UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D.C. 20555-0001

May 15, 2003

MEMORANDUM TO: ACRS Members

FROM: Tim Kobetz, Senior Staff Engineer
ACRS

SUBJECT: CERTIFICATION OF THE MINUTES OF THE ACRS SUBCOMMITTEE MEETING ON THE SAFETY EVALUATION REPORT RELATED TO THE LICENSE RENEWAL APPLICATION FOR ST. LUCIE UNITS 1 AND 2, APRIL 9, 2003 - ROCKVILLE, MARYLAND

The minutes of the subject meeting, issued on May 7, 2003, were certified on May 9, 2003, as the official record of the proceedings of that meeting. A copy of the certified minutes is attached.

Attachment: As stated

cc via e-mail:
J. Larkins
S. Bahadur
ACRS Fellows and Technical Staff

cc: ACRS Secretary
E. Barnard

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D.C. 20555-0001

MEMORANDUM TO: Tim Kobetz, Senior Staff Engineer
ACRS

FROM: Dr. Mario Bonaca, Chairman
License Renewal Subcommittee

SUBJECT: WORKING COPY OF THE MINUTES OF THE ACRS SUBCOMMITTEE MEETING ON THE SAFETY EVALUATION REPORT RELATED TO THE LICENSE RENEWAL APPLICATION FOR ST. LUCIE UNITS 1 AND 2, APRIL 9, 2003 - ROCKVILLE, MARYLAND

I hereby certify that, to the best of my knowledge and belief, the minutes of the subject meeting issued on May 7, 2003, are an accurate record of the proceedings for the meeting.

Mario V. Bonaca
Dr. Mario Bonaca, Chairman
License Renewal Subcommittee

5/9/03
Date

UNITED STATES
NUCLEAR REGULATORY COMMISSION
ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
WASHINGTON, D.C. 20555-0001

May 7, 2003

MEMORANDUM TO: Dr. Mario Bonaca, Chairman
Plant License Renewal Subcommittee

FROM: Tim Kobetz, Senior Staff Engineer
ACRS

SUBJECT: WORKING COPY OF THE MINUTES OF THE ACRS SUBCOMMITTEE MEETING ON THE SAFETY EVALUATION REPORT RELATED TO THE LICENSE RENEWAL APPLICATION FOR ST. LUCIE UNITS 1 AND 2, APRIL 9, 2003 - ROCKVILLE, MARYLAND

A working copy of the minutes for the subject meeting is attached for your review. I would appreciate your review and comment as soon as possible. Copies are being sent to the Plant License Renewal Subcommittee members for information and/or review.

Attachment: As stated

cc:
- M. Bonaca
- P. Ford
- G. Leitch
- S. Rosen
- G. Wallis

cc via e-mail:
- J. Larkins
- S. Bahadur
- S. Duraiswamy

Issued: 05/07/03
Certified: 05/09/03

# CERTIFIED

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
MINUTES OF ACRS SUBCOMMITTEE MEETING ON
PLANT LICENSE RENEWAL
ST. LUCIE UNITS 1 AND 2
APRIL 9, 2003
ROCKVILLE, MD

The ACRS Subcommittee on Plant License Renewal held a meeting on April 9, 2003, at 11545 Rockville Pike, Rockville, Maryland, in Room T-2B3. The purpose of the meeting was to hold discussions with representatives of NRC staff and Florida Power and Light (FP&L or applicant) concerning the safety evaluation report (SER), with open and confirmatory items and associated supporting information, for the license renewal of St. Lucie Units 1 and 2. Mr. Timothy Kobetz was the cognizant ACRS staff engineer for this meeting. The meeting was convened at 8:30 AM and adjourned at 3:15 PM on the same day.

**PARTICIPANTS:**

| ACRS | NRC Staff | FP&L |
|---|---|---|
| M. Bonaca, Chairman | N. Dudley | S. Hale |
| G. Leitch | D. Jeng | B. Beisler |
| P. Ford | C. Julian | A. Menocal |
| S. Rosen | P. T. Kuo | |
| G. Wallis | G. Galletti | |
| | R. Franovich | |
| | J. Medoff | |
| | S. Sheng | |
| | S. Bailey | |

There were no written comments or requests for time to make oral statements received from members of the public. Two stakeholders attended the meeting. A list of meeting attendees is available in the ACRS office files.

**ACRS SUBCOMMITTEE CHAIRMAN'S INTRODUCTION**

Dr. Mario Bonaca, Chairman of Plant License Renewal Subcommittee, convened the meeting and stated that the purpose was to review the staff's SER with open items related to the application for license renewal of the operating licenses for St. Lucie Units 1and 2. Dr. Bonaca then called upon NRC staff to begin.

**NRC STAFF INTRODUCTION** Mr. P. T. Kuo

Mr. Kuo noted that there were 11 open items at the time the draft SER was issued. Since then, all these items have been resolved. The staff will discuss the closure of these items and the inspections performed to support the review of the LRA. In addition, the staff will discuss the status of interim staff guidance (ISG) that has either been issued, or is under review, to supplement the Generic Aging Lessons Learned (GALL) technical reviews.

**FLORIDA POWER AND LIGHT PRESENTATION** Mr. Steve Hale

Mr. Hale, License Renewal Manager for FP&L, was responsible for Turkey Point and St. Lucie LRAs. FP&L submitted the St. Lucie LRA in November 2001, and received the renewed licenses for Turkey Point Units 1 and 1 on June 6, 2002.

The technical work performed on-site, was directed by the FP&L procedures used in 1996 in support of the Turkey Point license renewal effort. St. Lucie's PN&Ds, safety analysis report (SAR) and design basis documents (DBD) were all used for preparation of the LRA. In addition, FP&L made information trips to other license renewal applicants that have received a license for extended operation (e.g., Oconee).

The St. Lucie application format is the same format that FP&L used for Turkey Point. The methodology is described in Section 2-1 of the LRA is the same as for Turkey Point, and follows the guidance of Nuclear Energy Institute (NEI) document 95-10, "Industry Guideline for Implementing The Requirements of 10 CFR Part 54 –The License Renewal Rule."

Mr. Leitch questioned whether FP&L physically walked-down systems to look for potential interactions in which non-safety related equipment may affect safety related equipment. Mr. Hale replied yes walk-downs were performed; that the approach FP&L took for seismic II/I interactions was an area-based approach, which included all the non-safety related supports. In areas where there was non-safety and safety-related equipment, all of the supports and conduit were included. The only thing not included was the pipe because, from a design-basis standpoint, the pipe was never classified that way (Note: FP&L did eventually bring segments of the pipe into scope due to seismic II/I concerns). Mr. Hale added that there was quite a bit of field work involved in developing the LRA.

Mr. Rosen questioned which drawings were used to determine which non-safety related systems can affect safety systems, adding that just marking P&IDs would not seem to be adequate because P&IDs do not accurately represent the lengths of piping and component positions. Mr. Hale acknowledged that was true and pointed out that, because of that issue, FP&L physically designated areas that were in scope. For example, at St. Lucie, there is a room which has some swinging switch gear on the 19-5 foot-level, where engineers actually wrote on a wall stating that "non-safety related pipe in AB switch gear room,"

Mr. Rosen questioned whether isometric drawings were used at all. Mr. Hale replied no, because when coupled with on-site inspections and engineering walk-downs, P&IDs were adequate for that aging management program.

When reviewing the regulated events, there was some other documentation used. FP&L has a control document called the "Appendix R Safe Shut-Down List." In addition, there is an item called the "Essential Equipment List; EQ List," which is derived from the FP&L component database.

In summary, for the scoping of systems and structures for St. Lucie, FP&L identified 39 out of 70 systems were in scope, and 16 out of the 46 structures on-site were in scope.

In screening, the purpose is to identify structures and components which require an aging management review. The criteria FP&L used was component-level scoping. Once the entire structures in the scope have been identified, then the structure systems are scoped down to the component level, and screened to determine whether it is passive or not and whether it is long-lived or not.

In the mechanical area, FP&L established evaluation boundaries and interfaces with other systems to ensure it captured everything. Specific structures and components were identified that were included in the systems evaluation boundaries. FP&L reviewed the intended functions, and then identified which structures and components supported those functions from a passive standpoint and whether they were long-lived.

