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UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

Alex S. Karlin, Chairman
Dr. Richard E. Wardwell
Dr. William H. Reed

In the Matter of	)	
	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC	)	Docket No. 50-271-LR
and ENTERGY NUCLEAR OPERATIONS, INC.	)	ASLBP No. 06-849-03-LR
	)	
(Vermont Yankee Nuclear Power Station)	)	

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EPRI

TACKLING THE SINGLE-PHASE EROSION CORROSION ISSUE

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W. H. LAYMAN

J. S. HOROWITZ

TO BE PRESENTED AT

THE AMERICAN POWER CONFERENCE

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TACKLING THE SINGLE-PHASE EROSION CORROSION ISSUE

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and

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INTRODUCTION

In December 1986, a pipe burst in a U.S. nuclear power station. This accident was the result of pipe wall thinning (metal loss) due to flow-assisted corrosion. This phenomenon, known as erosion-corrosion, is complex and depends on the interrelationship of water temperature, water chemistry, the alloy content of the steel the flow velocity and the geometry of the flow path (straight, bend, tee, etc.).

Another instance of pipe rupture due to single phase erosion-corrosion occurred under similar conditions at a fossil plant in 1982. In light of the seriousness of pipe bursts in high energy lines and the potential for it to occur at any plant, the challenges to EPRI were (1) to find ways to determine where single phase erosion-corrosion most likely has occurred in piping, (2) to define accurate and low-cost methods to carry out inspections, and (3) to identify techniques for preventing further pipe degradation.

The Nuclear Management and Resource Council (NUMARC) and EPRI have designed an inspection plan (Figure 1) to help utilities identify areas of carbon steel piping that might undergo erosion-corrosion damage (1, 2). The key elements of the plan are (a) where to inspect, (b) how to inspect, (c) when to inspect, and (d) how to respond. The plan is designed to provide utilities with the ability to predict wall thickness as a function of plant life for a given component and to assess the costs and benefits of a variety of remedial options.

EPRI's role has been twofold. The first has been to develop and transfer to utilities the technical products needed to resolve the problem. This has been in the form of computer codes, reports, and workshops. The second has been to provide full support to utilities using these products.

The centerpiece of the EPRI effort has been the development of a predictive computer code, CHEC (3), that uses plant specific data to predict the extent of metal loss in various piping components. Based on extensive laboratory test data from Europe and the U.S., the CHEC code helps to avoid wholesale, random and non-productive inspection efforts. Fifty-one utilities currently have CHEC. One hundred and [illegible] (including more than sixty fossil

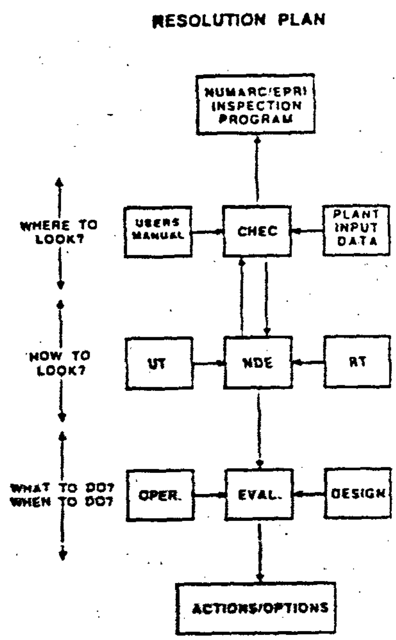


Figure 1--Inspection Plan.

plants) are expected to have CHEC in use by mid-1988. The correlation between CHEC predictions and plant data is good. The code is predicting erosion-corrosion rates within a ± 50% band, given accurate input data. This agreement is much better than other known erosion-corrosion correlations.

Additionly, reliable non-destructive inspection procedures are available to determine the extent of damage and to measure its progression. Corrective measures exist that can prevent future power plant incidents from single-phase erosion-corrosion.

Despite the unanticipated emergence of single-phase erosion-corrosion in carbon steel piping, the industry now has the knowledge and the tools needed to protect against this phenomenon. This paper describes the technical resolution products developed by EPRI to tackle this issue.

CHEC (CHEXAL HOROWITZ EROSION CORROSION) CODE

The CHEC code is designed to help utilities plan inspection programs to determine the extent of pipe thinning caused by erosion-corrosion (Figure 2). The program factors in available inspection data to make accurate predictions for a given plant. Information is provided to allow the development of a cost-effective inspection program. Other applications include:

- Conducting parametric studies to determine the effect of changing water chemistry, pipe size, piping layout and pipe materials o Designing new piping systems that are less likely to be damaged by erosion-corrosion

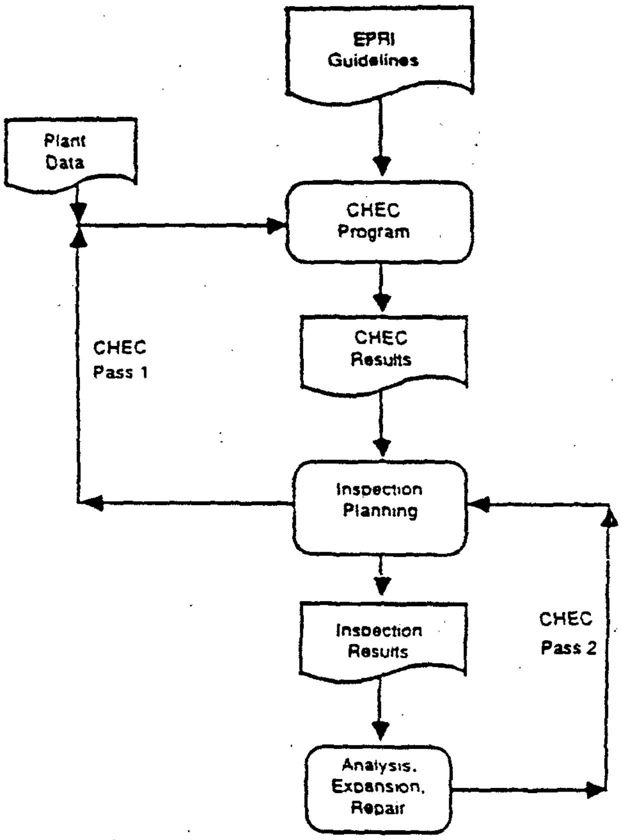


Figure 2--Planning with CHEC.

The CHEC code was developed and packaged to bring uniformity to the industry. The code provides:

- o Ten recommended inspection locations to identify plant susceptibility to erosion-corrosion
- o Erosion-corrosion rate prediction
- o Ranking of components for any system in order of the potential of erosion-corrosion damage
- o Plant specific predictions for all plant components at 50% bounding level using limited plant inspection results.
- o Prediction of the time at which the minimum code allowable wall thickness will be reached.

CHEC is a personal computer based program designed to be a complete analytical tool which is easy to use and flexible. An interactive user interface provides guidance through the various stages of data entry, analysis and evaluation of results.

The program is comprised of four modules:

(1) an executive module that controls overall operation of the program,

(2) a data input module to enter the plant parameter data,

(3) an analysis module to perform erosion-corrosion calculations and produce reports of results, and

(4) a results display module to produce graphical displays of the analysis results.

A data flow diagram for the CHEC program is provided in Figure 3. A more detailed description of CHEC's features and capabilities can be obtained from the CHEC Users Reference Manual (3).

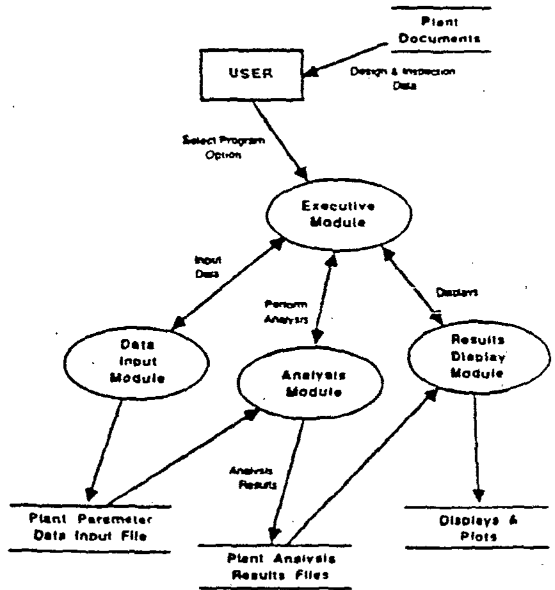


Figure 3--CHEC Program Data Flow.

The general formulation of the model is a series of factors which, when multiplied together, yield the predicted erosion-corrosion rate. Since some of the factors are interrelated, the model is not linear. The formulation is as follows:

$$\mathcal{E} = F_1(T)\bullet F_2(AC)\bullet F_3(MT)\bullet F_4(O_2)\bullet F_5(pH)\bullet F_6(G)$$

where $\mathcal{E}$ = erosion rate
$F_1(T)$ = factor for temperature effect
$F_2(AC)$ = factor for alloy content effect, i.e., chrominum, copper and molybdenum content
$F_3(MT)$ = factor for mass transfer effect (flow rate, piping diameter)
$F_4(O_2)$ = factor for oxygen effect
$F_5(pH)$ = factor for pH effect (amine type)
$F_6(G)$ = factor for geometry effect

Since the interrelation between these parameters was not initially apparent, the formulation was developed empirically. In doing so, the following principles were upheld:

- o All of the above parameters were incorporated into the model

- o All of the available data were used in the model development,
- o The model did not presuppose a form of the correlation,
- o Although the model is empirical, steps were taken to ensure that each part of the model made mechanistic "sense".

Using these principles, a data base was assembled from various laboratories. With this data base, an interactive procedure was used until an optimum model was obtained. This model followed all of the experimental trends, and correlated well with the bulk of the laboratory data.

The model was further refined by comparing the predictions of the model with data obtained from nuclear power plants and with further laboratory data. With the use of these additional data (particularly to take into account various geometrical mass transfer enhancement factors), the model was improved and has been released in CHEC Version 1.2. This model was used exclusively for the comparisons contained in this paper.

CHEC VALIDATION WITH LAB DATA

The CHEC Version 1.2 model was validated using data from British and French laboratories. The key features of the lab data were:

- o Initial wall thickness was well characterized relative to NDE field measurements.
- o Chemistry was controlled precisely and characterized.
- o Material composition was well known.
- o Tests were of short duration (<1000 hours).
- o Wear measurements were precise since thin-layer activation was used.
- o Tests were run for straight pipes.
- o Measurements were taken in a relaxed environment unlike the pressures on power plant personnel.

The range of lab conditions for which test data are available is as follows:

Diameter	: 0.315-0.378 inches
Temperature	: 210-437°F
pH	: 7-9.60
Amines	: Ammonia, Morpholine
O_2	: 0-7 ppb
Cr	: 0.025-0.10%
Cu	: 0-0.31%
Mo	: 0-0.04%
V	: 1.15-12.71 ft/sec
Re	: 16,700-177,000

Figure 4 presents an overall comparison between CHEC predictions and laboratory data. This comparison shows that the model predicts the laboratory data well, particularly at high values of material removal.

CHEC VALIDATION WITH PLANT DATA

The purpose of the CHEC computer program is to predict actual plant performance. To validate the methodology of CHEC Version 1.2, actual plant data were obtained from several operating U.S. nuclear plants.

The inherent accuracy of the measured plant data is less than the accuracy of measured laboratory data. Plant data are less precise because of the uncertainties in the initial thickness of the component and because of the greater uncertainty inherent in field NDE measurements. Furthermore, the components of interest in the field are often asymmetric such as elbows, tees, etc. In such components there is greater difficulty in defining the original thickness - especially in the absence of baseline measurements - and in establishing the point of maximum wear. The key features of plant data are:

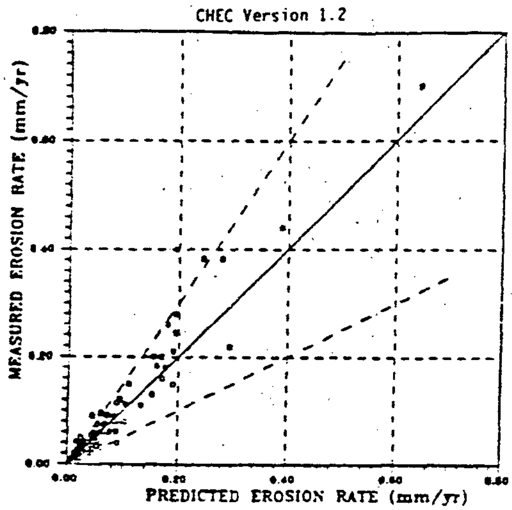


Figure 4--Comparison With Laboratory Data.

- o Baseline thickness measurements usually are not available.
- o Chemistry and reactor power vary with time.
- o NDE measurements at best are ±5% - for low wear situations, NDE uncertainty can overwhelm the actual wear measurement.
- o Material composition generally is unknown.

The range of plant data used for validation is as follows:

Plant Types	: PWRs, BWRs
Age	: 55,000-100,000 hours
V	: 3-31 Ft/sec
D	: 14-30 inches
T	: 92-440°F
O_2	: 0-100 ppb
pH	: 7-9.6
Amines	: Ammonia, Morpholine, Cyclohexylamine, Hydrazine, Neutral
Re	: 10^6-10^8

CHEC predicted wear values were compared with measured values at the point of maximum wear. Figure 5 provides a summary of "Measured Versus Predicted Wear" for all of the plants analyzed. The following paragraphs describe the procedure that was used to process the plant data.

Only raw NDE data were used for this validation process. These raw NDE data were reduced by examining each circumferential band for its thinnest (Tmin) and thickest (Tmax) reading. For each circumferential band, a wear was deterwith the highest wear determined the wear for the entire fitting.

Operating conditions were determined from each plant's maximum guaranteed 100% heat balance. Only heat balance values were used, and mass flow rates were always used instead of local fluid velocities.

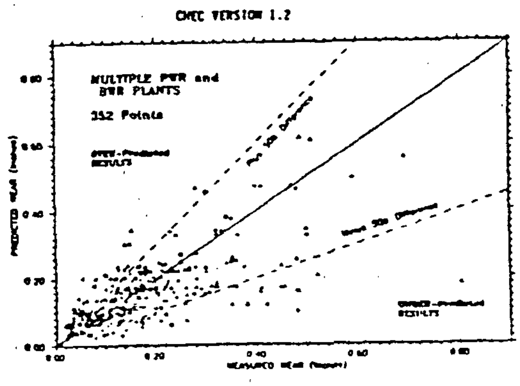


Figure 5--Comparison With Plant Data.

Component geometries were determined by using each plant's isometric, plan and elevation drawings. Components in lines which are not used during normal operation were not included.

Information concerning materials and alloy content was provided by the utility operating the specific power plant. Chemistry and operating histories were provided by the operating utility. In some cases, chemistry values were determined using mass balances.

Figure 5 supports the conclusion that CHEC Version 1.2 predicts wear within ± 50%. Only two small groups of data fall outside the ± 50% lines; each warrants further discussion. The outliers in both groups are due to uncertainties in the measurement techniques. The data where the measured wear is less than calculated wear occur when the wear rate is very small. It is difficult to measure low wear rate accurately with a single inspection. The data where the measured wear is greater than the calculated wear occur when the component thickness is large (~ 2.5 inch). An NDE measurement uncertainty of ± 5% of wall thickness for a 2.5 inch thick component means ± 125 mils on Figure 5. The inaccuracies inherent in NDE cannot be eliminated. However, in both of the anomalous situations -- the case of low wear rate and wear on thick walls -- the fittings are far from reaching the minimum wall thickness allowed by code.

NDE

There are several techniques available to perform pipe examinations (4). These are illustrated in Figure 6. To perform ultrasonic thickness (UT) measurements at power (i.e., with plant on line), personnel thermal protection and high-temperature UT transducer and couplant are required.

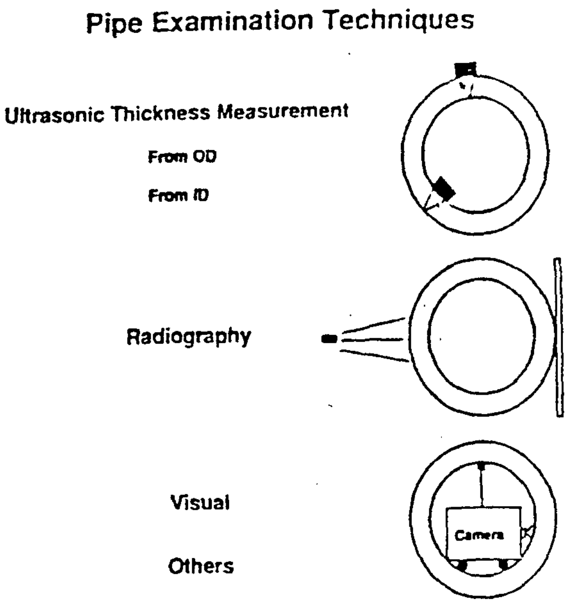


Figure 6--Pipe Examination Techniques.

UT MEASUREMENTS FROM OUTSIDE SURFACE

UT measurements made from the outside surface require insulation removal and surface preparation. However, external UT is a simple technique and a wide range of manual/auto instrumentation is available. The repeatability of measurements under laboratory conditions is within ± 0.004 average standard deviation (0.8% of average wall thickness) and the accuracy is ± 0.013 RMS (2.6% of average wall thickness). A minimum amount of specialized training is required. A typical time for a manual examination of an 18" elbow is ~1 hour; a typical time for an auto examination of 5' of 18" pipe is ~6 hours.

UT MEASUREMENTS FROM INSIDE SURFACE

In this case, there is no need for insulation removal. This technique requires an access port (plus repair of the access opening) and special equipment. A visual examination from inside can be performed using a wide variety of equipment such as a crawler, a submersible, borescopes and fiber optics. The factors that affect interpretation of the resulting visual information are the condition of backing rings, the condition of weld roots, the presence of gouges and grooves, discoloration, and pitting.

RADIOGRAPHY THICKNESS (RT) MEASUREMENTS

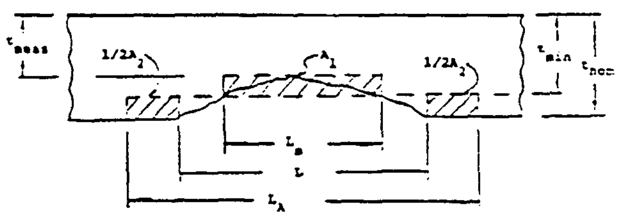
This technique can be used without removing insulation, and can be performed without draining lines. However, RT on filled lines means a loss in sensitivity, the need for high energy sources, and increased expense. It requires precise calibration and control of exposure and processing. RT measurements can detect local gouging and general thinning of 0.040". The total exposure time for one 18" elbow is ~24 hours. Radiation control of the area is required and access could be a problem.

ACCEPTANCE CRITERIA

EPRI has proposed guidelines (5) for allowable local thinning based on area reinforcement (Figure 7). The guidelines include a three-step evaluation process based on nominal, minimum allowable and local wall thickness requirements. These steps are:

1. Compare measured wall thickness (t_{meas}) with nominal wall thickness (t_{nom}). If $0.875\ t_{nom} > t_{meas} > 0.2\ t_{nom}$, further evaluation is necessary.
2. Compare t_{meas} with the minimum wall thickness (t_{min} from hoop and axial primary stress equations from code of record. In case bending loads are not available, bound or assume $t_{min}=t_{nom}$). If $t_{meas} < t_{min}$, further evaluation is necessary.
3. Compare t_{meas} and L_m (extent of thinning exceeding t_{min}) with local thinning criteria. This step involves evaluation that is based on one of the following:
   - o local membrane stress (NB-3200)
   - o local corrosion (ANSI B31G)
   - o branch reinforcement

The details on these are covered in reference 5.



$$\frac{t_{allow}}{t_{min}} = \left(\frac{L_A - L}{\beta L_m}\right)\left(1 - \frac{t_{nom}}{t_{min}}\right) + 1$$

$\beta = 1.0$ or 1.07 and

$L_A < 2L_m$ or $4R$ or $(L_m + 3/2\sqrt{Rt})$ depending on Code

Figure 7--Allowable Local Thinning Based on Area Reinforcement.

REMEDIAL OPTIONS

Depending upon the extent of wall thinning, the utility has several options to rectify the problem. These are:

- o Inspect and monitor in the future.
- o Implement water chemistry changes such as increasing pH or amine (e.g., ammonia to morpholine) for a PWR and oxygen level for a BWR.
- o Repair or replace the component.

PWR WATER CHEMISTRY

Feedwater pH recommendations given in the PWR secondary water chemistry guidelines (6) are intended to create acceptable levels of general corrosion in the condensate and feedwater system. This, in turn, minimizes deposit and sludge buildup in the steam generators. The recommendations for minimizing oxygen concentrations were based on evidence that dissolved oxygen and feedwater system corrosion products aggravate several steam generator corrosion modes. In systems containing only ferrous alloys, it is recommended that feedwater pH be controlled between 9.3 and 9.6. This range has been shown to yield acceptably low values of iron release from typical carbon, low alloy, and stainless steels in power systems. In plants with copper alloys in the feedwater heaters or condenser, a lower pH range (8.8-9.2) is recommended, as copper released from some alloys has been shown to increase markedly when the pH is above 9.2. However, the secondary chemistry guidelines do allow for operation above pH 9.2 if individual plant experience shows that copper transport did not increase significantly.

Guidance on the additive to be used for pH control is not provided in the PWR secondary water chemistry guidelines. Ammonia generally has been the additive selected for pH control in PWR systems. Hydrazine is normally employed for oxygen scavenging. In some units, decomposition of hydrazine generates enough ammonia to provide pH control, thus ammonia injection is not necessary. The adoption of morpholine rather than ammonia as the pH control additive can reduce the rate of flow-assisted corrosion in single and two phase regions.

BWR WATER CHEMISTRY

BWR water chemistry (7) differs significantly from that in a PWR. First, chemical additives are not employed routinely. Second, significant oxygen levels exist in the condensate, feedwater, and steam trains. There are several sources of oxygen generation. Water radiolysis in the reactor core leads to generation of oxygen and hydrogen. This yields equilibrium oxygen concentrations of 150 to 300 ppb in the reactor recirculating water. Oxygen concentrations in the steam normally range from 15 to 30 ppm with normal condensate and feedwater concentrations of 10 to 30 ppb. Oxygen concentrations in the extraction and drain systems also are elevated significantly with values in the range of 100 to 2000 ppb. Chemistry control options available to BWR operators for reducing flow assisted corrosion, are fewer than in PWR systems. Specifically, the only controllable variable is the feedwater and condensate dissolved oxygen concentration.

Until recently no attempt has been made to employ chemical additives for BWR chemistry control. However, several utilities have adopted or are in the process of adopting a chemistry approach named hydrogen water chemistry. In this approach, hydrogen is injected into the feedwater to suppress radiolysis in the core and reduce oxygen concentrations in the reactor recirculating water. This also leads to oxygen concentration reductions in other portions of the cycle. Feedwater oxygen concentration of 10-50 ppb is recommended in the BWR water chemistry guidelines. A significant data base exists illustrating the beneficial effect of maintaining the oxygen concentration in BWR feedwater and condensate above the minimum value given in industry guidelines. Although decreases in the release of iron from ferrous materials would not be considered significant with respect to reduction of deposits on fuel or primary systems activity levels, operation near the 50 ppb upper limit of the indicated achievable range could reduce the probability of flow assisted corrosion in single phase regions.

COMPONENT REPAIR OR REPLACEMENT

For component repair or replacement, the following issues (8) need to be addressed:

- o alternate piping materials
- o repair and replacement options
- o equipment and process selection options for cutting, machining, and welding.

The piping materials that are resistant to erosion-corrosion are low alloy steel (e.g., 1 1/4 Cr 1/2 Mo-P11 Grade and 2 1/4 Cr 1 Mo-P22 Grade) and austenitic steel.

Low alloy steels are used widely in the utility industry and are available in a variety of sizes. Current data suggest that 1/2%-1% chrominum provides adequate resistance to single phase erosion-corrosion in high purity water. Components of low alloy steel can replace existing low carbon steel components because the two steels have similar weights and thermal expansion coefficients, and low-alloy steel has superior mechanical properties. The disadvantage of P11 and P22 materials is that they require preheat and postweld heat treatment. P22 is favored over P11 because of better corrosion resistance and greater availability.

Austenitic steels also have excellent resistance to erosion-corrosion. Low carbon grades are preferable because of better intergranular stress corrosion cracking (IGSCC) resistance. The candidate materials are 304L, 316L, and 347L. These materials are readily available and do not require preheat or postweld heat treatment. The disadvantages of austenitic stainless steels are that piping reanalysis is required due to a higher thermal expansion coefficient (1.4 X carbon steel); the bimetallic welds need special attention; and susceptibility to chloride stress corrosion raises concern over the chloride contaminants in thermal insulation.

A comparison of repair and replacement options is provided in Table 1. A comparison of equipment and process selection options for cutting, machining, and welding is provided in Table 2.

CONCLUSIONS

This paper illustrates the significant effort that has been put forward by the industry to tackle the single phase erosion-corrosion issue. The utilities have received the knowledge and the tools needed to handle this phenomenon. To summarize:

- o EPRI has developed and transferred to the utility industry a predictive computer code, CHEC, designed specifically to avoid wholesale or random inspections. The CHEC code identifies 10 fittings for initial inspection to identify the plant susceptibility to single phase erosion corrosion. This approach minimizes the NDE resources needed for inspection.
- o An NDE source book has been prepared that discusses the inspection methods available, their limitations, their accuracy, and how to apply them.
- o Acceptance criteria have been proposed that define acceptable level of thinning.
- o In PWR secondary cycles, elevations of pH and adoption of morpholine (rather than ammonia) as the pH control additive are two approaches that can reduce the rate of flow assisted corrosion. In BWR systems, options for pH control or additive variations are not available. However, extensive laboratory and plant data demonstrate the value of maintaining the oxygen concentration in the feedwater and condensate near the upper bound given in BWR water chemistry guidelines. This concentration would be affected negatively if hydrogen water chemistry is implemented to reduce the rate of intergranular stress corrosion cracking in the reactor recirculating water system.
- o P11 and P22 grade low alloy steels and type 304L, 316L, and 347L (modified chemistry) stainless steels are all satisfactory replacement materials. The cost estimates vary with specific plant conditions but low alloy steels cost ~ 1.5-1.75 times carbon steel and austenitic stainless steels cost ~ 2 times carbon steel.

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TABLE 1
COMPARISONS OF REPAIR/REPLACEMENT OPTIONS

Options	Advantages	Disadvantages
Complete System Replacement	- Provides most complete repair - eliminates uncertainty - Permits change to an improved material - Permits establishment of accurate baseline information - Provides option for redesign - Eliminates need for augmented inspection - Addresses both partial or complete replacement	- Most expensive and time consuming option - Requires planning and mobilization of significant workforce - Requires locating and procuring appropriate components - Potential cost for optional redesign
Selected Component Removal	- Provides maximum practical access to ID - Approach deals with replacing a suspect component(s) - Straight-forward approach using conventional equipment - Ability to eliminate locally defective areas - Personnel access possible - Flaw location determination less critical	- Duration/cost greater than local repair on trepanning plug - Appropriate access is not assured - Requires installation equipment and skills be mobilized - Requires rigging and handling - Procurement required if new component utilized
Repair Existing Components	- Minimizes outage time - Ability to repair local regions - New material/components not required - Straight-forward approach using conventional equipment	- May only be an interim fix - Component removal may be required - System still may be suspect - Inprocess information may result in procurement and replacement with new material thus extending schedule
Provide internal access for inspection (≤ 2" ø)	- Economical (Fast) - Conventional skills required - Metallurgical specimen available if desired - Plug may be re-used if not destructively examined	- Limited access - Location determination critical - Inprocess decision may dictate procurement and replacement with new material thus extending schedule

TABLE 2

COMPARISON OF EQUIPMENT/PROCESS SELECTION OPTIONS FOR CUTTING, MACHINERY, AND WELDING[5]

Options	Complete System Replacement	Selected Component Removal	Repair Existing Components	PROVIDE INTERNAL ACCESS FOR INSPECTION
Oxy-Fuel Cutting	X	—	—	—
Plasma Cutting	X	—	—	—
SAW	0	X	—	—
OD Lathe	X	X	—	—
ID Lathe	X	X	—	—
Key Mill	—	—	—	X
Drill	—	—	—	0
Grinder	—	X	X	0
SMAW	0	X	X	X
GTAW	0[4]	0[4]	0	X[4]
GMAW-P	X[1]	X[1]	X[1]	—
FCAW	X[1]	X[1]	X[1]	—
GTAW-P-AU	X[2,5]	X[2,3,5]	—	

1) Not recommended for austenitic components
2) Requires the use of portable pipe beveling machine tools and skilled welding operators/contractor.
3) Critical path/economics may warrant use of this process despite Equipment/Labor/Contractor costs.
4) Recommended for welding roots.
5) This process is gaining wide plant acceptance due to its speed, quality, and reproducibility.
6) Reference EPRI/BWROG Contract T305; Equipment Reference Guide, et al.

X = Recommended

0 = Acceptable, but generally not economical

— = Not applicable

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Official Transcript of Proceedings

NEC-JH_39

NUCLEAR REGULATORY COMMISSION

Title:	Advisory Committee on Reactor Safeguards Thermal Hydraulic Phenomena Subcommittee
Docket Number:	(not applicable)
Location:	Rockville, Maryland
Date:	Wednesday, January 26, 2005
Work Order No.:	NRC-194 — Pages 1-364

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Okay. I also review the section on leak before break. And the operating conditions under the uprated conditions will not alter the conclusions of the previous leak before break analysis for Waterford 3. It's still valid.

Are there any additional questions?

I'll turn it over to John Tsao.

MR. TSAO: I'm John Tsao from the Materials and Chemical Engineer Branch. I reviewed five sections; coding system, flow accelerated corrosion programs, steam generator tube inspections, steam generator blowdown systems and chemical and volume control systems.

I will be talking about only two systems here; flow accelerated programs and steam generator tube inspections because they are more significant in terms of power uprate.

For the flow accelerated corrosion programs, this morning there was some issue as to how much you increase. I have this backup slide.

The FAC program measure the wear rates in terms of mils per year. And these are the changes that would be due to power uprate conditions.

Also, I want to show you another slide that gives the effectiveness of the FAC program. This is provided by the licensee. And as licensee said, it is more in the -- they used CHECWORKS. It's a computer program that considers hydrodynamics, heat balance, temperature in particular.

As you can see the predictive method is conservative considered to actual measurement.

DR. FORD: I'm sorry. Could you explain that?

MR. TSAO: Okay.

DR. FORD: It looks as though it's equally scattered around the one to one line. So why are you saying it's conservative?

MR. TSAO: Well, for example, you can see -- let's see.

You can see just for example, this point here the measurement is about 300 mils. The predict value, let's say, from here to here is about 240 mils. So what it says is that the methodology will predict that the tube wall thinner than measured, therefore it also indicated that the licensee may need to do some monitoring or replacement of that pipe.

DR. FORD: But equally there are points on the other side which are not, what you call it --

MR. TSAO: Well, that's true. Yes, that's correct. But as you know this is only a prediction.

Predictions, hopefully -- well, from the data point you can see they are scattered toward the conservative side. And also the FAC program according to EPRI is that it's a process. In other words, the licensees would go out, make an inspection, UT or ultrasonic measurements or the pipe thickness and then they will come back and they input that data into the computer code so that to make sure there is a certain accuracy in their predictions.

Also predict that the -- in the prediction method they include some safety factors.

DR. FORD: It seems to me as though there's a huge amount of scatter around that one-to-one line. And so the question immediately arises as to what is the impact of that in terms of could you get a through wall erosion event taking place when you had predicted it would not have done so?

MR. TSAO: It could.

DR. FORD: Did you go through that sort of "what if" argument? I mean if you look at that data base, you don't really have too much confidence in CHECWORKS.

MR. TSAO: Well, I wouldn't say they would be relying on CHECWORKS per se. The licensees, not only Waterford but other licensees, you know they include other factors. For example, other industry experience. You know if some plants have some problem with FAC water lines, then they will consider --

DR. FORD: I recognize that.

MR. TSAO: Right.

DR. FORD: But this particular EPU is putting a lot of basis on CHECWORKS to manage this problem. And if this a general observation as to how good CHECWORKS is, my confidence is a little bit shattered.

MR. TSAO: I should point out that Waterford is not unique. I did the review for license renewal, and I also asked questions. And this is type of plot that, you know, other licensee has shown me.

DR. FORD: Yes, I know.

MR. TSAO: In other words, I don't think that licensee is depending solely on what prediction is. They also, you know, include other experiences and inspections. Not only the inspections for the fact, but there are other SME code inspections they have to perform.

DR. FORD: I'll ask again. Did you go through the "what if" scenario?

MR. TSAO: I have Kris Parcziewski from my branch to elaborate on this.

DR. FORD: With that amount of uncertainty in your modeling capability and therefore your management capability, do you not feel uncomfortable?

MR. TSAO: No.

DR. FORD: No?

MR. PARCZIEWSKI: Kris Parcziewski from the Chemical Engineering Branch.

To answer your question, those points are predicted. CHECWORKS predicts but in addition there is a correction factor for each individual line which is here at the top right hand side, line correction factor which indicates that it is corrected for each individual line all the points predicted in the line are corrected by this line correction factor. And the line is defined as a portion of the system which has the same chemistry but not necessarily the same temperature. If I answer your question.

So all those points are already corrected. Ideally, if they were ideal, they would lie in the 45 degree line, the middle line. However, obviously, there is some scatter.

DR. FORD: I understand the physics --

MR. PARCZIEWSKI: Yes.

DR. FORD: -- of the erosion process. It's highly dependent on ph. High dependent on temperature. Highly dependent on corrosion potential and all of those things are interacting. So that if you're a little bit off on your definition of one of those parameters, then you're going to get a big change. So I can understand why there is a scatter there because you're not able to define your system adequately enough, and therefore that's the physical origin of your LCF. But I still feel uncomfortable about that huge scatter and how you use it in management from their point of view and in terms of regulation from your point of view.

MR. TSAO: Okay. For regulation, basically there's no regulation on FAC program.

DR. FORD: That's what worries me.

MR. TSAO: The FAC program is instituted because of the bulletin. Back in the '80s it was result of Bulletin 87-01 where Surry had a --

DR. FORD: Yes, sure.

MR. TSAO: -- a rupture. And Generic Letter 89-08 that required the licensees to institute some type of program, FAC program. And then the industry, you know, with EPRI guidance come up with this program. And so --

DR. FORD: I understand all that. I'm just looking at what the history has been since then.

And, you know, a few months ago we had fatalities in Japan because of this phenomenon, which was not managed well. And you know if this is supposed to be the state-of-the-art of prediction of management and therefore regulation, I just don't feel comfortable.

MR. TSAO: Okay. Speaking of the Japanese, again from my understanding is that Japanese did not inspect, you know, the last 20, 30 years.

DR. FORD: Correct.

MR. TSAO: Where here under FAC program the licensees will have to inspect at least they say 50 to 100 inspection points for their large bore piping and small bore piping they probably sometime inspect 100 percent. And so there's a constant inspections going on to make sure that the --

DR. FORD: I understand that.

MR. TSAO: Right.

DR. FORD: All I'm pointing out is everyone bows to CHECWORKS and says yes, yes that's the best thing that's around. And I'm just questioning it. Is it adequate?

MR. HOWE: This is Allen Howe.

And I'd just like to add in at this point that we understand the question and we will be happy to get back with you with a response on that.

We're now going to complete the NRR presentation.

MR. KALYANAM: I have one question. Before Rich Lobel goes, we have two experts, one of the FAC CHECWORKS program, the other one on the steam generator tubes. So we had some questions before the break, and I'm sure they'll be able to provide their response to that. Is that okay.

DR. FORD: Well, I've been bagging on the head about this FAC business. I understand it perfectly. The other members might enjoy having a presentation on that.

MR. KALYANAM: Okay. Either way is fine.

CHAIRMAN WALLIS: If it's something we're going to enjoy, I think we should do it.

MR. ROSEN: As many times as possible.

MR. SIEBER: That's one time.

MR. KALYANAM: I have Ken Karwoski from EMCB

MR. KARWOSKI: I guess I understand this morning there were questions from the steam generator two integrity standpoints some questions about whether or not the power uprate, what effect it would have on wear and cracking along the length of the tubes as a result of the increased flow through the steam generator. And then there may have also been a question about the adequacy of the 75 gallon per day leakage link.

In terms of the effect of the power uprate on the increased flow through the steam generator, there is a potential effect on the amount of wear that can happen at the various support locations, whether it be at the vertical straps, the diagonal bars or at the egg crate supports. There could be an effect on the wear.

In addition, Waterford has exhibited stress corrosion cracking at a number of locations along their steam generator tubes. Both of those mechanisms could be effected by the power uprate. However, the change in the conditions in terms of the flow, the temperatures and the pressures across the steam generator tubes are relatively small and well within the bounds of what exists at other plants. And it's been our experience at the other plants which have uprated power that these small changes have negligible increases in corrosion rates, negligible increases on wear rates. And by "negligible," I mean that it's well managed from one inspection to the next; that when they go in and do an inspection after a power uprate or after an interval, that they still have tube integrity. That the tubes have adequate regulatory margin --

CHAIRMAN WALLIS: This is where? On the inside of the tubes you're talking about?

MR. KARWOSKI: On the outside.

CHAIRMAN WALLIS: Are the tubes rattling and wearing.

MR. KARWOSKI: Rattling and wearing. And that happens at almost every --

CHAIRMAN WALLIS: These fluid interactions are a little hard to predict, aren't they?

MR. KARWOSKI: Actually, they're quite reliable. I mean there are some instances where some tubes, and this is usually in the life of a steam generator, where some tubes will wear quicker than others because of the placement of the anti-vibration bars or the diagonal straps in the case of Waterford.

So some tubes may wear more than others, but in general these phenomenon are very predictable. Plants leave wear scars in service, and in general they're very predictable. The wear rates tend to be very low and they're left in service for many cycles before they exceed the tech spec.

MR. ROSEN: Do they tend to decrease in rate because they kind of wear off whatever the contact point and that's it?

MR. KARWOSKI: That has been the experience, and I can't comment on the combustion engineering data, but I know that that's definitely been the experience at Westinghouse design steam generators. But the wear rates decrease with time because of the contact issue point.

MR. ROSEN: Now the question is brought up how about the effect of vibration, vibrational stresses on the kinetics of stress corrosion cracking?

MR. KARWOSKI: Once again, you know, it is possible that that would increase the rate of cracking, may even change the initiation of cracks. But it's been our experience that any change that does occur: (1) It's not readily measurable, and; (2) that it can be managed within the normal frequency of in service inspections. And certainly if there is a change, we will detect that as we review the annual reports that the plant sends in regarding their inspections. And we would expect them to take corrective action, and that would be something we would followed up. But in general we have not observed that. And in the case of Waterford, it's been their practice that when they find a crack, they plug that crack on detection. It's not like some of the other plants which leave cracks in service and try to manage cracks that --

MR. ROSEN: My questions on those two issues.

MR. SIEBER: The displacements are extremely small and the number of cycles is extremely large. So if there is going to be failure, it would show up fairly early, I would expect.

MR. KARWOSKI: That would be for like the cycle type of fatigue failure.

MR. SIEBER: Right.

MR. KARWOSKI: In this case it's more just the wearing of the tube, which it can be low cycle--

MR. SIEBER: But that's not fatigue failure.

MR. KARWOSKI: No, that is not fatigue. Yes, that's correct.

MR. SIEBER: Right. It's just wearing out.

MR. KARWOSKI: That's just wear.

DR. FORD: Jack, there's a problem discussed earlier on. It's not trangranular fatigue, cracking you see.

MR. SIEBER: Right.

DR. FORD: And therefore it's not covered by the ASME 3 code or anything like that. Similarly it's just stress code in cracking that's been accelerated.

MR. SIEBER: But wear phenomenon is covered by the ASME code.

DR. FORD: Yes.

MR. KARWOSKI: Through the plugging limits and what not and through the plant technical specifications.

DR. FORD: Right.

CHECWORKS?

MR. KARWOSKI: I think Louise Lund was going to talk about CHECWORKS.

DR. FORD: Maybe if I could just state what my problem was, Louise, and that would make it more efficient for you to answer it.

MS. LUND: Should I introduce myself first for the record?

DR. FORD: Yes.

MS. LUND: I'm Louise Lund. I'm the Section Chief for the Steam Generator and Integrity and Chemical Engineering Section, NRR. And, anyway, I was asked to come over and discuss the FAC program.

DR. FORD: My concern was that the way that they're using CHECWORKS right now, it is primarily a prioritization tool as to where you're going to look in the carbon steel piping. From the measures that were shown this morning, it's apparent that CHECWORKS is not good on one-to-one correlation. Therefore, it's quite possible that you may use CHECWORKS to say that I should not look at that pipe because of the particular operating conditions of that pipe, but I should look at this pipe. But in fact that pipe there might well be eroding at quite a large rate, but you wouldn't look at it for one, two, three cycles. In that time you could go through wall. So that was essentially my worry that you're using a model which is not precise to make prioritization decisions.

MS. LUND: Right. And I just want to say off the top, you know we have a very active interest in the FAC programs. Specifically we've had generic letters or generic correspondence that has asked industry to put together these type of programs which manage FACs and also have these predictive methodologies. However, it's not a case of just using the predictive methodologies blindly and looking at information on one line or another; there's a number of things that inform the decision as far as what's inspected and how it's inspected. Because it is a tool, but it's not a blind tool in that particular way. And, in fact, this gentleman I believe is from Waterford and he was mentioning, we had a kind of offline discussion about it and that's why I asked him to come up here and help discuss this, and specifically for Waterford.

I also wanted to say that for these FAC programs, I think that we have an interest in looking at them through power uprate and license renewal in that we ask that the licensee provide information on their most susceptible lines with their measures versus their predicted and whether it gave them information such that they could replace the lines, you know, in a timely manner. Because that's really what we want to know is, is it giving you the information at the time that you need it in order to make the decisions you need to make good decisions about running your plant.

So that's the kind of questions we ask. We do not do a re-review of their CHECWORKS data. We do not take all their raw data and subsequently do an audit of it. Okay. So I just wanted to kind of clarify what it is that we do, you know, in our review process. Usually through a request for additional information we usually will ask them for the most susceptible lines.

MR. ROSEN: We call that a performance-based regime?

MS. LUND: Right. Right. And when we put out that generic letter where we asked the licensees to put together a FAC program and also have these predictive methodologies, we did inspections of those programs at that time. Okay. In fact, to make sure that these programs were in place and in fact doing what we thought that they were doing. Okay.

Now, I now in license renewal, true license renewal we've been asked to come and give a presentation to the ACRS on FAC and FAC programs. And we've actually been in contact with CHECWORKS user script to ask them to come in and help present this information such that you can look industry-wide at how well these FAC programs are working, specifically with the CHECWORKS program and give you a lot of sense -- instead of looking at just one graph, kind of get a sense for generically how this is working and where it may be challenged in certain ways or another, because they think that they have a very good story to tell.

Now maybe if you could introduce yourself, and then also explain how programmatically it's a much lighter look at how you choose the lines and -- because there's a surrogate aspect to it where, you know, if you see something you look at other things that are like that. There are a lot of things that go into the program that don't rely on just this measurement.

So, anyway --

MR. ALEKSICK: Good afternoon. My name is Rob Aleksick. I'm with CSI Technologies representing Entergy today.

Real quick about my background. I've had the opportunity to be involved with flow accelerated corrosion since 1989 and in particular have modeled or otherwise addressed approximately 20 EPU efforts in the last two years.

Dr. Ford made a very good point earlier when he said that the graph that we looked at did not display a very good correlation between the measured results and the predicted results out of CHECWORKS. Programmatically -- well, let me back up a second. That is certainly true in the example that we looked at. That is not always the case.

CHECWORKS models are on a per line or per run basis. The run --

CHAIRMAN WALLIS: Could we go back to that graph that we saw? The graph was a plot of thickness versus predicted thickness.

MR. ALEKSICK: That's correct.

CHAIRMAN WALLIS: Because if you looked at amount removed versus predicted amount removed, it seems to me the comparison will be even worse.

MR. ALEKSICK: That's correct. In fact --

CHAIRMAN WALLIS: That's what you're really trying to predict is how much is removed.

MR. ALEKSICK: Yes, that is true. And my point is that in some subsets of the model, the one that we looked at here which was high pressure extraction steam, the correlation between measured and predicted is not so good. And in some subsets of the model, the correlation is much better.

CHAIRMAN WALLIS: It looks to me that in some cases it's predicting no removal whereas in fact there's a lot of removal. So the error is percentage wise enormous?

MR. ALEKSICK: Yes, exactly. Exactly. Some runs results are imprecise and some more precise. And we look at both accuracy and precision. Programmatically we account for that, that reality, by treating those runs that have what we call well calibrated results, i.e., precise and accurate results coming out of the model that are substantiated by observations, we treat those piping segments differently programmatically than we do areas where the model is less good. If the model results do not correlate well with reality, different actions are taken primarily increased inspection coverage to increase our level of confidence that those systems can continue to operate safely.

In addition to the CHECWORKS results many other factors are considered to assure that the piping retains its integrity, chief among these are industry experience as exchanged through the EPRI sponsored CHUG group. Plant experience local to Waterford in this case. And the FAC program owner maintains an awareness of the operational status of the plant so that, for example, modifications or operational changes that occur are taken into account in the inspection of the secondary site FAC susceptible piping.

DR. FORD: And my final question on this particular subject was given the uncertainties in the model, changed by this performance based aspect that you just talked about, is there any way that you can come up with a quantification of the risk associated with a failure of a specific pipe?

MR. ALEKSICK: There's currently no accepted methodology to quantify that risk, no. However, it is accounted for primarily on a judgment basis through industry experience and information exchange through the EPRI CHUG group.

DR. FORD: Okay.

MR. MITCHELL: Yes, this is Tim Mitchell.

Just to give you a feel for how we're addressing for this upcoming refueling outage, we have increased our scope for a couple of reasons. One to get additional data and we always do more than just exactly what CHECWORKS supports. So you're always out validating and getting more data to be able to help predict where do you need to be looking. But in addition, we're taking some additional points to make sure we have good baseline data for the next cycle to ensure that those points give us a good indication going forward after the EPU.

The analysis for flow accelerated corrosion shows very minimal changes as a result of power uprate. But we are taking seriously our inspection program and expanding it for this upcoming outage to ensure that we know what's happening not just what we're predicting.

MR. ROSEN: Let me roll that back now,

Tim. Can you tell me like for the last three or four outages have you done some actual replacement of piping based on predictions of FAC from the CHECWORKS code or have you never replaced anything? What are you seeing at Waterford?

MR. MITCHELL: I can give you non-Waterford data better than I can give Waterford to ponder.

MR. CHOWDHURY: My name is Prasanta Chowdhury and I'm working with Entergy design for last 20 years.

I was involved with FAC also for several years in the past.

It's not the CHECWORKS model that determines what replacement is to be done. We base it on actual measurement we take during the refuel outage. So we also project based on actual measurement that what will be our future projected thickness in next refueling outage. So you can survive until next cycle. And then we do some evaluation based on our criteria that makes the stress criteria -- or based on the code requirement. Like make all the equation.

Now code allows to go thinning in local area but the FAC is a local thinning. So we do some local thinning evaluation to make sure that it goes to

NEC-JH_40

A New Approach for Investigation of Erosion-Corrosion Using Local Flow Models

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ABSTRACT

rosion-corrosion (EC) is a piping degradation mechanism causes material loss from the inside of piping and thin- g of the wall. EC is believed to be a coupled phenomenon including chemical corrosion and mechanical erosion, which dominated by piping layout, fitting geometry, and local w structure. A new approach was proposed for investiga- ion of EC phenomenon using local flow models, including the multidimensional, two-fluid model to simulate flow character- tics within piping and EC models to predict two- mensional distributions of EC locations. Impacts of gravita- ional and centrifugal forces on two-phase flow behaviors were captured reasonably well by the current three-dimen- onal, two-fluid models. EC locations predicted by the oposed models showed satisfactory agreement with distri- utions of wear sites measured in practice. Results showed e models explained the EC phenomenon reasonably well.

Y WORDS: elbows, erosion-corrosion, ferrous ions, flow, ydrodynamics, impingement, mechanical erosion, modeling, uclear applications and environments, pipelines, reducers, ar

NTRODUCTION

osion-corrosion (EC) is a piping wear mechanism at causes material loss from the inside of pipes and ubsequent wall thinning. It is a crucial problem in piping systems for nuclear or fossil fuel power plants since it may force costly repairs and cause injuries. Essentially, this wear is dominated by two major mechanisms: chemical corrosion, including chemical oxidation near the wall and dissolution of its products, and mechanical erosion accelerated by fluid flowing inside the pipe or high-velocity liquid droplets impinging on the oxidized pipe wall. The EC phenomenon depends strongly upon piping layout, fitting geometry, local distributions of flow properties, and flow chemistry.

Previous research into the EC phenomenon has concentrated mostly on prediction of the wear rate. These efforts have included development of the CHEC† code,[1] CEACE† code,[2] KWU (Kraftwerkstechnik) correlation,[3] EdF (Electricité de France) model,[4] MIT (Massachusetts Institute of Technology) model,[5] and the hydrodynamic EC model.[6-11] Except for the hydraulic model,[6-11] these models evaluate the global wear rate of piping and can be considered as zero-dimensional models. The models presented by Nesic and Postlethwaite, et al., are localized models that essentially are derived from local flow structure and can be used to calculate the one-dimensional distribution of the wear rate.[11-12]

During the outage of the Maanshan nuclear power plant (MNPP) in Taiwan, wall thickness data as measured by an ultrasonic transmitter (UT) showed distributions of EC locations on the pipe wall displayed a two-dimensional behavior. The data were influenced strongly by upstream fittings and external forces, including centrifugal and gravitational forces. Previous models cannot capture these multidimen-

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sional characteristics and simulate the dependence of piping layout.

The present work focused on qualitatively investigating the multidimensional characteristic of EC phenomenon using local flow models to predict the multidimensional distributions of wear sites. The three-dimensional hydrodynamic model then was used to calculate the single- or two-phase flow structures, and EC models were used to predict the distributions of EC locations. The piping selected in the current simulation was located in the extraction and exhaust systems of high-pressure turbines (HPTB) within MNPP since most of the serious EC at the plant occurs there, based upon plant-measured wall thickness data. The current hydrodynamic model reasonably simulated flow characteristics governed by piping layout, centrifugal force, and gravitational force. Predicted distributions of EC locations by the current EC models coupling with local flow structures corresponded well with the plant-measured data. This agreement revealed that the proposed local flow models, including the hydrodynamic and EC models, could be used to explain EC occurring at fittings within MNPP.

LOCAL FLOW MODELS

The multidimensional flow structure within the piping was obtained using current hydrodynamic models. The major phenomenon for EC wear could be explained by the presented EC models, coupled with local flow characteristics. The EC models included the production of oxides for corrosion and oxide removal, as well as liquid droplet impingement for erosion.

Hydrodynamic Models

The hydrodynamic models studied consisted of one continuity equation, one momentum equation, one two-equation turbulent model (turbulent kinetic energy [k] – the energy dissipation rate [ε]),[12] constitutive models for interphase exchange phenomena, and appropriate numerical scheme and boundary conditions.

In these models, the following assumptions are made in deriving the governing equations, constitutive equations, and appropriate boundary conditions:

— No heat transfer or mass transfer between liquid and vapor phases is considered;

— Pressure is the same for both phases;

— The diameter of the liquid droplet is constant and set at 1.0 mm;

— The particle form of the interphase drag force is selected for the liquid droplet flow;

— The standard k – ε turbulent model for single-phase flow is adopted. The effect of bubble-induced turbulence is taken into account in the turbulent model of two-phase flow;

— The pipe length at the outlet side is long enough that fully developed flow can be assumed; and

— Since the steam quality in the simulated pipe systems is ~ 88% to 92%, the two-phase flow can be considered droplet flow.

The continuity governing equation is derived as:

$$\nabla \cdot \left(\alpha_i \rho_i \vec{u}_i\right) = 0 \qquad (1$$

where u is velocity, α is the volumetric fraction of each phase, and i = c for continuous vapor and d for dispersed liquid droplet.

The momentum equation is derived as:

$$\nabla \cdot \left(\rho_i \alpha_i \vec{u}_i \vec{u}_i\right) = -\alpha_i \nabla P + \nabla \cdot \left[\alpha_i \left(\mu_{Li} + \mu_{ti}\right) \nabla \vec{u}_i\right] + \vec{S}_{u,i} \qquad (2$$

where $\mu_{L,i}$ is the molecular viscosity, $\mu_{t,i}$ is the turbulent viscosity, $\vec{S}_{u,i}$ is the source term due to gravitational force and interphase drag, P is pressure, and ρ is density.

Turbulent Model — In the current model, the turbulent model for two-phase droplet flow essentially adopts the well-known k – ε two-equation model of the single phase. The turbulent shear stress for the continuous phase can be expressed by the Boussinesq concept:[13]

$$-\rho\, \overline{u'v'} = \mu_t \frac{\partial u}{\partial n} \qquad (3)$$

where u′ and v′ are velocity fluctuations, and n is the distance normal to the wall. Similarly, the turbulent viscosity (μ_t) can be evaluated by the traditional k – ε model:

$$\mu_t = c_\mu \frac{k^2}{\varepsilon} \qquad (4)$$

where c_μ is the turbulent model constant. Both parameters k and ε can be obtained by solving the transport equations:

$$\nabla \cdot \left(\rho\alpha\vec{u}\phi\right) = \nabla\left[\rho\alpha\left(\mu_l = \frac{\mu_t}{\sigma_\varphi}\nabla t\right)\right] + \rho\alpha\left(P_\phi - \varepsilon\right) + S_{p,\phi} \qquad (5)$$

where φ = k, the turbulent kinetic energy = ε, the turbulent energy dissipation rate. P_ϕ, the turbulent generation term, has the same expression as the standard k – ε two-equation model.

Additional source $S_{p,\phi}$ is used to take into account the enhanced effect on turbulence of the continuous phase caused by droplet agitation. Based upon the modified formula of Mostafa and Mongia. ...s source can be described as:[14]

$$S_{p,k} = \frac{2\rho_d \alpha_c \alpha_d k}{\tau_p}\left(1 - \frac{\tau_c}{\tau_c + \tau_p}\right) \tag{6}$$

$$S_{p,\varepsilon} = \frac{-2C_{\varepsilon 3}\rho_d \alpha_c \alpha_d \varepsilon}{\tau_p}\left(1 - \frac{\tau_e}{\tau_c + \tau_p}\right) \tag{7}$$

where $C_{\varepsilon 3}$ is the turbulent model constant, and τ_e is the time scale characterizing large-scale turbulent motion:

$$\tau_e = 0.34\frac{k}{\varepsilon} \tag{8}$$

where τ_p is the time scale characterizing the droplet response:

$$\tau_p = \frac{4}{3}\frac{D_b}{C_d}\frac{\rho_d}{\rho_c}\frac{1}{\left|\bar{u}_c - \bar{u}_d\right|} \tag{9}$$

where D_b is the droplet diameter, and C_d is the drag coefficient and has the following correlations as proposed by Clift, et al.:[15]

$$C_d = \begin{cases} 24.0\dfrac{\left(1.0 + 0.15\,Re^{0.687}\right)}{Re} + \dfrac{0.42}{\left(1.0 + 4.25\times 10^4\,Re^{-1.16}\right)} & Re \le 3.38\times 10^5 \\ 29.78 - 5.3\log_{10}(Re) & 3.38\times 10^5 < R \le 4\times 10^5 \\ 0.1\log_{10}(Re) - 0.49 & 4\times 10^5 < Re \le 10^6 \\ 0.19 - \dfrac{8\times 10^4}{Re} & Re > 10^6 \end{cases} \tag{10}$$

Constitutive Equations — The constitutive equations that account for interactions between the two phases include:

Void fraction:

$$\alpha_c + \alpha_d = 1 \tag{11}$$

Momentum exchange between the two phases:

$$\bar{F}_d = -\bar{F}_c \tag{12}$$

$$\bar{F}_c = f_{int}\left(\bar{u}_c - \bar{u}_d\right) \tag{13}$$

where F_d and F_c are the interphase drag forces for both the dispersoid and continuous phases, and f_{int} is the interphase friction factor between the vapor and liquid phases. The total drag force per unit volume can be evaluated as the sum of the drag forces on each individual spherical droplet contained in that volume. Then, f_{int} can be expressed as:

$$f_{int} = \frac{3}{4}\frac{\rho_c \alpha_c C_d}{D_b}\left|\bar{u}_c - \bar{u}_d\right| \tag{14}$$

Numerical Scheme — Three-dimensional, two-fluid equations are used to calculate the flow characteristics in the piping to simulate the EC phenomenon through the use of calculated local flow distributions. Since the geometry of the simulated pipe is not that of a simple rectangular or cylindrical system, a body-fitted coordinate (BFC) method is adopted to deal with this multidimensional geometry.[16] The differential equations are discretized using a control volume approach in a finite-difference form. The details of the control volume approach for the finite-difference method have been described previously.[17] The hybrid scheme is used to treat the convection terms coupled with the diffusion terms. The coupled equations for the velocity and pressure are solved by the interphase slip algorithm (IPSA),[18] which is a two-phase extension of the well-known SIMPLE (semi-implicit method for pressure-linked equations) scheme for single-phase flow.[19] The optimum false time (Δt_{false}) is used throughout the steady-state calculation and can be given by the Courant criterion as:

$$\Delta t_{false} = \frac{\Delta X}{U} = 1 \tag{15}$$

where ΔX is a characteristic length in the computation domain, and U is a characteristic velocity.

The procedure in solving this three-dimensional, two-phase model is:

— *Step 1:* Set the boundary conditions on the solution domain based upon the plant data,

— *Step 2:* Solve the momentum equations for the velocities of both phases,

— *Step 3:* Solve the pressure correction equation based on the joint continuity equation to eliminate the mass conservation error,

— *Step 4:* Correct the velocities and update the pressure,

— *Step 5:* Solve the continuity equations for the volume fractions,

— *Step 6:* Solve the $k - \varepsilon$ equations to obtain the turbulent characteristics and update turbulent viscosity, and

— *Step 7:* Repeat Steps 2 through 6 until the convergent criteria are satisfied.

Several computational flow codes can be applied to solve this problem, including TEACH,[†,20] PHOENICS,[†,21] and FLOW3D,[†,22] etc. The PHOENICS code was selected in the current calculation work. Most of the calculation works were performed on an HP-750[†] workstation.

Boundary Conditions — Inlet boundary conditions are set based upon the plant conditions, which include the velocities and volume fractions of both phases. A very long pipe is added to the outlet of the physical domain so that fully developed conditions can be reached at the outlet of the calculational domain. Then, no special outlet boundary conditions are specified, except for a fixed system pressure. Since the turbulent flow behaviors change abruptly near the wall, the wall function method is adopted for the velocity and turbulent distributions to avoid the need for finer grids near the wall.[23]

EC Models

The EC models in the current study essentially are divided into two major parts: the chemical corrosion model and the mechanical erosion model.

Basic EC Model — The basic EC model of carbon steel in a fully developed pipe flow can be divided into two parts:[4]

The first is the dissolution rate (R_p) of magnetite on the metal surface:

$$R_p = 2k_R\left(C_{eq} - C_w\right) \tag{16}$$

where k_R is the reaction-rate constant, C_{eq} is the soluble ferrous ion (Fe^{2+}) concentration at equilibrium with the magnetite, and C_w is the soluble Fe^{2+} concentration at the oxide water interface.

The second is the mass-transfer rate of Fe^{2+}, which can be modeled as:

$$R_c = \kappa_m\left(C - C_\infty\right) \tag{17}$$

where κ_m is the mass-transfer coefficient and C_∞ is the soluble Fe^{2+} concentration at the bulk water.

For steady-state, fully developed pipe flow, R_p should be equal to the mass-transfer rate of Fe^{2+} (R_c). Then, the total metal loss rate can be expressed as:

$$R = \frac{C_{eq} - C_\infty}{\dfrac{1}{2k_R} + \dfrac{1}{\kappa_m}} \tag{18}$$

Local EC Model — Local corrosion reactions include the electrochemical reaction, the precipitation reaction, and the chemical oxidation. The total reactions reasonably can be assumed to be completed at the pipe wall, while none of the iron ions produced in the electrochemical reaction are transported across the boundary layer prior to the subsequent chemical oxidation. The local EC rate then can be assumed to be dominated by the local oxide production rate and its transfer rate. According to experimental observation, the local corrosion production rate is proportional to the difference in the soluble Fe^{2+} concentration between the wall and the oxide.[4] In other words, the steeper the near-wall radial profile of concentration is, the higher the wear rate is. The concentration of soluble Fe^{2+} at the equilibrium with the magnetite depends upon the temperature of the solution and the concentration of the chemical agent. Lower local near-wall fluid velocity will cause lower concentrations of the chemical agent, such as pH value or dissolved oxygen, enhance the local corrosion production rate, increase the gradient of soluble Fe^{2+} concentration, and consequently promote metal loss of the pipe wall. Therefore, lower near-wall fluid velocity is a good indicator to express the possible distributions of EC locations.

In addition, the local mass-transfer rate of Fe^{2+} also may influence the corrosion rate. This transfer rate generally is governed by the mass transfer of Fe^{2+} near the pipe wall.[4,6-7] As described above, κ_m can be expressed in an analogy to the Dittus Boelter's equation:

$$\kappa_m \propto \frac{Sh X D_{diff}}{d} \tag{19}$$

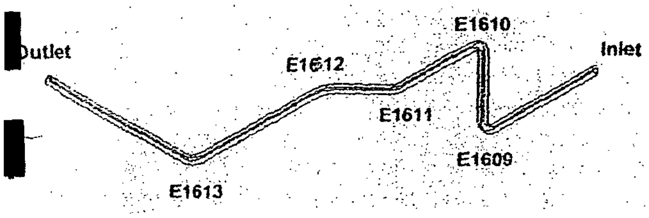
where $Sh = a_1 Re^{a_2} Sc^{a_3}$, and:

$$Re = \frac{\rho U d}{\mu} \tag{20}$$

$$Sc = \frac{D_{diff}}{\mu} \tag{21}$$

and where d is the pipe diameter; D_{diff} is the diffusivity of soluble ion; μ is the viscosity; U is the characteristic velocity; ρ is the fluid density; and a_1, a_2, and a_3 are constants.

The local EC rate is governed by this mass-controlled phenomenon,[6-7,11] which is proportional to its coefficient (Equation [17]). According to this equation, higher local velocity results in higher mass-transfer coefficients (κ_m), subsequently causing higher wear rates. In other words, high local velocity of flowing flow is an effective mechanism to remove Fe^{2+} near the pipe wall, which may enhance EC.



GURE 1. *Schematic of pipe layout.*

hen, the higher near-wall velocity may be a param-er to indicate possible wear sites.

The major task of the current work was to inves-gate the EC phenomenon by finding the possible stributions of wear sites using local flow models. hen, the qualitative indicators to express the wear atterns but not quantitative calculations to evaluate e wear rate, were adopted. In addition, the model ing the indicator of lower velocity to simulate EC verned by Fe^{2+} production is called the production odel, and the model using the parameter of higher ocity to describe the EC dominated by the Fe^{2+} nsfer rate is called the transfer model.

Droplet Impingement Model — The simulated tem in this work is a wet steam system with flow lity of 85% to 92%. This high-quality flow system n be considered as a droplet flow system in which size of the liquid droplet is sufficiently small, and droplet can be carried by the high-velocity steam. iuid droplet with enough high kinetic energy impinge the oxide layer of the metal and erode it the pipe wall surface, enhancing EC. This kind amage on the oxide layer is known as droplet ingement or liquid impact erosion that also domi-es EC wear.

Many parameters affect the complicated droplet ngement. A model simply describes the phenom-n as one where the oxide layer caused by sion is removed by the action of numerous indi-l impacts of liquid droplets.[4] Its form can be essed as:

$$m = C_s N F_\theta(\theta) \frac{\rho_f U_f^2}{HV} \qquad (22)$$

m is the wear rate. C_s is a system constant nated by fabrication and installation of piping. representation of frequency. F_θ is a character-nction. θ is the angle of impact, ρ_f is the liquid y. U_f is the normal velocity, and HV is the ess of the pipe wall. Equation (22) shows that tal loss from droplet impact is proportional to centration of liquid droplet and its normal ty. Then, the erosion rate reasonably can be ed to be associated with the erodent kinetic nat can be expressed simply as $\alpha_f U_f|U_f|$, which is a good parameter to indicate wear sites. In this form, α_f is the volume fraction of the liquid droplet, and U_f is its corresponding velocity in the normal direction toward the wall.

RESULTS AND DISCUSSION

A new approach is proposed to simulate the EC phenomenon through local flow models. This approach includes the multidimensional, two-fluid models and the EC models. The simulated pipes are located at the extraction and exhaust systems of HPTB within MNPP. In these systems, the quality of two-phase flow is ~ 88% to 92%, implying that the two-phase flow characteristic can be considered as droplet flow. The models including the droplet form of two-fluid equations and the erosion model due to droplet impingement can be applied in these systems.

HPTB Exhaust System

The simulated pipe in this system is a steam line of 14 in. (0.36 m) connecting HPTB and Feedwater Heater (FWHR) No. 2. This pipe is shown schematically in Figure 1 and consisted of two vertical elbows of 90° (Elbows E1609 and E1610), one horizontal elbow of 90° (Elbow E1613), and two horizontal elbows of 45° (Elbows E1611 and E1612). The flow properties within this pipe are that the system pressure is 199.7 psia (1.38 MPa), temperature is 382°F (467.6 K), quality is 88.6%, and mass flow rate is 263,152 lb/h (33.16 kg/s).

Figure 2 displays the liquid fraction distributions near the wall within this pipe, while the right part shows the liquid fraction distributed in Elbows E1609 and E1610. The left part shows the liquid fraction distributed in Elbows E1611 to E1613. Since three-dimensional results cannot be shown appropriately in a two-dimensional plane, only the liquid fraction distributions near the inner and outer sides of the elbow are shown. The scale on the right side of the figure represents the liquid fraction. As the two-phase mixture horizontally flows through Elbow E1609 and then turns to flow upward along the vertical pipe, the centrifugal force will push the heavier liquid droplet to the outer side of the elbow, causing more liquid to be accumulated there. The phenomenon that centrifugal force governs the liquid droplet behavior is shown clearly in the right portion of Figure 2. The yellow region located at the outer side of Elbow E1609 represents higher liquid fraction, and the blue region representing lower liquid fraction is shown at the inner side of the elbow. As the droplet flow passes upward through Elbow E1610 and turns to the horizontal direction, the centrifugal effect also demonstrates in the plot of liquid fraction distribution. The direction of centrifugal force points upward and is opposite to that of the gravitational force

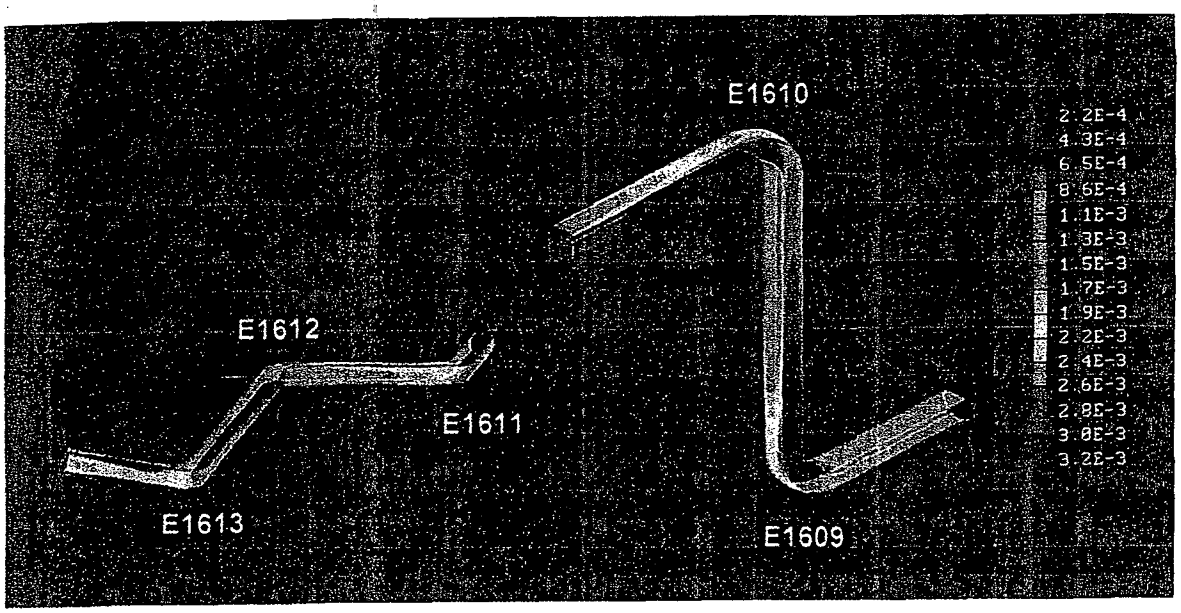


FIGURE 2. *Near-wall distribution of liquid fraction.*

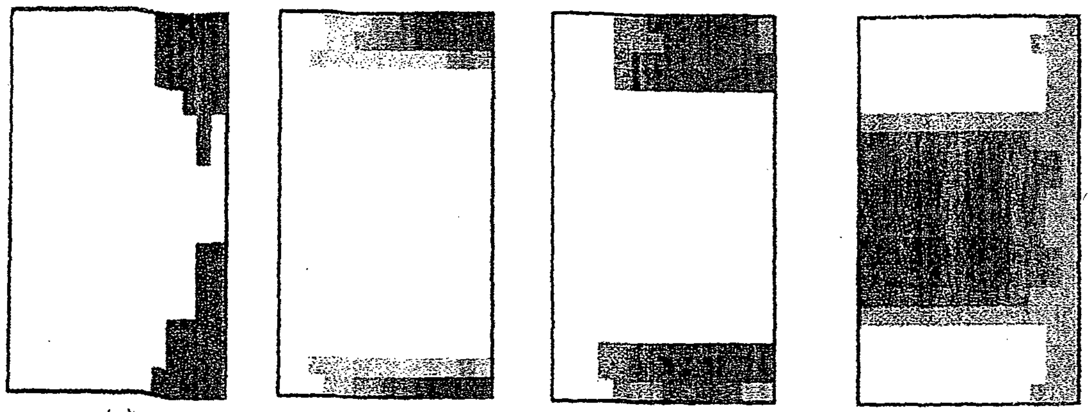
pointing downward. The yellow-red region appears at the outer and upper side of Elbow E1610, indicating more liquid droplets accumulated there. This phenomenon demonstrates that the centrifugal force overcomes the gravitational force within the vertical elbow and then dominates the behavior of liquid droplet existing in the two-phase mixture.

The liquid droplet gradually will fall down because of the downward gravitational force as the fluid continues to flow along the horizontal pipe. This result can be confirmed at the right portion of the liquid fraction plot in which the upper region gradually changes from yellow to green and, in contrast, the lower part changes from deep blue to blue. Since the pipe connecting Elbows E1611 to E1613 belongs to a horizontal pipe, the liquid fraction located at the left and right sides of the elbow is shown in the left part of Figure 2. The centrifugal force again governs the distribution of liquid phase so that the yellow region is shown at the outer sides of Elbows E1611 through and E1613, respectively.

After the three-dimensional two-phase characteristics have been obtained, it was crucial to find the distributions of wear sites from these calculated local flow parameters. Figures 3 and 4 show the comparison of EC locations between the plant measured data and the predicted results for Elbows E1610 and E1613, respectively, since only these elbows within the piping are measured by the plant staff. These plant measured data are the severe wear sites, which are derived from the raw data of pipe wall thickness by the smoothing method), as suggested by the Electric Power Research Institute (EPRI).[1] Wall thickness is measured by the UT during the plant outage period. These figures are the two-dimensional plots for the distributions of EC locations, which are plotted by cutting the elbows from the outer side. Then, the lower and upper parts of these two-dimensional plots represent the outer side of the elbow, and the central part indicates the inner side of the elbow. In the plots, the blacker the color is, the more severe the EC damage is. Plot (a) in Figures 3 and 4 is the distributions of EC locations measured by the plant staff, while Plot (b) is the distributions predicted by the liquid droplet impingement model. Plot (c) is the distribution predicted by the Fe^{2+} production model, and Plot (d) is predicted by its transfer model.

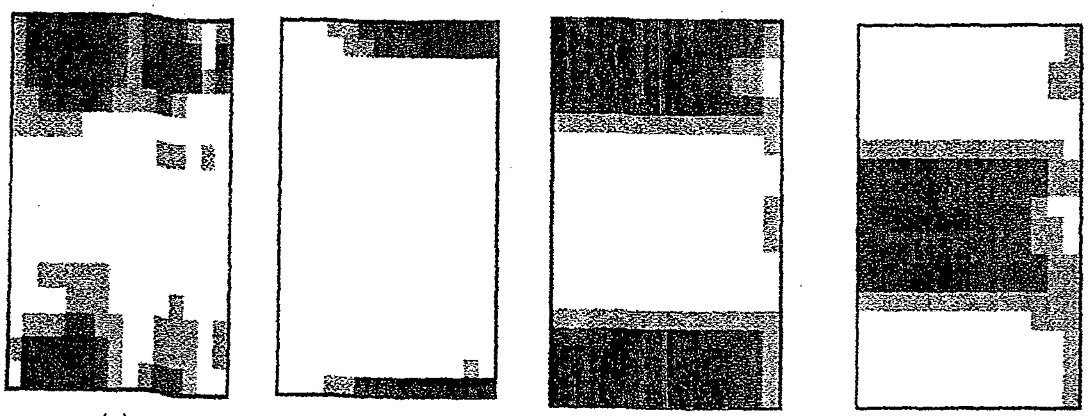
Since Elbow E1610 is located at the same plane with the upstream elbow and inlet, the flow behavior may display symmetry characteristics, which induces the symmetry pattern of EC wear. This phenomenon is shown in the measured data as well as the predicted results (Figure 3). In Plot (a) of Figure 3, the blacker regions are located at the upper-right and lower-right corners of the two-dimensional plots. The measured wear pattern of Elbow E1610 reveals that the serious EC is distributed on the outer and downstream location of the elbow. The calculated results of Plots (b) and (c) correspond with the measured wear locations, and Plot (d) predicted results cannot match the measurement. These comparisons clearly show that EC occurring at Elbow E1610 essentially is dominated by the liquid droplet impingement and the Fe^{2+} production effect based on the current EC models. A similar result is displayed in the EC phenomenon occurring at Elbow E1613 (Figure 4). The measured data shows the wear sites mostly are

[1] Electric Power Research Institute, 3412 Hillview Ave., Palo Alto, CA 94304-1395.



(a) (b) (c) (d)

FIGURE 3. *Comparison of wear sites for Elbow E1610.*



(a) (b) (c) (d)

FIGURE 4. *Comparison of wear sites for Elbow E1613.*

ocated at the outer side of the elbow (i.e., the black gions near the upper and lower sides of EC location ot), which is captured qualitatively by the droplet npingement and oxide generation models. The corsion model dominated by Fe^{2+} transfer predicts the rious EC distributed around the central portion of ie two-dimensional plot (i.e., the inner side of Elbow 1613), which does not agree with the measured ta. The EC phenomenon occurring at the horizon- elbow (Elbow E1613) can be explained to be ıused by the droplet impingement and Fe^{2+} producn effect, based upon the qualitative agreement in two-dimensional wear pattern between the model ediction and plant measurement.

PTB Extraction System

The HPTB extraction system is a steam system nnecting the HPTB and FWHR 1, in which the flow perties are that the system pressure is 413.7 psia 5 MPa), temperature is 447.9°F (504.2 K), ality is 92%, and mass flow rate is 382,331 lb/h kg/s). The simulated pipe located in this system includes two horizontal elbows of 16 in. (0.41 m, Elbows E1829 and E1830), one horizontal reducer of 16 in. to 14 in. (0.41 m to 0.36 m), and four vertical elbows of 14 in. (Elbows E1840, E1841, E1843, and E1844). Figure 5 shows the schematic of this pipe.

Figure 6 demonstrates the near wall distributions of liquid fraction along this pipe, while the left part shows the distributions for Elbows E1829, E1830, R1832, E1840, and E1841, and the right part shows the distributions for Elbows E1843 and E1844. As the two-phase mixture passes through these elbows, the centrifugal force governs the liquid droplet behavior and pushes the droplet to the outer side of the elbow, causing a higher liquid fraction (yellow-red region in the plots) to appear there. Special attention is focused on the liquid fraction distribution at vertical Elbow E1841. The downward gravitational force is opposite to the upward centrifugal force within this elbow. The left part of Figure 6 shows more liquid accumulated at the outer side (upper side) of Elbow E1841, which reveals that cen-

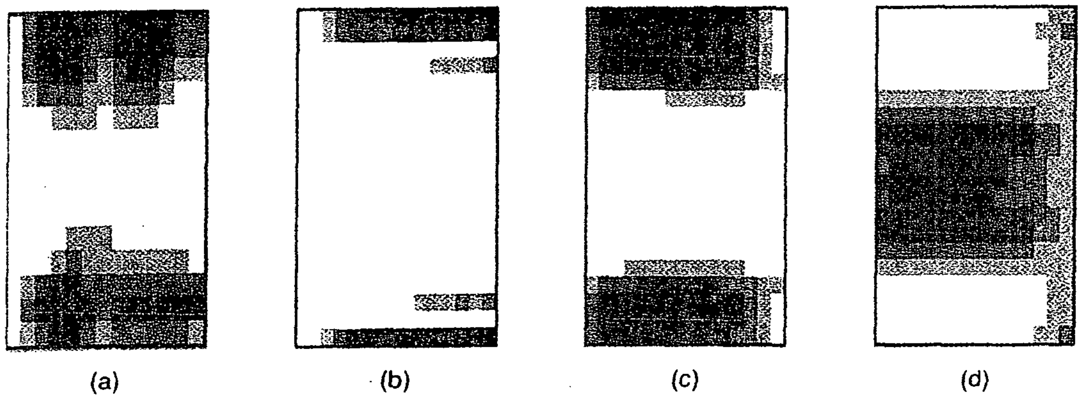


FIGURE 8. *Comparison of wear sites for Elbow E1841.*

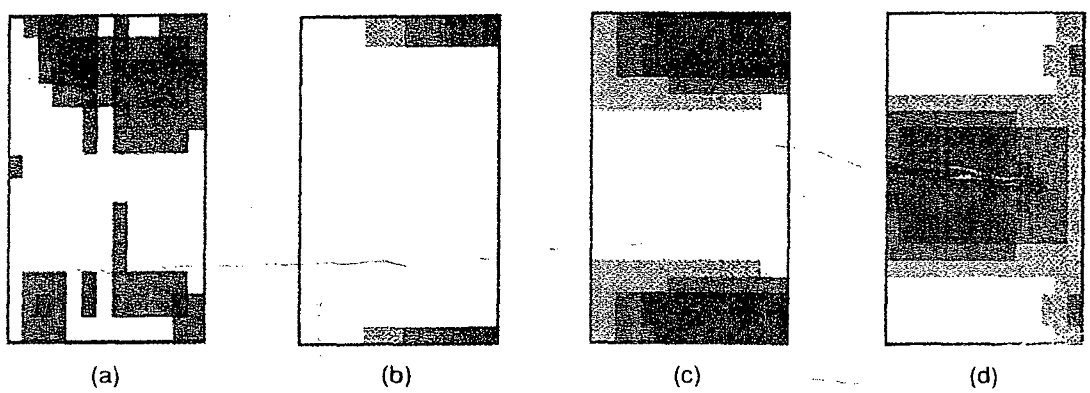


FIGURE 9. *Comparison of wear sites for Elbow E1843.*

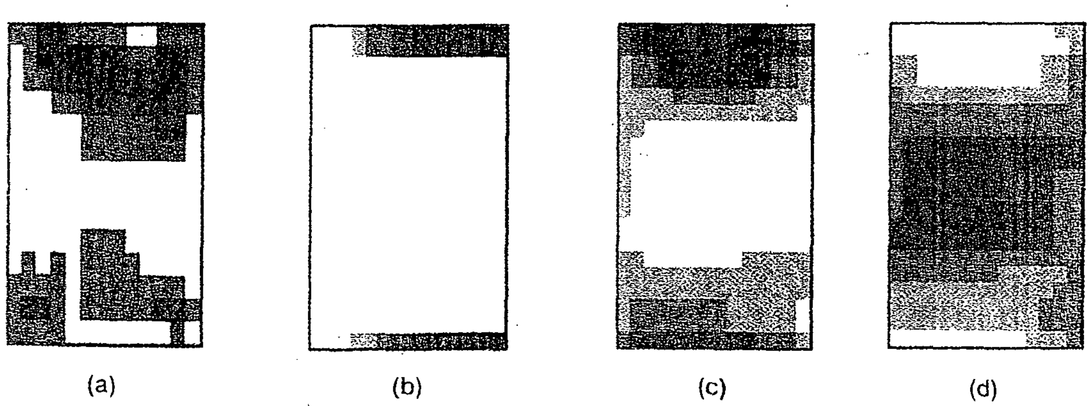
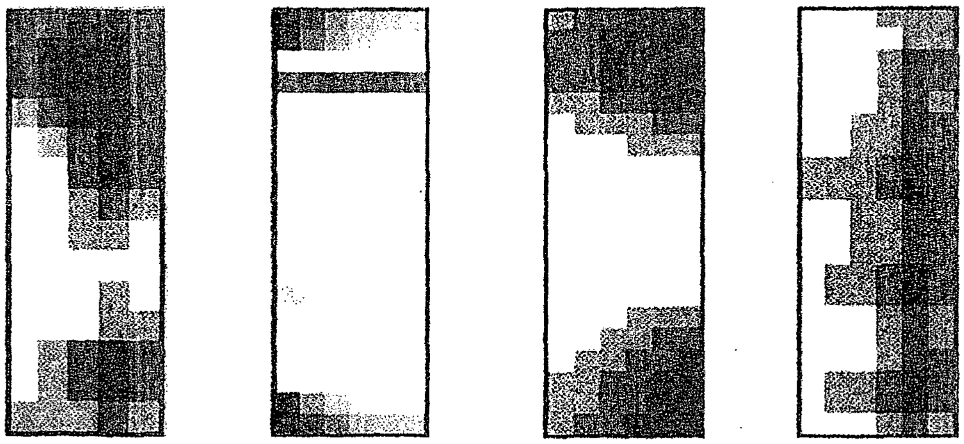


FIGURE 10. *Comparison of wear sites for Elbow E1844.*

predicted by the effects of Fe^{2+} production and droplet impingement show satisfactory agreements. These similar wear patterns reveal that these two effects dominate the EC phenomenon for the fittings within the high-quality system.

❖ Since the flow behaviors are not complicated within the elbow, reducer, or expander etc., these parameters (including Fe^{2+} production and droplet impingement) are proven to be enough to explain the EC phenomenon occurring within these fittings located in the high-quality system.

❖ The next step in the current study will be to simulate the flow characteristics and the related EC phenomenon for T-junctions, within which more sophisticated flow behaviors may occur. Then, additional EC models are needed to capture accurately



(a) (b) (c) (d)

FIGURE 7. *Comparison of wear sites for Reducer R1832.*

of the outer side in the reducer is located at the upper portion of the two-dimensional plots. In the mean time, Reducer R1832 is a horizontal reducer, and the heavier droplet will be accumulated at the bottom of the pipe because of gravitation, rendering unsymmetrical flow structure and wear pattern. This result is proven in both the measured and predicted wear patterns. This measured result can be captured reasonably by the predicted results using the EC models accounting for droplet impingement (Plot [b]) and Fe^{2+} production (Plot [c]) effects. The satisfactory agreement reveals that these two effects, not the Fe^{2+} transfer effect (Plot [d]), can explain the EC phenomenon occurring within Reducer R1832.

Among this simulated pipe, there are three sets of measured data for Elbows E1841, E1843, and E1844. These three elbows belong to vertical elbows of 90° and are located at the same plane. Similar flow structure and wear pattern within these elbows are expected. The measured distributions of EC locations in these three elbows display similar characteristics, as shown in Plot (a) of Figures 8 through 10. The same results can be simulated by the current local flow model, which includes a three-dimensional, two-fluid model and the appropriate EC models.. Comparisons shown in Figures 8 through 10 reveal that Plots (b) and (c) of the predicted wear patterns correspond with Plot (a) of the measured data. The agreement can be explained as the EC phenomena occurring within these elbows are dominated by the effects of droplet impingement and Fe^{2+} production.

Based on the aforementioned description, EC occurring in the high-quality wet steam system can be considered to include the chemical corrosion dominated by Fe^{2+} production and its transfer, and the mechanical erosion mainly contributed by liquid droplet impingement. The EC locations predicted by the Fe^{2-} production model and droplet impingement model are distributed around the upper and lower parts of the two-dimensional plots, that is, the outer side of the elbows. These distributions agree with the measured data. However, the Fe^{2+} transfer model calculates the serious wear sites that are concentrated at the central part. According to these comparisons of wear patterns, serious EC damage for high-quality wet steam system are governed mostly by the effects of Fe^{2+} production and liquid droplet impingement.

CONCLUSIONS

❖ The complicated three-dimensional, two-phase flow field is obtained by the current hydrodynamic model that treats the vapor phase as the continuous phase and the liquid phase as the dispersed phase because of its high-quality characteristics. The impacts of gravitational and centrifugal forces on the liquid droplet behaviors can be captured reasonably and are shown clearly in plots of near-wall distributions of liquid phase. These phenomena include the droplet being pushed to the outer side of the elbow as a result of centrifugal force and falling down to be accumulated at the bottom of the pipe as a result of gravitational force as the two-phase mixture passes along the horizontal pipe.

❖ The EC phenomenon is a piping degradation mechanism. It essentially consists of the chemical oxidation of carbon steel wall and the dissolution or erosion by flowing fluid. With respect to the high-quality system, the parameters of Fe^{2+} production rate, its transfer rate, and droplet impingement are considered to have profound influence on the wear patterns. Compared to the distributions of EC locations measured by the plant staff, the distributions the wear sites distributed in T-junctions. The current work focused on qualitative prediction of the distributions of EC locations. The quantitative wear rate for a fitting is another worthy topic that will be scheduled for future research.

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Chuck Serpan
Al Taboada

Our program at Argonne should be able to provide us with capability of agreeing or disagreeing with industry predictions on erosion/corrosion rates.

Bob

Portland General Electric Company

David W. Cockfield Vice President, Nuclear

July 31, 1987

Trojan Nuclear Plant
Docket 50-344
License NPF-1

U.S. Nuclear Regulatory Commission
ATTN: Document Control Desk
Washington DC 20555

Dear Sir:

Secondary Piping Erosion/Corrosion

During the 1987 refueling outage at Trojan, secondary piping inspections were performed which identified numerous locations where pipe wall thinning has occurred. Our letter of July 10, 1987 reported this finding and provided a summary of piping inspected and replaced in 1987. Piping has been replaced whenever the measured wall thickness is below minimum allowable, or is projected to fall below minimum allowable prior to the 1988 outage.

A Nuclear Regulatory Commission Task Force visited Trojan during the week of July 20 to inspect the removed piping and to gather information regarding the erosion/corrosion phenomenon experienced at Trojan. This task force requested that Portland General Electric Company (PGE) provide the following additional information: (1) a description of all safety-related piping or fittings replaced during the 1987 outage due to erosion/corrosion, (2) a description of the technical basis for assumed erosion rates used to determine that portions of the piping did not have to be replaced, and (3) our conclusions as to the safety of operation for Trojan through the next operating cycle.

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Table 1 summarizes Seismic Category I feedwater piping that has been ultrasonically inspected and the inspection results. Table 2 describes the actual grid or sweep patterns used to take the measurements. The grid and sweep patterns were designed to ensure that the types of erosion expected (based on visual inspections) would be detected.

All Seismic Category I feedwater piping removed for replacement has been visually inspected. In addition, sections of remaining pipe have been visually inspected when possible. Visual examinations have verified that ultrasonic thickness measurements have adequately characterized and quantified the erosion/corrosion being observed. Erosion/corrosion in Seismic Category I piping has been observed to be relatively uniform over an area. Localized pockets of deep erosion/corrosion have not been observed.

Review of all Trojan data has shown two areas in which visual inspection results caused the effectiveness of ultrasonic techniques to be questioned. One is at a 30-inch tee downstream of the last feedwater heater and the other is at the discharge of the main feedwater pumps. In both cases, there were small diameter pockets of erosion that exceeded uniform erosion/corrosion in the surrounding areas. It is possible that these pockets could have been missed using a standard 4-inch by 4-inch inspection grid.

These locations are considered anomalies since piping geometry caused very severe conditions that are not representative of conditions in Seismic Category I feedwater piping.

The 30-inch tee combines flows from two 24-inch pipes. One of the 24-inch pipes has a 90 degree elbow just upstream of the tee. Velocity in the tee is 20.7 fps. Nominal observed wall thickness in this pipe was about 1.5 inches, but one spot (detected by ultrasonic techniques as part of the monitoring program), was only 1.0 inch thick. This localized pocket is believed to be caused by the high local turbulence.

Consultants hired to review Trojan's erosion/corrosion monitoring program indicated that flow splitting or combining tees are one of the most severe geometries affecting erosion/ corrosion rates. Reference (6) lists closely coupled tees and elbows and entrant tees as the highest priority geometries to examine. There are no tees in the Seismic Category I portion of feedwater, so experience with the 30-inch tee is not considered applicable.

Fluid velocities at the discharge of the feedwater pump are 35.9 fps. The fluid is highly turbulent leaving the pump. The flow is into a flow splitting tee (for recirculation flow) and then into an expanding elbow. Turbulence and flow velocities are so high in this region that the conditions are considered unique and not applicable to Seismic Class I feedwater piping. The ultrasonic monitoring program did detect the lowest reading pockets before the pipe was removed and visual examinations were performed.

VY Piping FAC Inspection Program PP 7028 - 2007 Refueling Outage

Inspection Location Worksheets / Methods and Reasons for Component Selection

By: James C. Fitzpatrick JCF 4/3/06 Reviewed: Thomas M. O'Connor 5/11/06

FAC PROGRAM INSPECTION PLANNING:

Piping components are selected for inspection during the Spring 2007 refueling outage (RFO26) are based on the following groupings and/or criteria.

Large Bore Piping

LA: Components selected from measured or apparent wear found in previous inspection results.

LB: Components ranked high for susceptibility from current CHECWORKS evaluation and /or identified as having the highest increases in flow velocities under EPU conditions.

LC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

LD: Components selected to calibrate the CHECWORKS models.

LE: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).

LF: Engineering judgment / Other

LG: Piping identified from EMPAC Work Orders (malfunctioning equipment, leaking valves, etc.)

LH: Components "De-Scoped" (inspections deferred) from Previous Outages

Small Bore Piping

SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.

SB: Components selected from measured or apparent wear found in previous inspection results.

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

SD: Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).

SE: Engineering Judgment / Other.

SG: Piping identified from EMPAC Work Orders (malfunctioning equipment, leaking valves, etc.)

SH: Components "De-Scoped" (inspections deferred) from Previous Outages

Feedwater Heater Shells

No feedwater heater shell inspections will be performed during the 2007 RFO. All 10 of the feedwater heater shells have been replaced with FAC resistant materials.

LA: Large Bore Components selected (identified) from previous Inspection Results

From the 1996 though 2005 Refueling Outage Inspection Reports, references (2) to (8): Large Bore Piping components were identified as requiring future monitoring. The following components have either yet to be inspected as recommended, or the recommended inspection is in a future outage.

Inspect. No.	Loc. SK.	Component ID	Notes /Comments / Conclusions
96-18 96-19	001	FD13EL05 FD13SP06	1996 Report: calculated time to Tmin is 11.5 & 12 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. **UT inspect elbow and downstream pipe in 2008**
96-36	002	FD02SP05	1996 Report: calculated time to Tmin is 9.5 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. **UT inspect elbow and downstream pipe in 2007**
96-37	005	FD07SP01	1996 Report: calculated time to Tmin is 9.6 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. DS elbow shows significant margin RSL= 47 cycles from 1996. EPU flow will increase velocity ~22%. **UT inspect upstream pipe FD07SP01DS, elbow FD07EL02, and downstream pipe FD07SP02US in 2007 (repeat the 1996 inspections)**
96-39	005	FD07SP02US	1996 Report: calculated time to Tmin is 10.5 cycles based on a single measurement. The 2007 RFO is 7 cycles since the inspection. **UT inspect upstream pipe FD07SP01DS, elbow FD07EL02, and downstream pipe FD07SP02US in 2007 (repeat the 1996 inspections)**
98-05 98-07	005	FD07EL06 FD07EL07	1998 Report: calculated time to Tmin is 7.5 & 6.7 cycles based on a single measurement. The 2007 RFO is 6 cycles since the inspection. Review of 1998 data for FD07EL06, FD07SP07, and FD07EL07 shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. **UT inspect elbow FD07EL07 and downstream pipe FD07SP08 in 2008**
99-13	011	FD08EL04 FD08SP04	1999 Report: calculated time to Tmin is 7.9 & 12.5 cycles based on a single UT inspection. The 2007 RFO is 5 cycles since the inspection. Review of 1999 data for FD08EL04, & FD08SP04, shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. **UT Inspect elbow and downstream pipe in 2008**
99-16	011	FD08SP05	1999 Report: calculated time to Tmin is 6.1 cycles based on a single measurement. The 2007 RFO is 5 cycles since the inspection. **UT inspect pipe in 2007.**
02-08 02-09	016	FD18EL01 FD18SP02US	2002 Report: calculated time to Tmin is 7.92 cycles based on a single UT inspection. The 2007 RFO is 3 cycles since the inspection. Review of 2002 data for FD18EL01, & FD18SP02US, shows recommendations were made based on wear rates conservatively calculated from single low point measurements at weld counterbores. Significant margins exist on body of pipe and elbows. Defer this inspection to RFO 27 in 2008. At that time components will have ~1.7 cycles of operation under increased EPU flows. **Re-inspect elbow and downstream pipe in 2008 (4 cycles from 2002).**

LA: Large Bore Components selected (identified) from previous Inspection Results –continued

Inspect. No.	Loc. SK.	Component ID	Notes /Comments / Conclusions
04-03	001	FD01TE05	2004 recommendation to inspect tee in 2008 based on the default wear rate of 0.005 inch/cycle. Flow on B FDW pump increases from ½ usage/standby for CLTP to full time usage and 80% of CLTP flow for EPU. **Re-inspect upstream elbow and tee in 2008.**
04-06	002	FD02RD01	2004 recommendation to re-inspect in 2011 based on the default wear rate of 0.005 inch/cycle. Flow on B FDW pump increases from ½ usage/standby for CLTP to full time usage and 80% of CLTP flow for EPU. **Re-inspect reducer with downstream elbow and tee in 2008.**
04-08	001	FD02TE01	2004 recommendation to inspect tee in 2007 based on the default wear rate of 0.005 inch/cycle. Actual point to point measurements from 1999 to 2004 indicate no wear. Given EPU operation, **re-inspect with upstream elbow and reducer in 2008.**
04-09	001	FD03SP01	2004 recommendation to inspect pipe section in 2011 based on a single inspection and the default wear rate of 0.005 inch/cycle. **Re-inspect in 2011.**
04-10	001	FD07SP02DS	2004 recommendation to inspect pipe section in 2008 based on a single inspection. **Re-inspect with downstream elbow in 2008.**
04-13	001	FD14EL03	2004 recommendation to inspect Row 13 pup piece to DS valve in 2008 is based on a single UT inspection. **Re-inspect in 2008.**
04-23	001	MSD9TE01 to MSD9TE08	2004 recommendation to inspect pipe section in 2010 due to localized wear directly under 2 small bore lines entering flow at top of pipe. **Re-inspect in 2010.**
04-23	001	MSD9EL05	2004 recommendation to inspect pipe section in 2010 base on a single inspection. **Re-inspect in 2010.**
05-12	011	FD08RD03	2005 Recommendation to inspect this component and downstream straight pipe in RFO28 –Spring 2010 due to increases flow velocity from EPU. **Re-inspect FD08RD03 and FD08SP02 in 2010.**
05-03 05-04 05-05 05-06 05-07 05-08 05-09 05-10 05-11	017 018 019	FD04RD01 FD04TE01 Cond Nzl 32A FD05RD01 FD05TE01 Cond Nzl 32B FD06RD01 FD06TE01 Cond Nzl 32C	During normal operation there is no flow in these lines. No current leakage is indicated since the upstream FCV repairs were performed during RFO24. This piping was inspected in RFO 25 to determine if past leakage has caused wear since the last inspections and to insure the condition of the piping for Extend Power Uprate conditions. 2005 Recommendation to use the Thermal Performance Monitoring (TPM) system to determine if flow is occurring in this pipe during normal operation. **The Thermal Performance Monitoring (TPM) system will be used as a trigger to determine if future inspections are required. The monthly TPM report will be monitored by the FAC program Engineer.**

LA: Large Bore Components selected(identified) from previous Inspection Results –continued

Turbine Cross-around Piping:

Summary of previous Internal Visual UT & Repair History:

Line	Mat.	Year Replaced	Internal Visual =V , Internal Thickness =UT, Repairs Performed =R									
			RFO16 S1992	RFO17 F1993	RFO18 S1995	RFO19 F1996	RFO20 S1998	RFO21 F1999	RFO22 S2001	RFO23 F2002	RFO24 S2004	RFO25 F2005
36"-A	GE**	1983		V	V	V	V				V	V
36"-B	GE**	1981	V	V	V	V	V	V			V	
36"-C	GE**	1981	V	V	V		V				V	V
36"-D	GE**	1983		V	V		V				V	
30"-A	P-22*	1985	V		V		V					
30"-B	C.S.	Original	V/UT/ R	V/UT/ R	V/UT/ R	V/UT	V	V		V		V
30"-C	P-22*	1993	V/UT/ R								V	
30"-D	P-22*	1985			V						V	

** 36" straight pipe sections replaced with GE B50A242E, elbows on the B & C lines are original GE specification D50A67D, elbows on A &D lines are D50A67E (Tnom =0.625 inch).

* 30" A,B,C replaced with A691 CL22 (2-1/4Cr), Fittings A234 WP22. (Tnom. = 0.625 inch)

30" B remains GE B50A242D, fittings and GE D50A67D carbon steel (Tnom = 0.50 inch).

2007 RFO:

The last remaining carbon steel 30 inch, (30" B, upper east), line was inspected to confirm its condition prior to power uprate flows. Increased EPU flows and an expected drop in Moisture Separator efficiency will most likely result in resumption of FAC in this line. Results of the planned MS efficiency tests at EPU flows will quantify any drop in steam quality in these lines and provide some basis for estimating the increase in susceptibility to FAC damage. If the proposed testing at EPU flows shows no loss in MS efficiency, this inspection could be deferred until RFO27. For planning purposes:

Perform a complete visual Inspection of 30" B line in RFO 26 will be planned to insure wall loss due to FAC has not resumed under EPU flow conditions. This will require coordination with planned LP turbine work scheduled for RFO26.

LB: Components ranked high for susceptibility from current CHECWORKS evaluation and /or identified as having the highest increases in flow velocities under EPU conditions.

The current CHECWORKS wear rate calculations contain inspection data up to the 1999 RFO and wear rate predictions are current to the 2001 RFO. The 2001 and 2002 RFO inspection data has been entered into the CHECWORKS database. CHECWORKS predictive models for Piping FAC Inspection Program are updated as required per Appendix D of PP 7028. This is documented in CR-2005-2239. This is a procedure compliance issue. There are no operability concerns. Actual measured wear rates from 2001, 2002, 2004, and 2005 inspections are an order of magnitude less than the CHECWORKS predicted wear rates. If the 2002, 2004, and 2005 inspection data were incorporated into the models the CHECWORKS predicted wear rates would be reduced. Use of the un-updated CHECWORKS model results as a basis for inspection planning is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS Predicted wear rates significantly greater than actual measure wear.

The updated wear rate calculations are in progress, and won't be complete in time to support the outage schedule milestone date for issuing the inspection scope for the 2007 outage. Based on a review of the 2001 thru 2005 RFO inspection data for components on the Feedwater, Condensate, and Heater Drain Systems, the CHECWORKS models still appear to over-predict actual wear. The existing model results will be used to rank components for inspection in 2007. **The component selections will be reviewed upon completion of the CHECWORKS model updates.**

Feedwater System

Listed below are components which meet the following criteria:
a) Negative time to Tmin from the predictive CHECWORKS runs which include inspection data up to the 1999 RFO.
b) No inspections have been performed on these components or the corresponding components in a parallel train since the 1999 RFO.

