINEERING SUPERVISOR: [signature]	11-29-87

QUALITY PROGRAMS INSPECTION PLAN REVIEW

REVIEWER	DATE	INSPECTION PLAN FOR ADVANCED FCN
[signature]	11-27-87	☒ To Be Added at W.P. Level ☐ No Change ☐ Revised & Issued Working Copy ☐ Revised & Attached

PLANT REVIEW COMMITTEE APPROVAL (Required if checked YES above)

PRC APPROVAL BY PRC CHAIRMAN	DATE	MEETING NUMBER
N/A		N/A
INSTALLATION AUTHORIZED BY Nuclear Plant Manager: N/A	DATE	

NUCLEAR PLANNER VERIFICATION

THIS FCN HAS BEEN INCORPORATED INTO THE WAR PACKAGE BY (PRINT NAME)	POSITION
MICHAEL K. WILSON	NPS
COMPANY NAME: FPC	DATE: 7/13/92

CR3 085426

FIELD CHANGE NOTICE

Florida Power

REVIEW COMMITTEE APPROVED

Crystal River Unit 3

Sheet 1 of 10

T87-10-09-01	4ABU	☒ Yes ☐ No	☐ Yes ☒ No

PROJECT NAME

ASV-57/-204 POWER SEPARATION [redacted]

☐ Yes 4AE ☒ No	☐ Yes ☒ No	☐ Yes ☒ No

DRAWINGS AFFECTED

SKETCH 1 (REF. DWG. SS-211-008, AS-06)
SKETCH 9 (REF. DWG. EC-209-008, AS-06)
SKETCH 18 (REF. DWG. EC-210-624)
SKETCH 24 (REF. DWG. EC-211-124)
SKETCH 27 (REF. DWG. B-208-005)
SKETCH 37 (REF. DWG. EC-209-008, AS-06)
SKETCH 38 (REF. DWG. E-201-092)

DESCRIPTION OF FIELD CHANGE

THIS FCN ADDS LOCAL CONTROLS & INDICATION FOR VALVE ASV-204 TO TERM. BOX AS-9.

SEE SHEET 2 FOR DETAILED CHANGES.

FCN attachments, None.

Insert added per sheet 8A.

REASON FOR FIELD CHANGE

Local Control station provided for Personnel and Equipment safty and protection.

ORIGINAL

L. D. Kitey	11/25/87		12-4-87 ☐ Yes ☐ No ☒ N/A
R. S. Plemon	11/25/87	C. B. Paul	12/1/87

Glen Brandon	12-7-87	☐ No Change ☐ Revised & Issued W/Working Copy ☐ Revised & Attached ☐ To Be Added at W.P. Level

PRC APPROVAL BY PRC CHAIRMAN: N/A — DATE:

INSTALLATION AUTHORIZED BY: N/A — DATE:

MICHAEL K. WILSON	NPS
FPC	7/13/92

FIELD CHANGE NOTICE

Crystal River Unit 3

T87-10-04-01 NA

5A

X Yes — No NA — Yes — X No

ASU-5 / 208 POWER SEPARATION

MC-Yes-01 X No

Yes X No

Yes X No

SKETCH 17 (REF. DWG EC-210-622)
SKETCH 18 (REF. DWG EC-210-624)
SKETCH 27 (REF DWG ...)
SKETCH 36 (REF 8208-026, CF-15)

TB14 TERMINALS 19 THRU 22 ARE IN USE. THE FCN MOVES ASE37 TO TB15 TERMINALS 17 THRU 20.

CHANGE E.I. SECTION E.16.b, PER ATTACHED & E.16.c, PER ATTACHED.

INTERFERENCE WITH MAR 86-05-25-01

ORIGINAL

12-6-87

C. J. Kohler 12/6/87

12/7/87

12-08-87

No Change — Remove & Insert Controlling Copy — Remove & Attach — X To Be Added at W.P. Level

NA

NA

NA

MICHAEL K. WILSON

NPS

FPC

7/13/92

1 of 1

QUALITY PROGRAMS INSPECTION PLAN REVIEW

FIELD CHANGE NOTICE

Crystal River Unit 3

To be Added at W.P. Level 4

Sheet 1 of 1

T87-10-09-01	6A	Safety Related: ☒ Yes ☐ No		☐ Yes ☒ No

ASV-3/204 POWER SEPARATION

Safety Evaluation Required: ☐ Yes ☒ No | Regulatory Environmental Review Required: ☐ Yes ☒ No | ☐ Yes ☒ No

Drawings Affected:

SKETCH 9, SKETCH 27, SKETCH 37 (All Rev A)

Description of Field Change and Additional Sheets & Reasons

1) REVERSE ZENER DIODES ZD1, ZD2 & ZD3 ON SKETCH 9.

2) DELETE RESISTORS R4, R5 & R6 FROM SKETCH 27 & 37.

ORIGINAL

Reason for Field Change and Additional Sheets & Reasons

1) INCORRECTLY SHOWN, THIS FCN MAKES SKETCH 9 AGREE WITH SKETCH 27, WHICH IS CORRECT.

2) LIGHTS ARE 125V, RESISTORS ARE NOT REQUIRED.

NUCLEAR ENGINEERING APPROVAL

Design Engineer	Date		Date	
[signature]	12-11-87	[signature]	12/11/87	☒ Yes ☐ No ☐ N/A
		[signature]		12-11-87

QUALITY PROGRAMS INSPECTION PLAN REVIEW

Reviewer	Date	
J.O. Martin	12/16/87	☒ To be Added at W.P. Level ☐ No Change ☐ Revised & Issued W/Working Copy ☐ Revised & Attached

PLANT REVIEW COMMITTEE APPROVAL

	Date	
NA		NA

Installation Authorized by:

NA

NUCLEAR PLANNER VERIFICATION

	Position
MICHAEL KWIKSON	NPS
Company Name	Date
FPC	7/13/92

CR3 085429

FIELD CHANGE NOTICE

Florida Power

Crystal River Unit 3

REVIEW COMMITTEE APPROVAL ... YES ... Sheet 1 of 8

FCN NUMBER	FCR NUMBER	SAFETY RELATED	QC REVIEW REQUIRED
T87-10-09-01 NA	7A	X Yes ___ No	___ Yes X No

PROJECT NAME

ASV 5/204 Power Separation

SAFETY EVALUATION REQUIRED	REGULATORY ENVIRONMENTAL REVIEW REQUIRED	PRC REVIEW REQUIRED
☐ Yes X No	☐ Yes X No	☐ Yes X No

DRAWINGS AFFECTED AND/OR

SKETCH 32, 26, 19, 20 & NEW SKETCHES 20A & 39

DESCRIPTION OF FIELD CHANGE AND ADDITIONAL SHEETS

1) ADD SKETCHES 20A & 39 TO SECTION B - ATTACHMENTS

2) REVISE SKETCHES 32, 26, 19 & 20 AS SHOWN ON PAGES 2, 3, 4 & 5 OF THIS FCN

3) ADD THE FOLLOWING INSTALLATION INSTRUCTIONS TO SECTION E.

NOTE: THESE STEPS STAND ALONE.

1. AT THE PSA SECTION OF MCB (REF. SK 26), DETERM AND SPARE BLK (1) CONDUCTOR FROM ASK29 CABLE, NOW LANDED ON TB40-3
2. INSTALL JUMPER BETWEEN TB40-3 & TB40-5 (REF. SK26).
3. AT RR3A (REF SK 19) DETERM AND SPARE BLACK CONDUCTOR (1) FROM CABLE ASK29, NOW LANDED ON TB12-10.

(CONTINUED ON PAGE 2)

REASON FOR FIELD CHANGE AND ADDITIONAL SHEETS

AS PRESENTLY CONNECTED, THE EFP #2 'FAILURE TO START' ALARM WILL FUNCTION ONLY WHEN BOTH 'A' & 'B' EFIC SIGNALS ARE PRESENT TO START THE PUMP.

THIS CHANGE ALLOWS THIS ALARM TO FUNCTION IF THE 'PUMP START' SIGNAL COMES FROM EITHER 'A' OR 'B' EFIC SIGNALS. 12-27-87

ORIGINAL

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	
[signature]	12-27-87	[signature]	12/28/87	☐ Yes ☐ No ☐ N/A
		ENGINEERING SUPERVISOR	DATE	
		[signature]	12/28/87	

QUALITY PROGRAMS

APPROVED	DATE	INSPECTION PLAN FOR ADVANCES FOR
[signature]	12/29/87	☐ To Be Added at W.P. Level ☐ No Change ☐ Revised & Issued W/Working Copy ☐ Revised & Attached

PRC APPROVAL BY PRC CHAIRMAN	DATE	MEETING NUMBER
NA		NA

INSTALLATION AUTHORIZED BY	DATE
NA	

THIS FCN HAS BEEN INCORPORATED INTO THE ...	POSITION
MICHAEL E WILSON	NDS
COMPANY NAME	DATE
FPC	7/13/92

CR3 085430

Florida Power

FIELD CHANGE NOTICE

Crystal River Unit 3

Sheet 1 of 5

MAR NUMBER	FCN NUMBER	SAFETY RELATED	ISI REVIEW REQUIRED
T87-10-09-01	10	☒ Yes ☐ No	☒ Yes ☐ No

PROJECT NAME: ASV-5/204 POWER SEPARATION

EQ REVIEW REQUIRED: ☒ Yes ☐ No

SAFETY EVALUATION REQUIRED	REGULATORY/ENVIRONMENTAL REVIEW REQUIRED	PRC REVIEW REQUIRED
☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No

DRAWINGS AFFECTED: NONE

DESCRIPTION OF FIELD CHANGE

1) CORRECT ISI REVIEW REQUIREMENT ON THE MAR FORM & ADD GUIDELINES TO SECTION "H" OF ENGINEERING INSTRUCTIONS.