Mr. Leitch stated that he was concerned that electronic components (e.g., power supplies) are considered active and are eliminated during the screening process. However, in reviewing industry operating experience there appears to be a growing trend of plant upset conditions (e.g., scrams) that are the result of failed electronic components. Some of these electrical components are active in a sense that the failure can be detected by maintenance procedures and surveillance tests, however, some of them are revealed only in failure which can scram the plant, or cause some other kind of upset conditions. Mr. Leitch questioned whether, independent of license renewal, there is some kind of a program to assess which electronic components whose failure could, all by itself, cause an undesirable chain of events. Mr. Hale responded yes, there are breaker programs which perform preventative maintenance breakers at FP&L. Active electrical components receive a lot of attention. FP&L also has some strategic plans looking at obsolescence of instrumentations and controls at St. Lucie and Turkey Point in terms of long-term life cycle management. Electrical components are also included in the maintenance rule monitoring specifically related to some of those active components and systems.

Dr. Bonaca noted that he was reviewing the pressurizer spray system and the screening process concluded that the pressurizer spray head should not be in scope. The reason given was that the function of the spray head is enhancing the efficiency of the spray and that St. Lucie can survive a fire event where the pressurizer spray is for protection purposes, however, the event can be mitigated without the enhanced effect of the spray head. Dr. Bonaca questioned whether FP&L performs any inspection of the spray head because the component is subjected to significant thermal cycles and, therefore, subject to breaking or cracking over 60 years. Mr. Hale stated that FP&L took the position that the Westinghouse Owner Group originally took in its topical report (which was also used at Turkey Point). The aging effect is thermal embrittlement of stainless, not the fatigue issue.

Dr. Wallis asked what the definition of long-lived is. Mr. Hale responded that around 40 years is the criteria used by FP&L.

Mr. Hale stated that in the electrical and instrument and control (I&C) area FP&L took a slightly different approach to improve the efficiency its review. FP&L eliminated the active components up front because because 95% of the electrical components are active. For example the first time the engineers performed did a component download on our 40-volt system at Turkey Point, there were 18,000 components. It made more sense to eliminate the active categories up front and then deal with the passive components. One point to make clear for electrical components is that if something was in the environmental qualification (EQ) program, it is replaced on a qualified life. So even though some of these components may be greater than 40 years, the fact that it is in the EQ program allowed the engineers to eliminate it as a long-lived item. This is consistent with what previous utilities have done for license renewal.

The screening results are summarized in Chapter 2 of the LRA and the details are presented in Chapter 3. There are four mechanical sections: rack and cooling system, connective systems, ESF, auxiliary systems, and steam and power conversion. In the structural area and the electrical area FP&L provided license renewal boundary drawings to facilitate the NRC review the LRA and also included a SAR and boundary drawings.

Mr. Hale next discussed the aging management review (AMR) which demonstrated that the effects of aging will be adequately managed so the intended functions will be maintained consistent with the current licensing basis (CLB) for the extended period of operation. Aging effects requiring management were established based on two primary areas: 1) the AMR technical resources available, and 2) operating experience reviews. The methodology used for determining the aging effects requiring management for non-Class I in the civil and structural area is provided in Appendix C of the LRA. This is an approach that was originally developed by the Babcock and Wilcox (B&W) owner's group. It was then adopted by the other owner's groups and controlled by the Electric Power Research Institute (EPRI) as the standardized tool for the industry to utilize.

Even though St. Lucie is not a Westinghouse plant, there is a lot of good information that was developed in Westinghouse generic technical reports. In addition, the original NUMARC license renewal industry reports were used as well as B&W technical reports. FP&L established a large database from the Turkey Point aging management reviews that was used for St. Lucie as well as the GALL report. There are some unique materials at St. Lucie and, therefore, the engineers used materials handbooks and in-house materials expertise to address those issues.

Mr. Rosen requested more information on some unique materials at St. Lucie. Mr. Hale responded that the Unit 1 refueling water tank (RWT) is aluminum. There was no industry information for the use of aluminum in this application so FP&L had to research the aging effect of sodium hydroxide on stainless steel. Mr. Rosen questioned what sort of metallurgical issues were there with the aluminum Unit 1 RWT, and what evidence is there that it will last for 60 years. Mr. Hale stated that FP&L had confidence in the tank because there is a program to inspect that tank regularly. There is an epoxy coating on the bottom that has to be inspected that is identified in the LRA.

Dr. Ford stated that the St. Lucie galvanic-aging program makes the case for one-time inspections of various structures based on an algorithm which takes into account galvanic series. Dr. Ford questioned whether the algorithm had been tested against observation, and could it have predicted this galvanic corrosion of this aluminum in the Unit 1 RWT. Mr. Hale clarified that the galvanic program is where there are dissimilar metals in treated water systems. That it is a one-time inspection. Mr. Menocal added that the galvanic corrosion in the RWT for Unit 1 was at the tank bottom where there is a galvanic couple on one of the lines coming in. The corrective action was installation of a liner.

Dr. Ford requested more on this particular incident with the RWT noting that he has a concern about one-time inspections used to predict the validity of algorithms. Where is the evidence that this methodology is quantitatively correct? If you want to have one inspection to support extending the operating license from 40 to 60 years, that inspection better be at the right place at the right time. Mr. Hale noted that one-time inspections are performed in areas where aging effects are not expected to be found. If aging effects are found, then part of the corrective action may be to require additional inspections. Mr. Menocal added that since there are hundreds of potential inspection sites, FP&L is trying to limit its inspections by systematically identifying the most limiting locations based on the galvanic series, the electrolyte, and the contact area between the anodic and cathodic materials.

Dr. Ford stated that to make sure that the decision algorithm is correct FP&L must go beyond that boundary and take into account areas which have undergone the galvanic corrosion such as the RWT. Dr. Ford again questioned whether the algorithm used, predicted the corrosion in the RWT. Mr. Hale replied that he was not sure a galvanic program would identify the RWT corrosion. Dr. Ford noted that, that was the point he was trying to make.

Dr. Bonaca noted that the intake cooling water inspection identified a lot of small-bore piping that had corroded in the past 20 years and that FP&L has replaced 75 percent of it with a corrosion-resistant material. However, there is still 25 percent of the original. The LRA states, and the NRC accepted, that in the future, FP&L only is required inspect the connections between the small-bore piping and the large-bore piping. Dr. Bonaca questioned why the other 25 percent that has not replaced should not be inspected. Mr. Hale stated that FP&L determined that leakage inspections were adequate aging management programs for those nozzles. The problem is inspection techniques cannot get inside of that pipe. These are small-bore pipes. We can look at the connection, and that, typically, will be worst case. A combination of the crawl-through inspections are used in addition to periodic leakage inspections externally. The basis for saying leakage inspections are acceptable is that it is an open-cooling water system, and there is margin. As a result of St. Lucie operating experience if there is a leak, it is small, not catastrophic.

Mr. Hale continued with the presentation noting that in Chapter 3 of the LRA components grouped the same way they were presented in Chapter 2. The results are presented in six-column tables. These are consistent with what FP&L prepared for Turkey Point. The basis for the aging effects for the non-Class I are described in Appendix C of the LRA.

For the GALL comparisons FP&L flagged differences between the component listing in GALL versus the St. Lucie component listing. In general, FP&L listed what the differences in materials in internal and external environments between GALL and St. Lucie.

Mr. Beisler, a civil engineer for FPL stated that the staff asked FP&L to address two questions regarding the aging concrete, specifically the concrete below ground water. One had to do with phosphates and how that affects the concrete, and the second one has to do with corrosion of rebar and how that is managed.

During the license renewal process, FP&L had not come across any issues associated with the phosphates in the soil or the ground water affecting our buried concrete. FP&L did review the technical documentation in an attempt to identify find any information regarding phosphates.

In general, there was no limitations on phosphates in the American Concrete Institute (ACI) documents that FP&L reviewed. In addition, the American Society of Mechanical Engineers (ASME) Code Section III requirements for concrete reactor vessels and containments contained no information on phosphates. The American Society of Testing and Materials (ASTM) standards for the constituent materials for the concrete, the cement, the aggregates, did not contain limitations even on phosphates in the constituent materials. The EPRI documents that address license renewal also did not discuss any aging effects due to phosphates.