Component ID	Location Sketch	Location	Notes
FD07EL05	005	TB FPR Elev. 241	Comparable component on other train FD08EL04 was inspected in 1999 and results indicate minimal wear. **After updating the Checworks model with newer data, assess need for Inspections in 2008 RFO.** (Note upstream components FD07RD02 and FD07SP03 will be inspected in 2007)
FD07TE01 FD07EL11	006	T.B Heater Bay Elevs 228 & 248	Components on other train were inspected in 1998. Results indicate minimal wear. **Inspect FD07TE01, FD07EL01, and FD07SP11 in 2007 RFO.**
FD07EL12	006	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern. **After updating the Checworks model with newer data, assess need for inspection**
FD08TE01 FD08EL07	012	T.B Heater Bay Elevs 228 & 248	Intermediate components FD08EL06 & FD08SP06 were inspected in 1998. Results indicate minimal wear. **After updating Checworks model with newer data, assess need for inspecting components.**
FD08EL08	012	T.B Heater Bay Elev. 248	Feedwater heater replacement occurred in 2004 RFO. Informal visual inspections of internals and cut pipe profile indicated a stable red oxide and no distinguishable wear pattern.
FD15EL08	013	RX Steam Tunnel El. 266	Internal visual of elbow performed in 1996 during check valve replacement, no indication of wall loss at that time. Corresponding component on line 16"- FDW-14 was inspected in RFO24. **After updating Checworks model with inspection data, assess need for inspection in 2008 RFO.**

LB: Components ranked high for susceptibility from current CHECWORKS evaluation and /or identified as having the highest increases in flow velocities under EPU conditions - continued

Condensate System

Only one component was identified as having a negative time to Tmin. This was CD30TE02DS, the downstream side of a 24x24x20 tee on the condensate header in the feed pump room. The CHECWORKS prediction for the downstream side or the tee has a small negative hrs relative to the remainder of the components in the system and relative to the upstream side of the same tee. Other tees on the same header have been previously inspected and show no significant wear. The CHECWORKS model includes UT data up to the 1999 RFO. The inspections on this system performed in 2001, 2004, and 2005 indicate minimal wear.

Components CD30TE02 and CD30SP04 were inspected in 2004. Additional components downstream of condensate Flow elements FE-102-2A and FE-102-2B on inlets to FDW pumps A & B were performed in 2005 with no significant wear observed. This inspection data will be input to CHECWORKS to better calibrate the model.

Moisture Separator Drains & Heater Drain System

No components identified as having negative times to Tmin. No components were selected for inspection in 2001, 2002, or 2004 based on high susceptibility. However, operation under HWC changes dissolved oxygen in the system. A separate CHECWORKS evaluation was performed to assess the differences in projected wear rates between Normal water chemistry and Hydrogen water chemistry. Selected HD components were inspected in 2002 to obtain pre-HWC operation wall thickness data. See Section LD below.

Extraction Steam System

Three components on this system with negative time to code min. wall: The piping is Chrome-Moly. ES4ATE01 & ES4ATE02, 30inch diameter tees inside the condenser have negative prediction (-3426Hrs.) for time to min wall. The negative times to tmin may be conservative based on the modeling techniques used. Refinement of the model of this system is in progress. The negative time to tmin is most likely a function of lack of inspection data vs. actual wear. Due to external lagging on this piping and the location inside the condenser, no components are selected for external UT inspection in 2007 based on high susceptibility.

Note the short section of straight pipe on line 12"-ES-1A at the connection to the 36 inch A cross around is assumed to be A106 Gr. B carbon steel is not modeled in CHECWORKS. This component was inspected in 2004 by external UT and an internal visual inspection from the 36" cross around line was performed in both 2004 and 2005.

LC: Large Bore Components Identified by Industry Events/Experience.

Review of FAC related Large Bore Operating Experience (OE) and/or piping failures reported since April 2003

Date	Plant – Type	Description & Recommended Actions at VY
5/9/01	Grand Gulf – BWR	Pin Hole Leak in 4 inch carbon steel elbow in RHR min flow line. System has low use at VY (<2% of time). Perry also found thinning at elbow per C.Burton at CHUG meeting.) A review of VY drawings VYI-RHR-Part 14 Sht.1/1 and VYI-RHR Part 15 Sht.1/1 show elbows downstream of restriction orifices. Previous VY Inspections downstream of orifices on HPCI/and CS systems found no problems. Keep this OE listed for future consideration if similar industry events are identified.
1/15/02 CHUG Meeting	Surry 1-PWR	Leak in 8 inch Condenser drain header for 3rd/4th pt. FDW Heater vents. Also thinning in Gland Steam Piping inside the condenser and the 12" Condenser Drain header from MS Drain trap lines. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-9. This line is now part of the AST ALT boundary. Inspections of selected components on this line were performed during RFO24 with recommendations for repeat inspections in 2010 (Section LB above). Given this line is part of the ALT Boundary, **inspect approx. 2 ft. long section at condenser wall during RFO26 (2007) MSD9SP07 at condenser nozzle 67 (Location Sketch 097)**
6/26/03	Wolf Creek – PWR	OE16181: Leak in Main Feedwater Thermowell. The Thermowell is unused and was sealed with a pipe plug. Once the integrity of the plug was determined by RT, the main concern was potential for internal FME from the degraded Thermowell to affect downstream control valves. PWR feedwater piping more susceptible to FAC than BWR piping due to low DO. Keep this OE listed for future consideration if similar industry events are identified.
9/24/03	South Texas Project - PWR	OE17378: Pitting & internal wear found on discharge piping of Condensate Polishing System. Pipe is carbon steel, low water temperature (90 to 130F), neutral pH, and velocity of 12.2 Ft./sec Tortuous flow path and control valves, wear may be impingement. PWR system Low dissolved oxygen. Equivalent system at VY is Condensate Demineralizer System which is low temp and screens per NSAC-202L as not susceptible to FAC based on temperature. No OE on BWR Condemin systems.
10/10/03	Browns Ferry 3 –BWR	6/04 CHUG Meeting PER: Failure of No.2 Extraction Steam bellows inside condenser caused collateral damage in No.3, No.4A,& No.5B east bellows. In service for only 2-1/2 cycles. Failure due to welds/weld flaws in bellows. Additional erosion found in the carbon steel Extraction Steam lines inside the condenser was found during the unplanned mid-cycle outage for bellows repairs. At VY, the Extraction Steam piping inside condenser is Cr-Mo. The bellows were replaced in 1995. The System Engineer performed limited bellows inspections in RFO25. No new actions with respect to FAC for this OE.
10/17/03	Duane Arnold –BWR	OE17300: Through wall leak on 8 inch pipe between 6A feedwater heater and condenser. The pipe was chrome-moly. Temporary pipe configuration installed prior to replacing feedwater heater for power uprate. Cause of leak was droplet impingement erosion from use of bypass control valve. No actions required for VY. However, it should be noted that chrome-moly pipe is not immune to droplet impingement erosion.
10/31/03	Clinton -BWR	OE17412 / OE18478: Through-wall leaks in 2A/ B heater vent lines to the condenser (lager bore lines assumed given description of backing rings in piping). Apparent cause attributed to steam jet impingement from wet steam. Equivalent line at VY is common 4 inch feedwater heater vent line for No.4 FDW heaters. AT VY this line is included in the SSB database since it connects to (2) 2-1/2" lines. **Inspect this line at the condenser in RFO26 in 2007 [Inspection No.07-SB09]**

LC: Large Bore Components Identified by Industry Events/Experience - continued.

Date	Plant – Type	Description & Recommended Actions at VY
11/07/03	Braidwood 2-PWR	OE17454: Wall thinning found on FDW pump discharge nozzles and extending into downstream pipes on all 3 FDW pumps. Material has high chromium content. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY all three feedwater pump discharge nozzles and downstream piping have multiple inspection data. No further actions are anticipated from this OE.
11/19/03	Hope Creek – BWR	OE17700: Pinhole leak and wall thinning in 8" in carbon steel Extraction Steam supply line to Steam Seal Evaporator. Location of wear is downstream of pressure safety valves. Apparent Cause of leak & wear is due to liquid droplet impingement due to high flows from failure of pressure safety relief valves. No equivalent configuration at VY.
1/24/04	LaSalle 1 - BWR	OE17199 / OE18381: Through-wall holes in extraction steam piping inside condenser. Location of holes at inlet nozzles to No.2 FDW heaters located in the neck of the condensers (2nd lowest stage). All 12 nozzles are C.S. with A335-P11 upstream piping. VY has only the No. 5 FDW heaters in the neck of the condenser. The No. 5 FDW heaters were replaced with Chromo-moly shells and ES piping nozzles. ES piping is A335-P11 or equivalent which is FAC resistant. No further actions are anticipated from this OE.
2/17/04	Peach Bottom 2 - BWR	OE18637: On line leak in 10 inch main steam drain line header to the condenser. Hole was located directly below the connection of 1" main steam lead drain. The header was replaced with 1-1/4 Chrome material approx. 6 years before the leak. Also, R.O.s in steam drains were modified. The cause was attributed to steam impingement. Additional information to follow after next RFO. The only large bore drain collectors at VY are the 8 inch diameter low point drain header. line 8"MSD-9. and line 3"-MSD-4 near the condenser. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. These lines are now part of the AST ALT boundary. For MSD-9, inspection of the entire bottom of this header under the MSD lines was performed during RFO24 with recommendations for repeat inspections in 2010. **Inspect 8"-MSD-9 at the Condenser in RFO26 (2007). For line 3"MSD-4, see Small Bore OE in section SC below.**
3/17/04	Farley 2 - PWR	OE18059: Nameplate Screws Holes Found Extended Into Flow Nozzle Pipe. 16 in. Sch.60, A106 Gr.C. Evaluated as a flaw and found acceptable. Only a concern if FAC wear is occurring in the pipe at the location of the nameplate. VY inspections to date for FDW and Condensate flow elements show no wear in pipe. No further actions for this OE.
3/27/04	Perry -BWR	6/04 CHUG PER: Through wall leak in a 12" diameter drain header (Main Steam, Reheat Steam, Extraction Steam, and Misc Drains collector) connecting to the condenser. The only large bore drain collectors at VY are the 8 inch diameter low point drain header, line 8"MSD-9, and line 3"-MSD-4 near the condenser. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. These lines are now part of the AST ALT boundary. For MSD-9, inspection of the entire bottom of this header under the MSD lines was performed during RFO24 with recommendations for repeat inspections in 2010. **Inspect 8"-MSD-9 at the Condenser in RFO26 (2007). For line 3"MSD-4 See Small Bore OE in section SC below.**
7/05/04	Ohi-1 -PWR (Japan)	OE19492: OE describes wall thinning in PWR feedwater components between the feedwater isolation valves and the steam generators. No leaks, wall thinning was found through planned UT inspections. Components will be replaced with the same materials and additional inspections (increased frequency) will be performed. PWR feedwater piping more susceptible to FAC than BWR piping due to low DO. VY inspects final feedwater piping components. No wear found to date.

LC: Large Bore Components Identified by Industry Events/Experience - continued.

Date	Plant – Type	Description & Recommended Actions at VY
7/30/04	Darlington Unit 4 - PHWR	INPO Event No.934-040730-1. Leak in 10 inch diameter Sch.60, HP Drains manifold. Material is low chrome-moly (2.25/1) alloy carbon steel. Darlington plans to increase inspection scope for HP Drains manifold piping. Cause of leaks attributed to liquid impingement. **[See 2/17/04 Peach Bottom 2 OE and 3/27/04 Perry OE evaluation of for VY above. Also, note that this OE demonstrates that Cr-Mo P22 material may not be the ultimate solution if liquid impingement is occurring.]**
8/9/04	Mihama 3 - PWR	OE19368/OE18895: Rupture of Condensate line downstream of restriction orifice. PWR system highly susceptible to single phase FAC due to low DO. Similar region of system as 1986 Surry event (5 fatalities). Based on info gathered by INPO/CHUG/FACnet the location was omitted from previous inspections due to clerical error, once discovered management missed opportunity to inspect and deferred inspection until 9/04. Too late. Lesson: make sure all highly susceptible locations get inspected. PWR Condensate/feedwater piping is much more susceptible to single phase FAC than BWR with O2 injection. A review of previous inspections DS of Flow Elements at VY shows: Condensate piping at and downstream of FE-102-2A & -2B was inspected in RFO25(2005) and piping at and downstream of FE-102-2C was inspected in RF022(2001). Also feedwater piping downstream of FE-6 -11A was inspected in RFO23(2002). See section LF below for discussion of Flow Elements in lower temperature Condensate piping.
8/10/04	Sequoyah 2 – PWR	OE19074: Leak in Heater Drain Tank Recirculation line downstream of the recirc. nozzle of the automatic recirculation valve. Suspected leakage by Normally Closed Valve. No similar configuration at VY.
8/26/04	Palo Verde 3- PWR	OE20386: Through wall leak found on a 10 inch flashing tee cap on the LP feedwater heater drains. Problems with inspection of flashing tees in program. Only 14 out of 153 susceptible locations have UT data at Palo Verde 1,2,3. At VY there are 4 flashing tees D.S. of LCV-103-23A to -23D on the Moisture Separator Drain system at VY. These along with the blind flanges were replaced with Cr-Mo in 1992. The only other flashing tees at VY are located on the FWD pump min flow lines at the condenser. These have welded pipe caps. Inspection of all 3 lines 6"FDW-4, 6"FDW-5, and 6"FDW-6 performed in RFO25. No other actions for this OE.
9/18/04	Catawaba 2 – PWR	OE19350: Wall thinning found four different areas on FDW piping. Two areas are not considered specific to Catawba: 1)Area where main feedwater bypass reg valves reenters the feedwater header and 2) downstream of the main feedwater reg valves. PWR feedwater system chemistry has low D.O. therefore more susceptible to wall loss due to single phase FAC than BWR feedwater piping. At VY area 1) doses not exist (bypass lines dump to the condenser). 2) Inspections have been performed upstream and downstream of both main feed reg. valves. Inspections downstream of FCV-12B (FD08RD03 & FD03SP02) were performed in RFO25. **Inspections downstream of FCV-12A planned for RFO26 given the increased velocities under EPU. No further actions are anticipated from this OE.**
9/24/04	Palisades - PWR	OE19494: Wear found in carbon steel 12" Sch 40, Extraction Steam line downstream of bleeder trip valve. Wear found through FAC inspections. No through wall leak. This OE identifies potential for FAC damage in ES piping and problems with partial line (selected component) replacements. ES piping at VY is low alloy A335-P-11 Cr.Mo piping which is FAC resistant. No further actions for this OE

LC: Large Bore Components Identified by Industry Events/Experience - continued.

Date	Plant – Type	Description & Recommended Actions at VY
10/12/04	Prairie Island 1 – PWR	OE19365: Pipe Failure Internal to the Main Condenser Found During Outage Inspection. Failure in 14 x 8 reducing elbow and wall thinning in 8 inch pipe on line connecting heater drain tank to condenser. Failure discovered during routine condenser inspections before tube damage had occurred. VY performs internal condenser walkdowns each RFO with additional inspections during equipment maintenance. At VY piping attached to the condenser either has impingement plates to protect the tubes or spargers internal to the condenser to disburse flow. Extraction steam piping inside the condenser is Cr-Mo. Material. Visual inspection of the condenser stream space will be performed by System Engineering. No new inspections will be performed under the FAC Program for this OE.
11/3/04 (Note Follow-up present. at 6/05 CHUG Meeting)	Duane Arnold – BWR	OE19701: Wall thinning downstream of Torus Cooling Test Return Header Isolation Valve. Apparent cause was cavitation erosion due to throttling in valve during HPCI & RCIC testing. At VY, the equivalent valves are V10-34A & 34B. The degree of cavitation present is dependent of the system design and may vary from plant to plant. Previous UT inspections at VY were performed on valve bodies and downstream reducers in early 90s. No significant wear was found. **Consider inspection of downstream piping in RFO27 if additional OE warrants it.**
2/17/05	Clinton – BWR	OE20246 and CHUG PER 1/06: Through wall leaks found in 12", 20", and 30" Extraction Steam Piping inside the condenser. These lines were not in the FAC program according to the Heat Balance they carry superheated steam. Equivalent piping at VY is in the FAC program and is Cr-Mo, A335 P-11
2/26/05	Calvert Cliffs 1 - PWR	OE20127: Through wall leak in 6 inch steam vent header from MSR drain tank to hot reheat header. Location of leak was at the end of elbow which had a backing ring. Leak location was at the backing ring. At VY, there are no backing rings in piping systems containing primary steam/water. Also, there are No MSRs at VY.
5/23/05	Vogtle Unit 2 -PWR	OE20793: Extraction Steam expansion bellows failure inside condenser caused collateral damage to feedwater heater shroud and condenser tubes. Not FAC. No further actions require for this OE.
6/05 CHUG Meeting	TEPCO Fukushima Daini-1 (2F-1) - BWR	Wall thinning downstream of a restriction orifice in the CRD pump supply line from Condensate System. Pipe Size 100A (approx. 4.5 inch O.D.). Location is DS of Control valve and restriction orifice on supply line to CRD pumps from the condensate system. VY has a similar configuration but without the Restriction Orifice. This line screens out of the VY FAC Susceptibility Evaluation based on low temperature. Comparison with VY: 1. Condensate supply is upstream of the oxygen injection point, same at VY. 2. MOV is a globe valve the same size as pipe. The valve is operated at 8% open to control flow with a restriction orifice just downstream of the valve. VY has a smaller size control valve than the main line. A 1-1/2" control valve (LCV-102-1A-3) with expanders from 1-1/2" to 2-1/2 then to the 4" diameter line with no restriction orifice. 3. Supply line is downstream of low pressure condensate pump. At VY supply is directly from hotwell. This results in a higher DP across the MOV & RO at TEPCO than across the LCV at VY. TEPCO has higher potential for cavitation and/or flashing due to the higher DP. At VY, UT measurements on the valve body were performed 1992, but no measurements on the downstream piping. TEPCO root cause was FAC with cavitation contributing at the RO. Given there is no RO at VY and the LCV is operated at 60% open. The potential for a similar situation at VY is significantly less. **Scope out possible inspection locations on piping down stream of LCV-102-1A-3 during RFO26 in 2007.**
6/05 CHUG Meeting PER	Wolf Creek – PWR	Eroded elbow found in 12 Inch LP feedwater heater drain line inside condenser. Erosion was external to pipe from main steam dump to condenser. No equivalent piping at VY. At VY only the No.5 FDW Htrs. are in the neck of the condenser. Heater drain piping is external to the condenser. The extraction steam piping inside the condenser has external lagging for protection and thermal efficiency.

LC: Large Bore Components Identified by Industry Events/Experience - continued

Date	Plant – Type	Description & Recommended Actions at VY
6/05 CHUG Meeting	Hatch Units 1 and 2 - BWR	Pinhole leaks in 3 inch line between Steam Packing Exhauster Drain Tank and Condenser in both units. The leak locations were at the first elbow downstream of the tank level control valves. The equivalent piping at VY is 6"C-44 at condenser nozzle 63. This line screens out of the VY FAC Susceptibility Evaluation based on low temperature. VY has two LCVs in parallel vs. the single valve on each of the Hatch units. **Given that a leak in this line would affect condenser vacuum and challenge plant availability, inspect locations downstream of valves LCV-102-8-1 and LCV-102-8-2 in RFO26 (2007)**
6/22/05	Callaway - PWR	OE19965: Failure of the carbon steel body section of an internal pipe flow element manufactured by Badger Meter blocked flow in a Heater Drain tank Pump discharge line. A separate evaluation of this OE was performed for VY. 3 Flow elements in the Condensate System; FE-102-2A to -2C have been identified as the same construction. UT inspections of piping US, the pipe at the flow element, and DS of each of the flow elements shows no wear is occurring. This is not a pressure boundary issue. **An ER will be generated to develop the best scheme for inspection and evaluation of the internal portions of the pipe flow elements.**
6/23/05	Palo Verdi Unit 1 PWR	1/06 CHUG PER: Leak on 8"x 12" expander downstream of level control valve on MSR Drain tank to Heater Drain tank. No MSR or heater drain tank at VY. This is high pressure piping. The closest components would be the Moisture Separator Drain Piping down stream of LCV-103-24A to 24D. This piping is A335 P-22 material. Other components would be piping downstream of Heater Drain System LCV-103-1A-1/1B-1, LCV-103-2A-1/2B-1, and LCV-103-3A-1/3B-1. Piping downstream of these valves is either chrome moly or stainless steel. No new actions with respect to FAC for this OE.
8/15/05	Dresden 3 - BWR	OE21421/OE21966 Loss of Main Condenser vacuum due to air in leakage and a degraded SJAE train. Age related degradation of the 2nd stage steam jets at Dresden. VY replaced the SJAE nozzles in 1993 (JO 92-0140). However, US & DS piping is original. **ER 06-1190 was written to evaluate SJAE replacement including the need for additional FAC Inspections of the piping.** With respect to the vent line internal to the condenser at Dresden which experienced external wear due to steam erosion, the equivalent section of piping at VY is stainless steel. The need to establish PMs for AE lines in the condenser will be addressed in the response to ER 06-1190.
9/26/05	Hatch Unit 1 – BWR	OE21591: Through wall leak in a Fisher control valve body. MSR Reheater 2nd Stage High Level Dump. Hole in the 1 inch thick valve body was attributed to leakage past the seat. The valve had been modified for power uprate. The trim was changed to avoid installing a larger actuator on the valve. This OE was forwarded to the Systems/ TPM Engineer. **The TPM system will be used to identify leakage by normally closed valves to the condenser.. The monthly TPM report will be monitored by the FAC program Engineer.**
1/06 CHUG Meeting	Surry – PWR	Hidden spool piece discovered. Plant replacement practices in two separate local material replacements (Cr-Mo) on a 6 inch line at the upstream elbow and the downstream elbow resulted in a carbon steel spool piece remaining in the line. **This situation highlights importance of configuration control, potential hazards of partial replacement strategy, and the need for alloy sampling.**
1/06 CHUG Meeting	Susquehanna Unit 2 - BWR	Through wall damage found in 3" and 4" diameter FW heater vent piping and associated condenser nozzles during pipe replacement activities. Caused increased condenser in-leakage. Heater Vent Piping at VY is monitored for FAC in Small Bore Program.

LD: Large Bore Components Selected to Calibrate CHECWORKS

The CHECWORKS wear rate calculations have been upgraded to include the 96, 98, & 99 RFO inspection data. The 2001 and 2002 inspection data has been loaded however wear rate analyses have not been completed at this time.

Condensate:

In 2001 components on the higher temperature end of the Condensate System were inspected to calibrate the CHECWORKS models. The inspection data indicate minimal wear and should reinforce the assessment of low wear in the Condensate System. Additional inspections were performed on lines CD-30, CD-31 and CD-32 in 2004 and 2005. There is no inspection data on line 20"-C-28 between the E-4-1B and E-3-1B feedwater heaters for CHECWORKS calibration. Given the increase in operating temperature & flows for EPU, inspect components **CD28EL04 & CD28SP03US** in **RFO26 (2007).**

Heater Drains/ Moisture Separator Drains:

Prior to the 2002 RFO there was limited inspection data for the Heater Drain system. The current CHECWORKS models (Pass 1 and some Pass 2) indicate low wear rates. During 2002 a number of new inspections were performed on the carbon steel piping upstream of the level control valves (LCV) to obtain a baseline prior to operation on hydrogen water chemistry. The 2002 inspection data indicate significant margin for future wear in the components inspected.

Piping downstream of the level control valves (LCV) for the feedwater heaters is FAC resistant material, except for inlet to No.5 Feedwater heaters. The carbon steel piping downstream of the normal flow LCV-4B-1 will be inspected in RFO26. Additional components on lines which do not already have inspection data will be inspected in RFO26. (2007) are listed below.

Inspection	Component ID	Loc. Sketch	Location	Previous Inspections	Reasons / Comments / Notes
2007-27	HD1AEL06	043	T.B. Htr. Bay Elev. 235.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-28	HD1ASP08	043	" " "	NO	
2007-29	HD3BTE01	051	T.B. Htr. Bay Elev. 239.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-30	HD3BEL02	051	" " "	NO	
2007-31	HD3BSP05US	051	" " "	NO	
2007-32	HD5ATE01	045	T.B. Htr. Bay Elev. 239.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-33	HD5ASP06	045	" " "	NO	
2007-31	HD3BSP05US	045	" " "	NO	
2007-32	HD25RD02	053	T.B. Htr. Bay Elev. 253	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-33	HD5ASP02	053	Inlet to E5-1-B	NO	
2007-34	HD12TE01	057	T.B. Htr. Bay Elev. 229.	NO	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-35	HD12SP01	057	MS-1-1A drain	NO	
2007-36	HD12EL06	058	T.B. Htr. Bay Elev. 230.	1989	Checworks Calibration, HWC, and increased flow and temperature effects form EPU
2007-37	HD12SP07US	058	MS-1-1B drain	1989	

Main Steam and Feedwater:

None for RFO26.

LE: Large Bore Components subjected to off normal flow conditions identified by turbine performance monitoring system (Systems Engineering Group).

The Systems Engineering Production Variance Report for January 1 to January 31, 2006 lists 3 of the 10 normally closed Turbine Bypass Valves as suspected of having seat leakage. Elevated tailpipe temperatures (Approx. 250F vs. Approx 200F) have been recorded on valves 1, 5, & 7. (See Attached Plot) The tailpipes are 10 inch diameter carbon steel lines connecting directly to the condenser. Each line ends inside the condenser at multi-stage restriction orifice supplied by GE. This indicates that any pressure drop in these lines should occur inside the condenser. The steam temp at the bypass valve is approx 540F. The 250F temp measured on the three suspected leaking lines is approx. 50 F above the lines considered as not leaking. Any water condensing out of the steam should occur in the restriction orifices inside the condenser. Consider inspections on these lines only if temperatures continue to increase.

Since startup from 2005 (RFO25), only one small bore valve and no steam traps have been identified (to date) using the Turbine Performance Monitoring (TPM) system. The small bore valve is LCV-101-3B this is addressed in Section SD below. Piping Downstream of this valve, 2"-ES-9B is Cr.-Mo steel and is resistant to FAC. However, if new data indicates leaking valves then additions to the outage scope may be required.

LF: Engineering Judgment / Other

Nine ASME Section XI Class 1 Category B-J welds are to be inspected by the FAC program per Code Case N-560 in lieu of a Section XI volumetric weld inspection. The VY ISI Program Interval 4 schedule for inspection of these welds is as follows:

Refueling Outage	Section XI ISI Program Weld ID	Description	FAC Program Components
Spring 2004 (RFO24) Interval 4 Period 1, Outage 1.	FW19-F3B FW19-F3C FW19-F4 FW21-F1	upstream pipe to tee tee to reducer reducer to pipe tee to pipe	"A" Feedwater on Sketch 010 FD19TE01 FD19RD01 FD19SP04 FD21SP01
Fall 2011 (RFO29) Interval 4 Period 3, Outage 6.	FW18-3A FW20-3A FW20-F1 FW20-F1B FW18-F4	upstream pipe to tee tee to reducer reducer to pipe horizontal pipe to pipe tee to pipe	"B" Feedwater on Sketch 016 FD18TE01 FD20RD01 FD20SP01 FD18SP04

Extended Power Uprate (EPU)

Feedwater system:

EPU evaluation for Feedwater System: The primary focus of work to date (for PUSAR and RAIs) was on velocity changes given only slight increases in temps and no chemistry changes. With all 3 FDW pumps running the 16 inch diameter lines to the 24 inch FDW header have approx. [1.2(2/3) = 0.80] 20% reduction in velocity. Velocities in the remainder of the system increase approx. 20%. The highest velocities are at the 10 inch reducers upstream and downstream of the FDW REG valves. The expander and downstream piping have multiple inspection data with FD07RD03/FD07SP03 last inspected in 2001 and FD08RD03/FD08SP02 last inspected in 2005. **Both of these segments should be re- inspected after some time of operation at EPU flows. Assuming EPU starting early in 2006, inspect components FD07RD03 and FD07SP03 in 2007 for a post EPU measurement.**

Continued

LF: Engineering Judgment / Other –continued

Condensate System:

Given the 8/04 Mihama event: consider additional components in the condensate system for inspection : downstream of flow orifices & venturies:

FE-102-4 and downstream pipe on 24"C-8 venturi type (TB condensate pump room overhead) Given low operating temperatures and upstream of oxygen injection point, **scope out and evaluate for inspection in RFO27 in 2008**
FE-52-1A to FE-52-1E on Condensate De-mineralizer System (Restriction Orifices). Given low operating temperatures and upstream of oxygen injection point, **scope out and evaluate for inspection in RFO27 in 2008**
FE-102-7 and downstream pipe on 14"C-21 venturi type TB Heater Bay El 237.5 Given low operating temperatures and used for start-up, **scope out and evaluate for inspection in RFO27 in 2008**

Extraction Steam

All Extraction Steam piping is A335-P11, a 1-1/4 chrome material, except for a short carbon steel stub piece in line 12"-ES-1A at the connection to the 36" A cross around line. Internal visual inspections of this stub piece were performed with the cross around inspection in RFO24 and RFO25. Also an external UT inspection of ES1ASP01 was performed in RFO24.

LG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Word searches of open work orders on EMPAC were performed for the following keywords: trap, leak, valve, replace, repair, erosion, corrosion, steam, FAC, wear, hole, drain, and inspect. No previously unidentified components or piping were identified as requiring monitoring during the Fall 2005 RFO.

Note: the internal baffle plate in Condenser B for the AOG train tank return line to the condenser was to be replaced in RFO 25 (ER 04-1454/ ER 05-232 /ER 05-0274). Erosion on baffle plate is from condenser side (not piping side). This work was deferred from RFO25. See W.O. 04-1462.

Internal visual inspection of LCV-103-3A-2 during RFO 24 indicated some type of casting flaw. The System Engineer suspects possible leaking by the normally closed valve. The downstream piping was last inspected in 1990. The line typically has no flow. Re-evaluate using the Thermal Performance Monitoring System Data and consider inspection of downstream piping in RFO27.

A through wall leak in the steam seal header supply line 1SSH4 was discovered on 9/24/04 (CR-VTY-2004-02985). A temporary leak enclosure was installed and a planned permanent repair was scheduled for RFO25. The leaks are on the bottom of un-insulated piping upstream of the gland seal. Field inspection of the leak location shows that the piping at the leak sloping down to the gland seal, not sloping up to the seal a shown on the design drawings. UT data on the top of the piping near the leak shows full wall thickness. At this time, the exact mechanism which caused the leak is not known. Additional inspections to determine the extent of condition on the 3 other gland seal steam supply lines are were recommended. **Inspection of the 90 degree elbow and approx. 2 ft. of downstream piping on lines 1SSH3, 1SSH4, 1SSH5, and 1SSH6 was planned for RFO 25. Also based on industry OE and similar piping geometry, inspection of 2 of the SPE lines 1SPE3 and 1SPE5 was planned for RFO 25. These inspections were deleted from the RFO26 scope due to higher priority LP turbine work. (References 9 & 10). Perform these inspections in RFO26. See Section LH below.**

Small Bore Piping

SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an initial inspection.

Locations on the continuous FDW heater vents to the condenser on the No. 3 heaters were inspected in 2002. The continuous vents on the No. 4 heater were installed new in 1995. The start up vents operate less than 2% of operating time. No wear was found in previous inspections on Heater Vent piping from the No 1 & 2 heaters. Given that and the lower pressure in the No. 4 heater shells, a complete inspection of the remainder of the No. 4 heater vent piping can be deferred. The existing small bore date base and the piping susceptibility analysis is under revision. No additional components from Revision 1 of the data base will be inspected.

SB: Components selected from measured or apparent wear found in previous inspection results.

Small Bore Point No. 20. 2-1/2" MSD-6 @ connection to condenser A at Nozzle 33 (Inspection No. 96-SB01 identified a low reading at weld on stub to condenser). Upstream valves are normally closed. TPM system does not indicate any abnormal flow. **Inspect this piping in RFO 26**

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

Date	Plant – Type	Description & Recommended Actions at VY
4/29/99	Darlington 1 - PHWR	Severed line at steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. (INPO Event 931-990429-1) Threaded connections typically on condensate side of HHS piping. Lower energy/consequence of leak. **Include HHS piping in FAC Susceptibility Review, and in the Small Bore Database. Include ranking and consequences of failure.**
9/1/01	Peach Bottom 3 -BWR	(From 1/14/02 CHUG Meeting), leak on 1 inch Sch. 80 line from Off Gas Re-combiner pre-heater drain line to condenser. An additional review of AOG steam supply system was performed and incorporated into the FAC Susceptibility Review. **Update small bore database to include ranking and consequences of failure.**
1/15//02 CHUG Mtg.	Hatch1/2 -BWR	Condenser in leakage due to through wall erosion (external) of 1-1/2 inch "slop" drains lines inside the condenser. Lines in each unit were cut and capped, similar events at Byron Unit 1 (OE 12609) and Columbia (OE12145). Limerick & Dresden. VY slop drain lines inside condenser were walked down during RFO24 and RFO25. Some external erosion on piping and supports was found. **Slop Drain Issue. Coordinate with Systems Engineer**
4/2/03	Peach Bottom 3 -- BWR	OE16287: Steam leak found on 3"x2" elbow on RFP Turbine sealing steam system small bore piping. Leak was on piping susceptible to FAC but was not included in the scope of the FAC Program. This occurred as the piping was part of a vendor supplied skid and was not reflected on the drawings used for the FAC program. The VY FAC Susceptibility Evaluation has been updated to include all known vendor supplied piping (VY-RPT-05-00012, Rev.0.)
10/31/03	Clinton -BWR	OE17412 / OE18478: Through-wall leaks in 2A/B heater vent lines to the condenser (larger bore lines assumed given description of backing rings in piping). Apparent cause attributed to steam jet impingement from wet steam. Equivalent line at VY is common 4 inch feedwater heater vent line for No.4 FDW heaters. This line is included in the SSB database since it connects to (2) 2-1/2" lines. Inspection priority will be determined in the small bore ranking and prioritization.

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. – continued

Date	Plant – Type	Description & Recommended Actions at VY
11/7/2003	Limerick 1, BWR	OE17818: Through wall leak in 1 inch drain line back to condenser off ES piping at the connection to the large bore line. Normally no flow in line due to N.C. valve. Piping downstream of valves to condenser on all 3 lines was scheduled for replacement. Location US of valve was thought not to be susceptible. ES piping at VY is FAC resistant A335-P1. Lesson from this event is that any carbon steel line in a wet steam system is susceptible & should be monitored. *Also full line replacement insures all susceptible piping is replaced.*
1/16/04	Clinton – BWR	OE17654: Potential trend for adverse equipment condition downstream of orifices. (Ref. Previous experience a Clinton with CRD pump min flow ROs) Inspected CRD pump min flow orifices also piping DS of RO-64-2 in RFO25. Additional inspections will be performed if further OE is obtained.
12/06/04	V.C. Summer - PWR	OE19798/OE20075: Complete failure of a 1 inch ES line at the location of a previously installed Fermanite clamp repair. Previous leak at weld installed in May 2004. See presentation at January 2005 CHUG meeting. (They did not do UT on the pipe to assure structural integrity prior to installing the clamp.) Problems with leaving CS in system DS of material replacements. **Review of previous replacements at VY has identified 2 locations at the condenser with similar configuration. Planned Inspections Nos. 07-SB04 and 07-SB05.**
2/3/04	Columbia - BWR	6/04 CHUG Meeting PER: Through wall leak in 2" CS A106 Gr.B section of Misc drain line from bleed steam trap station to collection header. Location of leak is just upstream of where discharge piping enters the into the collection header. Piping upstream of location is stainless steel. At VY MSD piping downstream of ST-60A to 60D and LCV-101-38A to 38D connecting to 8"MSD-9 is carbon steel and is included in the Small bore Piping Database. Most locations have already been inspected. No further actions for this OE.
2/17/04	Peach Bottom 2 BWR	OE18637: On line leak in 10 inch main steam drain line header to the condenser. Hole was located directly below the connection of 1" main steam lead drain. The header was replaced with 1-1/4 Chrome material approx. 5 years before the leak. Also, ROs in steam drains were modified. The cause was attributed to steam impingement. Additional information to follow after next RFO. The only large bore drain collector at VY is the 8 inch diameter low point drain header, line 8"MSD-9. Flow is through steam traps and LCVs vs. a continuous flow through a restriction orifice. This line is now part of the AST ALT boundary. Inspections of the entire bottom of this header were performed during RFO24 with recommendations for repeat inspections in 2010. Also similar SSB configuration on 3"-MSD-4 near condenser. **Inspect 3"-MSD-4 from the two 2 steam trap drains connections to the condenser.**
3/2/04	Calvert Cliffs Unit 1 - PWR	OE18730: Though wall leaks in MSR drain piping at socket welded elbow fittings. Piping was replaced with Cr-Mo in the early 1990s. Cause attributed to liquid impingement. Plant is considering changing piping to eliminate SW elbows by using pipe bends. To date at VY: no leaks have been found on Cr-Mo piping replacements. No New action required for this OE.
5/9/04	Susquehanna Unit 2 - BWR	1/05 CHUG Meeting PER: Through wall leak in 1" Main Steam Bypass line drip leg drain to the condenser. The leak was at coupling joint at the condenser. The piping was replaced with P-22 in 1992. However, the coupling was not replaced at the condenser nozzle. A similar situation exists at VY for replacement of 2"MSD-406 (Steam Leads Drains) at the condenser. **Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Insp. 07-SB04 at condenser Nozzle 35)**

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. – continued

Date	Plant – Type	Description & Recommended Actions at VY
7/4/04	Hope Creek - BWR	1/05 CHUG Meeting PER: Through wall leak in 2" turbine bleed steam drain from HP extraction. Piping and coupling was 2-1/4% Cr-Mo. Leak attributed to abnormal fit-up into the coupling. Installation quality issue not FAC wear. No further actions for this OE.
10/1/04	Confrentes (Spain) - BWR	1/05 CHUG Meeting PER: Leak in 1-1/2" P-22 pipe bend on a turbine driven (feedwater) pump drain line in the Main & Re-Heated Steam System immediately downstream of an orifice. The only steam turbine driven pumps at VY are the HPCI and RCIC pumps These pumps have low usage. No further actions for this OE.
12/8/04	TEPCO Fukushima1-4 - BWR	1/05 CHUG Meeting PER: Through wall leak in drain line from steam turbine driven feedwater pump steam supply line. The drain line runs to the condenser. The only steam turbine driven pumps at VY are the HPCI and RCIC pumps These pumps have low usage. No further actions for this OE.
1/05 CHUG Meeting PER	River Bend – BWR	Through wall leak at condenser nozzle on the 2-1/2" emergency high level drain line from the steam seal evaporator drain receiver tank to the condenser. Sections of this line are stainless steel, but the condenser nozzle is carbon steel. The apparent cause is using this high level drain line for normal level control increased wear in the CS nozzle. The equivalent piping at line at VY is 3" and 6" C-44 downstream of valves LCV-102-8-1 and LCV-102-8-2 to condenser nozzle 63. **Given that a leak in this line would affect condenser vacuum and challenge plant availability, inspect locations downstream of valves LCV-102-8-1 and LCV-102-8-2 in RFO26 (2007)**
1/21/05	D.C. Cook 1 - PWR	OE20165: Leak in Middle Heater Drain Pump Emergency Leakoff Line assumed to have no flow when the pump was not running. Geometry different from North and South Heater Drain Pumps. However flow, was in the 1 inch line when the pumps were not running. Incorrect assumption in the FAC SSE. Assumption that pump was not in service and no flows in line. **No additional inspections as a result of this OE. However, one of the DC Cook Corrective Actions should be performed at VY: "Assumptions used in the SSE will be re-validated to confirm they are still accurate". Generate PCRS/WT or ER to have reviews performed by Systems Engineers and OPS**
2/4/05	TEPCO Kashiwazaki Kariwa (K-1) – BWR	6/05 CHUG Meeting Presentation and follow up at 1/06 CHUG Meeting PER**: Through wall leak at MS Leads Low Point Drains connecting to the condenser. Pipe 50A (approx. 2 inch dia.) **Pipe material is Cr-Mo. Steel**. Leak location is approx. 9 meters downstream of orifice in pipe on extrados of exit from a 90 degree SW. TEPCO root cause is two-phase flow incorporating droplet induced erosion. VY has similar geometry. Piping at VY was originally carbon steel and was replaced with Cr-Mo in 1998. TEPCO piping has a more tortuous path to the condenser (tee and 8 SW elbows) while VY only has the SW tee. **TEPCO plans to replace the line and move the RO into the condenser. **Consider inspection of Cr-Mo Piping immediately DS of the SW tee in either 2008 or 2010 due to expected increase in drain flows at EPU conditions. CS stub piece at the condenser and upstream Cr-Mo piping will be inspected in RFO26 (2007).**
3/1/05	McGuire 2-PWR	OE20163 : Though-wall leak in a 2 inch carbon steel vent line on the MSR heating steam vent line. Caused by FAC when flashing occurred upstream of RO (design location). No MSRs or equivalent locations at VY. At VY the only Restriction Orifices are in the FDW Heater Vent System Continuous vent lines . These are already in the scope of the FAC program.

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. – continued

Date	Plant – Type	Description & Recommended Actions at VY
6/05 & 1/06 CHUG Meetings	Peach Bottom Unit 3 –BWR	Through wall leak in RCIC Steam Supply Drain line to condenser. Location on CS section of line (running through the off gas pipe tunnel) which was not replaced with Cr-Mo P-11 material. The remainder of the line was previously replaced with P11. Event stresses importance of complete line replacements. A review of VYs combined HPCI/RCIC drains as shown on Drawing VYI-HPCI RCIC Drain Rev.1 and page 15 of JO file 89-0060 shows a carbon steel stub piece at the condenser was left in the line. **Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB05)**
6/05 CHUG Meeting PER	Wolf Creek – PWR	Pinhole leak in body of 2 inch MS drain line check valve due to erosion from leak-by through upstream steam trap. Thinning was found in 2" tee downstream of steam trap. At VY, piping downstream of MS steam traps has been previously inspected. Given expected increases in flow from EPU, piping DS of ST-60-3 will be inspected in RFO26 (Small Bore Inspection 07-SB02)
8/17/05 CHUG PER 1/06	Hope Creek – BWR	Through wall leak in 1-1/2" line from Steam Seal Evaporator Drain Tank to #3 FDW Htr. Temporary welded clamshell used for repair. Plant documentation indicated line was Cr-Mo P11 material. Lab analysis of metal filings indicates piping was carbon steel. No equivalent line at VY. However, note the installed material / documentation issue.
8/24/05 Presented at 1/06 CHUG Meeting	LaSalle Unit 1	Through wall leak in RCIC Steam Supply Pot Drain line to main condenser. Leak on straight section of pipe 11 ft D.S. of SW elbow. Major portion of line was replaced with Cr-Mo P-22 material. However this section running through a wall penetration was not replaced by field. Plant documentation indicated that the line was completely replaced. Event stresses importance of complete line replacements. Similar situation to peach Bottom leak presented at 6/05 CHUG meeting. A review of VYs combined HPCI/RCIC drains as shown on Drawing VYI-HPCI/RCIC Drain Rev.1 and page 15 of JO file 89-0060 shows a carbon steel stub piece at the condenser was left in the line. **Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB05 at condenser Nozzle 56)** Also, a similar situation exists at the previous replacement of 2"MSD-406 (Steam Leads Drains) at the condenser. **Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB04 at condenser Nozzle 35)**
9/14/05	Waterford 3 -PWR	OE21577: Pinhole leak in carbon steel drain line from Main Steam drip pot. Un isolable from the steam generator. Cause attributed to external corrosion, NOT FAC. Waterford has no turbine building and the MS drain piping is exposed to the weather. All steam process piping at VY is indoors. External corrosion is not a significant concern.
9/15/05 (1/06 CHUG Meeting PER)	Byron Unit 2 -PWR	Through wall leak in No.7 (highest) HP FDW Heater vent line to condenser. 2" schedule 80 line. Previous RT on elbows near FDW Heaters did not identify FAC wear. Location of wear in lines was toward the condenser. At VY all HP FDW Htr. vent lines were replaced with Cr-Mo in RFO24. No further actions for this OE.
9/23/05, 1/06 CHUG Meeting	Cooper –BWR	OE21586: Fatigue failure of 1-1/4" turbine slop drain piping inside condenser. Caused loss of condenser vacuum and manual scram. Lines were previously replaced in January 2005 due to external erosion from the steam space. Inadequate pipe supports and recent change out of LP turbines attributed as causes. RFO25 inspection at VY indicates piping has supports and some external surface wear is occurring. Markings on fittings indicate P-11 material is installed. This indicates previous replacements at VY. Keep OE listed for future reference (Also reference: OE20044-Calvert Cliffs-1/05, OE20032-Palisades-1/05, OE20112-Oconee-1/05, OE19961-Turkey Point-12/04, OE13108-St. Lucie-9/01, OE12609-Byron-3/01, and OE12601-Hatch-10/00.)

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG. – continued

Date	Plant – Type	Description & Recommended Actions at VY
9/21/05 CHUG PER 1/06	Nile Mile Pt. 1 - BWR	Through wall leak in 1" GE supplied turbine Bypass Valve 2nd stage leakoff line 2SLBPV line to SSH. Leak location at bend in 1" line off BPV. Similar layout to VY. VY has replaced the entire 1SLBPV line with Cr-Mo in RFO25. Previous FAC inspections on common 2-1/2" header to SSH line. No inspections in 1" lines. Schedule inspection of most probable BPV leakoff lines (1 to 10) based on ranking and consequences of failure in Small Bore Database.
11/15/05 CHUG PER 1/06	Peach Bottom 3 – BWR	Through wall leak in 1" schedule 160 Main Steam Leads drain downstream of orifice to condenser. Leak repair clamp installed. Equivalent piping at VY 2"MSD-406 Steam Leads Drains replaced with Cr-Mo steel except for piping stub at condenser. **Inspect the CS and P11 piping next to the condenser in RFO26 (Small Bore Inspection 07-SB04 at condenser Nozzle 35)**
11/1/05 CHUG PER 1/06	Susquehanna Unit 1 – BWR	Through wall leak in 2" fabricated coupling in Steam Seal Evaporator Drain at Feedwater Nozzle (SSE drains to #2 FW Htr). Attached piping was replaced with Cr-Mo. However, nozzle fitting was never replaced. No equivalent line at VY.
1/06 CHUG Meeting	Diablo Canyon – PWR	Trough wall leak in 2 inch MSR LP Vent Condenser Drain line. Plant documentation indicated that all the lines were replaced with Cr-Mo material. Inspections subsequent to the leak found 6 pieces of carbon steel (not Cr-Mo) during the pipe replacements. Only found through in-situ alloy sampling. Plant includes alloy sampling in their large bore piping FAC inspections. Apparent Cause indicates problem with plant QA (replacements were part of a large fixed price contract). To date at VY, reviews of previous piping replacements have found no such discrepancies. This information should be factored into the evaluation whether or not alloy sampling should be incorporated into the VY FAC program.

SD: Components subjected to off normal flow conditions, as indicated from the turbine performance monitoring system (Systems Engineering Group).

The Systems Engineering Production Variance Report for January 1 to January 31, 2006 lists LCV-103-3B as having seat leakage to the condenser. Extraction Steam piping small bore valve is LCV-101-3B is a drain back to the condenser. Piping downstream of the valve on line "-ES-10B is Cr.-Mo steel and is resistant to FAC. The piping was previously inspected in 1993 (Inspection No. 93-SB27) and in 1998 (Inspection No. 98-SB09). No further actions will be performed for RFO26.

Since startup from 2005 (RFO25), no other small bore valves and no steam traps have been identified (to date) using the Turbine Performance Monitoring (TPM) system. However, if new data indicates leaking valves then, additions to the outage scope may be required.

LH: Components "De-Scoped" (inspections deferred) from Previous Outages

This is a new category. Planned inspections had never been deferred at VY before RFO25.

Inspection	Component	Evaluation / Reasons for Recommendation
2005-24 2005-25 2005-26 2005-27 2005-28 2005-29 2005-30 2005-31	1SSH3EL05 1SSH3SP06US 1SSH4EL01 1SSH4SP02US 1SSH5EL01 1SSH5SP02US 1SSH6EL06 1SSH6SP08US	Planned inspections on the turbine Steam Seal header (SSH) and the Steam Packing Exhauster (SPE) lines to determine the extent of condition for CR-VTY-2004-02985 CA 03 were "de-scoped" from the 2005 RFO due to higher priority LP turbine work in the same location. **Inspect these locations during RFO26 in Spring 2007.**
2005-32 2005-33 2005-34 2005-35	2SPE3EL01 2SPE3SP01US 2SPE5EL01 2SPE5SP01US	Planned inspections on the turbine Steam Seal header (SSH) and the Steam Packing Exhauster (SPE) lines to determine the extent of condition for CR-VTY-2004-02985 CA 03 were "de-scoped" from the 2005 RFO due to higher priority LP turbine work in the same location. **Inspect these locations during RFO26 in Spring 2007.**

<u>Small Bore Piping</u>

SE: Engineering judgment

Look at piping DS of orifices based on BWR OE

<u>Condensate:</u> Given the 8/04 Mihama event: consider additional component in the condensate system for inspection downstream of flow orifices & venturies.

FE-102-6 and downstream pipe on 21/2"C-43 venturi type (TB heater bay elev. 230+/- Given low operating temperatures and upstream of oxygen injection point, **scope out and evaluate for inspection in R27 in 2008**

<u>Main Steam Drains:</u> Concerns with increased Moisture Carryover under EPU operating conditions: Inspect SSB components with may experience increase flow from EPU

Component	SSB DataBase Number	Location	Reasons/ Comments
1" & 2-1/2" Pipe & Fittings D.S. of Steam Trap ST-60-3	002	Rx Bldg. off Torus Catwalk - West	EPU concerns with increased Moisture carryover. Note this is part of AST ALT Boundary. Last inspected in 1993.
1" & 2-1/2" Pipe & Fittings D.S. LVC -2-143 of Steam Trap ST-60-3	003	Rx Bldg. off Torus Catwalk - West	EPU concerns with increased Moisture carryover. Note this is part of AST ALT Boundary. Last inspected in 1993.
2" CS pipe stub at Condenser wall on line 2"-MSD-406 at condenser nozzle 35 (Steam Lead Drains)	30B	Turb. Bldg. Heater Bay. Condenser A –North	EPU concerns with increased Moisture carryover. Also, recent industry experience OE with leaks in CS components in lines with partial material replacements.
2" CS pipe stub at Condenser wall on line 2"-HPCI/RCIC Drain line at condenser nozzle 56	33	Turb. Bldg. Heater Bay, Condenser B Northeast	Recent industry experience OE with leaks in CS components in lines with partial material replacements.

SG: **Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)**

See LG above. The EMPAC search performed in LG above is applicable to both Large bore and Small bore components.

SH: **Components "De-Scoped" (Inspections deferred) from Previous Outages**

None

Feedwater Heater Shells

No feedwater heater shell inspections will be performed during the 2007 RFO. All 10 of the feedwater heater shells have been replaced with FAC resistant materials.

Recent / Relevant Industry OE Regarding Feedwater Heater Shells.

Date	Plant – Type	Description & Recommended Actions at VY
1/24/04	LaSalle Unit 1, BWR	OE18381/OE17919: Through indication indications in #2 LP feedwater heater extraction steam inlet nozzles Carbon steel nozzles with Cr-Mo upstream piping. Similar situation existed at VY prior to replacement of all feedwater heater shells with FAC resistant materials. No new actions required at VY.
4/14/25	Browns Ferry 2 -BWR	OE20797: Higher wear rates than expected found in carbon steel Extraction Steam Inlet nozzles on No.3 LP feedwater heaters. Upstream pipe had been replaced with Cr-Mo and C.S. weld build-up had been performed on nozzles. Also a 105% power uprate increased flows. VY has Cr-Mo. ES piping with either Cr-Mo Nozzles or S.S. nozzles. No further actions are required for this OE.
7/26/05 Presented at 1/06 CHUG Meeting	LaSalle Unit 1, BWR	OE:21384: Through Wall Leak in #3 LP feedwater heater shell. Htrs were scheduled for inspection at next RFO. Ranked as lowest priority due to high ES steam quality. Through wall erosion primarily caused by heater design with common axial location for HD inlet and outlet, and to ES inlet nozzles. Through wall leak determined to be result of weld defect (porosity) aggravated by FAC and leading edge effect..

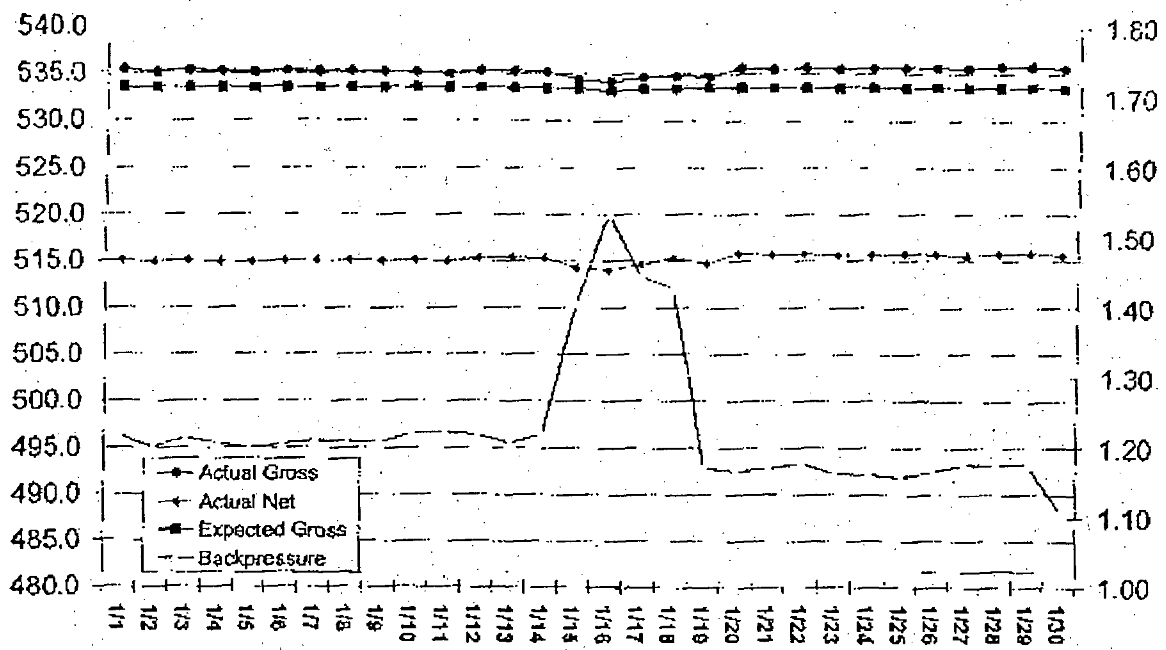
References

1. PP 7028 Piping Flow Accelerated Corrosion Inspection Program, LPC 1, 12/6/2001.
2. V.Y. Piping F.A.C. Inspection Program - 1996 Refueling Outage Inspection Report, March 23.1999.
3. V.Y. Piping F.A.C. Inspection Program - 1998 Refueling Outage Inspection Report, April 2,1999.
4. V.Y. Piping F.A.C. Inspection Program - 1999 Refueling Outage Inspection Report, February 11, 2000.
5. V.Y. Piping F.A.C. Inspection Program - 2001 Refueling Outage Inspection Report, August 11,2001.
6. V.Y. Piping F.A.C. Inspection Program - 2002 Refueling Outage Inspection Report, January 20, 2003.
7. VY-RPT-04-00010, Revision.0 ," Vermont Yankee Piping Flow Accelerated Corrosion Inspection Program (PP 7028) 2004 Refueling Outage Inspection Report (RFO 24)"
8. VY-RPT-06-00002, DRAFT ," Vermont Yankee Piping Flow Accelerated Corrosion Inspection Program (PP 7028) 2005 Refueling Outage Inspection Report (RFO 25 –Fall 2005)"
9. VYPPF 7102.01 RFO25 Scope Deletion of Restoration of TM 2004-031 (WO 04-4884-06), dated 10/24/05.
10. VYPPF 7102.01 RFO25 Scope Deletion of FAC Inspections 2005-24 to 2005-35 (WO 04-4983-000/010). dated 11/1/05.

SYSTEM ENGINEERING PRODUCTION VARIANCE REPORT

VY 2007 OUTAGE RFO26 SCOPING WORKSHEET

Actual vs. Expected Production January 1 to January 31, 2006



EVENTS

Date	Loss	Event
1/16/06	1 MWe/hr	Recirc Gate open to de-ice intake bay

Full Power Averages For Previous Four Weeks

- Actual Gross 535.3, Expected Gross 533.5, Net 515.2, Condenser Back Press: 1.22"HGA, Circ Water Inlet: 38° F, Average Difference in Heat Balance to actual: ~ 1.8 MWe (Gain)

Known Losses (MWe per hour)	Loss	Tracking Item
• Operation < 1593	~ 0.1	N/A
• Actual Operation < Indicated Operation	~ 0.7	ER 04-1187
• LCV-101-3B Seat Leakage	~ 0.13	WO 05-4597
• Main Steam Bypass Valves 1,5 & 7	~ 0.85	PM due in RFO26

System Engineering Observations and Recommendations:

- High Circ Water traveling screen dp's resulted because of ice and debris flushed into the river from the heavy rains this weekend. The Control Room needed to open the Recirc Gate to de-ice the intake bay to address this. As a result, the Condenser is operating at a higher backpressure and net generation is down by approximately 1 MWe. This will not be categorized as a loss per the PI's because it is caused by environmental conditions beyond plant managements control.
- Lower backpressure was achieved on 1/31/06 by throttling open the SJAE suction valves, PCV-OG-516A/B. Opening these valves during EPU summer operation may provide for lower backpressure.
- Cycle Isolation has been restarted. A blown fuse was found, presumably as a result of the UPS-2A restart. The work order is being left open to troubleshoot several computer points that are not indicating properly.

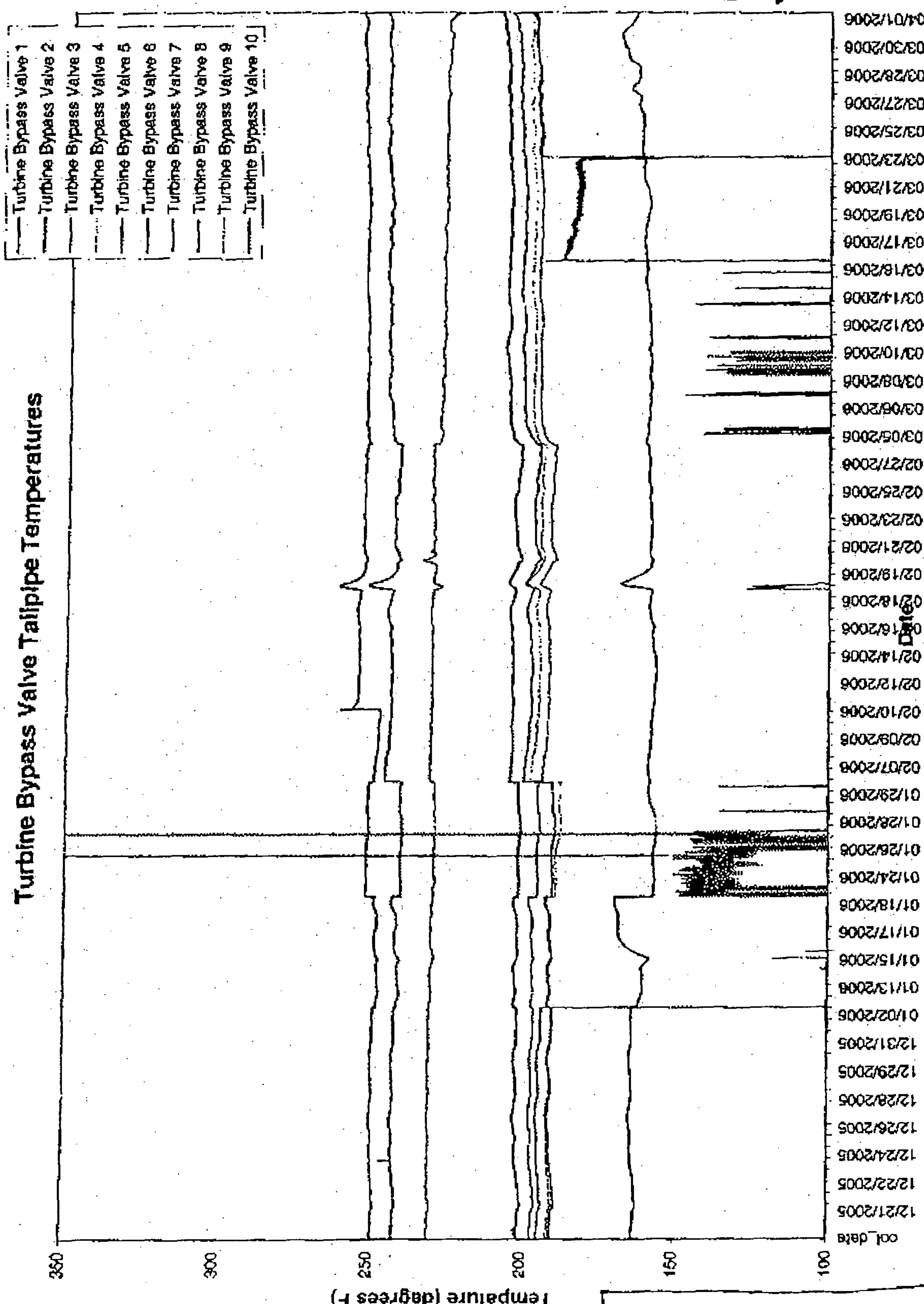
Thermal Performance Work Status

- Performed Heater Bay Thermography walkdown of un-instrumented high energy line valves to inspect for leaks during the 2/2/06 downpower. All valves inspected holding tight.

R/24 SB 1E

NEC017911

VY FAC PROGRAM RP026 (2007) FAC
SCOPING WORKSHEETS.



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PP 7028 FAC INSPECTIONS 2004 REFUELING OUTAGE

TABLE OF CONTENTS

2003-2004 Program Scope Memo
Vermont Yankee -Engineering Department

WBS Element:	6098	Pro"ect Number: 6098
Title:	Piping Flow Accelerated Corrosion (FAG) Inspection Program 2003 & 2004 Efforts	
De artmenl:	Des! n En ineerln - Mechanical I Structural	
Owner:	James Fltz trick	
Backu :	Thomas O'Connor	
Procedure No. & Title:	pp 7028, Piping Flow Accelerated Corrosion Inspection Program	

Detailed Scope of Prolect (explanation): Engineering activities to support ongoing Inspection Program to provide a systematic approach to insure thai Flow Accelerated Corrosion (FAC) does not lead to degradationofplanl piping systems. Program Procedure PP 7028 controls engineering and Inspection activities to predict, detect, monitor, and evaluate pipe wall thinning .due to FAC. Activities include modeling of plant piping using the EPRI CHEGWORKS code to predict susceptibility to FAG damage, selection of components for inspection, UT inspections of piping components, evaluation of data, trending, monitoring of industry events and best practices, and recommending future repairs and *for* replacements prior to component failure.

Expected Benefits (Justification): VY committed to have an effective piping FAG inspection program in response to GL 89-08.

Consequences of Deferral: Possible hazards to plant personnel, Loss of plant availability, unscheduled repairs, and deviation from previous regulatory commitments.

Duration of Program: Life of plant

Key Deliverables or Milestones:	Completion Estimate
Issue 2002 Outage Inspection Report Issue 2004 RFO Outage Inspection Scope per Entergy template (14 months before outage). Including Scoping worksheets.	1/22/03 3f27/03
Update Piping FAG susceptibility screening to account for piping and drawing updates. Include consideration of power uprate &life extension.	611/03
Update piping Small bore piping database and FAG screening to account for piping and drawing updates. Include consideration of power uprate &life extension.	7/1/03
Update GHECWORKS mOdels with 2001& 2002 RFO Inspection data (Note ideally results are to be used in detennining the 2004 inspection scope, however schedule mllestonas override program logic.)	9/1/03

Key Dellverables or Milestones: - continued	Completion Estimate
Updates to Program Procedures as identified in Self Assessments.	6/1/03
Develop FAC Program Health Report Template (Format and Performance Indicators) .	7/1/03
Perform Program Self Assessment (minimum once per cycle).	*10/1f03*
Ongoing Program Maintenance. Includes: procedure revisions. program Improvements, benchmarking, attendance at industry meatinns & evaluation of Indusl events for effects on VY.	*12f31/03*
RFO 24 support	*5/1f04*
Issue 2004 Outage Inspection Report	*7f15f04*
Update CHECWORKS mOdels with 2004 RFO InspecUon data.	*8115104*
Issue 2005 RFO Outage Inspection IScope per Entergy template (Approx. 14 months before outage) Including Scoping worksheets.	*8115104*
Perform Program Self Assessment (minimum once per cycle).	*1011104*
Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry meetinos & evaluation of industrv events tor effects on VY	12/31/04

Estimated Bud et or Ex enses:		Amount	
Ca lured in DE MechJStruclural Base Bud et		NfA	
Others Impacted By Project:	Support Required? Yes/No	Estimated Hours	Review
2120 - S tern En ineerin	YES	40	
2130 E ineeri Su ort			
2160 Fluid S stems En ineerin	YES	40	
2160 Electrical/I&C En ineerin			
2160 Mechanical/Structural Des' n			
others:			

Level 3 Fra net: Attached

Performance Indicator (as applicable) Performance Indicators for FAC Program wilt be developed in new Program Health Reports Task as defined above.

Engineering Department
Work Management Handbook

YEAR 2004

Task No.	Task Description	Preparer (HRSJ Estimated	Reviewer (HRS) Estimated.	TOTAL (HRS) Estimated.	Est. Start	Est. Delivery f Completion Date
04-1	RFO 24 support	160	80	240	3/15/04	5/1/04
04-2	Issue 2004 Outage Inspection Report. Required within 90 days of startup from 2004 outage	50	30	90	6/1104	7/15104
04-3	Update CHECWORKS models with 2004 RFO Inspection data.	120	50	160	6/1/04	8/15/04
04-4	Issue 2005 RFO Outage Inspection Scope per Entergy template (14 months before outage) Including Seoping worksheets.	40	20	50	8f1/04	8115f04
04-5	Perform Program Self Assessment {minimum once per cycle}.	40	20	50	9f1f04	1011/04
04-'	Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarkJng, attendance at industry meetings, evaluation of industry events for effects on VY.	200	50	250	1/01/04	12131104
2004			Total Hrs	880		

NEC020182

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Piping FAC Inspection Program
Level 3 Fragnet

Task No.	Task Description	PREP (JCF)	REVIEW (TOe)	TOTAL (Hrs)	Est. Start	Est. Finish	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
03-3	Update Piping FAC susceptibility screening to account for piping and drawing updates. Include consideration of power up"'t. & life extension).	150	30	80	14115/03	611/03												
03-4	Update piping Small bore piping database and FAC screening to account for piping and drawing updates. Include consideration of power uprate & life extension).	180	40	1120	5/1103	711/03												
03-5	Update CHECWORKS models with 2001& 2002 RFo Inspection data (Note ideally 'esults are to be used in determining the 2004 inspection scope, however schedule milestones override program logic.)	120	60	180	7/11031	911/03												
03-6	Updates to Program Procedures as identified in Self Assessments.	40	20	60	5/1/03	6/1/03												
03-7	Develop FAC Program Health Report Template (Format and Performance indicators)	20	10	30	611/03	7/1103												
03-8	Perform Program Self Assessment (minimum once per cycle)	40	120	160	7/1103	10111031												
	Ongoing Program Maintenance. Includes: procedure revisions, program improvements, benchmarking, attendance at industry meetings, & evaluation of industry events for effects on vy.	160	40	200	1/1103	12/31/03												

NEC020183

Activity ID	Activity Description	Current Start	Current Finish		Resource	Bud Qty	Total Float	Predecessors

Erosion Corrosion Program [redacted]

Activity ID	Activity Description	Current Start	Current Finish		Resource	Bud Qty	Total Float	Predecessors
6098033	Update Piping FAC Susceptibility Screening -Drwg	15APR03A	02JUN03	34*	ME-FITZP, [illegible]N	60.00	0	609803[illegible]
[illegible]9[illegible]036	Update to Program Pr[illegible]edu[illegible] as identified in SA	01MAY0[illegible]	[illegible]2JU[illegible]	22*	ME-FITZP, ME-OCONN	60.0[illegible]	2,450	
[illegible]	Upd[illegible] Piping Small [illegible] Pi[illegible]g Database [illegible]d FAC	03JUN03	01AUG03	43	ME-FITZP, ME-OCONN	20.00	0	
6098037	Develop FAC Program Health Re[illegible]rt Template	02JUN03*	01JUL0[illegible]	22*	ME-FITZP, ME-OCONN	30.00	0	
[illegible]09[illegible]03[illegible]	Update CHECKWORKS Model w/ 2001/2002 RFO [illegible]ct	01JUL03*	[illegible]2SEP03	44*	ME-FITZP, ME-OCONN	150.00	43	
609[illegible]038	Perform P[illegible]ram Self Assessment	01JUL03*	01OCT0[illegible]	[illegible]	ME-FITZP, ME-OCONN	60.00	59	2003END
23P6098	Erosion Corrosion P[illegible]ram Maintenence	[illegible]N[illegible]3A	31DEC03	2		200.0[illegible]	0	2003END

[redacted]

Activity ID	Activity Description	Current Start	Current Finish		Resource	Bud Qty	Total Float	Predecessors
6[illegible]042	Issue 2004 Outage Inspection [illegible]port (90 Day Req)	01JU[illegible]4*		32*	ME-FITZP, ME-OCONN	90.00	-28	6098043* RF24-20
609[illegible]	Update CHECKWORKS model w/ 2004 RF[illegible] Inspect Data	[illegible]JUL04	2[illegible]EP04	54	ME-FITZP, ME-OCONN	80.0[illegible]	-29	6098044*
[illegible]44	Issue 2005 RFO Outage [illegible]nspect [illegible]cope E[illegible]rgy Temp	20SEP04	[illegible]4OCT04	1	ME-FITZP, ME-OCONN	60.00	-29	
60[illegible]045	Perform [illegible]gram Self [illegible]essment	01SEP04*	01OCT04	23*	ME-FITZP, ME-OCONN	60.00	62	2004END
[illegible]4P60[illegible]	Erosion Corro[illegible]n P[illegible]ram Ma[illegible]nance	[illegible]2J[illegible]N04		2[illegible]7	ME-OCONN, ME-FITZP	250.00		

[redacted]

SI-Cycle Ba

Activity ID	Activity Description	Current Start	Current Finish		Resource	Bud Qty	Total Float	Predecessors
7230A05	[illegible] Cu[illegible] and V&V	[illegible]JUL03*	27AUG[illegible]3	22	ME-FITZP	0.00		
7230A06	SI/VY Historical Baselining	2[illegible]UG0[illegible]	1[illegible]OCT03	[illegible]	ME-FITZP	0.00	39	
7230A06	VY Dev[illegible]p Fatigue [illegible]nitoring	1[illegible]JUL[illegible]	2[illegible]OCT03	75	ME-FITZP	0.00	40	2003END
7230A07	SI Installation [illegible] Training	1[illegible]OCT03	[illegible]OCT03	11	ME-FITZP	0.00	39	2003END
723008	VY - Fatigue Project Support	[illegible]JAN03A	[illegible]1DEC0[illegible]	[illegible]	ME-FITZP	,000.00	0	2003END

Start Date	01JAN98
Finish Date	31MAY07
Data Date	12MAY03
Run Date	1[illegible]MAY03 14:00

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John Dougherty
EX 3098
VY Engineering Work Control

Inspection Location Worksheets / Methods and Reasons for Component Selection

By: [signature] 3/27/03 Reviewed [signature] 3/21/03

Piping components are selected for inspection during the 2004 refueling oUlage based on the following groupings and/or criteria.

Large Bore Piping

LA: Components selected from measured or apparent wear found in previous Inspection results.

LB: Components ranked high for susceptibility from current CHECWORKS evaluation.

Le: Components identified by induslryeventslexperience via the Nuclear Network or through the EPRI CHUG.

LD: Components selected to calibrate the CHECWQRKS mOdels.

LE: Components subjected to off normal flow conditions. Primarily isolated tines to the condenser In which leakage is indicated from the lurbine perfonnance monitoring system. (through the Systems Engineering Group).

LF: Engineering jUdgment / Other

LG: Piping identified from EMPAC Work Orders {malfunctioning equip., leaking valves, etc.l

Small Bore Piping

SA: Susceptible piping locations (groups of components) contained tn lhe Small Bore Piping data base which have nol received an initial inspection.

SB: Components selected from measured or apparent wear fOUnd in previous inspection resuits.

sc: Components Identified by industry events/experience via the Nudear Network or through the EPRI CHUG.

so: Components subjected to *cff* normal ftowconditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system. (through the Systems Engineering Group).

SE: Engineering Judgment / Other.

SG: P"lp'ing identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc;)

Feedwater Heater Shells

NO feedwater heater shell inspections will be performed dur'Ingthe 2004 RFO. Previcus plans were to complete the IIT grids on the No,1 & 2 heaters have been made moot by the decision to replace ali 4 HPfeedwater heaters for *EPU. The Shells on all four new heaters will be a Chrome-moly material* (P-11). *Informational visual inspections of* the open ends cf Feedwater, Extraction Steam, Heater Drain, Vents and Moisture Separator piping will be performed as access is available.

LA: Large Bore Components selected(Identified) from previous Inspection Results

From the 19951199611998119991200112.002. Refuelin9 Outage Inspections (Large Bore Piping) these components were identified as requiring future monitoring. Ttle following components have either yet to be inspected as recommended, or the recommended inspection is in a future outage

Inspect. No.	Loc. SK	ComponemID	Notes/Comments / Conclusions
96-13 96-14	001	FD01EL04 FD01SP04	1996 report recommended inclusion of FD01SP04 into 2001 RFO Scope (lower readings at U.S. counterbore). UT Inspect elbow and downstream i e In 2004
99-03 99-04	002	FD02.EL01 FD02.TE01	1999 Recommendation to inspect tee in 2002. Component is downstream of pump 18."B· Pump 'IS used a standby pump, based on usage, inspection was deferred until 2004. UT inspect elbow and downstream tee in 2004
99-25 99-26	00.	FD14EL03 FD14SP03	1999 recommendation to inspect pipe at upstream counterbore in 2004. Given that the only low readings were at the pipe counterbore and that 2004 RFO work includes replacement of both No.1 feedwater heaters located under the elbow. Defer re-inspectlon olthe elbow FD14EL03 & pipe FD14SP03 unlil the 2005 RFO.
101-03 01-04	001	FD01EL01 FD01TE05	2001 recommendation to inspectthe tee In 2.004. UT Inspect elbow and downstream tee in 2004 (1998 RFO results recommended inspection in 2001) Also add inspection of the reducer upstream olthe elbow
02-08 0:2-09	016	FD18EL01 FD18SP02US	2002 recommendation to Inspect the elbow in 2007 based on a single measurement. Re-Inspect elbOW and downstream pipe In 2007 (3 cycles from 2002).

LA: Large Bore Components eelected (identified) from previous Inspection Results - continued

Turbine Cross-around Piping:

Previous Intemal Visual UT & Repair History:

Line	Mat.	Year Replaced	Internal Visual =V Internal Thickness UT, Re irs Performed =R							
			RF016 81992	RFOt7 F1993	RF018 81995	RF019 F1996	RF020 S1998	RF021 F1999	RF022 82001	RF023 F200:2
36"-A	GE**	1983		V	V	V	V			
36"-B	GE**	1981	V	V	V	V	V	V		
36"-e	GE"	1981	V	V	V		V			
36"-D	GE**	1983		V	V		V			
30"-A	P-22"	1985	V		V		V			
30"-B	CS.	Or inal	VIUT/R	VIUTIR-	VIUTIR	V/UT _	V	V		V
30"-C	P-22"	1993	VIUT/R							
30"-0	P-22'	1985			V					

" 36' stalghtpipesactions raplacad With GE B50A24E, elbowson theB&Clines are Orginal GE pecification D50A67D, elbows on A &0 lines are 050A67E (Tnom =0,625 inch).
'30" A,B,C replaced with A691 CL22 (2_114Cr), Fittings A234 WP22. (Tnom. = 0.625 inch)
30' B remains GE B50A2420, fittings and GE 050A670 carbon steel (Tnom = 0.50 inch),

_NOTE: Reference Dwg. No. 5920-6841 Sh.1 of2 needs to be updated with correct information. This wlll be !perfonned during the EPU design change effort.

2004 RFO HP turbine work and MS internals/drain line work will have all (4) 36 inch line manways open for access to perform internal visual inspections.

Perform intemal visual inspection of all four lines, Priority is A 36'line for access to internals of the 12 inch diameter CS stub piece In extraction steam line. Also if manways and CIV SRVs are removed, perform visual inspection of the 30" C & D lines to confirm condition of P22 replacement materiais.

2005 RFO based on Increased flows and the possibility of different flow regimes in both the 36 & 30 inch piping, perform a visual inspection. LP turbine work in 2005 RFO may provide opportunity for access to the 30· lines. As a minimum inspect (2) 36 inch lines and the 30" B line.

LB: Large Bore Compon&nla Ranked High for Susceptibility from CHECWORKS Evaluation

The current CHECWORKS wear rate calculations contain Inspection data up to the 1999 RFO and wear rale predictions are current to the 2001 RFO. The 2001 and 2002 RFO inspection data has been entered into the CHECWORKS database, However, updaled wear rate calculations are not complete, and won't be in time to support the schedule date for Issuing the inspection scope for the Spring 2004 outage. Based on a review of the 2001 and 2002 RFO inspection data for components on Ihe Feedwater, Condensale, and Heatar Drain Systems, the CHECWORKS models still appear to over-predict actual wear, Nothing newar unanticipated was observed in 2002.

Feedwater System

Listed below are components wh',ch meet Ihe follow'Ing criteria:

a) negative time to Tmin from the predictive CHECWORKS runs which include Inspection data up to the 1999 RFO,

b} no inspections have been performed on these components or the corresponding components in a parallel train since the 1999 RFO.

Component ID	Location Sketch	Location	Notes
FD07EL03	005	T.B Feed Pump Room	No inspection data for corresponding component FD08EL02 in other train. Inspect this orthe other train component In 2004. This component will be Inspected In 2004.
'FD07TE01 'FD07EL11	006	T.B Healer Bay Elevs 228 & 248	Components on other train were inspected in 1998. Results indicate minimal wear. After updating the CHECWORKs model with newer data, assess need for additional ine ections In 2005 RFO.
FD07EL12	006	T.B Heater Bay Bev, 248	Feedwater healer replacement to occur in 2004 RFO. Perform Internal visual Inspection at open end on this comnonenl.
FD14EL07	009	RX Steam Tunnel El. 266	Internal visual of elbow performed In 1996 during Check valve replacement. no indication ofwaliloss at that time. Inspect this or the other train component in 2004. Inspect this com nent In 2004.
FD08EL02	011	T.B Feed Pump Room	No Inspection data for corresponding component FD07EL03 in other train. Inspect this or the other train component in 2004. FD07EI03 wlll be Inspect&d In 2004.
FD08TE01 FD08EL07	012	r,B Heater Bay Elevs 228 &248	Intermediate components FD08EL06 & FD08SP06 were inspected in 1998. Resulls indicate minimal wear. After updating CHECWORKs model with newer data, assess need for inspecting components on the train vs. these.
FD08EL08	012	T,B Heater Bay Elev. 248	Feedwater healer replacement to occur in 2004 RFO. Perform internal visual Inspection at open end on this component.
FD15EL08	01	RX Steam Tunnel EL 266	Internal visual of elbow performed in 1998 during check valve replacement. no Indication of wall loss at that lime. After updating CHECWORKs model with new&rdata, assess need for inspecting this component in 2005 RFO.

LB: Large Bore Components Ranked High for Susceptibility from CHECWORKS Evaluation. continued

Condensate System

Only one component was identified as having a negative time to Tmin. This was CD30TE02DS, the downstream side of a 24x24x20 tee on the condensate header in the feed pump room. The CHECWORKS prediction for the downstream side of the tee has a smatt negative hrs relative to the remainder of the components in the system and relative to the upstream side of the same tee. Other tees on the same header have been previously inspected and show no significant wear. The CHECWORKS model Includes UT data up to the 1999 RFO. The inspections on this system performed in 2001 indicate minimal wear. The 2001 inspection data witt be input to CHECWORKS to better calibrate the model.

To inspect the components with the highest susceptib'lity as ranked byCHECWORKS and to obtain a more complete set of inspection data for the Condensate System inspect additional components between the No.3 feedwater heaters and the feedwater pumps. Inspect CD30TE02 and CD30SP04 in 2004.

Moisture Separator prains & Heater Drain System.

No components identified as haVing negative times to Tmln. No components wera selected for inspection in 2001 or 2002 based on high susceptibility. However future operation under HWC will change dissolved oxygen in system. A separate evaluation has been performed and components were selected for inspection in 2002. See Section LD below.

Extraction Steam System

Three components on this system with negative time to code min. wall. The piping is Chrome-Moly. ES4ATEOI & ES4ATE02, 30inch diameter tees Inside the condenser have negative prediction (-3426Hrs.) for lime to min wall. The negative times to Imin may be conservative based on the modeling techniques used. Refinement of the model of this system is in progress. The negative time to tmin is most likely a function of lack of inspection data vs. actual wear. Due to exlernallagglng on this piping and the location inside the condenser. no components are selected for external UT inspection in 2004 based on high susceptibility. However, an opportunity to parfOlITl an Internal visual inspection of all the Extraction Steam lines inside the condenser during planed LP turbine work in the 2005 RFO may present itself. See Section LF below.

Note the short section of A106 Gr. B straight pipe on line 12'-ES-1A at the connection to the 36 Inch A cross around line is not modeled In CHECWORKS. The component material should be included in the next model update.

LC: Large Bore Components Identified by Industry Events/Experience.

Review of FAC related Large Bore Operating Experianee (OEI and/or piping failures reported since January 2001

Date	Plant Type	Deseri tion & Recommended Actions at VY
4/7101	Callaway - PWR	Unexpected extent of thinning in feedwater piping (NRC IN 2001-009 & INPO OE12342)Add'rtionai components were Inspected 'In the feedwaler system in the 0 ll durin the 2002 RFO in res onse to this event.
5/9/01	Grand GUlf-BWR	Pin Hole Leak in 4 inch carbon steel elbOW in RHR min flow line. System has low use atVY «2% of time). A review of VY drawings VYI-RHR-Part 14 Sht.111 and VYI-RHR Part 15 Sht111 show elbows downstream of restriction orifices. Additional research into this event is warranted. Inspections oan be performed with the plant operatino. Don't include in the scope of 2004 RFO.
11120/01	Hamoka 1 BWR	Rupture of HPCI/RCI 6 Inch steam supply line at a section of pipe to RHR Hx sprays. VY 'IS an older desion which does not have lhis configuration.
9124102	IP2 - PWR	Pin hole leak on 26 ½" cross-under piping (HP to MSR) in vicinity of dog bones at expansion joint under location of weld overlay localiZed wear under/aroUnd a previous weld overlay repair. VY has solld piping (no expansion joints. Visual Inspections of CAR pipina will be performed in 2004.
112102	Point Lepreau-PHWR	Failure of Extraction Steam Bellows from LP turbine. VY bellows are made from stainless steel. Primary causes of past failures have been cracking of convolutions and vibration failures of tie rods. The bellows were replaced in 1995 and should not be susceptible to FAC dama e.
1115102 CHUG Meeting	Surry 1-PWR	Leak in 8 inch Condenser drain headerfor 3 14 'pt. FDW Heatervents. Also thinning in Gland steam Piping Inside the condenser and the12" Condenser Drain header from MS Drain trap lines. The only large bore drain collecloral VY is the 8 inch diameter low point drain header. Inspect sections of this line during the 2004 RFO.
1/15/02 CHUG Meeting	Cooper BWR	Thinning found in two 20 inch diameter exit nozzles offLP turbine for extraction steam piping. (VY has replaced all LP turbine stub pieces upstream of the exoansian bellows with P-11 malerial. No actions are required at this time.
6/02 CHUG Meeting,	Oconee 1	Wear found In Heater Drain piping downstream of block valve. Ops was using the gate valve to control flow. All valves on VY HD system are control valves. Normal flow downstream of valves is directly into the teedwater heaters. Bypass valve discharge directly into condenser. TPM monitors possible leakage past the Bypass valves.
6/24102	Prairie Island 1 - PWR	Preliminary notice of possible extraction steam line piping/bellows failure inside condenser. (See 1/2102 Point Le reau notice above.
8129102	Turkey Point 3-PWR	Failure of a 6x10 SchedUle 40 carbon steel expander in Heater Drain System downstream of a level control valve. Same valve on other train was replaced. However, no inspections were performed on this valve (from INPO Event 250-020829-1, DE 14866. & Info al1103 CHUG Meeting), Location is similar to millstone 2 & 3 events in 1991/92. Piping on HD system at VY OS of normal level control valves is constructed from FAG resistant materials or planned for replacement with new Feedwatar Heaters. No actions are re uired for this OE.
1019102	Clinton -BWR	Interconnecting piping (4 and 6 Inch diameter) between RWCU Heat Exchanger not included in FAC program, Plant assumed they were equipment when in fact they are piping. VY has replaced the original 3 Perflex Hx design with aU-tube Hx. RWCU pi ing in this area is stainless steel. Therefore not an immediate concern.

LD: Large Bore Components Selected to Calibrate CHECWORKS

The CHECWORKS models have been upgraded to include the 96, 98, & 99 RFO inspection data. The 2001 and 2002 inspection data has been loaded however wear rate analyses are not complete at this time. In 2001 components on the higher temperature end of the Condensate System were inspected to calibrate the CHECWORKS models. The inspection data indicate minimal wear and should reinforce the assessment oflowwear in the Condensate System. Additional components selected for inspection in 2004 in Section LB above wiil bs used to calibrate the CHECWORKS model.

Prior to the 2002 there was limited Inspection data for the Heater Drain system. The current CHECVIIORKS modelS (Pass 1 and some Pass 2) indicate low wear rates. During 2002 a number of new Inspections were performed to obtain base line data prior to operation under GE Noble Metals HWC. NO additional components on the Heater Drain system will be inspected in 2004.

LE: Large Bore Components subjected to off nonnal flow conditions identified by turbine perfonnance monitoring system (Systems Engineering Group).

The Systems Engineering Production Variance Reports for 2002 & since startup from 2002 (RF023) do not identify any leaking valves. No other leaking valves or steam traps have been Identified (to date) using the Turbine Performance Monitoring (TPM) system. No components will be scheduled for the 2004 RFO based on the TPM reports to date. However, if new data indicates leaking valves then, addttions to the outage scope may be reqUired.

LF: Engineering Judgment / Other

Nine ASME Seelion XI Class 1 Category B-J welds are to be inspected by the FAC program per Code Case N-560 in lieu of a Section ~~XI~~ volumetric weld inspection. The VY ISI Program Interval 4 schedule for inspection of these welds is as follows:

Refueling Outage	Section XI ISI Program Weld D	Description	FAC Program Components
Spring 2004 (RF024) Interval 4 Period 1, Outage 1.	FW19-F3B FW19-F3C FW19-F4 FW21-F1	upstream pipe to tee tee to reducer reducer to pipe tee to pipe	"A" Feedwater on Sketch 010 FD19TE01 FD19RD01 FD19SP04 FD21SP01
Fall 2011 (RF029) Interval 4 Period 3, OutageS,	FW18-3A FW20-3A FW20-F1 FW20-F1B FW18-F4	upstream pipe to tee tee to reducer reducer to pipe horizontal pipe to pipe tee to oioe'	"B" Feedwater on Sketch 016 FD18TE01 FD20RD01 FD20SP01 FD18SP04

LF: Engineering Judgment I Other – continued

Al! Extraction Steam piping is A335-P11, a 1-114 chrome material, except for a short calbon steel stub piece in line 12"·ES·1A at the connection to the 36" A cross arournlline. Internal visual inspection of this stub piece will be performed along with the 36" A cross around line. This extraction stream line (6th point extraction) has the highest quality sleam of all extraction lines which indicates a relatively lower wear rala. Based on the 1996 inspection data for the carbon steel section, ES1ASP01 (inspection 96-07A) showing a small area of wall thickness less than 0.875 x nominal thickness, the expected changes in flow regime due to power uprate, and that this is the only carbon steel section in the ES system, a repeat inspection to confirm actual wall thickness and also to obtain a baseline thickness prior to power uprate should be performed. Porfonn external UT Inspection of ES1ASP01 in RF024.

Extraction Steam piping in the condenser has eXlernallagging which requires significant effort for removal when performing external vr inspections (pius there are significant staging costs). The piping is A335-P11. However an opportunity to perform an intemal visual inspecUon of all the Extraction Steam lines inside the condenser during planed LP turbine work in the 2005 RFO *may* present itself.

LG; Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

Word searches 01 opan work orders on EMPAG ware performed for the following keywords: trap, leak, valve, replace, repair, erosion, corrosion, steam. FAG, wear, hole, drain, and inspect. No previously unidentified components or piping were identified as requiring monitoring during the Spring 2004 RFO.

Small Bore Piping

SA: Susceptible piping locations (groups of components) contained in the Small Bore Piping data base which have not received an Initial inspection.

Locations on the continuous FDW heater vents to the condenser On the No.3 heaters were inspected in 2002. The continuous vents on the No.4 heater were installed new in 1995. The start up vents operate less than 2% of operating time. No wear was found In previous inspections on Heater Vent piping from the No.1 & 2 heaters. Given that and the lower pressure in the No.4. shells a complete inspection of the remainder of the NO.4 heater vant piping can be deferred. The existing small bore date base and the piping susceptibility analysis is under revision. No additional components from Revision 1 of the data base will be Inspected.

SB: Components selected from measured or apparent wear found in previous Inspection results.

Small Bore Point No. 20. 2-112" MSD-6 @ connection to condenser A at Nozzle 33 (Inspection No. 96-SB01 identified a low reading at weld on stUb to condenser). Upstream valves are normally closed. TPM system does not indicate any abnormaiflow. No inspections will be performed on this line in 2004.

A through wall leak in the turbine bypass valve chest 1st seal leak-off line form the No.1 bypass vales occurred in 2003. (ER 2003-044) A temporary leak enclosure has been installed (T.M.2003-002 to contain the leak). W.O. 03-0364 was written fo inspectlrepairireplaceiline. The line should be completely replaced with chrome-moly piping. (Dresden has already done this) Given the amount ofwork already scheduled forthe heater bay during the 2004 RFO a complete replaoement will be deferred. A local code repa'if of the piping will performed to remove the temp Mod during the 2004 RFO. Additional inspections should be performed to insure the integrity of the line. The long tern solution (if license renewal is pursued) Should include replacement the entire line With chrome-moly material.

S tem	Deserl tion	Ins ection No.
2" 1SLBPV	2 inch header off the turbine bypass valve chest first seal leak-off connections. Inspect five locations on !his line. include the ½ line at the No.2 valve. It has the next hi hest usa e from the no.l valve.	2004 5B01 to 5805
2-112" ISPL2	*HP Turbine pocket drains. inspect first two elbows and connecting piping under turbine based on readinll from 1993linspections 93-5849 to 93-SB52)*	20045B06 & 5807

Small Bore Piping

se: Components identified by industry eventslexperlence via the Nuclear Network or through the EPRI CHUG.

Date	Plant - T e	Descri tion & Recommended Actions at vY
1123198	Calvert Cliffs 2 -PWR	Rupture of a moisture separator re-heater (MSR) 2 inch vent line (INPO Event 318-980123-1) No MSRs at VY, therefore no ea'uivalent line at VY,
11103198	Hamoka 2 'WR	Leak due to FAC in turbine driven feed pump casing drain line No turbine driven feed oump at VY; therefore no eauivalent line at VY.
4/29/99	Darlington 1 - PHWR	Severed line at steam trap discharge pipe at threaded connection. Equivalent to HHS system at VY. (INPO Event 931-990429-1) Threaded connections typically on condensats side of HHS piping. Lower energy/consequence of leak. ConSider durin next undate of the Small bore data base.
5101199	Darlington 4 - PHWR	Leak On HP Feedwater Heater Vent Line downstream of orifice (INPO Event 934-990507-1\. At VY ins ctions have rformed OS of orifices on HV lines.
6114/99	Darlington 2 - PHWR	Leak on steam trap discharge pipe at threaded connection. Equivalent to HHS svstem at VY. INPO Event 932-990614-1) Same as above.
10101/99	Darlington 2 - PHWR	Leak on Feedwater HeaterVent Line downstream of orifice (INPO Event 932-991007:1\: At VY inspections have performed OS of orifices on HV lines.
10/1100	Ocone3_PWR	From 1/2001 CHUG Meeting. MSR Scavenging steam line Pinhole leak In I' i e downstream offlow control valve. No eoulvalent s stem VY.
1/8/01	Oyster Creek - 'WR	Rupture of 2 inch line connecting controller/transmitter level column to re-heater drain tank. No MSRs at VY, therefore no uivalent Hne at VY.
9/1101	Peach Boltom 3 -BWR	(From *1/14102* CHUG Meeting), leak on 1 Inch Sch. 80 line from in Off Gas Re-combiner pre-heater drain line to condenser. Additlonal review of AOG steam supply system is required. Consider during next update of the Small bore database.
6/22/01	Pilgrim -BWR	Leak on 2 inch feedwater heater venlline (OE discussed at 1/02 CHUG Meelinn\. Eauivalent lines at VY h been insoected.
10122101	st, Lucie 1 - PWR	(From *1/14102* CHUG Meeting), Leak on 1 inch Sch. 80 normally Isolated drain line remote from process system. TPM used to determine leaks from N.C. vaives
11/28/01	Browns Ferry 3 -BWR	Through - wall leaks in drain lines from extraction stream non-return check valves back to condenser. (Simiiar lines at VY are chrome-moly and there have been previous inspections performed on these lines. No additional inspections are uired.
11151/02 CHUG Mig.	Halch1/2 -BWR	Condenser in leakage due to through wall erosion (exlernal?) of 1-112 inch "slop' drains lines inside the condenser. Lines In each unit were cut and capped Similar events at Byron Unl11 (OE 12609) and Coiumbla (OE12145). Limerick & Dresden. VY slop drain lines do not show u on VY P&IOs.
1/15102 CHUG Mtg.	Catawba 2- PWR	Leak in HP turbine pocket shell drain 1 inch dia. OEM showed pipe as P-11. However, A-106 Gr. B was installed. Inspections will be performed on this line in 2004 I0 base line condition crior to HP turbine rotor replacement.
1/15/02 CHUG Mt	Columbia - 'WR	Leak in 2 inch drain line from bleed steam trap to condenser. At VY SB piping OS of steam trans Is included in the small bore dala base.
1/15/02 CHUG Mtg.	Peach Bottom2 . BWR	Pin Hole leaks in I' schedUle 160 HPCI Steam Supply drains {Plant thought piping was replaced with P-11, However field conditions showed that is was not. Pi in at VY ins cted in 1999 (99-SB01 to 99-SB03)

continued

Small Bore Piping

SC: Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG - contlnued.

Date	Plant T e	Descri tion & Recommended Actions at VY
1115102 CHUG Mtg.	Dresden 2 'WR	Thinning found in Bypass valve leak-off line to the 7 stage extraction steam line. Line is 2" Sch. 80, GE B4A39B. Lowest reading was 0,070· found using Phosphor Plate radiography. Line was replaced with A335 P-11. Same line as recent VY through wall leak, RFO 2M41nspect locally, then long tenn replacement with A335-P11.
6102 CHUG Mtg.	AN01 &ANO 2 PWR	Leaks in Gland seal steam to No.3 bearing 1-114 vendor supplied line, Leak in 1" Sch.SO drain Irom Reheat 2nd stage drain tank to condenser. Addlllonal review of GE supplied steam seal & drains is required. Consider during next u date of the Small bore data base.
6102 CHUG Mtg.	Brunswick 1 - 'WR	Replaced continuous vent llnes on #4 feedwater heaters with chrome-mOly pipe. (Smart move for long term.) New vent lines on No.1 & 2 FDW healers atVYwil1 be chrome–molv.
6102 CHUG Mtg.	Calvert Cliffs 1 PWR	Pin hole leakin ¾ inch Sch. 80 drain line off MS supply to stream generator feed ouma iustdownstream of orifice. No steam driven feed oumps at ¥Y.
6102 CHUG Mtg	Fenni 2 - BWR	Leak in first elbow downstream of AOV in 1/112" continuous vent from Turbine Bypass Valve seat dra'.n to condenser. Vawe has travel stop which prevents complete closure. Fermi has no steam traps, AOVs are used instead. Piping DS of steam traps on MSD lines are inclUded in the SB program. Thaonly continuous opening to the condenser at VY is the steam leads drains through RO 60-1. This oi inc has been reolaced with chrome-rnolv ai inc.
1/03CHUG Meeting.	JAF -BWR	Through wall leaks in 2" Soh. S0 C.S. lines from 5 /6 extracticn drain lines immediately downstream of restricting orifices. At VY the only drain lines on the action steam piping are upstream of the reverse cUJTenl valves. There are no restriction orifices at VY. The pining Is chrome-molv.
1/03 CHUG Meeling.	TUrkey PtA- PWR	Leak in HP turbine bowl drain, 1" sch 60 C.S. pipe. OEM recommended replacement with SS pipe in 19S2, did not occur. Equivalent line al VYwlll be inspected In 2004 to baseline thickness prior to HP turbine rotor repiacement.

SD: Components subjected to off nonnal flow conditions, as indicated from the turbine performance monitoring system (Systems Englneering Group).

No small bore llnes have been identified by Systems Engineering on or before 2/27/2003

SE: Engineering judgment

(None at this time,)

ISG: Piping identified from EMPAC Work Orders (malfunctioning equip., leaking valves, etc.)

See LG above. The EMPAC search performed in LG above is applicable to both Large and Small components.

ATTACHMENT TO (PG 1 OF 2) 2004 SCOPING WORKSHEET. OE/PEER GROUP INFORMATION.

- The meeting then split into breakout sessions. Aaron Kelley led a session on BWR issues. The following discussions were noted:

FAC Problem Areas.

Hatch has had lots of wear and repairs to their 8th stage extraction (3rd highest), even though the heat balance diagram shows it to be 99% steam. CHROME MOLY @ VY

LaSalle is wondering if there may be problems in their carbon steel turbine nozzles to extraction steam. Riverbend has had to inspect these locations from the turbine side because of the shields. " "

N/A. Quad Cities has had lots of problems in their expansion bellows.

Riverbend replaced the extraction steam check valves using chrome moly. Unfortunately, the internals were carbon steel and they had problems after only two cycles'- SOUND FAMILIAR

? LaSalle had a failure caused by droplet impingement in a heater vent line / T downstream of the valve.

ADD 8" MSD 9 - LaSalle is experiencing impingement damage in an 8" common drain header to condenser that collects six 10 eight 2" and smaller diameter lines. Stainless will help, but they still will need to inspect. INSPECT 8"-MSD 9 IN 2004

Hope Creek has seen a lot of damage in the drain to condenser of the steam to reactor feed pump turbines.

Water Chemistry.

- Riverbend experienced significant increases to iron transport after applying hydrogen injection (medium level of injection). GE did a mini-test. MONITOR Fe.

- Nine Mile Point had unexpected failures on the lower end of the healer drains after applying HWe.

7 LaSalle measured oxygen on the heater drains, and then used the data to revise the CHECWORKS model. The data caused to LCFs on the MSR drains, 1st stage reheaters, and 2nd stage reheaters to skyrocket.

1 Columbia River has tentatively concluded that noble metals does not effect the fuel. It is too soon to see if hydrogen water chemistry affects the FAC rates.

RPV BoUom Head Drain.

LaSalle has not inspected the first elbow below the vessel because of its inaccessibility and high radiation dose involved. For this reason, they selected the second 90" elbow which is outside the vessel pedestal. Results were provided on FACNet. Additionally, the sump will maintain water level if there is a break at the first elbow.

It was noled that it may be possible 10 inspect the nominally inaccessible areas when there is a 10% disassembly to replace some blades.

LaSalle and Clinton plan 10 inspect the accessible portions of th.c line.

Columbia River has inspected several locations on the line. No wear was found. Three inspections were also performed on the RWCU near the drywell. No damage was found.

Exelon (Harold Crockett) volunteered to collate and publish a summary of industry inspections on the line.

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ATTACHMENT TO 2004 SCOPING WORKSHEETS (Pg 2 of 2)

Inspection Methods.

LaSalle is performing some pre-outage RTs in selective areas due to final feedwater temperature reduction. This is the second time that some pre-outage work was done in nonnally high radiation areas. Aaron Kelly can be contacted for more information.

Riverbend is training their QC inspectors to perform *VT*.

Power Uprates.

Nine Mile Point saw little change to wear rates after a 7% uprate.

Dresden and Quad Cities did a 15% uprate. Some lines saw increases to wear rates ofup to 30%. Tem rature chan s are believed to be responsib

Perry did a pre-power uprate an ysis on the effects to FAC. They used the results to justify line replacements as part of the planning process.

LaSalle found no changes to their susceptible-not-modeled rankings as a result oftheir uprate.

Life Extension.

General comment was that theNRe has emphasized compliance with NSAG202L-Rl and brought up main steam susceptibility as part oftheir approval process.

At Nine Mile Point, the NRC brought up service water issues.

Southern Nuclear is taking credit for other programs inresponse to the NRC questions on valves.

[redacted] with the BWR session, Jeff Horowitz led the PWR Breakout Session. The session was broken down into three parts:

A descrip e very high levels ofiron transport experience an Onofre. This presentation inelude ils ofthe investigation into the ph <mon, a description of the deposits found, several p ible explanations for sits, and what the effects of the deposit were on plant p

A status report on the EdF hydrazine tes program. Unfortunatelv. no progress has heen made since the last report in J to n ber ofproblems. The latest problem, inadequate water quality, has resolved and tes resumed earlier this month. The testing program is take all year to complete. etails oflbe test program have been presented at ous CHUG meetings.