2) INDICATE THAT "E.Q. REVIEW" IS REQUIRED.

ORIGINAL

REASON FOR FIELD CHANGE

1) THIS CORRECTION IS IN RESPONSE TO RECA 87-015-01.

2) ORIGINAL ISSUANCE OF MAR WAS PRIOR TO THE MAR FORM HAVING A CHECK-BLOCK FOR E.Q. REVIEW.

NUCLEAR ENGINEERING APPROVAL

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE
[signature]	3/7/90	[signature]	

SITE FIELD ENGINEER / DATE / PRC REVIEW REQUIRED ☐ Yes ☐ No / ENGINEERING SUPERVISOR [signature]

QUALITY SYSTEMS REVIEW FOR QUALITY REQUIREMENTS

REVIEWER: [signature] DATE: 3/22/90

PLANT REVIEW COMMITTEE APPROVAL (Required if checked YES by Nuclear Engineering)

PRC APPROVAL BY PRC CHAIRMAN: [signature] DATE / MEETING NUMBER

INSTALLATION AUTHORIZED BY Nuclear Plant Manager / DATE

NUCLEAR PROJECTS SPECIALIST

THIS FCN HAS BEEN INCORPORATED INTO THE MAR PACKAGE BY: MICHAEL R WILSON — POSITION: NPS

COMPANY NAME: FPC — DATE: 7/13/92

FIELD CHANGE NOTICE

Florida Power — Crystal River Unit 3 — Sheet 1 of 2

MAR NUMBER	FCN NUMBER	SAFETY RELATED	ID REVIEW REQUIRED
T87-10-09-01	9	☒ Yes ☐ No	☐ Yes ☒ No

PROJECT NAME: ASV-5/204 POWER SEPARATION

SAFETY EVALUATION REQUIRED	REGULATORY ENVIRONMENTAL REVIEW REQUIRED	PRC REVIEW REQUIRED
☐ Yes ☒ No	☐ Yes ☒ No	☒ Yes ☐ No

DRAWINGS AFFECTED

201-071 DP-15A (INTERIM REV. A)
208-008 AS-07 (INTERIM REV. A)

DESCRIPTION OF FIELD CHANGE

CORRECT LOAD COMPONENT IDENTIFICATIONS FOR ASV-204 FEEDS TO READ:

SW. NO.	LOAD COMPONENT IDENTIFICATION
15	125V DC CONTROL TO (ASV-204)
17	250V DC POWER TO (ASV-204)

FCN ATTACHMENTS - PARTIAL DWG 201-071 DP-15A & PARTIAL DWG 208-008 AS-07

REASON FOR FIELD CHANGE

POWER FEED IDENTIFICATONS FOR THE POWER AND CONTROL FOR ASV-204 WERE INCORRECTLY IDENTIFIED BY FCN #8 TO MAR T87-10-09-01.

NUCLEAR ENGINEERING APPROVAL

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	CONCUR WITH ADVANCED FCN
Chris S. Sterner	9/11/89	[signature]	9/11/89	☐ Yes ☐ No ☒ N/A

FIELD ENGINEER	DATE	FCWP REQUIRED	ENGINEERING SUPERVISOR	DATE
		☐ Yes ☐ No	[signature]	9/11/89

QUALITY SYSTEMS REVIEW FOR QUALITY REQUIREMENTS

REVIEWER: J.D. Martin — DATE: 9/14/89

PLANT REVIEW COMMITTEE APPROVAL (Required if checked YES by Nuclear Engineering)

PRC APPROVAL BY PRC CHAIRMAN: NR — DATE — MEETING NUMBER

INSTALLATION AUTHORIZED BY — DATE

NUCLEAR PROJECTS SPECIALIST

THIS FCN HAS BEEN INCORPORATED INTO THE MAR PACKAGE BY: MICHAEL R. WILSON — POSITION: NPS

COMPANY NAME: FPC — DATE: 7/13/92

CR3 085432

PRC #156-
7-18-89

FIELD CHANGE NOTICE

PLANT REVIEW COMMITTEE Crystal River Unit 3 Sheet 1 of 3

MAR NUMBER	FCN NUMBER	SAFETY RELATED	RI REVIEW REQUIRED
T87-10-09-01	8	☒ Yes ☐ No	☐ Yes ☒ No

PROJECT NAME: ASV-5/204 Power Separation

SAFETY EVALUATION REQUIRED	REGULATORY/ENVIRONMENTAL REVIEW REQUIRED	PRC REVIEW REQUIRED
☐ Yes ☒ No	☐ Yes ☒ No	☒ Yes ☐ No

DRAWINGS AFFECTED:

SEE ATTACHED SHEET #2

DESCRIPTION OF FIELD CHANGE:

INCORPORATE INTERIMS OF CRITICAL CONTROL ROOM DRAWINGS INTO THE MAR BY COMPOSITING THE MAR SKETCHES [...] RELEVANT FCN SKETCHES.

"DOCUMENTATION ONLY" FCN

SEE SHEET #3 FOR ATTACHMENTS INCLUDED

ORIGINAL

REASON FOR FIELD CHANGE:

CRITICAL CONTROL ROOM DRAWINGS MUST BE AVAILABLE TO CONTROL ROOM PERSONNEL AND INTERIM DRAWINGS ARE THE PRESCRIBED METHOD EFFECTING THIS FOR PROPOSED CHANGES.
SEVERAL CONSTRAINTS AFFECTING THE ISSUANCE OF THE PERMANENT MAR AND PERFORMING A HELB REVIEW NECESSITATE MAKING THESE CRITICAL DRAWING AVAILABLE UNTIL THE MAR CAN BE MADE PERMANENT AND AS-BUILT.

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE
Chris S. Sterner	6/26/89	[signature]	6/27/89
		ENGINEERING SUPERVISOR: [signature]	[illegible]

REVIEWER	DATE	INSPECTION PLAN FOR ADVANCED FCN
J.D. Martin	7/12/89	☐ No Change ☐ Revised & Issued W/Working Copy ☐ Revised & Attached

PRC APPROVAL BY	DATE	MEETING NUMBER
[signature]	7/18/89	89-29

INSTALLATION AUTHORIZED BY	DATE
[signature]	7/19/89

THIS FCN HAS BEEN INCORPORATED INTO THE MAR PACKAGE BY	POSITION	DATE
MICHAEL K. WILSON	NPS	7/13/92
COMPANY NAME: FPC		

CR3 085431

Florida Power

FIELD CHANGE NOTICE

Crystal River Unit 3

Sheet 1 of 8

MAR NUMBER	FCN NUMBER	SAFETY RELATED	EQ REVIEW REQUIRED
T87-10-09-01 N/A	11	☒ Yes ☐ No	☐ Yes ☒ No

PROJECT NAME	EQ REVIEW REQUIRED
ASY-5/204 Power separation N/A	☒ Yes ~~☒ No~~

SAFETY EVALUATION REQUIRED	REGULATORY ENVIRONMENTAL REVIEW REQUIRED	PRC REVIEW REQUIRED
☐ Yes ☒ No	☐ Yes ☒ No	☐ Yes ☒ No

DRAWINGS AFFECTED AND NO.

208-008 sh. AS-07, Interim Rev.A

DESCRIPTION OF FIELD CHANGE (USE ADDITIONAL SHEETS IF NECESSARY)

See sheet 2.

THIS FCN INCLUDES ATTACHMENTS:

#1 (CHECKLIST FOR EQ DOCUMENT REVIEW, 2 SHEETS)

8/3/90 MR

REASON FOR FIELD CHANGE (USE ADDITIONAL SHEETS IF NECESSARY)

This FCN is required for documentation only to assist in making this T-MAR permanent.

ORIGINAL

NUCLEAR ENGINEERING APPROVAL

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	CONCUR WITH ADVANCED FCN
Robert L. Cairo	7/30/90	S. K. Balliet	8/1/90	☐ Yes ☐ No ☒ N/A

SHEL FIELD ENGINEER	DATE	PSWP REQUIRED	ENGINEERING SUPERVISOR	DATE
		☐ Yes ☐ No	D K Bach	8/3/90

SHEL SUPERVISOR - EQ GROUP: Hugh Stilton 8-3-90

QUALITY SYSTEMS REVIEW FOR QUALITY REQUIREMENTS

REVIEWER	DATE
Steve B.	8/7/90

PLANT REVIEW COMMITTEE APPROVAL (Required if checked YES by Nuclear Engineering)

PRC APPROVAL BY PRC CHAIRMAN	DATE	MEETING NUMBER
N/A		N/A

INSTALLATION AUTHORIZED BY NUCLEAR PLANT MANAGER	DATE
N/A	

NUCLEAR PROJECTS SPECIALIST

THIS FCN HAS BEEN INCORPORATED INTO THE MAR PACKAGE BY	POSITION
MICHAEL K WILSON	NPS
COMPANY NAME	DATE
FPC	7/13/92

CR3 085434

MAR# T87-10-09-01
FCN #
SHEET 2 OF 8
DWG # N/A

FCN# 11 TO T-MAR T87-10-09-01

DESCRIPTION OF FIELD CHANGE:

This FCN revises drawings and sketches to incorporate changes made by FCN 39 & 42 of MAR 87-03-13-02. FCN 39 was initiated to de-terminate the motor starter heater circuit of ASV-204. FCN 42 was initiated to assist the field in the implementation of FCN 39 and to correct the discrepancies between FCN 39 and T87-10-09-01. There is no field work involved, this FCN is for documentation only.

Interim drawings 201-061 sheets AC-19 & AC-19A are not being revised by this FCN, FCN 42 of 87-03-13-02 correctly updates these drawings.

SUMMARY:

Additional information is being added to the original MAR package in sections C. REFERENCE.