Next, FP&L contacted an expert at a large architectural and engineering firm who also could not find information in the technical documents regarding how phosphates affect concrete. The expert did some quick research and provided a brief write-up on what he was able to find. Basically, the expert found that phosphates are not very soluble in water in all ranges of pH, which is contrary to what you find with chlorides and sulfates, which are the main culprits in concrete degradation. Those are very soluble, so they are able to penetrate into the concrete, especially lesser-grade concretes and cause degradation. Additionally, he told us that typical ranges of phosphates and soil or ground water in the neighborhood of 500 to 100 PPM total phosphates, but most of that is fixed, meaning that it cannot be transported to the concrete to cause the degradation.

Nearly all the water soluble phosphates are converted to non-soluble shortly after, if they do come into contact with the concrete, shortly after they are not able to penetrate into the concrete. Of course, the phosphates, in general, are not harmful to the rebar. If there was any effect, it would affect the high alkalinity of concrete. So expert's conclusion, based on his research, supported the industry technical documents that the phosphates are not a contributor to degradation of concrete.

For the St. Lucie plant, FP&L recognized from the very beginning that the ground water was aggressive. The chlorides are higher than the published thresholds. The sulfates are higher than the published thresholds, so FP&L recognized from the very beginning that it needed to manage our concrete below ground water and stated that in the LRA.

Mr. Kobetz requested a copy of the paper that the expert prepared for FP&L on phosphates. Mr. Beisler responded that it is not a published paper, rather something that the expert put together very quickly based on some quick research, and discussions with some university professors. Mr. Kobetz recommended FP&L consider trying to provide something prior to the full Committee Meeting in an effort shorten the discussions in this area.

Mr. Beisler noted that the way to prevent the corrosion of rebar is with the use of high-quality concrete. FP&L reviewed ACI 201 which recommend a water/cement ratio less than 0.45 for durability. St. Lucie structures exposed to ground water were all specified at less than or equal or 0.44.

The ACI 201, dated 1977, recommends the ASTM C150 type five cement. However, the construction of St. Lucie predated 1977 and used type two cement, which was the preferred cement at that time for sulfate resistance. Also, the ACI document recommends an appropriate air entrapment be used; for St. Lucie, the range of air entrapment was two and a half to nine-percent based on what size aggregate is used in the concrete. This all met the ACI requirements.

In addition, the ACI document recommends the following: moist curing for seven days, and St. Lucie required seven to 14 days; high-quality constituent materials, including aggregates per the ASTM C33, cement, ASTM C150, and very clean water, and all those are included in the St. Lucie concrete; and one and a half or, preferably, two inches of concrete cover. St. Lucie structures all have a minimum of three inches, and, in fact, the structures that are exposed to ground water have even more cover, in some cases up to five or six inches of cover, which is specified on the individual drawings for the specific structures.

Concrete exposed to salt water should have a 28-day strength of, at least, 5,000 PSI. For St. Lucie Unit 1, the specification required 4,000 PSI, but the actual strengths of the concrete breaks, in general, were all over 5,000 PSI.

Mr. Beisler also noted that there is a program that includes visual inspections of exposed interior and exterior surfaces of the concrete looking for signs of degradations, specifically corrosion of the rebar, in which case you would see cracking, rust staining possibly, and spalling, although, usually, it never gets to that point. The program now includes inspections of buried structures, which are excavated for whatever reason.

Mr. Hale noted that for each aging effect requiring management, FP&L identified aging management programs on a component basis. Supporting that is an evaluation on-site which goes through an assessment of the GALL attributes versus FP&L program attributes, as well as the general program description and the criteria for the program. Those are documented in program basis documents on-site.

Mr. Leitch questioned whether St. Lucie will be able to fully comply with the new NRC Order related to vessel head penetration inspections. There is a plant similar to St. Lucie that is having some difficulty fully complying with that order because it, and St. Lucie, have guide sleeves or thermal sleeves in the CRDM penetrations, that make it difficult obtain the required data. Mr. Hale responded that St. Lucie has the guide sleeves on Unit 1, and, in anticipation of that question, Mr. Hale provided Mr. Leitch the 30-day inspection report that was issued after the 100 percent visual inspection was completed. FP&L performed a 100 percent visual and 100 percent ultrasonic test on Unit 1 last refueling outage, and the 30-day report to summarizes the findings. There was no indication of leakage, and no indications of cracking on Unit 1. Unit 2 does not have these types of sleeves.

Mr. Leitch questioned whether a decision has been made whether to replace the reactor vessel head at St. Lucie. Mr. Hale stated no decision has been made for St. Lucie, however, at Turkey Point, the heads will be replaced in 2004 and 2005, even though there has not been an indication of leakage.

Mr. Hale next discussed various aging management programs for St. Lucie including the flow accelerated corrosion program, the reactor vessel internals program, and the Alloy 600 program.

Mr. Rosen questioned whether the reactor vessel internals program evaluates how well repairs made to the reactor vessel will perform over the extended license term. Mr. Hale replied no, however, the program goes beyond what must be performed in accordance with ASME Code Section XI. St. Lucie is already committed under ASME Code Section XI to perform inspections and follow-up with regard to the barrel repairs. The reactor vessel internals program addresses some of the more research-type issues, such as the effect of radiation embrittlement, radiation-assisted primary water, there is a whole series of items right now that are being investigated under the MRP.

In conclusion, the aging management programs at St. Lucie, have demonstrated they'll manage the aging effects, so the intended functions will be maintained consistent with our CLB. For all the time-limited aging analyses (TLAA) for St. Lucie have been evaluated and shown to be acceptable for the extended period of operation.

**NRC STAFF OVERVIEW OF THE SAFETY EVALUATION REPORT AND STATUS OF OPEN ITEMS** Mr. Noel Dudley and Mr. James Medoff

Noel Dudley, project manager for the St. Lucie license renewal application, provided a brief overview of the staff's presentation noting that the staff will present the status of the open and confirmatory items and summarize the scoping and screening methodology and the scoping and screening results. The staff will also present the aging management program inspections; concrete aging, as requested by the ACRS members. The staff will conclude its presentation by explaining the Interim Staff Guidance (ISG) process and will provide the status of the identified ISG issues.

St. Lucie Nuclear Power Plant Units 1 and 2 are Combustion Engineering plants with large dry containments. Unit 1 is seven years older than Unit 2, which resulted in some design differences between the units.

The St. Lucie process and programs which are associated with license renewal are similar to those used for Turkey Point. The differences between the designs of the Combustion

Engineering plant and the Westinghouse plant introduces some unique aging management and TLAA.

When the staff received the St. Lucie license renewal application, they reviewed the application in detail and developed the draft request for additional information (RAI) concerning verification and clarification of information in the application. After meeting and discussing the draft RAI's with the application, the staff issued the RAIs that were required for completing the review. The applicant than submitted responses to these RAIs.

In some cases, additional meetings were held to discuss the draft responses. As a result of these meetings, the applicant revised the draft RAI responses before they were submitted to the NRC. On the basis of the information in the license renewal application and in the RAI responses, the staff prepared the SER with open items. Since issuing the SER with open items, the staff has continued its discussion with the application to resolve the open items. Once all the open items and confirmatory items are resolved, the staff will issue a final SER, which will provide the basis for issuing the license renewal.

The staff and the applicant have expended significant time and effort in this review process. The applicant used the lessons learned from its Turkey Point LRA when they prepared the St. Lucie application. About 70 fewer RAI's were issued during the St. Lucie license renewal application review as were issued for the Turkey Point review.

As a result of the NRC staff review, new components or commodity groups were identified and subject to an aging management review. Of these, about 75 components required aging management programs. In response to one RAI, the applicant created a new aging management program.

The NRC staff conducted one audit and two inspections to verify information contained in the application were in responses to the RAIs.

There were 11 open items identified in the SER with open items. Since the SER was issued the staff has reached resolution on all of these items.

In one open item the staff questioned the management of wall thinning due to internal corrosion of small-bore piping in the fire-protection system. For previous applications, the staff accepted aging management programs that included volumetric inspection of these lines. The fire protection system is supplied by city water, and the applicant's monitors internal piping conditions via pressure tests, leakage tests, and identification of excessive corrosion products during flushing of the systems. Past operating experience has not identified any degraded conditions of the internal surfaces, and during recent modifications of the system, the applicant obtained ultrasonic pipe wall-thickness measurements on stagnant portions of the system. The measured wall thicknesses were approximately nominal. Based upon a nominal wall thickness in the measured wall thicknesses, the applicant determined a worst-case corrosion rate might have occurred over the last 24 years of operation. The applicant then used the worst-case corrosion rate and calculated the pipe wall thickness at the end of the period of extended operations and found the wall thickness would be greater than the ASME B31.1 Code requirements for a minimum wall thickness. Therefore, based on the volumetric measurements and the corrosion rate calculations, this item was resolved.