There was al riefdiscussion of feedwater oxygen and FA. veral PWRs are now aUowin entry ofsmall amounts ofoxygen into the condensate system in hopes of red g the iron transport. The potential for change to the PWR Water Chemistry idelines in this area was discussed.

- Tina Gaudreau discussed several EPRI chemistry projects that have FAC implications. The first was the EdF testing {orthe effects ofhydrazine and oxygen on FAC as summarized by Jeff Horowitz in the PWR breakout session. The second project was the next revision to the PWR Secondary Chemistry Guidelines, that will begin this spring. The third project is an investigation into the influence ofdissolved iron, electrochemistry, and chemical parameters on

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CHROUD FILE COPY.

Entergy

Vermont Yankee Nuclear Power Station
oesign Engineering Department" Mechanical/Structural

To S.D.Goodwin Dale March 27,2003

From J.e. Fitzpatrick File # VYM 2003/009

Subject Piping FAC Inspection Scope forthe 2004 Refueling Outage

REFERENCES

(a) PP 7028 Piping Flow Accelerated Corrosion Inspection Program, LPG 1 12/06/01.
(b) V.Y. Piping F.A.C. Inspection Program - 1996 Refueling Outage Inspection Report, March 23,1999.
(o) V.Y. Piping FAC.Inspection Program -1998 Refueling Outage Inspection Report, April 2,1999.
(d) V.Y. Piping FAG. Inspection Program - 1999 Re1ueling Outage Inspection Report, February 11, 2000.
(e) V.Y. Piping FAG, Inspection Program - 2001 Refueling Outage Inspection Report, August 11,2001.
(l) V.Y. Piping FAC.Inspection Program- 2002 Refueling Outage Inspection Report, January 20,2003.

DISCUSSiON

Attached please find the Piping FAC Inspection Scope for the 2004 Refueling Outage. The scope Includes locations identified using: previous inspection results, the CHECWORKS models, Industry and plant operating experience, Input from the Turbine Performance Monitoring System, the CHECWORKS study performed to postulate affects of Hydrogen Water Chemistry operation on FAC wear rates in plant piping, postulated power uprate effects, and engineering judgment.

The planned 2004 RFO Inspection scope consists of 26 large bore components at 11 locations, internal Inspection of 6 of the Bllnes of the turbine cross around piping, and 11 sections of small bore piping. Given that it's a fUll year from the start of the outage, any Industry or plant events that occur In the interim or new infonnation may necessitate an Increase in the planned scope.

I am available to support planning and inspections as necessary. If you have any questions or need additional Information please conlsct me.

James C. Fitzpatrick
VY FAC Program Coordinator

ATTACHMENT: 2004 RFO FAC Inspection Scope (4 Pgs.)

CC D.Girroir (Code Programs Supervisor)
D,King (ISI Progmm Engineer)
T.MO'Connor (Design Engineering)
M.LeFrancois (Systems Engineering)

ATTACHMENT to VYM 20031009

VERMONT YANKEE PIPING FAC INSPECTION PROGRAM 20041NSPECII0N SCOPE (3127/03)

LARGE BORE PIPING: External UT Inspections

Point No.	Component 10	Location Sketch	Location	Previous Inspections	Reason / Comments / Notes
2004-01	FD01RDOl	001	T.B. FPR. Elav. 232.	2001	2001 recommendation for repeat inspection of
2004-02	FOOl EL01	001	• • •	2001	FD01TE05.
2004-03	FDQ1TEOS	001	" " "	2001	
2004-04	FD01EL04	001	T.B. FPR Elev.241.	1996	1996 recommendation for repeat inspection of
2004-05	FD01SP04	001	• " "	1996	FDQ1SP04.
2004-06	FD02RDOl	002	T.B. FPR. Elev. 232.	1999	1999 recommendation for repeat inspection of
2004-07	FD02EL01	002	• • •	1999	FDOZTE01,
2004-08	FD02TEOl	002	• " "	1999	
2004-09	FD03SP01	003	T.B. FPR. Elev. 232.	NO	Ranked hl h b CHECWORKS.
2004-10	FD07SP02DS	005	T.B. FPR. El v. 232.	NO	Ranked high by CHECWORKS include minimum
2004-11	FD07EL03	005	" " "	NO	of 36 Inch of vertical run upstream of elbow.
2004-12	FD14SP08DS	009	Stm Tunnel Elev. 266	NO	Ranked high by CHECWORKS include minimum
2004-13	FD14EL07	009	" " "	NO	of 32 inch of vertical run upstream of elbow.
2004-14	FD19TE01	010	Rx Drywell Elev. 270	1999	Required Inspections per ASME Section XI ISI
2004-15	FD19RD01	010	" " "	1999	Program FAC inspections per ASME Code
2004-16	FD19SP04	010	• • •	1999	Case N-560.
2004-17	FD21SPOl	010	" " "	1999	

LARGE BORE PIPING: External UT **Inspections - continued**

Point No.	Component 10	Location **Sketch**	Location	Previous Inspections	Reason / Comments / Notes
2004-18	CD30TE02	036	T.B. FPR El v.243.	NO	Ranked high by CHECWORKS include 12 inch long stub between CD32LE01 & CD32EL02.
2004-19	CD30SP04	036	" " "	NO	
2004-20	CD32ElO1	039	" " "	NO	
2004-21	CD32EL02	039	" " "	NO	
2004-22	ES1ASP01	063	T.B. HB Elev. 255.	1998	Highly susceptible to FAC damage. This is the only remaining carbon sleel section in Extraction Steam system. Baseline data for ower urate.
2004-23	MSD9TE01 thru MSD9TE08	097	T.B. HB Elev. 249.	NO	Industry Experience with numerous through waJlleaks in drain collector headers. Scan as much of header below drains from LeV 38A to 380 and ST-6D-2A to 20 as accessible. See Nole 3.
2004-24	MSD9EL05	097	T.B. HB Elev. 237.	NO	Industry Experience with numerous through wall leaks in drain collector headers. Inspect a minimum of 16 inch length on MSD9SP06US. See Note 3.
2004-25	MSD9EL06	097	" " "	NO	
2004-26	MSD9SP06US	097	" " "	NO	

LARGE BORE UT NOTES;

1. Coordinate minimum extent 01 insulation to be removed with J.Fitzpatrick or T.M. O'Connor from DE-MIS.
2. A "No" in the previous inspection column Indicates asbestos abatement may be required.
3, Piping is part of the proposed ALT Boundary/or Power Uprate AST.

NEC020200

22

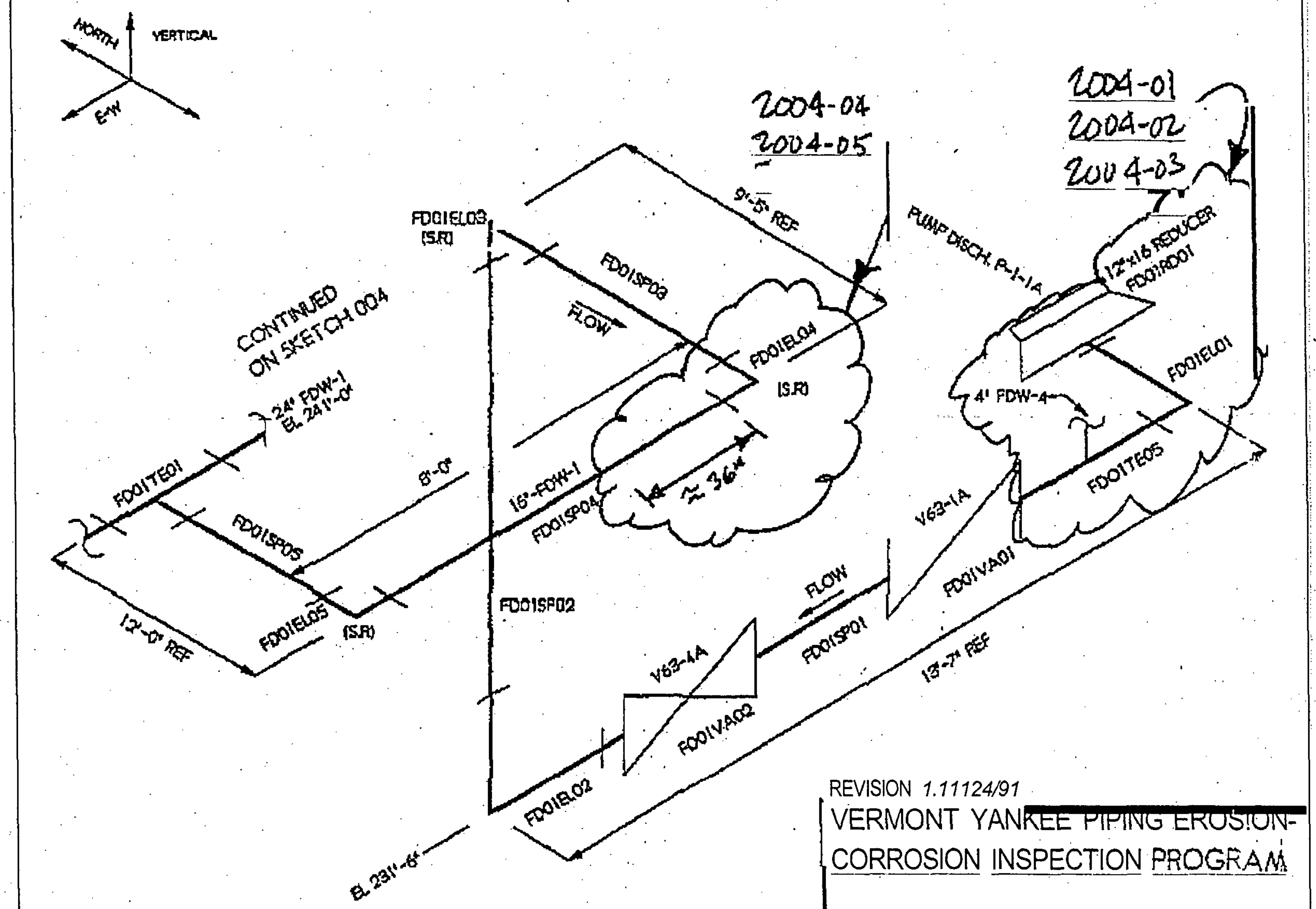
LARGE BORE PIPING: Internal Visual Inspections **(with supplementsl UT as required)**

Ins action Point No.	Oeser! lion
2004-27	'A" 36 inch diameter Turbine Cross Around line (CAR).
2004-28	"6" 36 inch diameter Turbine Cross Around line (CAR).
2004-29	"C" 36 inch diameter Turbine Cross Around line (CAR).
2004-30	"D" 36 inch diameter Turbine Cross Around line (CAR).
2004-31	"C" 30 inch diameter Turbine Cross Around line (CAR).
2004-32	"0" 30 inch diameter Turbine Cross Around line (CAR).

Note: Internal visual inspections of open ends at all large bore connections to the new High Pressure feedwater healers will be performed during installation of the new heaters during the 2004 RFO. (This includes Feedwatar, Extractlon Steam, Moisture Separator Drains, and Heater Drain piping.)

NEC020201

123



TURBINE BUILDING-FEEDWATER PUMP ROOM.
REFERENCES: G191157,G191182,G191183,5920-FS-124

REVISION 1.11124/91

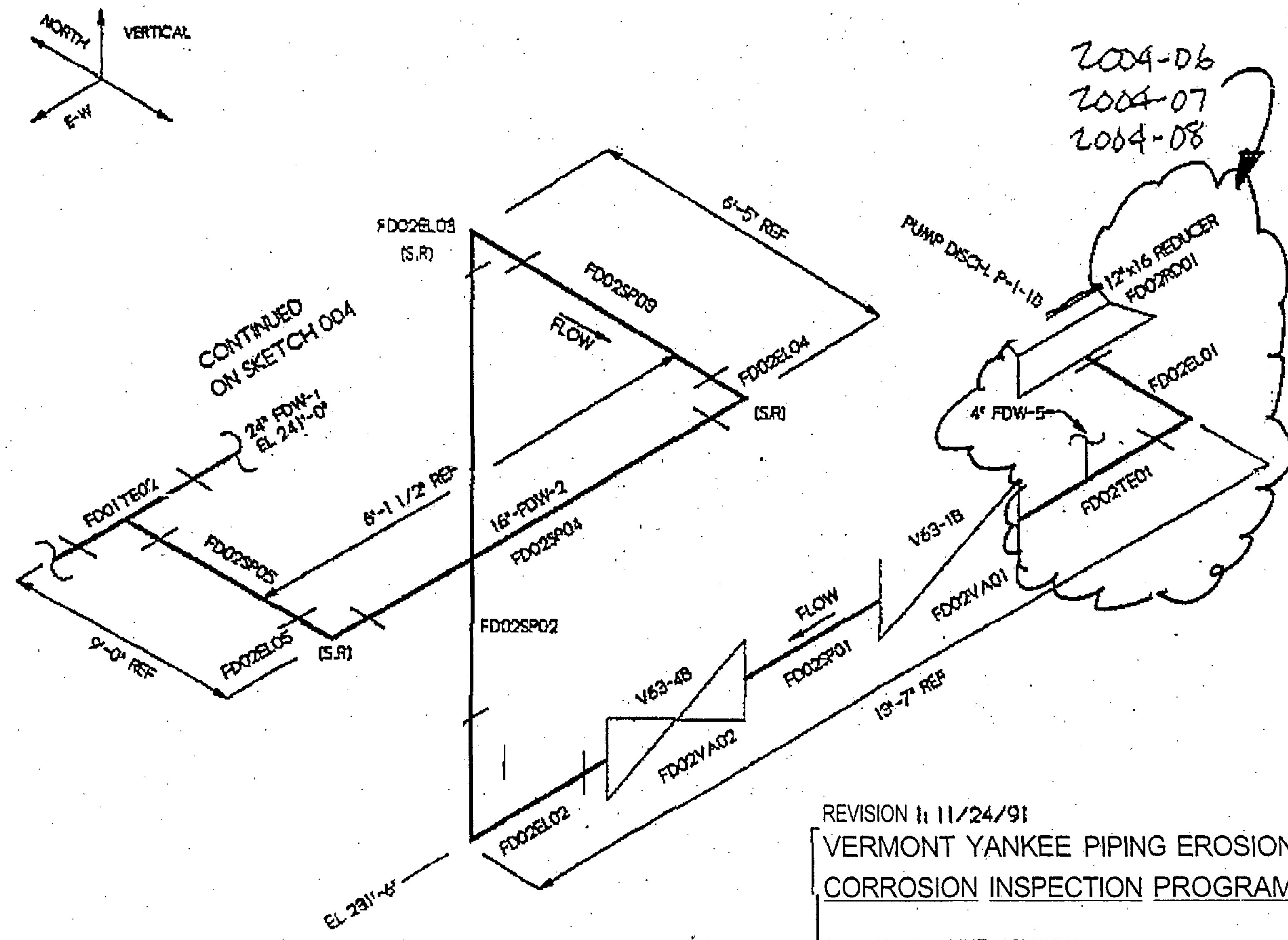
VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 16" FDW-1

COMPONENT LOCATION SKETCH No.001

24

NEC020203



REVISION 1: 11/24/91

VERMONT YANKEE PIPING EROSION
CORROSION INSPECTION PROGRAM

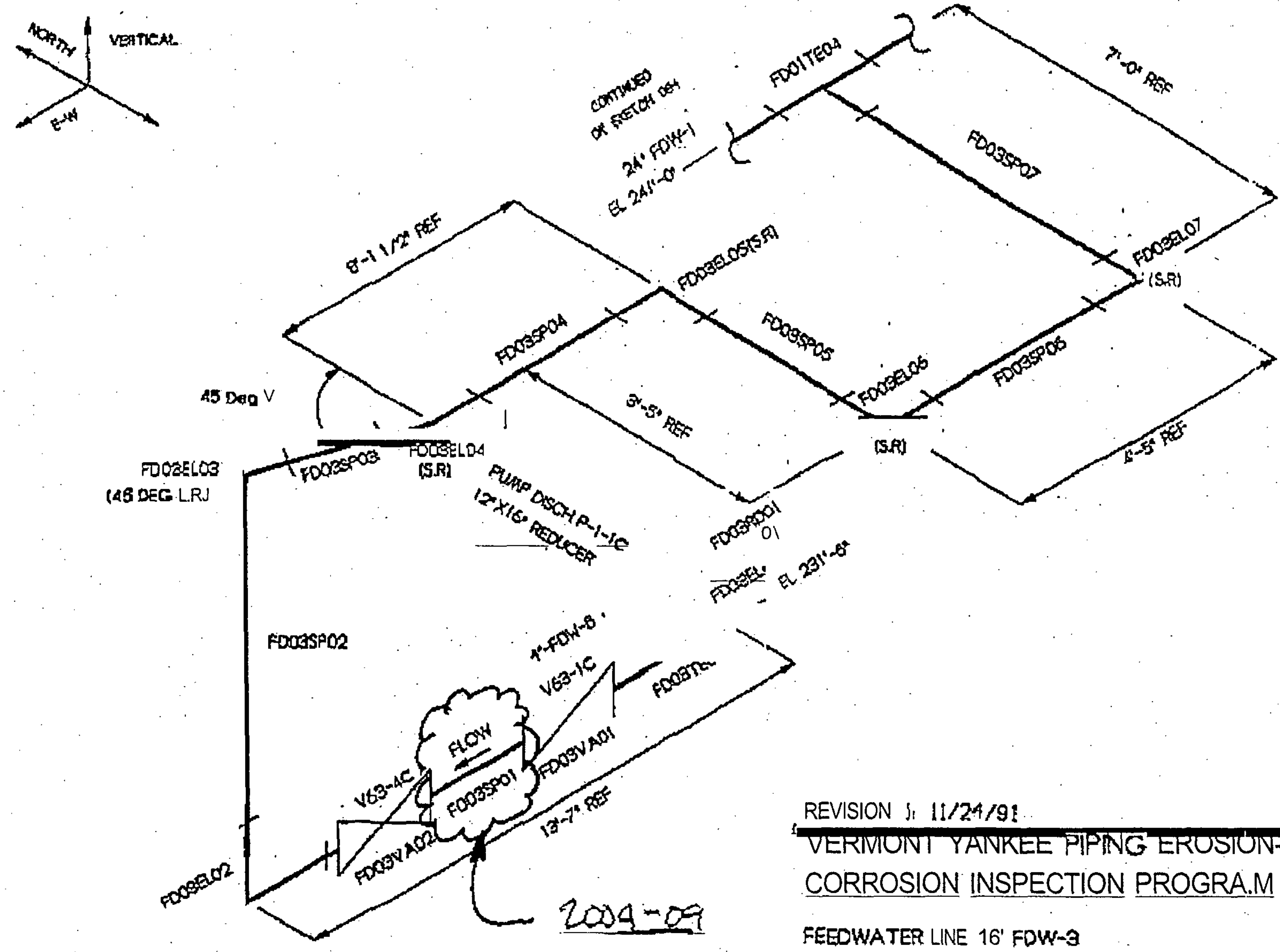
FEEDWATER LINE 16' FDW-2

COMPONENT LOCATION SKETCH No.002

TURBINE BUILDING-FEEDWATER PUMP ROOM.
REFERENCES: G191157, G191182, G191183, 5920-FS-124

25

NEC020204



TURBINE BUILDING-FEEDWATER PUMP ROOM
REFERENCES: G 191157, G 191182, G191183, 5920-FS-124

REVISION 1 11/24/91

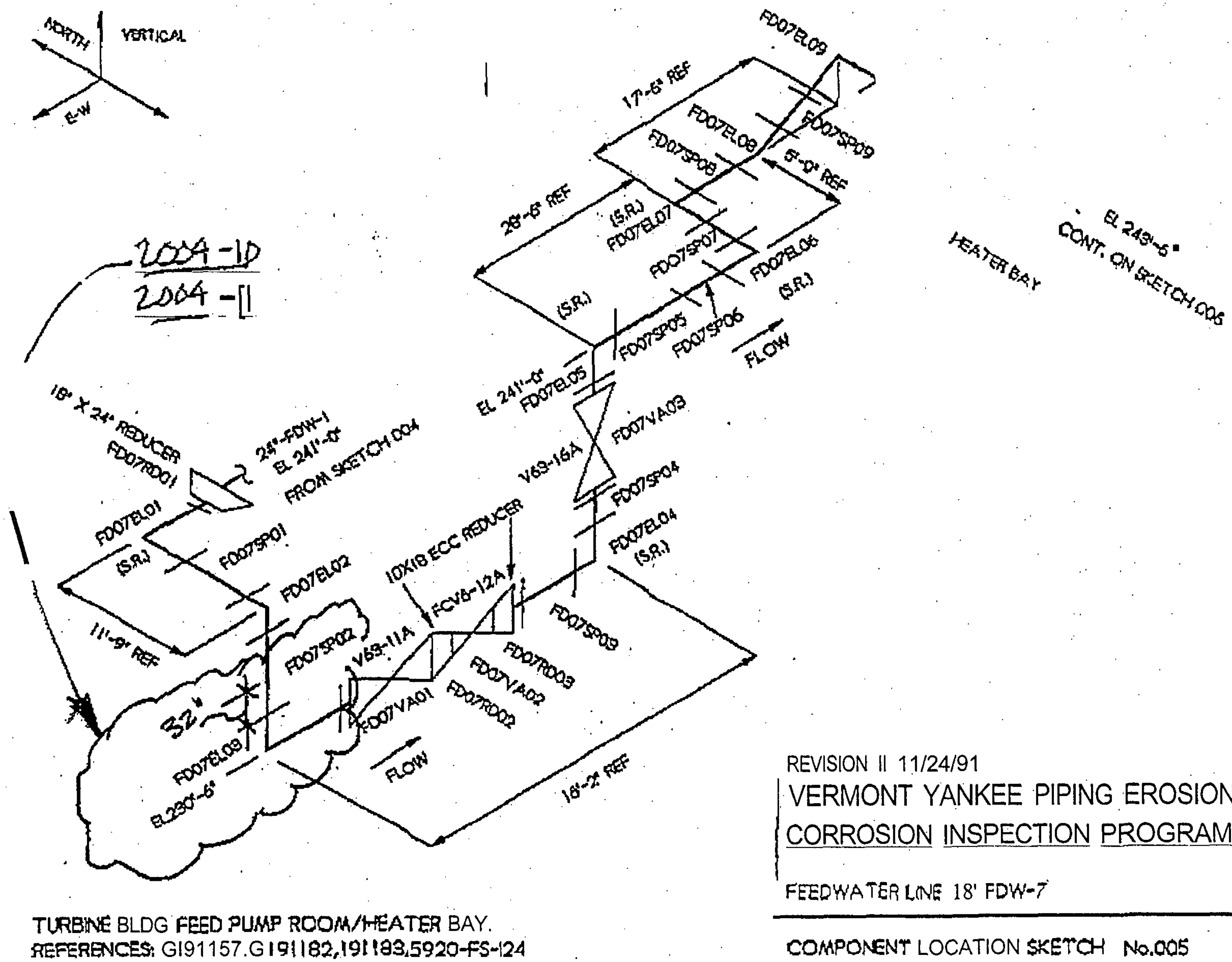
VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 16' FDW-3

COMPONENT LOCATION SKETCH No.003

26

NEC020205



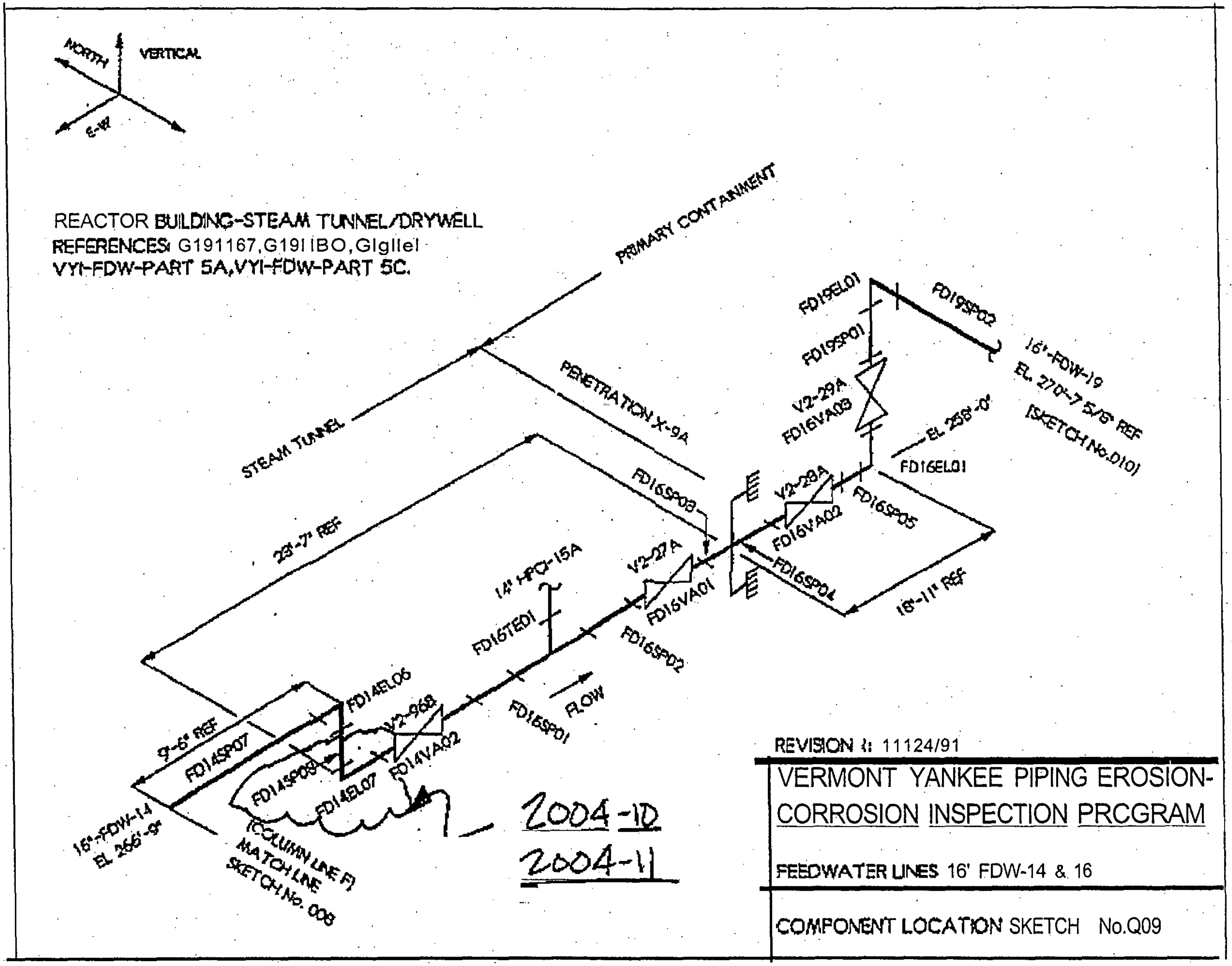
REVISION II 11/24/91

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

FEEDWATER LINE 18' FDW-7

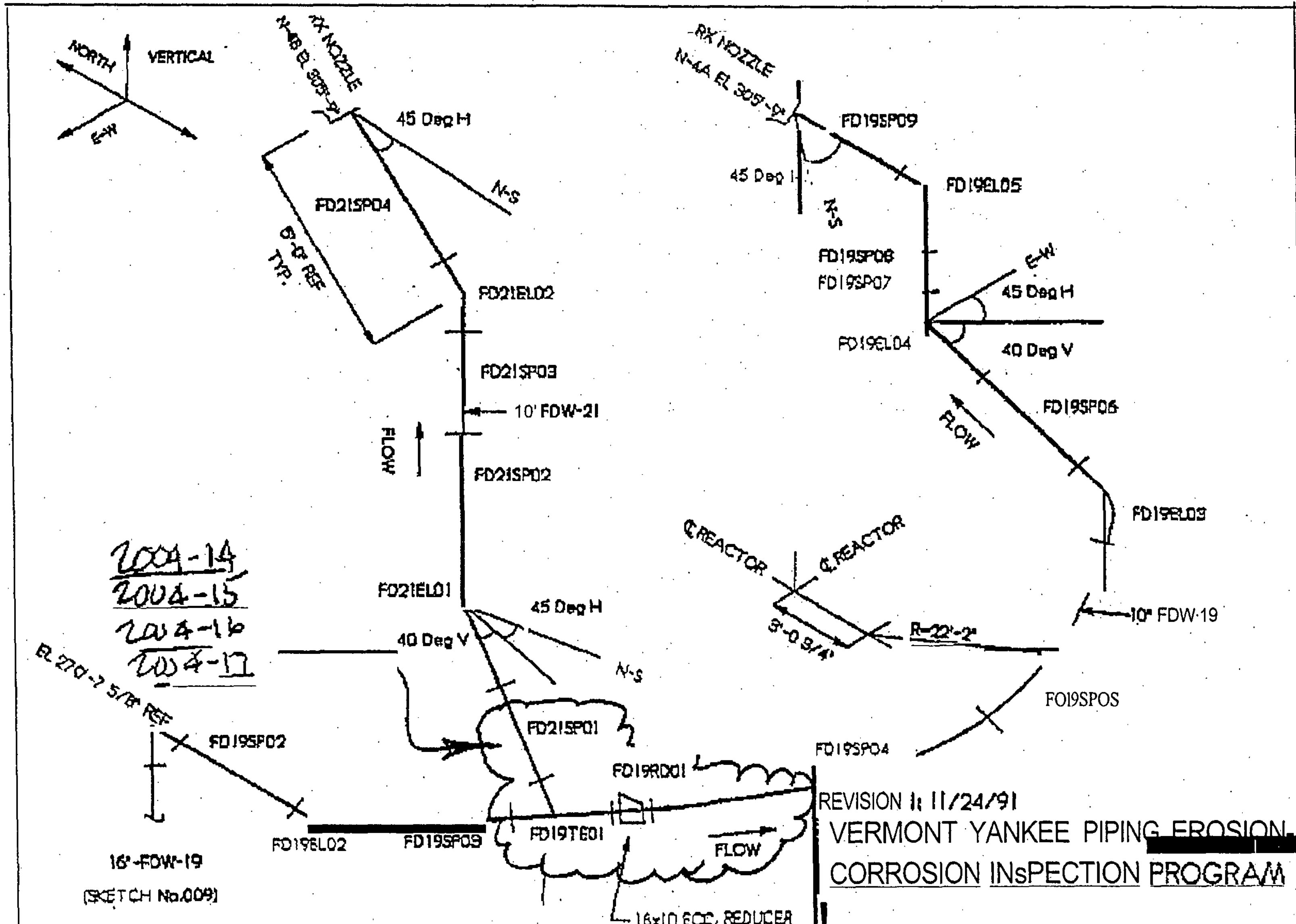
COMPONENT LOCATION SKETCH No.005

NEC020206



28

NEC020207



REACTOR BUILDING-DRYWELL
REFERENCES: G191167,G191180,G191181,VYI-FDW-PART 5A

REVISION 1: 11/24/91

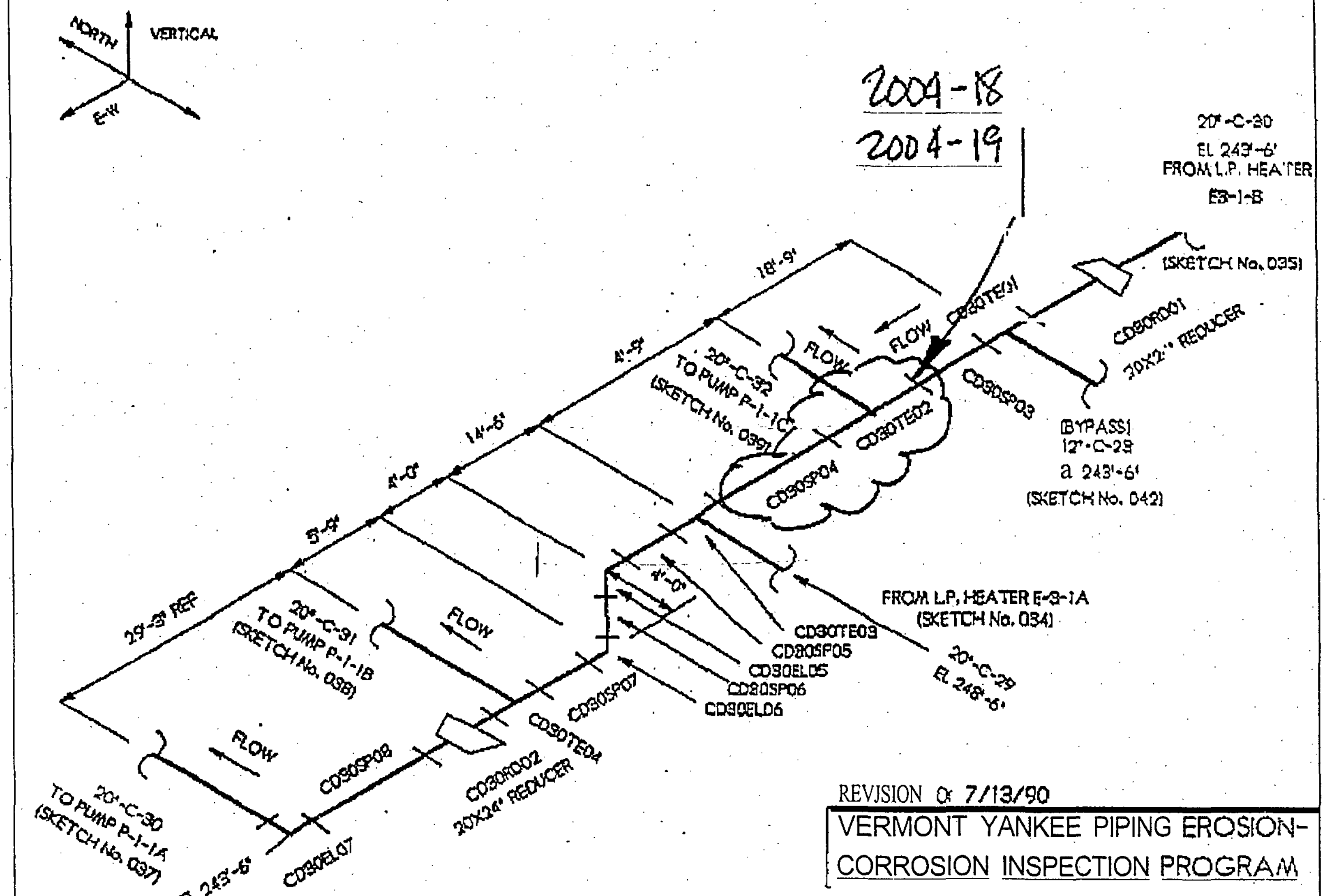
VERMONT YANKEE PIPIN[redacted]
CORROSION INSPECTION PROGRAM

FEEDWATER LINES 10"-FDW-19 & -21

COMPONENT LOCATION SKETCH No.010

29

NEC020208



TURBINE BULDING-FEEDWATER PUMP ROOM
REFERENCES: C191157,G1911811,0191187,5820-FS-116

REVISION 0 7/13/90

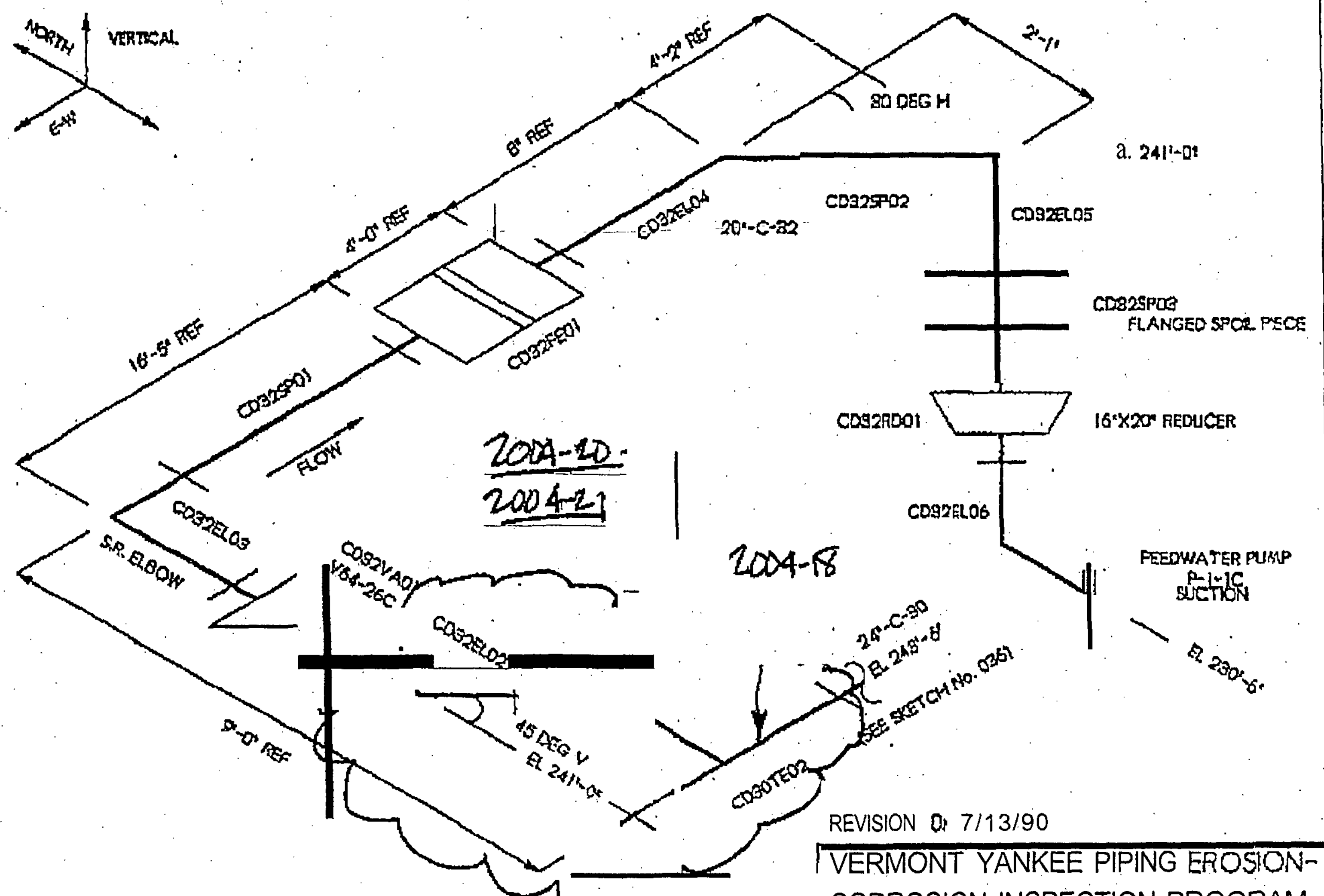
VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

CONDENSATE LINE 24"-C-30

COMPONENT LOCATION SKETCH No. 096

3D

NEC020209



REVISION 0: 7/13/90

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

CONDENSATE LINE 20"-C-32

COMPONENT LOCATION SKETCH No. 039

TURBINE BULDING-FEEDWATER PUMP ROOM
REFERENCES: G191157,G191186,G191187,5920-FS-116

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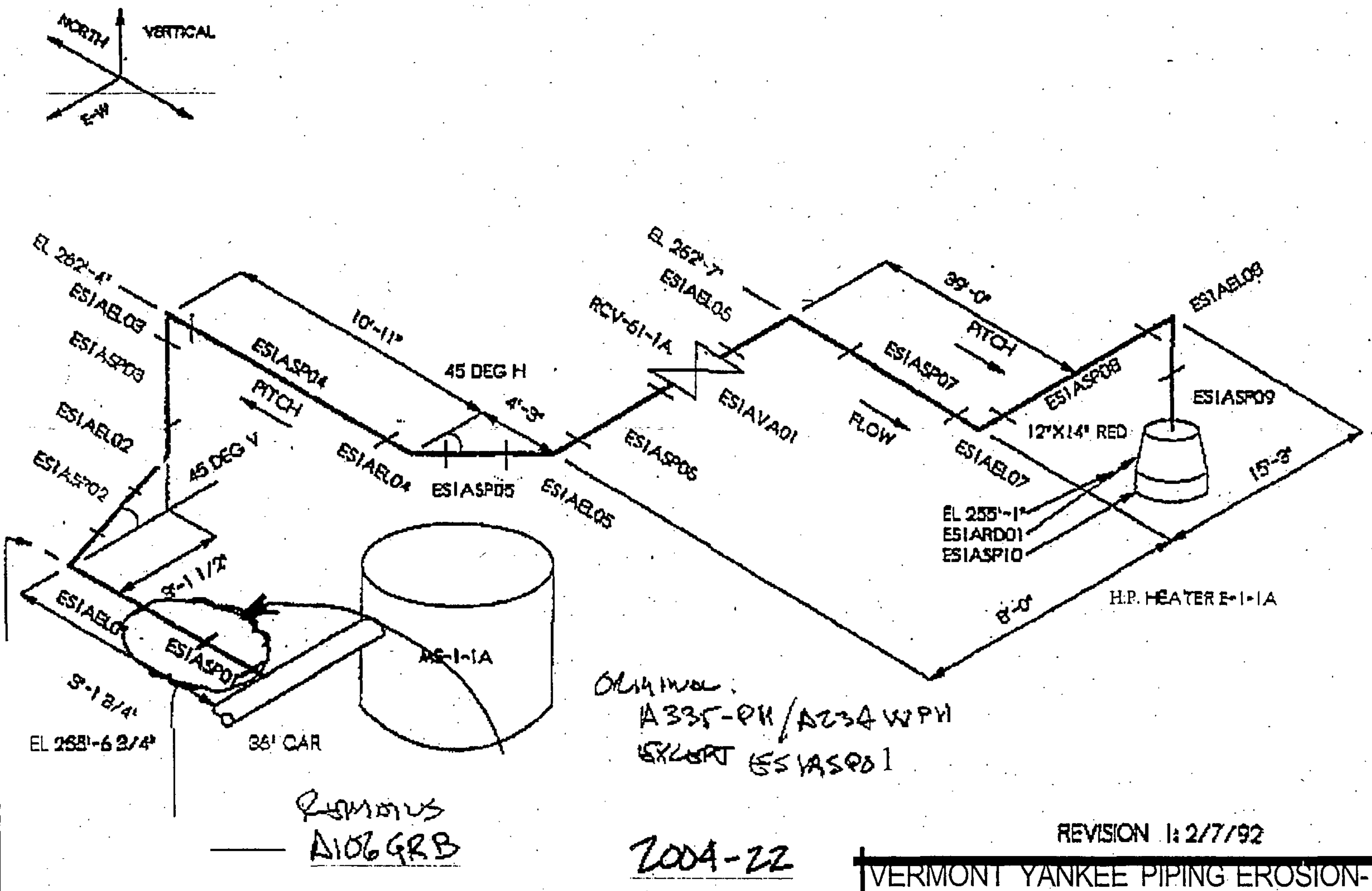


REVISION 1: 2/7/92

VERMONT YANKEE PIPING EROSION-CORROSION INSPECTION PROGRAM

EXTRACTION STEAM LINE 12"-ES-1A

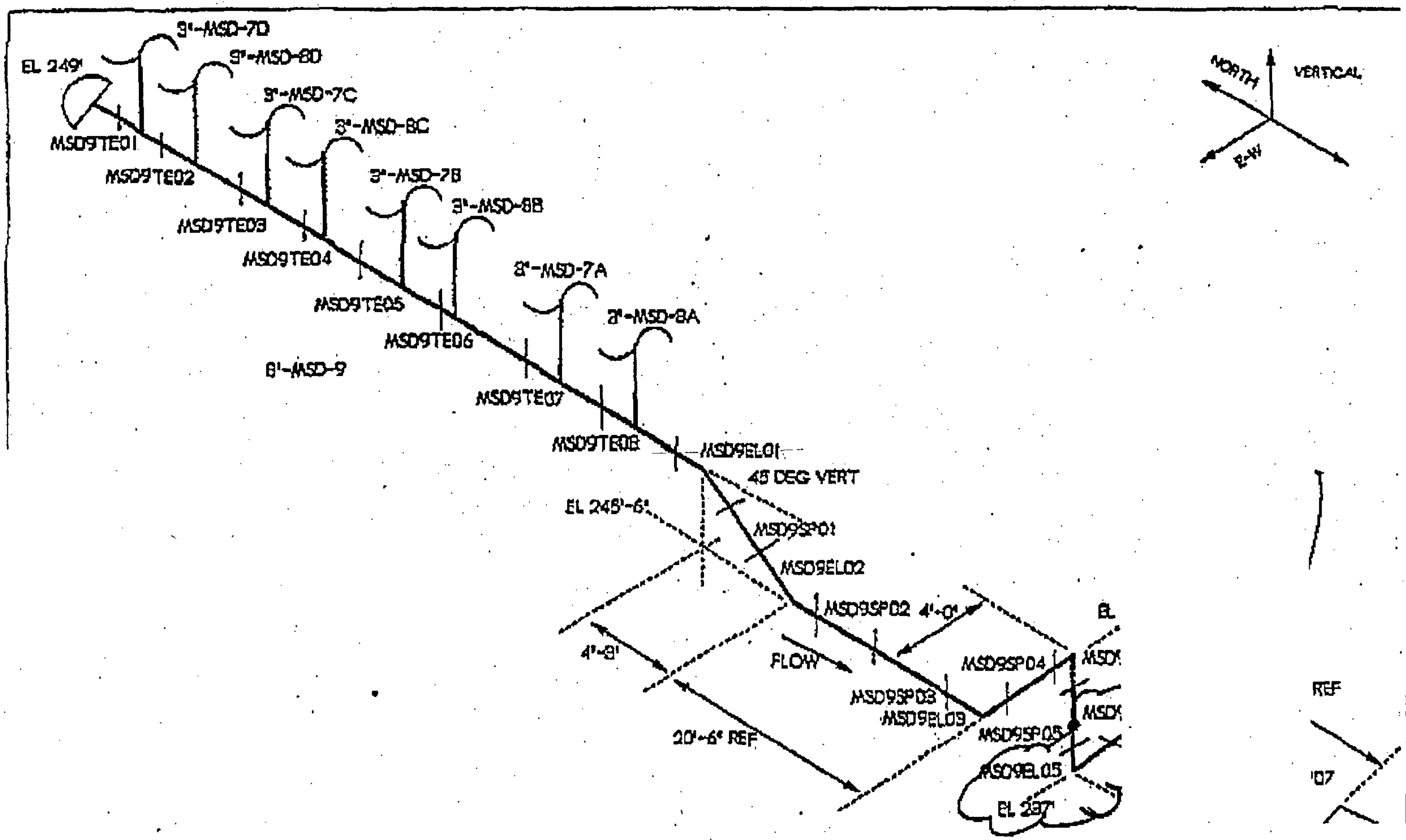
COMPONENT LOCATION SKETCH No. 063

TURBINE BULDING-HEATER BAY
REFERENCES: C191158,C191184,C191185,5920-FS-1-8

NEC020210

32

NEC020211



TURBINE BULDING-HEATER BAY
REFERENCES: G191156,G191182,G191183,5920-FS-I-18

REF DWG 5920-1819

[redacted]

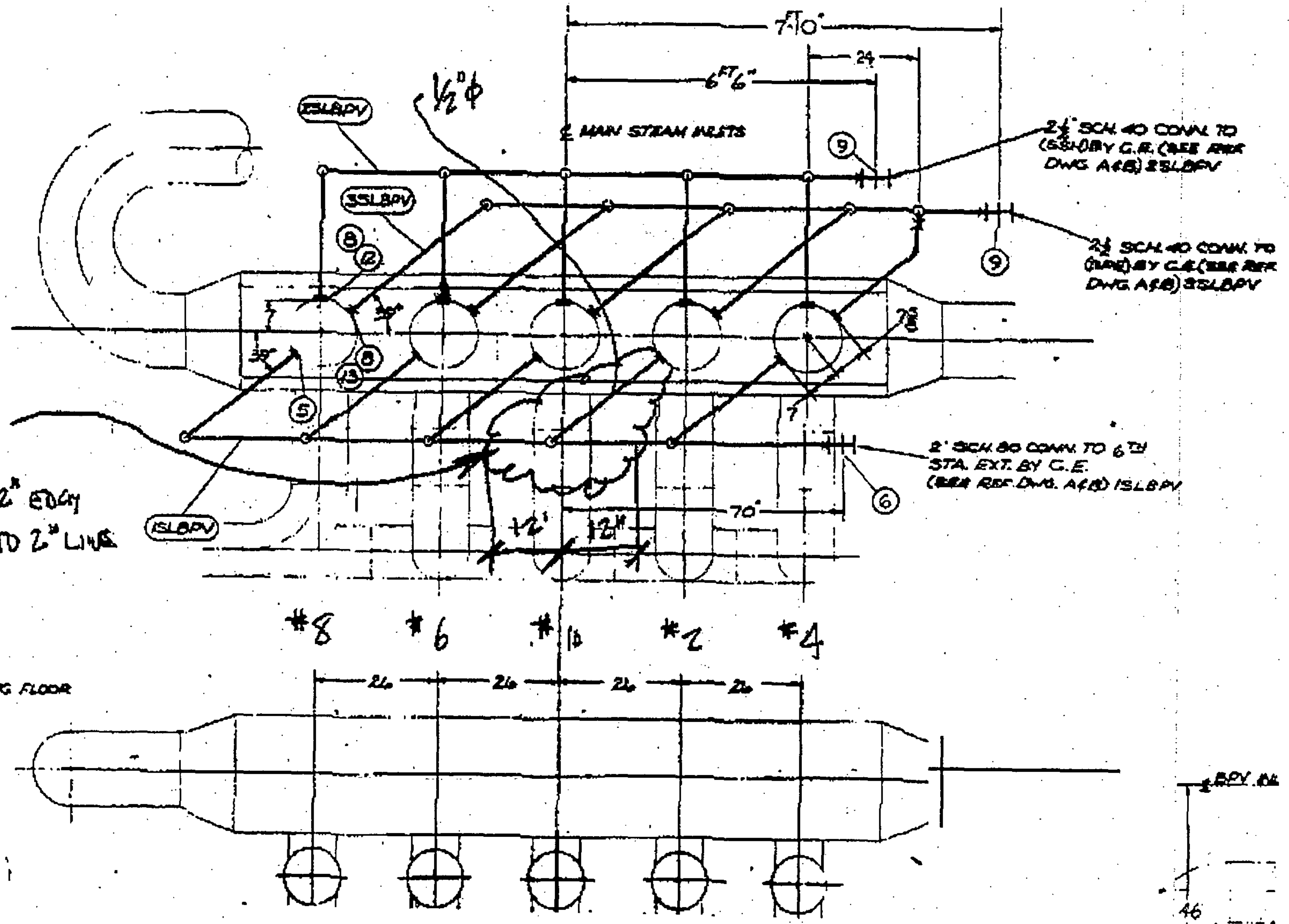
NORTH BYPASS VALVE CHEST

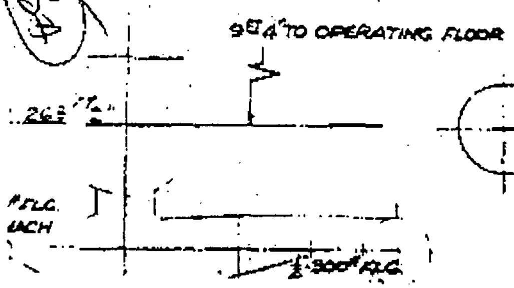
PLAN VIEW

2004 SMALL BORE

04-SB01

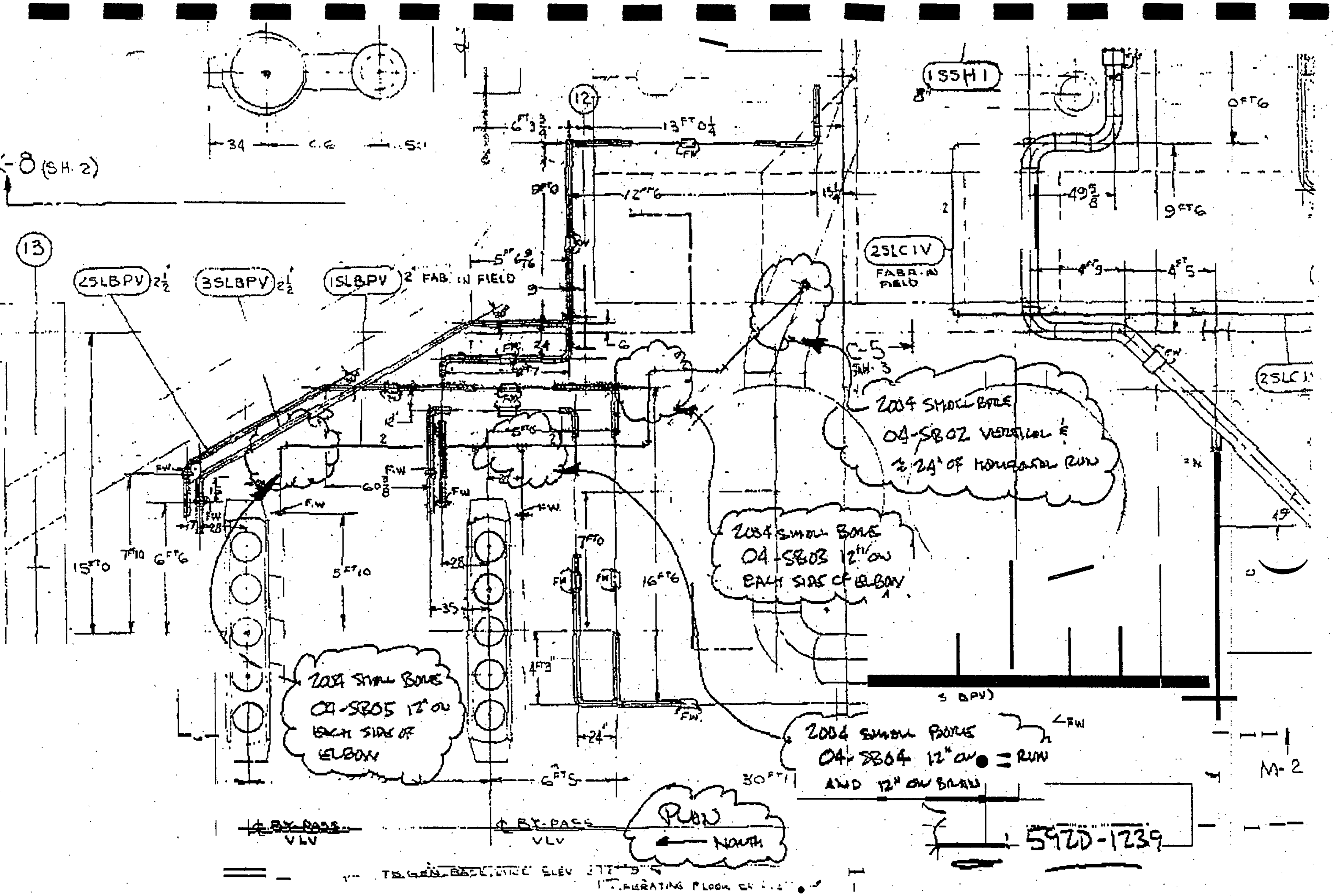
INSPECT 1/2"φ LINE & 12" EACH SIDE OF CONNECTION TO 2" LINE



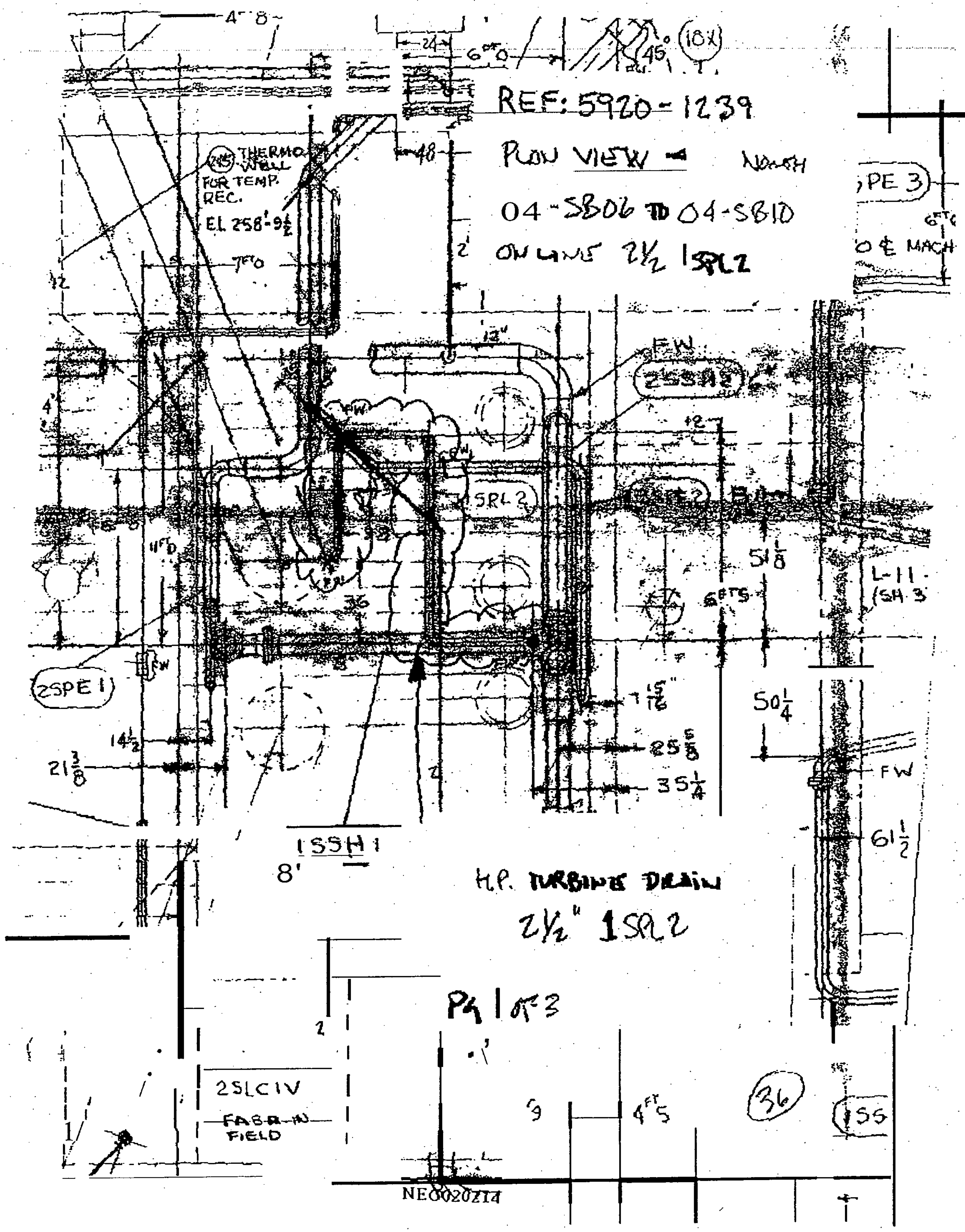


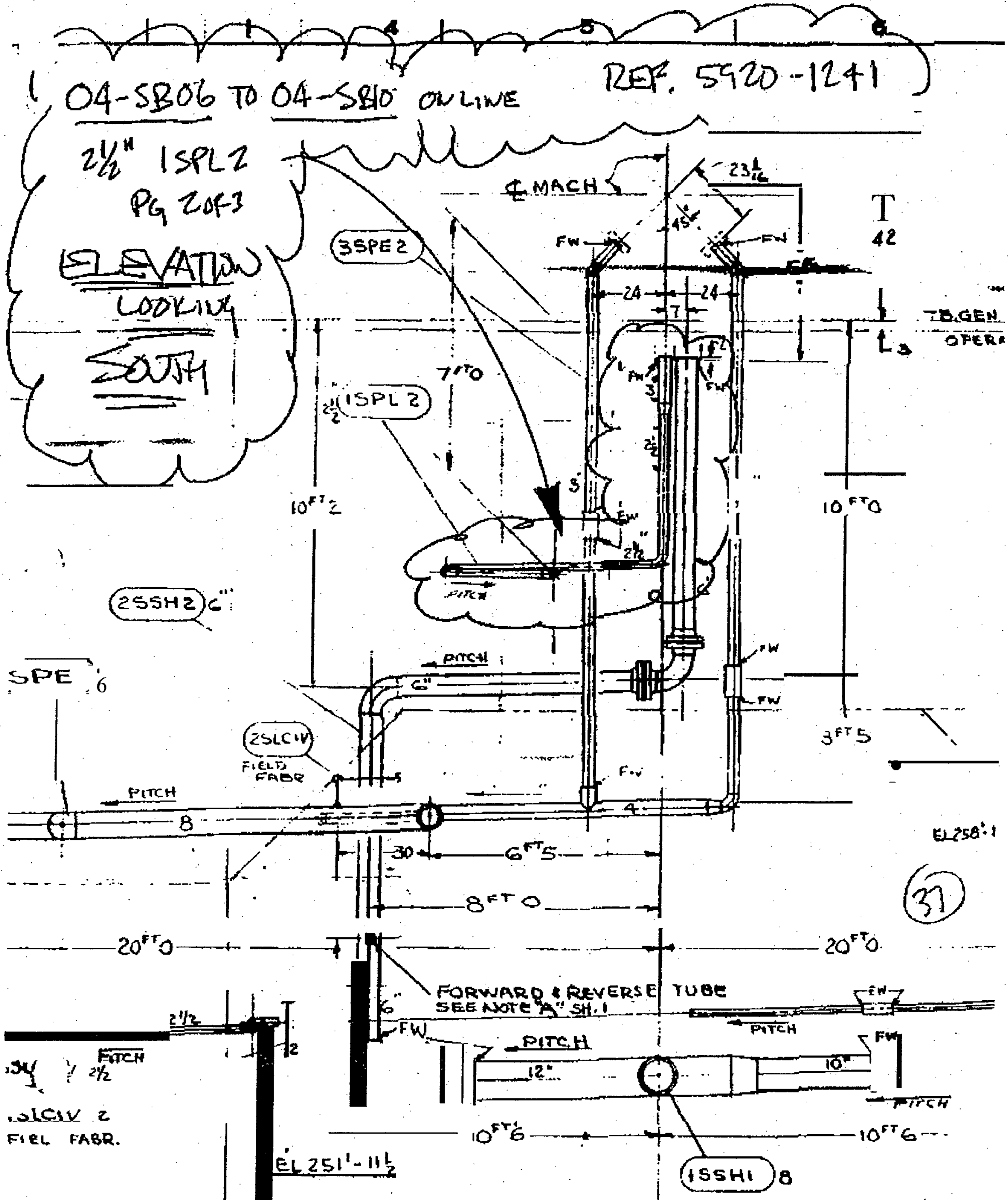
34

NEC020212



-8 (SH. 2)
13
12
1SSH1
2SLC1V
FABR. IN FIELD
2SLBPV 2½
3SLBPV 2½
1SLBPV 2" FAB. IN FIELD
13FT 0¼
12FT 6
9FT 6
49⅝
4FT 5
15FT 0
6FT 6
5FT 10
16FT 6
7FT 0
6FT 5
2004 Small Bore 04-SB02 Vertical & ± 24" of horizontal run
2004 Small Bore 04-SB03 12" on each side of elbow
2004 Small Bore 04-SB05 12" on each side of elbow
2004 Small Bore 04-SB04 12" on = run and 12" on bran
℄ BY-PASS VLV
℄ BY-PASS VLV
PLAN
North
M-2
59ZD-1239


REF: 5920-1239
PLAN VIEW ← NORTH
04-SB06 TO 04-SB10
ON LINE 2½ 1SPL2
THERMO WELL FOR TEMP. REC.
EL 258'-9½
2SPE1
2SSH2
FW
1SPL2
PE 3
L-11-(SH 3
$51\frac{1}{8}$
$50\frac{1}{4}$
$61\frac{1}{2}$
$35\frac{1}{4}$
$25\frac{5}{8}$
$21\frac{3}{8}$
14½
1SSH1
8'
H.P. TURBINE DRAIN
2½" 1SPL2
Pg 1 of 3
2SLCIV
FAB IN FIELD
36


04-SB06 TO 04-SB10 ON LINE
REF. 5920-1241
2 1/2" 1SPL2
PG 2 OF 3
ELEVATION
LOOKING
SOUTH
3SPE2
1SPL2
2SSH2 6"
SPE 6
2SLC1V
FIELD FABR
PITCH
FW
10FT2
7FT0
10FT0
3FT5
6FT5
8FT0
20FT0
EL 258'-1
FORWARD & REVERSE TUBE
SEE NOTE "A" SH.1
12"
10"
10FT6
EL 251'-11 1/2
1SSH1 8
FIEL FABR.
TB.GEN
OPERA
37

Page 1 of 3

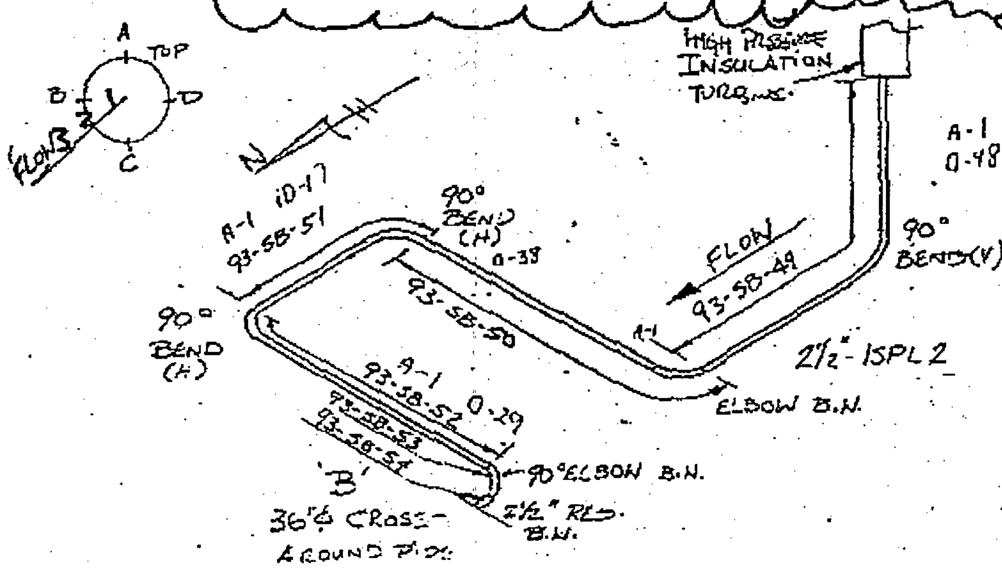
THICKNESS DATA SHEET DATA SHEET NO. UT-112-SB-021

PLANT VERMONT YANKEE OUTAGE Fall 1993 DRAWING 5920-1239 REV. N/A
SYSTEM HP TURBINE Drain COMPONENT/WELD NO. 93-SB-52 EN N/A
LOCATION TB 24

MATERIAL: CS PRODUCT FORM: Pipe APPROX. THICK.: .25"
INSTRUMENT: D-791-RM
MAKE: Panametrics MODEL: 26 DL Plus SERIAL NO.: 93129207
CRT ☐ DIGITAL ☑ HORIZONTAL LINEARITY PERFORMED ☐

TRANSDUCER MAKE/MODEL: Panametrics MODE: ☑ PITCH/CATCH ☐ PULSE/ECHO FREQUENCY: 5.0 MHz SIZE: .312
CAL. BLOCK MATERIAL: CS /SN 93-6448 PRODUCT FORM: wrought THICKNESSES: .1", .5"
CALIBRATION TIMES: INITIAL: 0900 CHECK: 1030 CHECK: N/A CHECK: N/A FINAL: 1200

SKETCH WITH RESULTS: 04-SB06 to 04-SB10 Pg 3 of 3



EXAMINER Jerry Maney DATE 9-19-93
EXAM AGENCY/COGNIZANT ENGINEER M. [illegible] DATE 9/21/93
ISI COORDINATOR (Optional) [illegible] DATE 9/27/93
QA (Optional) DATE
ANII (Optional) DATE

R65\7

PREVIOUS INSPECTION DATA

REVIEWED: [signature] 9/29/93

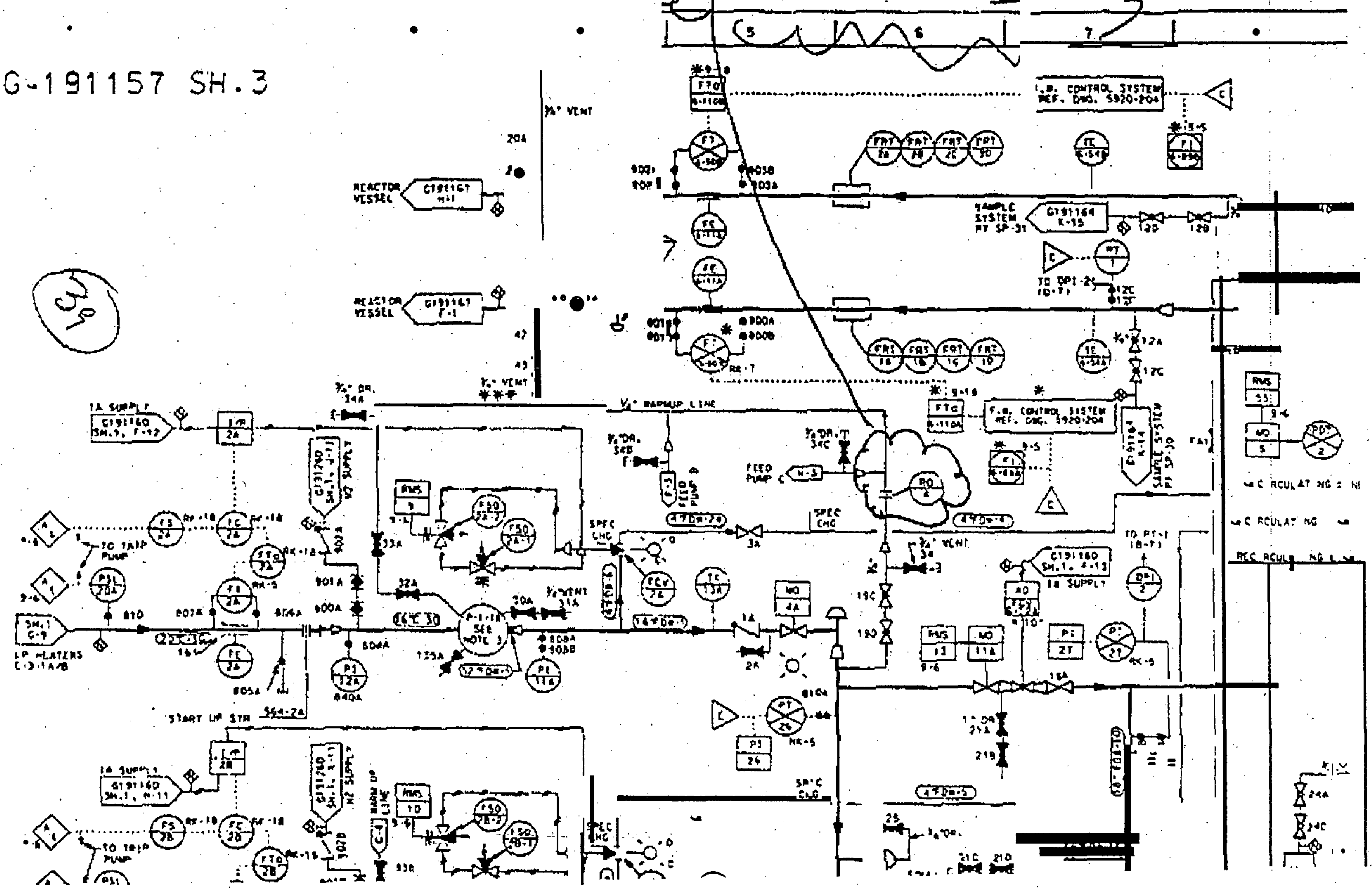
(38)

SMALL BORE 1 — 5

OA-SB11 P4

G-191157 SH.3

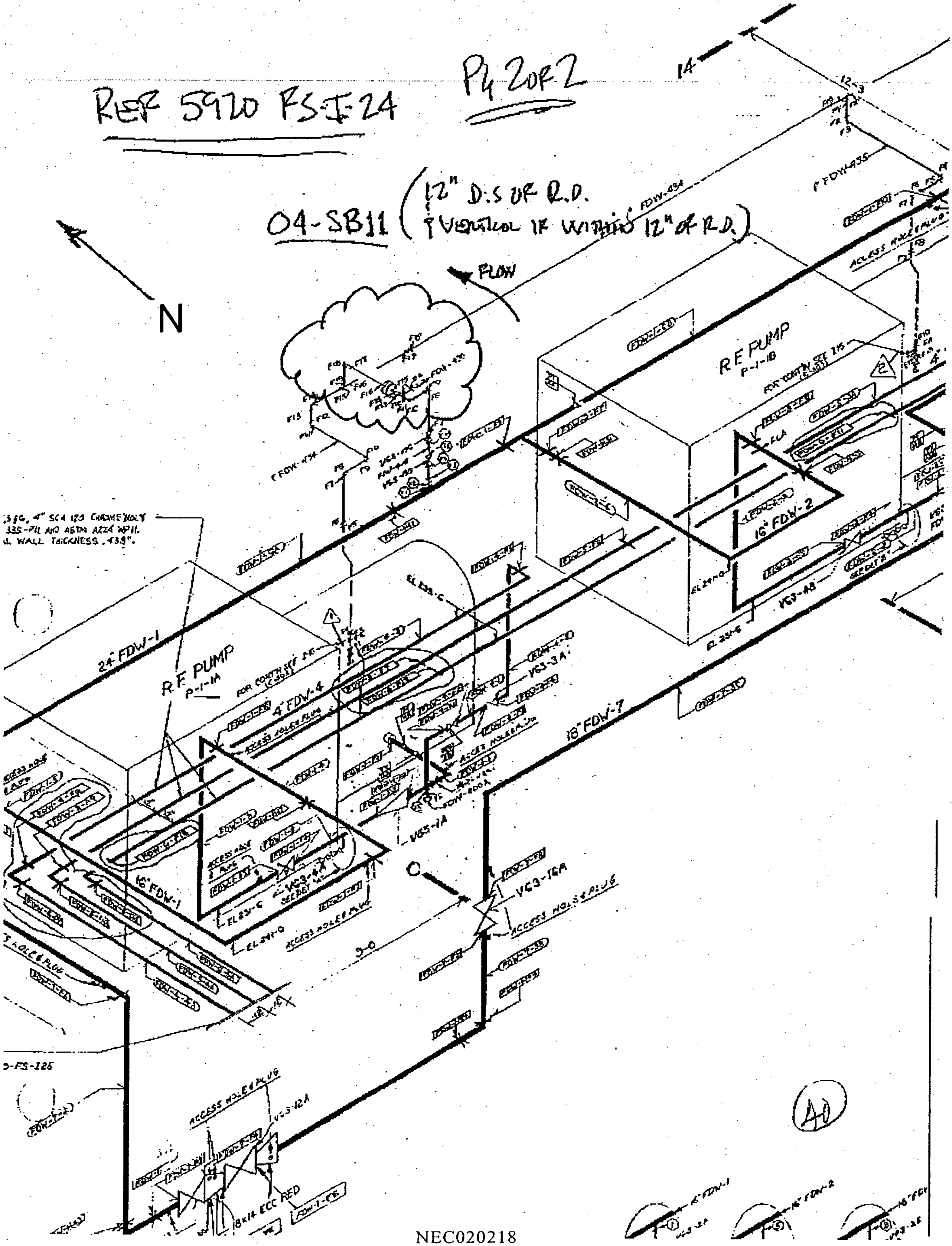
3/9



REF 5920 FS-I-24

Pg 2 of 2

04-SB11 (12" D/S of R.D. / Vertical if within 12" of R.D.)



PP 7028 VY PIPING FLOW ACCELERATED CORROSION (FAC) INSPECTION PROGRAM

RFO 24 - SPRING 2004

FAC SCOPE CHALLENGE MEETING 3/28/03

PLANNED SCOPE

- External Ultrasonic Thickness (UT) Inspection of 26 large bore components at 11 locations. Includes some new locations, sorne repeat inspections for trending, and for a baseline prior to power uprate.
- External Ultrasonic Thickness (UT) Inspection of 11 sections of small bore piping. Includes 5 sections on the turbine bypass valve 1st sealleakoff line if the line is not replaced during the outage.
- Internal Visual Inspection of 6 of the 8 Turbine Cross Around Lines (36A to 360, 30C, & 300).
- WO 02-4906 FAG Inspections -restraint removed with VYM *2003/009*

BASIS 1 COMMENTS

- Component selection based on previous inspection results, the CHECWORKS models, industry and plant operating experience, the FAC HWC study, postulated power uprate effects, and engineering judgment.
- Similar numbers of components to be inspected as in previous outages. VY inspects less than the industry average due to a simpler design (no reheat) and Chrome-Moly Extraction Steam piping.
- For Large Bore Piping: The combination of previous inspections and the proposed 2004 inspections should provide a solid basis for a high degree of confidence against unexpected piping wall loss. We will have sufficient base line data to evaluate any negative trends from Power Uprate and HWC.
- Recent Small Bore leaks at VY and numerous ones at other plants require an increased and more intelligent focus on small bore piping.
- Given that it's a full year from the start of the outage, any industry or plant events that occur in the interim or new information may necessitate an increase in the planned scope.

A1

Entergy

FOCUSED SELF-ASSESSMENT REPORT

DEPARTMENT: ENVY Design Engineering

TITLE: Vermont Yankee Piping Flow Accelerated Corrosion Inspection Program

Condition Report LO-VTYLO-2003-00327

Prepared By:

10/27/04

James C. Fitzpatrick/Date

Approved By:

10/28/04

James H. Callaghan/Date

TABLE OF CONTENTS

EXECUTIVE SUMMMARY

The objective this Self Assessment of the Vermont Yankee Piping Flow Accelerated Corrosion (FAC) Inspection Program was to review the program for compliance with applicable industry standards and NRC guidelines and requirements. A purpose of this assessment was to determine whether or not, problems, or generic weaknesses exist relative to the station implementation of its long term FAC monitoring program.

Specific objectives, evaluation criteria, and the corresponding assessment methodology were developed by the FAC working group (the 5 plant FAC Program Coordinators) using industry documents and previous ENS self-assessment reports. All aspects of the program plan including documentation, management controls, CHECWORKS predictive models, structural evaluations, drawings, condition reports, organizational interfaces were reviewed by the Self-Assessment team. In general, the following conclusions were drawn:

The Vermont Yankee Piping FAC Inspection Program is consistent with other FAC programs among the Entergy Nuclear South plants and throughout the industry. Any guidance provided by the NRC has been and is being followed appropriately.

Several strengths were identified in the methods and documentation of the selection of components for inspection, piping replacements with FAC resistant materials, and the level of FAC related experience of the program engineers.

No weaknesses or deficiencies were identified that would indicate that the VY Piping FAC Inspection Program could impact long-term monitoring of FAC or result in a challenge to nuclear or personnel safety, equipment reliability, or station performance.

Several Areas for Improvement were identified in the areas of formalized documentation of program reports and program related communications, transition issues related to converting to ENN procedures, and in timely updates of the CHECWORKS models.

Recommendations to enhance these areas and other minor process and procedural issues with the program are documented and appropriate actions have been entered into PCRS.

1.0 SCOPE OF ASSESSMENT

This assessment will focus on the Vermont Yankee Piping Flow Accelerated Corrosion (FAC) Inspection Program activities and processes to comply with generic letter 89-08. This assessment will include a thorough review and evaluation of the FAC Program processes in accordance with applicable industry standards and NRC guidelines. This assessment will verify that the FAC Program includes systematic methods for predicting which systems are susceptible to FAC, inspecting components determined to be susceptible, analyzing and trending inspection data to determine EC/FAC wear rates, determining future inspection times based on past inspection results, and repairing or replacing piping components determined or predicted to wear below minimum requirements.

This assessment will determine whether or not management controls, problems, or generic weaknesses exist relative to the station implementation of its long term FAC monitoring program.

2.0 OBJECTIVES, CRITERIA, & METHODOLOGY

This assessment is the first of five planned FAC program assessments for the ENN plants. Insights and findings from these assessments will be used to develop a common FAC Program for the ENN fleet. Specific objectives, evaluation criteria and the corresponding assessment methodology have been developed by the FAC working group (the 5 plant FAC Program Coordinators). The intent is to evaluate the FAC Program at each plant using essentially the same criteria.

The attributes that follow each or the objectives were taken from previous self assessments performed by ENS, INPO 97-002, "Performance Objectives and Criteria for Operating Nuclear Generating Stations" (OR, EN & OE), NSAC-202L "Recommendations for an Effective Flow-Accelerated Corrosion Program", the NRC Inspection Manual 49001 Sections 02 and 03, and Generic Letter, GL 89-08.

The fol/owing objectives and criteria were used to assess the specific areas of the self-assessment to determine the overall health and effectiveness of the Vermont Yankee Piping Flow Accelerated Corrosion (FAC) Inspection Program.

2.1 Programmatic leadership/Responsibility

Objective· Ensure that Vermont Yankee Nuclear Power Plant (VYNPP) Flow Accelerated Corrosion (FAC) Program is provided with adequate leadership and that the responsibility for the program is clearly defined. Determine if the FAC Program owner and any dedicated backup personnel are qualified for the position.

<u>Criterion 2.1.1 - Management</u> Determine if there is an active Management participation in, and commitment to the FAC program.

<u>Methodology:</u> Review of all levels of site procedures relating to FAC program to determine extent of Management's role in the program.

Criterion 2.1.2 - Documentation Determine if there is a station document that defines the overall program.

Methodology: Review station documents for definition and implementation of the FAG program.

Criterion 2.1.3 - Program Awareness Determine if appropriate site personnel are aware of who owns the FAG Program.

Methodology: Review Station documents or interview appropriate site personnel such as operations, system engineers, chemistry supervision, design engineering, and corporate metallurgist to determine their familiarity with the FAG program owner. Document their interactions with the FAG engineer.

Criterion 2.1.4 - Roles & Responsibilities Determine if the roles and responsibilities of the FAG program are clearly defined and understood.

Methodology: Review station documents for definition of FAG program roles and responsibilities. Interview program owner and support groups to determine if the roles and responsibilities are clear and followed.

Criterion 2.1.5 - Training Determine if personnel responsible for the FAG program have received appropriate training for the position.

Methodology: Request documentation or other evidence such as a training matrix or certificates shOWing the description and completion of training that has been obtained for the FAG program owner and any backup personnel. Such as Introductory FAG, EPRI GHEGWORKS, NDE training, etc.

Criterion 2.1.6 - Qualification Determine if FAC program owner is qualified for the position.

Methodology: Request documentation or other evidence such as a training matrix showing a description and completion of the position qualification.

Criterion 2.1.7 - Bench Strength Determine the bench strength and qualifications/training of backup personnel.

Methodology: Request documentation or other evidence such as a training matrix showing a description and completion of the position qualification.

Criterion 2.1.8 - Personnel Turnover Determine if personnel turnover is an issue for the FAC program.

Methodology: Interview program owner and supervisor to determine length of time in position for incumbent and predecessors. Review method and thoroughness of turnover.

Criterion 2.1.9 - Resources/Schedule Determine if program task/activities are completed in a timely manner and impact of time, schedule, resources, and accelerated milestones.

Methodology: Interview program owner to determine how much time is spent on FAG program during a fuel cycle, other responsibilities other than the FAG program and roles and responsibilities during outages. Interview program owners immediate supervisor for his expectations from program owner and perspective of the programs owner workload.

2.2 System Susceptibility

Objective - Determine if the FAC Program includes systematic methods for categorizing which systems are susceptible to FAC, predicting and analyzing FAC, and for prioritizing inspections. Determine if the methods are consistent with industry practice.

Criterion 2.2.1 - Susceptibility Review Determine if there is a formal susceptibility review performed for each system and component that may be susceptible to FAC.

Methodology: Perform a review of program documents to ensure that a formal FAC susceptibility evaluation has been performed. Ensure that scope of the review includes all susceptible plant piping shown on plant drawings and includes piping components on vendor supplied equipment. Ensure that the criteria used in the susceptibility evaluation is consistent with NSAC 202L.

Criterion 2.2.2 - Ranking Criteria Determine if the criteria used to rank the susceptible piping components in the various systems are in accordance with NSAC 202L or other accepted industry practices.

Methodology: Review FAC Program documents to determine whether the guidance provided in NSAC 202L is consistently applied. If other criteria are used, determine if the basis used is documented and defensible.

Criterion 2.2.3 - Documentation and Reviews Determine if the susceptibility analysis is adequately documented, checked, and/or independently reviewed.

Methodology: Review Program documentation / susceptibility analysis to verify jf the analysis was checked or independently reviewed.

Criterion 2.2.4 – Updates Determine if the susceptibility analysls report(s) are updated and at what frequency.

Methodology: Perform a document review of the susceptibility analysis report to determine if the report(s) are current. Also determine if the reports are updated at an appropriate frequency.

Criterion 2.2.5 Scope & System Alignment Determine whether systems and components being ranked are appropriately aligned with plant operating procedures and the pertinent drawings/ flow diagrams. Determine if piping on vendor supplied equipment is included in the scope of FAC program.

Methodology: Review program documents to determine whether systems and components being ranked are appropriately aligned with plant operating procedures and the pertinent drawings! flow diagrams. Review vendor supplied drawings to verify if piping drawings are included in the document system and in the FAC program.

Criterion 2.2.6 - Small Bore Susceptibility Determine if there is a susceptibility analysis performed for the small-bore piping and if there is inspection priority assigned to the piping.

Methodology: Perform a document review of the small bore susceptibility analysis, if applicable. Otherwise conduct interviews with FAC Responsible engineer to determine how the FAC program handles small bore piping.

Criterion 2.2.7- Department Interface Determine how other plant departments effectively contribute to the Susceptibility Analysis.

Methodology: Perform a document review of site procedures and protocols to determine if the roles and responsibilities for interfacing departments are clearly defined, and there is evidence of input from other plant departments. Conduct interviews with FAC Responsible engineer to determine how effective are the respective departmental inputs to enhancing the FAC program.

Criterion 2.2.8 - Abnormal Conditions Determine how changes in operating conditions, off-normal or abnormal system lineup, component leakage or operating experience are communicated, documented and evaluated for impact on the FAC program.

Methodology: Perform a document review of site procedures and protocols, system health reports, Condition Reports (Event Reports at VY), site and industry operating experience, E-Mail, or other communications to determine how system condition changes or alignment are documented, communicated then evaluated for impact on the FAC program. Conduct interviews with system engineering, operations, and performance groups to evaluate how are changes to system conditions and system alignment affecting the FAC program is documented and communicated to the FAC engineer.

2.3 Documentation

Objective - Ensure that FAC Documentation is in compliance with industry standards and that it is maintained in accordance with established processes and procedures.

Criterion 2.3.1 - Controlling Program procedure. The controlling program procedure is up to date and is current with respect to industry codes and standards.

Methodology: Review FAC program documents and references to determine if the controlling procedure is up to date and meets the requirements of applicable industry codes and standards. The controlling program procedure should be consistent with NSAC 202L guidelines.

Criterion 2.3.2 – Supporting Documents. Gridding procedures, engineering standards, and engineering directives, etc., are maintained up to date with current revisions.

Methodology: Review FAC program documents and references to determine if the supporting documents are up to date and meet the requirements of applicable industry codes and standards.

Criterion 2.3.3 - Document Reviews All appropriate program documents (Procedures, Models, Component Evaluations, etc.) are checked and reviewed per plant procedures and/or industry practices.

Methodology: Review FAC Program Documents (including a sample of historical records) to determine if Program Documents are reviewed and checked in accordance with program procedures or industry practices.

Criterion 2.3.4 - Component Database The component inspection database must be properly maintained.

Methodology: Review FAC component database to assure that it is properly updated and maintained.

Criterion 2.3.5 - Post-Outage Report The Post-Outage report must be completed and issued in a timely manner.

Methodology: Review FAC Documentation to assure that the Post-Outage Reports are completed and issued in a timely manner.

Criterion 2.3.6 - CHECWORKS Pass 2 CHECWORKS Pass 2 analysis and records must be up to date and adequately documented.

Methodology: Review FAC Documentation to assure that the CHECWORKS Pass 2 analysis and records are completed in a timely manner.

Criterion 2.3.7 - FAC Program Drawings FAC Program record drawings must document the component locations, the CHECWORKS numbering system, must be up to date. The documentation should be consistent with NSAC 202L Guidelines.

Methodology: Review a sample of plant FAC drawings to ensure that they indicate the component locations, the CHECWORKS numbering system, and they reflect the current plant configuration.

2.4 Model Verification and Review

Objective - Ensure that FAC predictive computer model used (such as CHECWORKS) is verified, reviewed and maintained in accordance to the plant's FAC Program procedures.

Criterion 2.4.1 - Model ReviewNerification. Determine if models are reviewed/verified and properly signed off.

Methodology: Review FAC program documents to determine if formal guidance for review/verification and sign off exists for the models. Review one system model to determine if it has been reviewed by a second person prior to being used.

Criterion 2.4.2 - Model Updates. Determine if model is updated with projected operating hours for the next outage, current chemistry conditions, and other changes in operating parameters.

Methodology: Review model to determine that operating parameters such as current chemistry conditions, operating hours and power level information are up to date.

Criterion 2.4.3 - Modeled systems accuracy. Determine if models reflect the complete piping system being modeled.

Methodology: Review a sample of one system model to ensure that all components in the piping system are included in the model.

Criterion 2.4.4 - Component data accuracy. Determine if component information in a system model is correct.

Methodology: Review a segment of a modeled system to ensure correct inputs were used such as material, geometry code, diameter, and nominal thickness. Also review a model segment in which a component has been replaced. Review replacement information for accuracy and ensure system drawings were updated appropriately.

Criterion 2.4.5 - Component Inspection data. Determine if component inspection data has been imported into model and processed correctly.

Methodology: Review a sample of one system model to ensure component inspection data was imported into model according to application guidelines.

Criterion 2.4.6 - Predictive Analyses Determine if the predictive computer model analyses are reviewed and used as part of the inspection selection process in accordance with program procedures.

Methodology: Review a sample of Pass1 and Pass 2 model results to ensure results are appropriately used for planning component inspections.

2.5 Inspection Planning

Objective - Ensure that FAC examination locations are selected in accordance with the site procedures and industry practices.

Criterion 2.5.1 - Inspection Process Determine if there is a procedure or formal process for selecting components for inspection.

Methodology: Review FAC Program documents to identify procedures and/or formal processes used to select components for inspection. Ensure that procedures provide sufficient guidance for component selection, and the guidance is consistent with NSAC 202L recommendations.

Criterion 2.5.2 - CHECWORKS Pass 1 Determine if only CHECWORKS Pass 1 analysis models are used as a basis in the selection process.

Methodology: Review FAC Program CHECWORKS analyses for use of only CHECWORKS Pass 1 analyses. Determine if the rational for only using a Pass 1 analyses for the inspection/selection process exists and is documented.

Criterion 2.5.3 – CHECWORKS Pass 2 Determine if CHECWORKS Pass 2 analysis models are used in the selection process.

Methodology: Review FAC Program CHECWORKS analyses for use of CHECWORKS Pass 2 analyses in the inspection/selection process. Determine if analyses are current and performed in accordance with site procedures and NSAC 202L Guidelines.

Criterion 2.5.4 - Previous Inspections Determine if & how previous inspection results are used in the selection process.

Methodology: Review FAC Program documents to determine if past inspection data is used in the selection process. Determine if the components recommended for repeat inspections in past inspection reports have in fact been inspected or scheduled for inspection.

Criterion 2.5.5 - Industry Events Determine if recent and past industry events are considered in the inspection planning process.

Methodology: Review a sample of industry operating experience (OE) to insure that it has been factored into the component selection process.

Criterion 2.5.6 - Selection Documentation Determine if the results of the inspection planning process are formally documented and if the selection logic for each location is captured.

Methodology: Review a sample of component selection documents to determine if the rational for component selection (or exclusion/deferral) is documented.

Criterion 2.5.7 - Control Valve Piping - Determine if susceptible components and piping downstream of control valves are covered in the program.

Methodology: Review a sample of plant flow diagrams for several susceptible systems and locate piping sections downstream of control valves. Determine if these locations are inspected and monitored for FAC.

Criterion 2.5.8 - Turbine Cross Around Piping Determine if the turbine cross around piping is inspected on a regular basis and if the frequency is supported by inspection data.

Methodology: Review the turbine cross around piping inspection reports and available documentation for inspection history, trending, and future inspection/repair/replacement plans.

Criterion 2.5.9 - Dissimilar Metal Effects Determine if piping components adjacent to upgraded materials are included in the inspection program scope to detect localized thinning caused by "entrance effect" at dissimilar metal connections.

Methodology: Review a sample of plant documents to determine locations of components replaced with FAC resistant materials. Verify inspections of original components adjacent to those replaced with FAC resistant materials.

Criterion 2.5.10 - Selection Review Determine if the piping component inspection list is reviewed by a person other than the originator and also if there are any program requirements for the review.

Methodology: Review component selection documents and /or interview responsible individuals for evidence that reviews of component selection documents are performed by another individual than the originator. Ensure evidence of reviews (documented by signature or other means) exists.

Criterion 2.5.11 - Selection Input Determine if input from other groups is included in the inspection planning process ((Le., Valve Group, Systems Engineering, Thermal Performance Monitoring, Operations, etc.)

Methodology: Review a sample of component selection documents and /or interview responsible individuals for evidence that input and/or reviews by other plant groups have been considered in the selection process.

Criterion 2.5.12 - Scope Expansion Determine if the program contains specific guidelines for scope expansion in the case of high or unexpected wear.

Methodology: Review program documents for specific scope expansion guidelines for in the case of high or unexpected wear. Review previous inspection reports for evidence that guidelines were followed.

Criterion 2.5.13 - Normally Closed Valves Determine if piping downstream of normally closed - but leaking valves is being considered for inspection.

Methodology: Review piping susceptibility analysis, previous inspection reports, Thermal Performance Monitoring Data, and condition reports to determine if a sample of piping downstream of normally closed (but leaking) valves is considered for inspection.

Criterion 2.5.14 - Small Bore Program Determine if there is an adequate small bore program for prioritizing and scheduling inspections.

Methodology: Review piping susceptibility analysis, previous inspection reports, and small bore related documents to determine the scope and schedule of the small bore piping inspection program. Compare plant documents to recommendations contained in Appendix A of NSAC 202L.

2.6 Performing Inspections

Objective - Ensure that FAC Examinations are performed in accordance with the site procedures and FAC Program documents and that they are consistent with industry standards.

Criterion 2.6.1 - Procedures Determine if there are formal procedures for performing inspections.

MethodoloQv: Review FAC Program documents to determine if formal procedures exist that provide sufficient guidance for performing FAC Inspections. Ensure this guidance is consistent with NSAC 202L. Ensure the procedures are current, properly reviewed, and reflect current industry techniques and practices.

Criterion 2.6.2 - Inspection Grids Determine if component inspection grids are permanently marked or documented to insure that future inspections can be repeated at the same locations.

Methodology: Review FAC Program documents for gridding instructions and determine that the grids are reproducible to ensure repeatability. Determine if the markers used for grid layout are permanent enough to ensure repeatability.

Criterion 2.6.3 - Gridding of Components Determine if inspection gridding is performed in accordance with industry practice and Program requirements.

Methodology: Review several FAC inspection reports, photographs, and drawings of components from past outages to ensure Inspection grids cover the entire component, the grid size used is consistent with NSAC 202L, the area on both sides of each pipe to component weld is inspected, and the grids extend upstream and downstream of the inspected component.

Criterion 2.6.4 – Qualifications/Certifications Determine if NDE Inspectors are properly qualified in accordance with the plant procedures and equipment certifications.

Methodology: Review a sample of inspector certificates of qualification from the last outage. Ensure inspectors qualifications were current and reviewed by QA prior to performing inspections, and inspectors were qualified to the proper UT Level for the inspections performed. Review a sample of equipment certifications from last outage and all equipment used in the inspections had current certifications.

Criterion 2.6.5 - Baseline Measurements Determine if UT measurements are taken on all components that are being replaced with susceptible materials.

Methodology: Review a sample of FAC inspection data of replaced components to ensure baseline data was obtained and documented in the FAC Program.

Criterion 2.6.6 - Suspect Readings Determine if suspect readings are verified for accuracy and areas of significant wear are scanned or the size of the grid reduced to identify the extent and depth of the thinning.

Methodology: Review a sample of FAC inspection data for evidence of checking data for suspect UT readings and verification that these readings were investigated and verified for accuracy.

Criterion 2.6.7- Organization of Data Files Determine if there is a formal system for organizing and maintaining the inspection data files.

Methodology: Interview FAC Responsible engineer and review process used for organizing and maintaining inspection data files. Ensure Inspection data is retained in accordance with plant procedures and are available for future retrieval.

2.7 Data Evaluation

Objective - Determine if the process for collecting, evaluating, analyzing and trending data is effective and is performed in accordance with established standards.

Criterion 2.7.1- UT Data Evaluation Determine if there is a formal process for evaluating UT data and performing wall thinning evaluations.

Methodology: Perform document reviews of UT procedure, data sheets and the component evaluation procedure to determine if the process is adequate for dispositioning components for continued service or replacement.

Criterion 2.7.2 - Evaluation Process Determine if the criteria and process used to evaluate components is in accordance with plant procedures and industry standards.

Methodology: Review evaluation procedure and a sample of evaluations to determine if the methodology used to perform the evaluations is in accordance with plant procedures and whether the evaluations provide the necessary data to effectively disposition the components for continued service.

Criterion 2.7.3 - Document Review Determine if the acceptance evaluations performed for each component are documented and reviewed.

Methodology: Review Program Documentation and a sample of component evaluations to verify if the evaluations are formally documented and are checked or independently reviewed.

Criterion 2.7.4 - Safety Margins Determine if appropriate safety margins are applied in remaining service life evaluations.

Methodology: Perform a document review of the evaluation process and sample some component evaluations to assess what safety margins are applied and whether it they are consistent with applicable codes and industry standards.

2.8 Performing Repairs

Objective - Ensure that FAC Repairs/Replacements are performed in accordance with established processes. procedures and applicable codes.

Criterion 2.8.1 - Repairs/Replacement Determine if formal procedures are followed when performing repairs or replacements.

Methodology: Review FAC program documents to determine if formal approved procedures are available that provide guidance for performing repairs and replacements that are consistent with applicable piping codes and meet the intent of NSAC-202L-R2.

Criterion 2.8.2 - External Repairs Determine if external repairs are performed in accordance with applicable codes and standards. There are several ASME code cases that may be utilized for safety related piping and components. Prior NRC approval may be required to use these code cases. These code cases can generally be used for non-safety related piping also.

Methodology: Review FAC Program documents and historical records to determine if External Repairs are performed in accordance with approved codes and standards and are consistent with NSAC 202L guidelines. Welding must be accomplished using approved procedures and qualified welders.

Criterion 2.8.3 - Internal Weld Repair Determine if internal weld repairs are performed in accordance with applicable codes and standards.

Methodology: Review FAC Program documents and historical records to determine if internal weld repairs are performed in accordance with approved codes and standards and are consistent with NSAC 202L guidelines. Welding must be accomplished using approved procedures and qualified welders.

Criterion 2.8.4 - Material Upgrade Process Determine if piping material upgrades are accomplished using approved site procedures.

Methodology: Review FAC documentation of material upgrades to ensure that the material upgrades have been reviewed and approved prior to installation in the plant and accomplished using approved procedures and processes.

Criterion 2.8.5 - Material Upgrade Documentation Determine if documentation of material upgrades is included in the FAC program documentation.

Methodology: Review FAC program documents to verify that material upgrade details have been properly incorporated into the plant drawings, specifications, predictive models, and associated data bases.

2.9 Long Term Strategy

Objective - Determine if the FAC Program has a long-term strategy that is consistent with the guidance provided in EPRI guideline NSAC-202L-R2, "Recommendations for an Effective FAC Program".

Criterion 2.9.1 - Establishment of a Long Term Strategy Determine if a long-term strategy is in place and if it is effective.

Methodology: Review FAC program documents to determine if a long-term strategy exists and if the strategy is consistent with NSAC-202L guidelines.

Criterion 2.9.2 - Reduction of wear rates Determine if the long-term strategy in place focuses on reducing FAC wear rates.

Methodology: Review FAC long-term strategy to determine if the strategy focuses on reducing wear rates and that the strategy on reducing wear rates is consistent to NSAC-202L guidelines.

Criterion 2.9.3 - Modeling Long-term Options Determine if analytical models used have been updated to reflect current information and used to evaluate long-term options.

Methodology: Review FAC program documents and a sample of predictive models to determine that all relevant information is up to date, and if model information is used in long-term planning efforts.

Criterion 2.9.4 – Water Chemistry Determine if past and future plant chemistry or water treatment is effectively used to control FAC degradation.

Methodology: Review program documentation to ensure changes in plant chemistry or water treatments are known and this information is used (either through FAC predictive model or other means) in controlling FAC degradation. Also review interface with Chemistry and FAC engineer.

Criterion 2.9.5 - System Changes Determine if system changes are reviewed and evaluated by the appropriate individual or department.