ADD TO: C. REFERENCES:

1. EQ# 90-1903
2. MAR 87-03-13-02 FCN's 39 & 42

Florida Power

RCT COPY

MODIFICATION APPROVAL RECORD

Crystal River Unit 3

MODIFICATION NUMBER	WORK REQUEST	SAFETY RELATED	ISI REVIEW REQUIRED
87-10-09-01A	105572	☒ Yes ☐ No	☒ Yes ☐ No

PROJECT NAME: ASV-5/ASV-204 Power Separation

EQ REVIEW REQUIRED: ☒ Yes ☐ No

SYSTEM/TAG NUMBER: AS

SOURCE DOCUMENTS: ~~100~~ N/A [initials] 2/5/92

TYPE OF MODIFICATION

☒ Permanent ☐ *Temporary Expiration Date ______ *W.R. No. for Removal ______

☐ Mechanical ☐ Electrical ☒ I&C ☐ Structural ☐ Support

PLANT STATUS

For Implementation ____ On-Line (Full load) ____ On-Line (Reduced load) _X_ Outage Required

DESCRIPTION OF PROPOSED MODIFICATION (Use Additional Sheets if Necessary)

This modification converts temporary modification MAR T87-10-09-01 into a permanent installation. Temporary MAR T87-10-09-01 was installed in refuel 6. Minor plant changes are needed to be performed for this modification before the T-MAR can be documented as a permanent installation. Three electrical devices installed per the T-MAR need to be relabelled to correct plant item tag designation. In addition, conduit routing near control station AS-9 need to be removed from the plant.

REASON FOR MODIFICATION (Use Additional Sheets if Necessary)

The temporary modification is being converted into a permanent installation in conformance with engineering design procedures. The temporary installation has been determined to be an acceptable method for electrical load demand reduction for the "A" emergency diesel generator. Electrical devices were only given a T-MAR numbering system instead of a proper equipment tag assignment designation. T-MAR deleted and requested that conduit routings be eliminated and actually work steps to remove them has not been accomplished per the T-MAR Engineering Instructions.

NUCLEAR ENGINEERING APPROVAL

DESIGN ENGINEER	DATE	ENGINEERING SUPERVISOR	DATE
C.C. Stamp [signature] 2/5/92	3/2/92	C. S. [signature]	3/2/92
VERIFICATION ENGINEER	DATE	SUPERVISOR, SHIFT ... OR DESIGNATED OR MAJ	DATE
[signature]	3/2/92	[signature] AN[illegible]	3/4/92

MODIFICATION APPROVALS

	SIGNATURE	DATE
FEWP REQUIRED ☐ Yes ☐ No	SRES FIELD ENGINEER	
Meeting Number ____ Plant Review Committee (PRC)	CHAIRMAN	
NGRC Review Required ☐ Yes ☐ No NGRC Approval	CHAIRMAN	
Installation Authorized	NUCLEAR PLANT MANAGER	
Cancellation	NUCLEAR PLANT MANAGER	
Temporary Modification Removed	NUCLEAR PROJECTS SPECIALIST	
Modification Testing Complete	MAR TEST SUPERVISOR	
Modification Installation Complete and All Documentation Enclosed	NUCLEAR PROJECTS SPECIALIST	

Florida Power Corporation

SAFETY EVALUATION

Check to indicate applicable review and enter applicable document number:

☒ MAR NO. 87-10-01-01A ☒ Procedure No.: NEP 0211 Rev. 08 TC ___

☐ FCN No. ______ ☐ Other ______

SAFETY EVALUATION: Answer the following questions and provide specific justification (use attachment if necessary).

1. Is the probability of an occurrence or the consequence of an accident or malfunction of equipment important to safety, as previously evaluated in the Final Safety Analysis Report, INCREASED? ☐ Yes ☒ No
   Because:

   See Attached Sheet

2. Is the possibility for an accident or malfunction of a different type than any previously evaluated in the Final Safety Analysis Report CREATED? ☐ Yes ☒ No
   Because:

   See Attached Sheet

3. Is the margin of safety, as defined in the basis for any Technical Specification, REDUCED? ☐ Yes ☒ No
   Because:

   See Attached Sheet

10CFR50.59 CHECKLIST

Does the proposed action change the Final Safety Analysis Report or require additional description to be added to the Final Safety Analysis Report?

☒ Yes → Notify Manager Nuclear Licensing

☐ No

Is a Change to the Technical Specification required?

☐ Yes → Request and receive NRC Authorization for change

☒ No

Is any unreviewed safety question involved, i.e.,

(1) Is the probability of an occurrence or the consequences of an accident or malfunction of equipment important to safety previously evaluated in the Safety Analysis Report increased? ☐ Yes ☒ No

(2) Is the possibility for an accident or malfunction of a different type than any previously evaluated in the Safety Analysis Report created? ☐ Yes ☒ No

(3) Is the margin of safety, as defined in the basis for any Technical Specification, reduced? ☐ Yes ☒ No

☐ Any answer Yes → Request and receive NRC Authorization for change

☒ All answers No → Document Change including: (1) Description of change (2) Written Safety Evaluation which provided basis for items (1), (2), and (3) above.

☐ Authorization Received

☒ Description Safety Evaluation Complete

Initiate Installation of Modification or approve procedure

Required changes to Technical Specifications should be processed in parallel to this checklist.

ENGINEER	DATE	VERIFICATION ENGINEER	DATE	SUPERVISOR	DATE
C C Stumph	3/2/92	T D [illegible]	3/2/92	C. D. Kramer	3/2/92

Rev. 12/91

RE2 Life of Plant RE&PI Nuclear Engineering 800 248

Florida Power Corporation

ANALYSIS / CALCULATION

Crystal River Unit 3

REI / MAR NUMBER: MAR 87-10-09-01A

PROJECT: ASV-5/204 POWER SEPARATION

ATTACHMENT TO MODIFICATION SAFETY EVALUATION

1. ASV-5 and ASV-204 are motor operated valves having identical functions of supplying steam to the turbine driven Emergency Feedwater Pump (EFP-2). Since EFP-2 is the ES "B" channel pump, ASV-5 and 204 were electrically connected in parallel to a common 250/125 VDC ES "B" channel power and control source. This modification electrically separates ASV-204 from ASV-5 and repowers ASV-204 from 250/125 VDC ES "A" channel power. Also, separate control room controls and separate "A" channel EFIC interlocks are being provided for ASV-204. Automatic control logic of ASV-204 has not changed. Therefore, the probability of an occurrence or the consequences of an accident or malfunction of equipment important to safety as previously evaluated in the FSAR is not increased since the logic of automatically opening ASV-204 whenever the EFIC System calls for emergency feedwater has not been altered. The reliability of EFP-2 has actually been increased because with this modification either "A" or "B" train power will control and operate one of the steam inlet valves to EFP-2 as opposed to both valves being 'B" train powered. FSAR Sections 7.2.4, 8.2.2.6 and 10.5.3 have been reviewed.

2. The electrical separation of ASV-204 from ASV-5 does not impact the design function of either valve to supply steam to the EFP-2 turbine. Power and control for ASV-5 is not affected by this modification and ASV-5 retains its automatic control logic, remote manual control, local manual control and remote shutdown isolation and control. ASV-204 is being powered from the redundant power channel, and will be provided with its own remote and local manual control and with separate EFIC interlocks for automatic operation. The type of manual control and automatic operation of ASV-204 is the same as for ASV-5. Therefore, based on the above, the possibility for an accident or malfunction of a different type than any previously evaluated in the FSAR is not created. FSAR Sections 7.2.4, 8.2.2.6, and 10.5.3 have been reviewed.

3. This modification enables the turbine driven Emergency Feedwater Pump (which is the 'B" channel pump) to be operational even if a failure should occur on the "B" channel power system for which shutdown operation would be via the 'A" channel systems. With this capability, the turbine driven EFW pump is able to operate and share the EFW requirements with the 'A" channel motor driven EFW pump. This will reduce the electrical load on the "A" channel diesel generator for the condition of an ES actuation coincident with a loss-of-offsite-power and failure of the 'B" channel power system. Consequently, with this modification the margin of safety, as defined in the basis for any Technical Specification, is not reduced. It is actually enhanced because of the increased availability of the turbine driven Emergency Feedwater Pump. Technical Specification Sections 3/4.7.1 and 3/4.8.1 have been reviewed.

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	SUPERVISOR, NUCLEAR ENGINEERING	DATE
C. E. Strumpk	3/2/92	[signature]	3/2/92	C. D. Kasman	3/2/92

Florida Power CORPORATION

ENGINEERING INSTRUCTIONS

Crystal River Unit 3

FCI/MAR NUMBER

MAR 87-10-09-01A

A. SUMMARY FUNCTIONAL DESCRIPTION:

This modification MAR 87-10-09-01A converts temporary modification MAR T87-10-09-01 into a permanent installation.

Temporary MAR T87-10-09-01 was installed in Refuel 6. The design function that is to be made permanent by this MAR is to assure that the turbine driven emergency feedwater pump (EFP-2) will be operable in the event of a failure of the Engineered Safeguard "B" 250/125V DC system coincident with loss-of-offsite power and an engineered safeguard actuation. Under this scenario, EFP-2 will be relied upon to share the emergency feedwater load with the motor driven emergency feedwater pump (EFP-1) in order to decrease the electrical load demand on emergency diesel generator EDG-3A. To assure this capability, the temporary modification removed the 250/125V DC distribution source Engineered Safeguard "B" power from ASV-204 and repowered the valve from 250/125V DC Engineered Safeguard "A" distribution source. This involved separating ASV-5 and ASV-204 power and control circuitry (which were wired in parallel) and providing a separate main control board control switch, local pushbuttons, indicator lights, and EFIC actuation signal to ASV-204.