Dr. Bonaca questioned whether the program will rely on the identification of leakage. Mr. Dudley responded not in this case. Mr. Hale added that with regard to ultrasonic as related to wet pipe systems that are pressurized all the time, like fixed sprinkler systems and that sort of thing, if any leakage is detected that would be an indication that was a problem, that would be corrected under the fire protection program. There is still quite a bit that needs to be done under the fire protection program, in terms of monitoring fixed systems, testing pumps, ensuring that flows rates produce the right pressure at the far end of the system. Mr. Rajan, NRC staff pointed out, that the staff based their acceptance primarily on the flushing pressure testing and performance testing, but this was one of the areas where the flow testing was not being conducted, so the staff questioned the licensee how it verified the acceptability of the wall thickness in those areas. The applicant performed a one-time inspection and based a an estimated corrosion rate based on the performance of that line and projected it out, it was determined that there was sufficient margin. The staff accepted that conclusion.

Mr. Dudley continued noting that the staff questioned FP&L's management of wall thinning in small-bore pipes in the intake cooling water system. The environment of the small-bore pipes is stagnant sea water. The staff also questioned the possibility of common mode failure of the small-bore pipe during a seismic event. In its response to the RAI, and in discussions with the staff, the applicant indicated the following: that there are crawl-through inspections of the majority of the intake cooling water (ICW) systems line pipes, which include, approximately 80 percent of the pipes in the system. The inspection also included as much of each branch line as possible. The branch lines consist of welded flanges to which small-bore piping is attached. The flanges are the most susceptible location for the development of corrosion cells since there is a break in the epoxy lining where the flange and pipe come together.

The applicant has established a program to replace small bore epoxy-lined carbon steel pipes with a more corrosive-resistant material. To date, the applicant has replaced approximately 75% of the carbon steel pipes with the more resistant material.

As part of the normal shift activities, operators walk down the ICW system, note any leaks, and initiate corrective action. The ICW system is an open system and is designed to perform its intended function with a sheered three-quarter inch instrument line and an additional hundred-gallon-per-minute leak. The maintenance history indicates that the localized failure of cement linings and internal epoxy coating of intake cooling water lines result in small corrosion cells that lead to two-wall leakage. The system and structures monitoring program and the ICW inspection programs are adequate to manage internal corrosion in the ICW piping. The staff considers this item resolved.

Dr. Bonaca again questioned 25 percent of the piping that has not been replaced. Mr. Hale replied that FP&L credited two aging management programs for aging of the small-bore lines. One is internal visual crawl-through inspections of the larger ICW piping; and the other is leakage inspection. The basis behind that is part of the corrective action for the other lines be established an acceptance criteria that says we can allow a certain amount of leakage, so if a leak is detected, it will be repaired.

Dr. Bonaca questioned why the remaining 25 percent of the piping was not replaced. Mr. Hale responded that part of it that this system is operating all the time, even during an outage. It is difficult to replace the piping unless the system is out of service. Therefore, based on operating experience leakage has been small, where the system safety function is not affected, FP&L will essentially go into a corrective maintenance mode for these small-bore lines.

Mr. Dudley continued the discussion stating that, as a result of industry experience with the unexpected aging degradation of Alloy 600 materials and Alloy 182 materials, the staff is developing guidance and requirements for managing these aging effects. To ensure applicants comply with future staff guidance, the staff requested a commitment from the applicants. The applicant committed to implement the commitments made in response to NRC bulletins and any further NRC communications associated with primary water stress, corrosion, cracking, and nickel-based alloy components. Therefore, the staff considers this item is resolved.

Dr. Ford noted that there are numerous degradation modes for Alloy 600, 690, and 182, and questioned whether the staff took into account whether some of these components had already been repaired as a possible indicator of future failures. The staff responded yes, the staff had the same concerns. NRC Bulletins 02-01, 02-02, and 01-01 are specific to primary water stress, corrosion, cracking that occurs in the upper vessel head. The bulletins do not address industry experience in other Class I Inconel locations. Therefore, the staff divided the open item in two; one open item on the vessel heads and one open item on the remaining components. Basically, the second open item requested clarification on which additional Inconel components are covered by the scope of your program and how will they be inspected. FP&L provided the locations and clarified that it was only using the current ASME Code Section XI programs. Depending on whether it is a nozzle joined by a partial penetration weld or an Alloy 182 safe end nozzle weld, which is a full-penetration weld, the ASME Code Section XI requirements are slightly different and may require a surface inspection, volumetric inspection, or a combination of the two. For the partial penetration welds, only leakage tests and VT-2 visual examinations are required.

Mr. Dudley continued with the presentation noting that the applicant plans to use risk informed methodologies for the one-time small-bore Class I piping inspection. The applicant confirmed that the risk informed methodologies will not be used to eliminate volumetric inspection of weld. The applicant committed to provide the NRC an inspection plan, prior to the period of extended operations, that describes the risk inform methodology and addresses how the methodology will be used to determine the location and the number of small-bore piping components for inspection. This commitment will be included as part of the UFSAR supplement.

Dr. Bonaca questioned whether the inspections would be one-time inspections. Mr. Dudley replied, yes. The details of the program will be provided prior to the period of extended operation. The applicant has committed to include specific information in that program description for staff approval. FP&L clarified that the Class I small-bore inspection program of ASME Code Section XI currently only requires visual inspection of small-bore piping. The concern raised by the staff is that there needs to be some volumetric inspection of the small-bore piping, in addition to ASME Code Section XI. Based on FP&L's aging assessment it did not anticipate finding any degradation in this piping. So FP&L committed, as other applicants have, to performing a one-time volumetric inspection, in addition to the ongoing visual inspections performed under ASME Code Section XI. Risk is used to establish the locations of the ultrasonic (volumetric) inspections in the small-bore piping. Dr. Bonaca asked what the applicant will do if the inspections identify sections of degraded piping that are not in a risk significant location, but are in a susceptible location. Mr. Hale responded that FP&L would take specific corrective action, which may include replacing the piping or additional inspections including volumetric inspections.

Mr. Dudley noted that, next, the staff questioned the applicant's basis for not managing stress relaxation for non-Class I bolting material. Non-Class I bolting does experience stress relaxation at temperatures above 700 degrees Fahrenheit. The non-Class I bolts at St. Lucie are environments that have temperatures below the 700 degrees Fahrenheit (by approximately 200-300 degrees Fahrenheit), and, therefore, do not require an aging management program specific to stress relaxation. Mr. Medoff added that when the staff performed its review it noticed the applicant has one global aging effect, which is loss of closure integrity, and the applicant evaluated it for different degradation mechanisms, such as severe corrosion or cracking or stress relaxation. During the review, the staff noticed that the applicant's identification of this aging effect for the non-Class I was handled slightly differently. The applicant did not identify stress relaxation as a mechanism leading to the loss of closure integrity. In response to an open item on this matter, the applicant provided the threshold for stress relaxation for the different materials for the Class I in contrast to the materials used for the non-Class I reactor coolant system (RCS) bolting. To confirm the validity of the responses, the staff reviewed the appropriate ASME Code section and confirmed the ASME Code thresholds for stress relaxation in the different materials. Therefore, based on the use of 700 degrees Fahrenheit as the threshold for stress relaxation and Grade B-7 bolting, which is being used for the non-Class I RCS bolting, the staff confirmed that stress relaxation would not be an applicable effect for those bolting materials because the operation of the RCS would be at a temperature lower than that. Probably around 560-600 degrees Fahrenheit, so maybe 100-140 degrees Fahrenheit and the bolts are actually cooler than that.

Mr. Dudley noted that the staff questioned the applicant's basis for not managing possible crack propagation from Alloy 182 welds in the base metal of the pressurizer nozzles and thermal sleeves. The thermal sleeves are not welded and do not perform a pressure boundary function. The thermal sleeves are machined, inserted, and expanded. Therefore, since there are no welds, there is no possibility of crack propagation to the base material that forms the pressure boundary, and this item is resolved.