Methodology: Review FAC program documentation to ensure there is a process in place for informing FAC engineer of system changes that may effect FAC susceptible systems and that the effects of these changes to FAC are considered by appropriate department prior to making modifications to FAC susceptible systems. Also, ensure that replacements performed under the FAC program are communicated to system engineering (as well as other related departments) and appropriate drawings are updated with new material changes.

Criterion 2.9.6 - Inspection and Replacement Goals Determine if inspection and replacement goals are developed and documented for the next 3 to 5 years.

Methodology: Review FAC program documentation to determine if inspection and replacement goals for the next 3 to 5 years have been set.

Criterion 2.9.7 - Plant Benefits Determine if there is evidence of continual improvement to the plant due to FAC program efforts.

Methodology: Review FAC program and plant documentation to determine if there has been improvement in areas of water treatment, a reduction of wear in once high FAC susceptible systems, and replacement of susceptible components with corrosion resistant materials.

3.0 EVALUATION SUMMARY

Criterion 2.1.1 - Management: Determine if there is an active Management participation in, and commitment to the FAC program.

Vermont Yankee's response to GL-89-08 was reviewed for commitment to maintaining a FAC Program. The FAC program procedure PP 7028, Section 3, and the Engineering Program Procedure PP 7031 which delineates management responsibilities to the Director level were also reviewed. It was concluded that there is an active Management role in the FAC Program.

Criterion 2.1.2 - Documentation: Determine if there is a station document that defines the overall program.

Program procedure PP 7028, VY Piping FAC Inspection Program defines the responsibilities and implementation requirements for the FAC Program. Engineering Program Procedure PP 7031 delineates management responsibilities to the Director level. These documents along with related station procedures define the overall program.

Criterion 2.1.3 - Program Awareness: Determine if appropriate site personnel are aware of who owns the FAC Program.

Program Procedures PP 7028 and PP 7031 were reviewed and a clear delineation of roles and responsibilities for the various departments for interaction with the FAC Program was found. The FAC Program Coordinator is in design engineering. Also reviewed examples of documentation which demonstrated close ties with other groups for timely notification of leaks, access to system engineering thermal performance reports, and the monthly and weekly chemistry reports. This information is also available on plant web site.

Criterion 2.1.4 - Roles & Responsibilities: Determine if the roles and responsibilities of the FAC program are clearly defined and understood.

Program procedure PP 7028 and PP 7031 clearly define the roles and responsibilities of the various groups that implement and support the FAC Program. Interviews with the Program Engineer clearly illustrated that everyone works together and provides support when needed, and are familiar with the needs of the FAC Program.

Criterion 2.1.5 - *Training:* Determine if personnel responsible for the FAC program have received appropriate training for the position.

Vermont Yankee and Yankee Atomic training records for the program owner and back-up were reviewed. Both individuals have received the appropriate training for the FAC Program. Examples include the CHECWORKS Training Session from EPRI, an ASME sponsored Assessment of Material Aging and Assessment of Remaining Life evaluation course, and a Piping Flow Accelerated Corrosion (Mechanical Only) course.

Criterion 2.1.6 - Qualification: Deterniine if FAC program owner is qualified for the position.

There is no qualification matrix for the FAC Program in the ESP Program at this time. However there is a qualification matrix for the MS/DE department that shows the Program Owner is qualified to administer the FAC Program.

Criterion 2.1.7 - Bench Strength: Determine the bench strength and qualifications / training of backup personnel.

Vermont Yankee and Yankee Atomic training records show that the program owner and back-up have received the appropriate training for the FAC Program. There is no qualification matrix for the FAC Program in the ESP Program at this time. However, there is a qualification matrix for the MS/DE department that shows the program owner and backup are qualified to implement the FAC program. Also, a third design engineer with previous FAC Program experience at other plants is available.

Criterion 2.1.8 - Personnel Turnover: Determine if personnel turnover is an issue for the FAC program.

There is no issue at this time as the program owner has been in this position since the start of the FAC Program. The backup engineer has also been involved with the program since 1993. The current status of the program and future work is well documented which would be a valuable tool if turnover would be necessary.

Criterion 2.1.9 - Resources/Schedule: Determine if program task/activities are completed in a timely manner and impact of time, schedule, resources, and accelerated milestones.

An interview with program owner revealed that the time actually spent on FAC Program is ½ FTE averaged over the fuel cycle. Other responsibilities included ISI and IWE support. The program owner also supports IWE during outages. The actual time spent on FAC is very close to the time budgeted. Normally this works well and emergent work can be fit in with little or no impact to the program. Work planning is excellent and is formally planned using the Engineering Work Control (EWC) process.

However, during the last operating cycle, this was not true. The program owner needed to spend a good deal of time working on the EPU and pushed out many of the program commitments over three months. This was recognized by the program owner and his supervisor as an unusual event. Program tasks are routinely performed on schedule.

An interview with Program owners' supervisor reiterated the issues stated above. After the EPU is finished, the workload will return to normal. The work scheduling process via the EWC is well suited to identify and track items to completion by Program owner and his supervisor.

Criterion 2.2.1 - Susceptibility Review: Determine if there is a formal susceptibility review performed for each system and component that may be susceptible to FAC.

A susceptibility review was performed for the plant piping in accordance with NSAC 202L. This review lumped all the piping systems together, while this approach gives a single place to verify inclusion or exclusion into the program the approach should have been to further separate the small bore review and rank the piping for inspections in terms of inspection priority and risk consequences to the plant. Since the CHECWORKS program for large bore piping provides such ranking. See Area for Improvement (AFI) 2.2-1

Further review of the report determined that the document is not formal even though there was a review performed. This document is not in the document system nor, is it an attachment to or an appendix to a procedure. Recognizing that a lot of the piping in the plant is corrosion resistant material it does not preclude the remainder of the piping from being prioritized in terms inspection priority and risk consequence. See AFI 2.2-2

A review of incorporation of the vendor supplied piping into the susceptible review was also performed by sampling the HPCI system and reviewing, drawing GE191169, with the result that all piping was included.

Criterion 2.2.2 - Ranking Criteria: Determine if the criteria used to rank the susceptible piping components in the various systems are in accordance with NSAC 202L or other accepted industry practices.

A review of the FAC Susceptible Piping Identification Report shows that the guidance provided by NSAC 202L was used to screen the various piping systems for inclusion or exclusion in the FAC program. The report did not rank the piping in terms of inspection priority or risk consequence to the plant. Since ranking for the large bore piping is provided by the CHECWORKS model, it is therefore important that small bore piping system be ranked (AFI 2.2-1). Per interview with the program coordinator this task was scheduled but currently not done due to other work assignment priority.

Criterion 2.2.3 - Documentation and Reviews: Determine if the susceptibility analysis is adequately documented, checked, and/or independently reviewed.

The FAC Susceptible Piping Identification Report was checked to determine if there was an adequate review performed and determined that only a peer review was performed. This report was a program generated document with no requirement for this review. This document is not in the document system nor, is it an attachment to or an appendix to a procedure. AFI 2.2-2

Criterion 2.2.4 - Updates: Determine if the susceptibility analysis report(s) are updated and at what frequency.

A review of program procedure PP 7028, Section 3.2.12 post outage activity requires the update and maintenance of the FAC susceptible piping document to reflect plant changes. During 2001 outage, approximately 6 ft of piping (on MSD piping in steam tunnel was replaced with chrome-moly piping. AOG steam reducing station drains from steam trap to condenser was also replaced. In addition lines ¾"-HCN-188-H1 and ¾"-HCN-189-D3 which are drains from 3"-MSD-4 from the steam traps at pressure reducing station were replaced. In accordance with PP7028 section 3.2.12, the report should have been revised. The last update of this report was May 15, 2000. See AFI 2.2-3

Criterion 2.2.5 Scope & System Alignment: Determine whether systems and components being ranked are appropriately aligned with plant operating procedures and the pertinent drawings/ flow diagrams. Determine if piping on vendor supplied equipment is included in the scope of FAC program.

Feedwater piping drawings 5920-FSI-24 & 5920-FSI-25 and a sampling of the components of the CHECWORKS model were reviewed to verify if the components within the model match with the piping configuration. A sampling of vendor supplied piping using HPCI piping (Vendor drawing G191169 Sht. 2/2) lines 2-HPCI-8, 2-HPCI-9, & 2-HPCI-12 was also checked to determine if those lines were in the FAC program. System line up was checked against OP-2172 to verify line for normal operation.

Large bore components being ranked are appropriately aligned with plant operating procedures and the pertinent drawings / flow diagrams and vendor supplied equipment piping is included in the scope of FAC program.

Criterion 2.2.6 - Small Bore Susceptibility: Determine if there is a susceptibility analysis performed for the small-bore piping and if there is inspection priority assigned to the piping.

The susceptibility analysis for small bore piping is complete. However, inspection priorities are not documented. Initially, engineering judgment was used to select small bore inspection locations, such as high pressure lines and steam leak offs. Without a priority ranking, it is difficult to determine if all the high priority lines have been selected. Ranking for the small bore lines was scheduled for the summer, 2003, but had to be pushed back due to emergent work on the power uprate project. AFt 2.2-1

Criterion 2.2.7- Department Interface: Determine how other plant departments effectively contribute to the Susceptibility Analysis.

Conducted an interview with the FAC program engineer to define how the respective departmental inputs are processed and updated. Reviewed system engineering variance reports, thermal performance reports and chemistry reports to determine what vital information was available and continues to exist for the development of the ranking for the small bore piping. Reports form the various departments are adequate to assist in performing the susceptibility analysis.

Criterion 2.2.8 - Abnormal Conditions: Determine how changes in operating conditions, off-normal or abnormal system lineup, component leakage or operating experience are communicated, documented, and evaluated for impact on the FAC program.

A document review of site procedures and protocols, system health reports, Event Reports (Condition Reports), site and industry operating experience, and Emails was performed to determine how system condition changes or alignments are documented, communicated then evaluated for impact on the FAC program. Off normal events are reported through the following reports; Monthly Chemistry Report, System Engineering Variance Report, and the Thermal Performance Report. These tools assist in scoping lines for inspection or incorporating in the susceptible report. However the link with operations needs to be strengthened. See AFt 2.2-4

Criterion 2.3.1 - Controlling Program Procedure: The controlling program procedure is up to date and is current with respect to industry codes and standards.

The program procedure is consistent with NSAC 202L guidelines. However, the program procedure was last changed in 2001 (PP 7028 LPC 1, 12/06/01). The FAC coordinator is aware that the procedure is in need for update, but has had limited time to contribute to the effort. Previous self assessments and audits performed on the FAC program have also recommended the updating of the FAC program procedure. There are two existing commitments (LO-VTVLO-2002-00341 and LO-VTVLO-2002-00568) in place for specific additions/improvements to PP7028. This update should include not only update to the procedure content per the commitments but also update the FAC isometric drawings which are part of the program procedure. See AFt 2.3-1

Criterion 2.3.2 - Supporting Documents: Gridding procedures, engineering standards, and engineering directives, etc., are maintained up to date with current revisions.

The gridding procedure has resided in NE-8053 until recently, when NE-8053 was made obsolete by ENN-NDE-9.05 rev 0. This new procedure does not include FAC gridding guidelines that were once a part of the VY site procedure. The gridding procedure will need to be moved to a new procedure or incorporated into an existing procedure. The FAC engineer is aware of the change, and will add the necessary gridding guidelines removed from the UT procedure to the FAC program procedure as a supplement. This is not only a problem for VY but also for other ENN FAC programs. Existing commitment No. LO-VTVLO-2003-00528 is in place to relocate the component gridding guidelines.

VY has not adopted the new ENN procedure for wall thinning evaluations, ENN-DC-133 for their FAC program. Adoption of the new ENN procedure for VY is TBD. At this time VY still uses its plant specific procedure for evaluating wall thinning (DP 0072). This structural evaluation procedure (DP 0072) should be checked to ensure that the current references shown are up to date and updated accordingly. Modification of DP 0072 and conversion to ENN-DC-133 for wall thinning evaluations is required. See AFI 2.3-2.

Criterion 2.3.3 - Document Reviews: All appropriate program documents (Procedures, Models, Component Evaluations, etc.) are checked and reviewed per plant procedures and/or industry practices.

The FAC program procedure, PP 7028, and department procedure DP 0072, for Structural Evaluation of Thinned Wall Piping Components, and several component evaluations were reviewed. The documents were prepared by the FAC engineer and reviewed by Backup FAC engineer. NDE reports are reviewed and checked by a Level III examiner as well as by the FAC engineer.

Criterion 2.3.4 - Component Database: The component inspection database must be properly maintained.

A component inspection database for small bore component inspections exists, but is not up to date. The last revision was in December of 1999. An update of the small bore database is currently in the EWC schedule. AFI 2.2-1.

For large bore components information and all inspection data to date has been included in the CHECWORKS database. At this time CHECWORKS is considered the main component database for large bore components. A separate a FACTRAK import into an Excel spreadsheet was created in 1996 to summarize which large bore components have been inspected, but has not been updated.

Criterion 2.3.5 - Post-Outage Report: The Post-Outage report must be completed and issued in a timely manner.

Section 4.1.12 of PP 7028 requires that Outage Inspection Reports are to be issued within 90 days of startup. The report itself is very detailed, giving a summary of the inspection activities performed, the goals that were planned and accomplished and inspection results. The report also includes recommendations for future replacements or repairs and future required monitoring. This report is prepared by the FAC engineer and is independently reviewed and signed. Reports from the 1999, 2001, and 2002 refueling outages were reviewed. All were issued with 90 days of plant startup.

Criterion 2.3.6 - CHECWORKS Pass 2: CHECWORKS Pass 2 analysis and records must be up to date and adequately documented.

A Pass 2 analysis was run for all CHECWORKS lines during 1996. After 1996 only the most susceptible lines were run. In 2003, only the feedwater models were ran using 1999 UT data. This information was not used to support 2004 scope selection as stated in the "Inspection Location Worksheets / Methods and Reasons for Component Selection" for the 2004 refueling outage. Updates of the CHECWORKS models are scheduled in the EWC process.

Criterion 2.3.7 - FAC Program Drawings: FAC Program record drawings must document the component locations, the CHECWORKS numbering system, must be up to date. The documentation should be consistent with NSAC 202L Guidelines.

FAC large bore location sketches are located in Appendix A of PP 7028. The sketches represent lines in CHECWORKS and all components in the CHECWORKS models are identified on the sketches using the CHECWORKS numbering system. Information on the component location sketches is consistent with the CHECKWORKS model and the component numbering system. The sketches reference P&IDs and pipe drawings used to develop drawings, but the FAC sketches can only be updated as a procedure update since they are part of the FAC program procedure.

The component location sketches are not included in the plant drawing list and are not controlled through configuration management. Specific sketches do not reflect current plant configuration and "marked up" pending a revision to the Program Procedure. The FAC drawings also do not reflect all the changes due to material replacements. AFI 2.3-1

Criterion 2.4.1 - Model ReviewNerification: Determine if models are reviewed / verified and properly signed off.

The complete CHECWORKS models and wear rate analyses were updated in 1996. These were prepared in-house and reviewed by FAC coordinator. After 1996, only a limited number of models were ran by FAC coordinator prior to outages (mainly feedwater piping) and these model updates were not formally documented and reviewed. Updates to the CHECWORKS models should be formally updated and reviewed. See AFI 2.4-1

Criterion 2.4.2 - Model Updates: Determine if model is updated with projected operating hours for the next outage, current chemistry conditions, and other changes in operating parameters.

CHECWORKS database has been updated with current operating hours (up to cycle 29) and heat balance parameters are current. There have been no significant chemistry changes performed at W, so chemistry parameters remain unchanged. FAC coordinator is aware of future plant plans such as starting HWC and power uprate and will update CHECWORKS according when these plans are implemented. The CHECWORKS models should be updated with UT data from 2001 and 2002 inspections. An update of the CHECWORKS models is currently in the EWC schedule. The CHECWORKS models should be formally updated and reviewed. AFI2.4-1

Criterion 2.4.3 - Modeled Systems Accuracy: Determine if models reflect the complete piping system being modeled.

A detailed review of the CHECWORKS model for a section of the feedwater system (Discharge line from pump P1-1-A to 24" FW header, FAC sketch No. 001) was performed. The modeled line segment included all components in the line from pump nozzle to the feedwater header. Component identifiers in CHECWORKS model matched identifiers on FAC drawings. The complete line was modeled in CHECWORKS.

Criterion 2.4.4 - Component Data Accuracy: Determine if component information in a system model is correct.

Review of CHECWORKS line segment FDW-001 showed all component information to be correct and verified by the heat balance and flow diagrams. Portions of the Feedwater Flush lines 8"-FDW-22A & 10"-FDW-23A on Location Sketch 022 have been upgraded to A335-P11 material. The P&ID, the CHECKWORKS model, and the FAC drawing were reviewed. While the P&ID and the CHECKWORKS model were updated, the FAC Component Location Sketches were only "marked-up". AFI 2.3-1.

Criterion 2.4.5 - Component Inspection Data: Determine if component inspection data has been imported into model and processed correctly.

Last inspection (2002) data was imported into CHECWORKS by NDE and reviewed to ensure that the data matched data logger readings. The UT data matrix from CHECWORKS is printed out and signed by NDE. Though the data was imported into CHECWORKS, it has not been evaluated in CHECWORKS or used to analyze wear rates for the 2004 refueling outage inspection selection. This is stated in the "Inspection Location Worksheets / Methods and Reasons for Component Selection" for the 2004 refueling outage. Updates of the CHECWORKS models are scheduled in the EWC process. AFI 2.4-1.

Criterion 2.4.6 – Predictive Analyses: Determine if the predictive computer model analyses are reviewed and used as part of the inspection selection process in accordance with program procedures.

A review of PP 7028 rev 1, Appendix A, Component Location Sketch 008, and the associated Pass1/Pass2 results was performed. Outage inspection plans considered these results in the location selection process. For example, Pass 2 analysis from the 2001 CHECWORKS run was used when developing the scope for 2002 outage. This is documented in the FAC inspection scope worksheets for the 2002 refueling outage which describes the reasoning behind the selection of each component scoped for the outage. Though the components selected were inspected during 2002, the inspection data recorded for that component was not used as part of the wear analysis in CHECWORKS for the 2004 scope. This is stated in the "Inspection Location Worksheets / Methods and Reasons for Component Selection" for the 2004 refueling outage. Updates of the CHECWORKS models are scheduled in the EWC process. AFI 2.4-1.

Criterion 2.5.1 - Inspection Process: Determine if there is a procedure or formal process for selecting components for inspection.

Reviewed program procedure PP 7028 where Section 4.4.1 specifies the process for selecting components and Appendix E of PP 7028 defines the criteria for selection of components for inspection. This approach is consistent with NSAC 202L R2 guidelines.

Criterion 2.5.2 - CHECWORKS Pass 1: Determine if only CHECWORKS Pass 1 analysis models are used as a basis in the selection process.

CHECWORKS Pass 1 analysis output is only used to exclude lines from the inspection selection process in terms of susceptible or not susceptible. Since a large number of the lines in the large bore FAC program were either originally FAC resistant Chrome-moly piping materials or have been replaced with FAC resistant materials and there are only few segments that have no inspection data, this approach is prudent.

Criterion 2.5.3 - CHECWORKS Pass 2: Determine if CHECWORKS Pass 2 analysis models are used in the selection process.

Generally most of the inspection selections from the CHECWORKS output are from the Pass 2 analysis output. This is consistent with the NSAC 202L approach. However, the model was last updated on October 24, 2001. Industry practice is to update the CHECWORKS models after each refueling outage. INPO in an industry operating experience (OE 12343) identified unanticipated wall thinning in feedwater piping as the result of relying on a dated CHECWORKS model. The OE highlighted the changes in component ranking occurred as result of not including the latest inspection data. AFI 2.4-1

Criterion 2.5.4 - Previous Inspections: Determine if & how previous inspection results are used in the selection process.

Criteria for selecting components for inspection during a refueling outage are contained in the "Inspection Location Worksheets/Methods and Reasons for Component Selection". One criterion is for components selected for measured or apparent wear found during previous inspections. Inspection Nos. 01-03 & 01-04, component Nos. FD01EL01 and FD01 TE05 as shown on Sketch 004 were tracked from the 2001 inspection report which recommended re-inspection in 2004. A review of the work scope for 2004 included these components for re-inspection. Components recommended for repeat inspections in past inspection reports have been re-inspected.

Criterion 2.5.5 - Industry Events: Determine if recent and past industry events are considered in the inspection planning process.

The "Inspection Location Worksheets/Methods and Reasons for Component Selection" for the 2004 RFO were reviewed. Under the criterion for "Largebore Components Identified by Industry Events/Experience", a total of 18 events since January 2001 are listed. From Surry-1 OE was tracked for a leak in the 8" condenser drain header for the 3rd/4th point FW Heater vents, the thinning in the Gland Steam piping inside the condenser and the 12" condenser drain header from the MS Drain Trap Lines. Similar piping at VY is an 8" low point drain header, which is scheduled for inspection during the 2004 RFO. The other 17 OE's were reviewed and found either they were dispositioned by scheduling for future inspection or explaining why no further action is required.

Criterion 2.5.6 - Selection Documentation: Determine if the results of the inspection planning process are formally documented and if the selection logic for each location is captured.

Reviewed program procedure PP 7028 which includes the section on "Inspection Location Worksheets / Methods and Reasons for Component Selection". These worksheets provide a rigorous and thorough method to aid in the identification and selection of components for inspection. It includes all the selection criteria necessary for a thorough review of small bore, large bore, feedwater heater shells, and cross-around piping. The worksheets address inspections based on previous inspection results, CHECWORKS evaluations, CHECWORKS model calibration, OE, off normal flow conditions, malfunctioning equipment such as leaking valves, and engineering judgment. The worksheets prepared by the program owner and reviewed by the backup FAC program Engineer. Components identified in the worksheets are compiled in the Scoping memo to Program Owners supervisor.

The worksheets used to select inspections should be considered a program strength STR **2.5-1**. They present a thorough, rigorous, documented approach to inspection selection incorporating all the criteria in NSAC-202L, and site specific issues.

Criterion 2.5.7- Control Valve Piping: Determine if susceptible components and piping downstream of control valves are covered in the program.

Plant flow diagrams and inspection reports on piping and components up and down stream of flow control valves FCV6-12A and -128 were reviewed. Up and downstream components of FCV6-12A (FD07RD02, FD07RD03 and FD07SP03) were inspected in 1990, 1993 and 1995. Up and down stream components of FCV6-128 (FD08SP02 and FD08RD03) were inspected in 1995. VY FAC program effectively addresses piping downstream of flow control valves.

Criterion 2.5.8 - Turbine Cross Around Piping: Determine if the turbine cross around piping is inspected on a regular basis and if the frequency is supported by inspection data.

The "Inspection Location Worksheets/Methods and Reasons for Component Selection" for the 2004 RFO was reviewed for the selection of the cross around piping. Also, a sampling of the 1998 and 1995 refueling outage inspection reports was performed. From these it can be concluded that the cross around piping has numerous inspections and the plans for future inspections as documented the 2004 inspection selection demonstrate that the piping is inspected on a frequent basis and is more than adequate.

Criterion 2.5.9 - Dissimilar Metal Effects: Determine if piping components adjacent to upgraded materials are included in the inspection program scope to detect localized thinning caused by "entrance effect" at dissimilar metal connections.

Reviewed plant flow diagrams for instances of non susceptible materials (chrome-moly, stainless steel) adjacent to susceptible materials (carbon steel). Although there are not many instances of dissimilar metal interfaces at VY, one interface was found on feedwater line 4"-FDW-4, sketch 017. The chrome component was pipe FD04SP12 connected to a carbon steel reducer FD04RD01. These components were inspected in 11/99, as documented on inspection data sheet YA-UT-112-222. The VY FAC program effectively addresses dissimilar metal connections.

Criterion 2.5.10 - Selection Review: Determine if the piping component inspection list is reviewed by a person other than the originator and also if there are any program requirements for the review.

The "Inspection Location Worksheets/Methods and Reasons for Component Selection" for the 2004 RFO were reviewed. The worksheets were reviewed and documented by signature. There is no program or procedural requirement for the review. Existing commitment No. LO-VTYLO-2002-341 is in place to formalize the-'nspection Location

Worksheet process. Documentation and review requirements will be included in the procedure update.

Criterion 2.5.11 - Selection Input: Determine if input from other groups is included in the inspection planning process ((Le.! Valve Group, Systems Engineering, Thermal Performance Monitoring, Operations, etc.)

Reviewed the system engineering production variance report and thermal performance report and determined that those reports are good sources for input into the selection process. Interviewed the program owner as to which other group contributed to the selection process and another good source cited is the operating experience group who routinely distribute issue FAC related industry events.

Criterion 2.5.12 - Scope Expansion: Determine if the program contains specific guidelines for scope expansion in the case of high or unexpected wear.

Reviewed program procedure PP 7028, section 4.4.7.2 and Appendix E relating to criteria for scope expansion. Reviewed 1996 Outage inspection report with specific examples of scope expansion as documented in data sheets YA-UT-112-95,YA-UT-112-114 &YA-UT-112-128 due to high or unexpected wear for the feedwater and condensate system.

Criterion 2.5.13 - Normally Closed Valves: Determine if piping downstream of normally closed - but leaking valves is being considered for inspection.

Reviewed the thermal performance variance report (1999) that shows valve leakage by indication of tail pipe temperature measurement with associated inspection during the 1999 refueling outage. Inspection data sheets YA-UT-112-220/221/222 AND YA-UT-112-214/215/216, document the inspections.

Criterion 2.5.14 - Small Bore Program: Determine if there is an adequate small bore program for prioritizing and scheduling inspections.

Reviewed piping susceptibility analysis, previous inspection reports, and small bore related documents to determine the scope and schedule of the small bore piping inspection program. Compare plant documents to recommendations contained in Appendix A of NSAC 202L. Small bore piping inspections are not ranked or prioritized. See AFI 2.2-1

Criterion 2.6.1 - Procedures: Determine if there are formal procedures for performing inspections.

Reviewed program procedure PP 7028 section 4.4.4. "Prepare piping components for inspection", Section 4.4.5, "Perform UT inspections", and Section 4.4 6 for Level III and compliance responsibilities. The procedure specific instructions and guidance for performing FAC inspections are consistent with NSAC 202L Rev.2.

Program procedure PP 7028 references NDE Procedure NE 8053 which has been superceded by ENN-NDE-9.05 Rev.O and subsequently needs to be revised. In addition the details for performing gridding do not exist in the new procedure and no active procedure contains those instructions. Therefore a new procedure has to be generated or the gridding instructions incorporated in the program procedure. Commitment LO-VTYLO-2003-00528 was previously generated to track the development of a FAC gridding procedure.

Criterion 2.6.2 - Inspection Grids: Determine if component inspection grids are permanently marked or documented to insure that future inspections can be repeated at the same locations.

Reviewed program procedure PP7028 Section 4.4.4.2 which references procedure NE 8053 Appendix A for gridding instructions. This procedure states the requirements for gridding to ensure the applied grids are documented and reproducible. Procedure NE 8053 has been superceded by ENN-NDE-9.05 Rev.0 and has no gridding instructions. As a consequence a new procedure needs to be generated. Commitment LO-VTYLO-2003-00528 was previously generated to track the development of a new FAC gridding procedure.

Criterion 2.6.3 - Gridding of Components: Determine if inspection gridding is performed in accordance with industry practice and Program requirements.

Reviewed program procedure PP7028, Section 4.4.4.2 which references procedure NE 8053 Appendix A for gridding instructions. This procedure states the requirement for gridding to ensure reproduction and repeatability. Also reviewed inspection data sheet 8053-02-111 for component FD14EL05 and data sheet 8053-02-110 for component FD14TE02 from the 2002 refueling outage and concluded that the gridding is consistent with the requirements of NSAC 202L Rev.2 and industry standards.

Criterion 2.6.4 - Qualifications/Certifications: Determine if NDE Inspectors are properly qualified in accordance with the plant procedures and equipment certifications.

Reviewed certification / qualification records for two FAC inspectors and determined that the processing and review of the technicians qualification and certification were conducted and accepted in accordance with plant protocol.

Criterion 2.6.5 - Baseline Measurements: Determine if UT measurements are taken on all components that are being replaced with susceptible materials.

No baseline measurements have been performed to date. However no permanent large bore replacements with carbon steel piping have been performed due to FAC related damage.

Criterion 2.6.6 - Suspect Readings: Determine if suspect readings are verified for accuracy and areas of significant wear are scanned or the size of the grid reduced to identify the extent and depth of the thinning.

Reviewed data sheet YA-UT-112-213 for component FD07EL01 for counter-bore and YA-UT-112-238 for component FD14SP03 with suspect reading lower than area reading and data sheet showed readings were re-taken and new measurement replaced the previous one.

Criterion 2.6.7- Organization of Data Files: Determine if there is a formal system for organizing and maintaining the inspection data files.

Reviewed program procedure PP 7028 with particular reference to Sections 4.4.1.3 and 6.3 which require formal record retention. Interviewed FAC program owner for compliance and determined inspection records are retained in accordance with PP 7028.

Criterion 2.7.1- UT Data Evaluation: Determine if there is a formal process for evaluating UT data and performing wall thinning evaluations.

DP 0072 is used to evaluate components for continued service or replacement and outlines a formal process to perform evaluations. Evaluations are not considered calculations but they are reviewed and signed by an independent reviewer and are permanently stored by records for plant lifetime. Safety class piping and components under ASME section XI requirements are dispositioned in accordance with DP 4027.

UT data is reviewed by Level III examiner and signed. Reviewed 2000 Outage Report Inspection No. 2000-04, DP 0072 provides a formalized process, data sheets, and is found to be adequate for dispositioning components for continued service or replacement.

With the removal of the FAC related guidelines from the UT procedure, it is recommended that the FAC program procedure be updated with these UT data requirements to ensure that the formal process for gathering FAC UT data is maintained. Commitment LO-VTYLO-2003-00528 was previously generated to track the development of a new FAC gridding procedure.

Criterion 2.7.2 - Evaluation Process: Determine if the criteria and process used to evaluate components is in accordance with plant procedures and industry standards.

The FAC program document, PP 7028 rev 1, refers to DP 0072 for evaluating components. Component evaluations are performed in accordance with plant procedure DP 0072, "Structural Evaluation of Thinned wall piping components. At this time, VY is not required to perform evaluations based on ENN-DC-133. Component evaluations are also consistent with industry procedure NSAC-202L.

Reviewed 2000 Outage Report Inspection No. 2000-04, DP 0072 provides a formalized process, data sheets, and is found to be adequate for dispositioning components for continued service or replacement.

Criterion 2.7.3 - Document Review: Determine if the acceptance evaluations performed for each component are documented and reviewed.

A review of the 2000 Outage Report Inspection No. 2000-04, the completed acceptance evaluation includes the component evaluations, NDE reports, and structural evaluations (entire component evaluation worksheet) was performed. These are reviewed, checked, and approved. All worksheets are stored in records for plant lifetime.

Criterion 2.7.4 - Safety Margins: Determine if appropriate safety margins are applied in remaining service life evaluations.

A safety margin of 1.2 on predicted wear rate is used per procedure DP 0072. NSAC-202L-R2 identifies but does not stipulate a value to be used for the safety factor (SF). DP 0072 Rev 1 uses an SF = 1.2. This is consistent with other plants which use either SF = 1.1 or 1.2.

Criterion 2.8.1 - Repairs/Replacement: Determine if formal procedures are followed when performing repairs or replacements.

Formal procedures exist for repair/replacement. Safety class ASME section XI components are dispositioned under DP 4027, and component repairs or replacements are performed under AP 0070. Non-safety repairs/replacements would be controlled via maintenance work orders for like-for-like. For upgraded material replacements, an engineering recommendation, followed by an equivalency evaluation and either a minor mod or design change to implement the replacement. AP 0070 "ASME Section XI Repair and Replacement Procedure" provides a formal process, that is consistent with ASME Section XI and NSAC-202L-R2.

Criterion 2.8.2 - External Repairs: Determine if external repairs are performed in accordance with applicable codes and standards. (There are several ASME code cases that may be utilized for safety related piping and components. Prior NRC approval may be required to use these code cases. These code cases can generally be used for non-safety related piping also.

All external weld repairs are considered temporary, are performed using approved procedures, and require approval from the ANII. These are either permanently repaired or replaced during the next opportune time or outage. External repairs to Safety Class Piping would require a relief request and would be performed under the requirements of AP 0070, "ASME Section XI Repair and Replacement Procedure". No external repairs to Safety Class piping due to FAC related damage have been performed at VY.

Criterion 2.8.3 - Internal Weld Repair: Determine if internal weld repairs are performed in accordance with applicable codes and standards.

Internal weld repairs on non Safety Class piping are considered permanent, are performed using approved procedures, and require approval from the ANII. Internal weld repairs to Safety Class Piping are performed under the requirements of AP 0070, "ASME Section XI Repair and Replacement Procedure" using approved welders and welding procedures. This is consistent with ASME Section XI and NSAC-202L-R2 guidelines.

Criterion 2.8.4 - Material Uporade Process: Detennine if piping material upgrades are accomplished using approved site procedures.

Equivalency evaluations, engineering recommendations, and mod packages for material upgrades due to FAC are reviewed and approved prior to installation in the plant. Replacement of FAC susceptible systems with Cr-Mo (P11 or P22) is common knowledge plant-wide and is not stated in FAC program procedure. All material changes are shown on system P&IDs.

PP 7028, does not identify a specific process or procedure to be used when making a material upgrade. After the FAC engineer determines that a material upgrade is required, the Design Engineering Group performs the required evaluations and develops the modification packages using the standard design processes provided by AP 0020, and AP 6008.

Documents pertaining to modifications made to line 1"-MSD-407 (dated 4-3-95) and line 2"-MSD-406 (dated 4-10-95) were reviewed and found reasonable. Additionally, document VY-DC-2003-02, an in-process modification package was likewise reviewed and found to be reasonable.

Criterion 2.8.5 - Material Upgrade Documentation: Determine if documentation of material upgrades is included in the FAC program documentation.

Material changes are captured on the plant P&IDs and not the plant's line specification (the Ebasco Piping Specification QC-10 line list is historical). For the FAC program, changes to material have been updated in CHECWORKS but not all updated lines have been captured in the FAC system susceptibility documentation, and FAC isometrics. See AFI2.2-3.

Portions of the Feedwater Flush lines (8"-FDW-22A & 10"-FDW-23A) have been upgraded to A335 P11 material. The P&ID, the CHECKWORKS model, and the FAC drawing were reviewed. While the P&ID and the CHECKWORKS model were updated, the FAC Component Location Sketches were only "marked-up".
See AFI 2.3-1.

Criterion 2.9.1 - Establishment of a Long Term Strategy: Determine if a long-term strategy is in place and if it is effective.

VY is a BWR which has limited chemistry options for reducing FAC. The most effective long term method for reducing FAC wear is replacements with FAC resistant materials. VY has been vigilant on replacing susceptible systems with FAC resistant materials in order to reduce FAC long term. Areas that have been replaced with FAC resistant material to date are:

- MS Drain Lines to #2 FDW heaters downstream of LCV
- MS drain bypass lines to condenser downstream of LCV
- FDW flush lines from normally closed valves to pressure reducing orifices near the condenser.
- FDW pump bypass lines for normally closed valves to the condenser.
- Turbine cross around piping (7 of 8 lines).
- Main steam small bore drains from HPCI and RCIC turbine steam supply to the condenser.
- Steam Leads continuous drain to the condenser downstream of turbine stop/control valves.
- Two condensate return lines from the AOG steam pressure reducing station to the condenser.
- LP turbine casings including the extraction steam stubs
- Extraction nozzles and partial shell replacement on #2 HP FW heater
- #3 & #4 feedwater heaters
- #5 feedwater heaters in the condenser neck

Other systems such as feedwater heater vents are planned for replacement with FAC resistant material due to the planned 20% power uprate. Replacements with FAC resistant materials performed to date are a major part of reducing FAC rates which is an important part of a long term strategy per NSAC-202L R2. Vermont Yankee's proactive piping replacements with FAC resistant material is considered as a program strength. See STR 2.9-1

Criterion 2.9.2 - Reduction of Wear Rates: Determine if the long-term strateQV in place focuses on reducing FAC wear rates.

Replacement efforts are the primary focus on reducing wear rates and consistent with NSAC-202L guidelines as stated in Criterion 2.9.1 above.

Criterion 2.9.3 - Modeling Long-Term Options: Determine if analytical models used have been updated to reflect current information and used to evaluate long-term options.

The CHECWORKS database has been updated with current operating hours (up to cycle 29) and heat balance parameters are current. There have been no significant chemistry changes performed at VY, so chemistry parameters remain unchanged. The FAC coordinator is aware of future plant plans such as starting HWC and power uprate and will update CHECWORKS according when these plans are implemented.

Though inspection data for the last two outages have been imported into CHECWORKS, this information must be incorporated into the current models and models ran for results. An update of the CHECWORKS models is currently in the EWC schedule. The updates should be formally updated and reviewed. See AFI 2.4.1.

Criterion 2.9.4 - Water Chemistry: Determine if past and future plant chemistry or water treatment is effectively used to control FAC degradation.

Since VY is a BWR, there is very little that can be done to reduce FAC wear rats through water chemistry changes. Dissolved oxygen in the final feedwater has been maintained in the 20 to 30 PPB range from 1996 to 2003. Future plans to start HWC may affect chemistry with respect to FAC. Monitoring of monthly chemistry reports for feedwater dissolved oxygen and iron transport will be performed.

Criterion 2.9.5 - System Changes: Determine if system changes are reviewed and evaluated by the appropriate individual or department.

Reviewed FAC program documentation to ensure there is a process in place for informing FAC engineer of system changes that may effect FAC susceptible systems and that the effects of these changes to FAC are considered by appropriate department prior to making modifications to FAC susceptible systems and to ensure that replacements performed under the FAC program are communicated to system engineering (as well as other related departments) and appropriate drawings are updated with new material changes.

Since the VY FAC Coordinator is part of the Design Engineering Group, he has direct access to information on system changes such as modifications and replacements being developed that may affect FAC susceptible systems. This is considered a strength of the program. See STR 2.9-2

Criterion 2.9.6 - Inspection and Replacement Goals: Determine if inspection and replacement goals are developed and documented for the next 3 to 5 years.

VY does not have a planned replacement goal for the next three to five years. Replacements have been based on current need. Also many piping systems which would have been found to be highly susceptible to FAC were originally designed with resistant materials or have already been replaced with FAC resistant materials. VY has made a conscious effort to replace piping systems and components that are susceptible with FAC resistant materials. STR 2.9-1

Criterion 2.9.7- Plant Benefits: Determine if there is evidence of continual improvement to the plant due to FAC program efforts.

The ongoing effort of replacing systems with FAC resistant material has drastically reduced the amount of inspections performed during refueling outages. On average the number of inspections performed are around 20 to 30 piping components which is far below the average of typical plants. This is seen as a program strength. STR 2.9-1

4.0 CONCLUSIONS AND RECOMMENDED ACTIONS

Objective 2.1 Programmatic Leadership/Responsibility - Ensure that Vermont Yankee Nuclear Power Plant (VYNPP) Flow Accelerated Corrosion (FAC) Program is provided with adequate leadership and that the responsibility for the program is clearly defined. Determine if the FAC Program owner and any dedicated backup personnel are qualified for the position.

Conclusion

There is an active Management role in the FAC Program. Program procedures define the responsibilities, implementation requirements, and interactions between the various plant departments that implement and support the FAC Program. The FAC Program owner and the assigned backup are qualified to administer the FAC Program. Also, a third design engineer with previous FAC Program experience at others plants is available.

Personnel turnover is no issue at this time as the program owner has been in this position since the start of the FAC Program. The backup engineer has also been involved with the program since 1993. The current status of the program and future work is well documented which would be a valuable tool if turnover would be necessary. The experience of both engineers along with a low turnover is considered as a program strength. SiR 2.1-1

Time actually spent on the FAC Program is ½ FTE averaged over the fuel cycle. The actual time spent on FAC is very close to the time budgeted. Normally this works well and emergent work can be fit in with little or no impact to the program. Work planning is excellent and is formally planned using the Engineering Work Control (EWe) process.

However, during the last operating cycle, this was not true. The program owner needed to spend a good deal of time working on the EPU and pushed out many of the program commitments over three months. This was recognized by the program owner and his supervisor as an unusual event. Program tasks are routinely performed on schedule. An interview with Program owners' supervisor reiterated the issues stated above. After the EPU is finished, the workload will return to normal. The work scheduling process via the EWC is well suited to identify and track items to completion by Program owner and his supervisor.

Areas for Improvement

None identified for Objective 2.1

Strengths

STR 2.1-1

The plant and FAC related experience of both the FAC program engineer and the backup engineer, program documentation, and low turnover is considered as a program strength.

Objective 2.2 - System Susceptibility- Determine if the FAC Program includes systematic methods for categorizing which systems are susceptible to FAC, predicting and analyzing FAC, and for prioritizing inspections. Determine if the methods are consistent with industry practice.

Conclusion

A susceptibility review was performed for the plant piping in accordance with NSAC 202L. This review evaluated all plant piping systems (large bore and small bore) for susceptibility to FAC. The scope of the document was to evaluate each system as either susceptible or not and if so, to classify each system for the methodology for evaluation. This approach gives a single place to verify inclusion or exclusion into the program. The report did not rank the piping in terms of inspection priority or risk consequence to the plant. No attempt to rank inspection priorities was made within the scope of this document.

Large bore components which are ranked for inspection priority using CHECWORKS are appropriately aligned with plant operating procedures and the pertinent drawings / flow diagrams. Vendor supplied equipment piping is included in the scope of FAC program.

Inspection priorities for small bore piping are not formally documented. Initially, engineering judgment was used to select small bore inspection locations, such as high pressure lines and steam leak offs. The majority of small bore inspections at VY were performed in 1993 and 1995 prior to the publishing of ranking criteria in Revision 1 of NSAC 202L. Without a formal priority ranking, it is difficult to determine if all the high priority lines have been selected. The recommended approach contained Appendix A of NSAC 202L is to rank the small bore piping for inspections in terms personal safety and consequences of failure. The formal ranking will insure that all the high priority lines are inspected. AFI 2.2-1

The review of the susceptibility report determined that the document is not formal even though there was a peer review was performed. The report was a program generated document with no requirement for this review. This document is not in the records management system as a separately controlled document nor is it an attachment to or an appendix to a procedure. AFI 2.2-2

A review of program procedure PP 7028, Section 3.2.1.2 post outage activity requires the update and maintenance of the FAC susceptible piping document to reflect plant changes. Piping material changes made during the 2001 refueling outage have not been incorporated into the report. AFI 2.2-3

Inputs from other plant departments which impact the susceptibility evaluation and inspection priorities include engineering monthly thermal performance monitoring and chemistry reports. These are adequate to assist the FAC program engineer in performing the susceptibility analysis. Off normal events affecting the FAC program are reported through PCRS, chemistry report, and the System Engineering Production Variance Report. These tools assist in scoping lines for inspection or incorporating in the susceptible report. However, the link with operations needs to be strengthened. AFI2.2-4 A recommendation is to develop a formal method for Operations Department to communicate changes in operating conditions, off-normal or abnormal system lineups to FAC Program for assessment.

<u>Areas for Improvement</u>

<u>AFI2.2-1</u>

Small bore piping inspections are not formally ranked or prioritized. Appendix A of NSAC-202L, Rev.2 provides recommendations for an effective small bore FAC program. Once lines are categorized as susceptible to FAC, it provides criteria for prioritizing inspections based on consequences to the plant. It is recommended that a ranking of small bore piping in accordance Appendix A of NSAC-202L Rev.2 be performed and formally documented.

Consequences

Susceptibility small bore lines have been identified in the piping FAC susceptibility analysis. A large number of small bore inspections at VY were performed in 1993 and 1995 prior to the publishing of ranking criteria in Revision 1 of NSAC 202L. Engineering judgment with respect to personal safety and consequences of failure were used in the location selections. Additional inspections have been performed each refueling outage since 1995. From 1992 to 2002, approximately 110 sections of small bore piping have been inspected, some sections have multiple inspections. This represents a significant portion of the total susceptible small bore population. Given the large number of inspections performed to date, these should include all high priority locations. Also, lines showing significant wearhave been replaced with FAC resistant materials. A formal ranking and inspection prioritization will insure that all high priority lines are inspected.

Recommendation

Update the FAC small bore database to include a detailed ranking of the small bore piping in terms of inspection priority and risk consequence to the plant. This activity is currently on the EWC schedule for the FAC Program activities. No new condition report is required.

AFI2.2-2

The susceptibility for the plant piping was performed and reviewed in accordance with NSAC 202L. However it is a program generated document not formally included into the plant records management system. This document resides in the FAC Program Notebook and is controlled by the FAC Program Coordinator. The VY document system in place prior to becoming Entergy only assigned formal numbers to calculations. No system was in place to number or catalog "reports" other than though incorporation into the program of job files.

Consequences

The susceptibility review was performed for the plant piping in accordance with NSAC 202L is an internal program document and is controlled by the FAC Program owner. Since the document is not in the formal records management system the possibility of obsolescence or loss with personnel turnover exists.

Recommendation

An update to the FAC susceptibility evaluation is currently on the EWC schedule. The revision will be performed and documented using ENN procedure No. ENN-DC-147, "Engineering Reports". All new program reports and other documents which are not classified as calculations will be incorporated into the RIMS using ENN-DC-147. No new condition report is required.

AFI2.2-3

A review of program documents including PP 7028, the FAC Susceptibility Evaluation, the Small Bore Piping Database, and updates to the CHECWORKS models shows that updates have not been performed in timely manner. Some activities were informally performed with significant time elapsed without a formal revision.

Consequences

Reliance on out of date information or documents which have not been formally updated, coupled with personnel turnover has resulted in discovering unexpected wear in plant piping and plant unavailability at other utilities. It is important to keep program information up to date.

Planned updates to the susceptibility report and the small bore database report only result in not formally documenting piping replacements performed since the last update. There is no adverse affects to the plant susceptibility, only on the timeliness of document updates. Timely updates to the CHECWORKS models are good practice. Given low wear rates from recent outage inspection data and nearly constant plant operating conditions, there is no immediate need for model updates. However operation under HWC and the planned power uprate warrant model revisions.

Recommendation

An update to the FAC susceptibility evaluation, small bore data base, and the CHECWORKS models is currently on the EWC schedule. However, based on the amount of EPU related work, which has resulted in deferring completion of planned program activities, additional monitoring may be required. A separate Snapshot Assessment should be performed insure that these planned program activities were actually performed in a timely manner. The results of the assessment may identify the need to revise/improve existing scheduling/resources & trend performance.

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AFI2.2-4

There is no formal method for Operations Dept to communicate changes in operating conditions, off-normal or abnormal system lineups to the FAC Program for assessment.

Consequences

Changes in operating conditions, off-normal or abnormal system lineups, component leakage or operating experience are communicated, can affect FAC wear rates in piping and components. Information on off normal conditions is currently obtained through a review of site procedures, system health reports, thermal performance monitoring reports, Condition Reports, and site and industry operating experience. These tools assist in scoping lines for inspection or incorporating in the susceptible report. However the link with operations needs to be strengthened.

Recommendation

Develop formal method or protocol for Operations Dept to communicate changes in operating conditions, off-normal or abnormal system lineups to FAC Program for assessment.

Condition Report: LO-VTYLO-2003-00327 CA3

Objective 2.3 - Documentation- Ensure that FAC Documentation is in compliance with industry standards and that it is maintained in accordance with established processes and procedures.

Conclusion

The FAC program procedure, PP 7028, and department procedure DP 0072, for Structural Evaluation of Thinned Wall Piping Components, and several component evaluations were reviewed. The documents were prepared by the FAG engineer and reviewed by the backup FAC engineer. NDE reports are reviewed and checked by a Level III examiner as well as by the FAG engineer. The program procedure and supporting procedures are consistent with NSAC 202L guidelines.

The program procedure was last changed in 2001. The FAG coordinator is aware that the procedure is in need for update and has identified updates and improvements in previous self assessments of the program. There are two existing commitments (LO-VTVLO-2002-00341 and LO-VTVLO-2002-00568) in place for specific additions/improvements to PP7028. This update should include not only update to the procedure content per the commitments as but also update and formalize the FAG isometric drawings which are part of the program procedure. AFI2.3-1

There are two procedure related issues related to the ENN transition. The gridding procedure has resided in the UT procedure (NE-8053) until recently, when NE-8053 was made obsolete by ENN-NDE-9.05 rev 0. This is not only an issue for VY but also for other ENN FAC programs. The new NDE procedure does not include FAC gridding guidelines that were once a part of the VY site procedure. The gridding procedure will be relocated into an Appendix in the FAC Program procedure. Existing commitment No. LO-VTVLO-2003-00528 is in place to relocate the component gridding guidelines.

VY has not adopted the new ENN procedure for wall thinning evaluations, ENN-DC-133 for their FAG program. Adoption of the new ENN procedure for VY is TBD. At this time VY still uses its plant specific procedure for evaluating wall thinning (DP 0072). Modification of DP0072 and conversion to ENN-DC-133 for wall thinning evaluations is required. AFI2.3-2.

A component inspection database for small bore component inspections is included in Appendix B of PP 7028, but is not up to date. The last revision was in December of 1999. An update of the small bore database is currently in the EWC schedule. See AFI 2.2-1. For large bore components, information and all inspection data to date has been included in the CHEGWORKS database. At this time CHECWORKS is considered the main component database for large bore components.

Refueling Outage Inspection Reports for the last three refueling outages have been issued within 90 days of startup. The reports summarize the inspection activities performed, the goals that were planned and accomplished, and the inspection results. The reports also include recommendations for future replacements or repairs and future required monitoring. The reports are prepared by the FAC engineer and independently reviewed and signed.

FAC large bore piping component location sketches are located in Appendix A of PP 7028. The sketches identify the lines and components included in the CHECWORKS database and predictive models. Information on the component location sketches is consistent with the CHECKWORKS model and the component numbering system. The sketches reference P&IDs and pipe drawings used to develop drawings, but the FAC sketches can only be updated as a procedure update since they are part of the FAC program procedure.

The component location sketches are not included in the plant drawing list and are not controlled through configuration management. Specific sketches have not been updated to reflect recent material replacements. Revisions to the sketches are not controlled using the same configuration management same process as for P&IDs or plant piping drawings. It is recommended that the FAC component location sketches be updated, removed from the procedure. converted into plant drawings, and placed under configuration management control. This will ensure that they reflect current plant configuration including material changes. AFI 2.3-1.

Areas for Improvement

AFI2.3-1

The FAC Component Location Sketches are contained in Appendix A of PP 7028. The practice at other ENN plants is that the "FAC Isometrics" are separate controlled drawings. Updating the FAC component location sketches, removing them from the procedure, and converting them into plant drawings placed under configuration management control will ensure that they reflect current plant configuration including material changes. A similar condition existed at VY for the plant fire barrier ketches. These were converted to VY plant drawings (8-191500 series). ENN FAC Program standardization will require converting the existing FAC Component Location Sketches to VY controlled drawings.

Consequences

The component location sketches are not included in the plant drawing list and are not controlled through configuration management. Specific sketches are marked up pending a change to the Program Procedure. Since the document is not in the formal records management system the possibility of using outdated information with loss or personnel turnover exists.

Recommendation

Update the FAC component location sketches to incorporate recent piping changes, remove them from the procedure, and convert them into plant drawings. This will ensure that they reflect current plant configuration inclUding material changes. (Note: This is not a trivial effort. The electronic files are on an obsolete format. A previous effort with J. Fortier was made, with little success. Need to explore options /costs etc.)

Condition Report: LO-VTYLO-2003-00327 CA4

AFI2.3-2

VY has not adopted the new ENN procedure for wall thinning evaluations, ENN-DC-133 for their FAC program. Adoption of the new ENN procedure for VY is TBD. At this time VY still uses its plant specific procedure for evaluating wall thinning (DP 0072). There are incompatibilities and different focus area in these procedures. Modification of DP0072 and conversion to ENN-DC-133 for wall thinning evaluations is required for fleet standardization.

Consequences

There is no choice. VY will use ENN standard procedures. Technical concerns with use of ENN-DC-133 must be resolved.

Recommendation

Resolve technical issues with use of ENN-DC-133 in its current form and support procedure revision to be consistent with requirements from the new ENN FAC Program Procedure, ENN-DC-315.

Condition Report: LO-VTYLO-2003-00327 CA5

Objective 2.4 - Model Verification and Review - Ensure that FAC predictive computer model used (such as CHECWORKS) is verified, reviewed and maintained in accordance to the plant's FAC Program procedures.

Conclusion

CHECWORKS models and wear rate analyses for large bore systems are used at Vermont Yankee. A complete revision to all plant models was performed in 1996. These were prepared in-house and reviewed by FAC coordinator. Since 1996, only a limited number of models updates were performed to include additional inspection data and to evaluate FAC effects of operation under hydrogen water chemistry. Outage inspection plans consider both CHECWORKS Pass 1 & Pass 2 results for selecting components for inspection.

The CHECWORKS database has been updated with current operating hours (up to cycle 29) and heat balance parameters are current. All inspection data to date has been imported into the CHECWORKS database. There have been no significant chemistry changes performed at VY to date. The FAC coordinator is aware of future plant plans such as starting HWC and power uprate and will update CHECWORKS according when these plans are implemented.

A review of the CHECWORKS models for two lines was performed. The models included all piping components, contained the correct component identifiers, and reflected the correct geometry. All component information was found to be correct and verified by the heat balance and flow diagrams.

Updates to the CHECWORKS models wear rate analyses to include the latest inspection data were not formally documented and reviewed. Although updates were planned in the EWC schedule, this is considered a program weakness. AFI 2.4-1.

Areas for Improvement

AFI2.4-1

Updates to the CHECWORKS models should be formally updated and reviewed.

Consequences

The evaluations are not considered as formal plant calculations based on the classification of the EPRI software. CHECWORKS is used as an inspection planning tool. The results are statistically based and do (did) not fit the attributes required for calculations under AP 0017. The current CHECWORKS evaluations are internal program documents. The VY document system in place prior to becoming Entergy only assigned formal numbers to calculations. No system was in place to number or catalog "reports" other than though incorporation into the program of job files. Since the model updates are not in the formal records management system the possibility of obsolescence or loss with personnel turnover exists.

Recommendation

With adoption of ENN-DC-147 "Engineering Reports" and "ENN-DC-126" formal mechanisms is now available to perform, review and document the CHECWORKS model input and analysis updates. Review all program generated documents and incorporate them into RIMS per ENN-DC-126 or ENN-DC-147 as appropriate.

Condition Report: LO-VTYLO-2003-00327 CA6

Objective 2.5 -Inspection Planning - Ensure that FAC examination locations are selected in accordance with the site procedures and industry practices.

Conclusion

Program procedure PP 7028 Section 4.4.1 specifies the process for selecting components and Appendix E of PP 7028 defines the criteria for selection of components for inspection. This approach used is consistent with NSAC 202L R2 guidelines.

CHECWORKS Pass 1 analysis output is only used to exclude lines from the inspection selection process in terms of susceptible or not susceptible. Generally most of the inspection selections from the CHECWORKS output are from the Pass 2 analysis output. This is consistent with the NSAC 202L approach. However, CHECWORKS model updates to include recent inspection data have not been performed. See AFI 2.4-1.

The selection of inspection locations effectively considers known industry issues with piping downstream of flow control valves, turbine cross around piping, dissimilar metal connections. Examination locations consider input from other plant departments such as System Engineering (thermal performance monitoring), Chemistry, and the Operating Experience Coordinator.

The selection of components for inspection during a refueling outage is documented on worksheets titled "Inspection Location Worksheets/Methods and Reasons for Component Selection". These worksheets provide a rigorous and thorough method to aid in the identification and selection of components for inspection. The worksheets include all the selection criteria necessary for a thorough review of small bore, large bore, feedwater heater shells, and cross-around piping. The worksheets address inspections based on previous inspection results, CHECWORKS evaluations, CHECWORKS model calibration, OE, off normal flow conditions, malfunctioning equipment such as leaking valves, and engineering judgment. The worksheets are prepared by the program owner and reviewed by the backup FAC program Engineer. Components identified in the worksheets are compiled in the

Refueling Outage Scoping memo to Program Owners supervisor. The worksheets used to select inspections should be considered program strength. STR 2.5-1 It presents a thorough documented approach to inspection selection incorporating all the criteria in NSAC-202L, and site specific issues.

Areas for Improvement

None identified for Objective 2.5

Strengths

STR 2.5-1

The worksheets used to select inspections should be considered a program strength. The worksheets present a thorough, rigorous, documented approach to inspection selection incorporating all the criteria in NSAC-202L, and site specific issues.

Objective 2.6 - Performing Inspections - Ensure that FAC Examinations are performed in accordance with the site procedures and FAC Program documents and that they are consistent with industry standards.

Conclusion

A review of program procedure PP 7028 and the applicable NDE procedures for Level 11/ supervision and compliance responsibilities was performed. The procedure specific instructions and guidance for performing FAC inspections are consistent with NSAC 202L Rev.2.

There is an issue related to the ENN transition. The gridding procedure has resided in the VY site UT procedure NE-8053. NE-8053 was made obsolete by ENN-NDE-9.05 rev 0. This is not only an issue for VY but also for other ENN FAC programs. The new NDE procedure does not include FAC gridding guidelines that were once a part of the VY site procedure. The gridding procedure will be relocated into an Appendix in the FAC Program procedure. EXisting commitment No. LQ-vrVLO-2003-00528 is in place to relocate the component gridding guidelines.

Several component inspection reports were reviewed and it was concluded that the gridding convention used (size & extent) is consistent with the requirements of NSAC 202L Rev.2 and industry standards.

Certification / qualification records for two FAC inspectors were reviewed and it was determined that the processing and review of the technicians qualification and certification records were conducted and accepted in accordance with plant protocol.

Data sheets were reviewed for evidence that repeat inspection of suspect readings is performed. Two inspections from the 2001 refueling outage demonstrated questioning of the data. One was at a counter-bore and the other at a suspect reading lower than the surrounding area. The documentation showed both readings were re-taken and new measurements replaced the previous ones.

Program procedure PP 7028 was reviewed with particular reference to Sections 4.4.1.3 and 6.3 which require formal record retention. Interviewed FAC program owner for compliance and determined inspection records are retained in accordance with PP 7028.

Areas for Improvement

None identified for Objective 2.6

Objective 2.7 Data Evaluation - Determine if the process for collecting, evaluating, analyzing and trending data is effective and is performed in accordance with established standards.

Conclusion

The FAC program document, PP 7028 rev 1, refers to DP 0072 for evaluating components. Component evaluations are performed in accordance with plant procedure DP 0072, "Structural Evaluation of Thinned wall piping components. At this time, VY is not required to perform evaluations based on ENN-DC-133. Component evaluations are also consistent with industry procedure NSAC-202L R2.

DP 0072 is used to evaluate components for continued service or replacement and outlines a formal process to perform evaluations. Evaluations are not considered calculations but they are reviewed and signed by an independent reviewer and are permanently stored by records for plant lifetime. Safety class piping and components under ASME section XI requirements are dispositioned in accordance with DP 4027.

The 2000 Refueling Outage Report was reviewed for examples of component evaluations, specifically inspection No. 2000-04. The completed acceptance evaluation includes the component disposition, NDE reports, and structural evaluation which is documented on a Component Evaluation Worksheet. UT data is reviewed by Level III examiner and signed. The evaluations are independently reviewed. All worksheets are stored in records for plant lifetime. DP 0072 provides a formalized process, which includes criteria and data sheets, and the appropriate safety factors. It is found to be adequate for dispositioning components for continued service or replacement.

Areas for Improvement

None identified for Objective 2.7

Objective 2.8 - Performing Repairs - Ensure that FAC Repairs/Replacements are performed in accordance with established processes, procedures and applicable codes.

Conclusion

Formal procedures exist for repair/replacement. Safety class ASME section XI components are evaluated and dispositioned under DP 4027, and component repairs / replacements are performed under AP 0070. Non-safety repairslreplacements would be controlled via maintenance work orders for like-for-like replacements. For upgraded material replacements, an engineering recommendation, followed by an equivalency evaluation and either a WOSE Minor Mod per AP 0020 or a design change per AP 6008 is required to implement the replacement. AP 0070 "ASME Section XI Repair and Replacement Procedure" provides a formal process, that is consistent with the requirements of ASME Section XI and NSAC-202L-R2.

All external weld repairs are considered temporary, are performed using approved procedures, and require approval from the ANII. These are either permanently repaired or replaced during the next opportune time or refueling outage. External repairs to Safety Class Piping would require a relief and would be performed under the requirements of AP 0070, "ASME Section XI Repair and Replacement Procedure". To date no external repairs to Safety Class piping due to FAC related damage have been performed at VY.

Internal weld repairs on non Safety Class piping are considered permanent, are performed using approved procedures, and require approval from the ANII. Internal weld repairs to Safety Class Piping are performed under the requirements of AP 0070, "ASME Section XI Repair and Replacement Procedure" using approved welders and welding procedures This is consistent with ASME Section XI and NSAC-202L-R2 guidelines.

Equivalency evaluations, engineering recommendations, and mod packages for material upgrades due to FAC are reviewed and approved prior to installation in the plant. Replacement of FAC susceptible systems with Cr-Mo (P11 or P22) is common knowledge plant-wide and is not stated in FAC program procedure. All material changes are shown on system P&IDs. PP 7028 does not identify a specific process or procedure to be used when making a material upgrade. After the FAC engineer determines that a material upgrade is required, the Design Engineering Group performs the required evaluations and develops the modification packages using the standard design processes provided by AP 0020, and AP 6008.

Areas for Improvement

None identified for Objective 2.8

Objective 2.9 • Long Term Strategy - Determine if the FAC Program has a long-term strategy that Is consistent with the guidance provided in EPRI guideline NSAC-202L-R2, "Recommendations for an Effective FAC Program".

Conclusion

VY is a BWR which has limited chemistry options for reducing FAC. The most effective long term method for reducing FAC wear is replacements with FAC resistant materials. VY has been vigilant on replacing susceptible systems with FAC resistant materials in order to reduce FAC long term. Areas that have been replaced include Moisture Separator Drain lines downstream of level control valves, feedwater flush and pump bypass lines downstream of normally closed valves on piping leading to the condenser, turbine cross around piping, small bore steam drain lines to the condenser. both LP turbine casings, all LP feedwater heaters.

Other systems and such as feedwater heater vents and the HP feedwater heaters are planned for replacement with FAC resistant material due to the 20% power uprate. These replacement efforts are the primary focus on reducing wear rates at VY and are consistent with NSAC-202L guidelines.

The FAC coordinator is aware of future plant plans such as starting HWC and power uprate and will update the CHECWORKS predictive models as these plans are implemented. Since VY is a BWR, there is very little that can be done to reduce FAC wear rats through water
e

chemistry changes. Dissolved oxygen in the final feedwater has been maintained in the 20 to 30 PPB range from 1996 to 2003. Future plans to start HWC will affect chemistry and will have to be monitored by the program.

The FAC program documentation was reviewed to ensure there is a process in place for informing FAC engineer of system changes that may effect FAC susceptible systems and that the effects of these changes to FAC are considered by appropriate department prior to making modifications to FAC susceptible systems and to ensure that replacements performed under the FAC program are communicated to system engineering (as well as other related departments) and appropriate drawings are updated with new material changes. Since the VY FAC Coordinator is part of the Design Engineering Group, he has direct access to information on system changes such as modifications and replacements being developed that may affect FAC susceptible systems. This is considered a strength of the program. STR 2.9-1

VY does not have a planned replacement goal for the next three to five years. Replacements have been based on current need. Also many piping systems which would have been found to be highly susceptible to FAC were originally design with resistant materials or have already been replaced with FAC Resistant materials. VY has made a conscious effort to replace piping systems and components that are susceptible with FAC resistant materials.

The ongoing effort of replacing systems with FAC resistant materials has reduced the amount of inspections performed during refueling outages. On average the number of inspections performed is around 20 to 30 piping components which is far below the average of typical plants. This is seen as a program strength. STR 2.9-2.

<u>Areas for Improvement</u>

None identified for Objective 2.9

<u>Strengths</u>

<u>STR 2.9-1</u>

The VY FAC Program Coordinator and the backup engineer are part of the Design Engineering Group. They have direct access to information on system changes such as modifications and replacements being developed that may affect FAC susceptible systems.

<u>STR 2.9-2</u>

The ongoing efforts of replacing piping with FAC resistant materials, has allowed a reduction in the number of inspections required to be performed during refueling outages. On average, around 20 to 30 piping components are inspected per refueling outage. This is less than the typical number of inspections performed for similar plants.

5.0 REFERENCES

- ENW Commitment LO-VTYLO-2003-00327 (VY AP0028 No. OPW-2003-0161_01), *Conduct a Focused Self-Assessment of ENW Piping FAC Inspection Program, PP 7028.*
- ENW Self Assessment No. OPW-2003-0145_01 Assessment Planning Worksheet
- INPO "Principles for Self-Assessment and Corrective Action Programs", December 1999
- EPRI NSAC-202L-R2, "Recommendations for an Effective Flow-Accelerated Corrosion Program", Final Report, April 1999.
- INPO 97-002, "Performance Objectives and Criteria for Operating Nuclear Generating Stations"
- *INPO 03-004 (Preliminary) "Performance Objectives and Criteria"*
- EPRI CHUG White Paper No.3, "A Summary of Tasks and Resources Required to Implement an Effective FAC Program", February 1999.USNRC Inspection Manual-Inspection Procedure 49001
- EPRI/Altran Report No. 95217-TR-01 Rev.O, "Guideline for Interviewing Plant Personnel within a FAC Program", August 1996.
- ENN-L1-104 Rev.4 , "Self Assessment & Benchmarking Process"
- Vermont Yankee Program Procedure PP 7028, "Piping FAC Inspection Program"
- Vermont Yankee Department Procedure DP 0072 "Structural Evaluation of Thinned Wall Piping Components"
- EPRI CHECWORKS Computer Program Users Guide TR-03496
- EPRI CHECWORKS "FAC Application Guidelines for Plant Modeling and Interpretation of Inspection Data", Draft Report, February 1997.
- ENN-DC-133 "Structural Evaluation of Wall Thinning in Carbon and Low Alloy Steel Piping"

6.0 TEAM MEMBERS

Team Leader: James Fitzpatrick*	V.Y. FAC Program Coordinator
Team Member: Hazel Pearsall	I.P.2 FAC Program Coordinator
Team Member: Harry Hartjen	I.P.3 FAC Program Coordinator
Team Member: Ian Mew	J.A.F. FAC Program Coordinator
Team Member: Gerald Bechen	Pilgrim FAC Program Coordinator
Team Member: John Moriarty**	C.A.&A (VY)**

* The Team Leader completed the Team Leader Checklist on completed 8/5/03.
** CA&A representative reviewed then Assessment Plan ,but was called to military duty prior to the *assessment.*

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

June 12, 2001

NRC INFORMATION NOTICE 2001-09: MAIN FEEDWATER SYSTEM DEGRADATION IN SAFETY-RELATED ASME CODE CLASS 2 PIPING INSIDE THE CONTAINMENT OF A PRESSURIZED WATER REACTOR

Trojan 16 years

Addressees

All holders of operating licenses for pressurized water nuclear power reactors except those who have ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice (IN) to alert addressees to the discovery of main feedwater (MFW) system wall thinning to below allowable limits in turbine building components and in risk-important, safety-related portions of American Society of Mechanical Engineers (ASME) Code Class 2 piping inside the reactor containment building (containment) at the Callaway Plant.

It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate. However, suggestions contained in this IN are not NRC requirements; therefore, no specific actions or written response is required.

Description of Circumstances

During a refueling outage that began on April 7, 2001, the Callaway Plant licensee conducted scheduled inspections to assess the effects of erosion/corrosion on steel piping exposed to flowing water (single-phase fluids) and water-steam mixtures (two-phase fluids). These effects are commonly referred to as flow-accelerated corrosion (FAC). Inspections identified several instances of localized MFW system piping wall thinning to below the minimum thickness required by ASME Boiler and Pressure Vessel Code, Section III, for safety-related piping, and to below the minimum thickness specified by American National Standards Institute (ANSI) B31.1, "Power Piping," for non-safety-related portions of the MFW system. The wall thicknesses in the degraded areas had not been previously measured.

The licensee had expanded and upgraded its FAC program following an August 11, 1999, event in which an 8-inch moisture separator reheater drain line experienced a double-ended guillotine break causing operators to manually trip the reactor. The upgraded and expanded FAC program, utilizing CHECWORKS™ Rev. F software, predicted wall thinning in the MFW system. However, without wall thickness trending data, the software was not able to accurately predict the extent of degradation. After performing an inspection during the current outage, the licensee found the MFW degradation to be more extensive than anticipated.

significance of pipe wall thinning.

MFW systems, like other power conversion systems, are important to the safe operation of nuclear power plants. Past failures of feedwater and other high-energy system components have resulted in complex challenges to operating staff when the released high-energy steam and water interacted with other systems, such as electrical distribution, fire protection, and security systems. Personnel injuries and fatalities have also occurred. The failure to maintain high energy piping and components within allowable thickness values can (1) increase the initiating event frequency for transients with loss of the power conversion system, main steam line breaks, and other initiating events due to system interactions with high-energy steam and water; (2) adversely affect the operability, availability, reliability, or function of systems required for safe shutdown and accident mitigation; and/or (3) impact the integrity of fission product barriers.

This IN requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/RA/

Ledyard B. Marsh, Chief
Events Assessment, Generic Communications and Non-Power Reactors Branch
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Attachments:

1. Table 1: Summary of Related Previous Generic Communications
2. Table 2: Summary of Previously Identified Pipe Wall Thinning Issues and Events
3. List of Recently Issued NRC Information Notices

(ADAMS Accession Number ML011490408)

ATTACHMENT 1

IN 2001-09

Table 1: Summary of Related Previous Generic Communications

The titles of generic communications referenced in the text of this IN or considered particularly relevant are underlined.

1. IN 82-22, "Failures in Turbine Exhaust Lines," July 9, 1982, addressed the rupture of a 24-inch-diameter long-radius elbow in a feedwater heat extraction line at Oconee Unit 2 and four similar failures identified by the Institute of Nuclear Power Operations (INPO).
2. IN 86-106, "Feedwater Line Break," December 16, 1986, addressed a potentially generic problem with feedwater pipe thinning and other problems related to the catastrophic failure of an 18-inch-diameter MFW pump suction line at Surry Unit 2.
3. IN 86-106, Supplement 1, "Feedwater Line Break," February 13, 1987, discussed the licensee's failure analysis, the parameters that could have potentially contributed to pipe break, the predictive measures used to detect erosion/corrosion, and the inservice inspection requirements of ASME Code for Code Class 1 and 2 piping systems and of ANSI B31.1 for other piping systems.
4. IN 86-106, Supplement 2, "Feedwater Line Break," October 21, 1988, addressed the discovery that an

Based on the licensee's initial findings and on additional industry information, FAC inspections were expanded to include portions of the condensate system, auxiliary feedwater (AFW) system, feedwater heaters, and other areas. Additional degradation was found in piping for the feedwater heaters.

Several instances of MFW system wall thinning were identified in risk-important sections of 14-inch ASME Code Class 2 safety-related piping components inside the containment. The licensee identified six 90-degree elbows, two 45-degree elbows, one 14-to-16-inch expander, and a 6-foot section of piping that had degraded to less than the ASME minimum design allowable wall thickness (below allowance) or that the licensee projected would degrade below allowance during the following cycle. The as-found wall thicknesses for components degraded below allowance ranged from 75 to 96 percent of the minimum allowable thickness required by the code. These components were identified in common MFW/auxiliary feedwater (AFW) flow paths to three of the unit's four steam generators (SGs). All safety-related components in the containment that were below allowance (or that the licensee predicted would degrade below allowance during the following cycle) were replaced. Some degraded non-safety-related components outside the containment were repaired rather than replaced.

Background

Since 1982, the NRC has issued numerous generic communications addressing various issues and events related to pipe wall thinning. Several of those communications are particularly relevant to the recently identified MFW wall-thinning at Callaway Plant. They are summarized below and annotated in Table 1, "Summary of Related Previous Generic Communications." Table 2 is a brief chronology of previously identified pipe wall thinning issues and events.

IN 87-36, "Significant Unexpected Erosion of Feedwater Lines," August 4, 1987, addressed the 1987 discovery of MFW degradation at the Trojan Nuclear Plant similar to that observed at Callaway Plant. The thinning was discovered when Trojan's steam piping inspection program was expanded to include single-phase piping. It was attributed to high fluid flow velocities and other operating factors.

IN 88-17, "Summary of Responses to NRC Bulletin 87-01, 'Thinning of Pipe Walls in Nuclear Power Plants'," April 22, 1988, summarized licensee responses to and NRC observations on the thinning of nuclear power plant pipe walls. The IN noted that all licensees reported having established programs for inspecting pipe wall thinning for two-phase, high-energy carbon steel piping systems. Inspection locations were generally reported to have been selected in accordance the 1985 guidelines in Electric Power Research Institute (EPRI) Document NP-3944, "Erosion/Corrosion in Nuclear Plant Steam Piping: Causes and Inspection Program Guidelines." However, because implementation of these guidelines was not required, the scope of the programs varied significantly from plant to plant.

Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," May 2, 1989, requested licensees to implement long-term erosion/corrosion monitoring programs to provide assurance that procedures or administrative controls were in place to maintain the structural integrity of all carbon steel systems carrying high-energy fluids. EPRI released the pipe wall thinning predictive computer code CHEC™ in June 1987, CHECMATE™ in April 1989, and CHECWORKS™ in August 1994, to assist licensees in selecting for testing those areas of the piping systems with the highest probabilities of wall thinning. The Massachusetts Institute of Technology method described in NUREG/CR-5007, "Prediction and Mitigation of Erosion-Corrosive Wear in Secondary Piping Systems of Nuclear Power Plants," September 1987, also ranked systems and components according to their erosion/corrosion susceptibility.

IN 93-21, "Summary of NRC Staff Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs," March 25, 1993, addressed NRC observations on the industry's design and implementation of erosion/corrosion programs in response to Generic Letter 89-08. Among other observations, the IN identified instances of erosion/corrosion in safety-related portions of MFW and main steam systems and described the problems licensees were having in implementing effective FAC programs. In November 1993, EPRI released document NSALC-202L, "Recommendations for an Effective Flow-Accelerated Corrosion Program." Rev. 2 of the document was released in April 1999.

Discussion

Although the MFW degradation was identified and addressed by the licensee before catastrophic failure, the extent of the degradation at the time of discovery is of concern to the NRC, given the maturity of the industry's FAC programs. Of particular concern is the degradation in risk-important non-isolable sections of single-phase ASME Code Class 2 piping inside the containment. These factors can impact the safety elbow installed on the suction side of a MFW pump during a 1987 Surry Unit 2 refueling outage had thinned more rapidly than expected, giving up 20 percent of its 0.500-inch wall thickness in 1.2 years. Wall thinning was also observed in safety-related MFW piping and in other non-safety-related condensate piping.

5. IN 86-106, Supplement 3, "Feedwater Line Break," November 10, 1988, further addressed the faster-than-expected wall thinning at Surry Unit 2, noting the disparity between the previously estimated 20-30 mils/year thinning rate and maximum observed rate of 90 mils/year. The IN also noted that accelerated wall thinning may have coincided with a reduction in feedwater dissolved-oxygen concentration.

6. NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," July 9, 1987, requested licensees to inform the NRC about their programs for monitoring the thickness of pipe walls of carbon steel piping in both safety-related and non-safety-related high-energy fluid (single-phase and two-phase) systems.

7. IN 87-36, "Significant Unexpected Erosion of Feedwater Lines," August 4, 1987, addressed potentially generic unexpected erosion which resulted in pipe wall thinning in both safety-related and non-safety-related portions of feedwater lines (both inside and outside the containment) at Trojan Nuclear Plant. The thinning was discovered when Trojan's steam piping inspection program was expanded to include single-phase piping and was attributed to high fluid flow velocities and other operating factors.

8. IN 88-17, "Summary of Responses to NRC Bulletin 87-01, 'Thinning of Pipe Walls in Nuclear Power Plants,'" April 22, 1988, reported the results of responses to NRC Bulletin 87-01 and described a recent event at LaSalle County Station Unit 1.

9. IN 89-01, "Valve Body Erosion," January 4, 1989, addressed a potential generic problem with erosion in carbon steel valve bodies in safety-related systems.

10. Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," May 2, 1989, requested licensees to implement long-term erosion/corrosion monitoring programs to obtain assurance that procedures or administrative controls were in place to maintain the structural integrity of all carbon steel systems carrying high-energy fluids.

11. IN 89-53, "Rupture of Extraction Steam Line on High Pressure Turbine," June 13, 1989, addressed a potential generic problem with erosion in carbon steel piping in secondary plant systems.

12. IN 91-18, "High Energy Pipe Failures Caused by Wall Thinning," March 12, 1991, addressed continuing erosion/corrosion of high-energy piping systems and apparently inadequate monitoring programs.

13. IN 92-35, "Higher Than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping Inside Containment at a Boiling Water Reactor," May 6, 1992, addressed an unexpectedly high rate of erosion/corrosion in certain main feedwater piping inside the containment at the Susquehanna Unit 1 boiling water reactor (BWR). The condition was noted to be of particular concern since it was in a section of piping that could not be isolated from the reactor vessel.

14. IN 93-21, "Summary of NRC Staff Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs," March 25, 1993, addressed NRC observations on the industry's design and implementation of erosion/corrosion programs in response to Generic Letter 89-08.

15. IN 95-11, "Failure of Condensate Piping Because of Erosion/Corrosion at a Flow-Straightening Device," February 24, 1995, addressed possible piping failures caused by flow disturbances that were not accounted for in erosion/corrosion programs.

16. IN 97-84, "Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion," December 11, 1997, addressed potential generic problems related to the occurrence and prediction of flow-accelerated corrosion (FAC) in extraction steam lines.

17. IN 99-19, "Rupture of the Shell Side of a Feedwater Heater at the Point Beach Nuclear Plant," June 23, 1999, addressed the rupture of the shell side of a feedwater heater at the Point Beach Nuclear Plant Unit 1.

Table 2: Summary of Previously Identified Pipe Wall [illegible] Events

Date	Site	Details	[illegible]
1976	Oconee 3	Pinhole leak in an extraction steam line. A surveillance [illegible] utilizing ultrasonic examination of extraction steam [illegible] initiated and, in 1980, identified two degraded elbows [illegible] the Unit 2 elbow that subsequently failed in 1982. The [illegible] were replaced.	[illegible]
1981	Millstone 2	Use of engineering personnel unfamiliar with plant [illegible] conditions, plant as-built designs, or erosion/corros[illegible]	[illegible]
January 1982	Vermont Yankee	Licensee shut down the plant after identifying steam [illegible] a leak in the 12-inch-diameter drain line between a [illegible] separator and heater drain tank.	[illegible]
January 1982	Trojan	Steam line failure resulting in plant shutdown.	[illegible]
February 1982	Zion 1	Steam leak in 150 psig high-pressure exhaust steam [illegible] originating from an 8-inch crack on a weld joining 24-[illegible] with the 37.5-inch high-pressure steam exhaust pip[illegible] the moisture separator reheater. The event resulted [illegible] shutdown.	[illegible]
June 1982	Oconee 2	While operating at 95-percent power, a 4-square-foot [illegible] occurred in a 24-inch-diameter long-radius elbow [illegible] heat extraction line. The reactor was manually tripp[illegible] destroyed a non-safety-related load center and [illegible] non-safety-related instrumentation. Personnel were [illegible] overnight with steam burns. An ultrasonic inspecti[illegible] substantial erosion of the elbow In March 1982, but [illegible] failed to meet the licensee's criteria for rejection.	IN 82-22
June 1982	Browns Ferry 1	Steam line failure resulting in plant shutdown.	IN 82-22
March 1983	Dresden 3	Steam leak from the shell side of the 3C3 low-pressure feedwater heater near the extraction steam inlet nozzle. The leak was attributed to erosion by deflected extraction steam. The feedwater heaters had not been included in a periodic inspection program.	IN 99-19
March 1985	Haddam Neck	Pipe rupture, approximately ½-by-2-1/4-inch, downstream of a normal level control valve for a feedwater heater.	GL 89-08
December 1986	Surry 2	Catastrophic failure of 18-inch MFW pump suction line elbow when a main steam isolation valve failed closed on one of the steam generators. A 2-by-4-foot section of the elbow was blown out and came to rest on an overhead cable tray. The reactive force completely severed the suction line. The free end whipped and came to rest against the discharge line for another pump. The failure of the piping, which was carrying single-phase fluid, was caused by erosion/corrosion of the carbon steel pipe wall. The unit had been operating at full power. An automatic plant trip occurred and four workers suffered fatal injuries. Released steam caused the fire suppression system to actuate, releasing halon and carbon dioxide into emergency switchgear. The NRC dispatched an augmented inspection team to the site.	IN 86-106 Bulletin 87-01 IN 88-17 GL 89-08

June 1987	Trojan	MFW degradation was discovered by the licensee in at least two areas of the straight sections of ASME Class 2 safety-related MFW piping inside containment. The thinning was discovered when the Trojan steam piping inspection program was expanded to include single-phase piping. The thinning was attributed to high fluid flow velocities and other operating factors.	IN 87-36 IN 88-17 GL 89-08
December 1987	LaSalle 1	Through-wall pinhole leaks due to erosion were discovered in a 45-degree elbow down stream of a turbine-driven reactor feedwater pump minimum-flow control valve. Subsequent inspections identified additional areas of wall thinning.	IN 88-17
September 1988	Surry 2	The pipe wall of an elbow installed on the suction side of a MFW pump during a 1987 refueling outage was discovered to have thinned more rapidly than expected, losing 20 percent of its 0.500-inch wall thickness in 1.2 years. Wall thinning was also observed in safety-related MFW piping and in other non-safety-related condensate piping.	GL 89-08
December 1988	Brunswick 1	Inspection indicated areas of significant but localized erosion on the internal surfaces of several carbon steel valve bodies. The affected safety-related valves were the 24-inch residual heat removal/low pressure core injection (RHR/LPCI) system injection and 16-inch suppression pool isolation valves.	IN 89-01
April 1989	Arkansas Nuclear One Unit 2	Steam escaping from a ruptured 14-inch high-pressure steam extraction line caused a spurious turbine/reactor trip from 100-percent power. This straight run of piping terminates at an elbow that was replaced during the previous outage because of erosion-induced wall thinning. The pipe and those of similar geometries had not been included in the licensee's surveillance samples, and the degraded condition was not detected during the elbow replacement.	IN 89-53
March 1990	Surry 1	Rupture of a straight section of piping downstream of a level control valve in the low-pressure heater drain (LPHD) system. The LPHD system was included in the licensee's FAC program at the time, but the program did not provide an inspection for the affected section of piping.	IN 91-18
May 1990	Loviisa 1 (foreign)	A flow-measuring orifice flange in the main feedwater system ruptured after one of five main feedwater pumps tripped, causing a check valve in the line to slam shut, creating a pressure spike. Subsequent inspections determined that 9 of 10 flanges had thinned to below minimum wall requirements.	IN 91-18
July 1990	San Onofre 2	The licensee was forced to shut down the unit after discovering a steam leak in one of the feedwater regulating valve bypass lines.	IN 91-18
December 1990	Millstone 3	Two 6-inch pipes in the moisture separator drain (MSD) system ruptured when a MSD pump was stopped to facilitate component isolation for repairs. Stopping the pump caused a pressure transient. The high-energy water flashed to steam and actuated portions of the turbine building fire protection deluge system. Two 480-volt motor control centers and one non-vital 120-volt inverter were rendered inoperable by the flooding, resulting in the loss of the plant process computer and the isolation of the instrument air to the containment building.	IN 91-18
November 1991	Millstone 2	Rupture at an 8-inch elbow of a moisture separator reheater. High-energy water flashed to steam, actuating portions of the turbine fire protection deluge system. The license had not selected the ruptured elbow for ultrasonic testing in its erosion/corrosion	IN 91-18

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		monitoring program. See LER 50-336/91-12.	
1992	Millstone 3	See LER 50-309/92-07.	IN 93-21
1992	Maine Yankee	See LER 92-007.	IN 93-21
1992	Salem 1	Improper determination of code minimum wall thickness acceptance criteria resulted in improper disposition of degraded components. See Inspection Report 50-272/92-08.	IN 93-21
1992	Hope Creek	Lack of baseline thickness measurements (history) of originally designed piping was identified. See Inspection Report 50-354/92-11.	IN 93-21
1992	Millstone 1	Lack of baseline thickness measurements of replacement piping before the replacement piping was put into service. See Inspection Report 50-245/92-80.	IN 93-21
1992	Hope Creek	Use of engineering personnel who are unfamiliar with plant operating conditions, plant as-built designs, or erosion/corrosion history.	----- -----
1993	Diablo Canyon 1	Erosion/corrosion wear was discovered behind a thermal sleeve in the interior of the feedwater nozzle and on the feedwater nozzle itself.	IN 93-21
November 1994	Sequoyah 1	Licensee identified a 180-degree circumferential crack in a reduced section of 14-inch condensate piping used for flow-metering. The section of piping had been modeled incorrectly in CHECMATE™ without any diameter or thickness changes and had not been visually inspected.	IN 95-11
April 1997	Fort Calhoun	Manual scram and emergency boration following a 6-square-foot rupture of a 12-inch diameter sweep elbow in the fourth-stage extraction steam piping. A non-safety-related electrical load center, several cable trays and pipe hangers were damaged. In addition, asbestos-containing insulation was blown throughout the turbine building and portions of the fire protection system were actuated.	IN 97-84
May 1999	Point Beach 1	Manual trip from 100-percent power and manual safety injection actuation when the shell side of the feedwater heater ruptured. The fish-mouth rupture was approximately 27-inches long and 0.75-inch at its widest point. Feedwater heater leaks were also identified at Pilgrim Station and the Susquehanna units. None of the feedwater heaters had been included in a periodic inspection program.	IN 99-19
August 1999	Callaway	Operators manually tripped the reactor on indication of a steam leak in the turbine building. An 8-inch line from the first stage reheater drain tank to the high-pressure heater experienced a double-ended guillotine break.	Event Notification 36015

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

March 12, 1991

Information Notice No. 91-19: STEAM GENERATOR FEEDWATER DISTRIBUTION PIPING DAMAGE

Addressees:

All holders of operating licenses or construction permits for pressurized water reactors (PWRs).

Purpose:

This information notice is intended to alert addressees to potential problems resulting from degradation of feedwater distribution piping in steam generators due to thermal stress, cracking, erosion and corrosion. Depending on the design of the steam generator feedwater system, these problems may affect operation of the auxiliary feedwater system. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice do not constitute NRC requirements; therefore, no specific action or written response is required.

Background:

The degradation noted below of the feedwater distribution system piping in the steam generators at San Onofre Units 2 and 3 may be applicable to Combustion Engineering steam generator designs predating the System 80 design and to similar designs in other steam generators at other nuclear power plants. This matter is considered safety-significant because the feedwater distribution system piping degradation may affect the delivery of auxiliary feedwater flow in some of these steam generators and because of the potential for consequential damage to the steam generator tubes from resulting debris. The NRC has issued several generic communications dealing with one or more aspects of such degradation (Attachment 3).

At San Onofre Units 2 and 3, both main feedwater and auxiliary feedwater enter the steam generators through a feedwater nozzle. The feedwater enters a distribution box and 12-inch diameter piping (feedring) that distributes the flow through top-mounted discharge elbows (J-tubes) around the periphery of the steam generator shell (Figure 1). The feedring is attached by two U-bolts at each of four supports that are welded to the shell wall. A 3-inch elbow and tee vent assembly is attached to the upper portion of the innermost (toward the interior of the steam generator) end of the distribution box (Figure 2).

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Combustion Engineering originally designed the distribution box without the vent assembly. However, in 1980 during preoperational testing at San Onofre Unit 2, a test of the auxiliary feedwater system caused a partial vacuum within both halves of the feedring in one of the steam generators, and the feedring collapsed. The licensee, Southern California Edison Co., determined that the inadequate flow area of the discharge elbows and the relatively thin-walled Schedule 40 piping constituting the feedring had contributed to the feedring collapse. Corrective actions included replacing most of the feedring with Schedule 120 piping (except for 9-inch segments on each side of the distribution box), enlarging the diameter of the discharge elbows from 1.5 inches to 3.5 inches, and installing the vent assembly on the distribution box.

Description of Circumstances:

San Onofre Unit 3:

On May 10, 1990, the licensee found several pieces of carbon steel debris during a routine inspection of the secondary side of the tubesheet of one steam generator (LER 50-362/90-05-01). During further inspection of the internal components of this and the other steam generator, the licensee found material missing from the lower portion of the feedring at its intersection with the distribution box, surface cracks in the heat-affected zone at the toe of the weld at that intersection, erosion and corrosion indications on the interior surfaces of the distribution boxes, erosion of the vent assemblies, "T" section tops missing from the vent assemblies, and deformation of several U-bolt supports.

San Onofre Unit 2:

On July 23, 1990, the licensee shut down Unit 2 to perform a similar inspection. The damage found was significantly less than on Unit 3. No material was found missing from the distribution box-feedring junction. One U-bolt was fractured.

Discussion:

The licensee determined the root cause contributing to the degradation of the feedwater distribution system piping to be inadequate design of the feedring and feedring supports. The design did not adequately consider the thermal stresses resulting from normal operating conditions, in particular the batch process of auxiliary feedwater addition during startup operations. In addition, the design of the vent assembly had not properly considered the potential for erosion and corrosion resulting from localized high velocity flow. The corrective actions taken by the licensee included replacing the remaining Schedule 40 piping material with Schedule 120 piping material, replacing the distribution box-feedring weld configuration with weld-o-let forgings, removing the distribution box vents from the design, repairing local thinning of the distribution box by weld buildup and removal of local interior surface discontinuities, modifying the feedring supports to provide flexibility for thermal expansion, and using stronger U-bolts. The licensee had previously modified the auxiliary feedwater system to provide continuous feeding of the steam generator rather than the batch feeding that was used during startup operations.

On September 20, 1990, the steam generator vendor, Combustion Engineering, issued an information bulletin (Combustion Engineering Infobulletin 90-04, "Feedwater Distribution System Degradation"), recommending that its client utilities perform a baseline inspection during their next refueling outage to detect wall thinning in the feedwater distribution system.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate NRR project manager.

Charles E. Rossi, Director
Division of Operational Events Assessment
Office of Nuclear Reactor Regulation

Technical Contacts: Vern Hodge, NRR
(301) 492-1861

Lawrence E. Kokajko, NRR
(301) 492-1380

Attachments:
1. Figure 1. Top View of the Feedwater Distribution Piping
2. Figure 2. Side View of the Feedwater Distribution Piping
3. List of References
4. List of Recently Issued NRC Information Notices

LIST OF REFERENCES

1. Bulletin No. 87-01: "Thinning of Pipe Walls in Nuclear Power Plants," July 9, 1987

2. Bulletin No. 79-13: "Cracking in Feedwater System Piping," June 25, 1979

3. Ibid., Revision No. 1: "Cracking in Feedwater System Piping," August 30, 1979

4. Ibid., Revision No. 2: "Cracking in Feedwater System Piping," October 16, 1979

5. Generic Letter No. 89-08: "Erosion/Corrosion-Induced Pipe Wall Thinning," May 2, 1989

6. Generic Letter No. 79-20: Untitled, on Cracking In Feedwater Lines, May 25, 1979

7. Information Notice No. 88-17: "Summary of Responses to NRC Bulletin 87-01, 'Thinning of Pipe Walls in Nuclear Power Plants,'" April 22, 1988

8. Information Notice No. 87-36: "Significant Unexpected Erosion of Feedwater Lines," August 4, 1987

9. Information Notice No. 86-106: "Feedwater Line Break," December 16, 1986

10. Ibid., Supplement 1: "Feedwater Line Break," February 13, 1987

11. Ibid., Supplement 3: "Feedwater Line Break," November 10, 1988

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UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

March 12, 1991

Information Notice No. 91-18: HIGH-ENERGY PIPING FAILURES CAUSED BY WALL THINNING

Addressees:

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose:

This information notice is intended to alert addressees to continuing erosion/corrosion problems affecting the integrity of high-energy piping systems and apparently inadequate monitoring programs. The piping failures at domestic plants indicate that, despite implementation of long-term monitoring programs pursuant to Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," piping failures caused by wall thinning continue to occur in operating plants. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice do not constitute NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances:

On December 31, 1990, while Unit 3 of the Millstone Nuclear Power Station was operating at 86-percent power, two 6-inch, schedule 40 pipes, in the moisture separator drain (MSD) system, ruptured. The high-energy water (approximately 360 degrees F, 600 psi) flashed to steam and actuated portions of the turbine building fire protection deluge system. Two 480-volt motor control centers and one non-vital 120-volt inverter were rendered inoperable by the flooding, resulting in the loss of the plant process computer and the isolation of the instrument air to the containment building.

On July 2, 1990, while Unit 2 of the San Onofre Nuclear Generating Station was operating at full power, the licensee discovered a steam leak in one of the feedwater regulating valve (FRV) bypass lines. The licensee shut down the reactor to depressurize the line for inspection and repair. Ultrasonic testing (UT) revealed wall thinning in an area immediately downstream of the weld attaching the 6-inch bypass line to the 20-inch feedwater piping.

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On March 23, 1990, at Unit 1 of the Surry Power Station, a straight section of piping, downstream of a level control valve in the low pressure heater drain (LPHD) system, ruptured. Measurement of the piping revealed that it had thinned to 0.009 inch at the rupture.

On May 28, 1990, at Loviisa, Unit 1, a foreign plant, a flow-measuring orifice flange in the main feedwater system ruptured. The rupture occurred after one of the five main feedwater pumps tripped causing a check valve in the line to slam shut, creating a pressure spike. The utility inspected the flange and found that the flange had thinned to approximately 0.039 inch. After inspecting the other flow-orifice flanges in Units 1 and 2, the utility determined that 9 of 10 flanges had been thinned to below minimum wall requirements.

Discussion:

For all of these events, system temperature was in the range of 280 to 445 degrees F, system pressure was 500 to 1080 psi, flow was 9 to 29 feet per second and the piping material was carbon steel. Also, in each event, flow turbulence was present.

The licensee for Millstone Unit 3 had noted a through-wall leak approximately two inches from the level control valve in train A of the MSD system and was preparing to isolate the line for repair. However, when MSD pump A was secured, a pressure transient resulted, causing MSD trains A and B to rupture. Information obtained from the licensee indicates that in both trains, the ruptured piping had thinned to approximately 20 mils near the level control valve. Although the licensee had identified the MSD system as one of the systems to be analyzed for erosion/corrosion susceptibility, that analysis was not performed because of a communication error. The spool piece numbers for the MSD system were incorrectly listed under the moisture separator reheater drain system which was exempted from analysis because of temperature. The licensee has analyzed the MSD system using the Electric Power Research Institute computer code CHEC and determined that the MSD system is highly susceptible to erosion/corrosion and should have been inspected.

At San Onofre Unit 2, the licensee's erosion/corrosion monitoring program had excluded the FRV bypass lines from inspection for wall thinning based on the system temperature (445 degrees F) exceeding a criterion established by the licensee. However, the thinning of the FRV bypass lines demonstrates that erosion/corrosion is a multi-variable phenomena and that exclusion based on one variable may not be appropriate. The variables of piping material, configuration, flow rate, water temperature, water chemistry (pH, pH control agent, dissolved oxygen), and steam quality for steam/water systems are important when evaluating piping systems for erosion/corrosion susceptibility.

At Surry Unit 1, the pipe failure occurred in a straight section of pipe located just downstream of a level control valve in the 2B low pressure heater drain (LPHD) system. The licensee's erosion/corrosion monitoring program included the LPHD system and provided for inspecting the wall thickness of the pipe elbow located immediately downstream of the failed piping. However, the program did not provide an inspection for the short section of piping between the elbow and the level control valve. After the pipe rupture occurred in train B, the licensee performed UT inspections of the same section in train A of the LPHD system and found that it had thinned to approximately 0.052 inch. The design requirement for minimum wall thickness in that pipe is 0.117 inch. The licensee replaced the damaged pipe with A106 grade B material and intends to replace that material with A335-P22 erosion resistant material during the next outage.

The licensee performed an analysis and found that the erosion/corrosion of the failed piping was caused by a combination of high velocity flow, a pH level of 9.0 or less in the heater drain system, and flow turbulence caused by valve throttling.

The feedwater pipe rupture at Loviisa Unit 1 occurred in the flange of the flow-measuring orifice (Figure 1). The 360-degree thinning of the interior wall of the flange started near the orifice plate and increased to the point of the rupture. In the area of the rupture, the flange wall had thinned to 0.039 inch. A 20 inch long pipe section attached to the downstream end of the flange had circumferential wall thinning from an initial wall thickness of 0.7 inch to a residual wall thickness of 0.195 - 0.390 inch. Neither this section of pipe nor the flange contained significant amounts of alloying elements. However, the piping downstream of the 20 inch pipe, which contained 0.20 percent chromium, 0.30 percent nickel and 0.30 percent copper, did not exhibit wall thinning.

The utility conducted an investigation and determined that the thinning was caused by erosion/corrosion. In 1982, the utility established a pipe inspection program for two phase (steam/water) systems and, in 1986, augmented the program to include single phase systems; however, the program concentrated on pipe elbows and tee fittings. To check for other degraded flanges, the utility inspected the flow-orifice flanges at Units 1 and 2 and found that 9 of 10 flanges were below minimum wall requirements. The utility replaced the flanges with the same material as the original flanges but is considering changing to a more erosion/corrosion resistant material as a final repair.

The NRC has issued the following related generic communications:

NRC Information Notice 86-106, "Feedwater Line Break," December 16, 1986, and supplements 1, 2, and 3.

NRC Information Notice 87-36, "Significant Unexpected Erosion of Feedwater Lines," August 4, 1987.

NRC Information Notice 88-17, "Summary of Responses to NRC Bulletin 87-01, 'Thinning of Pipe Walls in Nuclear Power Plants'," April 22, 1988.

NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," July 9, 1987.

NRC Generic Letter 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," May 4, 1989.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate NRR project manager.

Charles E. Rossi, Director
Division of Operational Events Assessment
Office of Nuclear Reactor Regulation

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(301) 492-0726

Roger Woodruff, NRR
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Attachments:
1. Figure 1. Loviisa Unit-1 Erosion/Corrosion Areas
2. List of Recently Issued NRC Information Notices

UNITED STATES

NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

May 6, 1992

NRC INFORMATION NOTICE 92-35: HIGHER THAN PREDICTED EROSION/CORROSION IN UNISOLABLE REACTOR COOLANT PRESSURE BOUNDARY PIPING INSIDE CONTAINMENT AT A BOILING WATER REACTOR

Addressees

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to erosion/corrosion rates that could be higher than predicted in certain unisolable reactor coolant pressure boundary piping inside the containment drywell at boiling water reactors. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

The Pennsylvania Power and Light Company (the licensee) recently performed erosion/corrosion inspections at the Susquehanna Steam Electric Station, Unit 1, and may have identified an unexpectedly high rate of erosion/ corrosion in certain main feedwater (FW) piping inside containment (Attachment 1). Erosion of this portion of FW piping is of particular concern since this portion cannot be isolated from the reactor vessel, and erosion/corrosion inspection strategies may not direct attention to that part of the FW system.

When the licensee began operating the unit commercially in June 1982, the nominal wall thickness for the pipe was about 0.688 inch. During the current refueling outage, wall thinning was found in one of the 20 inch by 12 inch reducing tee risers approximately 10 inches downstream from the tee in the 12 inch pipe section, immediately above a circumferential pipe weld. During the previous refueling outage (18 months ago) the licensee had measured the pipe wall as 0.619 inch thick at that location. During the current refueling outage, the licensee measured a thickness of 0.521 inch at the same location. The licensee measured a thickness of 0.482 inch within about 2 inches of that location. The licensee calculated a minimum allowable wall thickness of 0.440 inch for that portion of FW pipe. Previous experience and models had indicated an erosion wear rate of no more than 0.085 inch each cycle. However, the most

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recent measurement indicates a higher wear rate that may be greater than 0.100 inch each cycle.

The licensee evaluated the data for the FW system and determined that continued operation could not be justified for another fuel cycle. Therefore, the licensee repaired, rather than replaced, the FW pipe in accordance with Section XI of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code.

Discussion

The licensee determined that although it had expected to find erosion/ corrosion at this location, the magnitude of wall thinning exceeded expectations. The licensee is continuing its investigation to determine the root cause of the unexpected erosion/corrosion rate.

Related Generic Communications

Following a pipe rupture at the Surry Power Station in 1986, the NRC issued Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," July 9, 1987. In this bulletin, the staff requested licensees and applicants to inform the NRC about their programs for monitoring the wall thickness of carbon steel piping in both safety-related and nonsafety-related high energy fluid systems.

In 1989, following an audit of the erosion/corrosion programs at 10 plants, the NRC issued Generic Letter (GL) 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," May 2, 1989. In this generic letter, the staff requested licensees and applicants to implement long term erosion/corrosion monitoring programs. The staff made this request to obtain assurances that the addressees had implemented procedures or administrative controls to maintain the structural integrity of all carbon steel systems carrying high energy fluids.