This modification requires that some minor plant changes be implemented before the T-MAR can be documented as a permanent installation. The changes involve the re-labelling of electrical equipment devices in the rear of the PSA/EFIC section of the main control board and auxiliary relay rack cabinet RR3A. The device label designation was not per engineering tagging convention and were assigned a label prefix "TM" which corresponded to mean "Temporary Modification Item Number". The originators of the T-MAR did not acquire the appropriate equipment item tag designation. Therefore, the following electrical devices need to be relabelled as follows:

a) The valve position status indicating lights for ASV-204 labelled as "TM1", "TM2" and "TM3" need to be relabelled as item numbers "BM1", "BM2" and "BM3".

b) The three position GE CR2940US203E selector switch furnished on the PSA/EFIC bench board of the MCB along with the above indicating lights was labelled as board device item "TM4" and needs to be relabelled as "BM4".

c) In auxiliary relay rack RR3A relay devices labelled as "TMA" and "TMB" needs to be relabelled as device items "DB" and "DA" respectively.

d) This modification separates the alarm circuits for the valves. An alarm "steam supply not ready" will alarm if the valve is closed or valve control power is lost.

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	SUPERVISOR, NUCLEAR ENGINEERING	DATE
C C Strumpfle	3/2/92	[illegible] Patel	3/2/92	C. A. Kumar	3/2/92

RE: MAR NUMBER

MAR 87-10-09-01A

A. SUMMARY FUNCTIONAL DESCRIPTION: (Cont'd)

In the engineering instruction section for T-MAR 87-10-09-01 under installation instructions, it was instructed that a number of conduit routings be deleted and removed from in-plant service. This may not have been accomplished and possibly still remain in-place. To convert the T-MAR into a permanent installation, the below listed conduit routings may need to be removed (if not ready done so) from the plant. The conduit routings are:

ASK1 - 1-1/2"
ASE27 - 1"
ASE28 - 3/4"
ASE30 - 1-1/2"
ASF31 - 1"

B. ATTACHMENTS:

1. Design Data Sheets (2 Sheets with 3 Page Attachment)
2. Design Input Record (11 Sheets with EDG Loading Justification Sht.)
3. Verification Report (1 Sheet)
4. Fire Protection Review (with 2 Page Attachment)
5. HELB Review (1 Sheet with 1 Page Attachment)
6. Modification Safety Evaluation (2 Sheets)
7. Regulatory/Environmental Review (1 Sheet)
8. MCB Bill of Material Input Record (8 Sheets)
9. ALARA Analysis/Calc. Form (1 Sheet)
10. Environmental Qualification Applicability Review (1 Sheet)
11. Memo, J. A. Lese to R. Iwachow, July 12, 1991 (1 Sheet)
12. G/C, Inc. Interim Drawings (All Revision ~~A~~, EXCEPT AS NOTED) 3/5/92

CSI-95-4, Sheet 1 (BOTH REV. A & B)
CSI-95-4, Sheet 2 (BOTH REV. A & B)
CSI-95-4B
CSI-95-287
201-172
208-008 AS-01 (2 PARTIAL SHEETS) 3/16/92
208-008 AS-07
208-026 EF-01
208-026 EF-12
208-026 EF-15
209 ~~208~~-008 AS-01 (2 PARTIAL SHEETS) 3/16/92
209-008 AS-06 (2 PARTIAL SHEETS) 3/16/92
209-054-SS-01 (2 PARTIAL SHEETS) 3/16/92
209-106 SH. 1
209-136 SH. 3 (2 PARTIAL SHEETS) 3/16/92
209-166 (2 PARTIAL SHEETS)
210-120
210-123
210-124
210-543 (2 PARTIAL SHEETS) 3/16/92

211-008 AS-01
211-008 AS-06
211-026 EF-01
211-026 EF-12
212-008 ASE1
212-008 ASE3
212-008 ASE4
212-008 ASF4
212-008 ASK1
212-008 ASK2
212-008 ASK3
212-008 ASK4
212-026 EFC2
212-026 EFC5
212-026 EFK2
212-026 EFK4
212-026 EFK5
212-026 EFM1
215-032 SH. 1
215-032 SH. 2 (2 PARTIAL SHEETS) 3/16/92

CR3 005866

Florida Power CORPORATION

DESIGN INPUT RECORD

Crystal River Unit 3

FPC MAR NUMBER				
. 87-10-09-01A	[ ] Electrical	[x] I&C	[ ] Mechanical	[ ] Structural

PROJECT: ASV-5/ASV-204 Power Separation

1. The function of this modification is to convert temporary modification T-Mar 87-10-09-01 to a permanent installation which assures that the turbine driven emergency feedwater pump (EFW-2) will remain operable in the event of a failure of Emergency Safeguard "B" 250/125 Volt DC system coincident with loss-of-offsite-power and an Engineered Safeguard actuation. Under this scenario, emergency feedwater pump EFP-2 will be relied upon to share the emergency feedwater flow requirements with the motor driven emergency pump (EFP-1) in order to decrease the electrical load demand on emergency diesel generator EDG-3A. In order to assure that EFP-2 is operable for the above condition, this modification documents the removal of the 250/125V DC Engineered Safeguard "B" power from ASV-204 and repowers the valve onto the 250/125V DC Engineered Safeguard "A" distribution system. This involves the separation of ASV-5 and ASV-204 power and control circuits which were wired in parallel; thereby, providing redundant steam admission to EFP-2 for increase reliability. The physical wiring separation and circuit rerouting were accomplished under temporary MAR T87-10-09-01 which also provided for the addition of a control switch on the main control, local control station, pushbuttons, indicating lights and EFIC 'A' actuation signals to ASV-204.

   This modification requires that some minor plant changes need to be implemented before the T-MAR can be documented as a permanent installation. These additional changes are as follows:

   a. Electrical devices added by the T-MAR were labelled with only a numbering system instead of a proper equipment tag assignment designation. The item tag designation for the three position selector switch and its position status lights needs to be re-labelled from "TM1 thru TM4" to read as "BM1 thru BM4". Also, two Clark type relays installed in auxiliary relay rack cabinet RR3A have been tagged with the temporary designation "TMA" and "TMB" and should be relabelled as "DB" and "DA" respectively.

   b. In addition, the temporary modification separated power and control circuits but did not provide for separation of alarm circuitry between safeguard channels. This modification incorporates design changes to reroute and rewire alarm circuits for ASV-5 and ASV-204. Alarm (100AL) "Steam Supply Not Ready" is being retained for ASV-5 and a new alarm (1521AL) "Steam Supply Not Ready" is being added for ASV-204. The logic for these alarms is also being change to "loss of power" or "valve not open". To accomplish this, T-MAR relay "TMA" is being SPARED and an existing 125VDC (non-time delay) relay in RR3A is being wired into ASV-204 control circuitry. Since the ASV-5 alarm relay is 120 VAC, 5 second delay, it will be adjusted to the minimum

DESIGN ENGINEER	DATE	VERIFICATION ENGINEER	DATE	SUPERVISOR, NUCLEAR ENGINEERING	DATE
C C Strumph	3/2/92	I. O. Patel	3/2/92	C. A. Komic	3/2/92

4/84 RET: Life of Plant RESP: Nuclear Ops. Engineering delay (approximately 0.2 seconds). The differences in the relays is only a utilization of existing relays and not a diversification design requirement.

c. This permanent modification also spares alarm circuits that were affected by modification MAR 89-04-15-02 and MAR 89-04-15-03. The alarm circuits being spared provided an interlock interface for starting the old EFW chemical addition system which has now been abandoned.

Design changes for this modification will occur at the following plant components:

a) at both motor operated valves ASV-5 and ASV-204

b) at both terminal boxes AS-1 and AS-9

c) behind the PSA/EFIC section of the main control board

d) in auxiliary relay rack cabinets: RR-3A, RR-5B1, RR-PSA

e) in events recorder cabinet 5

f) at the secondary cycle sampling analyzer panel SSCP-1

g) at the 480V water treatment motor control center 3B, unit 6B

h) at the 4160V switchgear engineered safeguard bus 3A, Unit 3A3.

2. The performance requirements will remain unchanged for ASV-204. The same holds true for the capacity and rating requirements for the valve. The valve is required to open on an EFIC "A" actuation signal. This permits the start of steam turbine driven emergency feedwater pump (EFP-2) to account for the plant configuration change accomplished by the temporary modification to lessen the electrical demand on the "A" emergency diesel generator EDG-3A.

3. Code, Standards, Regulatory Requirements and other documents:

a) IEEE 323-1974, Qualifying Class 1E Equipment for Nuclear Power Generating Stations.

b) IEEE 344-1975, Seismic Qualification of Class 1E Equipment for Nuclear Power Generating Stations.

c) IEEE 383-1974, Type Test of Class 1E Electric Cables, Field Splices and Connections for Nuclear Generating Stations.

d) Code of Federal Regulations 10CFR50, Appendix R.

e) FPC Calculational Document No. E-87-0001, Revision 0, titled "Addition of ASV-204 to DPDP-8A".

f) FPC Calculational Document No. E-87-0002, Revision 0, titled "ASV-5 and ASV-204 Power Separation Qualification Review".

g) FPC Calculational Document No. E-87-0004, Revision 1, titled "Battery 3A size Verification".

h) FPC Calculation Document E-88-0019, Revision 1, titled "Conversion of Terminal Box AS-9 to a Control Station".

i) Vendor Qualification Package No. CNTL-G080-02, Revision 0, titled "FPC (General Electric) - Local Control Station (Pushbutton/Indicator Lights), Volumes 1 and 2".

j) Vendor Qualification Package No. VLV-L200-06, Revision 0, titled "Limitorque Model SMB Class H".

k) Vendor Qualification Package No. CABL-L080-05, Revision 0, titled "Kerite FR/FR Control Cable".

l) Vendor Qualification Package No. CABL-K080-06, Revision 0. titled "Kerite HTK/FR Power Cable".

m) Vendor Qualification Package No. CNTL-N431-03, Revision 0, titled "Nutherm 125VDC Motor Starter", Volumes 1 thru 3.

n) Vendor Qualification Package No. CNTL-N431-01, Revision 0, titled "Nutherm 125VDC Control Station", Volumes 1 thru 3.