In ISG-5, "Identification and Treatment of Electrical Fuse Holders for License Renewal," the staff stated that the fuse holders are considered passive electrical components and should be brought into scope of license renewal and subject to an aging management review. The applicant identified electrical boxes that contain fuses that were brought within scope. The fuse holders are located in electrical boxes in the electrical equipment rooms in the Unit 1 and Unit 2 reactor auxiliary buildings. The applicant conducted an aging management review of the effects of aging stressers, such as vibration, thermal cycling, electrical transients, mechanical stress, fatigue, corrosion, chemical contamination, and oxidation of connecting surfaces. The applicant concluded that no aging management programs are required. The staff performed an extensive review of this since this is the first LRA that addresses ISG-5; some of the things that the staff took into consideration when they reached the acceptance of the applicant's position was that the fuse holders are installed in parallel with breakers to address regulatory guide associated with providing double isolation for non-safety-related loads powered from safety-related power supplies. The non-safety related loads include instrumentation and heater strips to electrical panels. The fuse holder clips are made of copper or a copper alloy plated with a corrosion-resistant material, either tin or silver, and the fuse holders are in a mild, non-air-conditioned environment, and the staff was unable to identify any aging effects that would degrade the performance of the fuse holder. On this basis, the staff considers this item resolved.

The last open item, involves instances in which the St. Lucie Units 1 and 2 have experienced Alloy 600 instrument nozzle leakage. Four Unit 2 pressurizers steam space instrument nozzles and one Unit 1 reactor coolant system hot leg instrument nozzle were repaired with a half-nozzle repair technology. A mechanical analysis was submitted to support the St. Lucie Unit 2 pressurizer steam space half-nozzle repair performed in 1994. The staff is currently reviewing several aspects of the half-nozzle repair and associated topical reports. The staff is evaluating the acceptability of leaving the half-nozzle repairs in place due to the unknown effects of primary coolant contacting the ferritic material of the nozzles (this is a follow-up action to concerns identified at Davis Besse). The staff is reviewing a regulatory relief request from FP&L for leaving the half-nozzle repair in place for one cycle while Combustion Engineering assesses calculational errors in its topical report associated with the fracture mechanical analysis supporting half-nozzle repairs. The topical report is currently being reviewed by the staff.

The applicant also submitted a site-specific calculation for evaluating the crack growth associated with small-diameter nozzles for St. Lucie Units 1 and 2, and that's also under review by the staff.

Since the technical issues associated with the half-nozzle repairs have not been resolved for the current period of operations, the applicant cannot demonstrate that the fatigue analysis can be re-evaluated for the period of extended operations. The staff has not yet determined what is appropriate for a 40-year time period. Therefore, the staff cannot extend that calculation to the 60-year time period at this time. However, the applicant committed to implement any further NRC requirements associated with half-nozzle repairs and, on the basis of this commitment, this issue is resolved for license renewal. Again, the staff will rely on the 10 CFR Part 50 operating license for resolution of the adequacy of the half-nozzle repairs.

Mr. Dudley reviewed the findings of the reactor oversight process for St. Lucie. The performance indicators for St. Lucie were last updated in December 2002. All the indicators are green. St. Lucie has had two trips in past year. In October of 2000, there was a manual re-trip. Based on the loss of condenser vacuum. Operators were re-aligning the condenser vacuum system and, due to the misalignment, they lost pressure. In April 2003, there was a reactor trip during start-up when an auxiliary feed pump was started and tripped (most likely due to low steam generator water level). Neither of these events were recognized as a regulatory problem, and there was no non-cited violations issued in response to the trips in either case. There were several events of not following your radiological control programs. There was one instance of radioactive material (a hot particle) being carried off-site.

**SCOPING AND SCREENING METHODOLOGY AND RESULTS** Mr. Greg Galletti and Mr. Noel Dudley

Mr. Galletti, an operations engineer in the Equipment and Human Performance Branch, NRR, briefly explained the staff's audit of the scoping and screening methodology and the audit performed as part of that review process.

The team consists of three members to perform the audit. In preparation for the audit, the team conducts a procedures documentation review trip to the applicant's facility to gather information pertaining to the LRA. At that time the team assembles design basis documentation (DBD), scoping and screening result reports, and any other design basis information that may help the team review the LRA and review the process that the applicant used to determine what systems are in scope and, ultimately, what structures and components are then subject to aging management review.

The team spends several weeks performing a conservative desktop review. The team reviews how the application is structured in reference to the requirements of the 10 CFR Part 54 to ensure SSC's have been appropriately identified.

Once the desktop review is complete, the team returns to the applicant's facility for a full week to review in detail the implemented guidelines. In this case, the applicant assembled a suite of procedures called engineering instructions that were written and implemented in accordance with the FP&L 10 CFR Part 50, Appendix B, quality assurance program.

As part of the review, the team reviewed each of those procedures in detail with the cognizant FP&L engineers for that particular discipline. The team then selected certain systems to review.

The team normally reviews four mechanical systems initially: component cooling water; safety injection; auxiliary feed water; and main feed water and then main steam and condensate. There are several reasons the team selects these systems. First, there is a combination of both safety and non-safety related systems. Second, they are robust and complicated systems. Third, there is a lot of interface between some of these systems.

The team found that the applicant's implementation guidance was very well constructed, detailed, robust, and provided guidance necessary for its staff to implement their process.

Mr. Rosen questioned whether it was unusual for applicants to perform these reviews under procedures that are controlled by 10 CFR Part 50, Appendix B. Mr. Galletti responded no, however, some previous applicants have chosen not to perform it under their Appendix B program. Mr. Rosen and Mr. Leitch added that it was not clear how an applicant could choose not to follow its Appendix B program and that this was a concern they would like to pursue with the staff.

The team identified one major issue regarded the 10 CFR 50.54(a)(2) seismic II/I issue. Initially, the applicant had performed an internal evaluation of what it characterized as A2 issues (the effect of non-safety SSCs on safety-related SSCs). After lengthy discussions with the applicant, additional systems were brought into scope.

In summary, the team determined that that there was reasonable assurance that the applicant's methodology for scoping and screening was appropriate.

Mr. Dudley next provided a brief overview of the scoping and screening results and the aging management review process. The purpose of the staff's review of the results of the applicant's scoping and screening methodology is to verify that the applicant has properly implemented its methodology. The staff focuses its review on the methodology results. To confirm that there is no omission of the plant-level systems and structures within the scope of license renewal and that there is no omission of mechanical systems and components, structures, or electrical and I&C components, they are subject to an aging management review.

To conduct its review, the staff used guidance from the license renewal standard review plan and ISGs. The staff reviewed system drawings indicating license renewal boundaries, previous license renewal application reviews, and information in the updated safety evaluation reports to verify there were no omissions in the applicant's results. The staff's review confirmed that the applicant's responses to ISGs concerning station blackout, seismic II/I issue, and ventilation fan damper housings did not omit any structures or components that should be taken into consideration for license renewal. The staff concluded that there is reasonable assurance that the applicant has appropriately identified components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

The purpose of the staff's review of the applicant's aging management review results is to verify the applicant has identified the appropriate aging management program for the various combinations of materials, environments, and aging effects associated with the structures and components that are within the scope of license renewal.

In this case, the staff used existing regulatory requirements or guidance to reach a conclusion on the appropriateness of the aging management program identified by the applicant. Since the applicant did not claim credit for its aging management reviews being consistent with the GALL report, the staff did not reference the GALL reports in its evaluation of the aging management review results. However, in some cases, the staff used the technical information in the GALL report to provide justification for the acceptability of the applicant's results.

The staff reviewed the aging management program results in Chapter 3 of the LRA The staff concluded that the applicant has demonstrated the aging effects associated with different structures and components will be adequately managed. There is reasonable assurance that the intended function will be managed consistent with the current licensing basis for the period of extended operations, as required by 10 CFR 54.21(a)(3).

<u>AGING MANAGEMENT PROGRAM INSPECTIONS AND CONCRETE AGING ISSUES</u> Mr. Noel Dudley, Mr. Caudle Julian, and Mr. David Jeng

Mr. Julian next provided an overview of the license renewal inspection program. For each inspection, the staff assembles a site-specific inspection plan that's reviewed and approved jointly by the region and by NRR. In the case of St. Lucie the staff determined that a follow-up inspection is not warranted.

The objective of the scoping and screening inspection is to confirm the applicant included the appropriate systems, structures, and components in the scope of license renewal. The inspection focused on reviewing the system boundaries. The staff concluded that the applicant's scoping and screening process was successful in identifying those system structures and components needing to be given an aging management review and its documentation was a very good quality. The applicant did not use the method used by Peach Bottom in which components were brought into scope by realigning the systems at the boundaries.