The NRC also issued several information notices on the subject of erosion/ corrosion.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

Charles E. Rossi, Director
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Office of Nuclear Reactor Regulation

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David Gamberoni, NRR
(301) 504-1171

John White, Region I
(215) 337-5114

Attachments:
1. Feedwater System Erosion/Corrosion Location
2. List of Recently Issued NRC Information Notices

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

January 22, 1993

NRC INFORMATION NOTICE 93-06: POTENTIAL BYPASS LEAKAGE PATHS AROUND FILTERS INSTALLED IN VENTILATION SYSTEMS

Addressees

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to potential problems resulting from missing or deteriorated seals around shafts that penetrate fan or filter housings and inadequately sealed ducting seams used in engineered safety feature (ESF) ventilation systems. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

As a result of a review of a nonconforming condition involving the standby gas treatment system (SGTS), the licensee for Grand Gulf identified leakage paths associated with ventilation system ducting and housings, including fan plenums. These leakage paths resulted in reduction of the removal capability for radioactive material of the standby gas treatment and control room air systems which are engineered safety features. The affected ventilation system ducting serves as either part of the secondary containment boundary or an extension of the control room environment. The effect of such bypass leakage and the associated radiation doses was not considered as part of the facility design or the licensing review. As a result of these findings in June 1992, the licensee determined that the facility had been operating in a condition outside the facility design basis.

The licensee assessment of the safety significance of bypassing the SGTS radioactivity removal function (both adsorption and filtration), based on estimated inleakage rates and licensing methodology, initially indicated that potential calculated accident exposures could exceed the guidelines of 10 CFR Part 100 and the values in General Design Criterion (GDC) 19 of Appendix A to 10 CFR Part 50. The licensee did a second assessment, characterized as conservative but more realistic, which indicated that the potential exposures would be within the guidelines of Part 100 and within GDC 19 values.

9301140142.

Discussion

With respect to the SGTS, the licensee determined that an opening, or gap, between the fan hub and the hole in the fan housing could result in air being drawn into the suction plenum of the SGTS downstream of the charcoal adsorber and filter (HEPA). The paths were around a motor shaft, through a slotted opening to an actuator for a damper, and at a transition piece of ducting. These paths could allow radioactive gases that may have leaked from containment following a design-basis accident to be sucked into the ducting and discharged to the environment without the anticipated adsorption and filtration assumed in the design-basis analyses for the SGTS. Bypass leakage associated with the SGTS affects all calculated dose consequences that involve the use of the SGTS to mitigate the consequences of an accident. If the actual inleakage is not within the amounts assumed in the design-basis analyses, the facility may not be operating as intended and may be operating outside of the design basis with calculated accident exposures exceeding either 10 CFR Part 100 guideline values or GDC 19 values or both.

A subsequent investigation by the licensee of other filter trains at Grand Gulf disclosed that the ventilation system for the control room also had bypass paths. Air from the area around the fan plenum would be sucked into the ducting and discharged directly into the control room. This deficiency would result in unfiltered, potentially contaminated air being supplied to the control room. This supply source of potentially contaminated air was not incorporated in the design-basis analyses for the facility.

The licensee reported that the apparent root cause for these deficiencies, which included missing seals, was a failure to specify a leak-tight construction for the fan housings. At Grand Gulf, shaft seals were installed and other leak paths were reworked to reduce bypass flow and consequent potential release of radioactive materials.

Many licensees have designed these types of systems to the standards in the American National Standards Institute and American Society of Mechanical Engineers (ANSI/ASME) N509 and have committed to testing to the standards in ANSI/ASME N510. Testing in accordance with N510 can identify bypass leakage if the leakage is a significant fraction of system flow. Testing using tracer chemicals, such as S-F6, can determine small inleakage rates such as those identified at Grand Gulf.

The spread of contamination and potential for exposure of individuals can occur from outleakage as well as inleakage. There have been instances where the circulation of contaminated air through ducting located in a clean area has resulted in unfiltered leakage into the clean area. In addition, deficiencies identified in engineered safety feature ventilation systems may also be present in those systems used to limit normal effluents..

Related Generic Communications

IN No. 86-76, "Problems Noted in Control Room Emergency Ventilation Systems," August 28, 1986.

IN No. 90-02, "Potential Degradation of Secondary Containment," January 22, 1990.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

ORIGINAL SIGNED BY

Brian K. Grimes, Director
Division of Operating Reactor Support
Office of Nuclear Reactor Regulation

Technical contacts: J. Hayes, NRR
(301) 504-3167

J. Carter, NRR
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Attachment: List of Recently Issued NRC Information Notices

NEC-JH_50

UNITED STATES

NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

February 24, 1995

NRC INFORMATION NOTICE 95-11: FAILURE OF CONDENSATE PIPING BECAUSE OF EROSION/CORROSION AT A FLOW-STRAIGHTENING DEVICE

Addressees

All holders of operating licenses or construction permits for nuclear power reactors.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to possible piping failures caused by flow disturbances that are not accounted for in erosion/corrosion programs. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

On November 29, 1994, the Sequoyah Unit 1 reactor tripped from 100-percent power. Approximately 3 hours after the plant trip, Tennessee Valley Authority (TVA, the licensee) observed water pouring from a 16 inch nominal size diameter condensate line between the 1B4 and 1B3 feedwater heaters. A licensee investigation found a 180 degree circumferential crack in the reduced section of a nominal 14 inch pipe. This pipe section was part of a Westinghouse flow-metering device that had been installed during the first refueling cycle to test turbine performance.

The metering device consisted of three flanged sections of pipe: the first section reduced the pipe diameter from 16 inch to 14 inch; the last section expanded the diameter back to 16 inch; and the middle section contained a flow-straightening device, a nozzle, and flow taps. The flow straightener device consisted of three 0.95 cm [0.375 inch] thick, circular plates with drilled flow holes. The plates were spaced about 0.3 meter [1 foot] apart and held together by four 1.27 cm [0.5 inch] rods. The first circular plate fit the pipe flange face and held the fixture in place. The other two plates fit the machined, inside surface of the 14 inch diameter pipe section.

Discussion

TVA found that the pipe failure occurred at the interface of the edge of the middle plate and the inner surface of the pipe wall. The failure resulted from bypass flow around the edge of the plate, which caused very localized erosion along a narrow band, approximately 1.27 cm [0.5 in] wide and 360 degrees around the pipe wall. A 7.6 cm [3 inch] wide, 0.32 cm [0.125 inch] deep machined surface, 360 degrees, on the outer surface of the pipe in the same area of the internal erosion may have contributed to the pipe failure. This surface had been machined to serve as a reference surface and the inner surface was machined to ensure a snug fit of the flow straightener inside the pipe. At the failure area, erosion had further thinned the pipe wall to approximately 0.127 cm [0.05 inch].

The condensate line containing the flow-metering device was in the erosion/corrosion program and modeled with CHECMATE, but it was modeled as a straight 16 inch pipe section without any diameter or thickness change. CHECMATE is a program used by a majority of licensees that predicts erosion/corrosion rates in piping components, ranks the components in order of damage potential, and calculates the time remaining before reaching a user defined acceptable wall thickness. The licensee personnel responsible for operations and engineering were aware that the flow-metering device was installed; however, ambiguities in drawings prompted the personnel responsible for the erosion/corrosion program to assume that these sections had been removed. The pipe configuration had not been visually inspected and it had been modelled as a straight section.

After the pipe failure, the CHECMATE model, including the condensate line with the flow-metering devices, was re-analyzed. The CHECMATE program did not include a model for the flow straightener; the closest model for this device was a straight pipe section. The CHECMATE model would have indicated a high rank for erosion downstream of the nozzle, which would have been modelled as an orifice. Therefore, knowledge that the metering device was installed still may not have prompted an inspection of the area of piping that failed (the area of the flow straightener). Even if the area had been inspected, the band of erosion was so localized that it could have been missed since only grid intersections are inspected.

The licensee determined that the parallel condensate lines still had the temporary metering devices installed and replaced those sections with straight 16 inch sections of pipe. The licensee also determined that the heater drain system had two of these temporary metering sections but decided to leave the lines in service because the flow straighteners had been removed in an outage and present thickness measurements indicated no unacceptable erosion.

The root cause of the failure was the bypass flow around the middle plate of the flow straightener. This bypass flow was not anticipated and the NRC staff is not aware of any previous industry experience that would have demonstrated a need to have the CHECMATE program indicate a high rank for flow straighteners. This example is an indication of how flow disturbances not accounted for by modelling tools can affect the reliability of licensee erosion/corrosion programs..

Related Generic Communications

In NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," July 9, 1987, the staff requested licensees and applicants to inform NRC about their programs for monitoring the wall thickness of carbon steel piping.

By NRC Generic Letter (GL) 89-08, "Erosion/Corrosion-Induced Pipe Wall Thinning," May 2, 1989, the staff requested licensees and applicants to implement long term erosion/corrosion monitoring programs.

The NRC also issued several information notices on erosion and corrosion.

This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/s/'d by BKGrimes

Brian K. Grimes, Director
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Office of Nuclear Reactor Regulation

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Attachment:
List of Recently Issued NRC Information Notices

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555-0001

December 11, 1997

NRC INFORMATION NOTICE 97-84: RUPTURE IN EXTRACTION STEAM PIPING AS A RESULT OF FLOW-ACCELERATED CORROSION

Addressees

All holders of operating licenses for nuclear power reactors except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this information notice to alert addressees to potential generic problems related to the occurrence and prediction of flow-accelerated corrosion (FAC) in extraction steam systems. It is expected that recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements; therefore, no specific action or written response is required.

Description of Circumstances

On April 21, 1997, Omaha Public Power District's Fort Calhoun Station, while operating at 100-percent power, experienced an approximate 0.56 m^2 [6 ft^2] rupture of a 30.5-centimeter [12-inch]-diameter sweep elbow (radius equal to five times the pipe diameter) in the fourth-stage extraction steam piping. The operator, upon hearing steam noise and observing steam rising from the turbine deck, believed that a steam line had broken and manually scrammed the reactor. As a precaution, emergency boration was initiated. The main turbine tripped automatically as a result of the reactor trip. The turbine trip had the effect of isolating the rupture. Plant systems and related parameters responded as expected during the event.

The steam line rupture damaged a nonsafety-related electrical load center in the vicinity of the pipe break. Additionally, collateral damage was experienced in several cable trays and pipe hangers, and insulation containing asbestos was blown throughout the turbine building. Certain portions of the fire protection system actuated in response to fusible links in the sprinkler heads melting because of high temperature. Because there were no personnel in the immediate vicinity of the rupture, no one was injured.

The fourth-stage extraction steam system emanates from the outlet of the high-pressure turbine and preheats the feedwater heaters. The design operating conditions in the piping are 2068 kilopascal gauge [300 psig] and 218C [425F], with a steam quality of approximately 92 percent. The piping is fabricated of A-106B carbon steel and has a nominal wall thickness of 0.953 centimeter [0.375 inch]. The licensee's root cause assessment attributed the failure to FAC in the extraction steam piping. Initial indications of degradation in the extraction steam line at the Fort Calhoun facility were first discovered in 1985, when the furthest upstream long-radius elbow (radius equal to one and a half times the pipe diameter) was replaced because of a pinhole leak. At that time the next upstream sweep elbow was also replaced.

Discussion

The fourth-stage extraction steam system had been recognized as a system that was susceptible to erosion and/or corrosion. It was, therefore, being monitored by the licensee's erosion and corrosion control program. Part of the licensee program was utilizing the CHECWORKS computer code to identify high-wear-rate areas to be selected for inspection.

The CHECWORKS model for the fourth-stage extraction steam piping predicted that long-radius elbows would wear at a higher rate than the sweep elbows when exposed to similar conditions. Using CHECWORKS predictions, the licensee inspected and replaced all four long-radius elbows, but the failed sweep elbow was never inspected.

Part of the licensee's corrective actions following the rupture included inspecting all sweep elbows that had not been previously inspected. The measured wall thickness (0.112 centimeter [0.044 inch]) of the furthest downstream sweep elbow in the fourth-stage extraction piping was also significantly below the minimum wall thickness (0.272 centimeter [0.107 inch]) specified by code requirements and had to be replaced. Additionally, another sweep elbow in the fourth-stage extraction piping was also replaced because the wear (measured wall thickness of 0.394 centimeter [0.155 inch]) was considered excessive, even though it was not below the minimum allowable thickness.

The CHECWORKS predictions of the wear in the fourth-stage extraction steam system were not consistent with the actual observed wear rates as measured on the components, that is, sweep elbows showed substantially greater wear than predicted.

Subsequent investigations by the licensee determined that the inconsistencies between predicted and actual wear were due to two factors. First, the "line correction factor" calculated by CHECWORKS for the fourth-stage extraction steamline was not within the acceptable range specified in the CHECWORKS users' manual. The line correction factor in CHECWORKS is used to adjust wear rate predictions in a given line to account for plant operating conditions that may vary with time. It is determined by comparing predicted wear to measured wear at locations in the line which have been inspected.

In order for the CHECWORKS predicted wear rate for a location to be valid, the line correction factor must be between 0.5 and 2.5. For the line containing the sweep elbow that failed, the wear rates calculated by CHECWORKS used a line correction factor that was outside this range. Therefore, as specified in the CHECWORKS users' manual, the predicted wear rates for this line were not valid.

Second, the line correction factor was biased and thus underpredicted the wear rates. In 1987, the licensee updated the parameters used by CHECWORKS to include the wear measured in a long-radius elbow. One of the inputs in CHECWORKS is the length of time the component has been in service. The licensee assumed that this elbow had been in service since initial operation of the plant in 1973; however, the elbow had been replaced in 1985. Therefore, the actual wear occurred over 2 years rather than the presumed 14 years. Thus, the period of time that was assumed for the wear to have occurred caused CHECWORKS to calculate a line correction factor that underestimated the wear rates for sites in the line.

This event revealed the importance of understanding the limitation of methodologies used in computer programs and of incorporating accurate plant-specific data from nondestructive examination programs.

Related Generic Communications

In NRC Bulletin 87-01, "Thinning of Pipe Walls in Nuclear Power Plants," July 9, 1987, the staff asked licensees and applicants to inform the NRC about their programs for monitoring the wall thickness of carbon steel piping (Accession No. 8707020018).

In NRC Generic Letter 89-08, "Erosion/Corrosion Induced Pipe Wall Thinning," May 2, 1989, the staff asked licensees and applicants to implement long-term erosion/corrosion monitoring programs (Accession No. 8905040276).

Additionally, the following NRC information notices (INs) provide information about similar events related to FAC:

IN 82-22,	"Failures in Turbine Exhaust Lines,"	July 9, 1982	(Accession No. 8204210392).
IN 86-106,	"Feedwater Line Break,"	December 16, 1986	(Accession No. 8612160250).
IN 87-36,	"Significant Unexpected Erosion of Feedwater Lines,"	August 4, 1987	(Accession No. 8707290264).
IN 88-17,	"Summary of Responses to NRC Bulletin 87-01, `Thinning of Pipe Walls in Nuclear Power Plants,'"	April 22, 1988	(Accession No. 8804180039).
IN 89-53,	"Rupture of Extraction Steam Line on High Pressure Turbine,"	June 13, 1989	(Accession No. 8906070273).
IN 91-18,	"High Energy Pipe Failures Caused by Wall Thinning,"	March 12, 1991	(Accession No. 9103060153).
IN 91-18, Supplement 1,	"High Energy Pipe Failures Caused by Wall Thinning,"	December 18, 1991	(Accession No. 9112120218).
IN 93-21,	"Summary of NRC Staff Observations Compiled During Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs,"	March 25, 1993	(Accession No. 9303190051).
IN 95-11,	"Failure of Condensate Piping Because of Erosion/Corrosion at a Flow-Straightening Device,"	February 24, 1995	(Accession No. 9502210050).

This information notice requires no specific action or written response. However, recipients are reminded that they are required to consider industry-wide operating experience (including NRC information notices) where practical, when setting goals and performing periodic evaluations under Section 50.65, "Requirement for monitoring the effectiveness of maintenance at nuclear power plants," to Part 50 of Title 10 of the Code of Federal Regulations. If you have any questions about the information in this notice, please contact the technical contact listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

signed by

Jack W. Roe, Acting Director
Division of Reactor Program Management

Office of Nuclear Reactor Regulation

Technical contact: J. Shackelford, RIV
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E-mail: jls2@nrc.gov

(NUDOCS Accession Number 9712090140)

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Power Reactor                           |Event Number:  36015      |
+--------------------------------------------------------------------------+
+--------------------------------------------------------------------------+
| FACILITY: CALLAWAY                REGION:  4  |NOTIFICATION DATE: 08/11/1999|
|   UNIT:  [1] [] []              STATE:  MO |NOTIFICATION TIME: 12:04[EDT]|
|  RXTYPE: [1] W-4-LP                        |EVENT DATE:        08/11/1999|
+---------------------------------------------+EVENT TIME:        09:25[CDT]|
| NRC NOTIFIED BY:  DAVE NETERER              |LAST UPDATE DATE:  08/11/1999|
|  HQ OPS OFFICER:  BOB STRANSKY              +-----------------------------+
+---------------------------------------------+PERSON          ORGANIZATION |
|EMERGENCY CLASS:          N/A                |DALE POWERS          R4      |
|10 CFR SECTION:                              |ROBERT BENNEDICT     NRR     |
|ARPS 50.72(b)(2)(ii)     RPS ACTUATION       |FRANK CONGEL         IRO     |
|AESF 50.72(b)(2)(ii)     ESF ACTUATION       |                             |
|                                             |                             |
|                                             |                             |
+-----+----------+-------+--------+-----------------+--------+-----------------+
|UNIT |SCRAM CODE|RX CRIT|INIT PWR|  INIT RX MODE   |CURR PWR|  CURR RX MODE   |
+-----+----------+-------+--------+-----------------+--------+-----------------+
|1     M/R        Y        100      Power Operation  |0        Hot Standby     |
|                                                    |                          |
|                                                    |                          |
+--------------------------------------------------------------------------+
                              EVENT TEXT
+--------------------------------------------------------------------------+
| MANUAL REACTOR TRIP DUE TO HEATER DRAIN LINE BREAK                         |
|                                                                          |
| Operators manually tripped the reactor after receiving indication of a steam |
| leak in the turbine building. An 8" diameter line from the 'D' 1st stage     |
| reheater drain tank to the '6B' high pressure heater experienced a double   |
| ended guillotine break. All control rods inserted into the core following   |
| the trip, and all systems functioned as designed. The licensee reported that |
| the unit is currently stable in Hot Standby, and the steam leak has been    |
| isolated. No personnel injuries resulted from this event.                   |
|                                                                          |
| The NRC resident inspector has been informed of this event by the licensee. |
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Kewaunee
3Q/2006 Plant Inspection Findings

NEC-JH_52

Initiating Events

Significance: Jun 23, 2006
Identified By: NRC
Item Type: NCV NonCited Violation
Procedure for Reactor Startup Not Followed
The inspectors identified a finding associated with a non-cited violation of Technical Specification 6.8.a (written procedures and administrative policies). The finding was for the licensee's failure to follow approved procedures during a plant startup. The finding was of very low safety significance and there were three examples of the finding. The first example of a failure to follow approved procedures occurred when operators incorrectly marked a procedure step as not applicable and failed to execute the step. The second example of the failure to follow approved procedures occurred when operators executed procedure steps out of sequence. The third example occurred during the previous reactor startup conducted in November 2005 when operators performed procedure steps out of sequence in the same manner as executed during this plant startup. Corrective actions included placing Procedure N-0-01 on administrative hold until appropriate procedure changes could be made and training operating crews on procedure adherence.

This finding was of more than minor safety significance. Failure to comply with reactivity management requirements can lead to an uncontrolled reactivity event. In this particular event, the failure to follow the procedural sequence could have resulted in shutdown margin being less than that required by Technical Specifications. However, this finding is of very low significance because the actual shutdown margin did not go below the minimum required by Technical Specifications. This finding affected the cross-cutting issue of human performance.
Inspection Report# : 2006011*(pdf)*

Significance: Jun 23, 2006
Identified By: NRC
Item Type: NCV NonCited Violation
Inadequate Procedure for Reactor Startup
The inspectors identified a finding associated with an non-cited violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," of very low safety significance associated with an event. The inspectors identified that Procedure N-0-01, "Plant Startup from Cold Shutdown Condition to Hot Shutdown Condition," Revision BI, Step 4.45 was inadequate to start up the reactor for the conditions that existed on May 17, 2006. The procedure, as written, would have required the operators to dilute the reactor to a lower boron concentration than the Estimated Critical Position boron concentration prior to withdrawing the Shutdown Bank rods. Corrective actions to address this finding included placing Procedure N-0-01 on administrative hold until appropriate procedure changes could be implemented.

This finding was more than minor in safety significance because this issue, if left uncorrected, would have resulted in the core reactivity shutdown margin being less than that required by Technical Specifications. However, this finding is of very low significance because the procedure step was not executed and shutdown was never below that required by Technical Specifications. This finding affected the cross-cutting issue of human performance.
Inspection Report# : 2006011*(pdf)*

Significance: May 19, 2006
Identified By: NRC
Item Type: NCV NonCited Violation
Criterion XVI: Failed to Identify Causes and Corrective Actions to Preclude Repetition for Significant Conditions Adverse to Quality
The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50,

ıppendix B, Criterion XVI, "Corrective Actions." Specifically, for the turbine building flooding and auxiliary feedwater ir entrainment performance deficiencies, which were significant conditions adverse to quality, the licensee failed to dentify the causes, and to determine corrective actions to preclude repetition.

'he finding was greater than minor because the failure to identify the cause and corrective actions to preclude repetition of ignificant conditions adverse to quality, which led to a degraded cornerstone could result in the NRC needing to take more ignificant action. The finding was determined to be of very low safety significance based on management review, and the etermination that no additional instances of significant conditions adverse to quality have actually occurred due to the ailure to identify the causes and corrective actions for the previous performance deficiencies. The cause of the finding was elated to the evaluation aspect of the cross-cutting element of problem identification and resolution.
nspection Report# : 2006007*(pdf)*

ignificance: G May 05, 2006
dentified By: NRC
tem Type: NCV NonCited Violation
'ailure to Incorporate Operating Experience Into Preventive Maintenance Procedures
'he inspectors identified a finding associated with a non-cited violation (NCV) of 10 CFR 50.65 (the Maintenance Rule), aving very low safety significance for the licensee's failure to incorporate into station procedures available internal and xternal operating experience pertaining to 4.16-kilovolt (kV) switchgear mechanically operated contact (MOC) switch nkage assemblies. As a result, preventive maintenance procedures for 4.16-kV safety- and nonsafety-related switchgear reaker cubicles were inadequate and had not been upgraded to incorporate important MOC switch linkage measurements nd adjustments to be used during periodic breaker/cubicle maintenance. The licensee entered the problem with the rocedures into its corrective action program for resolution. Corrective action included the revision of the procedures to ncorporate the need to inspect the linkage and adjust it to within specified values.

'he finding is greater than minor because it is associated with the procedure adequacy attribute of the Initiating Events ornerstone and affected the cornerstone objective to limit the likelihood of those events that upset plant stability and hallenge critical safety functions during shutdown as well as power operation. The finding was determined to be of very ow safety significance because the transient initiator contributor is a reactor trip that did not contribute to both the ikelihood of a reactor trip and the likelihood that mitigation equipment or functions will not be available. The cause of the inding is related to the cross-cutting element of problem identification and resolution.
nspection Report# : 2006010*(pdf)*

ignificance: G Mar 31, 2006
dentified By: NRC
tem Type: FIN Finding
'ailure to Control Loose Materials Within the Protected Area in Response to Adverse Weather Conditions
ι finding of very low safety significance was identified by the inspectors for the licensee's failure to control loose naterials within the protected area south of the transformer bays in response to adverse weather conditions. The material ould have been blown into the transformers and initiate a transient. The primary cause of this finding was related to the ross-cutting area of problem identification and resolution for the failure to implement effective corrective actions in esponse to a similar, previous inspection finding (Inspection Report 05000305/2005008). No violation of regulatory equirements occurred.

'he licensee entered this issue into its corrective action program and removed the loose material from the transformer bays.

'he finding is more than minor because, if left uncorrected, the loose items would become a more significant safety oncern by becoming missile hazards; thereby, increasing the likelihood of an initiating event. Additionally, the inspectors etermined that this issue was associated with the procedure quality attribute of the Initiating Events cornerstone and ffected the cornerstone objective to limit the likelihood of those events that upset plant stability and challenge critical afety functions during shutdown as well as power operations because the station procedure used to control potential irborne material was too narrow in scope. The finding was of very low safety significance because the inspectors nswered "no" to all the screening questions in the Significance Determination Process Phase 1 Screening Worksheet under ıe Initiating Events column.

Inspection Report# : 2006002*(pdf)*

Significance: Mar 30, 2006
Identified By: NRC
Item Type: FIN Finding
Failure to Adequately Evaluate an Inoperative Indicating Lamp for a Turbine control Valve
A finding of very low safety significance was identified by the inspectors for the failure to adequately evaluate an inoperative indicating lamp associated with the turbine control valves. The primary cause of this finding was attributed to the cross-cutting area of human performance because procedures were available, but not followed, that would have facilitated proper performance of the task.

The licensee entered this item into its corrective action program and reviewed open work orders, provided a status update to management, and increased communications of related expectations.

The finding is greater than minor because the failure to adequately evaluate deficient conditions, if left uncorrected, would become a more significant safety concern. The finding was of very low safety significance because the inspectors answered "no" to all the questions in the Significance Determination Process Phase 1 Screening Worksheet under the Initiating Events column.
Inspection Report# : 2006002*(pdf)*

Significance: Dec 31, 2005
Identified By: NRC
Item Type: NCV NonCited Violation
Inadequate Startup Procedure Resulted in an Inadvertent Carbon-Dioxide Fire Suppression Discharge and Declaration of a Notice of Unusual Event
nding of very low safety significance was self-revealed during two events when use of an inadequate plant prestartup procedure resulted in actuation of the CARDOX Carbon Dioxide system. A Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for the failure to include adequate acceptance criteria in Procedure N-0-02-CLA, "Plant Prestartup Checklist". The primary cause of this finding was related to the resource attribute in the cross-cutting area of Human Performance. The licensee failed to provide the operators with quality procedures containing criteria to know when the secondary plant was appropriately aligned.

The inspectors determined that the finding was greater than minor because it involved the configuration control, human performance, and procedure quality attributes of the Initiating Events Cornerstone. Additionally the finding affected the cornerstone objective of limiting the likelihood of those events that upset plant stability during power operations. Specifically, an incorrect lineup could exist in the secondary system resulting in an initiating event, or an unanalyzed secondary system response after a trip. The issue was of very low safety significance because the finding did not contribute to both the likelihood of a reactor trip and the likelihood that mitigation equipment or functions would not be available. Corrective actions taken by the licensee include procedural enhancements to ensure that systems are lined up properly before continuing with plant startup.
Inspection Report# : 2005017*(pdf)*

Mitigating Systems

Significance: Sep 30, 2006
Identified By: NRC
Item Type: FIN Finding
Technical Specification LCO not Entered for diesel Generators Inoperable while in Refueling Shutdown

Inspection Report# : 2006004*(pdf)*

;ignificance: G Jun 30, 2006
dentified By: NRC
tem Type: NCV NonCited Violation
Reactor Protection System Surveillance Procedure Revised Without Proper Review
The inspectors identified a finding of very low safety significance and an associated non-cited violation of Technical ;pecification 6.8, "Procedures," during a review of a procedure. The licensee had changed the procedure to allow the urbine-driven auxiliary feedwater (TDAFW) pump to be considered available for risk management purposes while the ›ump control switch was in pull-to-lock during the performance of the surveillance procedure; however, the required Plant)perating Review Committee review and approval for the change was not obtained. Corrective actions, to date, included eview of the surveillance procedure by the Plant Operating Review Committee and inclusion into the procedure of ıdditional provisions to ensure availability of the TDAFW pump while the control switch is in pull-to-lock during ›erformance of the procedure. The cause of this finding is related to the cross-cutting area of human performance because ›f the licensee's failure to follow a plant procedure regarding the review and approval of safety-related procedures.

The finding is greater than minor because if left uncorrected the finding would become a more significant safety concern. ;pecifically, improper application of the temporary procedure change process could lead to a more significant unreviewed, mproper procedure change. Additionally, this issue is associated with the procedure quality attribute of the Mitigating ;ystems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems hat respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the failure to provide ıdequate review and approval of a safety-related surviellance procedure prior to issuance for use and the failure to include ıdequate provisions to ensure availability of a safety-related component in the surveillance procedure potentially impacted ›quipment availability. The finding is of very low safety significance because the answer to all the screening questions in he significance determination process Phase 1 screening worksheet in the Mitigating Systems column was "no".
nspection Report# : 2006003*(pdf)*

;ignificance: G Jun 30, 2006
dentified By: NRC
tem Type: NCV NonCited Violation
Leak Developed in Service Water Pipe after Wall Thinning Evaluation was Cancelled
A self-revealed finding of very low safety significance and an associated non-cited violation of 10 CFR Part 50, Appendix 3, Criterion XVI, "Corrective Action," were identified on April 25, 2006, when a leak due to pipe-wall thinning was dentified in a 90° elbow in a service water (SW) line to the 'B' emergency diesel generator. This wall-thinning and leak, a ›ondition adverse to quality, resulted in the need to declare the emergency diesel generator inoperable and a shut down of he reactor to allow repair of the leak. In April 2004, a work order to inspect the elbow for wall-thinning was cancelled after vall thickness in a nearby elbow was evaluated by the licensee and deemed acceptable. The extrapolation of inspection esults from one elbow to the other elbow was inappropriate. Corrective actions taken by the licensee included replacement ›f the failed section of SW piping, performance of additional inspections on SW piping, and replacement of other safety-elated sections of SW piping. The cause of this finding is related to the cross-cutting area of problem identification and esolution because the licensee failed to promptly identify an issue potentially impacting safety-related piping.

The finding is greater than minor because it is associated with the equipment performance attribute of the Mitigating ;ystem cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems hat respond to initiating events to prevent undesirable consequences (i.e., core damage). Specifically, the failure to conduct ı wall-thinning evaluation in April 2004 resulted in the need to take the emergency diesel generator out-of-service and shut lown the reactor to allow repair of the pipe. Additionally, the failure to inspect and correct, as necessary, wall-thinning in a ;afety-related system, if left uncorrected, would become a more significant safety concern through the possible levelopment of a large system leak or the complication of the operations of a safety-related system. The finding is of very ow safety significance because the answer to all the screening questions in the significance determination process Phase 1 ;creening worksheet in the Mitigating Systems column was "no".
nspection Report# : 2006003*(pdf)*

;ignificance: G May 19, 2006
dentified By: NRC
tem Type: NCV NonCited Violation

Criterion V: Failed to Incorporate Appropriate Acceptance Criteria for Assessing Operability of the AFW Pump
The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings." Specifically, the licensee failed to incorporate appropriate acceptance criteria for assessing operability of the auxiliary feedwater pump following identification of a piping obstruction.

The finding was greater than minor because the finding was associated with the Mitigating Systems cornerstone attribute of procedure quality which affected the cornerstone objective. Specifically, the relevant procedure was not adequate to ensure the availability, reliability, and capability of the auxiliary feedwater system to respond to initiating events. The finding was determined to be of very low safety significance because subsequent evaluation of the pipe occlusions, using appropriate acceptance criteria, supported past operability of the pump. The cause of the finding was related to the evaluation aspect of the cross-cutting element of problem identification and resolution.
Inspection Report# : 2006007*(pdf)*

Significance: G May 19, 2006
Identified By: NRC
Item Type: NCV NonCited Violation
Criterion III: Failed to Correctly Translate Containment Sump Volume into Design
The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Specifically, the licensee failed to ensure that design basis calculations correctly translated the containment sump volume at the time of the switch over from the refueling water storage tank to the containment sump to ensure adequate available net positive suction head and vortex suppression for the residual heat removal pumps.

The finding was greater than minor because the finding was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective because the inadequate calculation impacted the design requirements the new containment strainers being installed to resolve Generic Safety Issue 191. The finding was determined to be of very low safety significance because (1) the licensee normally kept the refueling water storage tank at a level above the Technical Specification minimum; (2) new strainers were not yet installed; and (3) inspector-independent calculations indicated that the pumps had adequate net positive suction head and vortex suppression, with the additional non-conservatisms incorporated. The cause of the finding was related to the corrective action aspect of the cross-cutting element of problem identification and resolution.
Inspection Report# : 2006007*(pdf)*

Significance: G May 19, 2006
Identified By: NRC
Item Type: NCV NonCited Violation
Criterion III: Failed to Verify or Check the Adequacy of the Design Canceling Design Change Request 2548
The NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control." Specifically, the licensee failed to properly evaluate the minimum flow requirements of the high head safety injection pumps.

The finding was greater than minor because the finding was associated with the Mitigating Systems cornerstone attribute of design control and affected the cornerstone objective as providing inadequate minimum flow to the SI pumps could result in the pumps failing under certain accident scenarios. The finding was determined to be of very low safety significance because both the licensee and the inspectors determined that the safety injection pumps remained operable with the 47 gpm minimum flow rate. The cause of the finding was related to the corrective action of the cross-cutting element of problem identification and resolution.
Inspection Report# : 2006007*(pdf)*

Significance: G May 05, 2006
Identified By: NRC
Item Type: NCV NonCited Violation
Failure to maintain cable separation for cables 1N15010 and IN15012 associated with train 'B' of ICCMS

he inspectors identified a finding associated with a non-cited violation of 10 CFR Part 50, Appendix B, Criterion III, Design Control," that pertained to a modification that failed to incorporate applicable design requirements for cable eparation. Nonsafety-related cables associated with train 'B' reactor coolant pump (RCP) safety-related cable trays and ables were bundled inside the RCP breaker cubicles with train 'A' RCP safety-related cables feeding the reactor protectio ystem (RPS). Consequently, a fault in the train 'B' cable/cable tray could propagate to train 'A'. The licensee entered the roblem into its corrective action program for resolution. Corrective actions included encasing the nonsafety-related cables n flexible metal conduit and confirming that other safety-related cables were not affected.

he finding is greater than minor because it was associated with the design control attribute of the Mitigating Systems ornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that espond to initiating events to prevent undesirable consequences (i.e., core damage). The finding was determined to be of ery low safety significance because of the redundancy and coincident logic in the RPS design; and it did not represent a oss of system safety function, an actual loss of safety function of a single train, an actual loss of safety function of one or nore non-technical specification trains of equipment, designated as risk significant per 10 CFR 50.65, for greater than 24 ours, and did not screen as potentially risk significant due to a seismic, flooding, or severe weather initiating event.
nspection Report# : 2006010*(pdf)*

ignificance: G Mar 31, 2006
dentified By: NRC
tem Type: NCV NonCited Violation
neffective Corrective Actions to Resolve Boric Acid Leakage from the 1A RHR Pump Flange Studs and Nuts
 finding of very low safety significance and an associated non-cited violation of 10 CFR Part 50, Appendix B, Criterion VI, "Corrective Action," was identified by the inspectors for ineffective identification and the initiation of corrective ctions to resolve boric acid leakage from the 1A residual heat removal (RHR) pump flange studs and nuts. The primary ause of this finding was attributed to the cross-cutting area of problem identification and resolution. During a review of orrective actions associated with the licensee's identification of a moderate amount of boric acid around various pump lange studs and nuts, the inspectors found that numerous prior occasions existed where the licensee had identified similar onditions yet failed to adequately identify and initiate actions to evaluate or correct this condition adverse to quality.

he licensee entered this item into its corrective action program and wrote a work order to replace the pump casing flange asket.

he finding is greater than minor because it is associated with the equipment performance attribute of the Mitigating ystem cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems hat respond to initiating events to prevent undesirable consequences (i.e., core damage). Additionally, failure to correct a ondition adverse to quality in a safety-related system, if left uncorrected, would become a more significant safety concern. he finding was of very low safety significance because the inspectors answered "no" to all the screening questions in the ignificance Determination Process Phase 1 Screening Worksheet under the Mitigating Systems column.
nspection Report# : 2006002*(pdf)*

ignificance: G Mar 31, 2006
dentified By: NRC
tem Type: NCV NonCited Violation
ailure to Apply Appropriate Quality Classification to TSC Diesel Generator Modifications as Required by rocedures
 finding of very low safety significance and an associated non-cited violation of the Kewaunee Technical Specifications, ection 6.8, "Procedures," was identified by the inspectors during a review of plant modification Design Change Request 490, which replaced the existing Technical Support Center diesel generator fuel oil day tank level switches with new level witches of a different design. The inspectors determined that, in accordance with procedure GNP-01.01.01, Determination of Nuclear Safety Designed Classifications, QA [Quality Assurance] Type and EQ [Environmental ualification] Type," the new level switches should have been designated as "Augmented Quality." Contrary to this, the ew switches were not designated as augmented quality. The primary cause of this finding was attributed to the cross-utting area of problem identification and resolution because of the licensee's failure to take effective corrective actions for reviously identified problems with its quality assurance program.

The licensee entered this item into its corrective action program and conducted supplemental audits of quality-designated equipment, added additional related elements to an upcoming quality assurance group audit of the quality assurance r--gram, and the conduct of a cause evaluation of related issues.

The finding is greater than minor because it is associated with the design control attribute of the Mitigating Systems cornerstone and affected the cornerstone objective to ensure the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences (i.e., core damage). Additionally, failure to comply with the provisions of nuclear safety-related procedures, if left uncorrected, would become a more significant safety concern. The finding is of very low safety significance because the inspectors answered "no" to all the screening questions in the Significance Determination Process Phase 1 Screening Worksheet under the Mitigating Systems column.
Inspection Report# : 2006002*(pdf)*

Significance: G Mar 30, 2006
Identified By: NRC
Item Type: FIN Finding
Failure to Adequately Evaluate the Extent-of-Condition of Degraded Fuses in Installed Equipment
A finding of very low safety significance was identified by the inspectors for the failure to adequately evaluate the extent-of-condition relative to installed equipment for a 10 CFR Part 21 notification for degraded Bussmann® fuses. The primary cause of the finding was attributed to the cross-cutting area of human performance because procedures were available, but not followed, that would have facilitated proper performance of the task.

The licensee entered this item into its corrective action program and planned to review other installed fuses and to conduct an evaluation of original problem.

The finding was greater than minor because the failure to adequately evaluate the impact of potentially degraded safety-related fuses on installed equipment, if left uncorrected, would become a significant safety concern. Specifically, the dition could cause premature circuit interruptions of safety-related or risk significant mitigating components, when called upon to perform the related functions, and this is an undesirable condition. The finding was of very low safety significance because the inspectors answered "no" to all the screening questions in the Significance Determination Process Phase 1 Screening Worksheet under the Mitigating Systems column.
Inspection Report# : 2006002*(pdf)*

Significance: G Dec 31, 2005
Identified By: NRC
Item Type: NCV NonCited Violation
Adjustments Performed on Safety-Related Service Water Valve 4B Without Procedure Resulted in Valve Being Declared Inoperable
On October 5, 2005, a finding of very low safety significance was self-revealed when SW-4B failed to meet its In-Service Testing stroke time requirements during the performance of Surveillance Procedure SP-02-138B and an associated unplanned entry into a Technical Specification Limiting Condition for Operation occurred. The condition occurred because the licensee made adjustments to safety-related Valve SW-4B, "Turbine Building Service Water Train "B" Header Isolation," without procedural guidance to perform such adjustments. The primary cause of this finding was related to the personal attribute of the cross-cutting area of human performance because maintenance was performed without required procedures.

The finding was more than minor because performing adjustment of safety-related equipment without procedural guidance, if left uncorrected, would become a more significant safety concern. Additionally, the finding is associated with the Reactor Safety/Mitigating Systems Cornerstone attribute of Procedure Quality and effects the associated Cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable sequences. Using IMC 0609, Appendix A, "Significance Determination of Reactor Inspection Findings for At-Power ..uations," the inspectors answered "no" to all five screening questions in the Phase 1 Screening Worksheet under the Mitigating Systems column. Therefore, this finding was of very low safety significance. A Non-Cited Violation of 10 CFR 50, Appendix B, Criterion V, "Instructions, Procedures, and Drawings," was identified for the failure to provide procedural guidance for adjusting SW-4B; a safety-related valve which could affect the ability of safety-related mitigating system components to perform their intended function. Corrective actions taken by the licensee include procedural revisions to

:trengthen guidance on adjustment of safety-related components.
nspection Report# : 2005017(pdf)

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iignificance: G Dec 31, 2005
dentified By: NRC
tem Type: NCV NonCited Violation
)perator Licensing Exam Results Were Less Than Minimum Acceptable Percentage For Passing
\ finding of very low safety significance was identified. The finding was associated with unsatisfactory operating crew ›erformance on the simulator during facility-administered licensed annual operator requalification examinations. Of the 7 :rews evaluated, 2 did not pass their annual operating tests. The finding is of very low safety significance because the 'ailures occurred during testing of the operators on the simulator, because there were no actual consequences to the failures, ınd because the crews were removed from watch-standing duties, retrained, and re-evaluated before they were authorized o return to control room watches.
nspection Report# : 2005017(pdf)

iignificance: G Dec 16, 2005
dentified By: NRC
tem Type: FIN Finding
\o Trending of Adverse Conditions Identified During Outages
[he inspectors identified a finding of very low safety significance for the licensee not reviewing corrective action program locuments (CAPs) during outages for potential trends of conditions adverse to quality. As part of the screening process of :APs, the licensee assigned, as possible, CAPs to various "hot buttons." Hot buttons were searchable categories in the :orrective action program computer system that had been established for various problems, such as equipment tagging :rrors, security door control, and reactivity management. For non-outage times, the licensee assigned a monthly number of iits for each hot button that, if exceeded for 3 months in succession, would result in the generation of a CAP to investigate ı possible trend. However, as of December 16, 2005, the licensee did not use hot button action levels during outages when he number of CAPs written was much higher than during non-outage times.

'his finding is greater than minor because if left uncorrected would become a more significant safety concern. This finding s not suitable for Significance Determination Process evaluation, but has been reviewed by NRC management and is letermined to be a finding of very low safety significance. No violation of regulatory requirements occurred. The cause of he finding is related to the cross-cutting element of problem identification and resolution, because of not identifying ›otential conditions adverse to quality through trending of CAPs during outages.
nspection Report# : 2005005(pdf)

iignificance: G Dec 16, 2005
dentified By: NRC
tem Type: NCV NonCited Violation
'ailure to Correct Procedure Non-Adherence
'he inspectors identified a finding of very low safety significance and a Non-Cited Violation of 10 CFR Part 50, Appendix }, Criterion XVI, "Corrective Action," for the failure to take corrective action for procedure non-compliance identified .uring the licensee's 2004 self-assessment of the corrective action program. As a result of the assessment, CAP025194, Corrective Action Program Procedure and Guidance Document Use," was written and documented that plant workers vere not following corrective action program procedures for apparent cause evaluations and root cause evaluations, ffectiveness review content, priority and due date assignments, initiator feedback, and documentation of corrective action ompletion. To correct this problem, corrective action CA018094, "Corrective Action Program Procedure and Guidance)ocument Use," was written and specified one or 2 weeks of requiring "in-hand" use by the plant staff of the corrective ction program administrative procedure. However, completion of this action was delayed several times and on July 25, 005, CAP025194 and CA018094 were closed with the only documented action taken being a July 18, 2005, meeting of ıe station human performance steering committee at which the licensee decided not to take action because of the pending ·ansition to the corrective action program documents of the plant's new owner.

:his finding is greater than minor because if left uncorrected would become a more significant safety concern. This finding ; not suitable for Significance Determination Process evaluation, but has been reviewed by NRC management and is

determined to be a finding of very low safety significance. The cause of the finding is related to the cross-cutting element of problem identification and resolution, because of the failure to take corrective action for non-adherence to station procedures.
Inspection Report# : 2005005*(pdf)*

Significance: G Dec 16, 2005
Identified By: NRC
Item Type: NCV NonCited Violation
Failure to Adequately Correct Residual Heat Removal Pump Seal Leakage
A finding of very low safety significance that was a Non-Cited Violation of 10 CFR Part 50, Appendix B, Criterion XVI, "Corrective Action," was identified for the licensee's ineffective corrective action to repair a leak on the seal of the "B" residual heat removal (RHR) pump. The leak was identified on November 2, 2005, when the pump was stopped following the performance of a required surveillance. The leak rate exceeded leakage control program limits. A similar leak was identified on June 16, 2004, for which the licensee replaced the seal in November 2004.

This finding is greater than minor because it was associated with the "RCS (reactor coolant system) equipment and barrier performance" attribute of the barrier integrity cornerstone and does affect the cornerstone objective of providing reasonable assurance that physical design barriers (fuel cladding, reactor coolant system, and containment) protect the public from radionuclide releases caused by accidents or events. Although the RCS barrier was affected, the finding did not affect the mitigation capability of the RHR system and did not contribute to the likelihood of a primary or secondary system loss of coolant accident initiator or affect the containment integrity. Therefore, the finding is of very low safety significance.
Inspection Report# : 2005005*(pdf)*

Significance: Y Oct 06, 2005
Identified By: NRC
Item Type: VIO Violation
Potential Flooding in the Turbine Building Basement
A review of design drawings by the inspectors revealed a direct piping connection from the turbine building sump to the trench in safeguards alley. The inspectors determined that there were no check valves located in the piping to prevent water spills in the turbine building basement from backing up into the safeguards alley. The inspectors also noted that no flood barriers specifically designed to protect equipment in the safeguards alley from flooding in the turbine building basement were installed. The inspectors requested additional information from the licensee regarding potential flooding events occurring in the safeguards alley. The licensee documented its response to the inspectors' information request in Condition Evaluation (CE) 014653. This CE stated that it would take approximately 3 hours for flooding caused by AFW pump discharge to affect safety-related equipment, and such flooding could be mitigated by opening doors between the safeguards alley and the turbine building basement. The CE also stated that other sources of flooding in the turbine building basement need not be considered since such flooding events are outside the design basis of the plant.

The inspectors identified a finding that was preliminarily determined to be of substantial to high safety significance because the licensee failed to provide adequate design control to ensure that Class I equipment was protected against damage from the rupture of a pipe or tank resulting in serious flooding or excessive steam release to the extent that the Class I equipment's function is impaired. Specifically, the design of Kewaunee Power Station (KPS) did not ensure that the auxiliary feedwater (AFW) pumps, the 480-volt (V) safeguards buses, the safe shutdown panel, emergency diesel generators (EDGs) 1A and 1B, and 4160-V safeguards buses 1-5 and 1-6 would be protected from random or seismically induced failures of non-Class I systems in the turbine building. The finding is also an apparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for not ensuring that the design of KPS prevented turbine building flooding from impacting multiple safety related equipment trains needed for safe shutdown of the plant. The inspectors determined that a primary cause of this finding was related to the cross-cutting area of Problem Identification and Resolution, because there was an earlier opportunity to discover and correct this issue based on the licensee's 2003 experience when minor flooding from the turbine building had challenged safety equipment located adjacent to the turbine building basement.

The finding was more than minor because it impacted Mitigating Systems cornerstone attributes of design control (initial design and plant modifications) and protection against external factors (internal flood hazards and seismic events) and it impacted the Mitigating Systems cornerstone objective to ensure availability, reliability and capability of multiple trains of safety related equipment to respond to events to prevent core damage. A Significance Determination Process Phase 3 risk nalysis determined that this finding was preliminarily of substantial to high safety significance. The licensee has taken gnificant corrective actions, including extensive system and structural modifications to address this issue.

fter considering the information developed during the inspection, and the additional information you provided prior to, uring, and in response to our questions at the Regulatory Conference, the NRC has concluded the inspection finding is ppropriately characterized as Yellow (i.e., an issue with substantial importance to safety, that will result in additional NRC ispection and potentially other NRC action).

ıspection Report# : 2004009*(pdf)*
ıspection Report# : 2005002*(pdf)*
ıspection Report# : 2005011*(pdf)*
ıspection Report# : 2005018*(pdf)*
ıspection Report# : 2006015*(pdf)*

ignificance: W Aug 16, 2005
lentified By: NRC
em Type: VIO Violation
otential Common Mode Failure of Auxiliary Feedwater
JRI 05000305/2005002-05 is associated with the design of the AFW pump's discharge pressure switches. The inspectors lentified the potential for air intrusion into operating AFW pumps, potentially resulting in a common mode failure of the FW system. This could occur during certain events where the suction source is lost prior to being able to manually swap ıe source of water from the CST to the SW system.

he inspectors identified a finding that was preliminarily determined to be of low to moderate safety significance, because ewaunee failed to provide adequate design control to ensure the AFW pumps would be protected from failure due to air ıgestion during tornado or seismic events; as well as from failure during potential runout conditions. The finding is also an pparent violation of 10 CFR Part 50, Appendix B, Criterion III, "Design Control," for not effectively providing controls to heck the adequacy of the design for protecting the AFW pumps during design and license basis events.

he finding was determined to be more than minor since it impacted Mitigating System cornerstone attributes of design ontrol (initial design and plant modifications) and the cornerstone objective to ensure availability, reliability, and apability of the AFW system to respond to events to prevent core damage. A Significance Determination Process Phase 3 isk analysis determined that this finding was preliminarily of low to moderate safety significance. The licensee has taken ignificant corrective actions, including extensive modifications to the system.

fter considering the information developed during the inspection, the NRC has concluded the inspection finding is ppropriately characterized as White (i.e., an issue with low to moderate increased importance to safety, which may require dditional NRC inspections).

nspection Report# : 2006015*(pdf)*
nspection Report# : 2005002*(pdf)*
nspection Report# : 2005010*(pdf)*
nspection Report# : 2005014*(pdf)*

3arrier Integrity

ignificance: G May 19, 2006
dentified By: NRC
tem Type: NCV NonCited Violation
riterion III: Failed to Properly Translate the ICS Design Basis into the Technical Specifications
he NRC inspectors identified a finding of very low safety significance that involved a violation of 10 CFR Part 50, ppendix B, Criterion III, “Design Control.” Specifically, the licensee failed to ensure that design basis calculations orrectly translated the internal containment spray flow requirements into the Technical Specification allowed number of locked internal containment spray nozzles.

The finding was greater than minor because the containment spray system could have been inoperable with the allowable ıp degradation and allowable number of blocked containment spray nozzles. The finding was determined to be of very ı.. v safety significance because the internal containment spray system was determined to be operable. The cause of the finding was related to the evaluation aspect of the cross-cutting element of problem identification and resolution.
Inspection Report# : 2006007*(pdf)*

Emergency Preparedness

Occupational Radiation Safety

Public Radiation Safety

Significance: G Jun 30, 2006
Identified By: NRC
Item Type: NCV NonCited Violation
Failure to Properly Calibrate the Waste Discharge Liquid and the Steam Generator Blowdown Radiation Monitors
The inspectors identified a finding of very low safety significance and an associated violation of NRC requirements for the ıre to comply with technical specification and Offsite Dose Calculation Manual (ODCM) requirements in the caıibration of two liquid discharge radiation monitors listed in the ODCM. Specifically, the radiation monitor high alarm trip functions were not verified with radiation sources during instrument calibration.

The finding is greater than minor because it is associated with the plant facilities/equipment and instrumentation attribute of the Public Radiation Safety cornerstone and affected the cornerstone objective of ensuring adequate protection of public health and safety from exposure to radioactive materials released into the public domain. Specifically, not verifying the proper operation of a radiation monitor at its high alarm trip setpoint could result in the use of a monitor that does not properly operate at the high alarm setpoint and the consequent unintended release of radioactive material to the environment in excess of regulatory limits. The finding is of very low safety significance because actual effluent discharges were adequately analyzed for radioactive content by the licensee prior to release, and the licensee's ability to assess dose from radioactive waste (radwaste) liquid discharges was not impaired, nor were regulatory dose limits or As-Low-As-Is-Reasonably-Achievable dose constraints exceeded due to liquid effluent discharges.
Inspection Report# : 2006003*(pdf)*

Significance: G Mar 30, 2006
Identified By: NRC
Item Type: NCV NonCited Violation
Failure to Adequately Evaluate Degraded Flow Conditions on a SW System Radiation Monitor
A finding of very low safety significance and an associated non-cited violation of the Kewaunee Technical Specifications, Section 6.8, "Procedures," was identified by the inspectors for the failure to adequately evaluate degraded flow in a service water system radiation monitor. The primary cause of this finding was attributed to the cross-cutting area of human performance because procedures were available, but not followed, that would have facilitated proper performance of the k.

The licensee entered this item into its corrective action program and planned to conduct inspections of other radiation monitor sample chambers, assess the need for an in-line filter, and assess the need for a modification to correct the recurring problem with the service water radiation monitor.

The finding was greater than minor because the finding involved conditions contrary to those required by the offsite dose calculation manual. Specifically, sampling requirements that were required to be initiated when the related radiation monitoring instrumentation should have been declared inoperable were not accomplished. The finding was of very low safety significance because no radiological releases were possible from the indicated pathways when the condition existed.
Inspection Report# : 2006002*(pdf)*

Physical Protection

Physical Protection information not publicly available.

Miscellaneous

Last modified : December 21, 2006

NEC-JH_53

Interim Summary on Secondary Piping Rupture Accident at Mihama Power Station, Unit 3 of the Kansai Electric Power Co., Inc.

September 27, 2004
The Nuclear and Industrial Safety Agency

(Translated by JNES)

Contents

1. Introduction

An accident occurred at Mihama Power Station, Unit 3 of the Kansai Electric Power Co., Inc. (abbreviated to KEPCO hereinafter) on August 9, 2004. A secondary piping ruptured and high temperature secondary cooling water flowed out, so the reactor shut down automatically. An investigation was carried out on the spot and an opening was confirmed in a pipe of the condensate system.

This accident was one of so-called secondary piping rupture accidents of a pressurized water reactor (PWR). When compared to the results of an analysis of the same kind accident in the safety review, no particular problem was recognized in the reactor parameter variations immediately after the accident. However, the accident resulted in a serious consequence that was unprecedented at a nuclear power plant. That is, of the workers working in the turbine building, 5 were killed and 6 were injured.

Immediately after the occurrence of the accident, the Nuclear and Industrial Safety Agency (abbreviated to NISA hereinafter) dispatched a Deputy Director-General to the scene and established an on-site countermeasure headquarters to take measures after the accident.

On the following day, the 10th, Minister Nakagawa of the Ministry of Economy, Trade and Industry visited the site. At the same time, NISA held a meeting of the Nuclear Reactor Safety Subcommittee of the Nuclear Power Safety and Security Committee under the Advisory Committee for Natural Resources and Energy and established an Investigation Committee on the Secondary Piping Rupture Accident at Mihama Power Station, Unit 3 (abbreviated to the Investigation Committee hereinafter) to investigate and discuss the secondary piping rupture accident that occurred at Mihama Power Station, Unit 3 of KEPCO. The Investigation Committee immediately dispatched two committee members and held the first Investigation Committee meeting on August 11.

After that, on August 11, NISA instructed the licensees of existing nuclear power plants or thermal power plants above a certain scale to report the state of implementation of pipe wall thickness control and on August 13, NISA conducted an on-the-spot inspection at the Mihama Power Station to investigate the ruptured portion and interviewed persons concerned of the power station. Additionally, on August 30, NISA collected reports from the business operators who did maintenance and inspection of the ruptured portion in question.

NISA has made efforts to fulfill its accountability for this accident by directly explaining the progress status of the investigation and discussion to local governments like Mihama-cho, Fukui Prefecture, etc.

The Investigation Committee has held six Investigation Committee meetings (4th meeting held in Fukui Prefecture) so far to identify the causes of the accident and discuss the measures to take for the problems identified so far. On the other hand, the investigation to find the causes of the pipe rupture is ongoing and, moreover, it was decided to conduct detailed analysis and assessment to elucidate the phenomenon. Therefore, it seems that an additional investigation period will be needed before the final result is obtained. Thus, NISA arranged the investigation results so far as an interim summary based on the discussion at the Investigation Committee.

2. Accident situations

While Mihama Power Station, Unit 3 was in operation at the rated thermal output, a "Fire Alarm Operation" alarm was generated at 15:22 on August 9 in the central control room. The operator grasped that the alarm-generated spot was on the second floor of the turbine building and checked the spot to find that the building was filled with steam. Thus, it was judged that there was a high possibility of steam or high temperature water leaking from the secondary piping. The operator started emergency load reduction at 15:26. While operations for that took place, a "3A SG Feed water < Steam Flow Inconsistency Trip[1)]" alarm was generated at 15:28 and the reactor and then the turbine shut down automatically.

No particular problem was recognized in the major plant parameter variations at the accident and the reactor reached to a cold shutdown at 23:45 on August 10.

The operator made an inspection in the turbine building and confirmed a rupture opening in a A-loop condensate pipe at 17:30, which was the feed water line from the 4th feed water heater[2)] to the deaerator[3)] running near the ceiling on the deaerator side at the 2nd floor of the turbine building. After that, the nuclear security inspector also confirmed the same situation.

For the unit in question, the 21st periodical inspection was planned from August 14, 2004. In the turbine building, a total of 105 workers of KEPCO and maintenance contractor employees were proceeding with preparation for the periodical inspection at the occurrence of the accident. Of them, the workers working near the ruptured A-loop condensate pipe fell victim to steam and hot water flown out of the rupture opening, and 5 were killed and 6 were injured.

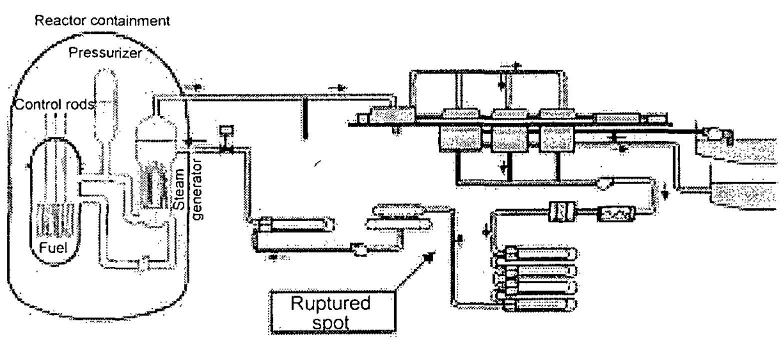

Figure 1 Major systems of PWR and the ruptured spot

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1 SG Feed water < Steam Flow Inconsistency Trip: An alarm issued when the water level of the steam generator is low and the feed water flow to the steam generator is less than the steam flow.

2 Feed water heater: A heat exchanger to heat feed water by the heat of extraction steam from the turbine.

3 Deaerator: A device to heat feed water by the heat of extraction steam from the turbine to separate and remove noncondensing gases (oxygen and others) in the feed water.

According to KEPCO, they examined the operation parameters before and after the occurrence of the accident but did not find out any variation indicating a symptom of rupture before the occurrence of the rupture. They say they did not perform any special operation that might induce the accident of this time.

3. Influences of the accident

3.1. Influences on the reactor

The type of Mihama Power Station, Unit 3 is a pressurized water reactor (PWR) in which the heat of the reactor is exchanged at the steam generator and the exchanged heat is conducted to the turbine. The system before the heat exchange is called the primary system and the system after the heat exchange is the secondary system, and they are isolated from each other.

Therefore, basically, no radioactive material is contained in the cooling water and in one view the secondary system of a PWR is equivalent to a thermal power plant. However, the secondary system of a PWR has the role of cooling the reactor (relieving the heat generated in the reactor). Therefore, from the viewpoint of securing the safety of the reactor facility, it is necessary to consider it as a whole system including not only the primary system but also the secondary system.

In this concept, the influence of secondary system damage on the reactor must be assessed. For this purpose, safety assessment analysis is performed in the safety review of a reactor facility, assuming a "main feed water pipe rupture accident[4]," "main steam pipe rupture accident[5]" and the like according to the "Regulatory Guide for Reviewing Safety Assessment of Light Water Nuclear Power Reactor Facilities (August 1990)" stipulated by the Nuclear Safety Commission.

The accident this time was a rupture of a condensate system pipe that caused cooling water in the secondary system to flow out of the system. As the influence on the reactor, part of the feed water to the steam reactor will be shut off and the heat removal capacity for the reactor will be reduced. Therefore, this accident can be said to be equivalent to a "main feed water rupture accident."

In the accident this time, the systems related to reactor safety operated normally and reactor pressure, primary coolant temperature and other major parameters did not indicate more severe influence than the result assumed in the safety assessment analysis performed at the safety review.

The time series of and about this accident is given in Appendix 1 and the process of actions taken by the nuclear security inspector is given in Appendix 2.

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4 Main feed water pipe rupture accident: The phenomenon in which a rupture occurs in a feed water pipe during power operation of the reactor and the coolant in the secondary piping is lost, resulting in a reduction in reactor cooling capacity.

5 Main steam pipe rupture accident: The phenomenon in which the primary coolant temperature drops at a hot shutdown of the reactor due to a rupture or the like of the secondary cooling system, resulting in an addition of reactivity.

NISA performed a provisional assessment of this accident based on the International Nuclear Event Scale (INES) and the result was 0+. The assessment result is low in spite of the death and injury of as many as 11 persons. This is because this scale is intended to indicate the severity of a nuclear accident and therefore consists of the severity of radiation effects on humans and the safety impact on reactor facilities.

3.2. Influences on neighboring environment

The record of outdoor monitors and ventilation duct monitors was examined and the result was that no significant change was recognized between before and after the accident and no influence of radiation on the neighboring environment due to the leaked secondary cooling water was observed.

3.3. Evaluation of leaked amount

According to a report from KEPCO, the amount of secondary cooling water that flowed out of the ruptured pipe was calculated based on the amount of make-up water from the secondary makeup water tank, the drop of water level in the deaerator and the amount of water contained in the piping (from the 4th low-pressure feed water heater to the deaerator) and it was evaluated to be about 885 tons. The amount of water contained in the secondary system in operation is about 1,100 tons.

Table 1 Leaked amount from various parts

(Unit: ton)

Amount of supplied water from secondary makeup water tank	About 565
Drop of water level in deaerator	About 307
Amount of water contained in piping	About 13
Total	About 885

(Reference information) Outline of the Mihama Power Station, Unit 3

1. Name: Mihama Power Station, Unit 3 of KEPCO
2. Location: Nyu, Mihama-cho, Mikata County, Fukui Prefecture
3. Rated thermal output: 2.44 million kW
4. Rated electric output: 826 thousand kW
5. Reactor type: Pressurized water reactor
6. Commissioning: December 1, 1976
7. Operating time: 185,700 hours

4. Investigation on pipe rupture mechanism

4.1. Ruptured condition of pipe

The portion where a rupture was confirmed was in a condensate pipe of the A-loop, one of the two loops of condensate piping going from the 4th low-pressure feed water heater to the deaerator near the ceiling on the deaerator side on the 2nd floor of the turbine building and was near the downstream of the orifice[6] for measuring the condensate flow of the A-loop.

NISA conducted an on-the-spot inspection and as a result confirmed a fracture opening in the ruptured portion, which extended a maximum of 515 mm in the axial direction and 930 mm in the circumferential direction of the pipe. KEPCO measured the pipe in the presence of the police, and the result was 0.4 mm at the thinnest portion of the pipe. As shown in Appendix 3, thinning was striking in the upper part of the pipe.

The A-loop pipe was cut out including the ruptured portion in question and examined at the Japan Atomic Energy Research Institute (abbreviated to JAERI hereinafter). As a result, a portion was found out downstream of the vent hole of the orifice[7] where pipe wall thinning reached to the flange for the orifice support.

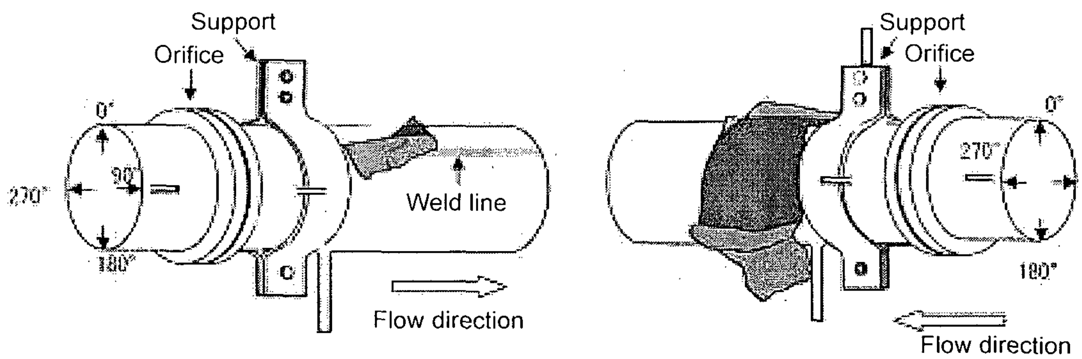

Figure 2 Ruptured condition of pipe

The inner surface of the pipe was observed using a digital microscope and it exhibited a fish scale-like pattern, which is characteristic of so-called erosion/corrosion[8], downstream of the orifice and over the entire surface except at the bottom (180°) of the pipe. At the bottom (180°) of the pipe, a portion of almost nominal wall thickness existed where a thick surface

6 Orifice: A throttling mechanism to narrow down the cross section of a pipeline through which fluid is flowing. It is installed to measure the flow rate of the fluid flowing in the pipe.

7 Vent hole of orifice: A hole provided at the top of the orifice to vent air (the diameter is 4 mm for the orifice in question).

8 Erosion/corrosion: The thinning phenomenon caused by the mutual action of erosion due to mechanical actions and corrosion due to chemical actions.

film (0.4 mm) existed and a fish scale-like pattern was not seen on the inner surface of the pipe.

The insulation material attached to the pipe was scattered around.

4.2. Investigation of similar portion

The ruptured portion this time is in the A-loop line, one of the two systems (A-loop and B-loop) going from the 4th feed water heater to the deaerator. KEPCO investigated the pipe wall thickness of the same portion of the B-loop (called a similar portion hereinafter). The B-loop piping was cut out including the similar portion and pipe wall thickness measurement and internal surface observation were performed at JAERI.

As a result, a thinning tendency was observed almost over the entire surface downstream of the orifice as shown in Appendix 3. Pipe wall thinning was observed downstream of the vent hole in the orifice. Upstream of the orifice, however, no significant thinning tendency was observed. At the thinnest portion of the wall, the thickness was 1.8 mm.

The inner surface of the pipe was observed using a digital microscope, and the result was that it exhibited a fish scale-like pattern almost over the entire surface, which is characteristic of so-called erosion/corrosion.

4.3. Major specifications of piping

Major specifications of the piping in question are as follows:

Table 2 Major specifications of the piping in question

Material	Carbon steel (SB42)
Outer diameter (mm)	558.8
Thickness (mm)	10
Maximum service temperature (°C)	195
Maximum service pressure (kg/cm^{2}G)	13

(Source: Application Document for Approval of Construction Plan, Mihama Power Station, Unit 3)

According to KEPCO, the temperature of the ruptured portion in the state of actual service is about 140°C, the pressure is about 0.93 MPa, and the flow rate is about 1,700 m^3/h.

The specifications of this piping were decided considering the service environment. The mill sheet[9] was examined concerning the tensile strength, material ingredients, etc. However, no problem was identified by NISA.

4.4. Investigation of installed condition of piping and the like

The roundness deviation of the A-loop pipe in question and B-loop pipe at the similar potion was examined. The results were that the tolerance of outer diameter exceeded the tolerance of JIS (±0.8%) in parts downstream of the ruptured portion of the A-loop pipe, however, the roundness deviation in other portions was within the tolerance.

The installed condition of the orifice and the like at the ruptured portion was examined, and the result was that the misalignment of the orifice hole center was 0.61 mm in the vertical direction and 0.71 mm in the horizontal direction with respect to the inner diameter center of the pipe.

4.5. Quality control of secondary system cooling water

According to KEPCO, Mihama Power Station, Unit 3 injects feed water treatment chemicals basically from downstream of the condensate treatment equipment from the standpoint of corrosion inhibition of the whole secondary piping. All volatile treatment (AVT) using ammonia (pH adjuster) and hydrazine (deoxidizer), as the feed water treatment chemicals, has been performed since the commissioning. As an anti-corrosion measure for the steam generator tube, boron injection[10] had been performed from the 10th to the 15th operation periods. From the 17th operation period, ethanolamine has been added as a pH adjuster.

KEPCO investigated the water quality control history since the commissioning and as a result it says that both the feed and condensate water quality data have been maintained within the water quality control values. At Mihama Power Station, Unit 3, condenser tube leaks occurred twice in the past and seawater flowed into the secondary system cooling water. However, KEPCO says that there was no variation in pH, dissolved oxygen, etc. in either case.

The effect of boric acid on pipe wall thinning was investigated; however, no significant difference was recognized in the effect on thinning rate between with and without boron injection.

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9 Mill sheet: In case of receiving an order of steel with specified standard, this document is attached to the product to certify that the manufactured results of the steel satisfy the requirements like specified standard, specifications and so on.

10 Boron injection: A substance injected for neutralization to prevent alkali from concentrating in parts of the steam generator tube/support plate and thereby prevent intergranular corrosion in 600-alloy tube.

Table 3 Secondary system water quality control values for Mihama Power Station, Unit 3

Item		Control value
pH (at 25°C) (Feed water)	AVT	8.8 to 9.3 (9.2)
	AVT + boron injection	8.5 to 9.3
	AVT + ETA injection	8.8 to 9.7
Ethanol amine (at injection of ETA in feed water)		≤ 3 ppm
Hydrazine (Feed water)	1	Dissolved oxygen in condensate + 5 ppb
	2 - 7	≥ 2 ppb
	8 - 15	≥ 5 ppb
	16 - 18	≥ 200 ppb
	19 - 21	≥ 100 ppb + (dissolved oxygen in condensate) × 40
Dissolved oxygen (in feed water)		≤ 5 ppb
Dissolved oxygen (in condensate)	1 - 15	≤ 50 ppb
	16 - 21	≤ 10 ppb
Total iron (in feed water)	1 - 15	≤ 20 ppb
	16 - 18	≤ 10 ppb
	19 - 21	≤ 20 ppb

(Note) Numbers in the "item" column denote operation periods.

4.6. Estimation of rupture mechanism

From the investigations performed so far, the following has been revealed.

- The ruptured pipe is of carbon steel and the ruptured portion was downstream of the orifice where channeling is apt to occur.
- The pH, dissolved oxygen and other water quality data of the feed water and condensate systems have been maintained within the control values.
- The condensate temperature was about 140°C in the neighborhood of the ruptured portion. So-called erosion/corrosion is apt to occur at this temperature.
- The inner surface of the pipe suffered substantial thinning and exhibited a fish scale-like pattern almost over the entire surface, which is characteristic of so-called erosion/corrosion.
- At the similar portion of the B-loop, the inner surface of the pipe similarly suffered substantial thinning and exhibited a fish scale-like pattern.

From these, the cause for the pipe rupture in question is estimated to be so-called erosion/corrosion, which has gradually reduced the pipe wall thickness with the lapse of operation time. At last, the pipe strength became insufficient and the pipe ruptured under the load during operation.

4.7. Investigation of the ruptured portion

Concerning the case in question, NISA is performing metallurgical and analytical investigations, including the following, of the ruptured portion by commissioning them to JAERI and an incorporated administrative agency, the Japan Nuclear Energy Safety Organization (abbreviated to JNES hereinafter). The investigation plans for the future and the analysis results about the rupture mechanism obtained so far are as follows:

1) Pipe flow analysis in neighborhood of the orifice (JNES, JAERI)

   Since flow analysis is apt to exhibit the feature of the method employed to make the model and the code used for the analysis, a flow confirmation analysis will be performed using multiple codes to evaluate the erosion tendency due to turbulence. The investigation will proceed also on the thinning of the vent hole.

   According to a one-dimensional two-phase flow analysis using the design values (at JNES), the result obtained is that the possibility of flash boiling (cavitation) is low downstream of the orifice.

   JNES and JAERI did an analysis to predict the thinning tendency due to turbulence and obtained the result that the largest thinning will occur downstream of the orifice (at a distance of about 1.2 times the pipe diameter).

2) Thinning behavior analysis of the ruptured portion (JAERI)

   Using the thinned wall pipe reliability analysis code (PASCAL-EC) owned by JAERI, so-called erosion/corrosion will be assessed in a single-phase water flow.

   So far, thinning and rupture analyses have been performed using PASCAL-EC and the following results have been obtained.

   - The thinning analysis results almost coincided with the maximum amount of thinning actually measured on the A- and B-loop pipes. From the sensitivity analysis of thinning rate, the result that pH and dissolved oxygen have large influences was obtained.

- In the case where an A-loop pipe is loaded with the operating pressure and design bending moment, the wall thickness at rupture is 0.6-0.7 mm. Bending moment does not have a large influence on the wall thickness at rupture.

3) Pipe rupture structural behavior analysis (JNES)

This analysis has the purpose of understanding the behavior outline of the rupture phenomenon, and dynamic analysis will be performed on the behavior of a two-phase flow and structural behavior after the pipe rupture to understand the spouting behavior of the two-phase flow.

JNES did an analysis using a two-dimensional model and obtained the result that steam would spout upward at high speed (100 m/s or more) from an enlarged opening of several millimeters at the top portion of the pipe.

4) Metallurgical ingredient analysis of the ruptured portion (JAERI, JNES)

An appearance inspection, wall thickness measurement, fracture surface observation, hardness test, pipe material ingredient analysis, etc. will be performed to identify the causes of the rupture.

5. Pipe wall thinning management

The actual condition, tasks and future actions to take for pipe wall thinning management practiced at nuclear power plants will be described separately for PWR and BWR and the implemented condition and future actions of wall thickness inspection related to pipe thinning at thermal power plants will be given.

5.1. Pipe wall thinning of PWR

(1) Control techniques

For PWR, thinning due to erosion/corrosion occurred in some plants in the latter half of the 1970s and investigations were carried out on pipe thinning. After that, a secondary piping rupture accident occurred at the Surry Power Station in the US in December 1986. With this accident as a turning point, the licensees, who had then conducted an investigation of the thinning condition of secondary system piping at various PWR plants, statistically evaluated the data obtained from the investigation results and examined the control method for such thinning.

As a result, the "Guidelines for Secondary Piping Wall Thickness Control at Nuclear Facilities (PWR)" (abbreviated to the PWR Management Guidelines hereinafter) were laid down in May 1990 and these guidelines have been used as a common control technique for secondary piping wall thickness. In the process of establishing the guidelines, opinions were heard from the Nuclear Power Generation Technical Advisors established in the then Ministry of International Trade and Industry.

The PWR operators reported to the then Public Utilities Department of the Agency for Natural Resources and Energy in July 1990 to the effect that they had established the PWR Management Guidelines and appended a note to the effect that they would conduct voluntary inspections after that according to the Guidelines.

(2) Validity of PWR Management Guidelines

The PWR Management Guidelines were laid down in 1990. Now, more than 10 years have passed since then and a lot of data has been obtained. However, no review has been done based on the latest data. Therefore, the validity of the PWR Management Guidelines was examined this time based on the thinning data[11)] measured at various PWR plants (Appendix 4).

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[11] Thinning data: The values of thinning rate and other data at the minimum thickness points (21 points for PWR, 27 points for BWR and 38 points at Mihama Power Station, Unit 3), obtained from the electric utilities

1) Measured points and thinning tendency of major pipings

The PWR Management Guidelines prescribe the initial thinning rate by flow velocity and temperature, differently for two-phase and single-phase water flow, for the systems to be inspected. This time, actual values of thinning rate based on the data obtained by the inspections so far, described later, at nuclear power plants throughout the country were analyzed and it was found that these values are less than the initially set value of thinning rate prescribed in the PWR Management Guidelines except for only a few of them. Therefore, the initially set value of thinning rate prescribed in the Guidelines can be assessed to be valid in principle.

2) Selection of sampling points

For the portions showing no tendency of thinning, the PWR Management Guidelines stipulate inspection of those portions at a rate of about 25% every 10 years. As a result of the investigation this time, the thinning tendency of the sampling points belonging to "other systems" is less than the main checked systems as an overall tendency. That is, the data obtained indicates that control by sampling will cause no problem. However, care must be taken because a thinning tendency of the same degree as the main checked systems was observed at some portions.

3) Measuring areas and measuring points of thinning

The PWR Management Guidelines stipulate the measuring area of thinning to be, for an orifice for example, from its installed place to 2 × D downstream (D is the pipe bore diameter). According to an investigation result, the place of severe thinning is within 2 × D. No measuring points are stipulated in the PWR Management Guidelines. In actual practice, however, 8 or 4 measuring points are set up per one cross section and if the wall thickness at a measuring point falls short of a certain criterion of wall thickness, detailed measurement is performed around the measuring point with a finer measuring pitch. As a result, the measuring area and measuring points stipulated in the PWR Management Guidelines are justified as being capable of appropriately keeping track of thinning in combination with the detailed measurement.

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according to "Collection of Reports on the Inspection Concerning the Pipe Thinning Phenomenon" (August 11, 2004) based on Paragraph 1, Article 106 of the Electric Utility Law.

(3) Future tasks regarding the PWR Management Guidelines

The major pipes in the PWR secondary piping were checked for thinning. On some pipes, the thinning rate exceeded the initially set thinning rate stipulated in the PWR Management Guidelines. Although it is necessary to conduct a verification by further accumulating data in the future, the actual value of thinning rate is within the value assumed in these Guidelines for most of the pipes. The initially set thinning rate is for use in determining the period to the first wall thickness measurement. Once the thickness measurement is done, a new thinning rate is set based on that measured value. This determines the remaining life and the period to the next measurement. Therefore, the first wall thickness measurement must be performed well in advance and appropriate thinning rate setting and appropriate remaining life evaluation must be done for the portions to be measured. It is thought that no safety problem will occur as long as repair and replacement are carried out based on these results.

For the "other systems" of a PWR under control by sampling, the thinning rate is fairly lower than the main checked systems as a whole. As seen in the case of Mihama Power Station, Unit 3 shown in Appendix 4 and the case of Ohi Power Station, Unit 1 shown in Appendix 5, some portions exhibited the same thinning rate as the main checked systems. For such portions including the similar portions, therefore, it is thought necessary to examine from the actual measurements so far to see whether or not there is a safety problem and to do a wall thickness measurement advancing the inspection date or otherwise if necessary. In addition, it should be examined after this whether or not there is the necessity for doing control of the portion in question as a main checked system.

By practicing measurement at representative measuring points and detailed measurement based on the data from that measurement, it is thought possible to keep track of the shape and size of various kinds of thinning. However, this technique is not specified in the PWR Management Guidelines. In the revising work of the Guidelines after this, current (currently employed) measuring methods should be reflected in the Guidelines by adding this detailed measuring technique to the Guidelines or otherwise.

5.2. Pipe wall thinning of BWR

(1) Control techniques in use

For BWR, thinning due to erosion/corrosion was also recognized at some plants in the initial stage of their operation. Oxygen injection to the feed water and condensate systems is performed as an environmental improvement measure of water quality, and replacement with erosion/corrosion-resistant materials is taking place. For thinning control, the secondary piping rupture accident at the Surry Nuclear Power Station described above acted as a trigger for beginning measurement of thinning data at various plants and each public utility has set down a control technique on its own right based on such measurements.

(2) Analysis of in-house control guidelines of BWR operators

Each BWR operator has set down control guidelines on its own right and in content there is much common matter. Compared to the PWR Management Guidelines, the BWR guidelines are wider as to the scope of entities to be inspected. As to the inspection frequency (for the portions to be inspected, the ratio of the number of portions actually inspected to the number of portions evaluated or otherwise checked at a representative inspection point instead), the PWR Guidelines are higher (Appendix 6).

The change of the amount of thinning measured at various BWR plants and the actual values of thinning rate based on the measurements were surveyed. As a result, the tendency of thinning is different between PWR and BWR, or the thinning rate of BWR is less than that of PWR. This is presumably related to the difference in water quality between PWR and BWR.

For the BWR as well, efforts should be made to utilize the thinning data at the utilities after this and make common control guidelines in the possible portions.

5.3. Pipe wall thinning of thermal power plants

On August 11, NISA requested a report from the electric utilities having thermal power generation facilities based on Paragraphs 3 and 4, Article 106 of the Electric Utilities Industry Law. The content was the state of execution of nondestructive inspection of water and steam pipe wall thickness at the portions where thinning can occur and an inspection execution plan for the portions not subjected to inspection yet.

According to the state of execution of wall thickness inspection reported to August 20, 1,467 units at 802 power plants are subject to reporting and, of these, nondestructive wall thickness inspection is carried out at 704 units and is not carried out at 763 units.

Table 4 State of execution of nondestructive wall thickness inspection at thermal power generation facilities

Number of power plants subject to reporting	Number of units subject to reporting	Nondestructive inspection	
		Units inspected	Units not inspected
802	1,467	704	763

By September 21, wall thickness inspection plans were reported from electric utilities, etc. (general electric enterprises and joint thermal power structure and captive electric structure establishers, etc.) for their thermal power plants aged over 20 years after commissioning. According to the reports, there are about 249,000 facilities to be inspected and, of these, inspection has not been performed at about 213,000 facilities yet. For these facilities, the operators claim that they will carry out the inspections, etc. one by one.

For the thermal power plants aged less than 20 years after commissioning, inspection execution plans will be reported in October.

NISA requires operators to surely perform safety assurance measures to prevent damage to the workers by a pipe rupture, etc. during operation of the facility in question until safety can be confirmed by conducting a pipe wall thickness inspection or otherwise.

5.4. Actions in the future

Thus far, a large amount of data on secondary piping thinning has been accumulated at each PWR plant by the inspections according to the PWR Management Guidelines. From the result of assessment using part of such data, the Guidelines are thought appropriate as a control technique in principle. To make assurance doubly sure on the control of pipe wall thinning, however, the persons concerned including the PWR operators should formulate new private guidelines to be discussed through a transparent process and disclosed by a neutral organization, referring to the actual measured values and overseas findings. At that occasion, it is thought necessary to consider the following matters.

1) Thinning rate based on actual measurements

2) Measuring area based on actual measurements

3) Division between portions subjected to 100% inspection and portions subjected to sampling inspection and the appropriate sampling number

4) Inspection frequency according to the remaining life evaluation result

5) Necessary minimum wall thickness and integrity assessment method based on the local thinning phenomenon and other new findings (minimum wall thickness value, maximum thinning rate, change rate of thinning rate, and the like)

6) Examination of measuring techniques (addition of the detailed measurement method to the guidelines, etc.)

For BWR as well, it is desirable that the licensees conduct the inspections using a unified control technique. Therefore, the persons concerned including the BWR operators should act and examine in harmony with the efforts made in PWR.

For thermal power plants, there are no common technical guidelines for pipe wall thickness at present. It is desirable to accumulate actual data of pipe thinning measured by the licensees after this and lay down appropriate technical guidelines for pipe wall thickness control.

In the control technique given in "5.1 Pipe wall thinning of PWR" and "5.2 Pipe wall thinning of BWR", measurement is done at 8 or 4 measuring points per cross section and, if a measured value falls short of a certain criterion of wall thickness, a detailed measurement is done. Judgment is made by comparing the measured minimum wall thickness with the necessary wall thickness calculated from technical standards. In this control technique, judgment is done assuming that the entire circumference of the pipe has thinned to the measured minimum wall thickness.

This control technique for pipe thinning is sufficiently conservative as long as the measurement detects the region of minimum wall thickness. In the actual pipe thinning phenomenon, however, such local thinning that the progress of thinning is locally different is seen in many cases.

Therefore, in discussing new private guidelines at a neutral organization as described above, it is desirable to extract the regions where such local thinning is liable to occur and additionally discuss a measuring method for that and an integrity assessment method, etc. in the case where this condition is confirmed in the detailed measurement.

6. Managerial processes of the ruptured portion

Thus far, NISA has conducted a survey on the contract relations among the 3 parties of KEPCO, Mitsubishi Heavy Industries (abbreviated to MHI hereinafter) and Nihon Arm Co., Ltd. (abbreviated to Nihon Arm hereinafter) and the thinning control system at them. The facts revealed are as follows.

6.1. Details of registration omission for the ruptured portion

(1) Before preparation of the PWR Management Guidelines (to 1990)

KEPCO has conducted thinning investigation by sampling of the secondary piping since the latter half of the 1970s. In February 1983, a steam leakage trouble occurred due to thinning of the balance pipe's branch pipe of the moisture separator drain tank at Takahama Power Station, Unit 2. To prevent this from recurring, KEPCO carried out, by commissioning to MHI, a systematic thinning examination and evaluation of the data obtained from this examination from 1985 to 1989.

In 1984, KEPCO laid down the "Procedure of Secondary Piping Aging Deterioration Survey Work and Countermeasures (July 1984)" and formulated the inspection details as an in-house standard according to the importance of the regions concerned.

After that, a feed water pump inlet pipe rupture accident occurred at the Surry Nuclear Power Station in the US in December 1986. This accident triggered KEPCO to commission the preparation of secondary piping inspection guidelines based on the data obtained by the thinning examination described above to MHI and to lay down the "PWR Management Guidelines" based on the results of that commissioning in May 1990.

(2) Preparation of the initial inspection list by MHI (1990)

In 1990, MHI prepared an inspection list and the like for Mihama Power Station, Unit 3 based on the PWR Management Guidelines. At that time, the registration of the ruptured portion in question had already been missing.

Of the total of 39 portions downstream of the orifices of Mihama Power Plant, Unit 3, the registration of 3 portions were missing, i.e., two portions downstream of the condensate flow meter and one portion downstream of the steam converter heating steam flow meter (the two portions downstream of the condensate flow meter are the ruptured portion in question (A-loop) and the portion downstream of the condensate flow meter of the B-loop. For the one portion downstream of the steam converter heating steam flow meter, KEPCO made an announcement on August 18 to the effect that the registration had already been missing). MHI explains that the process of the registration of the ruptured portion in question becoming overlooked is unknown.

The preparation of the inspection list and the like specifying the ruptured portion in question was performed by the "Secondary Piping Aging Deterioration Survey Work" commissioned by KEPCO to MHI. However, the commission furnisher, KEPCO, did not check the inspection list in question as a final outcome of the work from the standpoint of looking for registration omission.

(3) Registration of the overlooked portion of Tomari Power Station, Unit 1 of Hokkaido Electric Power Company corresponding to the ruptured portion in question in the checklist (1995)

MHI did maintenance and inspection of Tomari Power Station, Unit 1 of Hokkaido Power Electric Company and found the registration omission for the portion corresponding to the ruptured portion in question of Mihama Power Station, Unit 3. MHI itself registered this portion in the checklist in 1995 and this fact was disclosed after the accident when Hokkaido Electric Power Company made a general checkup according to the instruction of NISA.

MHI explains that the process of registration of this portion becoming overlooked is unknown and it had not been recognized until Hokkaido Power Electric Company made the announcement.

(4) Transfer of inspection service from MHI to Nihon Arm (1996)

KEPCO changed the contractor of inspection service from MHI to Nihon Arm in 1996. At that occasion, according to a commission from KEPCO, MHI marshaled the latest inspection drawings and actual data obtained from the past maintenance and inspections of the nuclear power plants of KEPCO, then owned in-house, and submitted them to KEPCO. The marshaled actual data was handed over to Nihon Arm. At this point in time, however, the registration omission of the ruptured portion in question of Mihama Power Station, Unit 3 was not corrected.

The marshalling of actual data and the like was carried out according to the "Survey on Nuclear Power Secondary Piping Thinning Evaluation" commissioned by KEPCO to MHI. The commission issuer, or KEPCO, did not make a check as to whether the actual data submitted from MHI conformed to the PWR Management Guidelines.

In January 1997, Nihon Arm made a commission contract for "Instrumentation Guidance Work for Secondary Piping Aging Deterioration Survey Work" with MHI. According to the contract, MHI made preparation for an inspection plan and undertook the task of teaching of instrumentation work at 4 plants (Ohi Power Station, Unit 1, Mihama Power Station, Unit 3, Takahama Power Station, Unit 4, and Ohi Power Station, Unit 4). In 1996, these were done by Nihon Arm.

(5) Commissioning of preparation of inspection drawings, etc. from KEPCO to Nihon Arm (1997)

KEPCO commissioned the amendment of inspection drawings based on an on-site survey and CAD formatting of inspection drawings (inspection drawings made in an electronic format) to Nihon Arm in 1997. At this point in time, the registration omission of the ruptured portion in question of Mihama Power Station, Unit 3 was not corrected yet.

The CAD formatting work described above was performed according to the "Preparation of Secondary Piping Inspection Data and Drawings" commissioned by KEPCO to Nihon Arm. However, the commission issuer, or KEPCO, did not make a check as to whether or not the data was prepared according to the PWR Management Guidelines when the work of CAD formatting, etc. was carried out.

(6) Registration of the overlooked portion in Tsuruga Power Station, Unit 2 of Japan Atomic Power Company corresponding to the ruptured portion in question in the checklist (2000)

After the accident, a general inspection was conducted according to instructions of NISA. As a result, Japan Atomic Power Company made an announcement to the effect that there was also registration omission for the portion in Tsuruga Power Station, Unit 2 corresponding to the ruptured portion in Mihama Power Station, Unit 3, but this portion was in fact registered as an inspection portion in 2000. Regarding this, MHI explains that, for Tsuruga Power Station, Unit 2 of Japan Atomic Power Company, the information on the condensate piping's thinning downstream of its orifice in Tomari Power Station, Unit 1 of Hokkaido Electric Power Company (in 1998) was spread horizontally and as a result the registration omission of the corresponding portion was discovered in 2000, so they made an additional registration of the portion in question as an inspection portion.

The registration omission in question seems to have existed since 1990 when application of the PWR Management Guidelines began. However, MHI explains that the process of registration of this portion becoming overlooked is unknown. MHI spread the information on thinning horizontally, but did not provide the information on the registration omission of the portion in question.

(7) Holding of regular liaison meetings of Nihon Arm and Nuclear Power Service Engineering Company (since 1998)

Nihon Arm and Nuclear Power Service Engineering Company (NUSEC hereafter), a subsidiary of MHI, have regularly held liaison (working) meetings as part of the contract between them since the commission recipient of inspection service was changed from MHI to Nihon Arm. In these meetings, NUSEC provided information to Nihon Arm about the progress of pipe wall thinning downstream of the orifice at other plants.

MHI explains that there was an agreement to the effect that horizontal spread of the pipe wall thinning information to the plants of KEPCO was a duty of Nihon Arm, who did maintenance and inspection of those plants. On the other hand, Nihon Arm explains that this thinning information is general technical information and the registration omission of the portion in question of Mihama Power Station, Unit 3 had not been pointed out.

(8) Discovery of registration omission of inspection portions by Nihon Arm (April 2003)

Nihon Arm did maintenance of inspection portion data from the year 2001 to 2002. In April 2003, a worker at work on this maintenance discovered the registration omission of the ruptured portion in question of Mihama Power Station, Unit 3 and registered it in the control system of that company. The ruptured portion in question registered in the control system was entered in the 20th periodic inspection work report (July 2003) and was proposed as an inspection portion for the 21st periodic inspection work plan by Nihon Arm to KEPCO (November 2003).

KEPCO did not make a check for the newly added portion in question when the periodic inspection work report was submitted or when the periodic inspection work plan was submitted. KEPCO and Nihon Arm made a service contract for inspection (Secondary Piping Aging Deterioration Survey Work) at each periodic inspection. In this contract, duty to report or otherwise was not stipulated in case of discovery of registration omission of an inspection portion.

KEPCO explains that they became aware of the registration of the portion in question for the first time after the occurrence of this accident.

6.2. Contractual relationship

From the viewpoint of quality assurance, it is important how the procurement requirements for quality assurance are positioned in the contractual relationship among the parties concerned.

The details of the contractual relationship regarding maintenance and inspection between KEPCO and MHI or Nihon Arm are as follows.

Considering the fact that the PWR Management Guidelines were laid down in 1990 through discussions between MHI and KEPCO and the fact that a copy of the PWR Management Guidelines was attached to the work reports submitted by MHI or Nihon Arm to KEPCO, it is estimated that the maintenance and inspection service proceeded on the premise of existence of the PWR Management Guidelines. However, it is not described explicitly in any contract that the inspection portions should be reviewed according to the PWR Management Guidelines.

- According to the contractual relationship concerning maintenance and inspection between KEPCO and MHI or Nihon Arm, the contractor proposes a survey work plan, etc. to KEPCO for each periodic inspection and a final draft is attained through discussions on the details. For each periodic inspection, a service contract is made for such a final draft as "Secondary Piping Aging Deterioration Survey Work."

- Checklists, etc. were prepared in 1990 based on the PWR Management Guidelines. At that occasion as well, the contractual relationship between KEPCO and MHI was only for "Secondary Piping Aging Deterioration Survey Work."

- When KEPCO changed the contractor of maintenance and inspection service from MHI to Nihon Arm in 1996, the following contracts were entered into among these companies:

  a) "Survey for Evaluation of Nuclear Secondary Piping Thinning" (September 1996)
  Commissioned by KEPCO to MHI. This stipulates preparing inspection drawings, marshaling actual data about maintenance and inspection in the past and submitting them to KEPCO.

  b) "Instrumentation Guidance Work for Secondary Piping Aging Deterioration Survey Work" (January 1997)
  Commissioned by Nihon Arm to MHI. This stipulates that MHI should give Nihon Arm guidance on preparation of an inspection plan and instrumentation work for doing the piping aging deterioration survey work, which Nihon Arm did in 1996 at the 4 plants (Ohi Power Station, Unit 1, Mihama Power Station, Unit 3, Takahama Power Station, Unit 4, and Ohi Power Station, Unit 4).

  c) "Secondary Piping Aging Deterioration Survey Assistance Work" (contracted for each periodic inspection every year)
  Commissioned by Nihon Arm to NUSEC. This stipulates that NUSEC should do,

for Nihon Arm, collecting of information on piping-related troubles, reporting them and reflecting them in the survey plan and making proposals, etc.

6.3. Investigations in the future

The investigation so far has revealed that the direct cause for this accident consists in "the portion to be controlled was missing from the initial control list and this could not be corrected until the accident" due to "a mistake in thinning control of the secondary piping involving the 3 parties of KEPCO, MHI and Nihon Arm." That is, quality assurance and maintenance management were not functioning well at KEPCO. Because of this, 1) the portion in question was missing from the portions to be inspected, 2) this has been left untouched for a long time without being corrected, and 3) when the missing inspection was discovered the communication to the parties concerned was insufficient and that was not appropriately reflected in the subsequent inspection plans; these can be cited as the causes.

It is important to cope with these problems immediately. On the other hand, it is also important to take an uninterrupted approach to investigate how these mistakes occurred in quality assurance and maintenance management, not only from the technical aspect but also from the managerial aspect. In concrete terms, it is suspected as the background of this accident that the organizational structure was not prepared or not functioning to reduce or overcome human or managerial mistakes and therefore the fundamentals of work management were made light of. It is necessary to investigate from this viewpoint why such a serious situation occurred.

It is necessary to admit that mistakes or so-called human errors inevitably occur in human actions. For example, a mistake in selecting potions to be inspected may cause an accident. How could such an accident be predicted and what was the recognition of the severity of the accident? Was there not a naive attitude in the persons in charge? It is required to investigate the actual condition based on objective facts about these. Deliberation about these will make an effective mechanism to prevent problems from occurring due to human errors. It is necessary to assess and examine anew how quality assurance was functioning at the licensee and maintenance contractors.

Thus, quality assurance was introduced in the safety regulations last year by the amendment of the inspection system for nuclear facilities. Investigation and discussion should proceed from the viewpoint of such quality assurance and mistake prevention measures should be considered in the managerial aspect. In concrete terms, it is required to proceed with the examination concerning the following matters after this.

1) Maintenance management, procurement management and other related processes at KEPCO (existence or absence of in-house procedures and standards, check whether or not these documents were used at the period relevant to 6.1)

2) In-house work processes at MHI and Nihon Arm (existence or absence of in-house procedures and standards, check whether or not these documents were used at the period relevant to 6.1)

3) Actual conditions of information communication in case of transfer of pipe inspection service from MHI to Nihon Arm and after that

7. General investigation on maintenance management for pipe wall thinning

7.1. Confirmation of maintenance management based on inspection management guidelines at KEPCO

(1) Process

For the accident this time, NISA instructed KEPCO on August 11 based on Paragraph 1, Article 106 of the Electric Utilities Industry Law to the effect that they should confirm whether there are potions where pipe wall thickness control has not been applied, and received reports on the confirmation result on August 18. NISA made report collection for additional confirmation of wall thickness measurement and received a report on August 23.

Besides the report collection stated above, NISA is doing sampling confirmation of inspection records by on-the-spot nuclear security inspectors. In parallel, it is proceeding with an examination about the adequacy of maintenance management for pipe thinning by KEPCO. As of now, the assessment by NISA is as follows.

(2) Outline of maintenance management for pipe thinning

In the latter half of the 1970's and the first half of the 1980's, KEPCO did wall thickness measurement for the thinning phenomenon of steam pipes and feed water pipes around the turbine. In February of 1983, a steam leakage trouble occurred due to thinning of the moisture separator drain tank balance pipe's branch pipe of Takahama Power Station, Unit 2. This accident triggered KEPCO to conduct a systematic thinning investigation from 1985 to 1987 for recurrence prevention by commissioning this to MHI.

From 1989 to September 2003, the maintenance management activities at KEPCO have been operated based on an in-house standard, "Guidelines for Repair Service Procedures." In response to the amendment of the inspection system at nuclear facilities in October 2003, KEPCO prepared and is using in-house Maintenance Guidelines at each power station.

(3) Assessment of uninspected portions, etc.

KEPCO reported in the report of August 18 that it had not been doing thinning control at 4 portions of a total of 4 steam converter pipelines, including the one of Mihama Power Station, Unit 3. At 3 units including Takahama Power Station, Unit 3, a total of 11 portions were missing from the objects of inspection. However, KEPCO reported that the integrity of these portions could be confirmed from the measured results at plants of the same specifications.

Thus, NISA inspected the validity of this report and checked the past records, separately from the sample measurement carried out by KEPCO itself to confirm the integrity.

1) Confirmation of the number of uninspected (uncontrolled) portions

NISA understood by checking of the records by the on-site Nuclear Security Inspector that two portions related to the portion where the accident occurred at Mihama Power Station, Unit 3 had been missing from the checklist since the beginning of application of the PWR Management Guidelines laid down in 1990, until recently. It also confirmed that thinning control had not been exercised until now at 4 portions of a total of 4 steam converter heating steam pipelines including that of this unit.

KEPCO claims that the 11 portions are controlled by estimation from the measured results at plants of the same specifications. However, the Agency confirmed that these portions had not been included in the objects of inspection and in fact had not been inspected before the instruction of report collection. In addition, thinning control using such an estimation technique is not provided for in the PWR Management Guidelines and is not made as a rule in the in-house standards, so its rationality cannot be admitted. Therefore, NISA judged that appropriate control had not been exercised on these 11 portions.

NISA did a sampling confirmation of skeletal drawings and the like mainly of major systems, sampled from the past inspection records obtained by report collection from KEPCO, and confirmed that there was no uninspected portion within this scope.

2) Confirmation of integrity of the portions at which thinning control had not been exercised

KEPCO says that they will shut down the plants now in operation as well from August 13, 2004 in a planned way and will confirm the integrity of pipings at all the plants. In concrete terms, they say that they will inspect a total of 293 portions, including the portions at which thinning control had not been exercised, as follows:

- Portions at which thinning control had not been exercised until now: 15 portions (Note 1)

- Portions downstream of the orifice of feed water and condensate systems:
144 portions (Note 2)

Portions in which the thinning phenomenon of the main feed water piping of Ohi Power Station, Unit 1 (Note 3) is reflected: 134 portions

Note 1: Excludes the ruptured portion of Mihama Power Station, Unit 3 and a similar portion.
Note 2: Includes the 17 portions that is overlapping of the portions at which thinning control had not been exercised with the portions in which the thinning phenomenon of the main feed water piping of Ohi Power Station, Unit 1 is reflected.
Note 3: For the thinning phenomenon of Ohi Power Station, Unit 1, refer to Appendix 5.

NISA confirmed, in the presence of the on-site nuclear security inspectors, that there was no problem at any of the 238 portions inspected by September 16.

3) Confirmation of the integrity of the portions at which NISA instructed inspections

NISA additionally instructed inspections at 21 portions (one portion of Mihama Power Station, Unit 1, 6 portions of Mihama Power Station, Unit 2, 2 portions of Takahama Power Station, Unit 2, 2 portions of Ohi Power Station, Unit 1, 6 portions of Ohi Power Station, Unit 2, one portion of Ohi Power Station, Unit 3, and 3 portions of Ohi Power Station, Unit 4) to examine the past inspection records other than Mihama Power Station, Unit 3. Of these, wall thickness measurement was done at 19 portions excluding Ohi Power Station, Unit 1. As a result, it was confirmed that there was no problem at any of the 16 portions except for the following 3 portions. The problems confirmed were that one portion was discovered in Mihama Power Station, Unit 2 where the remaining life was less than one year and one portion was discovered in each of Mihama Power Station, Units 1 and 2 where the wall thickness fell short of the necessary minimum thickness given in the ministerial ordinance stipulating technical standards for thermal power generation equipment.

The reason why such cases were found is because KEPCO uniquely interpreted the proviso in the "On the Interpretation of Technical Standards for Thermal Power Generation Equipment" and applied it to the pipes with short remaining life (evaluated remaining life less than one year). Such operation cannot be said to be appropriate. Thus, KEPCO says that they will replace pipes at the 3 portions in question.