4. Valve ASV-204 is required to be powered from a Engineered Safeguard "A" power distribution source. The 250V DC power for the valve is provided from distribution panel DPDP-8A, Fuse 17. The 125V DC control power for manipulating the valve is provided from the same distribution panel and fed from Fuse 15.

5. This modification does not alter the design modifications accomplished under the temporary modification T-MAR 87-10-09-01. The design change regarding the seismic integrity of the circuity changes were evaluated under the T-MAR.

6. Valve ASV-204 is identified per CMIS as an essential component that is required to support safe shutdown. This modification changes the power and control distribution source requirements for the valve's motor operator (ASV-204-MO). This modification does not change the Code Key Classifications. The component is still required to meet 10CFR50.49

criteria. CIDP NO. 91012303 dated 01/23/91 has been issued to correct the channel designation form "B" to "A" for the motor starter for the motor operator. This CIDP also updates the document cross reference listing with additional design drawing information. Refer to CR-3 Walkdown Package No. 0042 dated 10/06/89 pages 1 thru 52.

7. The design modification implemented under the T-MAR and this permanent modification occur in the control complex on building elevations 108', 124', 134', and 145'. Specifically in the areas of the main control room, CRDM rooms, EFIC Room B, the cable separating room and the 4160V Switchgear Room A. These floor elevations (or areas) are classified as mild environmental areas and the environmental conditions expected are listed on the environmental zone sheets as follows:

   a) Zone 13, Rev. 4; dated 8/90 titled "Elev. 145 - Control Complex, Control Room".

   b) Zone 43, Rev. 3; dated 8/90 titled "Elev. 95' and 108'- Control Complex".

   c) Zone 58. Rev. 3; dated 8/90 titled "Elev. 124' and 134'- Control Complex".

   Modification changes have occurred in the areas of elevation 95' and 119' of the Intermediate Bldg. The design changes occurred in the vicinity of the steam turbine driven emergency feedwater pump EFP-2. Power and control cables had to be routed from this area into the control complex by utilization of the plant's existing cable tray system. Both floor elevations of the "Intermediate Bldg. are listed as "Harsh" Environmental areas and their expected environmental conditions are listed on environmental zone sheets as follows:

   a) Zone 14, Rev. 5; dated 8/90 titled "Elev. 95' - Intermediate Bldg. Emergency Feedwater Pump Room".

   b) Zone 19, 4; dated 8/90 titled "Elev. 95' - Intermediate Bldg. HVAC Area".

   c) Zone 20, Rev. 4; dated 8/90 titled "Elev. 95' - Intermediate Bldg. Miscellaneous Equipment Area'.

   d) Zone 57, Rev. 5; dated 8/90 titled "Elev. 119' - Intermediate Bldg. Personal Hatch Area".

   Reference Environmental and Seismic Qualification Program Manual, Rev. 5 dated August, 1990 for determination of zone information.

The following Vendor Qualification Package Reports have been updated to incorporate the design changes initiated by the temporary modification:

a) VQP CNTL-N431-01, Revision 0, titled "Nutherm 125V DC Control Station", Volumes 1 thru 3.

b) VQP CNTL-N431-03, Revision 0, titled "Nutherm 125V DC Motor Station", Volumes 1 thru 3.

c) VQP VLV-L200-06, Revision 0, titled "Limitorque Model SMB Class H".

d) VQP CABL-K080-05, Revision 0, titled "Kerite FR/FR Control Cable".

e) VQP CABL-K080-06, Revision 0, titled "Kerite HTK/FR Power Cable".

f) VQP CNTL-G080-02, Revision 0, FPC (General Electric) - Local Control Station (Pushbutton/Indicator Lights)", Volumes 1 and 2.

8. The design modification interfaced with various plant components and cabinets. Interface occurred at the following locations:

a) The PSA/EFIC bench board section of the main control board was changed to add a GE CR2940 selector switch to permit the plant operator to take remote manual control of ASV-204. The bench board had to be reworked to accommodate the switch on the upper half of the EFW "A" channel flowpath.

b) Two time delay relays were added in relay cabinet 3A to pick-up the EFIC actuation signal for alarming the opening of valve ASV-204.

c) Terminal Box AS-9 was modified to become a local control station for ASV-204.

d) The control and power sources to valve ASV-204 which were commonly shared with ASV-5 were separated and assigned to an electrical safeguard channel "A" DC power distribution source. The DC power is fed from Distribution Panel DPDP-8A.

e) The 120VAC power supply to the motor starter space heater was disconnected and the actual work was accomplished under Modification MAR 87-03-13-02, FCN's 39 and 42.

f) The interlock alarms which interfaces with the EFW chemical addition pump had been spared and the chemical addition pump EFP-3 has been realigned to act morpholine transfer pump. This realignment of pump duty was done under modification MAR 89-04-15-02 and MAR 89-04-15-03.

9. The power and control cables were furnished from safety related cable inventory maintained at CR-3 site stores. The General Electric control switches selected for installation within local control station (AS-9) are qualified for the harsh environment and documented in VQP Report CNTL-G080-02. A General Electric three position selector switch type CR2940US203E was used for the installation on the control board PSA section. Indicating lamps used for valve ASV-204 position status were installed as Drake Gemlite model 5160 series type. Joslyn-Clark 120 VAC time delay relays model type 7313-PMT, were used and located in auxiliary relay cabinet RR3A by the T-MAR. One of these relays is being SPARED and an existing SPARE Clark 125 VDC relay, model 4U8-4, is being utilized in the alarm circuit.

14. The electrical source of power for ASV-204 motor operator and control circuitry is supplied from the "A" Engineered Safeguard distribution bus. The motor operator power is 250VDC and fed from distribution panel DPDP-8A, Fuse #17. The control power is 125VDC and also fed from distribution panel DPDP-8A, Fuse #15. The motor starter space heater for ASV-204 was supplied from a 120VAC distribution panel ACDP-54, Breaker #4; however, modification MAR 87-03-13-02, FCN's 39 and 42 disconnected the power feeder to the space heater.

    FPC Document No. E-87-0001, Rev. 0, titled "Addition of ASV-204 to DPDP-8A", evaluated the design capacity of the distribution panel to accept addition voltage loading and determine if this added load is within the design margin of the distribution panel. Also, another calculation was established to determine that the additional voltage load does not exceed the design capacity of DC Battery 3A. This determination is recorded in FPC Document No. E-87-0004, Revision 0, dated 10/20/87 titled "Battery 3A Size Verification". Both engineering calculations have resulted in showing that the added voltage loads are within the design margins of the DC distribution system.

15. The physical valve arrangements for ASV-5 and ASV-204 remain unchanged and both valves assemblies are parallel to each other and permit steam admission to the steam turbine driven emergency feedwater pump (EFP-2). Both valves ASV-5 and ASV-204 shared common power sources and control devices to actuate and cause motion of the valves. The commonality between the two was separated and terminal box AS-9 was converted to a local control station. In addition, the control devices located on the lower half of the PSA/EFIC bench section mimic for the steam turbine driven EFP-2 was altered to allow addition of a selector switch for ASV-204. The PSA/EFIC control board mimic arrangement for both emergency feedwater flowpaths were changed to allow addition of the three position selector switch.

16. Valve ASV-204 is operational during all plant modes except in plant start-up and shutdown modes where the EFIC actuation signals are bypassed to prevent spurious start of the steam turbine driven EF pump. ASV-204 is

required to be functional for a loss-of-power event coincident with an ES actuation and a single failure of the 125VDC ES channel "B" power system.

17. In the main control room a three position selector switch type GE CR2940US203E with position status lights of red, green and amber has been furnished for remote manual manipulation of valve ASV-204. The control function of the selector switch is such that the control switch must be held in either the open or close position to permit valve travel. Local control station AS-9 has been provided with two pushbutton switches of the model type GE CR2490YA202C and CR2940YA202E and three position status indicating lights of the model type GE CR2940UC212B2, CR2940UC212C2 and CR2940UC212D2. The control circuitry for ASV-204 interfaces with the EFIC actuation signals at the Relay Cabinet RR3A to provide the following system functions:

    a) A normally open EFIC actuation contact is wired in parallel with the selector switch and the pushbutton switch contacts in the valve's "open" circuit. This contact provides the automatic opening of valve ASV-204 upon and EFIC Channel "A" actuation signal.

    b) A normally closed EFIC actuation contact is wired in series with the selector switch and pushbutton switch contacts in the valves "close" circuit. This contact provides an interruption to the valves closure signal when an EFIC Channel "A" actuation signal is initiated to open the valve.

Auxiliary relays have been added and identified as Items "TMA" and "TMB" to provide alarm status for ASV-204. These item designations need to be changed since they were not assigned a permanent plant item identifier. Items "TMA" and "TMB" need to be retagged and relabelled as "DB" and "DA". The 120 VAC time delay relay "DB" will be made SPARE. An existing SPARE 125 VDC relay tagged "H" will be utilized for this alarm separation logic.

19. ASV-204 was added to the auxiliary steam supply system by MAR 80-11-48. The valve was installed to provide the Turbine Driven Emergency Feedwater Pump (EFP-2) with a parallel path (around ASV-5) for providing motive power. ASV-204 was added by MAR 80-11-48 to improve the reliability of the steam supply by providing a redundant path. However, since the pump was considered to be "B train", ASV-204 was powered with "B train" electric power. The power to ASV-204 was changed to "A train" by the temporary MAR T87-10-09-01 which is being made permanent by this MAR. This change provides a potential reduction of dependency on EFP-1 thus reducing loading concerns. This change also increases the reliability of achieving EFP-2 pump start by providing electrically and physically redundant steam supply valves. The "A train" circuits to ASV-204 are separated per the plant separation criteria from the "B train" circuits of ASV-5. The "A train" and "B train" signals to open ASV-204 and ASV-5 originate from redundant sensors and logic channels. Electric power is also fed from redundant, independent sources. A failure evaluation (FPC document E-90-0111 Rev. 0)

was performed to demonstrate sufficient independence existed between the "B train and "A train" to prevent simultaneous failure of the redundant trains of emergency feedwater.