The next inspection is the aging management program inspection in which the objective is to confirm that the existing aging management programs are working well and to examine the applicant's plans for establishing new aging management programs and enhancing existing aging management programs. In this inspection, the staff assessed existing aging management programs.

The inspectors walk down systems with the system engineers to assess how the systems are being maintained today to give the NRC confidence that the utility will do good in the future. There were no major problems identified during the aging management program inspection.

The inspectors did identify that the electrical cable manholes periodic inspection program needed enhancements. The applicant agreed to that and has since enhanced that program.

Mr. Rosen expressed concern that all nuclear plants have manholes in the yards that can collect water, yet this issues comes up consistently in LRA reviews. This is a real problem. Ms. Franovich responded that the GALL report contains an A&P that addresses cables exposed to moisture and significant moisture that is 10-year test and acknowledged that an ISG should be written on this matter.

Mr. Jeng, briefly discussed the staff's review of below-grade concrete aging management. The staff position for below grade concrete is that if it is not exposed to the environment then there will be no need for inspection of those concrete elements. However, if the environment is established to be an aggressive one, then the staff requires an applicant to propose an appropriate aging management program.

The criteria to determine whether an environment is aggressive consists of three points in the GALL and is not quite quantitative. The first point is that the pH of the environment should not be less than 5.5; the second point is that the chloride content of the ground water in the soil environment should not be larger than 500 PPM; and the third point are the solvent content requirements, which the staff maintains they should not exceed 1500 PPM.

In the case of the St. Lucie, the site is quite unique in having an aggressive environment. Specifically, the content of the chloride in the St. Lucie site ground water is in the order of 10,000 to 25,000 PPM (salt water is approximately 22,000 PPM) compared to the acceptable limit of 500 PPM.

In terms of the sulfate content of the St. Lucie ground water, it's in the order of 1,000 to 4,000 PPM, which exceeds the staff's limit of 1500 PPM. Therefore, the applicant took the initiative to treat the environment as a very aggressive one with regard to its aging management program. The staff finds this acceptable.

With regard to the applicant's management of rebar corrosion in concrete corrosion and how it has evaluated the affects of phosphate on the aging of concrete, the staff finds the applicant's conclusions (as stated previously in this Subcommittee Meeting) very reasonable and adequate

Dr. Ford expressed concern with the methods used by the applicant to monitor for sea water attack on concrete and rebar. Mr. Rosen added that, periodically looking for interior leakage is a good thing, but it is after the fact. Looking at exterior structures whenever they are excavated is good thing but it is random. Given the importance of the integrity of structures exposed to aggressive ground water environments more should be done to verify the integrity of the concrete and rebar. Dr. Kuo agreed and noted that this his is a generic problem and not St. Lucie specific.

**<u>TIME-LIMITED AGING ANALYSES</u>** Mr. Noel Dudley

Mr. Dudley noted that TLAA's have evolved since issuance of the original plant operating license. For example, analyses supporting core barrel repair or the reactor coolant system half-nozzle repairs. The staff's review of TLAA's confirms that the applicant has evaluated the TLAA's by verifying either the analysis is valid for a period of extended operation, or the analysis is projected to the end of the period of extended operations and the results continue to meet the design requirements, or there's a program to manage the aging effects.

Reactor neutron embrittlement consists of three separate analyses: the end of life Upper Shelf Energy; the pressurized thermal shock reference temperature; and the pressure and temperature limits as a discussion item since it's not truly a TLAA.

The analysis of the upper shelf energies for the different reactor vessel belt line materials was projected to the end of a period of extended operations. The results of the applicant's calculated upper shelf energies for Unit 1 reactor vessel ranged from 56 to 73 foot pounds, which are above the acceptance criterion of 50-foot pounds. The results for Unit 2 range from 70 to 130-foot pounds, which again is above the criterion. The staff performed independent calculations to confirm these results in accordance with the guidance in Regulatory Guide (RG) 1.99, "Radiation Embrittlement of Reactor Vessel Materials". Mr. Medoff added that to perform the independent calculations, the staff has a reactor vessel integrity database that includes all the belt line materials for all the U.S. plants, including St. Lucie 1 and 2. For the neutron embrittlement assessments for pressurized thermal shock and Upper Shelf, the staff performed independent calculations of all the materials, and the methods in the database follow the guidelines of regulatory guide 1.99, Revision 2, which has been in use for a long time.

Mr. Leitch questioned whether the applicant had committed to implement forthcoming guidance provided by NRC regarding the resolution of Generic Safety Issue (GSI) 168. Dr. Kuo responded that the applicant has committed to some of the programs in GALL Chapter 10, either E1 or E2 or E3, depending on the cables, but that the resolution of GSI 168 is a current operation issue. Mr. Hale added that FP&L performed an assessment with regard to adverse localized environments that is documented in summary in the LRA.

Dr. Kuo added that it would have to get back to the Committee regarding the process by which licensees implement the requirements of GSIs once they have been resolved. This includes that, if new requirements are established, how does the licensee implement them in the extended license.

That completed the staff's presentation regarding its SER.

**INTERIM STAFF GUIDANCE** Mr. Jack Cushing

Jack Cushing a project manager in the License Renewal Branch, NRR, stated that his presentation would focus on the ISG process and how the staff develops ISGs, not on the technical aspects of any specific ISG.

Interim Staff Guidance is new or expanded guidance that the staff requires to communicate in a timely manner to current and future applicants, as well as other stakeholders. ISGs provide guidance that will be incorporated into the license renewal guidance documents to state an approved method, but not the only method, of meeting the regulations. An applicant does not have to follow the guidance, but they do have to demonstrate to the staff that their alternative method complies with the regulations.

The license renewal process is a learning process. The staff and the industry learn from each review. The staff captures lessons learned from the reviews and communicates them to the stakeholders through an ISG. The ISG also provides the stakeholders a means to raise issues related to the license renewal guidance documents

The ISG process includes identification, development, and implementation. Implementation of the ISG includes current and future applicant and addresses evaluating licensees that hold renewed licenses. Compliant ISGs involve compliance with the regulation, the staff will track the licensees to which it applies and ensure that they're evaluated in accordance with existing staff guidance prior to entering the period of extended operation. Clarification ISG's do not involve compliance with the regulation, therefore, do not involve back-fit consideration.

A proposed ISG is issued for stakeholder comments. If the stakeholders agree, then the ISG will be published on the NRC web sites, and applicants may reference it in their license renewal applications. If the stakeholders do not agree, then they may provide written comments, and the staff will hold a public meeting to address these comments. At that point, the staff would resolve the ISG and publish it on the NRC web site.

Implementation for applicants, current and future applicants must address all approved ISG's before a renewed license is issued. Applicants may wish to address an ISG before it is approved so it does not have to be addressed in as a back-fit.

Currently, there are 14 ISG's (see attachment). The first five have been completed, and are on the NRC's web site, and current applicants are addressing them. Two are no longer ISG's because they do not involve technical information. These are ISG-8 and ISG-10. ISG-8 is the ISG process, which we are discussing today; and ISG-10 is the standard license renewal format, which provides guidance to the applicants for the license renewal applications based on lessons learned from reviews of applications using the new GALL format.

That completed the staff's formal presentations

## SUBCOMMITTEE MEMBER SUMMARYS AND CONCLUSIONS

Mr. Rosen:

- Expressed concern that 10 CFR Part 54 does not require LRA to be prepared in accordance with a 10 CFR Part 50, Appendix B, Quality Assurance Program
- Believes that an AMP should be established for the periodic inspection of cables contained in manholes.
- Not convinced that monitoring for interior leakage, and performing opportunistic inspections when areas are excavated for other work, are sufficient to monitor for the affects on concrete structures of aggressive ground water.

Mr. Leitch:

- Would like to hear more about TLAAs for reactor vessel core barrels at the September ACRS Full Committee Meeting.
- Would like to hear the applicant's follow-on process to track and implement license renewal commitments (similar to what the Peach Bottom applicant presented during the March 2003 ACRS Full Committee Meeting). The applicants commitments for the resolution of GSI-168, should be discussed during time.