For Ohi Power Station, Unit 1 as well, KEPCO plans to shut down the plant after this and continue to conduct the remaining inspection work. NISA will monitor the inspections carried out by KEPCO as well as confirm the integrity.

The past inspection records were examined also for Mihama Power Station, Unit 3 and three portions were discovered where the remaining life was less than one year and one portion was discovered where the wall thickness fell short of the necessary minimum thickness laid down in the technical standard. Thus, NISA instructed KEPCO to make additional inspections at the portions in question.

Table 5 State of implementation and results of thinning inspection of secondary piping (as of September 16, 2004)

Plant name		Operation status	State of inspection by KEPCO					State of inspection according to the instruction from NISA			
			Upper figures: Actual results Lower figures: Number of inspection objects			Number of portions requiring actions	Current state	Upper figures: Actual results Lower figures: Number of inspection objects	Number of portions requiring actions	Current state	Reason for the instruction
			A	B	C						
Mihama Power Station	Unit 1	In shutdown		8 8		0	Completed	1 1	1 (Replacement)	Completed	For confirming the remaining life: 1 (replacement)
	Unit 2	In shutdown		8 8	2 2	0	Completed	6 6	2 (Replacement)	Completed	For confirming the remaining life: 4 (replacement: 2 of them) For confirming the appropriateness of the measuring point: 2
	Unit 3	In shutdown	0 1	0 13	0 12			0 4			For confirming the remaining life: 4
Takahama Power Station	Unit 1	In shutdown	1 1	21 21	1 1	0	Completed	0 0	0	Completed	
	Unit 2	In operation		21 21	3 3	0	Completed	2 2	0	Completed	For confirming the remaining life: 2
	Unit 3	In operation	(8) (8)	14⑦ 14⑦	15 15	0	Completed	0 0	0	Completed	
	Unit 4	Under periodic inspection	(1) (1)	14 14	11 11	0	Completed	0 0	0	Completed	
Ohi Power Station	Unit 1	Under periodic inspection (in adjusting operation)		0 10④	0 6	0		0 2			For confirming the remaining life: 1 For confirming the state of control: 1
	Unit 2	In shutdown		9 9④	24 24	0	Completed	6 6		Completed	For confirming the remaining life: 1 For confirming the state of control: 5
	Unit 3	Under periodic inspection	1 (2) 1 (2)	13② 13②	30 30	0	Completed	1 1	0	Completed	For confirming the state of control: 1
	Unit 4	In operation	1 1	13 13	30 30	0	Completed	3 3	0	Completed	For confirming the state of control: 3
Total			3 (11) 4 (11)	121⑬ 144⑰	116 134	0		19 25	3		

Remarks A: Portions at which thinning control has not been exercised so far. Figures in parentheses are the numbers of portions whose integrity has been confirmed by estimation from the measured results at plants of the same specifications, so they are extra numbers.

B: Portions downstream of the orifice of feed water and condensate systems. Encircled figures are the numbers of portions overlapping A or C, so they are included numbers.

C: Portions in which the thinning phenomenon of the main feed water piping of Ohi Power Station, Unit 1 is reflected.

7.2. Confirmation of maintenance management at plants (nuclear power stations) other than KEPCO

For the accident this time, NISA issued an instruction on August 11 according to Paragraph 1, Article 106 of the Electric Utilities Industry Law to the licensees installing nuclear power plants to the effect that they should confirm the presence or absence of portions on which pipe wall thickness control is not exercised and on August 18 received a report of confirmation results from all the licensees.

On receiving the report, NISA made a documentary survey on the state of inspection in pipe wall thickness control at licensees other than KEPCO, that is, assessed the appropriateness of inspection implementation such as survey method, implementing structure, wall thickness control policy and inspection plan. For that purpose, the on-site nuclear security inspector made documentary checks by sampling, on-the-spot visits and the like from August 19 to 25.

Assessment results of the state of inspection at the licensees are as follows:

(1) General assessment

Mistakes were found in accumulated numbers and they are presumably ascribable to a large amount of documentary checking in a limited period. Although control is exercised now, some objects of inspection were recognized to have been missing in the past. Inconsistency was found in the scope of objects of inspection. For other matters, however, there is no fact found in the scope of this survey that will cause problems. Thus, NISA assesses that the inspections by the licensees were implemented appropriately (for the examination results, refer to Appendix 6).

(2) Individual assessment

1) Survey method

In deciding the scope of inspection, each licensee confirmed and marshaled the portions of occurrence of channeling using piping system diagrams (isometric or skeletal drawings) and collated them against the inspection drawings, piping system diagrams, etc. Thus, it was confirmed that appropriate control was exercised.

The number of objects to be surveyed is numerous for the licensees. At implementing the survey, therefore, they established a survey structure with manufacturers added appropriately to conduct the survey work. It was confirmed that a quality assurance section or other third-party section was in charge of checking to confirm the appropriateness of the survey.

2) Control policy

For PWR plants, it was confirmed that control was exercised according to the PWR Management Guidelines. For BWR plants, it was confirmed that they were exercising thinning control according to the rank determined by the fluid environment and material of the piping. For the control policy and the like in question, it was confirmed that appropriate operations were performed by the maintenance officers and other persons concerned of the power plant.

3) Inspection plan

It was confirmed at each of the plant that an appropriate inspection plan was laid out, an organizational structure was established to carry out the inspection work and subcontract management was exercised appropriately, according to their control policy, etc.

8. Immediate measures

NISA will promote detailed investigations of the rupture mechanism and establishment of new Management Guidelines as specified in "4.7 Investigation of the ruptured portion," "5.4 Actions in the future" and "6.3 Investigations in the future" as well as make an investigation focusing on the quality management systems at KEPCO and its maintenance contractors in order to determine the root cause of this accident.

By summarizing the facts that have been revealed so far, some measures readily applicable to operations of nuclear power plants to prevent recurrence of the accident can be clarified as described below. It is important to put these measures into practice as quickly as possible.

8.1. Measures in terms of quality assurance and maintenance management

The background factor behind the occurrence of the "mistake in thinning control for the secondary piping involving KEPCO, MHI and Nihon Arm " which is considered as the direct cause of this accident, may be that the quality assurance and maintenance management systems had not worked properly at KEPCO.

With the revision of the inspection system in October 2003, the specific requirements for quality assurance and maintenance management were enshrined into law and the periodic licensees' inspection was newly introduced. According to this new inspection system, licensees are obliged to establish quality assurance and maintenance management systems. NISA has the mechanism of conducting fitness-for-safety inspections and periodic safety management review to check the state of achievement of quality assurance and maintenance management at licensees. In these situations, it is necessary to take the following measures from the viewpoint of quality assurance and maintenance management regarding thinning control.

(1) Preparation of checklist and unified management

The periodic licensees' inspections to be carried out by licensees are confirmed by the regulatory agency as the periodic safety management review. For this purpose, JNES evaluates the implementation system of periodic licensees' inspections to be carried out by licensees based on the Electric Utilities Industry Law, Article 55. In concrete terms, JNES evaluates [1] the organization for implementation, [2] inspection methods, [3] process control, [4] management of maintenance contractors, [5] management of inspection records and [6] education and training.

Specific judgment criteria used in the reviw are mainly JEAC 4111-2003 "Regulations on quality assurance for safety at nuclear power plants" established by the Atomic Power

Standards Commission, Japan Electric Association, and JEAC 4209-2003 "Regulations on maintenance management at nuclear power plants" established by the Atomic Power Standards Commission, Japan Electric Association.

The fitness-for-safety program of Mihama Power Station specify detailed requirements for implementation of periodic licensees' inspections based on MR-7000 in JEAC 4209. The rules also require preparation of maintenance plans in MR-4000 and inspection plans in MR-4300, so-called "checklists" for implementation of maintenance management.

On the other hand, KEPCO has not established the basic system to prepare systematic "checklists" and to manage in a unified manner for inspection frequencies, timing, methods and other details for the equipment subject to periodic licensees' inspections.

To correct these situations and prevent recurrence of an "omission from checklist" in the future, it is essential for licensees to prepare systematic and unified "checklists" and to ensure maintenance management of the lists. In other words, licensees are required to manage the inspection frequencies, timing, methods, maintenance results and other details for the equipment subject to periodic licensees' inspections under proper outsourcing management, assign checklist managers and establish data management rules among licensees and maintenance contractors. It is necessary to establish as quickly as possible a systematic checklist management system to achieve effective maintenance management by taking these measures.

These measures are vital prerequisites for prevention of occurrence of problems due to human error and proper implementation of periodic licensees' inspections. The licensees should take these actions steadily and strictly. When doing so, they have to be certain to achieve the verification of the current inspection points and the verification of influences of additional or changed inspection points on the entire system, for example, by changing the current method, in which some people extract the points to be managed from piping system diagrams and manage these points, with an improved method, in which administration tables link with the computerized piping system.

(2) Implementation of accurate outsourcing management (management of procurement of maintenance contractors)

Nuclear power plants require services rendered by maintenance contractors to carry out maintenance management activities including periodic licensees' inspections. Reflecting this fact, outsourcing management is a very important task to ensure proper implementation of maintenance management activities. The fitness-for-safety program at Mihama Power Station, for which KEPCO applied for an approval of change in

December 2003 and obtained the approval in May 2004, specify the requirements for procurement management to be carried out as a licensee in outsourcing security activities according to Section 7.4 of JEAC 4111.

By examining the way the pipe ruptured point in this accident was managed, loose outsourcing management (management of maintenance contractors) in preparation of "checklists" can be considered as one of the contributing factors that caused the accident. In other words, KEPCO entrusted MHI with the inspection task for wall thickness control, but KEPCO as the outsourcer failed to thoroughly confirm the adequacy of extracting the points to be managed according to the "PWR Management Guidelines."

After transfer of the inspection task for wall thickness control from MHI to Nihon Arm and when Nihon Arm found omissions of inspection, there was no appropriate communication with KEPCO.

At present, KEPCO has already introduced procurement management rules based on JEAC 4111 as described above. In the future, individual licensees, including KEPCO, must clarify their outsourcing management methods, division of responsibilities and other details in subordinate regulations of the security regulations specified at each power plant according to the requirements of JEAC 4111, conduct a drastic review to make sure the regulations function effectively, and follow them up as the countermeasures against these problems. In addition to the management and inspection tasks for the secondary piping that led to this accident, licensees outsource waste treatment, radiation measurement and management and other various kinds of maintenance management tasks to external companies or agencies. However, rights and obligations in outsourcing these tasks are not always clarified sufficiently. To improve these situations, it is necessary for licensees to organize what is to be specified in contract documents, purchase orders and other documents for outsourcing of important tasks in the implementation of security activities. It is also necessary to actively address education and training to improve the competence of employees in outsourcing management according to the requirements for human resources specified in JEAC 4111, Section 6.2.

NISA will request licensees to strongly recognize outsourcing management as an important responsibility of licensees that conduct periodic licensees' inspections. The Agency will also collect information from maintenance contractors regarding the states of implementation of maintenance inspections at power plants, attitudes of licensees and others in the context of the actual situation, and instruct and supervise the licensees and the maintenance contractors adequately.

(3) Standardization of pipe wall thickness control

It was revealed that KEPCO applies standards not specified in the "PWR Management Guidelines" to the wall thickness control of the secondary piping when the remaining life of the piping becomes shorter than 2 years. Consequently, the pipes had not been replaced properly and there were pipes with wall thicknesses below the minimum necessary wall thickness specified in the technical standards.

In the present system, the in-house regulations on the wall thickness control of the secondary piping hold a subordinate position to the "fitness-for-safety programm" of licensees. Therefore, NISA will carefully check the conditions of licensees' compliance with their in-house regulations in fitness-for-safety inspections to be conducted on the licensees continuously.

In the periodic safety management review, it is necessary to effectively check how the parties concerned, including maintenance contractors, carry out the wall thickness control of the secondary piping.

(4) Sound implementation of sharing information among licensees to prevent problems from occurring

It is very important to promote so-called "horizontal spread," which means making use of knowledge about problems and their solutions obtained by security activities to prevent problems from occurring.

Horizontal spread has been considered a voluntary activity of licensees. With the revision of the inspection system for nuclear facilities in October 2003, licensees were obliged to adequately reflect not only knowledge obtained by implementation of their own security activities but also knowledge obtained from other licensees to promote horizontal spread.

For that purpose, not only KEPCO but also every other licensee must reflect knowledge obtained by this accident on its own security activities as well as establish a system to promote horizontal spread systematically and carry it out steadily. NISA will continuously check whether each licensee is promoting horizontal spread accurately and take measures to prevent problems effectively in fitness-for-safety inspections and on other occasions.

8.2. Clarification of technical guidelines

As specified in "5. Pipe wall thinning management", each PWR plant controls thinning in the secondary piping based on the in-house standards established according to the "PWR Management Guidelines." Each BWR plant uses its own uniquely specified in-house standards, referring to the "PWR Management Guidelines."

More than ten years have passed since the "PWR Management Guidelines" were established in 1990. Data on thinning control in real plant facilities have already been accumulated in Japan. In the United States, ASME Code Case N597-1 and the guidelines of the Electric Power Research Institute (EPRI)(NSAC/L202-R2) were established as the standards for pipe wall thickness control in the period of 1998 through 1999. The Nuclear Regulatory Commission (NRC) approved these standards and revised IP (inspection program) 49001 to check if licensees are implementing the pipe thinning control properly based on the above-mentioned regulations. (Refer to Appendix 7.)

In Japan, the Japan Society of Mechanical Engineers (JSME) is developing a standard regarding pipe wall thickness control techniques for electric power facilities. In developing a standard, it is important to make efforts to improve the accuracy of the standard, for example, by adding data on actual measurement results by each licensee and reflecting the results of investigation of the cause of this accident. NISA will conduct a technological assessment immediately and position it as the judgment criterion in the Administrative Procedures Act in order to utilize the nongovernmental standards developed by JSME for safety control.

In consideration of this case, NISA will conduct activities to ensure that licensees recognize the importance of their well-planned implementation of pipe thinning control based on the above-mentioned standards as well as check whether licensees are conducting the inspections accurately in security inspections and on other occasions, as in the United States.

As a tentative measure to be taken until JSME establishes the standard, NISA will clarify the requirements for safety control in administrative documents by reviewing and verifying the contents of the "PWR Management Guidelines" and in-house standards of each BWR plant.

8.3. Verification of pipe wall thickness control in periodic licensees' inspections

The secondary piping including the ruptured portion in the accident was left to voluntary inspections by licensees in the past. Since October 2003, licensees have been obliged to conduct periodic licensees' inspections on the secondary piping based on the Electric Utilities Industry Law. In other words, the importance of inspections by licensees is clarified in the law. On November 14, 2003, NISA issued written instructions entitled "Interpretation of periodic licensees' inspections at nuclear power plants" and others to each nuclear undertaker, which specify concrete details of periodic licensees' inspections.

The Rules for the Enforcement of the Electricity Utilities Industry Law specify that the ruptured portion in this accident is placed as "main piping" of "pipes and other parts associated with the steam turbine" in the "steam turbine" of the facilities of pressurized-water reactor power plants. The regulations specify that the ruptured portion in this accident is placed as "main piping" of "reactor coolant circulation equipment" in the "reactor cooling system equipment" of the facilities of boiling-water reactor power plants. The regulations also specify that periodic licensees' inspections shall be conducted on the "reactor cooling system equipment" and "steam turbine."

In addition, the regulations specify that periodic licensees' inspections shall be conducted using appropriate methods for confirmation of "situations of occurrence of damage, distortion and abnormality in each part" and "functional and operation conditions."

In consideration of this case, NISA will clarify the aforesaid regulations and take actions to familiarize the regulations to the licensees, and then confirm the "policies and situations of implementation of pipe wall thickness control" during fitness-for-safety inspections by nuclear security inspectors conducted continuously at nuclear power plants. JNES should confirm the system of periodic licensees' inspections conducted by licensees regarding the matters necessary to ensure safety, including piping management, during periodic safety management reviews.

There is an opinion that these pipes should be subject to periodic inspections. However, periodic licensees' inspections are important inspections required by the law to be carried out by licensees and the secondary piping inspections are already positioned in the inspections. For these reasons, it is necessary to discuss carefully whether to impose periodic inspections by the regulatory agency.

8.4. Measures concerning thermal power plants

(1) Positioning of pipe wall thickness measurements at thermal power plants

For thermal power plants, pipe wall thickness measurements were not subject to periodic licensees' inspections based on the Electric Utilities Industry Law. Some plants have confirmed the conformity to technical standards regarding pipe wall thickness as a part of voluntary security activities. However, over half of the power plants have not carried out wall thickness measurements and a majority of points to be investigated have remained unexamined. Licensees are required to confirm the soundness of piping by conducting wall thickness and other inspections one by one on the points that have remained unexamined. To ensure that the conformity to technical standards regarding pipe thinning phenomena are continuously checked in the future, it will be discussed whether to include wall thickness inspections on pipes with possible thinning in periodic licensees' inspections.

(2) Examination of technical guidelines

For thermal power plants, no common technical guidelines have been available regarding pipe wall thickness management. Some licensees defined their own voluntary management policies. However, most licensees did no more than inspect only a part of the piping based on cases of troubles that occurred at other power plants.

Many licensees are making inspection execution plans, for example, referring to the "PWR Management Guidelines." However, unlike nuclear power plants, thermal power plants have a variety of operating conditions, such as responses to base load and peak load, and suffer different temperatures and pressures. Therefore, it is desirable to collect data on measurement results obtained under inspection execution plans of each licensee to a neutral organization, analyze the data, and develop technical guidelines for appropriate pipe wall thickness management at thermal power plants.

9. Ensuring of workers' safety

When the accident occurred, 105 employees of KEPCO and maintenance contractors were working in the turbine building for Mihama Power Station, Unit 3 for preparation of a periodic inspection. Eleven workers working near the ruptured A-system condensate pipe fell victim to the accident.

In nuclear power plants, it is routine for workers to enter turbine buildings even during plant operation for daily walk-around checks by operators and for other purposes. The fact that the workers are working inside the turbine building for preparation of the periodic inspection during plant operation does not directly become a problem. However, the fact that the first fatal accident arising from nuclear power generation occurred as a labor accident must be recognized seriously.

It is important for licensees to clearly position not only prevention of radiation hazards but also prevention of labor accidents at nuclear power plants in their management systems and carry out proper management and administration to respond to every situation.

In nuclear power plant facilities, workers involved in maintenance and inspection tasks for equipment belong to a wide variety of positions. There are probably many cases where workers do not have adequate knowledge of potential risks in the places and environments in which they are working. In terms of radiation control at nuclear power plants, licensees are obliged to provide personnel engaged in radiation work with education and training at nuclear power plants according to the Industrial Safety and Health Law, the Nuclear Reactor Regulation Law and other regulations. However, there is a possibility that potential risks inherent in working environments in terms of general labor accidents have not always been disseminated sufficiently.

NISA will demand that licensees take measures, such as providing preliminary training to workers involved in maintenance and inspection tasks inside facilities of nuclear power plants and putting notices of risk information at dangerous points in order to familiarize those workers with potential risks in their working environments depending on the plant operating conditions.

We should not consider this accident as a mere accident but make use of various lessons learned from this accident to further enhance disaster-prevention measures including improvement and expansion of initial measures and strengthen partnership among pertinent organizations if any trouble or accident occurs at nuclear power plants in the future.

10. Conclusion

Nearly two months have passed since the secondary piping rupture accident occurred at Mihama Power Station, Unit 3. This accident caused eleven causalities and is under the police investigation. The final conclusions will not be obtained for quite a while. Meanwhile, other nuclear power plants continue operation. It is important to put measures into practice as soon as possible for the problems that were revealed by this accident and which have to be reflected on the currently operating plants, rather than waiting to take measures until the final conclusions are obtained. With such a perspective, we have put together the immediate measures in this document. It goes without saying that recurrence prevention measures will be added depending on the progress of the investigations in the future.

In addition, the problem of aging of nuclear power plants is pointed out after this accident. The primary cause of this accident is that necessary pipe thinning management was not carried out properly. At nuclear power plants that have operated over many years, so-called aging nuclear power plants, it is likely that aged deterioration events will increasingly come up to the surface. Needless to say, more careful inspection management will be required in the future.

At present, as a part of periodic safety reviews, the nuclear power plants that have operated over 30 years are required to make a comprehensive evaluation of aging. This accident indicates that this activity will be more important in the future. It is important to make an appropriate evaluation of changes caused by aging for the nuclear power plants that have operated for less than 30 years. It is also necessary to reaffirm the role of the periodic safety reviews that NISA requests to perform each decade.

11. List of members of the Accident Investigation Committee for the Secondary Piping Rupture at Mihama Power Station, Unit 3

Chairman	Yasuhide Asada,	Technical advisor of the Thermal and Nuclear Power Engineering Society
	Yoshinori Iizuka,	Professor of Graduate School of Engineering, the University of Tokyo (from the fourth meeting)
	Hideo Kobayashi,	Professor of Graduate School of Science and Engineering, the Tokyo Institute of Technology
	Katsuyuki Shibata,	Chief of Reactor Safety Engineering Department, Tokai Research Establishment, the Japan Atomic Energy Research Institute
	Shigeo Tsujikawa,	Professor Emeritus of the University of Tokyo
Deputy Chairman	Haruki Madarame,	Professor of Research Center for Nuclear Science and Technology, the University of Tokyo
	Kenzo Miya,	Professor of Graduate School of Science and Technology, Keio University

<Appendices>

(Appendix 1) History of major plant parameters at the secondary piping rupture accident

(Appendix 2) Response of nuclear safety inspectors after accident occurrence

(Appendix 3) Results of investigation for the secondary piping rupture accident in Mihama Power Station, Unit 3

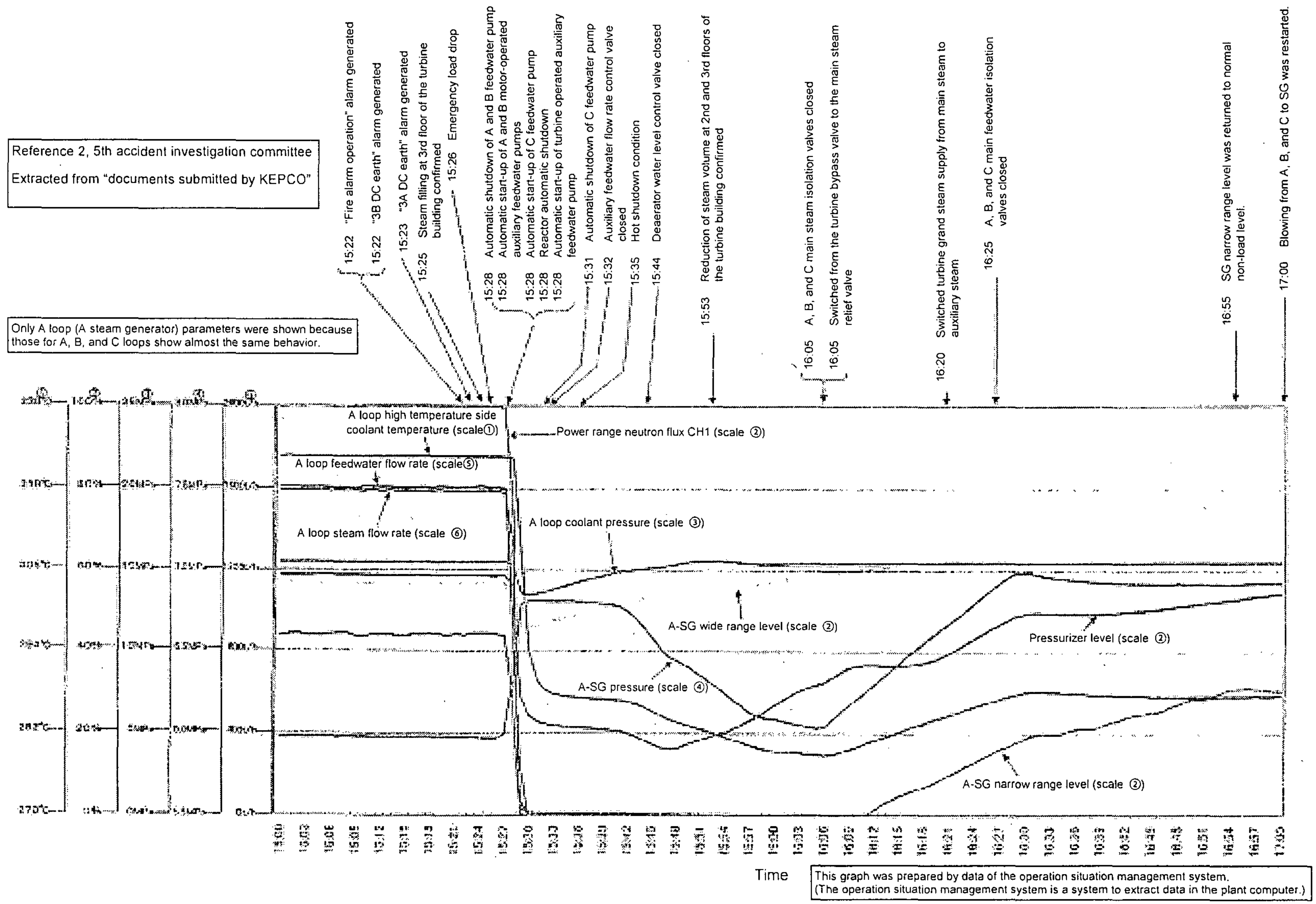
(Appendix 4) Study of validity of "PWR Management Guidelines"

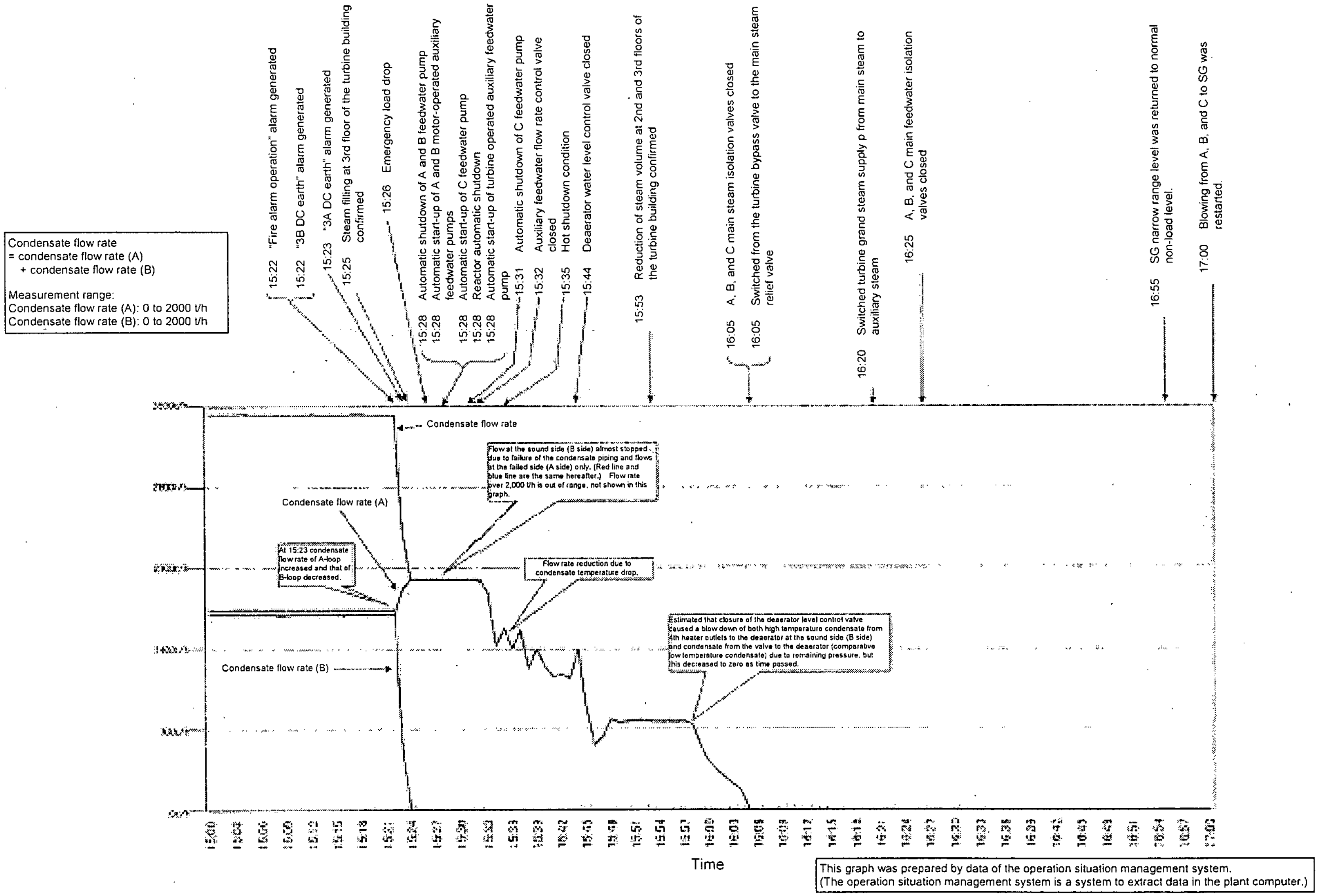
(Appendix 5) General description of thinning phenomenon of main feed water piping of Ohi Power Station, Unit 1

(Appendix 6) Results of verification by NISA for the reports of control situation of piping thinning electric power companies

(Appendix 7) Regulation of thinning control in the United States

History of major plant parameters at the secondary piping rupture accident




Condensate flow rate
= condensate flow rate (A)
+ condensate flow rate (B)
Measurement range:
Condensate flow rate (A): 0 to 2000 t/h
Condensate flow rate (B): 0 to 2000 t/h
15:22 "Fire alarm operation" alarm generated
15:22 "3B DC earth" alarm generated
15:23 "3A DC earth" alarm generated
15:25 Steam filling at 3rd floor of the turbine building confirmed
15:26 Emergency load drop
15:28 Automatic shutdown of A and B feedwater pump
15:28 Automatic start-up of A and B motor-operated auxiliary feedwater pumps
15:28 Automatic start-up of C feedwater pump
15:28 Reactor automatic shutdown
15:28 Automatic start-up of turbine operated auxiliary feedwater pump
15:31 Automatic shutdown of C feedwater pump
15:32 Auxiliary feedwater flow rate control valve closed
15:35 Hot shutdown condition
15:44 Deaerator water level control valve closed
15:53 Reduction of steam volume at 2nd and 3rd floors of the turbine building confirmed
16:05 A, B, and C main steam isolation valves closed
16:05 Switched from the turbine bypass valve to the main steam relief valve
16:20 Switched turbine grand steam supply p from main steam to auxiliary steam
16:25 A, B, and C main feedwater isolation valves closed
16:55 SG narrow range level was returned to normal non-load level.
17:00 Blowing from A, B, and C to SG was restarted.
Condensate flow rate
Condensate flow rate (A)
Condensate flow rate (B)
At 15:23 condensate flow rate of A-loop increased and that of B-loop decreased.
Flow at the sound side (B side) almost stopped due to failure of the condensate piping and flows at the failed side (A side) only. (Red line and blue line are the same hereafter.) Flow rate over 2,000 t/h is out of range, not shown in this graph.
Flow rate reduction due to condensate temperature drop.
Estimated that closure of the deaerator level control valve caused a blow down of both high temperature condensate from 4th heater outlets to the deaerator at the sound side (B side) and condensate from the valve to the deaerator (comparative low temperature condensate) due to remaining pressure, but this decreased to zero as time passed.
Time
This graph was prepared by data of the operation situation management system.
(The operation situation management system is a system to extract data in the plant computer.)

<Response of nuclear safety inspectors after accident occurrence>

Action at Mihama Power Station	On-site Response of NISA
August 9 (Monday)	August 9 (Monday)
15:22 "fire alarm operation" alarm generated	
15:25 Operators confirmed that deaerator side on the 3rd floor of the turbine building was filled with steam.	
15:26 Operators judged that steam or high temperature water potentially leaked from the secondary piping and started emergency load drop.	
15:27 Operators found a fallen victim at the front of elevator of the 2nd floor of the turbine building.	
15:28 "3A SG Feed Water < Steam Flow Inconsistency Trip" alarm generated, triggering automatic shutdown of the reactor and turbine.	
15:32 KEPCO delivered the first report to the Safety Agency (the head office and the on-site nuclear safety inspectors).	15:32 The on-site nuclear safety inspectors first received a verbal report at the site inspector's room and instructed the licensee to check for any problem with reactor safety and radiation leakage. Two on-site inspectors started situation investigation.
15:35 Operators confirmed that automatic shutdown situation was normal and the reactor was stable at hot shutdown condition.	15:34 The on-site nuclear safety inspectors telephoned to report to the disaster prevention section in the head office of NISA and the Mihama inspector's office sequentially and started to collect information from people concerned and instructed operators to confirm the situation regarding victims.
15:53 Operators confirmed that steam flow at 2nd and 3rd turbine floors was decreased.	
16:00 The first ambulance left (with one victim).	16:01 The on-site nuclear safety inspectors at the site inspector's room instructed the licensee to report at any time on existence of abnormality for reactor shutdown condition and also confirmed a written report that no radiation leakage had occurred and reported the information and the number of victims to the head office of NISA.

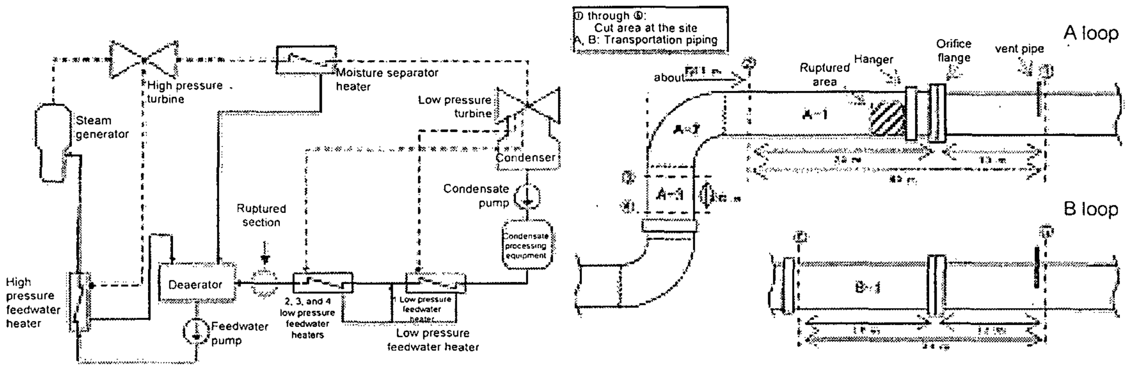
Action at Mihama Power Station	On-site Response of NISA
16:13 The second ambulance left (with three victims). 16:20 The third ambulance left (with two victims).	16:15 The on-site nuclear safety inspector at the site inspector's room continued to instruct the licensee to confirm the situation and reviewed the written report from the operator and reported it to the head office of NISA. Thereafter, the on-site nuclear safety inspectors instructed the operator to report the reactor situation and victims' conditions as needed and reported the information on plant conditions and victims' conditions to the head office of NISA as needed.
16:38 The fourth ambulance left (with two victims). 16:46 The fifth ambulance left (with two victims). Fire station's car left (with one victim).	
17:30 Operators inspected inside of the turbine building to confirm that A loop condensate piping, which connects from the fourth low pressure feedwater heater to the deaerator, was broken around the ceiling on the deaerator side at the 2nd floor of the turbine building .	18:45 After a safety statement by the fire station, the on-site nuclear safety inspectors entered the turbine building to check the situation.
19:00 Fire station confirmed that no victims were found in the turbine building.	19:05 The on-site nuclear safety inspectors confirmed the broken condensate piping and took pictures. 20:50 At the same time as the arrival of a councilor of NISA to Mihama office, an on-the-spot accident countermeasures headquarters of the Ministry of Economy, Trade and Industry was established. 21:00 Establishment of the on-the-spot accident countermeasures headquarters was announced to the local government and towns. Around 21:20 The on-site nuclear safety inspectors checked the situations of the main control room and plant conditions and reported them to NISA. 21:30 A three-way videoconference was held. (Fukui Prefecture, on-the-spot accident countermeasures headquarters, and NISA head office) 22:10 A two-way videoconference was held. (Fukui Prefecture and on-the-spot accident countermeasures headquarters)
23:30 Operators started the low temperature shutdown procedure.	

(Actions at Mihama Power Station were summarized based on the report from KEPCO)

Appendix 3

<Results of investigation for the secondary piping rupture accident at Mihama Power Station, Unit 3>

1. Summary of investigation



Main data:

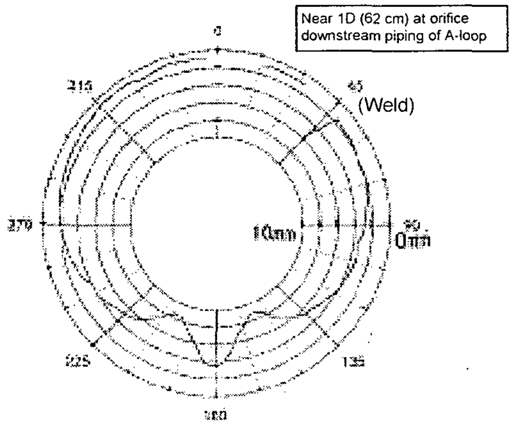
(1) Orifice downstream piping, Material: JIS G3103 SB42 Diameter (hereinafter referred to as D): about 560 mm, Thickness: about 10 mm

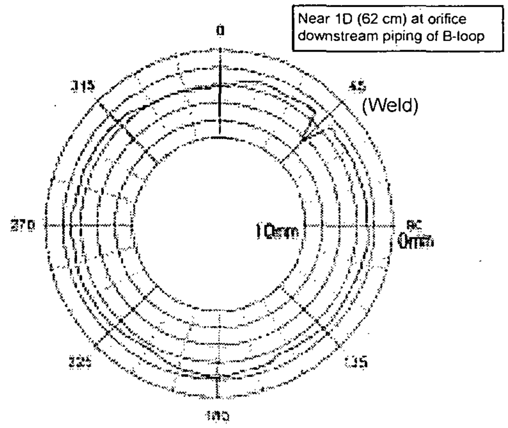
(2) Flow condition during operation, Flow rate: about 1,700 t/h, Pressure: about 0.93 MPa (10 kgf/cm^2), Temperature: 142°C, Flow velocity: about 2.2 m/sec

(3) Operation time, about 185,700 hours

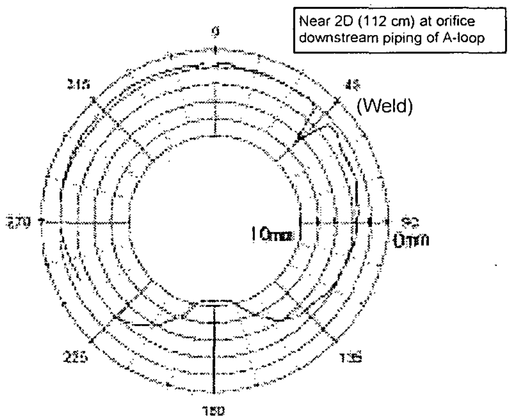
(4) Water chemistry: pH: 8.6 to 9.3, dissolved oxygen concentration: less than 5 ppb.

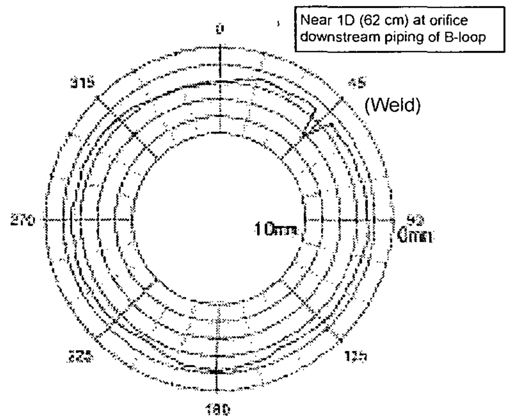
2. Results of piping thickness measurement





Near 1D from orifice downstream end





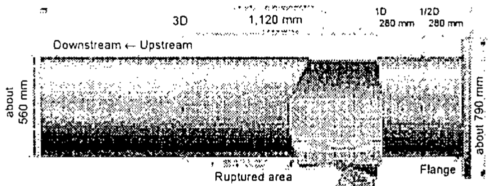
Near 2D from orifice downstream end

A-1 Situation of reduced thickness at orifice downstream piping

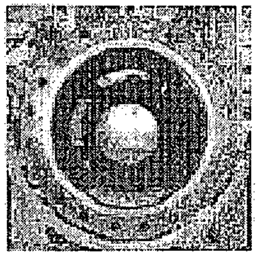
B-1 Situation of reduced thickness at orifice downstream piping

3. Observation results of the inside of the piping

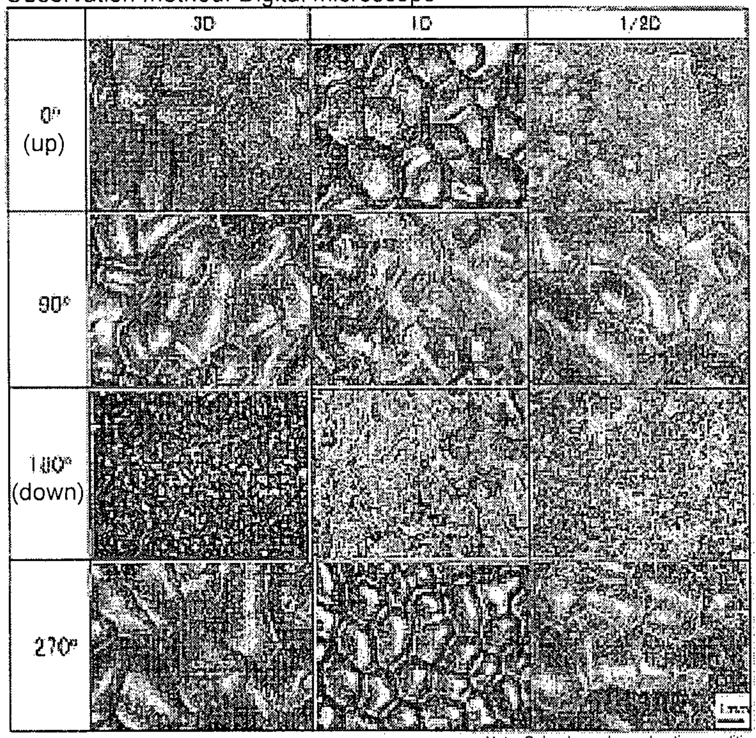
A-1 piping orifice downstream



Upstream side



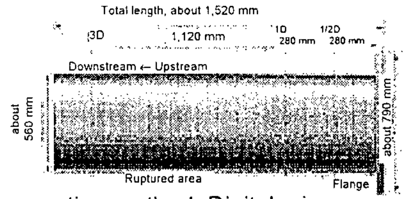
Observation method: Digital microscope



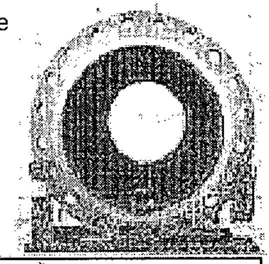
Note: Color depends on shooting conditions.

Conclusion: Fish Scale-like pattern was observed in areas other than at the underside of A-1 piping orifice downstream area (3D and 1/2D at 180 degrees.)

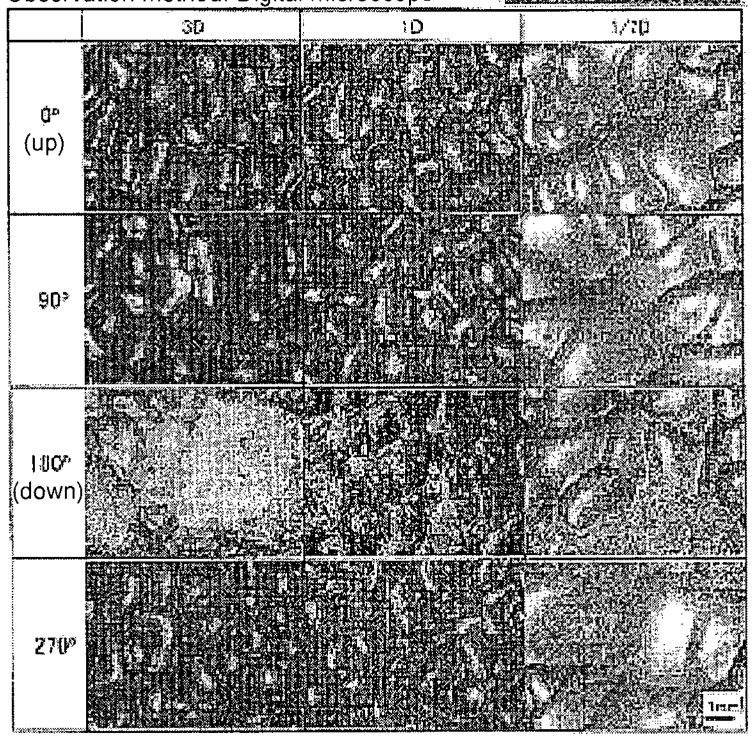
B-1 piping orifice downstream



Upstream side

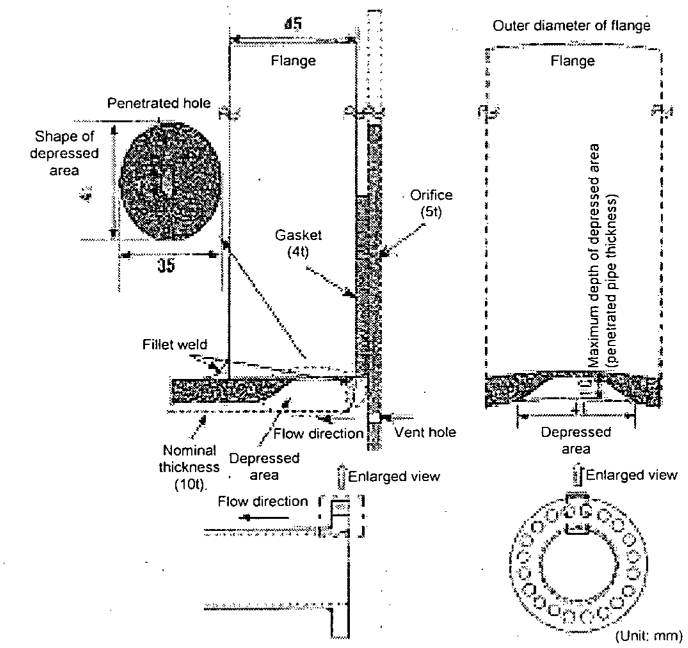


Observation method: Digital microscope

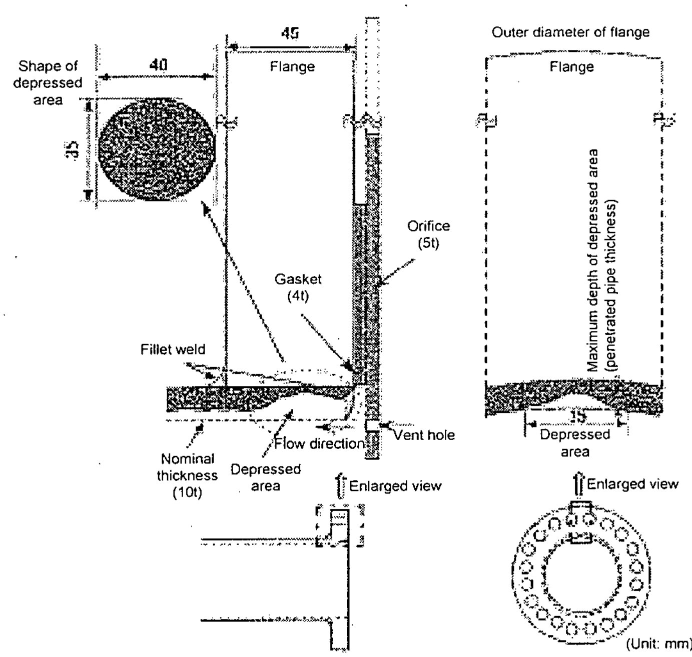


Conclusion: Fish Scale-like pattern was observed at B-1 piping orifice downstream area.

4. Situations at downstream of the vent hole



A loop orifice downstream flange



B loop orifice downstream flange

Source: Extracted from 5th accident investigation committee, reference 5-1-2 (Attachment 1) (documents submitted from JAERI and JNES)

Study of validity of "PWR Management Guidelines"

1. Summary of "PWR Management Guidelines"

(1) Scope

Carbon steel piping of PWR plant secondary side (excluding small diameter piping such as instrument system)

(2) Inspection method

Check by ultrasonic thickness measuring instrument based on JIS Z 2355 "Methods for measurement of thickness by ultrasonic pulse echo technique"

(3) Subject of inspection

Areas where channeling occurs and 2 × D downstream areas (D: piping diameter) among main systems to be inspected shown in Table 1 are specified as main inspection areas (Table 1).

For other areas, 25% of areas where channeling occurs are also specified as subject of inspection for ten years.

* Areas where channeling occurs include downstream area of a control valve, downstream area of a globe check valve, elbow, T pipe, orifice downstream, downstream area of a swing check valve, reducer, and curved piping.

(4) Inspection frequency

Remaining life to the necessary minimum thickness on calculation should be determined at each location, and the area concerned should be inspected before the remaining life is less than two years. It is also stipulated that the inspection should be repeated using evaluation of inspection results until the remaining life reaches to less than two years (Figure 1).

Table 1　Main systems to be inspected

Classification	Requirements			Typical system name	Remarks
	Wetness fraction	Flow velocity	Temperature		
Two-phase flow	More than 15%	Less than 30 m/sec	150-200°C	No. 6 high pressure heater drain piping, No. 5 high pressure heater drain piping	Apply for all main inspection areas.
			200-250°C	Moisture separator heater drain tank drain piping	
		30-50 m/sec	150-200°C	-	
			200-250°C	-	
		More than 50 m/sec	150-200°C	High pressure exhaust piping drain piping	
			200-250°C	-	
	5-15%	Less than 30 m/sec	150-200°C	-	
			200-250°C	Steam converter heating steam piping	
		30-50 m/sec	150-200°C	No. 5 extract piping, No. 4 extract piping	
			200-250°C	-	
		More than 50 m/sec	150-200°C	No. 5 extract piping, No.4 extract piping	
			200-250°C	No. 6 extract piping, No.5 extract piping	
	Less than 5%	Less than 30 m/sec	150-200°C	Deaerator air vent piping	
			200-250°C	No. 6 high pressure heater air vent piping, No. 5 high pressure heater air vent piping	
			More than 250°C	Moisture separator heater balance piping	
		30-50 m/sec	150-200°C	-	
			200-250°C	-	
			More than 250°C	Moisture separator heater balance piping	
		More than 50 m/sec	150-200°C	-	
			200-250°C	-	
			More than 250°C	-	
Single-phase flow	Water	Less than 3 m/sec	100-150°C	Main condensate piping	
			150-200°C	Feedwater booster pump suction piping, moisture separator drain piping	
		3-6 m/sec	100-150°C	-	
			150-200°C	Main feedwater piping, feedwater booster pump discharge piping	

Single-phase flow (cont.)	Water	More than 6 m/sec	100-150°C	-	
			150-200°C	-	
Two-phase flow	More than 15%	Less than 30 m/sec	100-150°C	No. 4 low pressure heater drain piping	Apply for only down-stream of control valve and globe check valve.
		30-50 m/sec		-	
		More than 50 m/sec		-	
Single-phase flow	Water	Less than 3 m/sec	200-250°C	-	
		3-6 m/sec		Main feedwater piping	
		More than 6 m/sec		-	

-: No piping exists at present plants.

Uninspected portion

Set of remaining life ($Lr^{(0)}$)

$$Lr^{(0)} = \frac{t_{no} - \text{Negative allowance} - t_{nr}}{\text{Thinning rate } (Wr^{(0)})} - H$$

- $Lr^{(0)}$: Remaining life
- t_{no} : Nominal thickness
- t_{nr} : Required thickness on calculation
- $Wr^{(0)}$: Initial thinning rate specified in Table 1
- H : Operation time

Table-1 $Wr^{(0)}$ value used for $Lr^{(0)}$ set

			Temperature: 100°C or less	100°C - 150°C	150°C - 200°C	200°C - 250°C	250°C or more
Two-phase flow, Wetness fraction, more than 15%	Flow velocity	30 m/s or less		0.30	0.35	0.35	
		30 m/s - 50 m/s		0.30	1.15	1.15	
		50 m/s or more		0.30	1.15	1.15	
Two-phase flow, wetness fraction, 5 to 15%	Flow velocity	30 m/s or less			0.35	0.35	
		30 m/s - 50 m/s			1.15	1.15	
		50 m/s or more			1.15	1.15	
Two-phase flow, Wetness fraction less than 5% (possibly involving drain)	Flow velocity	30 m/s or less			0.35	0.35	0.35
		30 m/s - 50 m/s			1.15	1.15	1.15
		50 m/s or more			1.15	1.15	1.15
Water single-phase flow	Flow velocity	3 m/s or less		0.45	0.45	0.30 (0.30 applied only for downstream of control valve and glove check valve)	
		3 m/s - 6 m/s		0.45	0.45	0.30	
		6 m/s or more		0.45	0.45	0.30	

Note) 1. Unit of $WR^{(0)}$. $\times 10^{-4}$ mm/Hr
2. Scope marked with shadow

(1) For downstream of control valve, figures in the table should be multiplied by 5.
(2) For downstream of glove check valve, figures in the table should be multiplied by 2.

Number of inspections, once or twice

Inspect two years before expiring remaining life

(first inspection)

Evaluation of remaining life by the thickness difference method

$$Lr^{(1)} = \frac{t_{min} - t_{nr}}{\text{Thinning rate } (Wr^{(1)})}$$

- $Lr^{(1)}$: Remaining life (time)
- t_{min} : Measured minimum thickness
- t_{nr} : Required thickness on calculation
- $Wr^{(1)}$: By the method in Table-2

Remaining life ($Lr^{(1)}$) → (Two years or less) → Replacement plan

(Longer than two years)

Inspect two years before expiring remaining life

(Second inspection)

Reevaluation of the thickness difference method

Remaining life ($Lr^{(1)}$) → (Two years or less) → Replacement plan

(Longer than two years)

Inspect two years before expiring remaining life

(Second inspection)

Table-2 $Wr^{(0)}$ value used for $Lr^{(1)}$ set

	Method classification (area concerned)	Calculation of thinning rate
Number of inspections, once or twice	Longitudinal thickness method Thickness immediately after manufacturing is *uniform longitudinally* (elbow, mother pipe side of T pipe, curved pipe)	$Wr^{(1)}$=(Maximum thickness in pipe axis direction)/(operation time) Maximum thickness difference = $t_{max} - t_{min}$
	Circumferential thickness method Thickness immediately after manufacturing is *uniform circumferentially* (reducer, straight pipe*, branch pipe side of T pipe)	$Wr^{(1)}$=(Maximum thickness in pipe axis direction)/(operation time) Maximum thickness difference = $t_{max} - t_{min}$
	Nominal thickness method (reducer*, straight pipe*)	$Wr^{(1)} = \frac{\text{(Nominal thickness - measured minimum thickness)}}{\text{(operation time)}}$

* For reducer or straight pipe, apply the thinning rate by the thickness difference method or the nominal thickness method, whichever is larger, for evaluation.

Number of inspections, more than three times

Evaluate remaining life by the least-squares method

Remaining life ($Lr^{(2)}$) → (Two years or less) → Replacement plan

(Longer than two years)

Inspect two years before expiring remaining life

$$Lr^{(2)} = \frac{t_{min} - t_{nr}}{\text{Thinning rate } (Wr^{(2)})}$$

- $Lr^{(2)}$: Remaining life (time)
- t_{min} : Measured minimum thickness
- t_{nr} : Required thickness on calculation
- $Wr^{(2)}$: By the method in Table-3

Table-3 $Wr^{(2)}$ value used for $Lr^{(2)}$ set

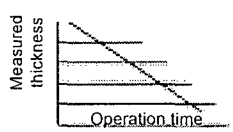
	Method classification (area concerned)	Calculation of thinning rate
Number of inspections, three or more times	Least square method (for all areas)	Obtain the slope by the least-squares method to determine $Wr^{(2)}$ 

Figure 1 Remaining life determination method

2. Piping thinning control method and trend of thinning

(1) Factors of thinning to be controlled

The PWR Management Guidelines used by PWR operators and the management method used by BWR operators are intended to control thinning due to erosion and corrosion. In this case, erosion and corrosion mean the "thinning phenomenon caused by combined actions of mechanical erosion and chemical corrosion," typically showing fish scale-like pattern on the thinned surface.

(2) Evaluation based on data submitted in report collection

We analyzed the thinning trend using the following two materials: (1) Thinning measurement data for individual plants reported from every licensee responding to the report collection for inspection related to piping thinning phenomenon dated August 11, 2004; (2) Thickness measurement data of secondary piping of Mihama Power Station, Unit 3 submitted by KEPCO responding to the report collection on the secondary piping rupture at Mihama Power Station, Unit 3 dated August 18, 2004.

(3) Thinning related to PWR piping

Figure 2 shows the trend of thinning measured by every PWR plant and its resultant actual thinning rate. Comparison between the actual thinning rate and the initially set value of thinning rate specified in the PWR Management Guidelines reveals that the actual thinning rate, except for the main feedwater piping in A-loop, is lower than the initially set value of thinning rate.

Figure 3 shows the trend of thinning measured at Mihama Unit 3, and comparison with the initially set value of thinning rate shown in the PWR Management Guidelines. According to the figure, the actual trend of thinning is lower than the initially set value of thinning rate except small part of data.

Figure 4 shows a comparison of thinning between main inspected systems, all of which are inspected in accordance with the PWR Management Guidelines and other systems inspected on a sampling basis. As a result, the thinning rate of other systems is smaller than that of the main inspected systems as a whole. This suggests that the thinning rate is affected by an environmental difference. Nevertheless some other systems show thinning rates comparable with the main inspected systems.

(4) Estimated thinning rate of ruptured piping of Mihama Unit 3

Estimated thinning rate of ruptured piping of Mihama Unit 3 was calculated based on the remaining life evaluation equation in the PWR Management Guidelines to be 0.47×10^{-4} mm/Hr. This is almost the same as 0.45×10^{-4} mm/Hr, the initially set value of thinning rate in the guidelines.

The remaining life evaluation equation to determine the remaining life for uninspected areas usually uses "nominal thickness - negative allowance" for the original thickness , but for conservative evaluation of thinning rate the negative allowance will not be included in calculation. This is an issue to study in the future.

3. Measuring area and measuring points in main inspection areas

(1) Determination of measuring points

PWR operators determine measuring area and measuring points at every periodic inspection on a contract basis with inspection companies. Concretely, they specify measuring sections depending on the structure at measuring areas and determine eight or four measuring points at a section (hereinafter referred to as "typical measuring points") and apply 3 × D (D: piping diameter) for downstream area of an orifice for measurement. At the typical measuring point, the thickness if less than the threshold thickness for detailed measurement will be measured in detail at a 20 mm pitch around the typical measuring point.

(2) Analysis of measured results

NISA used detailed measurement results of Mihama Unit 3 obtained from KEPCO through the report collection requirement to analyze the relation between the measuring area and measuring points and occurring situation of thinning. Figure 5 shows distribution of measured results. This reveals that measurement by the typical measuring points and resultant detailed measurements are effective to judge the shape and dimensions of the area concerned.

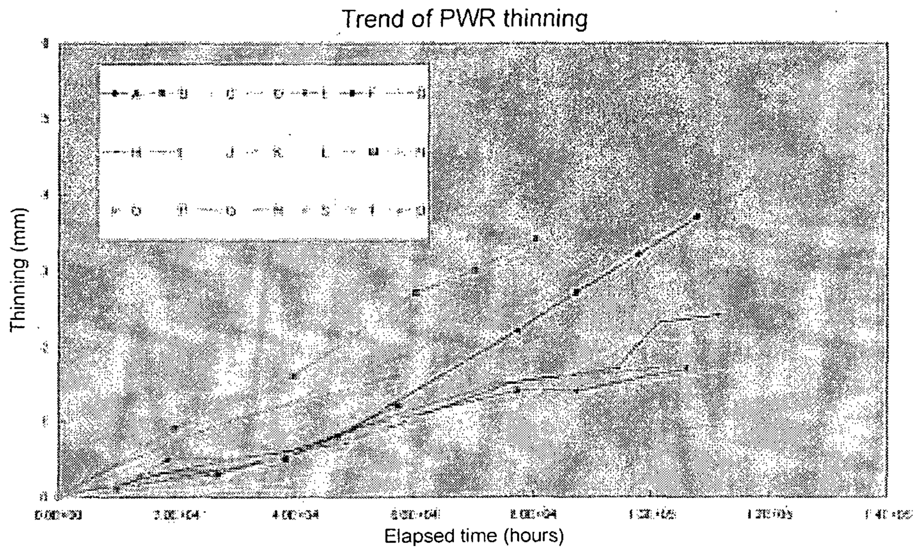
4. Thinning of BWR piping

(1) Applied management method

BWR operators specify their own management methods individually, but the contents have many common descriptions. Comparison with the PWR Management Guidelines shows that the inspection area concerned is wider for BWR than PWR, but the inspection for PWR is more frequently than BWR because of the following reasons. One reason is that PWR has main inspection systems for entire inspection required much more than BWR and the other reason is that BWR has less numbers of inspection areas than PWR because of frequent sampling inspection.

(2) Thinning of BWR piping

Figure 6 shows the trend of thinning measured at BWR plants and its resultant actual thinning rate. Comparison of Figure 2 and 6 reveals that PWR and BWR are different in the trend of thinning and the rate of BWR is lower than that of PWR. This is caused by the difference in water chemistry control between PWR and BWR.



* Elapsed time is the time after an initial inspection.

No.	System name	Inspection area	Material	Tempera-ture (°C)	Flow velocity (m/s)	Wetness Fraction	Thinning rate ($\times10^{-4}$ mm/Hr)	Guide-line category
A	Main feedwater piping	Straight pipe (Downstream of control valve)	STPT49	228	5.3	Water	0.40	⑨
B	Main condensate piping	Straight pipe (Downstream of orifice)	SB42	145	3.0	Water	0.43	⑧
C	Main condensate piping	Straight pipe (Downstream of orifice)	SB42	147	4.0	Water	0.41	⑧
D	Main feedwater piping	T pipe	STPT49	220	5.4	Water	0.38	Others
E	Condensate piping	T pipe	SB42	118	1.4	Water	0.19	⑧
F	Main feedwater piping	90 degree elbow	SB49	190	5.1	Water	0.42	⑧
G	Condensate system	90 degree elbow	SB42	132	3 or less	Water	0.30	⑧
H	Condensate system	90 degree elbow	STPT38	147	3 or less	Water	0.30	⑧
I	Condensate system	T pipe	SB410	148	3 - 6	Water	0.18	⑧
J	High and low pressure vent drain system	Curved pipe	PG370	187	3 or less	Water	0.26	⑧
K	High and low pressure vent drain system	Reducer	SB42	191	3 or less	Water	0.17	⑧
L	Feedwater system	90 degree elbow	SB42	189	3 - 6	Water	0.24	⑧
M	Feedwater pump minimum flow piping	90 degree elbow	STPT38	182	2.3	Water	0.19	⑧
N	Feedwater pump minimum flow piping	Downstream piping	STPT38	182	2.3	Water	0.32	⑧
O	Main feedwater piping	Straight pipe (Downstream of control valve)	STPT49	221 or less	0.0	Water	0.04	⑧
P	Condensate piping	T pipe (Mother pipe side)	SB42	151	3.7 (Mother pipe side)	Water	0.10	⑧
Q	Condensate piping	T pipe (Branch pipe side)	STPT38	151	3.7 (Mother pipe side)	Water	0.28	⑧
R	Main feedwater booster pump discharge piping	90 degree elbow	SB42	188	5.7	Water	0.35	⑧
S	Main feedwater booster pump discharge piping	Downstream piping	SB42	188	5.7	Water	0.09	⑧
T	Moisture separating heater No. 1, 2 heater air piping	T pipe (Mother pipe side)	STPT38	224	6.1 (Mother pipe side)	5% or less	0.28	⑦
U	Moisture separating heater No. 1, 2 heater air piping	T pipe (Branch pipe side)	STPT38	224	6.1 (Mother pipe side)	5% or less	0.21	⑦

<u>Average thinning rate:</u>
<u>0.26×10^{-4}mm/Hr</u>

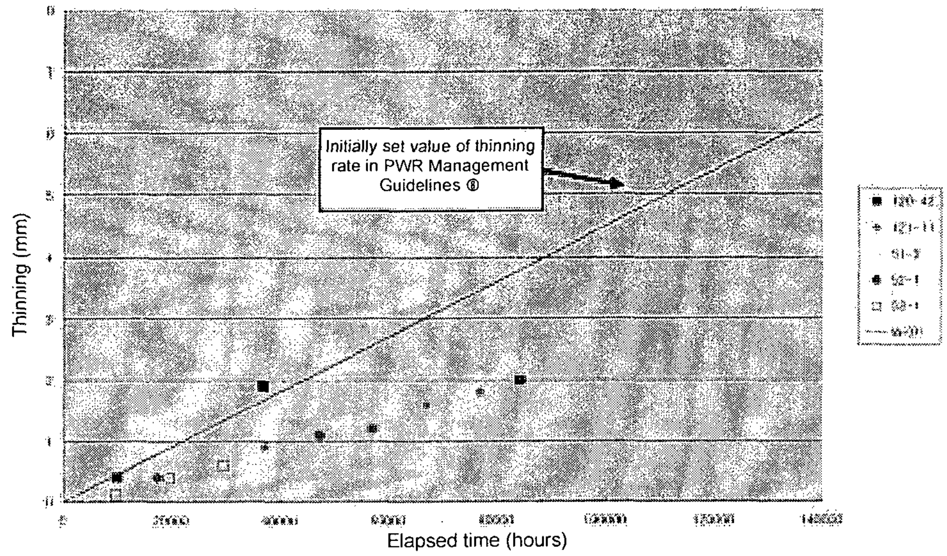
(Note) Initially set value of thinning rate in PWR Management Guidelines

<table>
<tr><th colspan="3" rowspan="2"></th><th colspan="5">Temperature</th></tr>
<tr><th>100°C or less</th><th>100°C - 150°C</th><th>150°C - 200°C</th><th>200°C - 250°C</th><th>250°C or more</th></tr>
<tr><td rowspan="3">Two phase flow, Wetness fraction 15% or more</td><td rowspan="3">Flow velocity</td><td>30 m/s or less</td><td></td><td rowspan="3">① 0.30</td><td colspan="2">② 0.35</td><td></td></tr>
<tr><td>30 m/s - 50 m/s</td><td></td><td colspan="2" rowspan="2">③ 1.15</td><td></td></tr>
<tr><td>50 m/s or more</td><td></td><td></td></tr>
<tr><td rowspan="3">Two phase flow, Wetness fraction 5 to 15%</td><td rowspan="3">Flow velocity</td><td>30 m/s or less</td><td></td><td></td><td colspan="2">④ 0.35</td><td></td></tr>
<tr><td>30 m/s - 50 m/s</td><td></td><td></td><td colspan="2" rowspan="2">⑤ 1.15</td><td></td></tr>
<tr><td>50 m/s or more</td><td></td><td></td><td></td></tr>
<tr><td rowspan="3">Two phase flow, Wetness fraction 5% or less (possibly involving drain)</td><td rowspan="3">Flow velocity</td><td>30 m/s or less</td><td></td><td></td><td colspan="3">⑥ 0.35</td></tr>
<tr><td>30 m/s - 50 m/s</td><td></td><td></td><td colspan="3" rowspan="2">⑦ 1.15</td></tr>
<tr><td>50 m/s or more</td><td></td><td></td></tr>
<tr><td rowspan="3">Water single-phase flow</td><td rowspan="3">Flow velocity</td><td>3 m/s or less</td><td></td><td colspan="2" rowspan="3">⑧ 0.45</td><td rowspan="3">⑨ 0.30 applied only for downstream of control valve and downstream of globe check valve</td><td></td></tr>
<tr><td>3 m/s - 6 m/s</td><td></td><td></td></tr>
<tr><td>6 m/s or more</td><td></td><td></td></tr>
</table>

Note) 1. Unit of $WR^{(0)}$: 10^{-4} mm/Hr
2. *Scope marked with shadow*

(1) For downstream of control valve, figures in the table should be multiplied by 5.
(2) For downstream of globe check valve, figures in the table should be multiplied by 2.

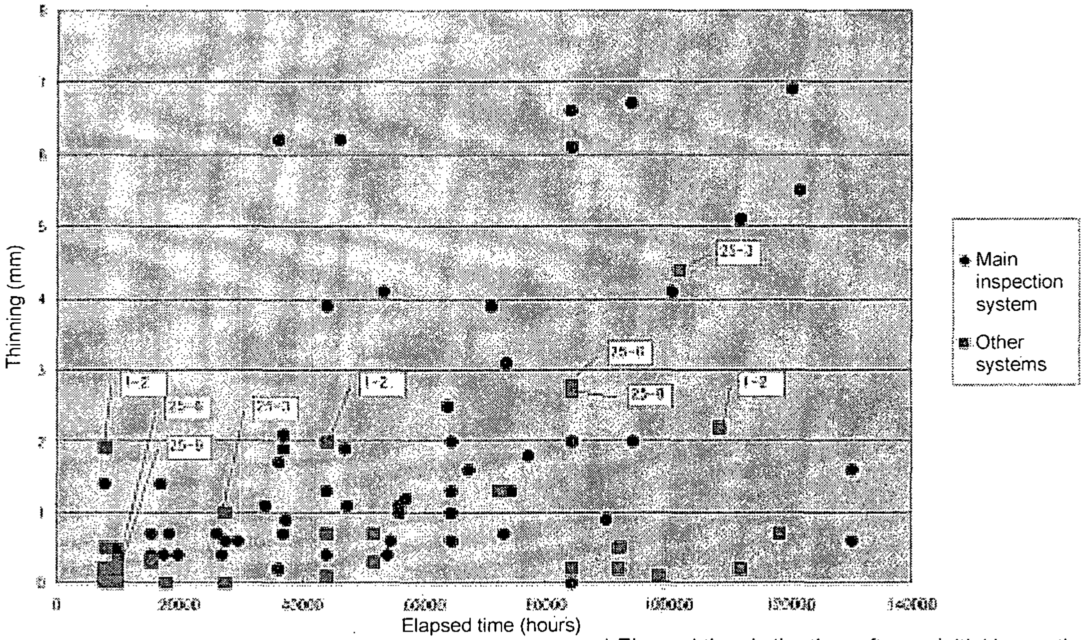
Figure 2 Measurement area and the trend of thinning in PWR piping



* Elapsed time is the time after an initial inspection.

No.	System	Inspection area	Material	Wetness fraction	Flow velocity (m/s)	Temperature (°C)	$Wr^{(0)}$ ($\times 10^{-4}$ mm/hr)	Measured thinning rate ($\times 10^{-4}$ mm/hr) mm
120-42	Feedwater booster pump suction piping	Elbow	STPT38	Water	3 or less	150 - 200	0.45	0.239
121-11	Feedwater booster pump suction piping	Elbow	SB42	Water	3 or less	150 - 200	0.45	0.242
51-2	Moisture separator drain piping	Elbow	STPT38	Water	3 or less	150 - 200	0.45	0.22
52-1	Moisture separator drain piping	Elbow	STPT38	Water	3 or less	100 - 150	0.45	0.161
53-1	Main feedwater piping	Straight pipe	STPT49	Water	3 - 6	150 - 200	0.45	0.213

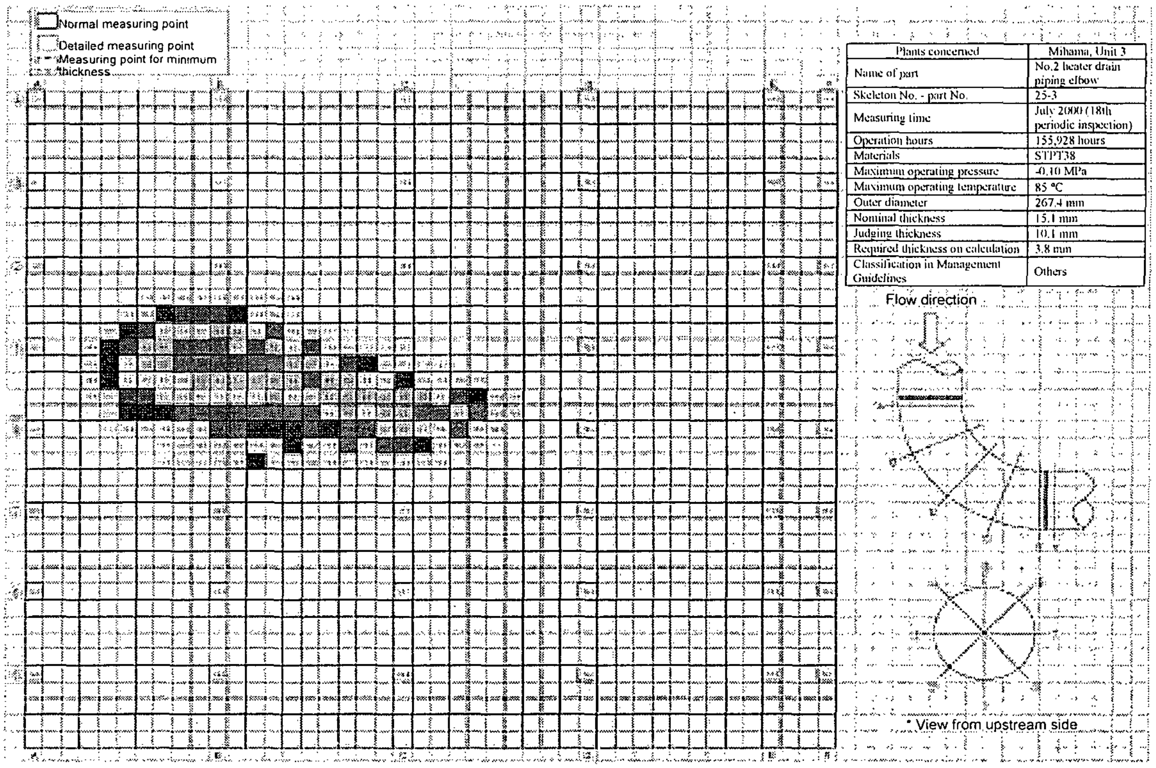
Figure 3 Measurement area and the trend of thinning in Mihama Unit 3 piping



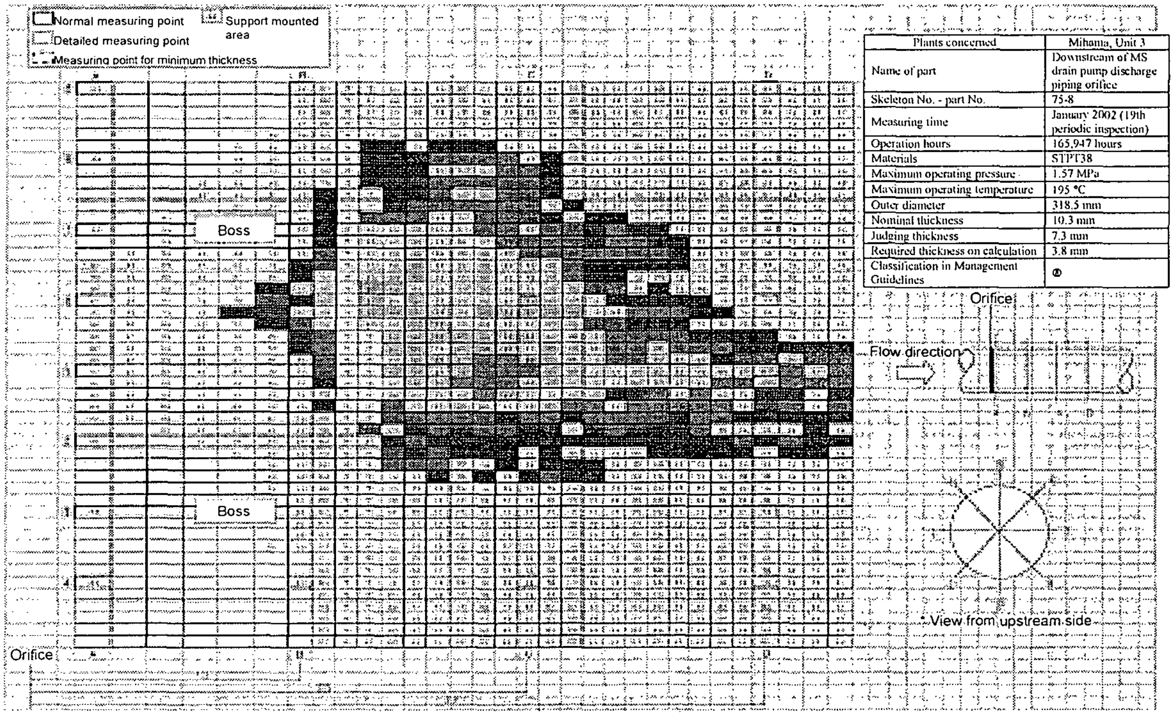
* Elapsed time is the time after an initial inspection.

No.	System	Inspection area	Material	Wetness fraction	Flow velocity (m/s)	Temperature (°C)	Measured thinning rate ($\times10^{-4}$ mm/hr) mm
1-2	No.3 extracting piping	T pipe	STPT38	5% or less	30 - 50	100 - 150	0.266
15-1	Turbine bypass piping	Reducer	STPT39	5% or less	30 or less	250 or more	0.075
16-5	Turbine bypass piping	Reducer	STPT40	5% or less	30 or less	250 or more	0.024
17-2	Moisture separator heater steam piping	Elbow	STPT41	5% or less	30 - 50	250 or more	0.02
19-1	Moisture separator heater steam piping	Elbow	STPT42	5% or less	30 - 50	250 or more	0.135
20-7	Moisture separator heater steam piping	Reducer	STPT43	5% or less	30 - 50	250 or more	0.032
23-1	Deaerator heater steam piping	Elbow	STPT44	5% or less	30 or less	250 or more	0.203
25-3	No.2 heater drain piping (Downstream of control valve)	Elbow	STPT45	15% or more	30 or less	100 or less	0.438
25-6	No.2 heater drain piping (Downstream of control valve)	Elbow	STPT46	15% or more	30 or less	100 or less	0.334
25-9	No.2 heater drain piping (Downstream of control valve)	Elbow	STPT47	15% or more	30 or less	100 or less	0.327
42-6	Low-pressure drain tank balance piping	Elbow	STPT48	Water	3 or less	100 or less	0.025
65-4	Main steam piping	T pipe	SB42	5% or less	50 or more	250 or more	0.194
66-2	Turbine steam dump piping	T pipe	STPT38	5% or less	30 or less	250 or more	0.101

Figure 4 Comparison of main inspection systems and other systems in Mihama Unit 3



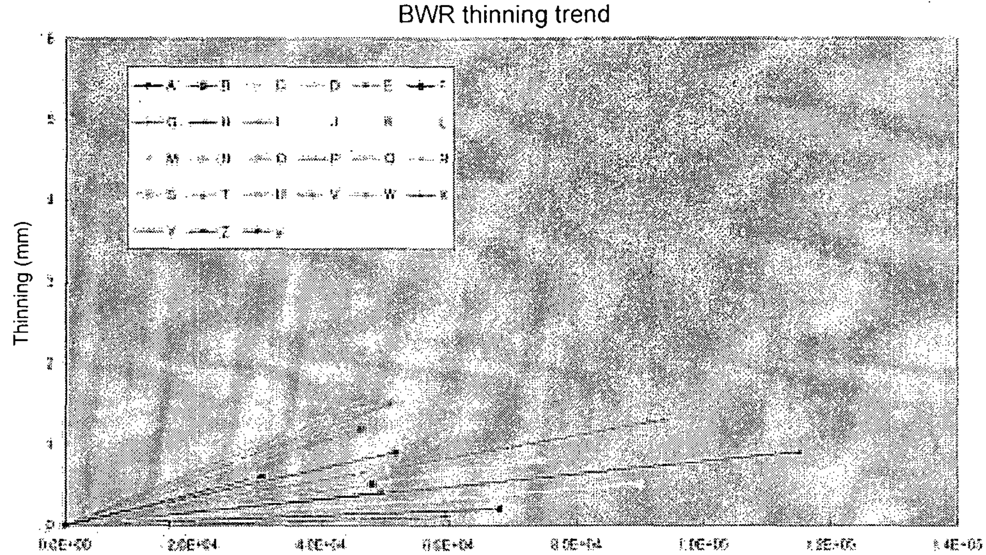
Plants concerned	Mihama, Unit 3
Name of part	No.2 heater drain piping elbow
Skeleton No. - part No.	25-3
Measuring time	July 2000 (18th periodic inspection)
Operation hours	155,928 hours
Materials	STPT38
Maximum operating pressure	-0.10 MPa
Maximum operating temperature	85 °C
Outer diameter	267.4 mm
Nominal thickness	15.1 mm
Judging thickness	10.1 mm
Required thickness on calculation	3.8 mm
Classification in Management Guidelines	Others



Plants concerned	Mihama, Unit 3
Name of part	Downstream of MS drain pump discharge piping orifice
Skeleton No. - part No.	75-8
Measuring time	January 2002 (19th periodic inspection)
Operation hours	165,947 hours
Materials	STPT38
Maximum operating pressure	1.57 MPa
Maximum operating temperature	195 °C
Outer diameter	318.5 mm
Nominal thickness	10.3 mm
Judging thickness	7.3 mm
Required thickness on calculation	3.8 mm
Classification in Management Guidelines	②

Figure 5 Measured results of Mihama Unit 3 (example)

BWR thinning trend



* Elapsed time is the time after an initial inspection.

No.	Inspection part	Material	Temperature (°C)	Flow velocity (m/s)	Wetness fraction	Thinning rate ($\times 10^{-4}$ mm/Hr)
A	Reactor feedwater pump inlet elbow	SB49	114	3.1	Water	0.10
B	Moisture separator drain line elbow	STPT42	194	0.4	Water	0.26
C	Downstream of condensate cleanup line orifice	STPT38	34	6	Water	0.16
D	Downstream of M/DRFP outlet line valve	STPT49	196	6.3	Water	0.02
E	Feedwater heater drain line elbow	STPT38	113	5.6	Water	0.08
F	Straight piping at downstream of feedwater recirculation line orifice	SB49	34	4.3	Water	0.10
G	HPCP suction line elbow	SB46	33	2	Water	0.14
H	M/DRFP suction header line T pipe	SB49	190	4	Water	0.08
I	M/DRFP mini-flow valve after valve downstream elbow	STPT49	145	5	Water	0.04
J	No.3 feedwater heater outlet line straight pipe	SB42	144	5	Water	0.01
K	M/DRFP mini-flow piping orifice upstream safe end	A105	190	5.2	Water	0.14
L	M/DRFP mini-flow valve downstream reducer	SF50A	144	5.1	Water	0.08
M	Condensate pump discharge flow rate regulating valve downstream reducer	STPT38	60	1.3	Water	0.04
N	T/DRFP discharge piping elbow	SB49	145	5.4	Water	0.05
O	T/DRFP mini-flow line FCV downstream	STPT49	145	5.1	Water	0.30
P	High pressure drain pump seal water regulating valve downstream elbow	STPT370	43	1.8	Water	0.05
Q	Main steam stop valve outlet straight pipe	STPT42	277	39.3	0.4%	0.05
R	T/DRFP outlet elbow	STPT42	158	4.7	Water	0.05
S	Feedwater pump recirculation line condenser return area straight pipe	STPT49	160	6.6	Water	0.02
T	Condensate pump outlet straight pipe	SM41A	33	1.2	Water	0.10
U	Condensate system orifice downstream straight pipe	STPT38	65		Water	0.11
V	Extracting system reducer	SB46	207		1.5% or more	0.30
W	Feedwater system flow nozzle downstream straight pipe	SB480	231		Water	0.31
X	Downstream of extracting system T pipe	SB42B	193	43	Water	0.05
Y	Feedwater heater inlet elbow	SM50A	98	4.5	Water	0.40
Z	Drain system cap	SM41A	40		1.5% or more	0.20
a	Condensate system elbow	STPT49	70		Water	0.18

Averaged thinning rate: 0.13×10^{-4} mm/Hr

Figure 6 Measured parts of thinning and its trend of BWR piping

General description of thinning phenomenon of main feed water piping of Ohi Power Station, Unit 1

On July 5, 2004, measurement of thickness of main feedwater piping (carbon steel) connected to the steam generator at KEPCO, Ohi Power Station, Unit 1 (PWR, rated electric output of 1,175,000 kW) under periodic inspection revealed that the thickness of piping elbows at three lines in four lines was partially thinner than the thickness required on calculation (subject of report based on the law.)

Visual inspection of the inside of cut-off piping shows that no abnormality such as cracks or corrosion, etc. occurred, but thickness decreased with fish scale-like patterns characteristic of erosion/corrosion on the entire region. Analysis for flow condition at the elbow and its upstream main feedwater isolation valve (globe valve) reveals that the flow disturbance that occurred inside the piping was further intensified, potentially causing erosion/corrosion.

In 1989 and 1993, the elbow area concerned was inspected in the self-controlled inspection by KEPCO to detect the trend of thinning, but since then the area had not been inspected until the periodic inspection this time.

KEPCO decided to take the following countermeasures considering the above findings.

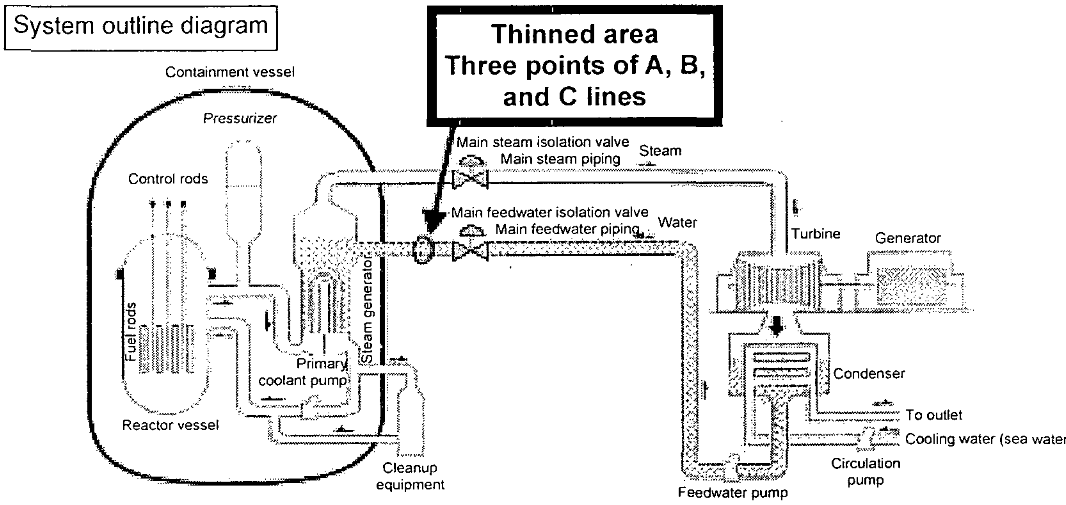
1) To replace the elbow area concerned with piping manufactured at the same dimensions using the same material.

2) To strengthen, in the future, monitoring of thinning trends at the areas concerned including Ohi Power Station, Unit 2 with the same type of main feedwater isolation valve, and to take the same countermeasures for areas with the potential to generate significant thinning at the main feedwater system, including at other plants.

3) To review the total maintenance management system mainly for issues clarified this time regarding the maintenance management and to take measures based on the results.

This thinned area belongs to the water piping operated at 230°C, so it is classified into "other systems" in the PWR Management Guidelines. "Other systems" require inspection on a sampling basis. The thinning causes a need to review the PWR Management Guidelines regarding whether the sampling inspection requirement is adequate for "other systems" and how to manage the D system, because no significant thinning was detected in the D system, which has the same structure and environment as the area concerned.

System outline diagram



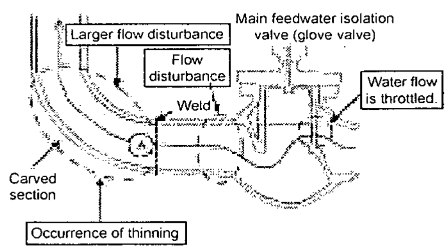
Measurement results

Piping shape	Required thickness on calculation	Measured minimum thickness
A main feedwater piping curved section (45°)	15.7 mm	14.5 mm
B main feedwater piping curved section (90°)		12.1 mm
C main feedwater piping curved section (90°)		13.9 mm
D main feedwater piping curved section (90°)		20.0 mm

Piping specification

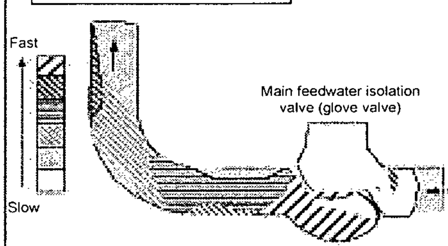
Outer diameter: about 410 mm
Thickness: about 21 mm
Maximum internal pressure: about 8 MPa
Maximum temperature: about 230°C
Material: Carbon steel pipe
Flow rate: about 1,700 t/h, loop

Thinning mechanism



It was confirmed that the flow disturbance that occurred at the inside of the main feedwater isolation valve (globe valve) was further intensified at the piping curved section to potentially cause erosion/corrosion.

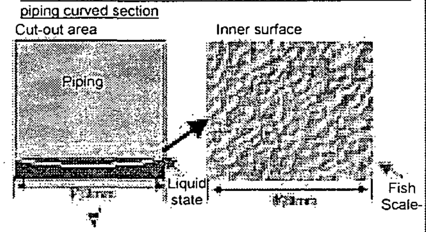
Flow pattern analysis



It was confirmed that flow was disturbed downstream of the main feedwater isolation valve to potentially cause erosion/corrosion.

Enlarged view of "A" area

Example B: Expanded observation result of main feedwater piping curved section



Fish Scale-like pattern typically appearing in erosion/corrosion leading to thinning

Figure Investigation results of thinning at secondary system main feedwater piping elbow area at Ohi Power Station, Unit 1

Appendix 6 Results of verification by NISA for the reports of control situation of piping thinning from electric power companies

		Number of inspection areas concerned	Number of areas applying thinning control		Number of areas missing inspections	Remarks
		After confirmation based on instruction (*1)	Inspected (*2)	Already evaluated at typical inspection area, etc. (*3)		
PWR (23 units)	Condensate system	12,027	8,985	3,042	0	Area where accident occurred at Mihama, Unit 3 and the similar area are excluded.
	Feedwater system	7,374	6,761	608	5	Takahama, Unit 3 (5)
	Main steam system	14,376	9,834	4,538	4	Takahama, Unit 3 (2) and Ohi, Unit 3 (2)
	Extracting system	4,357	3,139	1,212	6	Mihama, Unit 3, Takahama, Unit 1, 3, and 4, Ohi, Unit 3 and 4 (1 each)
	Drain system	35,661	28,859	6,802	0	
	Others	7,974	4,356	3,618	0	Steam dump system, SG blow-down, etc. (Some companies counted this system as part of the drain system or main steam system.)
	Subtotal	81,769	61,934	19,820	15(*4)	
BWR (29 units)	Condensate system	34,343	4,815	29,528	0	
	Feedwater system	7,308	2,446	4,862	0	
	Main steam system	7,971	928	7,043	0	
	Extracting system	1,966	326	1,640	0	
	Drain system	14,558	1,213	13,345	0	
	Subtotal	66,146	9,728	56,418	0	
Total		147,915	71,662	76,238	15(*4)	

(*1) "After confirmation based on instruction": Total number of inspection areas after reviewing the inspection area concerned by comparing PWR Management Guidelines.

(*2) "Inspected": Number of areas inspected at reporting time.

(*3) "Already evaluated at typical inspection area, etc.": Number of areas other than typical inspection area and number of areas scheduled in the future among areas adequate for sampling inspection and number of areas using low alloy steel

(*4) "Number of areas missing inspections": Except for the area of Mihama, Unit 3 where the accident occurred, 14 of 15 areas reported to have missed inspections at the time of reporting have now been inspected.

Regulation of thinning control in the United States

Troubles

'76 Millstone, Unit 3
'82 Oconee, Unit 1 and 2
Vermont Yankee
Trojan
Zion
'85 Trojan
'85 Haddam Neck

1986
Feedwater piping of Surry, Unit 2 was ruptured.

Many thinning and rupture phenomena occurred.

Main phenomena noticed in NRC's IN, etc.
IN: Information Notice for information communication of safety issues

'87 Trojan
'88 Surry, Unit 2
'89 ANO 2
'90 Millstone, Unit 3
San Onofre, Unit 2
Surry, Unit 1
Loviisa, Unit 1
'91 Millstone, Unit 2
'92 Catawba, Unit 2
Susquehanna
'94 Sequoyah, Unit 1
'97 Fort Calhoun
'99 Callaway, Unit 1
'01 Callaway
'02 Columbia
'03 Millstone, Unit 2
Watts Bar, Unit 1

Damages due to erosion/corrosion (E/C) are often generated at the turbine system.

E/C: Erosion/Corrosion

NRC's response

NRC: Nuclear Regulatory Commission
BL: Bulletin
Notice on emergency issues
GL: Generic Letter
Notice on generic issues
IP: Inspection Procedure
NRC's inspection procedure

1987
BL 87-01
Regarding thinning of piping

1989
GL 89-08
Regarding thinning of piping due to erosion/corrosion

Finally issued GL 89-08 requiring all licensees to submit information on monitoring program for piping thickness of carbon steel piping at high-energy single-phase and two-phase flow.

1992
Staff Inspections
Inspections on execution of monitoring program for erosion/corrosion (5 plants)

IP 49001
Inspection procedure of erosion/corrosion monitoring program

1998
IP 49001
Revision

- This monitoring-type inspection continuously monitors the licensee's activity responding to erosion/corrosion in licensed plants.
- Additional inspections conducted as needed.

* Items indicated in outlined characters are used at present.

Response by U.S. industry concerned

Approved private codes

1985
EPRI's report (NP3944) explains primary causes of erosion and corrosion and guideline of inspection program.

EPRI: Electric Power Research Institute

1987
NEI
Erosion/corrosion guideline for single-phase flow in carbon steel piping

NEI: Nuclear Energy Institute
ASME: American Society of Mechanical Engineers

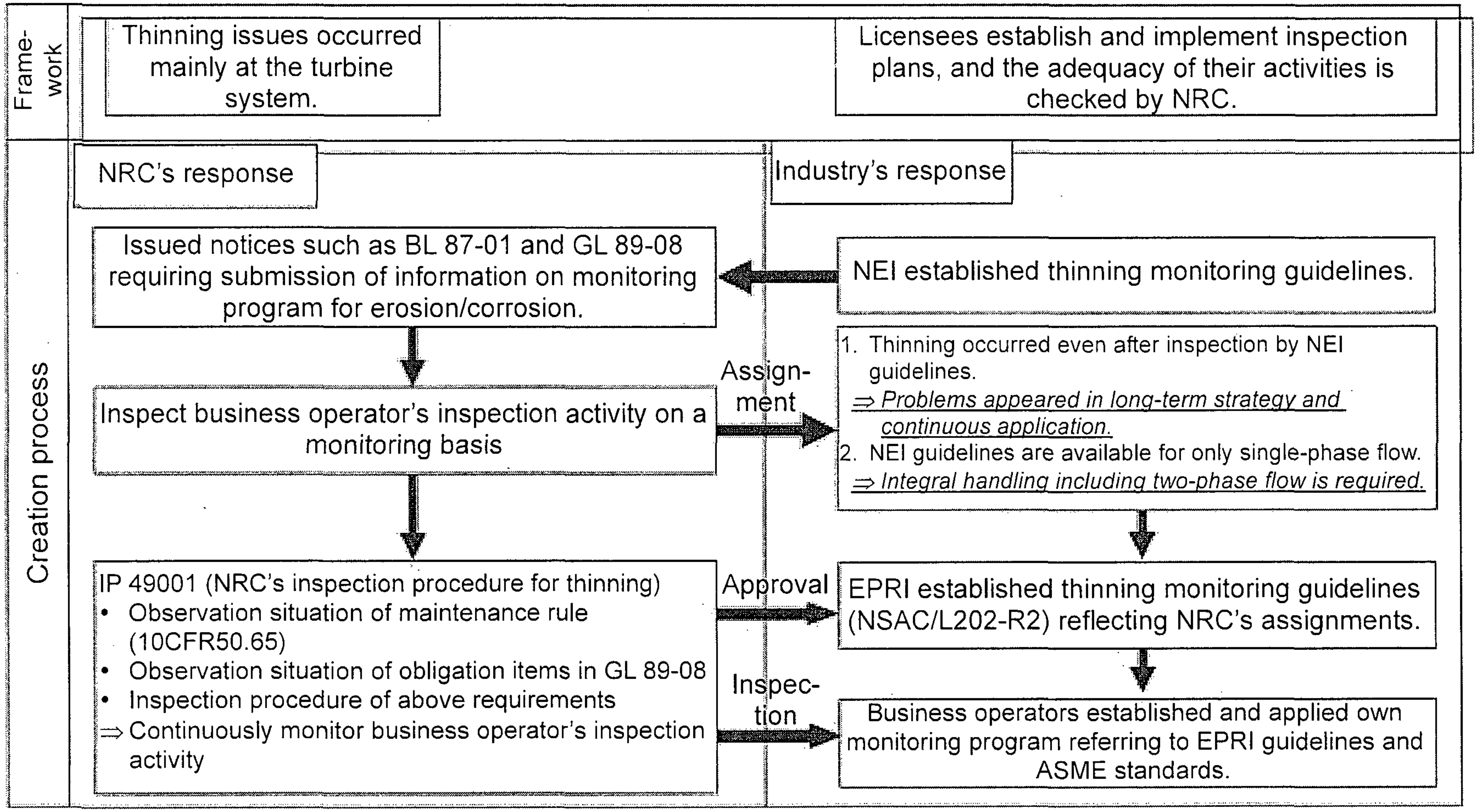
EPRI: Development of thinning estimating code available for single/two-phase flow (finally integrated to CHECWORKS)

ASME: Establishment of the erosion/corrosion guidelines in ASME Sec. XI. According to NRC requirement

1999
EPRI (NSAC/L202-R2)
Recommended program effective for flow acceleration corrosion (FAC)

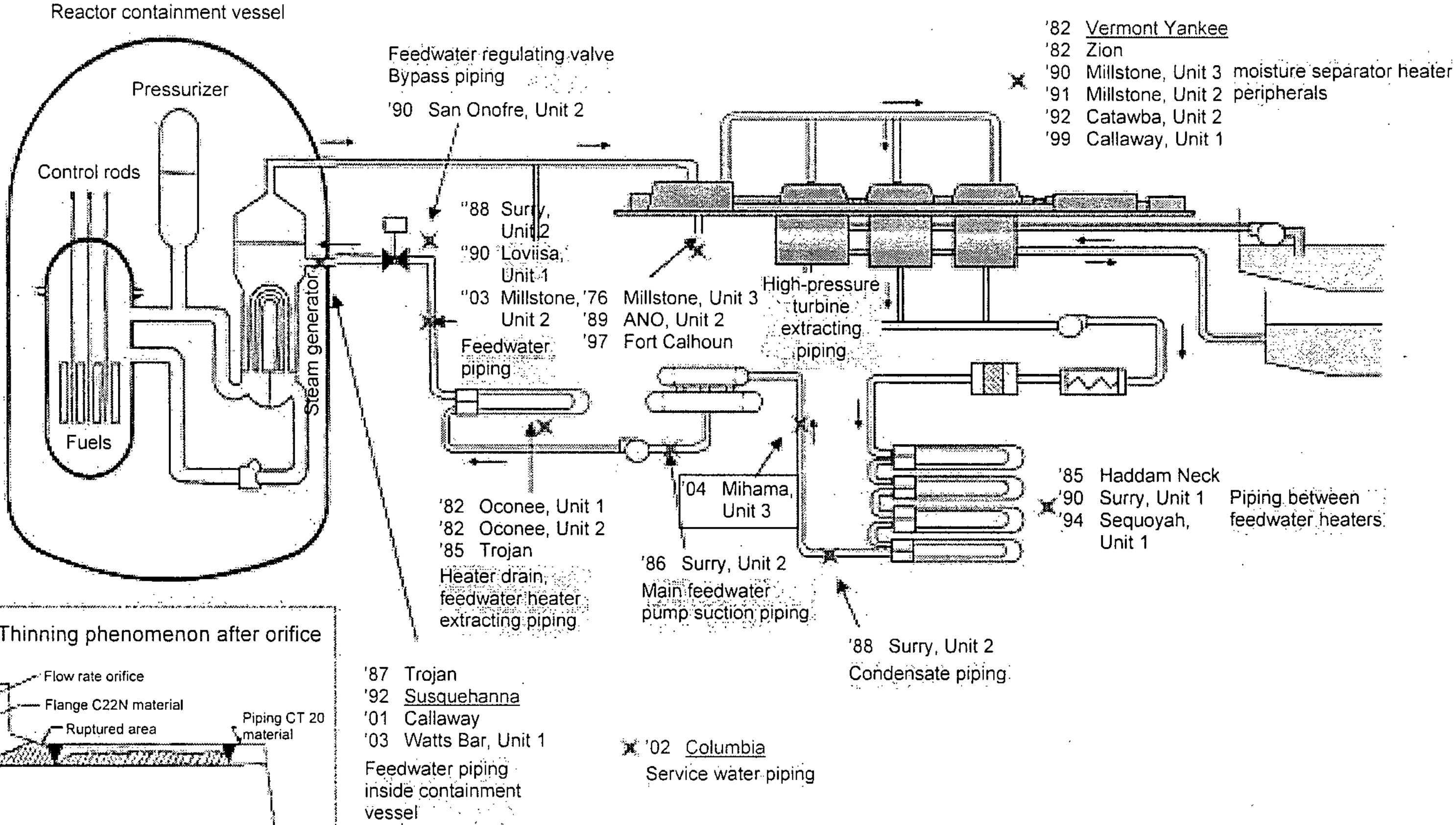
1998
ASME
(Code Cases N 597-1)
Analytical requirements of piping thinning

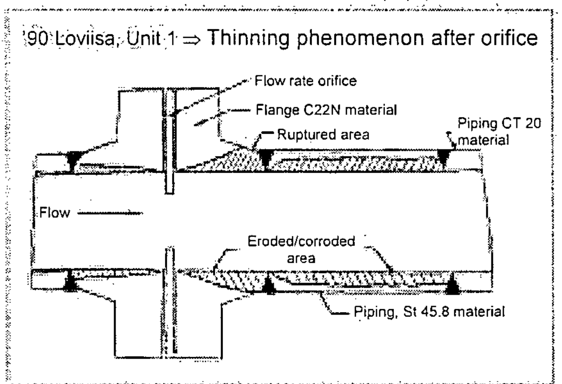
Framework of regulations on thinning and its creation process



* Maintenance rules
- Required self-controlled monitoring for effectiveness of maintenance management (10CFR50.65)
- Licensees established own maintenance program based on above private codes and NRC inspected it.