20. Temporary Modification TMAR 87-10-09-01A was implemented during Refuel 6 to reduce electrical load demand on emergency diesel generator EDG-3A. To achieve this load reduction on EDG-3A, the two parallel steam emission valves (ASV-5 and ASV-204) to the steam driven emergency feedwater pumps were reconfigured to permit the valves to be electrically powered from two separate distribution sources versus both being powered from the same power source. The Temporary modification accomplished this realignment of power sources by removing auxiliary steam emission valve ASV-204 from the 250/125 volt DC, Engineered Safeguard "B" source to the 250/125 volt DC, Engineered Safeguard "A" source. This effort involved the physical separation of the power and control circuits which were commonly shared between ASV-5 and ASV-204. The temporary modification did not touch the actual valve assembly and it still remains in parallel to ASV-5. FPC Failure Modes and Effects Analysis Document No. E-90-0111, Revision 0, titled "ASV-204 Failure Evaluation" demonstrates that no propagated failures can result due to valve assembly ASV-204 and it's electrical circuitry which are still within the vicinity of the "B" side steam turbine driven emergency feedwater pump EFP-2. The analysis shows that no fault or failures could cause impairment of the entire "A" engineered safeguard train due to initiating events on the "B" side.

28. Material selection has been based on compatibility with as-installed system and existing plant design. Control devices for ASV-204 mounted in control station AS-9 are similar to design configuration of qualified control stations furnished by Nutherm. This similarity in design is documented in VQP #CNTL-G080-02. Relay "DB", "DA" and "H" located in RR3A are Clark-Joslyn type which are similar in design to other existing relays in RR3A.

30. This modification provides for the documentation of cable routings for electrical circuits designated as ASE-34, ASE-35, ASE-36, ASE-37 and ASK-1. The circuits identified are part of the emergency feedwater system which is designated as a safe shutdown system. The circuit paths are routed through the Intermediate Bldg. and the Control Complex and located in the following fire areas/zones:

Fire Area IB-95-200C
Fire Area IB-119-201
Fire Area AB-95-003B
Fire Area CC-134-118A
Fire Area CC-108-108
Fire Area CC-124-117
Fire Area CC-145-118B

The fire areas/zones have been determined as listed in the Crystal River Unit 3 Fire Hazards Report No. 03-0920-1103, Revision 3, and visual inspection of Appendix R Fire Area Layout drawings 213-021, Revision 3, 213-023, Revision 3 and 213-028, Revision 01.

a) The modification has occurred in fire areas containing safe shutdown equipment.

b) The modification does not add, delete, or relocate systems, structures, or components into a zone or area where an unprotected opposite train exists.

c) The modification does not add, delete or relocate non-safety related circuits that share power supplies, signal sources, enclosures and raceways with safety related circuits.

d) Emergency lighting is not being obstructed or relocated by this modification.

This modification documents the addition of power and control circuits into the exiting plant cable tray system in the above fire areas. The increase in combustible loading does not exceed the maximum permissible loading in each zone.

32. FPC Specification SP-5145, Revision 1 titled "Human Factors Design Conventions for the Control Room" was consulted for addition of the control switch for ASV-204 on the bench board of the PSA/EFIC section. This arrangement of the EFW board included the reconfiguration of the EFW pump display of both emergency feedwater flowpath mimics and the pump matrix switches in the area of the EFW pump controls.

34. This modification has an impact on the loading of the Emergency Diesel Generator and the loading evaluation has been addressed and documented in FPC, IOC WPN 966-0434 dated April 15, 1988. This modification has intentions on reducing the continuous duty loading of the motor driven emergency feedwater pump EFP-1 on the electrical load demand requirements for the "A" emergency diesel generator. The modification relies on having the steam turbine driven emergency feedwater pump EFP-2 share the emergency feedwater flow requirements with the motor driven emergency feedwater pump EFP-1. This was accomplished by having the power source for ASV-204 removed (which commonly shared the same power source with ASV-5 from the 250/125VDC, Engineered Safeguard "B" source) and assigned to a 250/125VDC, Engineered Safeguard "A" source. This change permits the start of the steam turbine driven EFW pump (EFP-2) both on a EFIC Channel "A" and Channel "B" actuation signal. Valve ASV-204 is auto-loaded on ES load Block 1.

Valve ASV-204 motor operator previously received 250 VDC power from Distribution Panel DPDP-8B, Fuse #5. The 125 VDC control power for ASV-204 is previously received from Distribution Panel DPDP-8B, Fuse #6. The load reduction to this panel is 4520.25 watts. (4462.75 watts of motor operator locked rotor load from Fuse #5 and 57.5 watts of control power load from Fuse #6.)

The motor operator locked rotor DC load of 4462.75 watts is being added to Distribution Panel DPDP-8A, Fuse #17. This load is intermittent duty and auto-loaded onto the "A" EDG. The estimated time of ASV-204 energization is one minute. Reference FPC Document No. E-90-0105, Revision 0 dated 12/11/90 titled "Electrical DC System Revalidation Program DC Master Data Base (G/CI Report #2851)", Volume 2, Section 1.0, pages DPDP8A17-1 thru DPDP8A17-4.

The control power DC load of 57.5 watts (in-rush) and 25.0 watts (steady-state) is being added to Distribution Panel DPDP-8A, Fuse #15. The DC load for the in-rush condition is intermittent duty and auto-loaded onto the "A" EDG for a period of one minute. The steady-state load is continuous and also auto-loaded onto the "A" EDG. Determination of the control power electrical loads is based on input data found in FPC Document No. E-90-0105, Revision 0 dated 12/11/90 titled "Electrical DC System Revalidation Program DC Motor Data Base (G/CI Report #2851)", Volume 2, Section 1.0 pages DPDP8A15-1 thru DPDP8A15-4.

38. MOVATs testing is not required since the modification deals with electrical wiring changes and has no affect on the pressure retaining characteristics of the valve.

39. The modifications were performed in the following Dominant Area of Concern:

a) Room No. CB303 - Relay/CRD Switchgear Room

b) Room No. CBEFB - EFIC "B" Room

c) Room No. CB208 - 4160V Switchgear Room

d) Room No. IB095 - EFWP Room

e) Room No. CB504 - Control Room

An SBO review form has been completed and evaluation by the SBO Reviewer. Valve ASV-204 is identified as a major component required to meet Station Black-out requirements.

40. FPC Documents No. E-90-0110, Revision 0, titled "HELB Evaluation for Valve ASV-204 and FPC IOC NEA90-0991 dated June 9, 1990 have been prepared to assess the impact in the operability of ASV-204 during and after exposure to a HELB event in the vicinity of the steam driven emergency feedwater pump EFP-2.

DESIGN INPUT RECORD CONTINUATION SHEET

Florida Power CORPORATION

Crystal River Unit 3

FEI/MAR NUMBER
MAR 87-10-09-01A

42. The modification will cost less than $50,000 based on:

    1) the majority of the modification was installed by T-MAR 87-10-19-01.

    2) the additional changes to be completed can be installed by less than $10,000 ... conservatively assuming: (2 men for 1 week) x 2 for paper work times 1.5 for cost increase, and including material.

Exhibit___(WRJ-8)

Licensee Event Report 97-000-00

J.S. Baumstark	SA2C	J.H. MacKinnon	SA2C
P.E. Bass	NA2C	R.C. Widell	NU47
R.A. Anderson	SA2C	Docket File	SA2A
J.P. Cowan	SA2C	Records Mgmt.	NR2A
W.L. Conklin	SA2C	R.A. Glenn	A3E
W.L. Rossfeld	NA2H	Licensing	SA2A
J.J. Holden	NA2J	D.F. Kunsemiller	
		P.M. Beard	

J.R. Dunn	SEC	G. Oberndorfer	SA2D
K.V. Dyer	NA2J	Records Center	INPO
Corp. Comm.	SA1E	R.C. Williams	FMPA
L.M. Lesniak	BWNS	J.H. Terry	NA2J
J.M. McGarry	W/S	K.R. Wilson	NT06
P.F. McKee	NR3B	NGRC	
W. Woodruff	NU47		

Florida Power

CORPORATION
Crystal River Unit 3
Docket No. 50-302

February 27, 1997
3F0297-26

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, D. C. 20555-0001

Subject: Licensee Event Report (LER) 97-001-00

Dear Sir:

Please find the enclosed Licensee Event Report 97-001-00 which discusses an unanalyzed condition which could have rendered the Emergency Feedwater System incapable of fulfilling its intended safety and accident mitigation functions.

This report is submitted by Florida Power Corporation in accordance with 10 CFR 50.73.

Sincerely,

JJHolden

J. J. Holden, Director
Nuclear Engineering and Projects

JJH/TWC

Attachment
xc: Regional Administrator, Region II
Project Manager, NRR
Senior Resident Inspector

NRC FORM 366 (5-92)

U.S. NUCLEAR REGULATORY COMMISSION

APPROVED OMB NO. 3150-0104

EXPIRES 5/31/95

ESTIMATED BURDEN PER RESPONSE TO COMPLY WITH THIS INFORMATION COLLECTION REQUEST: 50.0 HOURS. FORWARD COMMENTS REGARDING BURDEN ESTIMATE TO THE RECORDS AND REPORTS MANAGEMENT BRANCH (MNBB 7714), U.S. NUCLEAR REGULATORY COMMISSION, WASHINGTON, DC 20555-0001, AND TO THE PAPERWORK REDUCTION PROJECT (3150-0104), OFFICE OF MANAGEMENT AND BUDGET, WASHINGTON DC 20503.