Dr. Ford:

- No comments specific to the St. Lucie LRA.
- The GALL needs to be updated to include the synergistic effects of AMPs
- Inspection intervals need to be quantified. Currently, licensees are relying on engineering judgement. A decision process needs to be established.
- At the full Committee Meeting the applicant should discuss in more detail its program for concrete inspections.

Mr. Bonaca:

- At the full Committee Meeting the applicant should discuss in more detail the independent assessment it had performed on the affects of phosphates on concrete performance.
- At the full Committee Meeting the applicant should not spend much time on process and scoping. The applicant's presentation should focus on future activities associated with license renewal.
- At the full Committee Meeting the staff should discuss the ISG process and status.

## STAFF AND INDUSTRY COMMITMENTS

1. The staff committed to meet with the staff regarding the quality assurance used to develop of LRAs.

2. The staff should be prepared to discuss the periodic inspection of electrical cables in manholes.

3. The staff committed to brief the Committee regarding the process by which licensees implement the requirements of GSIs once they have been resolved.

4. At the September 2003 full Committee Meeting the applicant and staff will discus the following:

   - the TLAAs for reactor vessel core barrels in more detail,
   - the follow-on process for tracking, implementing, and tracking commitments, including a follow-up of the applicant's commitments to GSI-168.
   - concrete inspection programs in more detail including the independent assessment the applicant had performed on the affects of phosphates on concrete performance,
   - the inspection of buried concrete structures.
   - the applicant should not spend much time on process and scoping. The applicant's presentation should focus on future activities associated with license renewal.
   - the staff should discuss the ISG process and status.
   - any relevant significant operational events

## SUBCOMMITTEE DECISION

The Subcommittee decided not to prepare an interim letter regarding this LRA. The Subcommittee Chairman briefed the full Committee on the St. Lucie LRA at the April 2003 ACRS Meeting. The Subcommittee requested that the staff present an abbreviated version of its presentation regarding the SER, and the applicant discuss its programs to track and implement commitments made for license renewal, to the ACRS one month after it submits the final SER to the Committee for review.

## PRESENTATION SLIDES AND HANDOUTS PROVIDED DURING THE MEETING

The presentation slides and handouts used during the meeting are available in the ACRS office files and as attachments to the transcript which will be made available in ADAMS.

## BACKGROUND MATERIAL PROVIDED TO THE SUBCOMMITTEE

1. "Safety Evaluation Report with Open Items Related to the License Renewal of St. Lucie Units 1 and 2," February 2003 (CD-ROM also included).

2. St. Lucie Units 1 and 2 License Renewal Application, November 30, 2001 (CD-ROM also included).

3. License Renewal Interim Staff Guidance
   Nos. 1 through 4 (issued)
   Nos. 5 through 14 (under staff development)

4. Memorandum to Timothy Kobetz from Noel Dudley, Dated December 16, 2003, regarding FP&L Responses to Staff Requests for Additional Information.

5. Florida Power and Light response to NRC BL 2002-01,Reactor Pressure Vessel Head Degradation and Reactor Coolant Pressure Boundary Integrity, " dated April 2, 2002.

6. Florida Power and Light response to NRC BL 2002-02, Circumferential Cracking of Reactor Pressure vessel head penetration Nozzles, dated January 31, 2003.

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NOTE: Additional details of this meeting can be obtained from a transcript of this meeting available in the NRC Public Document Room, One White Flint North, 11555 Rockville Pike, Rockville, MD, (301) 415-7000, downloading or view on the Internet at http://www.nrc.gov/reading-rm/doc-collections/acrs/ can be purchased from Neal R. Gross and Co., 1323 Rhode Island Avenue, NW, Washington, D.C. 20005, (202) 234-4433 (voice), (202) 387-7330 (fax), nrgross@nealgross.com (e-mail).

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## Attachment

**Interim Staff Guidance (ISG)**
**Status List**
**for License Renewal**

Status as of February 2003

| No | ISG Issue (Approved ISG No.) | Purpose | Actions | Status (Issue date) |
|---|---|---|---|---|
| 1 | GALL report contains one acceptable way, not only way **(ISG-01)** | To clarify GALL report contains one acceptable way, not only way | Staff issued 11/23/01 Letter<br>NEI responded 01/03/02<br>**Changes to**<br>GALL: No<br>SRP: Yes | Completed<br><br>ML013300531 (11/23/01) |
| 2 | Station Blackout (SBO) Scoping **(ISG-02)** | To add SBO scoping | Staff issued 11/14/01<br>UCS response 2/19/02<br>NEI responded 3/19/02<br>Final position issued 4/01/02<br>**Changes to**<br>GALL: No<br>SRP: Yes | Completed<br><br>ML020920464 (04/01/02) |
| 3 | Concrete Aging Management Program **(ISG-03)** | To clarify the applicable aging management programs (AMPs) in GALL and SRP | Staff issued 11/23/01<br>NEI responded 3/14/02<br>Staff responded 4/5/02<br>NEI responded 4/29/02<br>**Changes to**<br>GALL: Yes<br>SRP: Yes | Completed<br><br>ML013300426 (11/23/01) |

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|---|---|---|---|---|
| 4 | Fire Protection System Piping **(ISG-4)** | To clarify AMPs M26 and M27 | Staff issued 1/28/02<br>Final position issued 12/03/02<br>**<u>Changes to</u>**<br>GALL: Yes<br>SRP: Yes | Completed<br><br>ML022260137 (12/03/02) |
| 5 | Identification and Treatment of Electrical Fuse Holder | To include fuse clips and fuse block for fuse holders and to add a new AMP for fuse clips (i.e., metallic) | Staff issued 5/16/02<br>UCS concurred 5/23/02<br>NEI responded 06/19/02<br>Staff is revising its position<br>**<u>Changes to</u>**<br>GALL: Yes<br>SRP: Yes | Under Staff Development |
| 6 | Identification and Treatment of Housing for Active Components | To clarify a need for aging management review (AMR) for housing for fans, dampers, and H/C coils | Staff issued 5/01/02<br>Staff will re-issue its position<br>**<u>Changes to</u>**<br>GALL: Yes<br>SRP: Yes | Under Staff Development |
| 7 | Scoping Guidance for Fire Protection (FP) Systems, Structures, and Components | To clarify the FP scoping | Staff issued 11/13/02 | Awaiting NEI response |
| 8 | Updating the Improved Guidance Documents ISG Process | To establish ISG process. The appeal process will be a part of ISG process | Staff issued 12/21/01<br>NEI response 3/13/02<br>Staff issued 07/30/02 (ML022120383) | Under Staff Development |

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|---|---|---|---|---|
| 9 | Scoping Criteria 54.4(a)(2) | To clarify the scoping Criteria 54.4(a)(2) | Staff issued 12/03/02 on Seismic II/I. Staff issued 3/15/02 on scoping criteria 54.4(a)(2). NEI submitted white paper via E-mail 11/18/02 | Under Staff Development |
| 10 | "Class of 03" Standard License Renewal Application (SLRA) Format | To standardize license renewal application format for 2003 applicants | NEI submitted January 24, 2003 | Under Staff Development |
| 11 | Aging Management of Environmental Fatigue for Carbon/Low-Alloy steel | To review this fatigue issue as ISG process, agreed by September 18, 2002, meeting | NEI submitted ISG input January 17, 2003 for staff review | Under Staff Development |
| 12 | Operating Experience with Cracking of Class 1 Small-Bore Piping | | Identified as ISG on May 29, 2002, Public Meeting | On hold |
| 13 | Management of loss of preload on reactor vessel internals bolting using the loose parts monitoring system | | Identified as ISG on May 29, 2002, Public Meeting | On hold |
| 14 | Operating Experience with Cracking in Bolting | | Identified as ISG on May 29, 2002, Public Meeting | On hold |

T/m



NRC has determined not to prepare an environmental impact statement for the proposed action.

For further details with respect to the proposed action, see the licensee's letter dated July 23, 2002, as supplemented by letters dated November 15, 2002, and January 24, 2003. Documents may be examined, and/or copied for a fee, at the NRC's Public Document Room (PDR), located at One White Flint North, Public File Area O1 F21, 11555 Rockville Pike (first floor), Rockville, Maryland. Publicly available records will be accessible electronically from the Agencywide Documents Access and Management System (ADAMS) Public Electronic Reading Room on the Internet at the NRC Web site, *http://www.nrc.gov/reading-rm/adams.html.* Persons who do not have access to ADAMS or who encounter problems in accessing the documents located in ADAMS, should contact the NRC PDR Reference staff by telephone at 1–800–397–4209 or 301–415–4737, or by e-mail to *pdr@nrc.gov.*

Dated at Rockville, Maryland, this 12th day of March 2003.