(Reference) Piping thinning occurred at overseas plants





'YY plant name ⇒ occurrence year and PWR
'YY plant name ⇒ occurrence year and BWR
The above diagram shows PWR, but BWR data are also indicated at corresponding areas.

NEC-RH_03

Discussion of the Empirical Modeling of Flow-Induced Localized Corrosion of Steel under High Shear Stress

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April 25, 2008

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Discussion of the Empirical Modeling of Flow-Induced Localized Corrosion of Steel under High Shear Stress

Introduction and Objective

Multiple failures of carbon steel pipes, apparently due to the high velocities of the high-temperature water and steam they carry, have been observed in the past in nuclear power plants. Dr. Joram Hopenfeld has listed a small sample of apparently random, not predicted failures.[1] As a consequence, the industry has attempted to collect these multiple occurrences in a database, called "CHECWORKS," on the basis of which multiple correlations could be established for the purpose of predicting failures.[2]

Since CHECWORKS (or related computer codes) is based on the experiences from a variety of power plants, its application to an individual facility requires plant-specific input. The process of inputting plant-specific data has been termed "recalibration." Recalibration essentially consists of assessing the prevailing metallurgy, accurately describing the environmental conditions, and determining the prevailing corrosion rates at specific locations deemed most likely to be susceptible to rapid deterioration and failure.[3]

Of particular concern are the effects of a recent power upgrade ("EPU") and the concomitant effects on Flow-Induced Localized Corrosion ("FILC").

Since the Utility intends to use a recalibrated CHECWORKS for Aging Management of pipes, which are subject to high flow rates, it is the objective of this discussion to:

a) Review the reliability of empirical modeling in view of modern understanding of Flow-Induced Localized Corrosion (FILC), and

b) Assess the time requirements for recalibration from a statistical point of view.

To evaluate the corrosion of iron at elevated temperature, one must begin by considering the inherent corrosion processes. Iron will react with water under all environmental conditions (i.e. over the entire pH range).

The rate of reaction depends on the state of the interphase[4], which controls the rate of reaction (i.e. the corrosion kinetics). The hydrodynamic conditions (including geometry)

[1] Joram Hopenfeld, "Review of License Renewal Application for Vermont Yankee Nuclear Power Station: Program for Management of Flow-Accelerated Corrosion, April 24, 2008, Exhibit NEC-JH_36 at 9-11.

[2] The CHECWORKS computer code is treated as proprietary.

[3] The description represents our understanding of recalibration without detailed knowledge of the software's proprietary code.

[4] The interphase is defined as the three-dimensional space between the base metal and the bulk of the solution, which is different from either in all its properties. The interphase in general presents a complex structure, which involves a solid phase (corrosion product), an interface between the corrosion product and

are the next relevant aspects of corrosion. One must specifically consider the flow field at locations most likely to be subject to high shear stress, which defines all prevailing mass transfer processes, and the nature of the flow (single phase or multiphase).

When one superimposes the hydrodynamic conditions on the corrosion processes a complex interdisciplinary problem emerges which involves:

- Metallurgy
- Inorganic chemistry
- Electrochemistry
- Solid state chemistry and transport processes
- Hydrodynamics and associated liquid transport processes.

In light of these complexities, it cannot be the goal of this discussion to produce a detailed understanding of the corrosion mechanisms and kinetics of iron in water/steam at high temperatures. Rather we will attempt to produce an overview of the parameter field, which needs to be considered and controlled if one is attempting to model iron corrosion for the purpose of predicting failure under certain defined conditions. We will also attempt to summarize the major correlations, which have been shown to govern the kinetics of iron oxide dissolution/erosion, i.e. what has been called "Flow Assisted Corrosion" (FAC) and what more appropriately should be termed "Flow Induced Localized Corrosion" (FILC). FILC emphasizes the fact that in disturbed turbulent flow the incurred corrosion damage is always highly localized.

Definitions of Flow Regimes

The terminology "Flow-Induced Localized Corrosion" was introduced in the late 1980s, and has now been widely adopted in many parts of the world.[5] The concept of FILC embraces all phenomena that involve the localized effects of flow on corrosion processes.

For clarification, Figure 1 shows the four main types of flow-induced or flow-assisted corrosion.

The simplest case is that of simple mass transfer controlled corrosion. Here the corrodent (for instance oxygen, hydrogen ion, etc. dissolved in the water) is transported to the metal surface by convective mass transport. This phenomenon, while flow-assisted, generally leads to uniform corrosion and is kinetically controlled by either pure mass transfer, or both mass transfer and metal dissolution kinetics (mixed kinetic control).

---

the metal, an interface between the corrosion product and the liquid, and an interphase between the solid and the liquid made up of a various property gradients (including mass transfer gradients).

[5] See for instance *Flow Induced Corrosion: Fundamental Studies and Industry Experience*, K.J. Kennelley, R. H. Hausler and D. C. Silverman, NACE publication 1991, Chapters 15, 16 and 17 by Hausler, Stegmann, Cruz, et. al

The next phenomenon, which is another case of FAC, occurs when the aggressive phase (for instance water) is carried in a gas stream. This case is central to the flow and corrosion phenomena in wet steam transport.

The third phenomenon in Figure 1 is customarily identified as Erosion Corrosion. However, there are two subcategories to the flow effects occasioned by geometric phenomena. The first is linked to increased turbulence in single-phase flow caused by a change of the geometry in the flow channel (disturbed turbulent flow). The second is attributed to solids carried in the fluid, but does not necessitate a geometric change. For this reason, the term "erosion corrosion" is now being reserved for the situation of solids carried in the fluids, while the term Flow-Induced Localized Corrosion (FILC) refers to single-phase flow associated with a geometric change.

Finally, there is the case in which gas bubbles are carried in the fluids (most often generated by an abrupt pressure drop at a flow disturbance) and collapse under a sudden pressure increase causing extremely high shear stresses locally.

Corrosion Mechanism

Iron (steel) will react with water across the entire pH range.[6] The reactions

$$Fe + 2H_2O \rightarrow Fe^{++} + 2OH^- + H_2$$ or

$$2Fe + 6H_2O \rightarrow 2Fe^{+++} + 6HO^- + 3H_2$$ where

$$2Fe^{+++} + 6OH^- \rightarrow Fe_2O_3 + 3H_2$$ or

$$2Fe^{+++} + Fe^{++} + 8OH^- \rightarrow Fe_3O_4 + 4H_2O$$

are all thermodynamically favored. The last reaction leads to the well-known magnetite. Under the conditions generally encountered in the industry, a protective magnetite layer forms on the surface of the metal and reduces the progress of further corrosion reactions to essentially nil. It is precisely this passivation phenomenon that renders iron or steel such a useful and pervasive material of construction.

However, passivation is not an absolute phenomenon in the sense that it invariably leads to minimal corrosion. Rather, it is subject to breakdown or removal under certain circumstances. Consequently, the study of iron corrosion must focus on the stability or

[6] See also: *Atlas of Electrochemical Equilibria in Aqueous Solutions*, Marcel Pourbaix, Cebelcor/NACE 1974, pg. 307

breakdown of the passivation layer. There are a number of mechanisms that can lead to breakdown of passivity or at least increased corrosion by removal of the magnetite layer. These will be briefly discussed around a more detailed description of the nature of the protective oxide layer.

The Nature of the Passive Layer

As indicated above, passivity comes about because of the formation of a magnetite layer on the surface of the metal. Many studies have focused on the formation of this layer as well as on its properties and protectiveness.[7] By means of electrochemical studies, it has been established and is well accepted that the iron oxide (magnetite) is an ionic composite with a cubic structure, grown epitaxially on the surface of the metal. Magnetite is electrically conductive, but presents a barrier to both iron ion and oxide ion diffusion. Therefore, iron can be electrochemically polarized to high positive potential without the corrosion product layer growing beyond a certain thickness due to any of the above equations, until at about +1.2 V (vs H_2/H^+), in the so-called transpassive region, oxygen evolution takes place.

It is important to understand that under ideal steel/water/temperature conditions, the oxide layer is almost totally protective of iron corrosion. The layer cannot grow significantly either from the metal/oxide interface, nor from the oxide solution interface, because the first case would require oxide ion diffusion to the metal, while the second case requires iron ion diffusion to the water side, and neither can take place at any appreciable rate.

Nevertheless, there are conditions where the passivity can either break down or be removed. Passivity can break down because of certain chemical effects. Chlorides, for instance, will react with the magnetite resulting in a series of iron-oxy-chlorides that are no longer protective.

Of more immediate interest, however, are the phenomena that lead to removal of the passive layer, or at least to temporary removal thereof. Iron oxides (magnetite and mixed hematite/magnetite oxides) have a finite, albeit extremely low, solubility in water above pH 7. These oxides are therefore subject to dissolution, a process that is mass transfer controlled and therefore flow-dependent. Hence, purely phenomenologically, the faster the flow over the surface, the greater the dissolution rate and hence the corrosion rate, because passivity will tend to be reestablished. A steady state develops between dissolution and formation or between the corrosion rate (i.e. formation rate) and the flow rate. Therefore, one must study the mass transfer dependent dissolution rate of the oxide layer.

---

[7] See also Maurice Cohen (Dissolution of Iron); Vlasta Brussic (Ferrous Passivation), J.E. Draly (Corrosion of Valve Metals), published in Corrosion Chemistry, ACS Symposium Series, Vol 89, (1982) Lecture Series organized by R.H. Hausler and edited by G. R. Brubaker and P.B. Phipps.

The Effects of Mass Transfer

It is important to note that only in the case of convective mass transport has it been possible to describe the effect of flow on the metal dissolution rate from first principle. For example, in laminar flow the pressure losses due to flow are described by the Hagen Poiseuille equation:

$$\Delta P = \frac{8\mu L}{R^2} \cdot U$$

where: ΔP = pressure drop along the length of the pipe
U = linear velocity
R = diameter of pipe
L = length of pipe
μ = absolute viscosity of fluid

Since the shear stress is proportional to the pressure drop, which is proportional to linear velocity,

$$\tau \approx \Delta P \approx U$$

a linear relationship between shear stress and linear velocity is obtained, and in fact an additional relationship between the mass transfer rate and the flow rate is established.[8] If the corrosion rate is dependent on the dissolution rate of the passive film, then the corrosion rate does in fact become proportional to the flow rate for laminar flow.

In turbulent flow, the pressure drop ceases to be proportional to the first power of the average velocity and becomes approximately proportional to the second power of linear velocity. Various formulations have in the past been presented for the case of turbulent flow in circular pipes. All of them involve empirical correlations with dimensionless parameters (like the Reynolds number) and therefore cannot be said to be derived from first principle, but relate to specific cases.

In the majority of cases a relationship between the corrosion rate, w, and the flow rate, U, can be approximated with an exponential relation of the form:

$$w \approx U^{\alpha}$$

For the trivial case of corrosion which is not flow dependent, α=0.

[8] See E. Heitz in Ref. 5, chapter 1, Chemo-Mechanical Effects of Flow on Corrosion

The relationship for transport-dependent processes is well known in the form of the power law:

$$Sh \approx \mathrm{Re}^{m}$$

where: Sh = the Sherwood number (nondimensional)
Re = Reynolds number (nondimensional)

The exponents in this case are in the range of 0.3 < a <1, with the small values relating to laminar flow and larger values relating to turbulent flow conditions.

For corrosion types that involve a mechanical removal of the surface layers (intermittent increase in transport rate) and/or of the basic material, on the other hand, exponents of $\alpha > 1$ are usually found.[9]

Where the surface layer is broken down by shear stress the following estimate can be made for pipe flow:

The pressure loss in circular pipe flow has a linear relationship to the shear stress:

$$\tau_w \approx \Delta P = \lambda \frac{1}{D_0} \frac{\rho}{2} \cdot u_m^2$$

Using the Blasius theorem, one can arrive at:

$$\tau_w = u_m^{-0.25} \cdot u_m^2 = u_m^{1.75}$$

If the breakdown of the surface layer is proportional to the shear stress, relationships for smooth pipe of the form

$$w \approx u^{1.75}$$

and

$$w \approx u^2$$

for rough pipe flow are obtained.

[9] U. Lotz, E. Heitz, Flow-Dependent Corrosion. I. Current Understanding of the Mechanisms Involved, Werkstoffe und Korrosion, 34. 454-461 (1983)

Since the failures described by J. Hopenfeld[10] point in the direction of Flow-Induced Localized Corrosion, one can safely assume that these localized occurrences are due to the destruction of the protective magnetite layers. This raises doubts at least as to whether the rates of FILC [or FAC] are less than proportional to the flow rate and suggests that the proportionality is of a higher order.

From all of the above reasoning, it should be clear that the corrosive forces following the EPU are much larger than anticipated and not necessarily predictable. Hence the extreme necessity for calibration.

The reason why predictions are so very difficult is again phenomenological and is depicted in additional figures:

Figure 2 shows that in the case of a flow channel diameter change backflow occurs with very high local turbulences. The point of reattachment of the flow is very much dependent on the geometry and will migrate up and down the pipe with flow rate changes.

Figure 3 illustrates the momentum transfer for various flow regimes by way of pictorial explanation. In particular, the pressure impact, which leads to localized corrosion (also often designated as erosion), will need to be discussed in greater detail below.

Figure 4 shows the corrosion mechanism occurring on flow disturbances for copper and ferrous materials. It is important to note that pitting can occur in stagnant (or relatively stagnant) areas while the areas of high flow become cathodic. This is counterintuitive and another reason why it is so very difficult to predict a) where the localized corrosion will occur, b) how fast it will take place, and c) where it will be moved to as the flow rate changes.[11] Finally, in Figure 5 one can see that a flow channel restriction can lead to FILC upstream of the restriction as well as downstream.

Further Investigations into the Removal Mechanisms of Corrosion Product Layers

More recently, questions have been asked with respect to the stability and strength of corrosion product layers and the shear forces one might need to actually destroy these layers such that the corrosion rate would no longer be controlled by the kinetics of dissolution of these layers.

G. Schmitt dealt extensively with these questions over the years.[12] He concluded that extrinsic stresses like wall shear stresses (as conventionally calculated) in flowing media are generally too small to contribute much to the destruction of corrosion product layers.

[10] Exhibit NEC-JH_36 at 9-11.

[11] Pitting is particularly prevalent under conditions where the passivity can be impaired, as for instance in the presence of chlorides.

[12] G. Schmitt, T. Gude, E. Strobel-Effertz, *Fracture Mechanical Properties of CO_2 Corrosion Product Scales and Their Relation to Localized Corrosion,* NACE CORROSION/96, paper 9

FILC is initiated at sites of local spalling if critical flow intensities prevent re-formation of protective scales.

Subsequently it was shown that fracture stresses for iron sulfide, iron carbonate, and iron oxide layers were in the range of 10^6 to 10^8 Pa (N/m^2).[13] Shear forces of this order of magnitude cannot be accounted for by conventional hydrodynamic modeling. Since it was clear, however, that in practice many situations are known where apparently flow effects are capable of destroying corrosion product layers, Schmitt set about to measure the shear forces in highly turbulent areas with micro-electrodes and an electrochemical methodology based on the determination of limiting diffusion currents. The methodology is exceedingly complex and only some relevant results can be listed here. In systems of high turbulence it is clear that the limiting diffusion current would be "noisy." Algorithms were developed to extract from the electrochemical noise the appropriate maximum diffusion currents and convert these to shear stress signals.

It was found that local shear stresses in small areas of 50 to 100 μ diameter were of the order of 10^6 to 10^7 Pa, but not enough to actually greatly damage the corrosion product scales. However, single events of much greater shear stress (10^9 Pa) were observed. These events were attributed to micro "freak waves." The phenomenon is well known on a macro scale on the oceans, and has recently been reproduced again on a semi-macro scale in the laboratory.

It was visualized that these freak waves act as a continuous barrage of pinpricks, highly localized in areas of highest turbulence. What is not known is the frequency of the phenomenon or the degree of randomness. Additionally, the rate of re-passivation, which in the case of magnetite formation is certainly very high, is also not known.

Nevertheless, the importance of this work can be seen in the fact that it has been possible to measure shear stress phenomena in highly turbulent areas of a magnitude surpassing anything that has been known so far, or modeled with conventional theoretical approaches.

Schmitt defined a critical shear stress as follows:

$$\tau_{w,crit} = \frac{K_v}{n} \cdot \frac{1}{K_{SAC}} \cdot \sigma_y$$

where: K_v = turbulence coefficient that can be calculated from hydrodynamic correlations
n = number of impacts from near-wall turbulence elements
K_{SAC}= accounts for the effects of surface active components that might be present in the system

[13] R.H. Hausler, G. Schmitt, *Hydrodynamic and Flow Effects on Corrosion Inhibition* NACE CORROSIOn/2004, paper #402.

σ_y = fracture stress of the protective scale.

This approach visualizes a fatiguing mechanism in the sense that micro turbulences of sufficient strength keep hammering onto the corrosion product layer until fracture occurs.

The importance of these studies and observations is that it is virtually impossible to predict where and to what extent such micro turbulences of sufficient strength might occur, nor exactly when the critical wall shear stress might be reached. Phenomenologically, however, one can certainly pinpoint general locations subject to high turbulence where these events might occur; how they might be shifted as the velocity vectors change must still be determined by observation.

It would therefore be erroneous for the utility to continue to rely on grids established prior to EPU since these grids may not specifically capture the FILC phenomena observed at the lesser velocities. One might, for instance, refer to Figure 4 and readily understand that the point of reattachment of the flow would move up and down the pipe with changes in the linear flow rate.

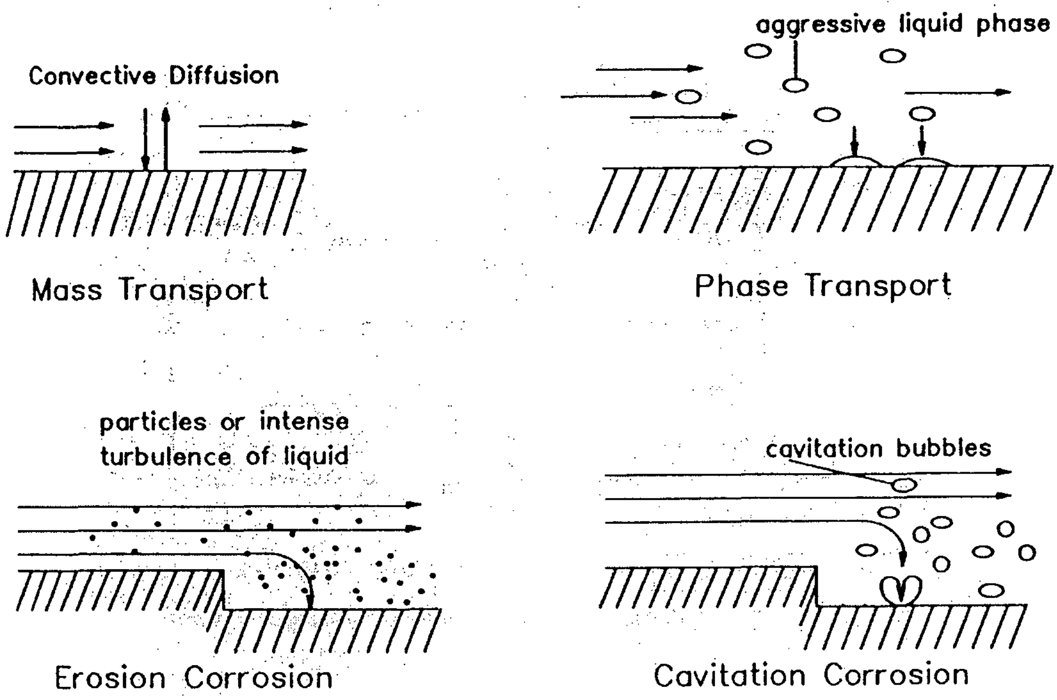

Figure 1: Schematic representation of the four main types of Flow-Induced Localized Corrosion

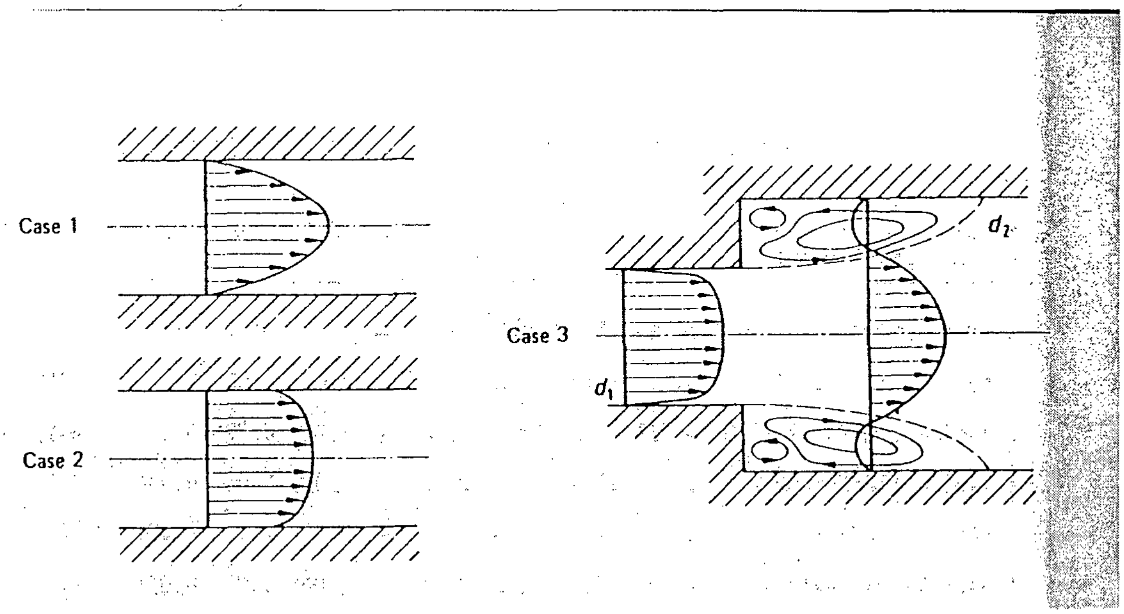

Figure 2: Velocity Profiles in Pipe flow: 1) established laminar pipe flow; 2) turbulent flow with logarithmic velocity profile; 3) turbulent flow with separation; complex velocity field with reverse flow.

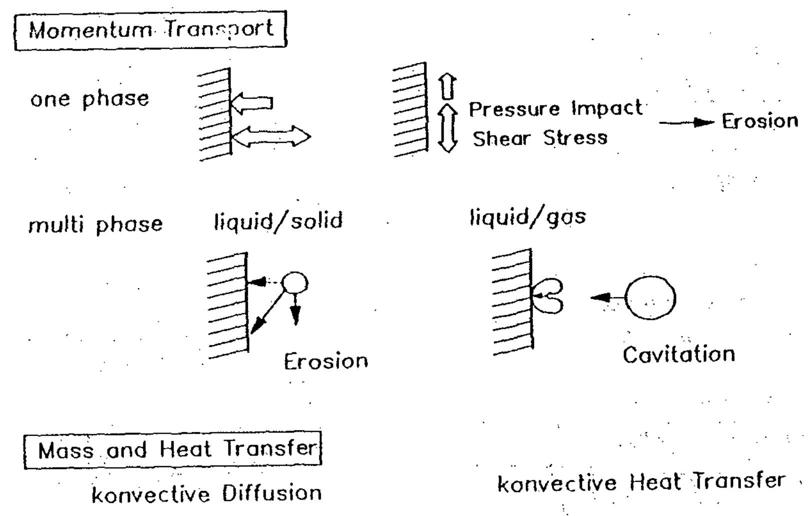

Figure 3: Interaction of liquid flow with a solid boundary (wall of the flow system)

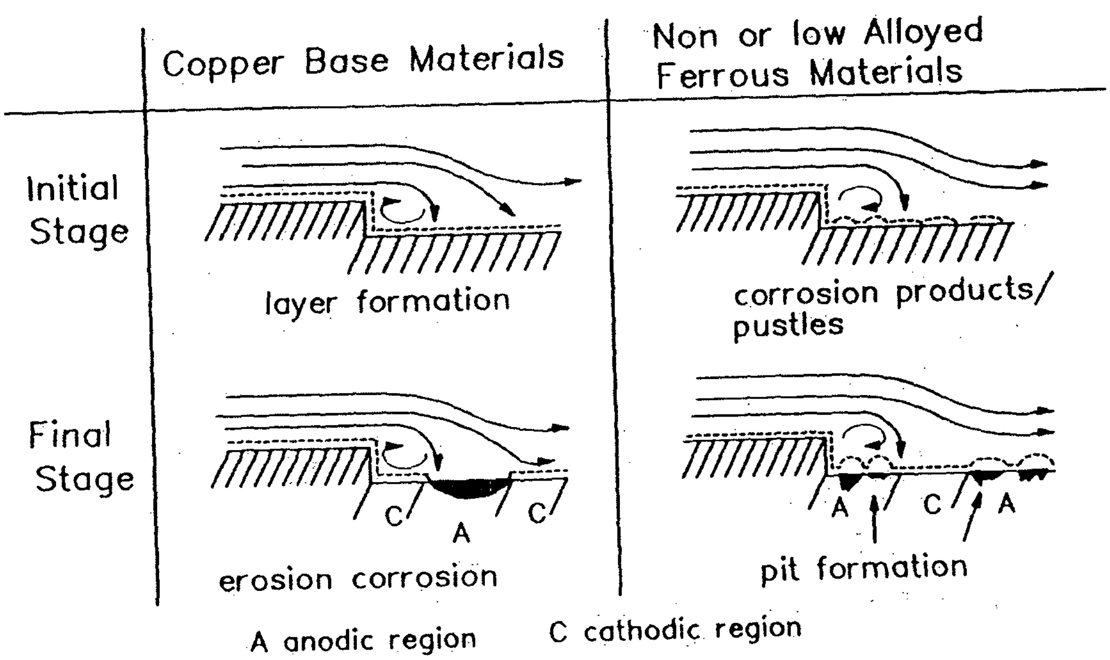

Figure 4: Flow-induced macro cell formation on copper and iron materials in disturbed turbulent flow

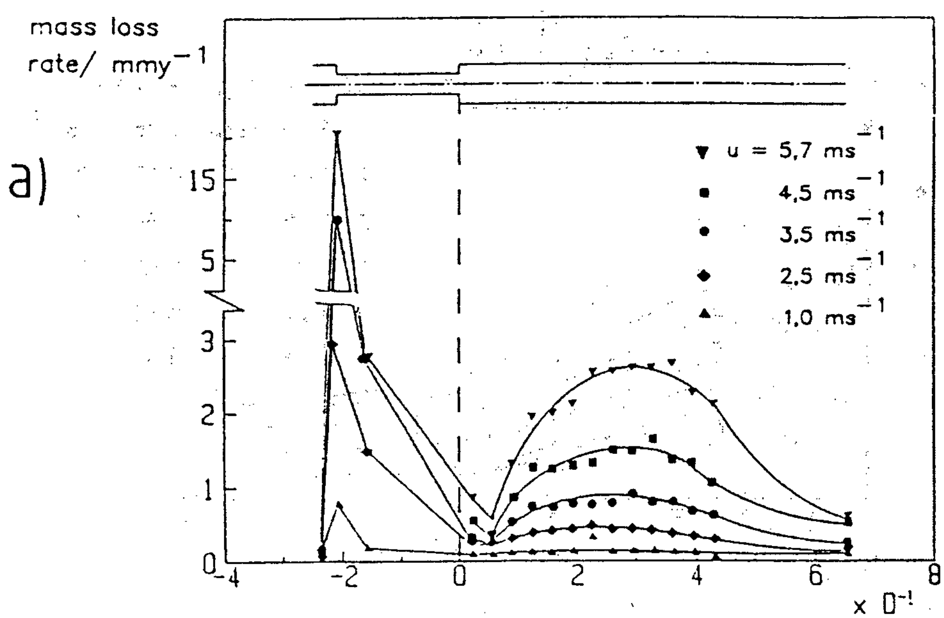

Figure 5: Mass loss rates of 13 % Cr steel in formation water containing sand, measured in a pipe with a constriction; abscissa: normalized pipe length (x/D)

Appendix A

Considerations Regarding the Frequency of Monitoring Based on Statistics and Required Confidence

I. The Problem

Aging management essentially consists of making multiple measurements over time for the purpose of:

- Assessing the integrity of a structure, and
- Estimating the rate of deterioration in order to predict time to failure and consequently taking timely action to prevent such failure.

It therefore stands to reason that at least two measurements are needed to determine the rate of deterioration. However, from two measurements one cannot determine the confidence limit of the resulting slope (rate). Therefore, a minimum of three measurements is required in order to assess confidence limits. However, since with three data points there remains only one degree of freedom for the assessment of the confidence limits, clearly even in the best of cases these assessments would remain wide and predictions uncertain.

When applied to aging management of pipe subject to high flow rates, this phenomenon suggests the following:

If a new thickness measurement is made sometime after the EPU, and if prior to the EPU the rate of deterioration at that particular location had somehow been established, a new rate will likely emerge.[14] The newly calculated rate is afflicted with all the uncertainties inherent in the methodology of measurement.

The uncertainties arise from two factors:

- The inherent variability of the instrument with which the measurements are being made. Handheld ultrasonic thickness ("UT") measurements have a 95% confidence limit, or about +/- 1% to 2% of wall thickness.
- The inherent difficulty of placing the handheld UT probe at exactly the same location for repeat measurements one-and-a-half to two years apart. This problem applies even to the case where a defined grid may have been used.

In order to develop the most simplified methodology VYNPU should pursue, the following hypothetical example will be discussed.

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[14] This scenario presumes that because of the higher flow rate the point of maximum turbulence has not been shifted to a new location – an assumption which cannot be made in good conscience.

II. Determination of Confidence Limits of Corrosion Rate Estimation

In order to perform the necessary calculations, the well-known software from the SAS Institute, JMP, has been used[15].

Table 1 below lists nine UT thickness measurements, which hypothetically have been made over the past nine years, and includes the original thickness.

Figure 1 shows a linear correlation of the first four measurements, including the origin. One can see that the hypothetical data fit the hypothesis of a linear correlation with a correlation factor (R^2) of nearly 0.98, generally considered excellent. The figure shows the 95% confidence limits for the fit (inner boundaries) and the 95% confidence limits for individual measurements (outer boundaries). The slope of the linear correlation is 28.2 mpy with a standard deviation of 2.3 mpy. Hence the slope can vary between 30.5 mpy and 25.9 mpy. These confidence limits for the slope, therefore, are much larger than would be required for the customary 95% acceptance criteria.

Figure 2 shows the correlation for all nine measurements including the origin. It can be seen that the 95 % confidence limits for the fit ($R^2 = 0.98$) are much closer together. This change is essentially because of the increased degree of freedom for the estimate; the data themselves have not become more accurate. However, the slope now is 24 mpy with a standard deviation of 1.3, and 95% confidence limits of +/- 2.6 mpy, or from 21.4 to 26.6 mpy.

The result in Figure 2 is much more accurate than the prediction made on the basis of four years of experience, but still not accurate enough to fulfill the customary NRC requirement of at least 95% accuracy.

III. CONCLUSION

The preceding example refers to a single location where FILC [FAC] can be expected. Basically, the argument shows that the absolute minimum number of thickness measurements required for reasonably accurate prediction of failure is three, if an assessment of the confidence limits of the resulting trend is to be made This is in agreement with Dr. Joram Hopenfeld's statements in his report titled "Review of License Renewal Application for Vermont Yankee Nuclear Power Station: Program for Management of Flow-Accelerated Corrosion," (April 24, 2008).[16]

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[15] SAS: Statistical Analysis Software from SAS Institute Inc. SAS Campus Drive, Cary, NC 27513, Ver. 3.1 of JMP

[16] Exhibit NEC-JH_36 at 16.

This also means that a rate prediction (establishing the new trend) could not be made before two regular outages following the EPU, and that upper and lower limits of this rate prediction would likely be very wide. It is entirely possible, however, that more than three measurements might be required because of how the results may turn out. In other words, one cannot prejudge the accuracy to be expected. In practical terms, this may mean the following: If at a particular location identified by pre-EPU operation or by information imbedded in CHECWORKS, the higher confidence limit of the observed corrosion rate [trend] were such as to predict failure beyond the anticipated service life, then this location would be classified as low risk and would not be monitored as frequently as others. If on the other hand the extrapolation of the upper trend were to show failure within the time interval scheduled for the next inspection of this location, the location would have to be monitored more frequently.

However, the assumption that the locations of highest FILC rates before the EPU should be the same as after is not likely to stand up to scrutiny. It may very well be found that the grids have to be extended or that new grids have to be developed. In this case inspections may extend over originally anticipated time spans.

Since, furthermore, it cannot be assumed that overall operations will be steady state, but that rather power fluctuations will result in flow rate variations, good rate predictions will be difficult. Therefore any risk assessment based on measured trends must take into consideration statistical probabilities. In this light, we think that Dr. Hopenfeld's assessment of the time necessary to recalibrate CHECWORKS, may be reasonable and perhaps even overly optimistic.[17]

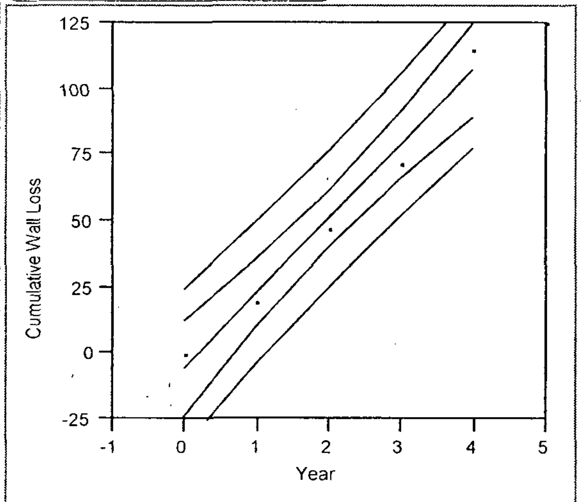
[17] See, Id.

Table 1
Hypothetical Wall Thickness Measurements over Time

Elapsed Time [years	Measured Wall Thickness [mils]	Cumulative Wall Thickness Loss [mils]	Corrosion Rate [mpy]
0	375	0	.
1	355	20	20.0
2	328	47	23.5
3	303	72	24.0
4	260	115	28.8
5	250	125	25.0
6	210	165	27.5
7	200	175	25.0
8	187	188	23.5
9	160	215	23.9

Figure 1
Statistical Evaluation of Corrosion Rate Using Data
From First Four Years

Cumulative Wall Loss By Year



Linear Fit

Linear Fit

Cumulative Wall Loss = -5.6 + 28.2 Year

Summary of Fit

RSquare	0.979987
RSquare Adj	0.973316
Root Mean Square Error	7.357536
Mean of Response	50.8
Observations (or Sum Wgts)	5

Analysis of Variance

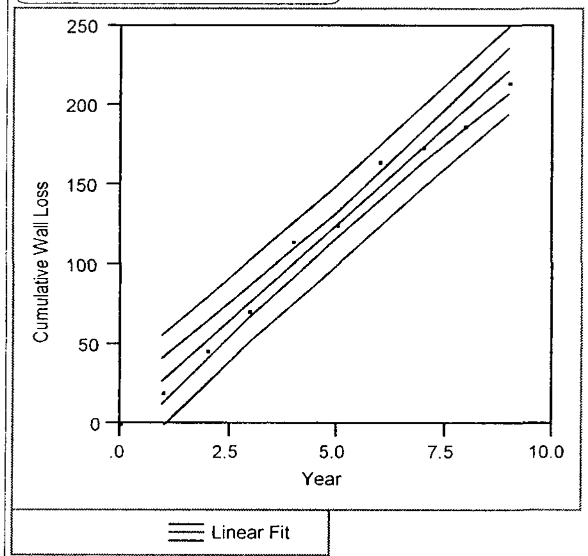
Source	DF	Sum of Squares	Mean Square	F Ratio
Model	1	7952.4000	7952.40	146.9039
Error	3	162.4000	54.13	Prob>F
C Total	4	8114.8000		0.0012

Parameter Estimates

Term	Estimate	Std Error	t Ratio	Prob>|t|
Intercept	-5.6	5.699123	-0.98	0.3983
Year	28.2	2.326657	12.12	0.0012

Figure 2
Statistical Evaluation of All Corrosion Rate Data
For All Nine Years of Measurements

Cumulative Wall Loss By Year



Linear Fit

Cumulative Wall Loss = 3.08333 + 24.3167 Year

Summary of Fit

RSquare	0.980435
RSquare Adj	0.97764
Root Mean Square Error	10.05686
Mean of Response	124.6667
Observations (or Sum Wgts)	9

Analysis of Variance

Source	DF	Sum of Squares	Mean Square	F Ratio
Model	1	35478.017	35478.0	350.7796
Error	7	707.983	101.1	Prob>F
C Total	8	36186.000		<.0001

Parameter Estimates

Term	Estimate	Std Error	t Ratio	Prob>|t|
Intercept	3.0833333	7.306141	0.42	0.6857
Year	24.316667	1.298335	18.73	<.0001

This Exhibit Contains Proprietary Information

January 24, 2003

Mr. John L. Skolds, President
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, Illinois 60555

SUBJECT: CLINTON POWER STATION
NRC INSPECTION REPORT 50-461/02-10(DRS)

Dear Mr. Skolds:

On December 13, 2002, the NRC completed an inspection at your Clinton Power Station. The enclosed report documents the inspection findings, which were discussed with Mr. K. Polson and other members of your staff at the completion of the inspection.

The inspectors examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. Specifically, the inspection focused on the Evaluations of Changes, Tests, or Experiments per 10 CFR 50.59 and Permanent Plant Modifications.

No safety significant items were identified and no response to this inspection report is required.

In accordance with 10 CFR 2.790 of the NRC's Rules of Practice, a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Ronald N. Gardner, Chief
Electrical Engineering Branch
Division of Reactor Safety

Docket No. 50-461
License No. NPF-62

Enclosure: Inspection Report 50-461/02-10(DRS)

See Attached Distribution

Mr. John L. Skolds, President
Exelon Nuclear
Exelon Generation Company, LLC
4300 Winfield Road
Warrenville, Illinois 60555

SUBJECT: CLINTON POWER STATION
NRC INSPECTION REPORT 50-461/02-10(DRS)

Dear Mr. Skolds:

On December 13, 2002, the NRC completed an inspection at your Clinton Power Station. The enclosed report documents the inspection findings, which were discussed with Mr. K. Polson and other members of your staff at the completion of the inspection.

The inspectors examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel. Specifically, the inspection focused on the Evaluations of Changes, Tests, or Experiments per 10 CFR 50.59 and Permanent Plant Modifications.

No safety significant items were identified and no response to this inspection report is required.

In accordance with 10 CFR 2.790 of the NRC's Rules of Practice, a copy of this letter and its enclosure will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,
/RA/

Ronald N. Gardner, Chief
Electrical Engineering Branch
Division of Reactor Safety

Docket No. 50-461
License No. NPF-62

Enclosure: Inspection Report 50-461/02-10(DRS)

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REGION III

Docket No: License No:	50-461 NPF-62
Report No:	50-471/02-10(DRS)
Licensee:	Exelon Generation Company, LLC
Facility:	Clinton Power Station
Location:	Route 54 West Clinton, IL 61727
Dates:	December 9 through 13, 2002
Inspectors:	H. Walker, Lead Inspector R. Winter, Engineering Inspector H. Anderson, Contract Inspector
Approved by:	Ronald M. Gardner, Chief Electrical Engineering Branch Division of Reactor Safety

SUMMARY OF FINDINGS

IR 05000471-02-10(DRS), Exelon Generation Company, LLC; on 12/09-13/02, Clinton Power Station; Evaluations of Changes, Tests, or Experiments per 10 CFR 50.59 and Permanent Plant Modifications.

The inspection was a one week baseline inspection of Permanent Plant Modifications and Evaluations of Changes, Tests, or Experiments. The inspection was conducted by regional engineering specialists, with the assistance of a mechanical consultant. No findings were identified during the inspection.

REPORT DETAILS

1. **REACTOR SAFETY**

Cornerstone: Mitigating Systems

1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

Review of Evaluations and Screenings for Changes, Tests, or Experiments

a. Inspection Scope

The inspectors reviewed five 10 CFR 50.59 evaluations and nine screenings. These documents were reviewed to ensure consistency with the requirements of 10 CFR 50.59. The inspectors used Nuclear Energy Institute (NEI) 96-07, "Guidelines of 50.59 Evaluations," Revision 1, to determine acceptability of the completed evaluations, and screenings. The NEI document was endorsed by the NRC in Regulatory Guide 1.187, "Guidance for Implementation of 10 CFR 50.59, Changes, Tests, and Experiments," November 2000. The inspectors also consulted Inspection Manual, Part 9900, 10 CFR GUIDANCE: 50.59. Documents reviewed during the inspection are listed at the end of the report.

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications (71111.17)

.1 Review of Recent Permanent Plant Modifications

a. Inspection Scope

The inspectors reviewed eleven permanent plant modifications that were installed during the last two years. These changes affected various systems in the plant. The review of the records completed the activities required by Attachment 17 of NRC Inspection Procedure 71111. The modifications were reviewed to verify that the completed design changes were in accordance with specified design requirements and the licensing bases and to confirm that the changes did not affect the modified system or other systems' safety function. Calculations which were performed or revised to support the modifications were also reviewed. As applicable to the status of the modification, post-modification testing was reviewed to verify that the system, and associated support systems, functioned properly and that the modification accomplished its intended function. The inspectors also verified that the completed modifications did not place the plant in an increased risk configuration. The inspectors evaluated the modifications against the licensee's design basis documents and the updated final safety analysis report (UFSAR). The inspectors also used applicable industry standards, such as the American Society of Mechanical Engineers Code, to evaluate acceptability of the modifications.

In addition to the normal review of permanent plant modifications, the inspectors reviewed selected design changes and other licensee documents associated with the effects of the plant power up-rate on the flow accelerated corrosion (FAC) program. This review is discussed in this section of the report.

b. Findings

No findings of significance were identified.

.2 Flow Accelerated Corrosion (FAC) Program

a. Inspection Scope

In accordance with Inspection Procedure 49001, "Inspection of Erosion-Corrosion/Flow-Accelerated-Corrosion Monitoring Programs," the inspectors reviewed documents and records to verify selected aspects of the FAC program. The review included associated design changes and calculations completed or revised to address the potential effects of the extended power up-rate (EPU) on the FAC program at the Clinton Power Plant. Evaluation of these documents also involved extensive discussions with licensee personnel.

In the review, the inspectors noted that Revision A of calculation 01065301, "CHECWORKS FAC Analysis," was confirmed to have incorporated inputs from the General Electric up-rate heat balance into the current FAC analysis. The Safety Evaluation Report (SER) related to the EPU was issued prior to completion of Revision A of the calculation; however, the SER summarized "in-progress" results provided by licensee personnel prior to issuance of Revision A of the calculation.

By reviewing documents and records, per Inspection Procedure 49001, "Inspection of Erosion-Corrosion/Flow-Accelerated-Corrosion Monitoring Programs," the inspectors verified the following aspects of the FAC program:

- The FAC program included a systematic method to predict system and component susceptibility, analyze inspection data to determine wall thinning rates, determine inspection intervals based on past inspection results, and repair or replace piping components.
- The program had defined criteria for selection of inspection locations.
- The program procedurally included measures to support effective monitoring and management of FAC effects during the life of the plant.
- The FAC program monitored the effect on FAC of expected changes in operating plant parameters as a result of the EPU in systems as identified in the SER, including main steam and attached piping, feedwater, and other pressure boundary piping.

- The program identified risk significant FAC concerns as a result of the EPU including identification of FAC program material replacements scheduled for installation during refueling outage RF09 in 2004.

The licensee personnel confirmed that the "in-progress" results discussed in the SER were conservative. The calculation results predicted wall thinning rates of 25 mils at 100 percent power and 27 mils at EPU conditions, an increase of approximately 8 percent.

Concerns raised by the inspectors were discussed with the licensee.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA2 Identification and Resolution of Problems

a. Inspection Scope

The team reviewed seventeen condition reports that were identified by licensee personnel and had been entered into the corrective action program. The inspectors reviewed these issues to verify an appropriate threshold for identifying issues and to evaluate the effectiveness of corrective actions related to the permanent plant design and evaluations for Changes, Tests, or Experiments issues. In addition, the condition report, written on an issue identified during the inspection, was reviewed to verify adequate problem identification and incorporation of the problem into the corrective action system. The specific corrective action documents that were sampled and reviewed by the team are listed in the attachment to this report.

b. Findings

No findings of significance were identified.

4OA6 Meetings

Exit Meeting

The inspectors presented the inspection results to Mr. K. J. Polson, and other members of licensee management, on December 13, 2002. The licensee acknowledged the inspection results presented. Licensee personnel were asked to identify any documents, materials, or information provided during the inspection that were considered proprietary. No proprietary information was identified.

KEY POINTS OF CONTACT

Licensee Management
K. Polson, Plant Manager
K. Baker, Senior Manager Design Engineering
R. Frantz, Regulatory Assurance
W. Iliff, Regulator Assurance Manager
R. Kerestes, Engineering
J. Madden, Nuclear Oversight Manager
P. Marcum, Engineering
E. Schwertzer, Engineering
R. Schmidt, Maintenance Director
J. Williams, Site Engineering Director

NRC
C. Brown, Resident Inspector
R. Gardner, Chief, Electrical Engineering Branch, DRS
P. Louden, Senior Resident Inspector
A. Stone, Chief, Projects Branch 4, DRP

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Closed

None

Discussed

None

LIST OF DOCUMENTS REVIEWED

The following documents were selected and reviewed by the inspectors during the Clinton biennial inspection of Evaluations of Changes, Tests, or Experiments and Permanent Plant Modifications conducted from December 9 through 13, 2002. The inspection was conducted to accomplish the objectives and scope of the inspection and to support the findings and issues noted. The list may include documents prepared by others for the licensee. Inclusion on this list does not imply that the NRC inspectors reviewed the documents in their entirety, but that selected portions of the documents were evaluated as part of the overall inspection effort. Also inclusion on this list does not imply NRC acceptance of the document, unless specifically stated in the body of the inspection report.

1R02 Evaluations of Changes, Tests, or Experiments

Evaluations

CL-2001-E-01890; DCP No. 333952 Temporary Modification, Defeat RR 'A' Runback; dated December 14, 2001

CL-2001-E-01900; DCP No. 334153 Temporary Modification, Manual RR 'A' FCV Position Control; dated December 14, 2001

CL-2002-E-00028; Activity/Document Number: CPS 3302.03 - Noble Metal Injection; Revision 1

CL-2002-E-00052; Clinton Unit 1 Cycle 9 Reload Core Design and Licensing; Revision 0

CL-2002-E-00520; Temporary Modification EC 338256, Temporarily Disable Turbine Control Valve #4; dated September 13, 2002

Screenings

CL-2001-S-0018; ECN 32439, Installation of Tie-In for WO Piping and Valves for the New Suppression Pool Cooling Heat Exchanger; dated March 22, 2001

CL-2001-S-0115; Reduction of Main Steam Line Radiation Monitors from Four to Two; dated October 25, 2001

CL-2001-S-01740; ORM 35-6, Setpoint Sign Changes; dated November 30, 2001

CL-2002-S-00210; USAR Change Package 8-303, USAR Change Package for Containment and Drywell Volume Corrections Including EPU; dated February 26, 2002

CL-2002-S-00510; USAR Change 10-095(change to 6.2.1.1.5.5 only), Evaluation of Change in the Analysis of the Small Break LOCA with Drywell Bypass Leakage; dated April 16, 2002

CL-2002-S-00780; EC337228, USAR Change 10-109, TS Bases Change, Instrumentation Aspects of Diesel Fuel Tank Level Requirements; dated June 27, 2002

LS-AA-104-1001; Reclassification of RCIC Pump Tech Spec Surveillance Parameters from Not Nominal to Nominal; dated May 20, 2002

LS-AA-104-1003; Replacement of Cylinder Indicator Valves on Div. 1 Diesel Generator - (1DG01KA); dated January 11, 2001

1005.06F001; Replace DG Air Start Solenoid Pilot Valves per ECNs 30444 and 30745; dated November 6, 1998

Condition Reports Written as a result of the Inspection

CR 00135358; Inconsistent Methods Were Used to Document the Results of 10 CFR 50.59 applicability Reviews for Modification; dated December 13, 2002

Condition Reports

CR 2-00-11-127; OD/OE Process/Procedure Does Not Provide Adequate Barriers to Assure Timely Corrective Actions; dated November 17, 2000

CR 2-01-06-017; 50.59 Screening Form Was Not Prepared; dated June 4, 2001

CR 2-01-05-157-0; Inadequate Implementation of LS-AA-104; dated May 15, 2001

CR 00099796; FP Diesel Tank Level Changed Without Documentation Bases; dated March 18, 2002

CR 00123080; Potential Expiration of TS 3.4.11 Pressure/Temperature Curve; dated September 16, 2002

CR 00124037; 50.59 Review Not Completed as Required per CPS 1870.02; dated September 22, 2002

Procedures

LS-AA-104; Exelon 50.59 Review Process; Revision 2

LS-AA-104-1000; Exelon 50.59 Resource Manual; Revision 0

LS-AA-104-1001; 50.59 Review Coversheet Form; Revision 0

LS-AA-104-1002; 50.59 Applicability Review Form; Revision 0

LS-AA-104-1006; Exelon 50.59 Training and Qualification; Revision 0

LS-AA-107; UFSAR Update Procedure; Revision 0

1R17 Permanent Plant Modifications

Modifications

31717; Replace Division II DG Crank Lockout Pressure Switches 1PSDG064C and 1PSDG065C with a Model with a Smaller Dead Band; dated November 21, 2001

32181; Remove the ERAT/RAT SVC Freeze Input to The SVC Controller by Jumpering the Breaker Aux Contact "B" from the Division 1 Diesel Generator Output Breaker; dated November 21, 2001

330499; Authorization for an Acceptable Replacement for Obsolete Gould ITE Type HE, JL, KM and E2 Molded Case Circuit Breakers Used in Gould ITE 5600 Series 125 VDC Motor Control Center; dated May 9, 2002

331074; Rotate Rosemont Transmitter 1LT-SM016 Suppression Pool Level; Revision 1

331208; Install Ball Valves in the MCR Breathing Air System Fill Lines; Revision 1

331323; Feedwater Support Modification; Revision 0

331896; Replacement of Cylinder Indicator Valves on Div 1 Diesel Generator; Revision 0

333256; Replace the Division III Carbon Steel Vacuum Breakers with New Stainless Steel Replacements (1SX315A/B and 1SX316A/B); Revision 0

333417; Upgrade Woodward Controls 2301A Load Sharing and Speed Control on the Division II Diesel Generator 1B Control Panel (1PL12JB); Revision 1

334569; 0DG-ST-11 Line Replacement; Revision 0

335110; Allow Replacement of Existing Reactor Core Isolation Cooling (RI) Piping of Carbon Steel Material with 2 1/4 CR-MO (Chrome-Moly) Material; Revision 0

Equivalency Evaluations

Evaluation #10718/1106915; Hydrogen Ignitors - The original AC Delco 7G glow plug is obsolete and possesses a high failure rate per CR 2-01-02-143. The Champion CH-78 (Stock # 178) glow plug is an acceptable alternate in fit, form, and function to the original AC Delco 7G.

Evaluation #16231/1146463; Emergency Diesel Generator (EDG) Right Hand Air Start Motors - Evaluation #16231 performed IEE to approve material changes as per equivalency performed by diesel vendor, ESI, and scanned into IEE OLE field. Part number of motors did not change.

Design Report

DR-A020104; Design Report DR-A020104 Revision 0 for 3/4", stainless steel, ANSI Class 600, In-line Check Valve with Screwed End Endcaps (Purchase order No. PO 00037775, BNL Shop Order No. A020104); Revision 0

Condition Reports

CR 1-96-11-252; *Unauthorized Modification Installed in WS System under MWR* D74712 - System Declared Operable; dated November 16, 1996

CR 86825; RR FCV A Temp Mod Implementation Problems; dated December 15, 2001

CR 93284; Discrepancies ID'ed in D C P 32236; dated January 31, 2002

CR 2-01-05-157-0; Inadequate Implementation of LS-AA-104; dated May 15, 2001

CR 00064517; 2-01-07-053 Design Change Process Breakdown for EC 331444 CO; dated July 5, 2001

CR 00099796; FP Diesel Tank Level Changed Without Documentation Bases; dated March 18, 2002

CR 00105636; Design Deficiency in RCIC MOD; dated May 20, 2002

CR 00108356; NON (Nuclear Operations Network) Review of Effects of Diesel Exhaust on Charcoal Filters; completed October 30, 2002

CR 00115251; Non-compliance w/ANSI N18.7 Configuration Changes; completed July 23, 2002

CR 00119318; Enhancements to OP-AA-108-101/102; completed August 26, 2002

CR 00123080; Potential Expiration of TS 3.4.11 Pressure/Temperature Curve; dated September 16, 2002

Procedures

CI-01.00; Instrument Setpoint Calculation Methodology; Revision 2

CC-AA-102; Design Input and Configuration Change Impact Screening; Revision 4

CC-AA-103; Configuration Change Control; Revision 3

CC-MW-103-1001; Configuration Change Control Guidance; Revision 0

CC-AA-107; Configuration Change Acceptance Testing Criteria; Revision 2

CC-AA-107-1001; Post Modification Acceptance Testing; Revision 0

CC-AA-309; Control of Design Analysis; Revision 3

SM-AA-300; Procurement of Engineering Support; Revision 0

SM-AA-401; Material Procurement; Revision 2

Miscellaneous Documents

Assessment of Maintenance Effectiveness 10CFR50.65 (a)(3) Assessment, Clinton Power Station, March 1, 2000 to October 20, 2002

Flow Accelerated Corrosion Issues

CSI Calculation No. 01065301; CHECWORKS FAC Analysis - Clinton Power Station; Revision A (For Use); dated January 11, 2002

ER-AA-430; Conduct of Flow Accelerated Corrosion Activities; Revision 0

ER-AA-430-1001; Guidelines for Flow Accelerated Corrosion Activities; Revision 0

ER-AA-430-1002; Feedwater Heater Shell Inspection for Detection of Flow Accelerated Corrosion; Revision 1

LIST OF ACRONYMS USED

ADAMS	Agency-wide Document Access and Management System
CFR	Code of Federal Regulations
DRS	Division of Reactor Safety
EPU	Extended Power Up-rate
FAC	Flow Accelerated Corrosion
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PARS	Publicly Available Records System
SDP	Significance Determination Process
SER	Safety Evaluate Report
UFSAR	Updated Final Safety Analysis Report

Inspection was rescheduled from July 29, 2002 to December 9, 2002

MODIFICATION AND 50.59 INSPECTION DOCUMENT REQUEST

The following information was provided electronically to the licensee prior to the inspection:
E-mailed on June 7, 2002

Lead Inspector: Zelig Falevits
Team Members: Gerard O'Dwyer, Ken O'Brien, Bob Winter

I **<u>Information Needed for In-Office Preparation Week</u>** <u>(July 22-26,2002)</u>

The following information is needed by July 19, 2002, or sooner, to facilitate the selection of specific items that will be reviewed during the onsite inspection week. The team will select specific items from the information requested below and submit a list to your staff by July 24, 2002. We request that the specific items selected from the lists be available and ready for review on the first day of onsite inspection (July 29, 2002). If you have any questions regarding this information, please contact me at (630) 829-9717 or e-mail zxf@nrc.gov as soon as possible. All lists requested should cover the time frame July 2000 until present. All information should be sent electronically if at all possible.

Permanent Plant Modifications

1. List of permanent plant modifications/ design changes. In addition to the list, please provide a brief (one paragraph) description of each modification (e.g., copy of modification description from DCP or safety evaluation.)

2. List of setpoint changes. (Identify system and instrument).

3. List of equivalency evaluations or suitability analysis.

4. List of commercial grade dedications.

5. List of condition reports (open or closed) issued to address permanent plant modification issues, concerns, or process.

6. Copy of procedures for the following: modifications, design changes, set point changes, equivalency evaluations or suitability analyses, commercial grade dedications, and post-modification testing.

Changes, Tests, or Experiments (10 CFR 50.59)

1. List of all 10 CFR 50.59 completed evaluations involving: (A) changes to facility (modifications); (B) procedure revisions; (C) tests or non-routine operating configurations; (D) changes to the UFSAR; or (E) calculations

2. List of all 10 CFR 50.59 screenings that have been screened out as not requiring a full evaluation involving: (A) changes to facility (modifications); (B) procedure revisions; (C) tests or non-routine operating configurations; (D) changes to the UFSAR; or (E) calculations

3. List of condition reports (open or closed) issued to address problems associated with 10 CFR 50.59 evaluations, screenings, or process.

4. Copy of procedures that specify how 10 CFR 50.59 evaluations and screenings are performed.

5. Copy of procedures that delineate how 10 CFR 50.59 FSAR updates are prepared by engineers or staff and how the licensee submits 10 CFR 50.59 FSAR updates.

6. List of special tests or experiments and non-routine operating configurations in the last two years (if any.)

General Information

1. Latest engineering organization chart

2. Site phone list

3. System and Design Engineering lists

4. List of maintenance rule high safety significant systems

5. List of maintenance rule (a)(1) systems. (Those systems presently in (a)(1) and systems that were (a)(1) in 2001 or 2002 and returned to (a)(2) [List date system went to (a)(1) and date system returned to (a)(2)])

II **<u>Information to be Available on First Day of Onsite Inspection</u>**

We request that the following information be <u>available</u> to the inspectors once they arrive onsite. (Copies of the updated final safety analysis report, independent plant evaluation probabilistic safety analysis, vendor manuals, or technical specifications do not need to be solely available to the team as long as the inspectors have ready access to them.)

- The latest 10 CFR 50.59 Final Safety Analysis Report Update Submittal

- Updated Final Safety Analysis Report

- Technical Specifications

- Independent Plant Evaluation Probabilistic Safety Analysis Report

- Vendor Manuals
- Equipment Qualification Binders
- Relevant Calculations And Analyses (for selected modifications and 50.59s)
- Copies of previously selected modifications, permanent plant changes, design changes, setpoint changes, procedure changes, equivalency evaluations, suitability analyses, calculations, commercial grade dedications, 10 CFR 50.59 evaluations and screenings and condition reports.

NEC-UW_05

NUREG-1801, Vol. 2, Rev. 1

Generic Aging Lessons Learned (GALL) Report

Tabulation of Results

Manuscript Completed: September 2005
Date Published: September 2005

Division of Regulatory Improvement Programs
Office of Nuclear Reactor Regulation
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001

X.M1 METAL FATIGUE OF REACTOR COOLANT PRESSURE BOUNDARY

Program Description

In order not to exceed the design limit on fatigue usage, the aging management program (AMP) monitors and tracks the number of critical thermal and pressure transients for the selected reactor coolant system components.

The AMP addresses the effects of the coolant environment on component fatigue life by assessing the impact of the reactor coolant environment on a sample of critical components for the plant. Examples of critical components are identified in NUREG/CR-6260. The sample of critical components can be evaluated by applying environmental life correction factors to the existing ASME Code fatigue analyses. Formulae for calculating the environmental life correction factors are contained in NUREG/CR-6583 for carbon and low-alloy steels and in NUREG/CR-5704 for austenitic stainless steels.

As evaluated below, this is an acceptable option for managing metal fatigue for the reactor coolant pressure boundary, considering environmental effects. Thus, no further evaluation is recommended for license renewal if the applicant selects this option under 10 CFR 54.21(c)(1)(iii) to evaluate metal fatigue for the reactor coolant pressure boundary.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program includes preventive measures to mitigate fatigue cracking of metal components of the reactor coolant pressure boundary caused by anticipated cyclic strains in the material.

2. ***Preventive Actions:*** Maintaining the fatigue usage factor below the design code limit and considering the effect of the reactor water environment, as described under the program description, will provide adequate margin against fatigue cracking of reactor coolant system components due to anticipated cyclic strains.

3. ***Parameters Monitored/Inspected:*** The program monitors all plant transients that cause cyclic strains, which are significant contributors to the fatigue usage factor. The number of plant transients that cause significant fatigue usage for each critical reactor coolant pressure boundary component is to be monitored. Alternatively, more detailed local monitoring of the plant transient may be used to compute the actual fatigue usage for each transient.

4. ***Detection of Aging Effects:*** The program provides for periodic update of the fatigue usage calculations.

5. ***Monitoring and Trending:*** The program monitors a sample of high fatigue usage locations. This sample is to include the locations identified in NUREG/CR-6260, as minimum, or propose alternatives based on plant configuration.

6. ***Acceptance Criteria:*** The acceptance criteria involves maintaining the fatigue usage below the design code limit considering environmental fatigue effects as described under the program description.

7. ***Corrective Actions:*** The program provides for corrective actions to prevent the usage factor from exceeding the design code limit during the period of extended operation.

Acceptable corrective actions include repair of the component, replacement of the component, and a more rigorous analysis of the component to demonstrate that the design code limit will not be exceeded during the extended period of operation. For programs that monitor a sample of high fatigue usage locations, corrective actions include a review of additional affected reactor coolant pressure boundary locations. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. ***Confirmation Process:*** Site quality assurance procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of Appendix B to 10 CFR Part 50. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The program reviews industry experience regarding fatigue cracking. Applicable experience with fatigue cracking is to be considered in selecting the monitored locations.

References

NUREG/CR-5704, *Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels,* U.S. Nuclear Regulatory Commission, April 1999.

NUREG/CR-6260, *Application of NUREG/CR-5999 Interim Fatigue Curves to Selected Nuclear Power Plant Components,* U.S. Nuclear Regulatory Commission, March 1995.

NUREG/CR-6583, *Effects of LWR Coolant Environments on Fatigue Design Curves of Carbon and Low-Alloy Steels,* U.S. Nuclear Regulatory Commission, March 1998.

XI.M17 FLOW-ACCELERATED CORROSION

Program Description

The program relies on implementation of the Electric Power Research Institute (EPRI) guidelines in the Nuclear Safety Analysis Center (NSAC)-202L-R2 for an effective flow-accelerated corrosion (FAC) program. The program includes performing (a) an analysis to determine critical locations, (b) limited baseline inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm the predictions, or repairing or replacing components as necessary.

Evaluation and Technical Basis

1. *Scope of Program:* The FAC program, described by the EPRI guidelines in NSAC-202L-R2, includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained. Valve bodies retaining pressure in these high-energy systems are also covered by the program. The FAC program was originally outlined in NUREG-1344 and was further described through the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-08. A program implemented in accordance with the EPRI guidelines predicts, detects, and monitors FAC in plant piping and other components, such as valve bodies, elbows and expanders. Such a program includes the following recommendations: (a) conducting an analysis to determine critical locations, (b) performing limited baseline inspections to determine the extent of thinning at these locations, and (c) performing follow-up inspections to confirm the predictions, or repairing or replacing components as necessary. NSAC-202L-R2 (April 1999) provides general guidelines for the FAC program. To ensure that all the aging effects caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, criteria for development of procedures and control of special processes.

2. *Preventive Actions:* The FAC program is an analysis, inspection, and verification program; thus, there is no preventive action. However, it is noted that monitoring of water chemistry to control pH and dissolved oxygen content, and selection of appropriate piping material, geometry, and hydrodynamic conditions, are effective in reducing FAC.

3. *Parameters Monitored/Inspected:* The aging management program (AMP) monitors the effects of FAC on the intended function of piping and components by measuring wall thickness.

4. *Detection of Aging Effects:* Degradation of piping and components occurs by wall thinning. The inspection program delineated in NSAC-202L-R2 consists of identification of susceptible locations as indicated by operating conditions or special considerations. Ultrasonic and radiographic testing is used to detect wall thinning. The extent and schedule of the inspections assure detection of wall thinning before the loss of intended function.

5. *Monitoring and Trending:* CHECWORKS or a similar predictive code is used to predict component degradation in the systems conducive to FAC, as indicated by specific plant data, including material, hydrodynamic, and operating conditions. CHECWORKS is

acceptable because it provides a bounding analysis for FAC. CHECWORKS was developed and benchmarked by using data obtained from many plants. The inspection schedule developed by the licensee on the basis of the results of such a predictive code provides reasonable assurance that structural integrity will be maintained between inspections. Inspection results are evaluated to determine if additional inspections are needed to assure that the extent of wall thinning is adequately determined, assure that intended function will not be lost, and identify corrective actions.

6. *Acceptance Criteria:* Inspection results are input for a predictive computer code, such as CHECWORKS, to calculate the number of refueling or operating cycles remaining before the component reaches the minimum allowable wall thickness. If calculations indicate that an area will reach the minimum allowed wall thickness before the next scheduled outage, the component is to be repaired, replaced, or reevaluated.

7. *Corrective Actions:* Prior to service, components for which the acceptance criteria are not satisfied are reevaluated, repaired, or replaced. Long-term corrective actions could include adjusting operating parameters or selecting materials resistant to FAC. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. *Confirmation Process:* Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. *Administrative Controls:* See Item 8, above.

10. *Operating Experience:* Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC IE Bulletin No. 87-01; NRC Information Notices [INs] 81-28, 92-35, 95-11) and in two-phase piping in extraction steam lines (NRC INs 89-53, 97-84) and moisture separation reheater and feedwater heater drains (NRC INs 89-53, 91-18, 93-21, 97-84). Operating experience shows that the present program, when properly implemented, is effective in managing FAC in high-energy carbon steel piping and components.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR Part 50.55a, Codes and Standards, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 89-08, *Erosion/Corrosion-Induced Pipe Wall Thinning*, U.S. Nuclear Regulatory Commission, May 2, 1989.

NRC IE Bulletin 87-01, *Thinning of Pipe Walls in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, July 9, 1987.

NRC Information Notice 81-28, *Failure of Rockwell-Edward Main Steam Isolation Valves*, U.S. Nuclear Regulatory Commission, September 3, 1981.

NRC Information Notice 89-53, *Rupture of Extraction Steam Line on High Pressure Turbine*, U.S. Nuclear Regulatory Commission, June 13, 1989.

NRC Information Notice 91-18, *High-Energy Piping Failures Caused by Wall Thinning*, U.S. Nuclear Regulatory Commission, March 12, 1991.

NRC Information Notice 91-18, Supplement 1, *High-Energy Piping Failures Caused by Wall Thinning*, U.S. Nuclear Regulatory Commission, December 18, 1991.

NRC Information Notice 92-35, *Higher than Predicted Erosion/Corrosion in Unisolable Reactor Coolant Pressure Boundary Piping inside Containment at a Boiling Water Reactor*, U.S. Nuclear Regulatory Commission, May 6, 1992.

NRC Information Notice 93-21, *Summary of NRC Staff Observations Compiled during Engineering Audits or Inspections of Licensee Erosion/Corrosion Programs*, U.S. Nuclear Regulatory Commission, March 25, 1993.

NRC Information Notice 95-11, *Failure of Condensate Piping Because of Erosion/Corrosion at a Flow Straightening Device*, U.S. Nuclear Regulatory Commission, February 24, 1995.

NRC Information Notice 97-84, *Rupture in Extraction Steam Piping as a Result of Flow-Accelerated Corrosion*, U.S. Nuclear Regulatory Commission, December 11, 1997.

NSAC-202L-R2, *Recommendations for an Effective Flow Accelerated Corrosion Program*, Electric Power Research Institute, Palo Alto, CA, April 8, 1999.

NUREG-1344, *Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants*, P. C. Wu, U.S. Nuclear Regulatory Commission, April 1989.

XI.M18 BOLTING INTEGRITY

Program Description

The program relies on recommendations for a comprehensive bolting integrity program, as delineated in NUREG-1339, and industry recommendations, as delineated in the Electric Power Research Institute (EPRI) NP-5769, with the exceptions noted in NUREG-1339 for safety-related bolting. The program relies on industry recommendations for comprehensive bolting maintenance, as delineated in EPRI TR-104213 for pressure retaining bolting and structural bolting.

The program generally includes periodic inspection of closure bolting for indication of loss of preload, cracking, and loss of material due to corrosion, rust, etc. The program also includes preventive measures to preclude or minimize loss of preload and cracking.

Other aging management programs, such as XI.M1, "ASME Section XI Inservice Inspection (ISI) Subsections IWB, IWC, and IWD" and XI.S3, "ASME Section XI Subsection IWF" also manage inspection of safety-related bolting and supplement this bolting integrity program.

Evaluation and Technical Basis

1. ***Scope of Program:*** This program covers bolting within the scope of license renewal, including: 1) safety-related bolting, 2) bolting for nuclear steam supply system (NSSS) component supports, 3) bolting for other pressure retaining components, including non-safety-related bolting, and 4) structural bolting (actual measured yield strength ≥ 150 ksi). The aging management of reactor head closure studs is addressed by XI.M3, and is not included in this program. The staff's recommendations and guidelines for comprehensive bolting integrity programs that encompass all safety-related bolting are delineated in NUREG-1339, which include the criteria established in the 1995 edition through the 1996 addenda of ASME Code Section XI. The industry's technical basis for the program for safety-related bolting and guidelines for material selection and testing, bolting preload control, ISI, plant operation, and maintenance, and evaluation of the structural integrity of bolted joints, are outlined in EPRI NP-5769, with the exceptions noted in NUREG-1339. For other bolting, this information is set forth in EPRI TR-104213.

2. ***Preventive Actions:*** Selection of bolting material and the use of lubricants and sealants is in accordance with the guidelines of EPRI NP-5769, and the additional recommendations of NUREG-1339, to prevent or mitigate degradation and failure of safety-related bolting (see element 10, below). NUREG-1339 takes exception to certain items in EPRI NP-5769, and recommends additional measures with regard to them. Bolting replacement activities include proper torquing of the bolts and checking for uniformity of the gasket compression after assembly. Maintenance practices require the application of an appropriate preload, based on EPRI documents.

3. ***Parameters Monitored/Inspected:*** This program monitors the effects of aging on the intended function of bolting. Specifically, bolting for safety-related pressure retaining components is inspected for leakage, loss of material, cracking, and loss of preload/loss of prestress. Bolting for other pressure retaining components is inspected for signs of leakage.

High strength bolts (actual yield strength ≥150 ksi) used in NSSS component supports are monitored for cracking. Structural bolts and fasteners are inspected for indication of potential problems including loss of material, cracking, loss of coating integrity, and obvious signs of corrosion, rust, etc.

4. ***Detection of Aging Effects:*** Inspection requirements are in accordance with the ASME Section XI, Tables IWB 2500-1, IWC 2500-1 and IWD 2500-1 editions endorsed in 10 CFR 50.55a(b)(2) and the recommendations of EPRI NP-5769. For Class 1 components, Table IWB 2500-1, Examination Category B-G-1, for bolts greater than 2-inches in diameter, specifies volumetric examination of studs and bolts and visual VT-1 examination of surfaces of nuts, washers, bushings, and flanges. Examination Category B-G-2, for bolts 2-inches or smaller, requires only visual VT-1 examination of surfaces of bolts, studs, and nuts. For Class 2 components, Table IWC 2500-1, Examination Category C-D, for bolts greater than 2-inches in diameter, requires volumetric examination of studs and bolts. Examination Categories B-P, C-H, and D-B require visual examination (IWA-5240) during system leakage testing of all pressure-retaining Class 1, 2 and 3 components, according to Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, respectively. In addition, degradation of the closure bolting due to crack initiation, loss of prestress, or loss of material due to corrosion of the closure bolting would result in leakage. The extent and schedule of inspections, in accordance with Tables IWB 2500-1, IWC 2500-1, and IWD 2500-1, combined with periodic system walkdowns, assure detection of leakage before the leakage becomes excessive.

   For other pressure retaining bolting, periodic system walkdowns assure detection of leakage before the leakage becomes excessive.

   High strength structural bolts and fasteners (actual yield strength 150 ksi) for NSSS component supports, may be subject to stress corrosion cracking (SCC). For this type of high strength structural bolts that are potentially subjected to SCC, in sizes greater than 1-inch nominal diameter, volumetric examination comparable to that of Examination Category B-G-1 is required in addition to visual examination. This requirement may be waived with adequate plant-specific justification. Structural bolts and fasteners (actual yield strength < 150 ksi) both inside and outside containment are inspected by visual inspection (e.g., Structures Monitoring Program or equivalent). In addition to visual and volumetric examination, degradation of these bolts and fasteners may be detected and measured by removing the bolt/fastener, a proof test by tension or torquing, in situ ultrasonic tests, or a hammer test. If these bolts and fasteners are found cracked and/or corroded, a closer inspection is performed to assess extent of corrosion. An appropriate technique is selected on the basis of the bolting application and the applicable code.

5. ***Monitoring and Trending:*** The inspection schedules of ASME Section XI are effective and ensure timely detection of applicable aging effects. If bolting connections for pressure retaining components (not covered by ASME Section XI) is reported to be leaking, then it may be inspected daily. If the leak rate does not increase, the inspection frequency may be decreased to biweekly or weekly.

6. ***Acceptance Criteria:*** Any indications of aging effects in ASME pressure retaining bolting are evaluated in accordance with Section XI of the ASME Code. For other pressure retaining bolting, NSSS component support bolting and structural bolting, indications of aging should be dispositioned in accordance with the corrective action process.

7. *Corrective Actions:* Replacement of ASME pressure retaining bolting is performed in accordance with appropriate requirements of Section XI of the ASME Code, as subject to the additional guidelines and recommendations of EPRI NP-5769. Replacement of other pressure retaining bolting (i.e., non-Class 1 bolting) and disposition of degraded structural bolting is performed in accordance with the guidelines and recommendations of EPRI TR-104213. Replacement of NSSS component support bolting is performed in accordance with EPRI NP-5769. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. *Confirmation Process:* Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. *Administrative Controls:* See item 8, above.

10. *Operating Experience:* Degradation of threaded bolting and fasteners in closures for the reactor coolant pressure boundary has occurred from boric acid corrosion, SCC, and fatigue loading (NRC IE Bulletin 82-02, NRC Generic Letter 91-17). SCC has occurred in high strength bolts used for NSSS component supports (EPRI NP-5769). The bolting integrity program developed and implemented in accordance with commitments made in response to NRC communications on bolting events have provided an effective means of ensuring bolting reliability. These programs are documented in EPRI NP-5769 and TR-104213 and represent industry consensus.

    Degradation related failures have occurred in downcomer Tee-quencher bolting in BWRs designed with drywells (ADAMS Accession Number ML050730347). Leakage from bolted connections has been observed in reactor building closed cooling systems of BWRs. (LER 50-341/2005-001).

    The applicant is to evaluate applicable operating experience to support the conclusion that the effects of aging are adequately managed.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR 50.55a, *Codes and Standards*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2001 edition including the 2002 and 2003 Addenda, American Society of Mechanical Engineers, New York, NY.

EPRI NP-5769, *Degradation and Failure of Bolting in Nuclear Power Plants*, Volumes 1 and 2, April 1988.

EPRI TR-104213, *Bolted Joint Maintenance & Application Guide,* Electric , December 1995.

NRC Generic Letter 91-17, *Generic Safety Issue 79, Bolting Degradation or Failure in Nuclear Power Plants,* U.S. Nuclear Regulatory Commission, October 17, 1991.

NRC IE Bulletin No. 82-02, *Degradation of Threaded Fasteners in the Reactor Coolant Pressure Boundary of PWR Plants*, U.S. Nuclear Regulatory Commission, June 2, 1982.

NUREG-1339, *Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, June 1990.

Failure of Safety/Relief Valve Tee-Quencher Support Bolts, NRC Morning Report for March 14, 2005, ADAMS Accession Number ML050730347.

XI.M19 STEAM GENERATOR TUBE INTEGRITY

Program Description

The steam generator tube integrity program is applicable to managing the aging of steam generator tubes, plugs, sleeves and tube supports.

Mill annealed alloy 600 steam generator (SG) tubes have experienced tube degradation related to corrosion phenomena, such as primary water stress corrosion cracking (PWSCC), outside diameter stress corrosion cracking (ODSCC), intergranular attack (IGA), pitting, and wastage, along with other mechanically induced phenomena, such as denting, wear, impingement damage, and fatigue. The dominant degradation mode at this time for thermally treated alloy 600 and 690 tubes is wear. Nondestructive examination (NDE) techniques are used to inspect all tubing materials and sleeves to identify tubes with degradation that may need to be removed from service or repaired in accordance with plant technical specifications. In addition, operational leakage limits are included to ensure that, should substantial tube leakage develop, prompt action is taken. These limits are included in plant technical specifications, such as standard technical specifications of NUREG-1430, Rev. 1, for Babcock & Wilcox pressurized water reactors (PWRs); NUREG-1431, Rev. 1, for Westinghouse PWRs; and NUREG-1432, Rev. 1, for Combustion Engineering PWRs.

The technical specifications specify SG inspection scope, frequency, and acceptance criteria for the plugging and repair of flawed tubes. NRC Regulatory Guide (RG) 1.121, “Bases for Plugging Degraded Steam Generator Tubes,” provides guidelines for determining the tube repair criteria and operational leakage limits. Acceptance criteria for the plugging and repair of flawed tubes are incorporated in plant technical specifications. In addition to flaw acceptance (or plugging/repair) criteria, the technical specifications also specify acceptable tube repair methods (e.g., plugging and/or sleeving). Plants may also apply for changes in their technical specifications to provide an alternate repair criteria for SG degradation management.

In addition to plant technical specifications, all PWR licensees have committed voluntarily to a SG degradation management program described in the Nuclear Energy Institute (NEI) 97-06, “Steam Generator Program Guidelines.” This program references a number of industry guidelines and incorporates a balance of prevention, inspection, evaluation, repair, and leakage monitoring measures. The NEI 97-06 document (a) includes performance criteria that are intended to provide assurance that tube integrity is being maintained consistent with the plant's licensing basis, and (b) provides guidance for monitoring and maintaining the tubes to provide assurance that the performance criteria are met at all times between scheduled inspections of the tubes. Steam generator tube integrity can be affected by degradation of SG plugs, sleeves and tube supports. Therefore, these components are also addressed by this aging management program.

The NEI 97-06 program includes an assessment of degradation mechanisms that considers operating experience from similar steam generators (SGs) and, for each mechanism, defines the inspection techniques as well as the sampling strategy. The industry guidelines provide criteria for the qualification of personnel, specific techniques, and the associated acquisition and analysis of data, including procedures, probe selection, analysis protocols, and reporting criteria. The performance criteria pertain to structural integrity, accident-induced leakage, and operational leakage. The SG monitoring program includes guidance on assessment of degradation mechanisms, inspection, tube integrity assessment, maintenance, plugging, repair, and leakage monitoring, as well as procedures for monitoring and controlling secondary-side and primary-side water chemistry. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry and secondary water chemistry.

Lastly, NRC Generic Letter (GL) 97-06, "Degradation of Steam Generator Internals," dated December 30, 1997, notified the industry of various steam generator tube support plate damage mechanisms identified in foreign and domestic steam generators. In response to GL 97-06, licensees indicated whether they had a program in place to detect degradation of steam generator internals, and included a description of the inspection plans, including the inspection scope, frequency, methods, and components.

As evaluated below, the plant technical specifications, including alternate repair criteria for SG degradation management that have been previously approved by the staff for that plant, the licensee's response to GL 97-06, and the licensee's commitment to implement the SG degradation management program described in NEI 97-06, are adequate to manage the effects of aging on the SG tubes, plugs, sleeves, and tube supports.

Evaluation and Technical Basis

1. ***Scope of Program:*** The scope of the program is specific to SG tubes, plugs, sleeves and tube supports. The program includes preventive measures to mitigate degradation related to corrosion phenomena, assessment of degradation mechanisms, inservice inspection (ISI) of steam generator tubes, plugs, sleeves, and tube supports to detect degradation, evaluation, and plugging or repair, as needed, and leakage monitoring to maintain the structural and leakage integrity of the pressure boundary. Tube and sleeve inspection scope and frequency, plugging or repair, and leakage monitoring are in accordance with the plant technical specifications and the licensee's SG degradation management program implemented in accordance with NEI 97-06. Plug inspection scope and frequency, plugging or repair, and leakage monitoring are in accordance with the licensee's SG degradation management program implemented in accordance with NEI 97-06. Lastly, tube support plate inspection scope and frequency are in accordance with the licensee's SG degradation management program implemented in accordance with NEI 97-06 as well as the program described in the licensee's response to GL 97-06.

2. ***Preventive Actions:*** The program includes preventive measures to mitigate degradation related to corrosion phenomena. The guidelines in NEI 97-06 include foreign material exclusion as a means to inhibit wear degradation. The water chemistry program for PWRs relies on monitoring and control of reactor water chemistry based on the EPRI guidelines in TR-05714 for primary water chemistry and TR-102134 for secondary water chemistry. The program description and the evaluation and technical basis of monitoring and maintaining reactor water chemistry are presented in Chapter XI.M2, "Water Chemistry," of this report.

3. ***Parameters Monitored/Inspected:*** The inspection activities in the program detect flaws in tubing, plugs, sleeving, and degradation of tube supports needed to maintain tube integrity. Tubes are repaired or removed from service based on technical specification repair criteria. Sleeves are removed from service based on technical specification repair criteria. Degraded plugs and tube supports are evaluated for corrective actions.

4. ***Detection of Aging Effects:*** The inspection requirements in the technical specifications are intended to detect tube and sleeve degradation (i.e., aging effects), if they should occur. NEI 97-06 provides additional guidance on inspection programs to detect

degradation of tubes, sleeves, plugs and tube supports. The intent of the inspection and repair criteria is to provide assurance of continued tube integrity between inspections. A licensee's response to GL 97-06 also provides a description of plant-specific inspection programs for detection of degraded SG internals.

5. ***Monitoring and Trending:*** Condition monitoring assessments are performed to determine whether structural and accident leakage criteria have been satisfied. Operational assessments are performed after inspections to verify that structural and leakage integrity will be maintained for the operating interval between inspections, which is selected in accordance with the technical specifications and NEI 97-06 guidelines. Comparison of the results of the condition monitoring assessment with the predictions of the previous operational assessment provides feedback for evaluation of the adequacy of the operational assessment and additional insights that can be incorporated into the next operational assessment.

6. ***Acceptance Criteria:*** Assessment of tube and sleeve integrity and plugging or repair criteria of flawed and sleeved tubes is in accordance with plant technical specifications. The criteria for plugging or repairing SG tubes and sleeves are based on NRC RG 1.121 or other criteria previously reviewed and approved by the staff and incorporated into plant technical specifications. Some examples of acceptance criteria that are applicable under certain circumstances include F*, L*, or NRC Generic Letter (GL) 95-05, "Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside-Diameter Stress-Corrosion Cracking."

7. ***Corrective Actions:*** Tubes and sleeves containing flaws that do not meet the acceptance criteria are plugged or repaired. Degraded plugs and tube supports are evaluated for corrective actions. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Failures to detect some flaws, uncertainties in flaw sizing, inaccuracies in flaw locations, and the inability to detect some cracks at locations with dents have been reviewed in NRC Information Notice (IN) 97-88. Recent experience indicates the importance of performing a complete inspection by using appropriate techniques and components for the reliable detection of tube degradation and to provide assurance that new forms of degradation are detected. Implementation of the program provides reasonable assurance that SG tube integrity is maintained consistent with the plants' licensing basis for the period of extended operation. Experience with the condition monitoring and operational assessments required for plants that have implemented the alternate repair criteria in NRC GL 95-05 has shown that the predictions of the operational assessments have generally been consistent with the results of the subsequent condition monitoring assessments. In cases where discrepancies have been noted, adjustments have been made in the operational assessment models to improve agreement in

subsequent assessments. In addition, the industry has programs/processes for incorporating lessons learned from plant operation into guidelines referenced in NEI 97-06.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

10 CFR Part 50.55a, Codes and Standards, Office of the Federal Register, National Archives and Records Administration, 2005.

EPRI TR-102134, *PWR Secondary Water Chemistry Guidelines: Revision 3*, Electric Power Research Institute, Palo Alto, CA, May 1993.

EPRI TR-105714, *PWR Primary Water Chemistry Guidelines: Revision 3*, Electric Power Research Institute, Palo Alto, CA, November 1995.

EPRI TR-107569, *PWR Steam Generator Examination Guidelines: Revision 6*, Electric Power Research Institute, Palo Alto, CA, October 2002.

NEI 97-06, Rev. 1, *Steam Generator Program Guidelines*, Nuclear Energy Institute, January 2001.

NRC Generic Letter 95-05, *Voltage-Based Repair Criteria for Westinghouse Steam Generator Tubes Affected by Outside-Diameter Stress-Corrosion Cracking,* U.S. Nuclear Regulatory Commission, August 3, 1995.

NRC Generic Letter 97-06, *Degradation of Steam Generator Internals*, U.S. Nuclear Regulatory Commission, December 30, 1997.

NRC Information Notice, 97-88, *Experiences during Recent Steam Generator Inspections*, U.S. Nuclear Regulatory Commission, December 12, 1997.

NRC Regulatory Guide, 1.83, Rev. 1, *Inservice Inspection of Pressurized Water Reactor Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, July 1975.

NRC Regulatory Guide, 1.121, *Bases for Plugging Degraded PWR Steam Generator Tubes*, U.S. Nuclear Regulatory Commission, August 1976.

NUREG-1430, Rev. 1, *Standard Technical Specifications for Babcock and Wilcox Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.

NUREG-1431, Rev. 1, *Standard Technical Specifications for Westinghouse Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.

NUREG-1432, Rev. 1, *Standard Technical Specifications for Combustion Engineering Pressurized Water Reactors*, U.S. Nuclear Regulatory Commission, April 1995.

XI.M20 OPEN-CYCLE COOLING WATER SYSTEM

Program Description

The program relies on implementation of the recommendations of the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-13 to ensure that the effects of aging on the open-cycle cooling water (OCCW) (or service water) system will be managed for the extended period of operation. The program includes surveillance and control techniques to manage aging effects caused by biofouling, corrosion, erosion, protective coating failures, and silting in the OCCW system or structures and components serviced by the OCCW system.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program addresses the aging effects of material loss and fouling due to micro- or macro-organisms and various corrosion mechanisms. Because the characteristics of the service water system may be specific to each facility, the OCCW system is defined as a system or systems that transfer heat from safety-related systems, structures, and components (SSC) to the ultimate heat sink (UHS). If an intermediate system is used between the safety-related SSCs and the system rejecting heat to the UHS, that intermediate system performs the function of a service water system and is thus included in the scope of recommendations of NRC GL 89-13. The guidelines of NRC GL 89-13 include (a) surveillance and control of biofouling; (b) a test program to verify heat transfer capabilities; (c) routine inspection and a maintenance program to ensure that corrosion, erosion, protective coating failure, silting, and biofouling cannot degrade the performance of safety-related systems serviced by OCCW; (d) a system walk down inspection to ensure compliance with the licensing basis; and (e) a review of maintenance, operating, and training practices and procedures.

2. ***Preventive Actions:*** The system components are constructed of appropriate materials and lined or coated to protect the underlying metal surfaces from being exposed to aggressive cooling water environments. Implementation of NRC GL 89-13 includes a condition and performance monitoring program; control or preventive measures, such as chemical treatment, whenever the potential for biological fouling species exists; or flushing of infrequently used systems. Treatment with chemicals mitigates microbiologically-influenced corrosion (MIC) and buildup of macroscopic biological fouling species, such as blue mussels, oysters, or clams. Periodic flushing of the system removes accumulations of biofouling agents, corrosion products, and silt.

3. ***Parameters Monitored/Inspected:*** Adverse effects on system or component performance are caused by accumulations of biofouling agents, corrosion products, and silt. Cleanliness and material integrity of piping, components, heat exchangers, elastomers, and their internal linings or coatings (when applicable) that are part of the OCCW system or that are cooled by the OCCW system are periodically inspected, monitored, or tested to ensure heat transfer capabilities. The program ensures (a) removal of accumulations of biofouling agents, corrosion products, and silt, and (b) detection of defective protective coatings and corroded OCCW system piping and components that could adversely affect performance of their intended safety functions.

4. ***Detection of Aging Effects:*** Inspections for biofouling, damaged coatings, and degraded material condition are conducted. Visual inspections are typically performed; however, nondestructive testing, such as ultrasonic testing, eddy current testing, and heat transfer

capability testing, are effective methods to measure surface condition and the extent of wall thinning associated with the service water system piping and components, when determined necessary.

5. *Monitoring and Trending:* Inspection scope, method (e.g., visual or nondestructive examination [NDE]), and testing frequencies are in accordance with the utility commitments under NRC GL 89-13. Testing and inspections are done annually and during refueling outages. Inspections or nondestructive testing will determine the extent of biofouling, the condition of the surface coating, the magnitude of localized pitting, and the amount of MIC, if applicable. Heat transfer testing results are documented in plant test procedures and are trended and reviewed by the appropriate group.

6. *Acceptance Criteria:* Biofouling is removed or reduced as part of the surveillance and control process. The program for managing biofouling and aggressive cooling water environments for OCCW systems is preventive. Acceptance criteria are based on effective cleaning of biological fouling organisms and maintenance of protective coatings or linings are emphasized.

7. *Corrective Actions:* Evaluations are performed for test or inspection results that do not satisfy established acceptance criteria and a problem or condition report is initiated to document the concern in accordance with plant administrative procedures. The corrective actions program ensures that the conditions adverse to quality are promptly corrected. If the deficiency is assessed to be significantly adverse to quality, the cause of the condition is determined, and an action plan is developed to preclude repetition. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. *Confirmation Process:* Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. *Administrative Controls:* See Item 8, above.

10. *Operating Experience:* Significant microbiologically-influenced corrosion (NRC Information Notice [IN] 85-30), failure of protective coatings (NRC IN 85-24), and fouling (NRC IN 81-21, IN 86-96) have been observed in a number of heat exchangers. The guidance of NRC GL 89-13 has been implemented for approximately 10 years and has been effective in managing aging effects due to biofouling, corrosion, erosion, protective coating failures, and silting in structures and components serviced by OCCW systems.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, April 4, 1990.

NRC Information Notice 81-21, *Potential Loss of Direct Access to Ultimate Heat Sink*, U.S. Nuclear Regulatory Commission, July 21, 1981.

NRC Information Notice 85-24, *Failures of Protective Coatings in Pipes and Heat Exchangers*, U.S. Nuclear Regulatory Commission, March 26, 1985.

NRC Information Notice 85-30, *Microbiologically Induced Corrosion of Containment Service Water System*, U.S. Nuclear Regulatory Commission, April 19, 1985.

NRC Information Notice 86-96, *Heat Exchanger Fouling Can Cause Inadequate Operability of Service Water Systems*, U.S. Nuclear Regulatory Commission, November 20, 1986.

XI.M21 CLOSED-CYCLE COOLING WATER SYSTEM

Program Description

The program includes (a) preventive measures to minimize corrosion and stress corrosion cracking (SCC) and (b) testing and inspection to monitor the effects of corrosion and SCC on the intended function of the component. The program relies on maintenance of system corrosion inhibitor concentrations within the specified limits of Electric Power Research Institute (EPRI) TR-107396 to minimize corrosion and SCC. Non-chemistry monitoring techniques such as testing and inspection in accordance with guidance in EPRI TR-107396 for closed-cycle cooling water (CCCW) systems provide one acceptable method to evaluate system and component performance. These measures will ensure that the intended functions of the CCCW system and components serviced by the CCCW system are not compromised by aging.

Evaluation and Technical Basis

1. *Scope of Program:* A CCCW system is defined as part of the service water system that is not subject to significant sources of contamination, in which water chemistry is controlled and in which heat is not directly rejected to a heat sink. The program described in this section applies only to such a system. If one or more of these conditions are not satisfied, the system is to be considered an open-cycle cooling water system. The staff notes that if the adequacy of cooling water chemistry control cannot be confirmed, the system is treated as an open-cycle system as indicated in Action III of Generic Letter (GL) 89-13.

2. *Preventive Actions:* The program relies on the use of appropriate materials, lining, or coating to protect the underlying metal surfaces and maintain system corrosion inhibitor concentrations within the specified limits of EPRI TR-107396 to minimize corrosion and SCC. The program includes monitoring and control of cooling water chemistry to minimize exposure to aggressive environments and application of corrosion inhibitor in the CCCW system to mitigate general, crevice, and pitting corrosion as well as SCC.

3. *Parameters Monitored/Inspected:* The aging management program monitors the effects of corrosion and SCC by testing and inspection in accordance with guidance in EPRI TR-107396 to evaluate system and component condition. For pumps, the parameters monitored include flow, discharge pressures, and suction pressures. For heat exchangers, the parameters monitored include flow, inlet and outlet temperatures, and differential pressure.

4. *Detection of Aging Effects:* Control of water chemistry does not preclude corrosion or SCC at locations of stagnant flow conditions or crevices. Degradation of a component due to corrosion or SCC would result in degradation of system or component performance. The extent and schedule of inspections and testing should assure detection of corrosion or SCC before the loss of the intended function of the component. Performance and functional testing ensures acceptable functioning of the CCCW system or components serviced by the CCCW system. For systems and components in continuous operation, performance adequacy should be verified by monitoring component performance through data trends for evaluation of heat transfer capability, system branch flow changes and chemistry data trends. Components not normally in operation are periodically tested to ensure operability.

5. ***Monitoring and Trending:*** The frequency of sampling water chemistry varies and can occur on a continuous, daily, weekly, or as needed basis, as indicated by plant operating conditions and the type of chemical treatment. In accordance with EPRI TR-107396, internal visual inspections and performance/functional tests are to be performed periodically to demonstrate system operability and confirm the effectiveness of the program. Tests to evaluate heat removal capability of the system and degradation of system components may also be used. The testing intervals should be established based on plant-specific considerations such as system conditions, trending, and past operating experience, and may be adjusted based on the results of a reliability analysis, type of service, frequency of operation, or age of components and systems.

6. ***Acceptance Criteria:*** Corrosion inhibitor concentrations are maintained within the limits specified in the EPRI water chemistry guidelines for CCCW. System and component performance test results are evaluated in accordance with system and component design basis requirements. Acceptance criteria and tolerances are to be based on system design parameters and functions.

7. ***Corrective Actions:*** Corrosion inhibitor concentrations outside the allowable limits are returned to the acceptable range within the time period specified in the EPRI water chemistry guidelines for CCCW. If the system or component fails to perform adequately, corrective actions are taken. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** Degradation of closed-cycle cooling water systems due to corrosion product buildup (NRC Licensee Event Report [LER] 50-327/93-029-00) or through-wall cracks in supply lines (NRC 50-280/91-019-00) has been observed in operating plants. Accordingly, operating experience demonstrates the need for this program.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

EPRI TR-107396, *Closed Cooling Water Chemistry Guidelines*, Electric Power Research Institute, Palo Alto, CA, October 1997.

NRC Generic Letter 89-13, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, July 18, 1989.

NRC Generic Letter 89-13, Supplement 1, *Service Water System Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, April 4, 1990.

NRC Licensee Event Report LER 50-280/91-019-00, *Loss of Containment Integrity due to Crack in Component Cooling Water Piping*, October 26, 1991.

NRC Licensee Event Report LER 50-327/93-029-00, *Inoperable Check Valve in the Component Cooling System as a Result of a Build-Up of Corrosion Products between Valve Components*, December 13, 1993.

XI.M22 BORAFLEX MONITORING

Program Description

A Boraflex monitoring program for the actual Boraflex panels is implemented in the spent fuel racks to assure that no unexpected degradation of the Boraflex material would compromise the criticality analysis in support of the design of spent fuel storage racks. The applicable aging management program (AMP), based on manufacturer's recommendations, relies on periodic inspection, testing, monitoring, and analysis of the criticality design to assure that the required 5% subcriticality margin is maintained. The frequency of the inspection and testing depends on the condition of the Boraflex, with a maximum of five years. Certain accelerated samples are tested every two years. Results based on test coupons have been found to be unreliable in determining the degree to which the actual Boraflex panels have been degraded. Therefore, this AMP includes: (1) performing neutron attenuation testing, called blackness testing, to determine gap formation in Boraflex panels; (2) completing sampling and analysis for silica levels in the spent fuel pool water and trending the results by using the EPRI RACKLIFE predictive code or its equivalent on a monthly, quarterly, or annual basis (depending on Boraflex panel condition); and (3) measuring boron areal density by techniques such as the BADGER device. Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of current or projected future Boraflex degradation.

Evaluation and Technical Basis

1. *Scope of Program:* The AMP manages the effects of aging on sheets of neutron-absorbing materials affixed to spent fuel racks. For Boraflex panels, gamma irradiation and long-term exposure to the wet pool environment cause shrinkage resulting in gap formation, gradual degradation of the polymer matrix, and the release of silica to the spent fuel storage pool water. This results in the loss of boron carbide in the neutron absorber sheets.

2. *Preventive Actions:* For Boraflex panels, monitoring silica levels in the storage pool water, measuring gap formation by blackness testing, periodically measuring boron areal density, and applying predictive codes, are performed. These actions ensure that degradation of the neutron-absorbing material is identified and corrected so the spent fuel storage racks will be capable of performing their intended functions during the period of extended operation, consistent with current licensing basis (CLB) design conditions.

3. *Parameters Monitored/Inspected:* The parameters monitored include physical conditions of the Boraflex panels, such as gap formation and decreased boron areal density, and the concentration of the silica in the spent fuel pool. These are conditions directly related to degradation of the Boraflex material. When Boraflex is subjected to gamma radiation and long-term exposure to the spent fuel pool environment, the silicon polymer matrix becomes degraded and silica filler and boron carbide are released into the spent fuel pool water. As indicated in the Nuclear Regulatory Commission (NRC) Information Notice (IN) 95-38 and NRC Generic Letter (GL) 96-04, the loss of boron carbide (washout) from Boraflex is characterized by slow dissolution of silica from the surface of the Boraflex and a gradual thinning of the material. Because Boraflex contains about 25% silica, 25% polydimethyl siloxane polymer, and 50% boron carbide, sampling and analysis of the presence of silica in the spent fuel pool provide an indication of depletion of boron carbide from Boraflex; however, the degree to which Boraflex has degraded is ascertained through measurement of the boron areal density.

4. *Detection of Aging Effects:* The amount of boron carbide released from the Boraflex panel is determined through direct measurement of boron areal density and correlated with the levels of silica present with a predictive code. This is supplemented with detection of gaps through blackness testing and periodic verification of boron loss through areal density measurement techniques such as the BADGER device.

5. *Monitoring and Trending:* The periodic inspection measurements and analysis are to be compared to values of previous measurements and analysis to provide a continuing level of data for trend analysis.

6. *Acceptance Criteria:* The 5% subcriticality margin of the spent fuel racks is to be maintained for the period of extended operation.

7. *Corrective Actions:* Corrective actions are initiated if the test results find that the 5% subcriticality margin cannot be maintained because of the current or projected future degradation. Corrective actions consist of providing additional neutron-absorbing capacity by Boral or boron steel inserts, or other options, which are available to maintain a subcriticality margin of 5%. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. *Confirmation Process:* Site quality assurance (QA) procedures, site review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. *Administrative Controls:* See item 8, above.

10. *Operating Experience:* The NRC IN 87-43 addresses the problems of development of tears and gaps (average 1-2 in., with the largest 4 in.) in Boraflex sheets due to gamma radiation-induced shrinkage of the material. NRC INs 93-70 and 95-38 and NRC GL 96-04 address several cases of significant degradation of Boraflex test coupons due to accelerated dissolution of Boraflex caused by pool water flow through panel enclosures and high accumulated gamma dose. Two spent fuel rack cells with about 12 years of service have only 40% of the Boraflex remaining. In such cases, the Boraflex may be replaced by boron steel inserts or by a completely new rack system using Boral. Experience with boron steel is limited; however, the application of Boral for use in the spent fuel storage racks predates the manufacturing and use of Boraflex. The experience with Boraflex panels indicates that coupon surveillance programs are not reliable. Therefore, during the period of extended operation, the measurement of boron areal density correlated, through a predictive code, with silica levels in the pool water is verified. These monitoring programs provide assurance that degradation of Boraflex sheets is monitored, so that appropriate actions can be taken in a timely manner if significant loss of neutron-absorbing capability is occurring. These monitoring programs ensure that the Boraflex sheets will maintain their integrity and will be effective in performing its intended function.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

BNL-NUREG-25582, *Corrosion Considerations in the Use of Boral in Spent Fuel Storage Pool Racks*, January 1979.