LICENSEE EVENT REPORT (LER)

FACILITY NAME (1)	DOCKET NUMBER (2)	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	1 OF 0 8

TITLE (4)

Ineffective Change Management Results in Unrecognized NPSH Issue Affecting Emergency Feedwater Availability

EVENT DATE (5)			LER NUMBER (6)			REPORT DATE (7)			OTHER FACILITIES INVOLVED (8)	
MONTH	DAY	YEAR	YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	MONTH	DAY	YEAR	FACILITY NAMES	DOCKET NUMBER(S)
									N/A	0 5 0 0 0
0 1	2 8	9 7	9 7	— 0 0 1 —	0 0	0 2	2 7	9 7	N/A	0 5 0 0 0

OPERATING MODE (9): 5

POWER LEVEL (10): 0 0 0

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR §: *(CHECK ONE OR MORE OF THE FOLLOWING)* (11)

	20.402(b)		20.405(c)		50.73(a)(2)(iv)		73.71(b)
	20.405(a)(1)(i)		50.36(c)(1)		50.73(a)(2)(v)		73.71(c)
	20.405(a)(1)(ii)		50.36(c)(2)	X	50.73(a)(2)(vii)		OTHER *(Specify in Abstract below and in Text, NRC Form 366A)*
	20.405(a)(1)(iii)		50.73(a)(2)(i)		50.73(a)(2)(viii)(A)		
	20.405(a)(1)(iv)	X	50.73(a)(2)(ii)		50.73(a)(2)(viii)(B)		
	20.405(a)(1)(v)		50.73(a)(2)(iii)		50.73(a)(2)(x)		

LICENSEE CONTACT FOR THIS LER (12)

NAME	TELEPHONE NUMBER	
	AREA CODE	
T. W. Catchpole, Sr. Nuclear Licensing Engineer	3 5 2	5 6 3 - 4 6 0 1

COMPLETE ONE LINE FOR EACH COMPONENT FAILURE IN THIS REPORT (13)

CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS		CAUSE	SYSTEM	COMPONENT	MANUFAC-TURER	REPORTABLE TO NPRDS	

SUPPLEMENTAL REPORT EXPECTED (14)		EXPECTED SUBMISSION DATE (15)	MONTH	DAY	YEAR
YES *(If yes, complete EXPECTED SUBMISSION DATE)*	X NO				

ABSTRACT *(Limit to 1400 spaces, i.e., approximately fifteen single-space typewritten lines)* (16)

On January 28, 1997, Florida Power Corporation's (FPC) Crystal River Unit 3 (CR-3) was in MODE 5 (COLD SHUTDOWN). Discussions with NRC inspection personnel identified that FPC had not explicitly reported a condition that existed prior to May, 1996 involving inadequate net positive suction head (NPSH) affecting one of the two Emergency Feedwater Pumps (EFP). On a loss of 'B' DC power, the turbine-driven pump's (EFP-2) flow control valves would remain fully open and EFP-2 would start in a maximum flow condition resulting in cavitation from inadequate NPSH which could lead to pump failure. In addition to an Emergency Diesel Generator load management concern, the postulated loss of 'B' DC power single failure coincident with a Small Break Loss of Coolant Accident and Loss of Offsite Power, a low probability event, could have resulted in two situations in which emergency feedwater may not have been available to perform its intended safety and accident mitigation functions. These include a design feature which trips the motor driven pump, EFP-1 at a Reactor Coolant System pressure of 500 pounds per square inch gauge, and a point in time at which EFP-1 would need to be secured in order to load the Low Pressure Injection pump onto the EDG in order to provide adequate NPSH to the High Pressure Injection pump. As a result, CR-3 was in an unanalyzed condition which could have rendered the emergency feedwater system incapable of fulfilling its intended safety and accident mitigation functions.

The cause of this event was ineffective configuration change management. Corrective Actions include a power upgrade of the 'A' EDG, EFW system modifications to eliminate NPSH concerns, and a failure modes and effects analysis.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6) YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	PAGE (3)
CRYSTAL RIVER UNIT 3 (CR-3)	05000302	97	001	00	02 OF 06

TEXT (If more space is required, use additional NRC Form 366A's) (17)

EVENT DESCRIPTION

On January 28, 1997, Florida Power Corporation's (FPC) Crystal River Unit 3 (CR-3) was in MODE 5 (COLD SHUTDOWN). The unit has been in shutdown since September, 1996. FPC management decided to voluntarily keep the plant shutdown until concerns with various design related issues were resolved. Discussions with NRC inspection personnel identified that FPC had not explicitly reported a condition that existed prior to May, 1996 involving inadequate net positive suction head (NPSH) affecting one of the two Emergency Feedwater Pumps [BA,P](EFP). This condition was described as an initiating event in two recently submitted event reports, LER 96-020-00 regarding Emergency Diesel Generator [EK,DG](EDG) loading issues and LER 96-024-01 which discussed an unanalyzed condition regarding Emergency Feedwater (EFW) availability. See Previous Similar Events for additional information.

The steam-driven emergency feedwater pump, EFP-2, would not be able to perform its intended safety function after a postulated failure of the 'B' DC bus coincident with a Loss of Offsite Power (LOOP). The 'B' EDG would not start due to reliance on the 'B' DC system [EJ,BTRY]. No AC or DC power would be available to 'B' train Engineered Safeguards (ES) components. However, the 'A' Emergency Feedwater Initiation and Control [JB](EFIC) train would open one of the two redundant steam admission valves, Auxiliary Steam Valve [SA,ISV] ASV-204, which provides motive steam for EFP-2. Due to the loss of 'B' DC power, the EFP-2 flow control valves [BA,FCV] would remain fully open and EFP-2 would start in a maximum flow condition resulting in cavitation from inadequate NPSH which could lead to pump failure. This NPSH concern was initially determined to affect only one train of EFW. During the root cause analysis and other investigations in support of LER 96-024-01, near the end of 1996, it became evident that a dependency existed in which EFP-2 was relied upon to support EDG-1A operability. The motor-driven pump, EFP-1, would also be unavailable either when the Low Pressure Injection [BP](LPI) actuation occurs or when the High Pressure Injection/LPI "piggyback" mode would need to be established. These situations are explained further in the Event Evaluation section. Therefore, in certain scenarios, a single failure (loss of 'B' DC power) rendering EFP-2 unavailable could result in both trains of EFW and possibly the 'A' EDG inoperable/ unavailable.

The above condition existed from December 1987 when ASV-204 was powered and received its open signal from the 'A' EFIC system until this EFIC signal was removed in May, 1996 during Refueling Outage 10. As a result, CR-3 was in an unanalyzed condition which could render EFW incapable of fulfilling its intended safety and accident mitigation functions. This unanalyzed condition is reportable under 10CFR50.73 (a)(2)(ii)(B) as a condition outside design basis and 10CFR50.73(a)(2)(vii)(D) as an event where a single condition caused two independent trains to become inoperable in a single system designed to mitigate the consequences of an accident.

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 7	— 0 0 1	— 0 0	0 3 OF 0 4

TEXT (If more space is required, use additional NRC Form 366A's) (17)

BACKGROUND/SYSTEM DESCRIPTION

The Emergency Feedwater (EFW) system provides secondary coolant to the Once Through Steam Generators [AB,SG](OTSG) in the event the Main Feedwater System [SJ](FW) is rendered inoperable and is unable to perform this function. The EFW system has two equipment trains (See Figure 1). Each train is capable of feeding both OTSG's. The two trains take suction from a common line. The flow control valves associated with each pump operate on DC power. The valves are normally open and require DC power to close and are open in the standby mode. EFP-1 is motor-driven and is aligned to the 'A' Emergency Diesel Generator during LOOP conditions. EFP-2 is turbine-driven; motive steam is supplied from the Main Steam [SA](MS) header. The system includes two valves, ASV-5 and ASV-204, which open to admit steam to EFP-2 when EFW actuates. The valves are installed in parallel with one another. Only one of the valves must open in order to start the pump. ASV-5 receives an OPEN command from an actuation of the 'B' EFIC train.

ASV-204 was installed in 1985, was powered from 'B' Class 1E power sources, and received its OPEN command from the 'B' EFIC train.

In December 1987, FPC moved the ASV-204 power supply and OPEN command to the 'A' side Class 1E sources so the valve opened on the 'A' EFIC actuation train signal, thus allowing use of EFP-2 for 'A' EDG load reduction. This configuration was established so that, during a Loss of 'B' DC bus, EFP-2 could be run in parallel with EFP-1, the motor-driven Emergency Feedwater pump. With both pumps sharing secondary coolant flow to the OTSG's, the electrical load of the motor driven pump on the 'A' EDG was reduced. This modification was implemented to reduce EDG demand if there was a loss of 'B' train power.

Even with this load reduction achieved in December 1987, the 'A' EDG did not have the capacity to support both EFP-1 and the Low Pressure Injection [BP,P](LPI) pump concurrently. A modification was installed in June, 1990 to trip EFP-1 and start the LPI pump when RCS pressure dropped below 500 pounds per square inch gauge (psig) when the EDG was powering the 'A' bus.

EVENT EVALUATION

This event becomes a concern in certain scenarios when EFW is required. The EFW system was designed to handle several abnormal events including Loss of main feedwater, Loss of main feedwater with loss of offsite power, Loss of main feedwater with loss of offsite and on-site AC power, Main feedwater line break, Main steam line break/EFW line break, and Small Break Loss of Coolant Accident (SBLOCA).

The scenario of concern in this event involves a single failure of the 'B' DC bus coincident with a SBLOCA and Loss of Offsite Power (LOOP). This scenario does not impact the current Probabilistic Safety Analysis (PSA) analyses for core damage due to the extremely low frequency of occurrence. The probability of a SBLOCA with a LOOP and a Loss of 'B' DC bus is 8.3x10E-11 per year.