For the Nuclear Regulatory Commission.

**L. Raghavan,**

*Chief, Section 1, Project Directorate III, Division of Licensing Project Management, Office of Nuclear Reactor Regulation.*

[FR Doc. 03–6544 Filed 3–18–03; 8:45 am]

**BILLING CODE 7590–01–P**

## NUCLEAR REGULATORY COMMISSION

### Advisory Committee on Reactor Safeguards, Subcommittee Meeting on Planning and Procedures; Notice of Meeting

The ACRS Subcommittee on Planning and Procedures will hold a meeting on April 9, 2003, Room T–2B1, 11545 Rockville Pike, Rockville, Maryland.

The entire meeting will be open to public attendance, with the exception of a portion that may be closed pursuant to 5 U.S.C. 552b(c)(2) and (6) to discuss organizational and personnel matters that relate solely to internal personnel rules and practices of ACRS, and information the release of which would constitute a clearly unwarranted invasion of personal privacy.

The agenda for the subject meeting shall be as follows:

*Wednesday, April 9, 2003—3:30 p.m. until the conclusion of business*

The Subcommittee will discuss proposed ACRS activities and related matters. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official, Mr. Sam Duraiswamy (telephone: 301/415–7364) between 7:30 a.m. and 4:15 p.m. (ET) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Electronic recordings will be permitted only during those portions of the meeting that are open to the public.

Further information regarding this meeting can be obtained by contacting the Designated Federal Official between 7:30 a.m. and 4:15 p.m. (ET). Persons planning to attend this meeting are urged to contact the above named individual at least two working days prior to the meeting to be advised of any potential changes in the agenda.

Dated: March 11, 2003.

**Sher Bahadur,**

*Associate Director for Technical Support, ACRS/ACNW.*

[FR Doc. 03–6547 Filed 3–18–03; 8:45 am]

**BILLING CODE 7590–01–P**

## NUCLEAR REGULATORY COMMISSION

### Advisory Committee on Reactor Safeguards, Meeting of the Subcommittee on Plant License Renewal; Notice of Meeting

The ACRS Subcommittee on Plant License Renewal will hold a meeting on April 9, 2003, Room T–2B3, 11545 Rockville Pike, Rockville, Maryland.

The entire meeting will be open to public attendance.

The agenda for the subject meeting shall be as follows:

*Wednesday, April 9, 2003—8:30 a.m. until the conclusion of business.*

The purpose of this meeting is to review the license renewal application for the St. Lucie nuclear plant and the NRC staff's initial Safety Evaluation Report. The Subcommittee will hear presentations by and hold discussions with representatives of the NRC staff, the Florida Power and Light Company, and other interested persons regarding this matter. The Subcommittee will gather information, analyze relevant issues and facts, and formulate proposed positions and actions, as appropriate, for deliberation by the full Committee.

Members of the public desiring to provide oral statements and/or written comments should notify the Designated Federal Official, Mr. Timothy Kobetz (telephone 301/415–8716) five days prior to the meeting, if possible, so that appropriate arrangements can be made. Electronic recordings will be permitted.

Further information regarding this meeting can be obtained by contacting the Designated Federal Official between 7:30 a.m. and 4:15 p.m. (ET). Persons planning to attend this meeting are urged to contact the above named individual at least two working days prior to the meeting to be advised of any potential changes to the agenda.

Dated: March 11, 2003.

**Sher Bahadur,**

*Associate Director for Technical Support, ACRS/ACNW.*

[FR Doc. 03–6548 Filed 3–18–03; 8:45 am]

**BILLING CODE 7590–01–P**

## NUCLEAR REGULATORY COMMISSION

### Draft Regulatory Guide; Issuance, Availability

The Nuclear Regulatory Commission (NRC) has issued for public comment a proposed revision of a guide in its Regulatory Guide Series. Regulatory Guides are developed to describe and make available to the public such information as methods acceptable to the NRC staff for implementing specific parts of the NRC's regulations, techniques used by the staff in evaluating specific problems or postulated accidents, and data needed by the staff in its review of applications for permits and licenses.

The draft guide is temporarily identified by its task number, DG–1107, which should be mentioned in all correspondence concerning this draft guide. Draft Regulatory Guide DG–1107, "Water Sources for Long-Term Recirculation Cooling Following a Loss-of-Coolant Accident" is being developed to describe methods acceptable to the NRC staff for implementing requirements with respect to the sumps and suppression pools performing the functions of water sources for emergency core cooling, containment heat removal, or containment atmosphere clean up. Section 1.1.4 of DG–1107 contains discussions of active debris mitigation systems in lieu of the passive sump screens that are in many of the nuclear plants. Specifically, comments on alternative solutions to debris strainers for ensuring long-term cooling are solicited.

This draft guide has not received complete staff approval and does not represent an official NRC staff position.

Comments may be accompanied by relevant information or supporting data. Written comments may be submitted by mail to the Rules and Directives Branch,

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
PLANT LICENSE RENEWAL SUBCOMMITTEE MEETING
ST. LUCIE UNITS, 1 & 2
APRIL 9, 2003, ROCKVILLE, MARYLAND

Contact: Tim Kobetz (301-415-8716, tjk1@nrc.gov )

**-PROPOSED SCHEDULE-**

| | Topics | Presenters | Time |
|---|---|---|---|
| I. | **Opening Remarks** | M. Bonaca, ACRS | 8:30-8:35 a.m. |
| II. | **Staff Introduction** | P. T. Kuo, NRR | 8:35-8:45 a.m. |
| III. | **Florida Power and Light, Presentation**<br>A. Background<br>B. License Renewal Application Scoping and Screening Process<br>C. Aging Effects<br>D. Aging Management Programs<br>E. Time Limited Aging Analyses | S. Hale | 8:45-9:30 a.m. |
| IV. | **Overview and Status** of Open Items Related to License Renewal of St. Lucie Units 1 & 2 SER (including ROP and recent events, if applicable). | N. Dudley<br>J. Medoff<br>D. Nguyen<br>J. Fair<br>S. Sheng | 9:30-10:15 a.m. |
| | **BREAK** | | **10:15-10:30 a.m.** |
| V. | **SER Chap. 2:** Scoping and Screening Methodology and Results, and aging management reviews | G. Galletti<br>N. Dudley | 10:30-11:30 noon |
| | **LUNCH** | | **11:30-12:30 p.m.** |
| VI. | **Aging Management Program Inspections and Concrete Aging Issues** | N. Dudley<br>C. Julian<br>D. Jeng | 12:30-1:00 p.m. |
| VII. | **SER Chap. 3:** Aging Management Programs | | 1:00-1:30 p.m. |
| | **BREAK** | | **1:30-1:45 p.m.** |
| VIII. | **SER Chap. 4:** Time Limited Aging Analyses | | |
| | A. Overview<br>B. Reactor Vessel Neutron Embrittlement<br>C. Thermal Fatigue<br>D. Leak-before-break | N. Dudley | 1:45-2:15 p.m. |
| IX. | **Interim Staff Guidance:** Process and Status | J. Cushing | 2:15-3:00 p.m. |
| X. | **Subcommittee Discussion** | | 3:00-3:15 p.m. |
| XI. | **Adjourn** | | 3:15 p.m. |

**NOTE:**
- Presentation time should not exceed 50 percent of the total time allocated for specific item. The remaining 50 percent of the time is reserved for discussion.
- 25 copies of the presentation materials to be provided to the Subcommittee

# ADVISORY COMMITTEE ON REACTOR SAFEGUARDS
# SUBCOMMITTEE MEETING ON PLANT LICENSE RENEWAL

**APRIL 9, 2003**

**ATTENDEES PLEASE SIGN IN BELOW**
**PLEASE PRINT**

| NAME | AFFILIATION |
| --- | --- |
| Bruce Beisler | FPL |
| ANTONIO G. MENOCAL | FPL |
| CAUDLE JULIAN | NRC REGION II |
| STEVE HALE | FPL |
| Joe Gasper | OPPD |
| BEN GITNICK | ISL, INC |
| AL PAGUA | SCE+G VC SUMMER |
| W. Koo | NRC/NRR/DE/EMCB |
| T. Mensah | NRC/NRR/DSSA/SPLB |
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