Historically, for SBLOCA's, FPC's nuclear steam system supplier, Framatome Technologies, Inc. (FTI), formerly Babcock & Wilcox, maintained that mitigation of the transient with acceptable consequences could be demonstrated with only one train of Emergency Core Cooling System (ECCS) available: one High Pressure Injection (HPI) pump [BQ,P], one LPI pump, and one EFW pump. However, with only one EDG available providing power to 'A' train components and failure of EFP-2, there are two situations in which the remaining Emergency Feedwater pump, EFP-1, would not be available.

One situation wherein EFW would not be available occurs at the point in which the Reactor Coolant System (RCS) depressurizes to 500 psig at which time EFP-1 is tripped due to the LPI/EFP-1 trip block modification discussed in the Background section.

Another situation could occur if the Borated Water Storage Tank [BP,TK](BWST) had to be isolated before RCS pressure was reduced below the maximum discharge pressure for the LPI pumps. During a design basis LOCA, the Reactor Building Spray [BE](BS), LPI, and HPI systems are automatically aligned to obtain suction from the BWST. As inventory is lost through the break, it accumulates in the Reactor Building [NH](RB) Sump. After the BWST is drained to the swapover level, ECCS pump suction is transferred to the RB Sump. If this situation occurred, it would be necessary to place the HPI-LPI systems into the "piggy-back" mode of operation. This is the mode in which LPI pumps take suction from the sump in order to provide adequate NPSH to the HPI pumps. In order to load the LPI pump onto the EDG, EFP-1 would have to be secured. With EFP-1 secured, no feedwater would be provided to the OTSG's. Emergency Operating Procedures (EOP's) do not provide guidance to maintain emergency feedwater for this case. This operator action to place the LPI pump in the piggyback alignment is necessary to satisfy the long term core cooling requirements specified in 10 CFR 50.46.

In either of the above cases, FPC would be unable to ensure compliance with 10CFR50.46 acceptance criteria for Emergency Core Cooling Systems. In certain postulated scenarios, peak clad temperatures may exceed regulatory limits. A loss of heat transfer from the core will result in increasing fuel and cladding temperature which, if not mitigated, will result in fuel uncovery and damage.

In addition to the above, even if the RCS stays above 500 psig and the HPI/LPI "piggy-back" arrangement is not required, at some point after the event, operators must apply certain manual loads to the 'A' EDG to address Control Complex (CC) cooling concerns. The EDG loading calculations assume the Control Complex Emergency Duty Supply Fan [VI,FAN], the CC Return Air Fan, and the CC EFIC Room Fan are manually loaded at 30 minutes. The same calculations assume the Control Complex Chillers [NA,KM,CHU] are manually loaded at one hour. The Chilled Water System is used to maintain the Control Room and other enclosures within the control complex, particularly those which contain electronic components, at a temperature/humidity level that affords personnel comfort and is compatible for electronic equipment. With EFP-1 supplying the entire EFW load, the resulting 'A' EDG kilowatt (KW) loading could be increased by greater than 200 KW which would allow the 'A' EDG to remain within its design rating but not provide sufficient margin to allow all of the additional manual loads to be added. Analyses indicate there may be sufficient margin to accommodate the CC Emergency Duty Supply fans, but not the EFIC 'A' Room Fan and the CC chillers. Presuming operators would not be able to manage additional EDG loads, not having the EFIC 'A' Room Fan and the CC chillers would result in increased temperature beyond the qualified operating conditions of vital plant instrumentation.

CAUSE

The cause of this event was ineffective configuration change management. As noted in CR-3's Phase II Management Corrective Action Plan (MCAP II), there was a heavy reliance upon Architect-Engineer, contractor, and NSSS resources for performance of design activities for the first eighteen years of plant operation. As a result, there was ineffective technology transfer from the external sources to CR-3 engineers. Specifically, reliance on EFP-2 and the effects of loss of DC power scenarios were not fully understood.

IMMEDIATE CORRECTIVE ACTION

Due to the EFW/EDG issues, and other design related issues, FPC management made a decision to voluntarily keep the plant shut down until these issues are adequately addressed. FPC has developed MCAP II to communicate management expectations and provide direction in several areas of plant performance. For reference purposes, the following additional corrective actions are identified as applicable with MCAP II Action Item designations. In addition, FPC formed a Restart Panel patterned after the NRC Inspection Manual Chapter 0350 "Staff Guidelines for Restart Approval" process to manage actions necessary to safely return CR-3 to power operation and ensure subsequent reliable operation. The following additional corrective actions are identified as applicable, with Restart Issue numbers.

ADDITIONAL CORRECTIVE ACTION

A power upgrade for the 'A' EDG will be accomplished and appropriate EFW system modifications such as installation of cavitating venturis will be implemented to eliminate NPSH concerns and reduce operator burden prior to restart from the current voluntary outage. (FPC Restart Issues D-5 and D-6).

A Failure Modes and Effects Analysis of the LOCA, LOOP and Loss of DC Power scenario has been initiated and will be completed prior to restart. (MCAP Action C-CC1-1).

ACTION TO PREVENT RECURRENCE

A "stand down" was implemented in Nuclear Operations Engineering (NOE) to emphasize the importance of improving safety culture. (MCAP Action B-RC1-1).

Engineering staffing levels have been increased to attract talent from outside FPC that can increase design competency. (MCAP Action B-RC1-7).

A directive has been issued to restore system design margins primarily through physical means (modification or testing) as opposed to analytical means. (MCAP Action B-RC1-8).

PREVIOUS SIMILAR EVENTS

There has been one previous event involving the EFW system reported in accordance with 10CFR50.73(a)(2)(v) in which the condition was determined to have prevented the fulfillment of a safety function. LER 85-027 reported a condition wherein the steam-driven EFP was disabled per procedure and the motor-driven pump was disabled due to a spurious EFIC actuation while calibrating EFIC instrumentation. A second spurious actuation occurred resulting in no EFW response.

LER's 94-006, 95-015, and 95-016 reported setpoints for EFIC system instrumentation determined to be non-conservative relative to revised analyses using new setpoint methodology which resulted in questioning the system's ability to perform its intended safety function.

On October 10, 1996, FPC provided a voluntary LER (96-020-00) to describe an unreviewed safety question (USQ) involving the EDG loading calculation that was developed in support of the plant modification which removed the automatic open signal from ASV-204.

On November 12, 1996, FPC issued LER 96-024-00, subsequently supplemented on February 14, 1997, to report an unanalyzed condition regarding emergency feedwater unavailability below 500 psig RCS pressure created as a result of the plant modification implemented in May 1996 which removed the automatic open signal from ASV-204.

ATTACHMENT

Figure 1 - Emergency Feedwater System (Simplified Current Configuration)

NRC FORM 366A (6-89)

U.S. NUCLEAR REGULATORY COMMISSION

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LICENSEE EVENT REPORT (LER) TEXT CONTINUATION

FACILITY NAME (1)	DOCKET NUMBER (2)	LER NUMBER (6)			PAGE (3)
		YEAR	SEQUENTIAL NUMBER	REVISION NUMBER	
CRYSTAL RIVER UNIT 3 (CR-3)	0 5 0 0 0 3 0 2	9 7	— 0 0 1	— 0 0	0 8 OF 0 8

TEXT (If more space is required, use additional NRC Form 366A's) (17)

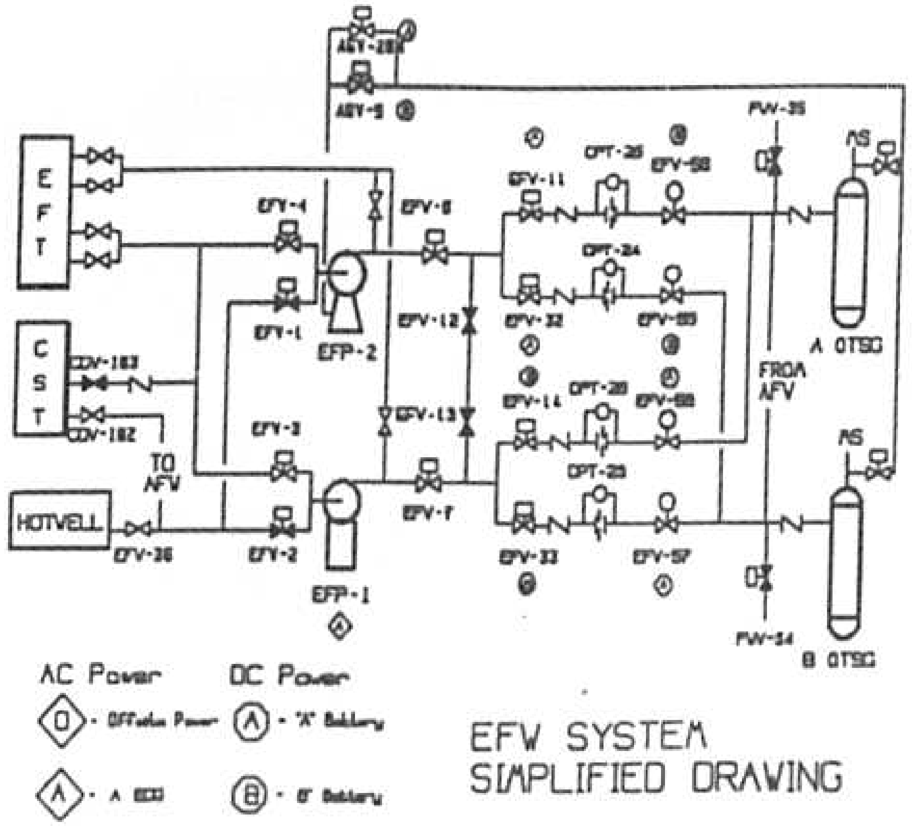

Figure 1