EPRI NP-6159, *An Assessment of Boraflex Performance in Spent-Nuclear-Fuel Storage Racks*, Electric Power Research Institute, Palo Alto, CA, December 14, 1988.

EPRI TR-101986, *Boraflex Test Results and Evaluation*, Electric Power Research Institute, Palo Alto, CA, March 1, 1993.

EPRI TR-103300, *Guidelines for Boraflex Use in Spent-Fuel Storage Racks*, Electric Power Research Institute, Palo Alto, CA, December 1, 1993.

NRC Generic Letter 96-04, *Boraflex Degradation in Spent Fuel Pool Storage Racks*, U.S. Nuclear Regulatory Commission, June 26, 1996.

NRC Information Notice 87-43, *Gaps in Neutron Absorbing Material in High Density Spent Fuel Storage Racks,* U.S. Nuclear Regulatory Commission, September 8, 1987.

NRC Information Notice 93-70, *Degradation of Boraflex Neutron Absorber Coupons*, U.S. Nuclear Regulatory Commission, September 10, 1993.

NRC Information Notice 95-38, *Degradation of Boraflex Neutron Absorber in Spent Fuel Storage Racks*, U.S. Nuclear Regulatory Commission, September 8, 1995.

NRC Regulatory Guide 1.26, Rev. 3, *Quality Group Classifications and Standards for Water, Steam, and Radioactive-Waste-Containing Components of Nuclear Power Plants (for Comment),* U.S. Nuclear Regulatory Commission, February 1976.

XI.M23 INSPECTION OF OVERHEAD HEAVY LOAD AND LIGHT LOAD (RELATED TO REFUELING) HANDLING SYSTEMS

Program Description

Most commercial nuclear facilities have between 50 and 100 cranes. Many are industrial grade cranes, which meet the requirements of 29 CFR Volume XVII, Part 1910, and Section 1910.179. Most are not within the scope of 10 CFR 54.4, and therefore are not required to be part of the integrated plant assessment (IPA).

Normally, fewer than 10 cranes fall within the scope of 10 CFR 54.4.

The program demonstrates that testing and monitoring programs have been implemented and have ensured that the structures, systems, and components of these cranes are capable of sustaining their rated loads. This is their intended function during the period of extended operation. It is noted that many of the systems and components of these cranes perform an intended function with moving parts or with a change in configuration, or subject to replacement based on qualified life. In these instances, these types of crane systems and components are not within the scope of this aging management program (AMP). This program is primarily concerned with structural components that make up the bridge and trolley. NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants," provides specific guidance on the control of overhead heavy load cranes.

Evaluation and Technical Basis

1. *Scope of Program:* The program manages the effects of general corrosion on the crane and trolley structural components for those cranes that are within the scope of 10 CFR 54.4, and the effects of wear on the rails in the rail system.

2. *Preventive Actions:* No preventive actions are identified. The crane program is an inspection program.

3. *Parameters Monitored/Inspected:* The program evaluates the effectiveness of the maintenance monitoring program and the effects of past and future usage on the structural reliability of cranes.

4. *Detection of Aging Effect:* Crane rails and structural components are visually inspected on a routine basis for degradation.

5. *Monitoring and Trending:* Monitoring and trending are not required as part of the crane inspection program.

6. *Acceptance Criteria:* Any significant visual indication of loss of material due to corrosion or wear is evaluated according to applicable industry standards and good industry practice. The crane may also have been designed to a specific Service Class as defined in the Crane Manufacturers Association of America, Inc. (CMAA) Specification #70 (or later revisions), or CMAA Specification #74 (or later revisions). The specification that was applicable at the time the crane was manufactured is used.

7. *Corrective Actions:* Site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. *Confirmation Process:* See Item 7, above.

9. *Administrative Controls:* See Item 7, above.

10. *Operating Experience* There has been no history of corrosion-related degradation that has impaired cranes. Likewise, because cranes have not been operated beyond their design lifetime, there have been no significant fatigue-related structural failures.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

Crane Manufactures Association of America, Inc., CMAA Specification No. 70, *Specifications for Electric Overhead Traveling Cranes*, 1970 (or later revisions)

Crane Manufactures Association of America, Inc., CMAA Specification No. 74, *Specifications for Top Running and Under Running Single Girder Electric Overhead Traveling Cranes, 1974 (or later revisions)*

Electric Overhead Crane Institute, Inc

NUREG-0612, *Control of Heavy Loads at Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, 1980.

NRC Regulatory Guide 1.160, Rev. 2, *Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*, U.S. Nuclear Regulatory Commission, March 1997.

XI.M24 COMPRESSED AIR MONITORING

Program Description

The program consists of inspection, monitoring, and testing of the entire system. This includes (a) frequent leak testing of valves, piping, and other system components, especially those made of carbon steel and stainless steel; and (b) preventive monitoring that checks air quality at various locations in the system to ensure that oil, water, rust, dirt, and other contaminants are kept within the specified limits. The aging management program (AMP) provides for timely corrective actions to ensure that the system is operating within specified limits.

The AMP is based on results of the plant owner's response to Nuclear Regulatory Commission (NRC) Generic Letter (GL) 88-14, augmented by previous NRC Information Notices (IN) 81-38, IN 87-28, and IN 87-28 S1, and by the Institute of Nuclear Power Operations Significant Operating Experience Report (INPO SOER) 88-01. The NRC GL 88-14, issued after several years of study of problems and failures of instrument air systems, recommends each holder of an operating license to perform an extensive design and operations review and verification of its instrument air system. The GL 88-14 also recommends the licensees to describe their program for maintaining proper instrument air quality. The AMP also incorporates provisions conforming to the guidance of the Electric Power Research Institute (EPRI) NP-7079, issued in 1990, to assist utilities in identifying and correcting system problems in the instrument air system and to enable them to maintain required industry safety standards. Subsequent to these initial actions by all plant licensees to implement an improved AMP, some utilities decided to replace their instrument air system with newer models and types of components. The EPRI then issued TR-108147, which addresses maintenance of the latest compressors and other instrument air system components currently in use at those plants. The American Society of Mechanical Engineers operations and maintenance standards and guides (ASME OM-S/G-1998, Part 17) provides additional guidance to the maintenance of the instrument air system by offering recommended test methods, test intervals, parameters to be measured and evaluated, acceptance criteria, corrective actions, and records requirements.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program manages the effects of corrosion and the presence of unacceptable levels of contaminants on the intended function of the compressed air system. The AMP includes frequent leak testing of valves, piping, and other system components, especially those made of carbon steel and stainless steel, and a preventive maintenance program to check air quality at several locations in the system.

2. ***Preventive Actions:*** The system air quality is monitored and maintained in accordance with the plant owner's testing and inspection plans, which are designed to ensure that the system and components meet specified operability requirements. These requirements are prepared from consideration of manufacturer's recommendations for individual components and guidelines based on ASME OM-S/G-1998, Part 17; ISA-S7.0.01-1996; EPRI NP-7079; and EPRI TR-108147. The preventive maintenance program addresses various aspects of the inoperability of air-operated components due to corrosion and the presence of oil, water, rust, and other contaminants.

3. ***Parameters Monitored/Inspected:*** Inservice inspection (ISI) and testing is performed to verify proper air quality and confirm that maintenance practices, emergency procedures,

and training are adequate to ensure that the intended function of the air system is maintained.

4. *Detection of Aging Effects:* Guidelines in EPRI NP-7079, EPRI TR-108147, and ASME OM-S/G-1998, Part 17, ensure timely detection of degradation of the compressed air system function. Degradation of the piping and any components would become evident by observation of excessive corrosion, by the discovery of unacceptable leakage rates, and by failure of the system or any item of components to meet specified performance limits.

5. *Monitoring and Trending:* Effects of corrosion and the presence of contaminants are monitored by visual inspection and periodic system and component tests, including leak rate tests on the system and on individual items of components. These tests verify proper operation by comparing measured values of performance with specified performance limits. Test data are analyzed and compared to data from previous tests to provide for timely detection of aging effects.

6. *Acceptance Criteria:* Acceptance criteria are established for the system and for individual components that contain specific limits or acceptance ranges based on design basis conditions and/or components vendor specifications. The testing results are analyzed to verify that the design and performance of the system is in accordance with its intended function.

7. *Corrective Actions:* Corrective actions are taken if any parameters are out of acceptable ranges, such as moisture content in the system air. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. *Confirmation Process:* The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. *Administrative Controls:* See Item 8, above.

10. *Operating Experience:* Potentially significant safety-related problems pertaining to air systems have been documented in NRC IN 81-38, IN 87-28, IN 87-28 S1 and license event report (LER) 50-237/94-005-3. Some of the systems that have been significantly degraded or have failed due to the problems in the air system include the decay heat removal, auxiliary feedwater, main steam isolation, containment isolation, and fuel pool seal system. As a result of NRC GL 88-14 and consideration of INPO SOER 88-01, EPRI NP-7079, and EPRI TR-108147, performance of air systems has improved significantly.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME OM-S/G-1998, Part 17, *Performance Testing of Instrument Air Systems Information Notice Light-Water Reactor Power Plants*, 1ISA-S7.0.1-1996, "Quality Standard for Instrument Air," American Society of Mechanical Engineers, New York, NY, 1998.

EPRI NP-7079, *Instrument Air System: A Guide for Power Plant Maintenance Personnel*, Electric Power Research Institute, Palo Alto, CA, December 1990.

EPRI/NMAC TR-108147, *Compressor and Instrument Air System Maintenance Guide: Revision to NP-7079*, Electric Power Research Institute, Palo Alto, CA., March 1998.

INPO SOER 88-01, *Instrument Air System Failures*, May 18, 1988.

NRC Generic Letter 88-14, *Instrument Air Supply Problems Affecting Safety-Related Components*, U.S. Nuclear Regulatory Commission, August 8, 1988.

NRC Information Notice 81-38, *Potentially Significant Components Failures Resulting from Contamination of Air-Operated Systems*, U.S. Nuclear Regulatory Commission, December 17, 1981.

NRC Information Notice 87-28, *Air Systems Problems at U.S. Light Water Reactors*, U.S. Nuclear Regulatory Commission, June 22, 1987.

NRC Information Notice 87-28, Supplement 1, *Air Systems Problems at U.S. Light Water Reactors*, U.S. Nuclear Regulatory Commission, December 28, 1987.

NRC Licensee Event Report LER 50-237/94-005-3, *Manual Reactor Scram due to Loss of Instrument Air Resulting from Air Receiver Pipe Failure Caused by Improper Installation of Threaded Pipe during Initial Construction*, U.S. Nuclear Regulatory Commission, April 23, 1997.

XI.M25 BWR REACTOR WATER CLEANUP SYSTEM

Program Description

The program includes inservice inspection (ISI) and monitoring and control of reactor coolant water chemistry to manage the effects of stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC) on the intended function of austenitic stainless steel (SS) piping in the reactor water cleanup (RWCU) system. Based on the Nuclear Regulatory Commission (NRC) criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC Generic Letter (GL) 88-01. Coolant water chemistry is monitored and maintained in accordance with the Electric Power Research Institute (EPRI) guidelines in boiling water reactor vessel and internals project (BWRVIP) -29 (TR-103515) to minimize the potential of cracking due to SCC or IGSCC.

Evaluation and Technical Basis

1. ***Scope of Program:*** Based on the NRC letter (September 15, 1995) on the screening criteria related to inspection guidelines for RWCU piping welds outboard of the second isolation valve, the program includes the measures delineated in NUREG-0313, Rev. 2, and NRC GL 88-01 to monitor SCC or IGSCC and its effects on the intended function of austenitic SS piping. The screening criteria include:

   a. Satisfactory completion of all actions requested in NRC GL 89-10,

   b. No detection of IGSCC in RWCU welds inboard of the second isolation valves (ongoing inspection in accordance with the guidance in NRC GL 88-01), and

   c. No detection of IGSCC in RWCU welds outboard of the second isolation valves after inspecting a minimum of 10% of the susceptible piping.

   No IGSCC inspection is recommended for plants that meet all the above three criteria or that meet criterion (a) and piping is made of material that is resistant to IGSCC.

2. ***Preventive Actions:*** The comprehensive program outlined in NUREG-0313 and NRC GL 88-01 addresses improvements in all three elements that, in combination, cause SCC or IGSCC. These elements are a susceptible (sensitized) material, a significant tensile stress, and an aggressive environment. The program delineated in NUREG-0313 and NRC GL 88-01 includes recommendations regarding selection of materials that are resistant to sensitization, use of special processes that reduce residual tensile stresses, and monitoring and maintenance of coolant chemistry. The resistant materials are used for new and replacement components and include low-carbon grades of austenitic SS and weld metal, with a maximum carbon of 0.035 wt.% and a minimum ferrite of 7.5% in weld metal and cast austenitic stainless steel (CASS). Inconel 82 is the only commonly used nickel-base weld metal considered resistant to SCC; other nickel-alloys, such as Alloy 600, are evaluated on an individual basis. Special processes are used for existing as well as new and replacement components. These processes include solution heat treatment, heat sink welding, induction heating, and mechanical stress improvement.

   The program delineated in NUREG-0313 and NRC GL 88-01 varies depending on the plant- specific reactor water chemistry to mitigate SCC or IGSCC.

3. ***Parameters Monitored/Inspected:*** The aging management program (AMP) monitors SCC or IGSCC of austenitic SS piping by detection and sizing of cracks by implementing the inspection guidelines delineated in the NRC screening criteria for the RWCU piping outboard of isolation valves. The following schedules are followed:

   Schedule A: No inspection is required for plants that meet all three criteria set forth above, or if they meet only criterion (a). Piping is made of material that is resistant to IGSCC, as described above in preventive actions.

   Schedule B: For plants that meet only criterion (a): Inspect at least 2% of the welds or two welds every refueling outage, whichever sample is larger.

   Schedule C: For plants that do not meet criterion (a): Inspect at least 10% of the welds every refueling outage.

4. ***Detection of Aging Effects:*** The extent, method, and schedule of the inspection and test techniques delineated in the NRC inspection criteria for RWCU piping and NRC GL 88-01 are designed to maintain structural integrity and to detect aging effects before the loss of intended function of austenitic SS piping and fittings. Guidelines for the inspection schedule, methods, personnel, sample expansion, and leak detection guidelines are based on the guidelines of NRC GL 88-01.

   NRC GL 88-01 recommends that the detailed inspection procedure, components, and examination personnel be qualified by a formal program approved by the NRC. Inspection can reveal cracking and leakage of coolant. The extent and frequency of inspections recommended by the program are based on the condition of each weld (e.g., whether the weldments were made from IGSCC-resistant material, whether a stress improvement process was applied to a weldment to reduce the residual stresses, and how the weld was repaired if it had been cracked).

5. ***Monitoring and Trending:*** The extent and schedule for inspection in accordance with the recommendations of NRC GL 88-01 provide timely detection of cracks and leakage of coolant. Based on inspection results, NRC GL 88-01 provides guidelines for additional samples of welds to be inspected when one or more cracked welds are found in a weld category.

6. ***Acceptance Criteria:*** The NRC GL 88-01 recommends that any indication detected be evaluated in accordance with the requirements of ASME Section XI, Subsection IWB-3640 (2001 edition[8] including the 2002 and 2003 Addenda).

7. ***Corrective Actions***: The guidance for weld overlay repair, stress improvement, or replacement is provided in NRC GL 88-01. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. ***Confirmation Process:*** Site quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with requirements

[8] An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code.

of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process and administrative controls.

9. ***Administrative Controls:*** See Item 8, above.

10. ***Operating Experience:*** The IGSCC has occurred in small- and large-diameter boiling water reactor (BWR) piping made of austenitic stainless steels or nickel alloys. The comprehensive program outlined in NRC GL 88-01 and NUREG-0313 addresses improvements in all elements that cause SCC or IGSCC (e.g., susceptible material, significant tensile stress, and an aggressive environment) and is effective in managing IGSCC in austenitic SS piping in the RWCU system.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, ASME Boiler and Pressure Vessel Code, 2001 edition including the 2002 and 2003 Addenda, American Society of Mechanical Engineers, New York, NY.

BWRVIP-29 (EPRI TR-103515), *BWR Vessel and Internals Project, BWR Water Chemistry Guidelines-1993 Revision, Normal and Hydrogen Water Chemistry,* Electric Power Research Institute, Palo Alto, CA, February 1994.

Letter from Joseph W. Shea, U.S. Nuclear Regulatory Commission, to George A. Hunter, Jr., PECO Energy Company, *Reactor Water Cleanup (RWCU) System Weld Inspections at Peach Bottom Atomic Power Station, Units 2 and 3 (TAC Nos. M92442 and M92443),* September 15, 1995.

NRC Generic Letter 89-10, *Safety-related Motor Operated Valve Testing and Surveillance,* U.S. Nuclear Regulatory Commission, June 28, 1989; through supplement 7, January 24, 1996.

NRC Generic Letter 88-01, *NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping,* U.S. Nuclear Regulatory Commission, January 25, 1988.

NUREG-0313, Rev. 2, *Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping,* W. S. Hazelton and W. H. Koo, U.S. Nuclear Regulatory Commission, 1988.

XI.M26 FIRE PROTECTION

Program Description

For operating plants, the fire protection aging management program (AMP) includes a fire barrier inspection program and a diesel-driven fire pump inspection program. The fire barrier inspection program requires periodic visual inspection of fire barrier penetration seals, fire barrier walls, ceilings, and floors, and periodic visual inspection and functional tests of fire rated doors to ensure that their operability is maintained. The diesel-driven fire pump inspection program requires that the pump be periodically tested to ensure that the fuel supply line can perform the intended function. The AMP also includes periodic inspection and testing of the halon/carbon dioxide (CO_2) fire suppression system.

Evaluation and Technical Basis

1. *Scope of Program:* For operating plants, the AMP manages the aging effects on the intended function of the penetration seals, fire barrier walls, ceilings, and floors, and all fire rated doors (automatic or manual) that perform a fire barrier function. It also manages the aging effects on the intended function of the fuel supply line. The AMP also includes management of the aging effects on the intended function of the halon/CO_2 fire suppression system.

2. *Preventive Actions:* For operating plants, the fire hazard analysis assesses the fire potential and fire hazard in all plant areas. It also specifies measures for fire prevention, fire detection, fire suppression, and fire containment and alternative shutdown capability for each fire area containing structures, systems, and components important to safety.

3. *Parameters Monitored/Inspected:* Visual inspection of approximately 10% of each type of penetration seal is performed during walkdowns carried out at least once every refueling outage. These inspections examine any sign of degradation such as cracking, seal separation from walls and components, separation of layers of material, rupture and puncture of seals, which are directly caused by increased hardness, and shrinkage of seal material due to weathering. Visual inspection of the fire barrier walls, ceilings, and floors examines any sign of degradation such as cracking, spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates. Fire-rated doors are visually inspected on a plant-specific interval to verify the integrity of door surfaces and for clearances. The plant-specific inspection intervals are to be determined by engineering evaluation to detect degradation of the fire doors prior to the loss of intended function.

   The diesel-driven fire pump is under observation during performance tests such as flow and discharge tests, sequential starting capability tests, and controller function tests for detection of any degradation of the fuel supply line.

   The periodic visual inspection and function test is performed at least once every six months to examine the signs of degradation of the halon/CO_2 fire suppression system. Material conditions that may affect the performance of the system, such as corrosion, mechanical damage, or damage to dampers, are observed during these tests.

4. *Detection of Aging Effects:* Visual inspection of penetration seals detects cracking, seal separation from walls and components, and rupture and puncture of seals. Visual inspection by fire protection qualified inspectors of approximately 10% of each type of seal

in walkdowns is performed at least once every refueling cycle. If any sign of degradation is detected within that sample, the scope of the inspection is expanded to include additional seals. Visual inspection by fire protection qualified inspectors of the fire barrier walls, ceilings, and floors, performed in walkdowns at least once every refueling outage ensures timely detection of concrete cracking, spalling, and loss of material. Visual inspection by fire protection qualified inspectors detects any sign of degradation of the fire door such as wear and missing parts. Periodic visual inspection and function tests detect degradation of the fire doors before there is a loss of intended function.

Periodic tests performed at least once every refueling outage, such as flow and discharge tests, sequential starting capability tests, and controller function tests performed on diesel-driven fire pump ensure fuel supply line performance. The performance tests detect degradation of the fuel supply lines before the loss of the component intended function.

Visual inspections of the halon/CO_2 fire suppression system detect any sign of added degradation, such as corrosion, mechanical damage, or damage to dampers. The periodic function test and inspection performed at least once every six months detects degradation of the halon/CO_2 fire suppression system before the loss of the component intended function.

5. ***Monitoring and Trending:*** The aging effects of weathering on fire barrier penetration seals are detectable by visual inspection and, based on operating experience, visual inspections are performed at least once every refueling outage to detect any sign of degradation of fire barrier penetration seals prior to loss of the intended function.

Concrete cracking, spalling, and loss of material are detectable by visual inspection and, based on operating experience, visual inspection performed at least once every refueling outage detects any sign of degradation of the fire barrier walls, ceilings, and floors before there is a loss of the intended function. Based on operating experience, degraded integrity or clearances in the fire door are detectable by visual inspection performed on a plant-specific frequency. The visual inspections detect degradation of the fire doors prior to loss of the intended function.

The performance of the fire pump is monitored during the periodic test to detect any degradation in the fuel supply lines. Periodic testing provides data (e.g., pressure) for trending necessary.

The performance of the halon/CO_2 fire suppression system is monitored during the periodic test to detect any degradation in the system. These periodic tests provide data necessary for trending.

6. ***Acceptance Criteria:*** Inspection results are acceptable if there are no visual indications (outside those allowed by approved penetration seal configurations) of cracking, separation of seals from walls and components, separation of layers of material, or ruptures or punctures of seals; no visual indications of concrete cracking, spalling and loss of material of fire barrier walls, ceilings, and floors; no visual indications of missing parts, holes, and wear and no deficiencies in the functional tests of fire doors. No corrosion is acceptable in the fuel supply line for the diesel-driven fire pump. Also, any signs of corrosion and mechanical damage of the halon/CO_2 fire suppression system are not acceptable.

7. *Corrective Actions:* For fire protection structures and components identified within scope that are subject to an AMR for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. This commitment is documented in the final safety analysis report (FSAR) supplement in accordance with 10 CFR 54.21(d). As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. *Confirmation Process:* See Item 7, above.

9. *Administrative Controls:* See Item 7, above.

10. *Operating Experience:* Silicone foam fire barrier penetration seals have experienced splits, shrinkage, voids, lack of fill, and other failure modes (IN 88-56, IN 94-28, and IN 97-70). Degradation of electrical racing way fire barrier such as small holes, cracking, and unfilled seals are found on routine walkdown (IN 91-47 and GL 92-08). Fire doors have experienced wear of the hinges and handles.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NRC Generic Letter 92-08, *Thermo-Lag 330-1 Fire Barrier*, U.S. Nuclear Regulatory Commission, December 17, 1992.

NRC Information Notice 88-56, *Potential Problems with Silicone Foam Fire Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, August 14, 1988.

NRC Information Notice 91-47, *Failure of Thermo-Lag Fire Barrier Material to Pass Fire Endurance Test*, U.S. Nuclear Regulatory Commission, August 6, 1991.

NRC Information Notice 94-28, *Potential problems with Fire-Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, April 5, 1994.

NRC Information Notice 97-70, *Potential problems with Fire Barrier Penetration Seals*, U.S. Nuclear Regulatory Commission, September 19, 1997.

XI. M27 FIRE WATER SYSTEM

Program Description

This aging management program (AMP) applies to water-based fire protection systems that consist of sprinklers, nozzles, fittings, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components that are tested in accordance with the applicable National Fire Protection Association (NFPA) codes and standards. Such testing assures the minimum functionality of the systems. Also, these systems are normally maintained at required operating pressure and monitored such that loss of system pressure is immediately detected and corrective actions initiated.

A sample of sprinkler heads is to be inspected by using the guidance of NFPA 25 "Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (1998 Edition), Section 2-3.1.1, or NFPA 25 (2002 Edition), Section 5.3.1.1.1. This NFPA section states "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing." It also contains guidance to perform this sampling every 10 years after the initial field service testing.

The fire protection system piping is to be subjected to required flow testing in accordance with guidance in NFPA 25 to verify design pressure or evaluated for wall thickness (e.g., non-intrusive volumetric testing or plant maintenance visual inspections) to ensure that aging effects are managed and that wall thickness is within acceptable limits. These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. The plant-specific inspection intervals are to be determined by engineering evaluation of the fire protection piping to ensure that degradation will be detected before the loss of intended function. The purpose of the full flow testing and wall thickness evaluations is to ensure that corrosion, MIC, or biofouling is managed such that the system function is maintained.

Evaluation and Technical Basis

1. *Scope of Program:* The AMP focuses on managing loss of material due to corrosion, MIC, or biofouling of carbon steel and cast-iron components in fire protection systems exposed to water. Hose stations and standpipes are considered as piping in the AMP.

2. *Preventive Actions:* To ensure no significant corrosion, MIC, or biofouling has occurred in water-based fire protection systems, periodic flushing, system performance testing, and inspections may be conducted.

3. *Parameters Monitored/Inspected:* Loss of material due to corrosion and biofouling could reduce wall thickness of the fire protection piping system and result in system failure. Therefore, the parameters monitored are the system's ability to maintain pressure and internal system corrosion conditions. Periodic flow testing of the fire water system is performed using the guidelines of NFPA 25, or wall thickness evaluations may be performed to ensure that the system maintains its intended function.

4. *Detection of Aging Effects:* Fire protection system testing is performed to assure that the system functions by maintaining required operating pressures. Wall thickness evaluations of fire protection piping are performed on system components using non-

intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections are performed before the end of the current operating term and at plant-specific intervals thereafter during the period of extended operation. As an alternative to non-intrusive testing, the plant maintenance process may include a visual inspection of the internal surface of the fire protection piping upon each entry to the system for routine or corrective maintenance, as long as it can be demonstrated that inspections are performed (based on past maintenance history) on a representative number of locations on a reasonable basis. These inspections must be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the design flow of the fire protection system. If the environmental and material conditions that exist on the interior surface of the below grade fire protection piping are similar to the conditions that exist within the above grade fire protection piping, the results of the inspections of the above grade fire protection piping can be extrapolated to evaluate the condition of below grade fire protection piping. If not, additional inspection activities are needed to ensure that the intended function of below grade fire protection piping will be maintained consistent with the current licensing basis for the period of extended operation. Continuous system pressure monitoring, system flow testing, and wall thickness evaluations of piping are effective means to ensure that corrosion and biofouling are not occurring and the system's intended function is maintained.

General requirements of existing fire protection programs include testing and maintenance of fire detection and protection systems and surveillance procedures to ensure that fire detectors, as well as fire protection systems and components are operable.

Visual inspection of yard fire hydrants performed annually in accordance with NFPA 25 ensures timely detection of signs of degradation, such as corrosion. Fire hydrant hose hydrostatic tests, gasket inspections, and fire hydrant flow tests, performed annually, ensure that fire hydrants can perform their intended function and provide opportunities for degradation to be detected before a loss of intended function can occur.

Sprinkler heads are inspected before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner.

5. ***Monitoring and Trending:*** System discharge pressure is monitored continuously. Results of system performance testing are monitored and trended as specified by the associated plant commitments pertaining to NFPA codes and standards. Degradation identified by non-intrusive or internal inspection is evaluated.

6. ***Acceptance Criteria:*** The acceptance criteria are (a) the ability of a fire protection system to maintain required pressure, (b) no unacceptable signs of degradation observed during non-intrusive or visual assessment of internal system conditions, and (c) that no biofouling exists in the sprinkler systems that could cause corrosion in the sprinkler heads.

7. ***Corrective Actions:*** Repair and replacement actions are initiated as necessary. For fire water systems and components identified within scope that are subject to an AMR for license renewal, the applicant's 10 CFR Part 50, Appendix B, program is used for corrective actions, confirmation process, and administrative controls for aging management during the period of extended operation. As discussed in the appendix to

this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. **Confirmation Process:** See Item 7, above.

9. **Administrative Controls:** See Item 7, above.

10. ***Operating Experience:*** Water-based fire protection systems designed, inspected, tested and maintained in accordance with the NFPA minimum standards have demonstrated reliable performance.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NFPA 25: Inspection, Testing and Maintenance of Water-Based Fire Protection Systems, 1998 Edition.

NFPA 25: Inspection, Testing and Maintenance of Water-Based Fire Protection Systems, 2002 Edition.

XI.M28 BURIED PIPING AND TANKS SURVEILLANCE

Program Description

The program includes surveillance and preventive measures to mitigate corrosion by protecting the external surface of buried carbon steel piping and tanks. Surveillance and preventive measures are in accordance with standard industry practice, based on National Association of Corrosion Engineers (NACE) Standards RP-0285-95 and RP-0169-96, and include external coatings, wrappings, and cathodic protection systems.

Evaluation and Technical Basis

1. ***Scope of Program:*** The program relies on preventive measures, such as coating, wrapping, and cathodic protection, and surveillance, based on NACE Standard RP-0285-95 and NACE Standard RP-0169-96, to manage the effects of corrosion on the intended function of buried tanks and piping, respectively.

2. ***Preventive Actions:*** In accordance with industry practice, underground piping and tanks are coated during installation with a protective coating system, such as coal tar enamel with a fiberglass wrap and a kraft paper outer wrap, a polyolifin tape coating, or a fusion bonded epoxy coating to protect the piping from contacting the aggressive soil environment. A cathodic protection system is used to mitigate corrosion where pinholes in the coating allow the piping or components to be in contact with the aggressive soil environment. The cathodic protection imposes a current from an anode onto the pipe or tank to stop corrosion from occurring at defects in the coating.

3. ***Parameters Monitored/Inspected:*** The effectiveness of the coatings and cathodic protection system, per standard industry practice, is determined by measuring coating conductance, by surveying pipe-to-soil potential, and by conducting bell hole examinations to visually examine the condition of the coating.

4. ***Detection of Aging Effects:*** Coatings and wrapping can be damaged during installation or while in service and the cathodic protection system is relied upon to avoid any corrosion at the damaged locations. Degradation of the coatings and wrapping during service will result in the requirement for more current from the cathodic protection rectifier in order to maintain the proper cathodic protect potentials. Any increase in current requirements is an indication of coating and wrapping degradation. A close interval pipe-to-soil potential survey can be used to locate the locations where degradation has occurred.

5. ***Monitoring and Trending:*** Monitoring the coating conductance versus time or the current requirement versus time provides an indication of the condition of the coating and cathodic protection system when compared to predetermined values.

6. ***Acceptance Criteria:*** In accordance with accepted industry practice, per NACE Standard RP-0285-95 and NACE Standard RP-0169-96, the assessment of the condition of the coating and cathodic protection system is to be conducted on an annual basis and compared to predetermined values.

7. *Corrective Actions:* The site corrective actions program, quality assurance (QA) procedures, site review and approval process, and administrative controls are implemented in accordance with the requirements of 10 CFR Part 50, Appendix B. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions, confirmation process, and administrative controls.

8. *Confirmation Process:* See Item 7, above.

9. *Administrative Controls:* See Item 7, above.

10. *Operating Experience:* Corrosion pits from the outside diameter have been discovered in buried piping with far less than 60 years of operation. Buried pipe that is coated and cathodically protected is unaffected after 60 years of service. Accordingly, operating experience from application of the NACE standards on non-nuclear systems demonstrates the effectiveness of this program.

References

10 CFR Part 50, Appendix B, *Quality Assurance Criteria for Nuclear Power Plants*, Office of the Federal Register, National Archives and Records Administration, 2005.

NACE Standard RP-0169-96, *Control of External Corrosion on Underground or Submerged Metallic Piping Systems*, 1996.

NACE Standard RP-0285-95, *Corrosion Control of Underground Storage Tank Systems by Cathodic Protection,* Approved March 1985, revised February 1995.

VERIFICATION OF VYNPS LICENSE RENEWAL PROJECT REPORT

Title of Report: **Aging Management Program Evaluation Results**

Report Number: LRPD-02

Revision:

This report documents evaluations related to the VYNPS license renewal project. Signatures certify that the report was prepared, checked and reviewed by the License Renewal Project Team in accordance with the VYNPS license renewal project guidelines and that it was approved by the ENI License Renewal Project Manager and the VYNPS Manager, Engineering Projects.

License Renewal Project Team signatures also certify that a review for determining potential impact to other license renewal documents, based on previous revisions, was conducted for this revision.

Other document(s) impacted by this revision: _ Yes, See Attachment _X_ No

License Renewal Project Team

Prepared by William L. Nichols — Date: 5/9/06

Reviewed by Lori Ann Potts — Date: 5/9/06

Approved by ____________________ David J. Lach, ENI LR Project Manager — Date: _

VYNPS Approval

Reviewed by — Date: _

Approved by ____________________ VYNPS Manager, Engineering Projects — Date: _

4.13 Flow-Accelerated Corrosion Program

A. Program Description

The Flow-Accelerated Corrosion (FAC) Program at VYNPS is comparable to the program described in NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion.

This program applies to safety-related and nonsafety-related carbon steel components carrying two-phase or single-phase high-energy fluid ≥ 2% of plant operating time.

The program, based on EPRI Report NSAC-202L-R2 recommendations for an effective flow-accelerated corrosion program, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. This program includes (a) an evaluation to determine critical locations, (b) initial operational inspections to determine the extent of thinning at these locations, and (c) follow-up inspections to confirm predictions, or repair or replace components as necessary.

This program is credited in the following.

- AMRM-05, High Pressure Coolant Injection System
- AMRM-06, Reactor Core Isolation Cooling and Condensate Storage and Transfer Systems
- AMRM-26, Main Condenser and MSIV Leakage Pathway System
- AMRM-30, Nonsafety-Related Systems and Components Affecting Safety-Related Systems
- AMRM-33, Reactor Coolant System Pressure Boundary

B. Evaluation

1. Scope of Program

a. NUREG-1801 Scope

"The FAC program, described by the EPRI guidelines in NSAC-202L-R2, includes procedures or administrative controls to assure that the structural integrity of all carbon steel lines containing high-energy fluids (two phase as well as single phase) is maintained. Valve bodies retaining pressure in these high-energy systems are also covered by the program. The FAC program was originally outlined in NUREG-1344 and was further described through the Nuclear Regulatory Commission (NRC) Generic Letter (GL) 89-08. A program implemented in accordance with the EPRI guidelines predicts, detects, and monitors FAC in plant piping and other components, such as valve bodies, elbows and expanders. Such a program includes the following recommendations: (a) conducting an analysis to determine critical locations, (b) performing limited baseline inspections to determine the extent of thinning at these locations, and (c) performing follow-up inspections to confirm the predictions, or repairing or replacing components as necessary. NSAC-202L-

R2 (April 1999) provides general guidelines for the FAC program. To ensure that all the aging effects caused by FAC are properly managed, the program includes the use of a predictive code, such as CHECWORKS, that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 CFR Part 50, Appendix B, criteria for development of procedures and control of special processes."

b. <u>Comparison to VYNPS Scope</u>

This program applies to safety-related and nonsafety-related carbon steel components carrying two-phase or single-phase high-energy fluid ≥ 2% of plant operating time.
(Ref. Appendix C, PP 7028)

The program, based on the recommendations of EPRI Report, NSAG-202L-R2, predicts, detects, and monitors FAC in plant piping and other pressure retaining components. The program includes an evaluation to determine critical locations, baseline inspections to determine the extent of thinning at these locations, and follow-up inspections.
(Ref. Section 1.3, PP 7028 and FAC Susceptible Piping Identification)

CHECWORKS, a predictive code that uses the implementation guidance of NSAC-202L-R2 to satisfy the criteria specified in 10 GFR Part 50, Appendix B, is used in this program.
(Ref. Section 4.3, PP 7028)

VYNPS scope is consistent with NUREG-1801.

2. Preventive Actions

a. <u>NUREG-1801, Preventive Actions</u>

"The FAC program is an analysis, inspection, and verification program; thus, there is no preventive action. However, it is noted that monitoring of water chemistry to control pH and dissolved oxygen content, and selection of appropriate piping material, geometry, and hydrodynamic conditions, are effective in reducing FAG."

b. <u>Comparison to VYNPS Preventive Actions</u>

As stated in NUREG-1801, the FAG program is an analysis, inspection, and verification program; thus, there is no preventive action.

VYNPS preventive actions are consistent with NUREG-1801.

3. Parameters Monitoredflnspected

   a. NUREG-1801! Parameters Monitored/Inspected

   "The aging management program (AMP) monitors the effects of FAC on the intended function of piping and components by measuring wall thickness."

   b. Comparison to VYNPS Parameters Monitored/Inspected

   The VYNPS program monitors wall thickness to ensure that FAC does not lead to loss of intended function of piping and components.
   (Ref. Section 1.1, *PP 7028)*

   VYNPS parameters monitored and inspected are consistent with NUREG-1801.

4. Detection of Aging Effects

   a. NUREG-1801! Detection of Aging Effects

   "Degradation of piping and components occurs by wall thinning. The inspection program delineated in NSAC-202L consists of identification of susceptible locations as indicated by operating conditions or special considerations. Ultrasonic and radiographic testing is used to detect wall thinning. The extent and schedule of the inspections assure detection of wall thinning before the loss of intended function."

   b. Comparison to VYNPS Detection of Aging Effects

   Non-destructive examinations (e.g. ultrasonic testing) are used to detect wall thinning at susceptible locations. The extent and schedule of inspections provide reasonable assurance of detection of wall thinning before loss of intended function.
   (Ref. Sections 1.2, 1.3 *and* 4.4.5, *PP 7028)*

   This program is credited with managing the following aging effects.

   - loss of material from internal surfaces of selected carbon steel components (AMRM-05, 06, 26, 30, 33)

   VYN PS detection of aging effects is consistent with NU REG-1801.

5. Monitoring and Trending

   a. NUREG-1801! Monitoring and Trending

   "CHECWORKS or a similar predictive code is used to predict component degradation in the systems conducive to FAC, as indicated by specific plant data, including material, hydrodynamic, and operating conditions.

CHECWORKS is acceptable because it provides a bounding analysis for FAC. CHECWORKS was developed and benchmarked by using data obtained from many plants. The inspection schedule developed by the licensee on the basis of the results of such a predictive code provides reasonable assurance that structural integrity will be maintained between inspections. Inspection results are evaluated to determine if additional inspections are needed to assure that the extent of wall thinning is adequately determined, assure that intended function will not be lost, and identify corrective actions."

b. Comparison to VYNPS Monitoring and Trending

The EPRI software program, "CHECWORKS," is used to predict component degradation in FAC susceptible piping. The inspection schedule provides reasonable assurance that structural integrity will be maintained between inspections. If degradation is detected such that the predicted wall thickness at the next refueling outage is less than minimum allowable thickness, (or much less than the nominal thickness), additional evaluations or examinations are performed to assure the component's intended function will not be lost and identify corrective actions.
(Ref. Sections 1.2, 4.3 and Appendix E, PP 7028 and Section 3, DP 0072)

VYNPS monitoring and trending are consistent with NUREG-1801.

6. Acceptance Criteria

a. NUREG-1801, Acceptance Criteria

"Inspection results are used as input to a predictive computer code, such as CHECWORKS, to calculate the number of refueling or operating cycles remaining before the component reaches the minimum allowable wall thickness. If calculations indicate that an area will reach the minimum allowed wall thickness before the next scheduled outage, the component is to be repaired, replaced, or reevaluated."

b. Comparison to VYNPS Acceptance Criteria

Based on inspection results, CHECWORKS calculates the number of refueling or operating cycles remaining before the component reaches minimum allowable wall thickness. If calculations indicate that an area will reach minimum allowed thickness before the next scheduled outage, the component is repaired, replaced, or reevaluated.
(Ref. Section 4.4, PP 7028 and Section 3, DP 0072)

VYNPS acceptance criteria are consistent with NUREG-1801.

7. Corrective Actions

a. NUREG-1801, Corrective Actions

"Prior to service, components for which the acceptance criteria are not satisfied are reevaluated, repaired, or replaced. Long term corrective actions could include adjusting operating parameters or selecting materials resistant to FAC. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions."

b. Comparison to VYNPS Corrective Actions

If acceptance criteria are not satisfied for particular components, they are repaired, replaced or reevaluated prior to returning to service. Use of improved materials for replaced components and appropriate design changes are part of the VYNPS long-term strategy to mitigate FAC.
(Ref Sections 1.3 and 4.4, PP 7028 and Section 3, DP 0072)

VYNPS corrective actions are consistent with those discussed in NUREG-1801.

8. Confirmation Process

This attribute is discussed in Section 2.0, Background.

9. Administrative Controls

This attribute is discussed in Section 2.0, Background.

10. Operating Experience

a. NUREG-1801, Operating Experience

'Wall-thinning problems in single-phase systems have occurred in feedwater and condensate systems (NRC IE Bulletin No. 87-01; NRC Information Notices [INs] 81-28, 92-35, 95-11) and in two-phase piping in extraction steam lines (NRC INs 89-53, 97-84) and moisture separation reheater and feedwater heater drains (NRC INs 89-53,91-18,93-21,97-84). Operating experience shows that the present program, when properly implemented, is effective in managing FAC in high-energy carbon steel piping and components."

b. Comparison to VYNPS Operating Experience

Operating experience shows that this program has been effective in managing aging effects. Therefore, continued implementation of the program provides reasonable assurance that effects of aging will be managed so that components crediting this program can perform their intended function consistent with the current licensing basis during the period of extended operation. For more information on applicable operating experience, see VYNPS Report LRPD-05, Operating Experience Review Results.

C. References

DP 0072, Rev. 00, LPC 01, Structural Evaluation of Thinned Wall Piping Components

FAC Susceptible Piping Identification, Rev. 0, May 15, 2000

PP 7028, Rev. 00, LPC 01, Piping Flow Accelerated Corrosion Inspection Program

D. Summary

The Flow-Accelerated Corrosion Program has been effective at managing aging effects. The program has been improved through implementation of lessons learned from operating experience. The Flow-Accelerated Corrosion Program provides reasonable assurance that effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

The Flow-Accelerated Corrosion Program at VYNPS is consistent with the program described in NUREG-1801, Section XI.M17, Flow-Accelerated Corrosion.

Cornerstone Rollup

Program: Flow Accelerated Corrosion
Plant: VERMONT YANKEE
Quarter: 3rd
Last Update: 10/03/2006

Monitored Parameter	Criteria	Color	Total Quality Points	Comments
Overall Program	Green: 110 – 120 White: 85 – <110 Yellow: 75 – <85 Red: <75	Green	110	
Program Personnel Cornerstone	This cornerstone provides an indication of whether or not we have the right personnel with the right skills in the right positions to manage the program.	Green	26	
Program Infrastructure Cornerstone	This cornerstone provides an indication of the quality of the infrastructure in place to support the program. Infrastructure includes necessary equipment, program procedures, etc.	White	21	Corrective Action Plan to complete open LO-CA tasks developed 10/2/06 (CR-2006-02699)
Program Implementation Cornerstone	This cornerstone provides an indication of how well we execute programmatic requirements.	Green	33	
Equipment / Related Plant Performance Cornerstone	This cornerstone provides an indication of the health of the components (or other performance indicators impacting plant performance) monitored by the program.	Green	30	

Rev. 0
Date: 04-25-06

NEC038419

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NEC038420

Personnel Performance Cornerstone

Program: Flow Accelerated Corrosion

Plant: VERMONT YANKEE
Quarter: 3rd
Last Update: 10/03/06

Cornerstone Rollup	
Green: 26-30 cornerstone quality points	Green
White: 20-25 cornerstone quality points	
Yellow: 15-19 cornerstone quality points	
Red: <15 cornerstone quality points	

Select Cornerstone Trending	
↑	Up
↔	Stable
↓	Down

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Staff Qualification and Experience	Green – Incumbent fully qualified with 3 years or more experience within the program. White – Incumbent fully qualified. Yellow – Incumbent in partially qualified (> or = 25% complete with qualification card.) Red – No incumbent or unqualified incumbent < 25% complete with qualification card.	Green	3	9	Current FAC Program Owner (JCF) and backup (TO'C) have more than 3 years of FAC experience. Also, new engineer in Code Programs (R.Lane).
Bench strength	Green – Backup fully qualified with 3 years or more experience within the program. White – Backup fully qualified. Yellow – Backup in partially qualified (> or = 25% complete with qualification card.) Red – No backup or unqualified backup < 25% complete with qualification card.	Green	1	3	Backup is fully qualified with more than 3 years of FAC experience.
Training (CHECWORKS BASIC and ADVANCED Training)	Green: Completed CHECWORKS FAC BASIC and ADVANCED Training. White - Completed CHECWORKS FAC BASIC Training and Qualification Card. Yellow - Incumbent is partially qualified (≥ 25% complete with CHECWORKS Training and Qualification Card) Red - Unqualified	GREEN	1	3	Program owner and backup had completed CHECWORKS training prior to split to Basic & Advanced. Both individuals have more than 12 years experience using CHECWORKS.
Industry Participation	Green – Committee membership, other voting	Green	1	3	Participation in EPRI CHUG

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
(Includes any within the ENS region)	White – Active participation within industry within the past year with active sharing across sites. Yellow – No active involvement over the past year but active involvement within the past two years. Red – Inactive participation.				(Voting and Advisory Committee access through single Entergy contact R.Jackson/RBS) Program owner member of CHUG Long Term Planning Group

NEC038421

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Program Human Performance (Does not include errors in implementation)	Green – No HPEs over the past 12 months. White – 1 HPE over the past 12 months Yellow – 2-3 HPE over the past 12 months Red – 4 or more HPE over the past 12 months	Green	1	3	No FAC Program related human performance error clock resets in the past 12 months.
Owner Availability	Green – Supervisor determines sufficient time is available for proactive program improvements White – Supervisor determines sufficient time allotted for necessary program up keep. Yellow – Supervisor determines insufficient time allotted for long term program up keep. Red – Supervisor determines insufficient time allotted for immediate program needs.	Yellow	2	2	Problems identified with timely update of CHECWORKS models (CR-2006-2699). CHECWORKS models and wear rata analyses updated with all previous inspection data in 3rd QTR 2006. Corrective Action Plan to prevent similar issues with remaining FAC program tasks developed 10/2/06.
Peer Interaction (Does not include PI worksheet development)	Green – 2 or more peer White – 1 peer meeting/teleconference quarterly Yellow – less than full regional participation for the meeting/teleconference within the quarter. Red – Did not participate in peer meeting/teleconference for the quarter.	Green	1	3	Entergy FAC Program fleet call held on 7/26/06. EPRI CHUG Long Term Planning Group Telcons.
			Total	26	

NEC038422

Infrastructure Performance Cornerstone

Program: Flow Accelerated Corrosion

Plant:	VERMONT YANKEE
Quarter:	3rd
Last Update:	10/03/2006

Cornerstone Rollup	
Green: 26-30 cornerstone quality points	White
White: 20-25 cornerstone quality points	
Yellow: 15-19 cornerstone quality points	
Red: <15 cornerstone quality points	

Select Cornerstone Trending	
↑	Up
↔	Stable
↓	Down

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Program Infrastructure CRs (Internal) and External Findings. (External findings are defined as conditions found by independent oversight agencies resulting in A or B level CRs. Oversight agencies include QA [audits], INPO, and NRC.)	Green – (identified within the last two quarters)	Green	2	6	No program infrastructure related CRs this operating cycle. For 3rd Qtr. participated in development of new EN standard FAC program procedure EN-DC-315. EN-AD-101 RAF forms complete. Minimal impact to VY program for adoption of EN-DC-315.
	No A or B level CR AND				
	No external findings AND				
	< 4 C level CRs				
	White – (identified within the last two quarters)				
	No A level CR; AND				
	No external findings; AND				
	< 3 B level CRs; and AND				
	< 6 total B and C level CRs				
	Yellow – (identified within the last two quarters)				
	No A level CRs AND				
	Any of the following				
	3-4 B level CRs OR				
	5-15 total B or C level CRs OR				
	1 external finding.				
	Red – (Any of the following within the last two quarters)				
	Any A level CR OR				
	5 or more B level CRs OR				
	15 or more total B or C level CRs OR				
	2 or more external findings OR				
	Any NRC violation.				

NEC038423

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Long Range Plan (plan for items requiring significant resources such as outage support requirements, scheduled assessments, program updates, critical infra-structure upgrades, and scheduled component replacements.)	Green – Long range plan in place covering the next 5 years, updated within the last year and with budgetary items IDd in the long range budget. White – Long range plan in place covering the next 3 years, updated within the last year and with budgetary items IDd in the long range budget. Yellow - Foreseeable issues requiring significant resources within the 1 to 3 years not included in the long range plan. Red – Foreseeable issues requiring significant resources within the next 12 months not included in the long range plan. Yellow or Red can be upgraded once adequate plans are in place including funding in budget.	White	1	2	Completed transition to ENN standard FAC program this cycle. No formal long range plans have been developed for ENN FAC programs to date. However, VY has just implemented 120% power uprate. To assess effects on piping, the number of inspection locations will be increased approx 50% over previous outages for the next 3 refueling outages. Additional planning for small bore piping with respect to recommended replacements will be performed upon completion of VY-RPT-05-00013.
Open Action Items (Includes ALL CR-CAs, ER post-action items and LO-CAs.)	Green – No due date extensions and no items greater than 6 months old. White – No action items greater than 1 year old. Yellow – Any action item greater than 1 year old. Red – 2 or more CR-CAs and/or ER post-action items (excluding LOs action items) greater than 1 year old.	Yellow	1	1	LO-VTYLO-2003-00327-CA2 LO-VTYLO-2003-00327-CA4 LO-VTYLO-2003-00327-CA6 LO-VTYLO-2004-00004-CA4 LO-VTYLO-2004-00399-CA1 LO-VTYLO-2005-00215-CA1 (Listed LO-CAs are tracked under Corrective Action Plan for CR-2006-02699)
Document / Database Health	Green – No outstanding changes to the program documents (or databases) which impact program performance (e.g. missed commitment, surveillance past due); no outstanding changes for enhancements greater than two quarters old; and use of best-in-practice database or tracking software. White – No outstanding changes to the program documents (or databases) which potentially impact program performance. Yellow – Database compatibility issues OR any outstanding issues with the potential to impact program performance. Red – Any procedural or database issue which directly impacted program performance within the past quarter.	White	3	6	CHECWORKS models and wear rata analyses updated with all previous inspection data in 3rd QTR 2006. (CR-2006-2699)

NEC038424

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Test Equipment	Green – Best-in-practice, functional and properly calibrated equipment in the proper numbers to get the job done efficiently.	Green	2	4	Test Equipment (Parametrics UT/Data loggers) used during refueling outages is the same as used in the ISI Program. Equipment is tested and calibrated per NDE procedures prior to each refueling outage.
	White – Equipment functional and properly calibrated in the proper numbers to get the job done efficiently.				
	Yellow – Test Equipment Obsolescence Issues OR Test equipment failure (which did not impact scheduled or required program implementation activity) within the last quarter OR Insufficient equipment available (functional and properly calibrated) for efficient program implementation.				
	Red – Equipment unavailable to support scheduled or required program implementation activity.				
Benchmarks/Self-Assessments	Green: Benchmark or Self-Assessment within the last 2 years.	White	1	2	Next SA scheduled for completion 12/08/06 (LO-VTYLO-2003-00327-CA2)
	White: Benchmark or Self-Assessment within the last 3 years.				
	Yellow: Benchmark or Self-Assessment within the last 4 years.				
	Red: No Benchmark or Self-Assessment within the last 4 years.				
			Totals	21	

NEC038426

Implementation Performance Cornerstone

Program: Flow Accelerated Corrosion

Plant:	VERMONT YANKEE
Quarter:	3rd
Last Update:	10/03/2006

Cornerstone Rollup	
Green: 26-30 cornerstone quality points	Green
White: 20-25 cornerstone quality points	
Yellow: 15-19 cornerstone quality points	
Red: <15 cornerstone quality points	

Select Cornerstone Trending	
↑	Up
↔	Stable
↓	Down

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Program Implementation CRs (Internal) and External Findings. (External findings are defined as conditions found by independent oversight agencies resulting in A or B level CRs. Oversight agencies include QA [audits], INPO, and NRC.)	Green – (identified within the last two quarters) No A or B level CR AND No external findings AND < 4 C level CRs White – (identified within the last two quarters) No A level CR; AND No external findings; AND < 3 B level CRs; AND < 6 total B and C level CRs Yellow – (identified within the last two quarters) No A level CRs AND Any of the following 3-4 B level CRs OR 5-15 total B or C level CRs OR 1 external finding.	Green	1	3	CR-2006-2699 8/30/06 Level C, Identified CHECWORKS models were not updated in a timely manner. Problems identified with timely update of CHECWORKS models (CR-2006-2699). CHECWORKS models and wear rata analyses updated with all previous inspection data in 3rd QTR 2006. Corrective Action Plan to prevent similar issues with remaining FAC program tasks developed 10/2/06.

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
	Red – (Any of the following within the last two quarters) Any A level CR OR 5 or more B level CRs OR 15 or more total B or C level CRs OR 2 or more external findings OR Any NRC violation.				
Internally Identified Implementation Issues – Other than CRs (Self revealing issues, self assessments' benchmarking, Operating Experience including	Green: None White: Identified issue with action resolved. Yellow: Identified issue less than 1 year old. Red: Any identified issue greater than 1 year old.	Green	1	3	None (Issues addressed in Corrective Action Plan for CR-2006-2699 above)
Outage Performance Note: Indicator should remain the color until corrective actions are taken to preclude recurrence during the	Green: Met original scope and goals (duration, White: Less than 100% greater than 90% Yellow: Less than 90% greater than 80% Red: Less than 80%	Green	1	3	No Outage this Qtr. Outage planning milestones have been met.

NEC038427

NEC038428

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
On-line Performance	Green: Met original scope and goals (duration, White: Less than 100% greater than 90% Yellow: Less than 90% greater than 80% Red: Less than 80%	Green	1	3	No on-line FAC Related goals
PM's/Surveillance Tasks (window stays the color until the deferred PM's are completed)	Green: No deferrals for the quarter White: Greater than 95% complete for the quarter Yellow: Greater than 90% complete for the quarter Red: Less than 90% complete for the quarter	Green	1	3	No PMs under FAC program. Surveillances scheduled for RFO 26.
Other Identified Concerns or Issues (Only captures program concerns that do not fall under other PIs)	Green: No concerns / issues White: Any non-significant concern/issue with action plan Yellow: Any significant concern or issue with action plan or any non significant issue without action plan Red: Any significant issue/concern without action plan	Green	1	3	None. Internally identified implementation issues above addressed under (CR-2006-2699) Corrective Action Plan developed 10/2/06.
Implementation resources (i.e. number of qualified personnel)	Green: No identified resource concern White: Identified concern with action plan Yellow: Identified concern without action plan Red: Significant concern without action plan	Green	1	3	Currently 2 Program Engineers are qualified per ENN-TK-ESPG042 Training for new program engineer is process.
Piping Replacements (Unplanned during cycle or outage)	Green: 0 unplanned pipe or component replacements due to current outage findings. White: 1 unplanned pipe or component replacement due to current outage finding. Yellow: > 1 < 2 unplanned pipe or component replacements due to current outage finding Red - > 2 unplanned pipe or component replacements due to current outage finding.	Green	2	6	No outage this qtr. No unplanned piping replacements during this operating cycle. Possible FAC related small-bore replacement required in RFO26, (WO 06-6880) 1" SSH low pt.drain is in planning for RFO26.

NEC038429

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
	(Note: Color can be up-graded once corrective actions to piping are completed and Program has been corrected to prevent recurrence; i.e., additional exams or exam frequency specified)				
Operating Experience	Green: 1 OR less items generated by plant OE department that has not been reviewed.	Green	1	3	No unreviewed OE generated by plant OE department.
	White: 2 items generated by plant OE department that has not been reviewed.				
	Yellow: 3 items generated by plant OE department that has not been reviewed.				
	Red: > 4 items generated by plant OE department that has not been reviewed.				
Outage Scope Increase (Unplanned) (PWRs include online inspections in current cycle)	Green: < 10% increase in inspection scope due to inspection findings.	Green	1	3	No unplanned outage scope increase to date.
	White: 10% to < 12% increase in inspection scope due to inspection findings.				
	Yellow: ≥ 13% increase in inspection scope due to inspection findings.				
	Red: > 15% increase in inspection scope due to inspection findings.				
			Total	33	

Equip...ent / Related Plant Performance Cornerstone

Program: Flow Accelerated Corrosion

Plant:	VERMONT YANKEE
Quarter:	3rd
Last Update:	10/03/2006

Cornerstone Rollup	
Green: 26-30 cornerstone quality points	Green
White: 20-25 cornerstone quality points	
Yellow: 15-19 cornerstone quality points	
Red: <15 cornerstone quality points	

Select Cornerstone Trending	
↑	Up
↔	Stable
↓	Down

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Generation Health	Green - No Transients or power reduction resulting from a program issue	Green	2	6	No transients or power reuctions resulting for program activities of FAC related leaks so far this operating cycle.
	White - No Transients or power reduction resulting from a program issue or component on a quarterly basis				
	Yellow - A " near miss" , transient or a power reduction < 1000 mwhr/qt as a result of a program issue or component				
	Red - A plant trip or significant power reduction > 1000 mwhr/qtr as a result of a program issue of component				
Large Bore Failures (Based on Cycle of operation)	Green: No Large Bore failures in load	Green	4	12	No large bore failures this operating cycle
	Red: ≥ 1 Large Bore failure resulting in load reduction or safety issues.				
	Note: color can be up-graded once corrective actions to piping are completed and the Program has been corrected to prevent recurrence; i.e.., additional exams or exam frequency specified)				

NEC038430

Monitored Parameter	Criteria	Result	Relative Value	Quality Points	Comments
Small Bore Failures (Based on Cycle of operation)	Green: ≤ 1 Small Bore FAC related failure resulting in a load reduction White: < 3 Small Bore FAC related failures resulting in a load reduction or safety issue. Red: > 3 Small Bore FAC related failures resulting in a load reduction or safety issue. (Note: color can be up-graded once corrective actions to piping are completed and the Program has been corrected to prevent recurrence; i.e., additional exams or exam frequency specified)	Green	2	6	1 smallbore leak identified this operating cycle possibly due to FAC. Location is on elbow of 1" low pt. drain on SSH (WO 06-6880)
Stress Analysis (Cycle of operation including outage)	Green: 1 to 3 detailed stress analysis required. White: 3 to 5 detailed stress analysis required. Red: ≥ 6 detailed stress analysis required.	Green	2	6	No stress analyses required this operating cycle
			Totals	30	

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion (FAC) Program

...C **Owner: Jim Fitzpatrick** **Phone: 802.451.3086**

Controlling Document: PP 7028; ENN-DC-315 **Supervisor: Scott Goodwin**

Date:	06-Apr-06
Quarter:	First Quarter, 2006
Program Color:	White
Trend:	Steady

2004-Q4	2005-Q1	2005-Q2	2005-Q4

Current Status Basis:

The FAC Program has just completed the 1st Qtr. 2006. (1/01 to 3/31)

Program is white, based on 20 Green, 3 White, and 1 Yellow indicators.

There are no outstanding issues which are not already addressed that may impact the program.

Current Activities:

1st Qtr. 2006 (1/01 to 3/31)

RFO25 FAC Outage Inspection Report

RFO26 Outage Program Scope Milestone 2/19/06. RFO26 FAC Scope Memo, VYM-...C-2006-001 issued 2/16/06.

...doption of ENN Standard FAC Program Procedure ENN-DC-315 Rev.1 on 3/15/06.

Attended EPRI Checworks Users Group Meeting on 1/9 & 1/10. OE at meeting from LaSalle, Peach Bottom 3, and Surry on partial line replacements resulted in addition of three inspection locations for RFO26.

ENN FAC Working Group Meeting 1/26 at PNPS.

Participation in IPEC FAC Program Focused Self Assessment 2/6 to 2/10.

Significant Accomplishments:

Adoption of ENN-DC-315 Rev.1

Met RFO26 Outage Planning Milestone

Actions To Return To Green:

Current Program engineers still involved with EPU related tasks (Nulcear Change and Power Accension). Code Programs attempts at hiring a new Program Engineer have not yielded results to date.

Completion of identified tasks listed in the "Open LO-CAs" in this Program Health Report will bring Program status back to ...en. To ensure that ongoing program ...s are re-scheduled and performed for remainder of 2006, the action plan per ENN-MS-S-008 will be revised and activities input to EWC by 4/15/06.

Exceptions To Grading Criteria:

NONE

REGULATORY:

LERs:

No FAC Program Related LERs this quarter.

INPO Findings:

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det:

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance:

The FAC Program currently meets all regulatory requirements.

New RRs and Code Cases:

New ENN Engineering Standard for Pipe Wall Thinning Evaluation, ENN-CS-S-008, incorporates ASME Code Case N-597. C.C. N-597 was incorporated into R.G 1.147 Rev.13 with new caveats for use. NRC approval is required to implement code case as written.

ADMINISTRATIVE:

Procedure, Program Compliance Issues:

No Program Compliance issues with current Regulations of Codes.

With adoption of ENN-DC-315 Rev.1, VY Procedures PP7028 and DP0072 will be canceled per AP0096.

Budget, Resources:

FAC Program personnel (resources) were utilized on EPU related tasks. Currently no Program activities are scheduled into EWC. Activities will be input to EWC once scheduling of RFO26 design change work is complete.

Ownwership of FAC Program to be transferred to Programs & Components Engineering. Currently interviewing for new FAC program Engineer position in Code Programs.

Audits:

No audits this quarter.

Open Action Items:

LO-VTYLO-2003-00327 CA 2 due 12/10/06 (three due date extensions)
LO-VTYLO-2003-00327 CA 6 due 5/30/06 (two due date extensions)
LO-VTYLO-2004-00399 CA 1 due 5/17/06 (two due date extensions)
LO-VTYLO-2003-00327 CA 4 due 8/30/06 (two due date extensions)
LO-VTYLO-2003-00327 CA 5 due 8/01/06 (two due date extensions)

BenchMarking, SelfAssessment:

Focused Self Assessment October 2003. Ongoing work for Corrective Actions generated from assessment. See LO-CAs (2003-0327) under Open Action Items

EWC Milestones, New Eng Issues:

Continued difficulty in meeting re-projected schedules due to emegent work, EPU, & other unscheduled tasks. There is currently no EWC schedule in place for any Program. Program activities will be included in EWC after RFO26 design changes are scheduled.

A formal action plan per ENN-MS-S-008 to adress issues to get program to Green status and ENN standardization was developed in 2nd. Qtr. 2005. Status has 4 of 11 tasks as not complete. A revision to the Action Plan and EWC scheduling will be performed when EWC is up and functioning.

Program Concerns:

Continued difficulties in completeing scheduled FAC program activities due to resources spent on EPU related work. Concern from previous quarters. A formal Action Plan per ENN-MS S-008 was developed to get program to Green status.

Lack of progress in hiring a new FAC Program Engineer for Code Programs is a concern.

CORRECTIVE ACTIONS:

Significant CRs:

No significant CR's (Category A or B) were written against the FAC program for this quarter.

Open CR CAs:

No open CRs as of 3/31/06

EQUIPMENT:

Open Eng Req:

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion (FAC) Program

. AC **Owner: Jim Fitzpatrick** **Phone: 802.451.3086**

Controlling Document: PP 7028; ENN-DC-315 **Supervisor: Scott Goodwin**

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P.Turbine Steam Seal Piping

ER 05-0767 for Converting FAC Component Location Sketches Located into Appendix A of PP7028 into Controlled VY Drawings

ER 05-1004 for Upadating FAC Program Checworks Models for RFO26.

Operator Work Arounds:

N/A - There are no operator works arounds related to the FAC program.

Prog Related LCOs:

There are no LCOs related to the FAC program this qtr.

PMs Within Due Date:

N/A - There are no PMs associated with the FAC program.

Repetitive Failures:

...re are no repetitive equipment related issues for the FAC program this quarter.

Unanticipated Failures:

SSH pin hole leaks identified in CR VTY-2004-02985. Tenmporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO25. However, inspections were deferred until RFO26 due to schedule for LP turbine work.

No new Unanticipated Failures since October 2004.

Trending Results:

No components projected to wear to wall thickness below code minimum within two cycles from RFO26.

Open Work Requests:

N/A - There are no work requests over 2 yrs old.

Surveillances Within Due Date:

N/A No Technical Specifiaction Surveillances under the FAC program this qutarter.

Significant Parts Issues:

. - There are no parts issues associated with the FAC program this quarter

Identified Concerns:

No other identified equipment concerns.

ORGANIZATION:

Staff Qual and Trng:

The program owner and Backup engineer are qualified to perform FAC Program tasks.

3rd Engineer obtained basic FAC training and CHECWORKS SFA training, June 6-8.

Bench Strength:

The program owner and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in Civil/Structural (R. Omer) has FAC related experience and has completed updated FAC training.

Program Ownership:

Site personnel are aware of the Program Owner based results from last SA.

FAC Program Ownership to be transferred to Code Programs Group per ENN model. Interviews for a new FAC Program Engineer to reside in Code Programs started in October 2005.

HU Errors:

There were no human performance errors (HPE) as a result of Program implementation activities for this quarter.

AP0098 Expectations:

Continued difficulties in completeing program activities on schedule. EPU work is still affecting FAC Program activities in 1st quarter of 2006.

A formal action plan per ENN-MS S-008 to get program Green status and adddress ENN standardization issues was developed. The ENN standization efforts are complete as of 3/15/06 with the exception of cancelling PP7028 & DP0072 per AP0096. All other tasks required are being tracked in PCRS. Completion of identified tasks listed in the "Open LO-CAs" in this Program Health Report will bring Program status back to Green.

Status: Progress needs to be monitored. Keep status as White

Operating Experience:

See RFO26 (2007) Scoping Worksheets for a detailed list of FAC related OE and disposition for VY.

ECIs:

None

Outage Health:

Outage Perf:

No refueling outage in 1st QTR 2006.

RFO26 program scoping Milestone of 2/19/06 met (Memo VYM-FAC-2006-001 dated 2/16/06).

Outage Preparation:

RFO26 Outage planning milestones met.

Generation Health:

Generation Health:

There were no transients or power reductions as a result of a FAC Program issue in 1st quarter of 2006.

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion (FAC) Program

FAC | Owner: Jim Fitzpatrick | Phone: 802.451.3086

Controlling Document: PP 7028; ENN-DC-315 | Supervisor: Scott Goodwin

Date:	15-Mar-06
Quarter:	Fourth Quarter, 2005
Program Color:	White
Trend:	Steady

2004-Q3	2004-Q4	2005-Q1	2005-Q2

Current Status Basis:

This report covers 3rd & 4th quarters of 2005.

Program is White, based on 17 Green, 6 White, and 1 Yellow indicators.

There are no outstanding issues which are not already addressed that may impact the program.

Current Activities:

3rd & 4th Qtr. 2005 (7/1/05 to 12/31/05)

RFO25 Outage Planning & Preparation

NRC FAC Program Inspection week of July 25

..C Suseptibility Evaluation updated for EPU and other piping design changes (VY-RPT-05-00012, Rev.0)

Transition efforts to adopt ENN Standard FAC Program Procedure ENN-DC-315 Rev.0 :
1. Gap Analysis with PP7028 Completed 9/14/05
2. ENN-LI-100 Att.9.1, ENN-LI-101 Att.9.1 and EN-AD-101 Att9.1 with VY comments sent to WPO on 9/22/05.
3. Engineering Standard & Approval form for ENN-CE-S-008 Pipe Wall Thinning Structural Evaluation, Rev.0 for VY completed 9/22/05.
4. Engineering Standard & Approval form for ENN-EP-S-005 FAC Component Scanning & Gridding Standard, Rev.0 for VY completed 9/22/05.

J. Fitzpatrick and T. O'Connor completed documentation for ENN standard FAC Qual Card ENN-TKESPG-042 on 10/5/05

RFO25 outage support, data evaluations and trending of inspection results.

Provided support for Management Presentations at ACRS Power Uprate Subgroup on Power Uprates Meeting in Bethdesda, MD on 11/30 & 31.

gnificant Accomplishments:

NRC FAC Inspection Complete. No findings of significance were identified. (NRC Inspection Report for VY 2005-004 dated October 19,2005).

Support of RFO25 inspection efforts

Actions To Return To Green:

Ensure that ongoing program tasks which were re-scheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adquate time & personnel be alloted to perform program tasks. A formal action plan per ENN-MS-S-008 to get program Green status and adddress ENN standardization issues was developed in May 2005. Status 8 of 9 items complete in 2005.

Exceptions To Grading Criteria:

NONE

REGULATORY:

LERs:

No FAC Program Related LERs these quarters.

INPO Findings:

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det:

No GL 91-18 issues or operability evaluations related to the FAC Program these quarters.

Regulatory Compliance:

The FAC Program currently meets all regulatory requirements.

New RRs and Code Cases:

New ENN Engineering Standard for Pipe Wall Thinning Evaluation, ENN-CS-S-008, effective date 9/28/05, incorporates ASME Code Case N-597. C.C. N597 was incorporated into R.G 1.147 Rev.13 with new caveats for use. NRC appoval is required to implement the code case as written.

ADMINISTRATIVE:

Procedure, Program Compliance Issues:

No Program Compliance Issues with current Regulations of Codes.

PP7028 and DP0072 to be cancelled once ENN-DC-315 is made effective at VY.

Budget, Resources:

2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program Scoping Memo. FAC Program personnel (resources) were utilized on EPU related design changes and calculations. EWC schedule has Program resources pushed back to 2nd half of 2005.

Ownership of FAC Program to be transfered to Program & Components Engineering . Currently interviewing for new FAC Program Engineer position in Code Programs.

Audits:

An NRC Inspection of the FAC Program for addressing EPU changes to piping and operating conditions was conducted the week of July 25,2005. No findings of significance were identified. (NRC Inspection Report for VY 2005-004 dated October 19,2005).

Open Action Items:

LO-VTYLO-2003-00327 CA 2 due 1/13/06 (two due date extensions)
LO-VTYLO-2003-00327 CA 6 due 5/30/06 (two due date extensions)
LO-VTYLO-2004-00399 CA 1 due 5/17/06 (two due date extensions)
LO-VTYLO-2003-00327 CA 4 due 2/10/06 (one due date extension)
LO-VTYLO-2003-00327 CA 5 due 1/15/06 (one due date extension)

BenchMarking SelfAssessment:

Focused Self Assessment October 2003. Ongoing work for Corrective Actions generated from assessment See LO-CAs (2003-0327) under Open Action Items

EWC Milestones, New Eng Issues:

Ongoing program tasks were rescheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo. Continued difficulty in meeting re-projected schedules due to emegent work, EPU, & other unscheduled tasks. A formal action plan per ENN-MS-S-008 was developed in 2nd. Qtr. 2005.

Action Plan addresses issues to get program to Green status and ENN standardization. All items on action plan completed in 2005 except incorporation of Small Bore Databse into VY-RPT-05-00013. This work is inprocess.

Program Concerns:

Scheduled FAC program activities were started late in 3rd quarter due to resources spent on EPU related work. Concern from previous qtr. A formal Action Plan per ENN-MS-S-008 was developed to get program status Green and adddress ENN

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion (FAC) Program

FAC **Owner: Jim Fitzpatrick** **Phone: 802.451.3086**

Controlling Document: PP 7028; ENN-DC-315 **Supervisor: Scott Goodwin**

standardization issues.
Progess was made on action plan items. However, the root cause for not completing EWC schduled work has not been addressed.

CORRECTIVE ACTIONS:

Significant CRs:

No significant CR's (Category A or B) were written against the FAC program for these quarters.

Open CR CAs:

No Open CRs as of 12/31/05.
CR-VTY-2005-02239 was closed out to ER 05-1004 on 12/19/05.

EQUIPMENT:

Open Eng Req:

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC resistant materials was implemented during RFO25.

. 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P.Turbine Steam Seal Piping. Removal of Temp Mod, and additional inspections to determine extent of condition were not performed in RFO25 due to schedule conflicts with LP turbine work. Deferred until RFO26. (Ref. VYPPF 7102.01 for W.O. 04-004983-000/010, dated 11/1/05)

Operator Work Arounds:

N/A - There are no operator work arounds related to the FAC program.

Prog Related LCOs:

There are no LCOs related to the FAC program theses quarters.

PMs Within Due Date:

N/A - There are no PMs associated with the FAC program.

Repetitive Failures:

There are no repetitive equipment related issues for the FAC program these quarters.

Unanticipated Failures:

SSH pin hole leaks identified in CR VTY-04-02985. Temporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO 25. However deferred until RFO26 due to schedule for LP turbine work.

Trending Results:

N/A with respect to equipment.

Open Work Requests:

N/A - There are no work requests over 2 yrs old.

Surveillances Within Due Date:

N/A No Technical Specification Surveillances under the FAC program were perfored in RFO25.

Significant Parts Issues:

N/A - There are no parts issues associated with the FAC program this quarter

Identified Concerns:

No other identified equipment concerns.

ORGANIZATION:

Staff Qual and Trng:

The program owner and backup engineer are qualified to perform FAC Program tasks.

3rd Engineer obtained basic FAC training and CHECWORKS SFA training, 2nd Qtr. 2005.

Program owner and backup qualified to ENN Standard FAC Qual Card. ENN-TKESPG042 10/5/05

Bench Strength:

The program owner and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in C/S (R. Orner) has FAC related experience and has updated training 2nd Qtr. 2005.

Program Ownership:

Site personnel are aware of the Program Owner based results from last SA.

FAC Program ownership to be transfered to Code Programs Group per ENN model. Interveiws for new FAC Program Engineer to reside in Code Programs Group started in October 05.

HU Errors:

There was one 1 human performance error (HPE) as a result of Program implementation activities for the third quarter of 2005 (CR-VTY-2005-02239 on procedure complance)

AP0098 Expectations:

Continued difficulties in completing program activities on schedule. EPU work is winding down in second qtr. of 2005. FAC Program engineering work has been begun with update of the piping FAC susceptibilty review and ENN prpcedure transition activities. A formal action plan per ENN-MS-S-008 to get program status to Green and address ENN standardization issues was developed and work has begun. Status: 8 of 9 items completed in 2005. Remaining task is in progress. Keep status as White.

Operating Experience:

See 2005 RFO Scoping Worksheets for a list of FAC related OE.

ECIs:

None

Outage Health:

Outage Perf:

RFO25 in October/November 2005. All planned inspections performed except Nos. 2004-24 to 2005-35. These are located on LP Turbine SSH and SPE lines to determine extent of condition for CR-VTY-2004-02925. These inspections were to be coordinated with removal of Temp Mod 2004-031. Restoration of the Temp Mod was deleted from the outage scope on 10/24/05 as documeted on YPPF 7102.01. Access to this piping could not be obtained due to critical path work on the LP turbines. Inspections were deferred to RFO26.

Outage Preparation:

RFO25 Outage planning milestones met.

Generation Health:

Generation Health:

There were no transients or power reductions as a result of a FAC Program issue in Q3 & Q4 2005.

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion Program (FAC)

\C **Owner: Jim Fitzpatrick** **Phone: 802.451.3086**

ontrolling Document: PP 7028 **Supervisor: Scott Goodwin**

Date:	06-Sep-05
Quarter:	Second Quarter, 2005
Program Color:	White
Trend:	Steady

2004-Q1	2004-Q3	2004-Q4	2005-Q1

Current Status Basis:

The FAC Program has just completed 2nd Qtr. 2005.

Program is white , based on 22 Green, 3 White, and 1 Yellow indicators.

There are no outstanding issues which are not already addressed that may impact the program.

Current Activities:

2nd. Qtr. 2005 (4/1/05 to 6/30/05)

WANO Inspection, April 2005

RFO25 Outage Planning & Preparation

RFO25 Outage Scope Challenge Meeting 5/4/05

; program and ENN procedure transition acticities were rescheduled into EWC to start 2nd Qtr. 2005. Activities were started but not completerd due to EPU related design changes. This a continued trend from the previous quarter program health reports.

Preparation for July NRC FAC Inspection.

Significant Accomplishments:

WANO Inspection Complete - No AFIs for FAC Program

Actions To Return To Green:

Ensure that ongoing program tasks which were re-scheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adquate time & personnel be alloted to perform program tasks. A formal action plan per ENN-MS S-008 to get program Green status and adddress ENN standardization issues was developed in May 2005.

Exceptions To Grading Criteria:

NONE

REGULATORY:

Rs:

No FAC Program Related LERs this quarter.

INPO Findings:

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det:

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance:

The FAC Program currently meets all regulatory requirements.

New RRs and Code Cases:

ASME Code Case N-597 was incorporated into R.G 1.147 Rev.13 with new caveats for use. This will affect DP-0072 and transition to ENN-DC-133. WPO has decided to replace ENN-DC-133 with a new engineering Guide ENN-CE-G-001. VY Comments on draft sent to WPO on 5/24/05.

ADMINISTRATIVE:

Procedure, Program, Compliance Issues:

No Program Compliance issues with current Regulations of Codes.

Budget, Resources:

2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program Scoping Memo.

FAC Program personnel (resources) were utilized on EPU related design changes and calculations. EWC schedule has Program resources back onto FAC work in 2nd Qtr. 2005.

Audits:

WANO inspection April 2005.

An NRC Inspection of of the FAC Program for addressing EPU changes to piping and operating conditions is scheduled for July 25,2005.

Open Action Items:

LO-VTYLO-2003-00327 CA 2 due 1/13/06 (two due date extensions)
LO-VTYLO-2003-00327 CA 6 due 10/03/05 (one due date extension)
LO-VTYLO-2004-00399 CA 1 due 12/31/05 (one due date extension)
LO-VTYLO-2003-00327 CA 4 due 2/10/06 (one due date extension)
LO-VTYLO-2003-00327 CA 5 due 1/15/06 (one due date extension)
LO-VTYLO-2005-00030 CA11 due 10/03/05 (one due date extension)

BenchMarking, SelfAssessment:

Focused Self Assessment October 2003. Ongoing work for Corrective Actions generated from assessment See LO-CAs (2003-0327) under Open Action Items

EWC Milestones, New Eng Issues:

Ongoing program tasks were rescheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo. Continued difficulty in meeting re-projected schedules due to emegent work, EPU, & other unscheduled tasks. A formal action plan per ENN-MS-S-008 was developed in 2nd. Qtr. 2005. Action Plan addresses issues to get program to Green status and ENN standardization.

Program Concerns:

Scheduled FAC program activities were started late in quarter due to resources spent on EPU related work. Concern from previous qtr. A formal Action Plan per ENN-MS S-008 was develped to get program Green status and adddress ENN standardization issues.

CORRECTIVE ACTIONS:

Significant CRs:

No significant CR's (Category A) were written against the FAC program for this quarter.

Open CR CAs:

None for 2nd Qtr. 2005

EQUIPMENT:

Open Eng Req:

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal. Leakoff lines with FAC Resitant materials. Aprroved in EWC. Replacement to be implemented in RFO 25

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P.Turbine Steam Seal Piping

Operator Work Arounds:

N/A - There are no operator works arounds related to the FAC program.

Prog Related LCOs:

There are no LCOs related to the FAC

program this qtr.

PMs Within Due Date:

N/A - There are no PMs associated with the FAC program.

Repetitive Failures:

There are no repetitive equipment related issues for the FAC program this quarter.

Unanticipated Failures:

SSH pin hole leaks identified in CR VTY-2004-02985. Tenmporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO 25 .

Trending Results:

N/A with respect to equipment.

Open Work Requests:

N/A - There are no work requests over 2 yrs old.

Surveillances Within Due Date:

Inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24. No surveillances scheduled for 2nd Qtr. 2005.

Significant Parts Issues:

N/A - There are no parts issues associated with the FAC program this quarter

Identified Concerns:

No other identified equipment concerns.

ORGANIZATION:

Staff Qual and Trng:

The program owner and Backup engineer are qualified to perform FAC Program tasks.

3rd Engineer obtained basic FAC training and CHECWORKS SFA training, June 6-8.

Bench Strength:

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Orner) has FAC related experience and has updated training (June 6-8) .

Program Ownership:

. personnel are aware of the Program Owner based results from last SA.

HU Errors:

There were no human performance errors (HPE) as a result of Program implementation activities for this quarter.

AP0098 Expectations:

Continued difficulties in completeing program activities on schedule. EPU work is winding down in secornd qtr. of 2005. FAC Program engineering work has been begun with update lof the piping FAC susceptibilty review and ENN prpcedure transition activities. A formal action plan per ENN-MS S-008 to get program Green status and adddress ENN standardization issues was devlopred and work has begun. Status: Progress needs to be monitored. Keep status as White .

Operating Experience:

See 2005 RFO Scoping Worksheets for a list of FAC related OE.

CPIs:

None

Outage Health:

Outage Perf:

No outage in 2nd QTR 2005

Outage Preparation:

RFO-25 Outage planning milestones met.

Generation Health:

Generation Health:

There were no transients or power reductions as a result of a FAC Program issue in Q2.

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion Program (FAC)

FAC | Owner: Jim Fitzpatrick | Phone: 802.451.3086

Controlling Document: PP 7028 | Supervisor: Scott Goodwin

Date:	10-May-05
Quarter:	First Quarter, 2005
Program Color:	White
Trend:	Improving

2003-Q4	2004-Q1	2004-Q3	2004-Q4

Current Status Basis:

The FAC Program has just completed 1st Qtr 2005.

Program is white , based on 21 Green, 3 White, and 1 Yellow indicators.

There are no outstanding issues which are not already addressed that may impact the program.

Current Activities:

1st Qtr 2005 (1/1/05 to 3/31/05)

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC resistant materials. Replacement to be implemented in RFO 25

04-1315 for Evaluation of Temporary Steam Leak Repair on L.P.Turbine Steam Seal Piping. Inspection of additional components was added to the 2005 RFO scope to detemine the extent of condition on the SSH piping.

Scheduled FAC Program Activities for the 1st quarter 2005 were not completerd due to EPU related design changes. This a continued trend from the previous quarter program health report. EPU work scheduled to end early 2nd qtr. 2005. FAC program acticities were rescheduled into EWC to start 2nd Qtr. 2005.

Significant Accomplishments:

Completed Corrective Actions from CR-VTY-2004-3061 and CR-VTY-2004-3062.

Met Outage Milestones for sub-work order genetation.

Actions To Return To Green:

Ensure that ongoing program tasks which were re-scheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo are in fact performed on or near to schedule. This requires adquate time & personnel be alloted to perform program tasks. A formal action plan per ENN-MS S-` to get program Green status and `ress ENN standardization issues will ... delvelopred in the 2nd Qtr. 2005.

Exceptions To Grading Criteria:

NONE

REGULATORY:

LERs:

No FAC Program Related LERs this quarter.

INPO Findings:

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det:

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance:

The FAC Program currently meets all regulatory requirements.

New RRs and Code Cases:

ASME Code Case N-597 was incorporated into R.G 1.147 Rev.13 with new caveats for use. This will affect DP-0072 and transition to ENN-DC-133. WPO has decided to replace ENN-DC-133 with a new enginineering Guide ENN-CE-G-xxx . Draft of guide sent out for comment on 3/09/05. Scheduled to have review complete by June 2005.

ADMINISTRATIVE:

Procedure, Program, Compliance Issues:

No Program Compliance issues with current Regulations of Codes.

Budget, Resources:

2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program Scoping Memo.

FAC Program personnel (resources) were utilized on EPU related design changes and calculations. EWC schedule has Program resources back onto FAC work in 2nd Qtr. 2005.

Audits:

A QA audit was performed in Sept/October 2004. The audit identified two procedure compliance issues related to program documention and timely completion of activities.

CR VTY-2004-03061 identified that the FAC Inspection Report for the 2004 RFO was not completed within 90 days of plant startup as required per PP-7028. Report was completed 2/15/05 and CR was closed on 2/16/05.

CR VTY-2004-03062 identified a backlog in inspection records being sent to RIMS per AP-6807. For each refuelig outage; Progam PP7028 inspection records, reports, memos, and component evaluations were packaged similar to job order files and sent to RIMS. CR was closed on 2/16/05

WANO inspection is scheduled for April 2005.

An NRC Inspection of of the FAC Program for addressing EPU changes to piping and operating conditions is scheduled for July 25,2005.

Open Action Items:

LO-VTYLO-2003-00327 CA 2 due 6/1/05 (one due date extension)
LO-VTYLO-2003-00327 CA 3 due 5/15/05 (one due date extension)
LO-VTYLO-2003-00327 CA 6 due 6/13/05 (one due date extension)
LO-VTYLO-2004-00399 CA 1 due 12/31/05 (one due date extension)
LO-VTYLO-2003-00327 CA 4 due 7/1/05
LO-VTYLO-2003-00327 CA 5 due 7/1/05
LO-VTYLO-2005-00030 CA11 due 7/31/05

BenchMarking, SelfAssessment:

Focused Self Assessment October 2003. Ongoing work for Corrective Actions generated from assessment See LO-CAs (2003-0327) under Open Action Items

Participated in Focused Self Assessment of PNPS FAC Program per EN-LI-104, January 24-28, 2005.

EWC Milestones, New Eng Issues:

Ongoing program tasks were rescheduled for remainder of 2005 per ENN-DC-183 Program Scope Memo. Continued difficulty in meeting re-projected schedules due to emegent work, EPU, & other unscheduled tasks. A formal action plan per ENN-MS-S-008 will be developed in 2nd. Qtr. 2005. Action Plan will address issues to get program to Green status and ENN standardization.

Program Concerns: 3

Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. (Action Plan: Activities were rescheduled in EWC into 2nd qtr. 2005) Same concern from previous qtr. A formal Action Plan per ENN-MS S-008 will be developed to get program Green status and adddress ENN standardization issues will be delvelopred in the 2nd Qtr. 2005.

CORRECTIVE ACTIONS:

Significant CRs:

No significant CR's (Category A) were written against the FAC program for this quarter.

Open CR CAs:

None

EQUIPMENT:

Open Eng Req:

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resitant materials. Aprroved in EWC. Replacement to be implemented in RFO 25

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P.Turbine Steam Seal Piping

rator Work Arounds:

N/A - There are no operator works around related to the FAC program.

Prog Related LCOs:

There are no LCOs related to the FAC program this qtr.

PMs Within Due Date:

N/A - There are no PMs associated with the FAC program.

Repetitive Failures:

There are no repetitive equipment related issues for the FAC program this quarter.

Unanticipated Failures:

SSH pin hole leaks identified in CR VTY-2004-02985. Tenmporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO 25 .

Trending Results:

N/A with respect to equipment.

Open Work Requests:

- There are no work requests over 2 old.

Surveillances Within Due Date:

All inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24. No surveillances scheduled for 1st Qtr. 2005.

Significant Parts Issues:

N/A - There are no parts issues associated with the FAC program this quarter

Identified Concerns:

No other identified equipment concerns.

ORGANIZATION:

Staff Qual and Trng:

The program owner and Backup engineer are qualified to perform FAC Program tasks.

Bench Strength:

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

Program Ownership:

Site personnel are aware of the Program Owner based results from last SA.

HU Errors:

There were no human performance errors (HPE) as a result of Program implementation activities for this quarter.

AP0098 Expectations:

Continued difficulties in completeing program activities on schedule. EPU work is currently scheduled to end early in secomd qtr. of 2005. FAC Program engineering work has been rescheduled to start in 2nd qtr 2005. FAC related milestones and activities to support RFO25 have been completed per schedule. Completion of corrective actions for CR-VTY-2004-3061 and CR-VTY-2004-3062 have resulted in reducing backlog in program documetation. The situation is improving based on end of EPU work, new EWC schedule, and reduction in documetation backlog. A formal action plan per ENN-MS S-008 to get program Green status and adddress ENN standardization issues will be delvelopred in the 2nd Qtr. 2005.

Status change form Yellow to White .

Operating Experience:

See 2005 RFOscoping worksheet for a list of FAC related OE.

CPIs:

None

Outage Health:

Outage Perf:

No outage in 1st QTR 2005.

Outage Preperation:

RFO-25 Outage planning milestones met.

Generation Health:

Generation Health:

There were no transients or power reductions as a result of a FAC Program issue in Q1.

FAC | Owner: Jim Fitzpatrick | Phone: 802.451.3086

Controlling Document: PP 7028 | Supervisor: Scott Goodwin

Date:	18-Jan-05
Quarter:	2004-Q4
Program Color:	Yellow
Trend:	Declining

2003-Q3	2003-Q4	2004-Q1	2004-Q3

Current Status Basis:

The FAC Program has just completed 4th Qtr 2004].

Program is Yellow, based on 17 Green, 2 White, and 5 Yellow indicators.

There are no outstanding issues that may impact the program.

Current Activities:

4th Qtr 2004 (10/1/04 to 12/31/04)

Design Engineering Manager approved 2003 Focused Self Assement Report on 10/28/04. Five new LO CAs were generated to address areas for improvement indentified in the SA.

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC resistant materials. Approved in EWC. Replacement to be implemented in RFO 25

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P.Turbine Steam Seal Piping. Inspection of additional components was added to the 2005 RFO scope to detemine the extent of condition on the SSH piping.

Scheduled FAC Program Activities for the 4th quarter 2004 were not completerd due to emergent work and EPU related design changes. This a continued trend from the previous quarter program health report.

Significant Accomplishments:

Approval of Focused Self Assessment Report (LO-VTY-2003-0327 CA1)

Actions To Return To Green:

Ensure that ongoing program tasks which were re-scheduled for remainder of 2004 per ENN-DC-183 Program Scope Memo are in fact preformed on or near to schedule. This requires adquate time & personnell be alloted to perform program tasks.

Exceptions To Grading Criteria:

NONE

REGULATORY:

LERs:

No FAC Program Related LERs this quarter.

INPO Findings:

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det:

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance:

The FAC Program currently meets all regulatory requirements.

New RRs and Code Cases:

ASME Code Case N-597 was incorporated into R.G 1.147 Rev.13 with new caveats for use. This will affect DP-0072 and transition to ENN-DC-133. WPO controls ENN-DC-133. Revisions are planned for 1st Qtr.2005.

ADMINISTRATIVE:

Procedure, Program Compliance Issues:

No Program Compliance issues with current Regulations of Codes.

Budget, Resources:

2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program Scoping Memo.

FAC Program personnel (resources) were utilized on EPU related design changes and calculations.

Audits:

There was one QA audit performed for this quarter. The audit was performed in Sept/October 2004. The audit identified two procedure compliance issues related to program documention and timely completion of activities.

CR VTY-2004-03061 identified that the FAC Inspection Report for the 2004 RFO was not completed within 90 days of plant startup as required per PP-7028.

CR VTY-2004-03063 identified a backlog in inspection records being sent to RIMS per AP-6807.

An NRC Inspection of of the FAC Program for addressing EPU changes to piping and operating conditions is scheduled for 2005.

Open Action Items:

LO-VTYLO-2003-00327 CA 2 due 3/1405
LO-VTYLO-2003-00327 CA 3 due 3/18/05
LO-VTYLO-2003-00327 CA 6 due 4/1/05
LO-VTYLO-2004-00399 CA 1 due 4/1/05
LO-VTYLO-2003-00327 CA 4 due 7/1/05
LO-VTYLO-2003-00327 CA 5 due 7/1/05

BenchMarking, SelfAssessment:

Focussed SA reoprt for VY FAC Program approved by DE Manager 10/28/04. Did not meet EN-LI-104 SA completion date expectations.

Planned participation if Fcused Self Assessment of PNPS FAC Program per EN-LI-104 4rd Qtr. deferred until 1/24/05 at PNPS requestof PNPS.

Administrative Backlog:

CORRECTIVE ACTIONS:

Significant CRs:

No significant CR's (Category A) were written against the FAC program for this quarter. Existing VY commitments are equivalent to LO-CAs.

Open CR CAs:

CR-VTY-2004-03061 CA2 due 2/04/05
CR-VTY-2002-02568 CA3 due 3/01/05
CR-VTY-2004-02985 CA3 due 3/11/05

EQUIPMENT:

Open Eng Req:

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resitant materials. Aprroved in EWC. Replacement to be implemented in RFO 25

ER 04-1315 for Evaluation of Temporary Steam Leak Repair on L.P.Turbine Steam Seal Piping

Operator Work Arounds:

N/A - There are no operator works around related to the FAC program.

Prog Related LCOs:

There are no LCOs related to the FAC program this qtr.

PMs Within Due Date:

FAC | Owner: Jim Fitzpatrick | Phone: 802.451.3086

Controlling Document: PP 7028 | Supervisor: Scott Goodwin

N/A - There are no PMs associated with the FAC program.

Repetitive Failures:

There are no repetitive equipment related issues for the FAC program this quarter.

Unanticipated Failures:

SSH pin hole leaks identified in CR VTY-2004-02985. Tenmporary leak enclosure installed. Additional inspections of similar piping incorporated into scope of RFO 25 .

Trending Results:

N/A with respect to equipment.

Open Work Requests:

N/A - There are no work requests over 2 yrs old.

Surveillances Within Due Date:

All Inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24. No surveiliances scheduled for 4th QTR 2004.

Significant Parts Issues:

N/A - There are no parts issues associated with the FAC program this quarter

Identified Concerns:

No other identified equipment concerns.

ORGANIZATION:

Staff Qual and Trng:

The program owner and Backup engineer are qualified to perform FAC Program tasks.

Bench Strength:

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

Program Ownership:

Site personnel are) aware of the Program Owner based results form recent SA.

HU Errors:

There were 2 reported human performance errors (HPE) as a result of Program implementation activities for this quarter.
CR VTY-2004-03061 identified that the FAC Inspection Report for the 2004 RFO was not completed within 90 days of plant startup as required per PP-7028.
CR VTY-2004-03063 identified a backlog in inspection recorrds being sent to RIMS per AP-6807.

AP0098 Expectations:

Continued difficulties in completeing program activities on schedule.

Operating Experience:

See 2005 RFOscoping worksheet for a list of FAC related OE.
In addition, LO-OEN-2004-00272 for the 8/04 Mihama Event was generated. CA3 assisgned to VY to review FAC Program & Inspection Efforts for applicabilty to VY. Inspections of piping at two restriction orifices in the Condensate System were added to the RFO 25 scope.

CPIs:

None

Outage Health:

Outage Perf:

No outage in 4th QTR 2004.

Outage Preparation:

RFO-25 Outage Milestones met. Initial outage scope memp issued 7/7/04. Scope freeze on WO generation met 10/7/04.

Generation Health:

Generation Health:

There were no transients or power reductions as a result of a FAC Program issue in Q4.

NEC038441

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion Program (FAC)

. AC | **Owner: Jim Fitzpatrick** | **Phone: 802.451.3086**

Controlling Document: PP 7028 | **Supervisor: Scott Goodwin**

Date:	19-Nov-04
Quarter:	2004-Q3
Program Color:	White
Trend:	Declining

2003-Q2	2003-Q3	2003-Q4	2004-Q1

Current Status Basis:

Program is -White , based on 16 Green; 3 White; 2 Yellow; and 0 Red

Current Activities:

3rd Quarter 2004 (6/16/04 to 9/30/04)

Review and comments on new ENN Standard FAC Program Procedure, ENN-DC-315, and new Gridding Standard, ENN-EP-S-005.

Addressed NRC RAIs relating to FAC for the VY Power Uprate Submittal.

FAC Program coordinator cancelled attendance at June 28 EPRI Checworks Users Group Meeting due to VY forced ·age. Meeting information availble on JG web site.

FAC Program coordinator participated in QA Audit of FPL Corporate FAC Inspection Program at Juno Beach FL. July 12 to 16.

FAC program engineers participated in NRC Inspection for EPU affects on FAC progam.

Incorporated Design Engineering Manager comments on 2003 Focussed Self Assessment. Returned report to DE Mgr. on 9/1/04.

Scheduled FAC program work activities for 3rd qtr. were deferred due to emergent work; forced outage, NRC inspection, engineering support for intervenor requests for information, and intervenor contentions.

Significant Accomplishments:

NRC Inspection

Actions To Return To Green:

Ensure that ongoing program tasks which were rescheduled for remainder of 2004 per ENN-DC-183 Program Scope Memo *are in fact performed on or near to* schedule. This requires adequate time & personnel be allotted to perform program ks.

..atus: There was no improvement in this area for the 3rd quarter of 2004.

Exceptions To Grading Criteria:

None

REGULATORY:

LERs:

No FAC Program Related LERs this quarter.

INPO Findings:

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det:

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance:

No Regulatory Compliance issues related to the FAC Program this quarter.

New RRs and Code Cases:

ASME Code Case N-597 was incorporated into R.G 1.147. This will affect DP-0072 and transition to ENN-DC-133. WPO controls ENN-DC-133.

ADMINISTRATIVE:

Procedure, Program Compliance Issues:

There are no LPCs or relief requests required for regulatory or code compliance.

Budget, Resources:

2004-2005 budget and schdule for FAC Program established through EWC process using ENN-DC-183 Program Scoping Memo.

For 3rd quarter 2004, FAC Program personnel were utilized on EPU related design changes, calculations, audit support, and intervenor issues.

Audits:

An NRC Inspection for EPU included questions on affects of FAC on plant piping and equipment. Final evaluation and documetation had not been performed as of the inspection date. No immdiate findings/concerns were identified.

Open Action Items:

LO-VTYLO-2003-00327 CA1 (2 due date extensions during period)
LO-VTYLO-2004-00399 CA1 (1 due date extension during period).

BenchMarking, SelfAssessment:

Incorporated Design Engineering Manager comments on 2003 Focussed Self Assessment. Returned report to DE Mgr. on 9/1/04.

Documetation of Benchmarking performed during FP&L QA Audit, July 12-16, has not been completed.

Planned participation in Focused Self Assessment of PNPS FAC Program per EN-LI-104 4th Qtr. (Dec.13-16,2004)

Administrative Backlog:

Procedure changes to PP 7028 (will be resolved by transition to ENN-DC-315)
Data transmittal(s) to RIMS

CORRECTIVE ACTIONS:

Significant CRs:

No significant CR's were written against the FAC program for this quarter.

Open CR CAs:

CR-VTY-2002-02568 CA3 (due 3/1/05)
CR-VTY-2004-02985 CA3 (due 3/11/05)

EQUIPMENT:

Open Eng Req:

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resitant materials Status: 9/27/04: Recommend transfer to MPRC after approval by the department manger. Project Sponsor: JH Callaghan, SD Goodwin to prepare Funding justification form. 9/30/04 approved by MPRC.

Operator Work Arounds:

N/A - There are no operator works around related to the FAC program.

Prog Related LCOs:

N/A - There are no LCOs related to the FAC program this qtr.

PMs Within Due Date:

N/A - There are no PMs associated with the FAC program.

Repetitive Failures:

There are no repetitive equipment related issues for the FAC program this quarter.

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion Program (FAC)

rAC **Owner: Jim Fitzpatrick** **Phone: 802.451.3086**

Controlling Document: PP 7028 **Supervisor: Scott Goodwin**

Unanticipated Failures:

Non Maintenace Rule. Steam leak identified in LP SSH supply line on 9/24/04. See CR-VTY-2004-02985. Planning for evaluation & repair is in progress as of 9/30/04.

Trending Results:

N/A with respect to equipment

Open Work Requests:

N/A - There are no work requests over 2 yrs old.

Surveillances Within Due Date:

All inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24. None were schedulred for 3rd qtr. 2004.

Significant Parts Issues:

N/A - There are no parts issues associated the FAC program this quarter

Identified Concerns:

Significant Concern: Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. (Action Plan: Activities were rescheduled in EWC into 3rd/4th qtr. 2004) Same concern from 4th qtr. 2003. This is an ongoing issue and may require realignment of program resources to insure program activities take priority. No Progress was made in the 3rd Quarter of 2004.

Transition to ENN Standard FAC program, ENN-DC-315, will require revision to ENN-DC-133. Previously sheduled working meetings for revision of ENN-DC-133 for the first quarter of 2004 were not held. WPO controls ENN-DC-133.

ORGANIZATION:

Staff Qual and Trng:

The program owner and Backup engineer are qualified to perform FAC Program tasks.

Bench Strength:

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has related experience.

Program Ownership:

Based on pending results form recent SA the answer is yes.

HU Errors:

Completion of the RFO24 FAC Program Inspection Report went past the 90 days from plant start-up as required by PP 7028. Identified by CR-VTY-2004 -03061 on 10/04/04. CR and CAs will be addressed in 4th Qtr program health report .

AP0098 Expectations:

RFO 24 Inspection Report was not completed within 90 days from plant start up as required by PP7028. CR VTY-2004-03061 written on 10/4/04, not "prompt" as required by Appendix A of AP0098.

Operating Experience:

See 2005 RFO FAC Program Scoping Worksheets for detailed list.

CPIs:

None

Outage Health:

Outage Perf:

Initial RFO 25 outage scope memo issued 7/7/04.

Outage Preparation:

Initial RFO 25 outage scope memo issued 7/7/04.

Generation Health:

Generation Health:

No adverse impact on generation by FAC Program issues or component failures. No transients or power reductions were reported as a result of a FAC Program issue this quarter.

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion Program (FAC)

FAC   Owner: Jim Fitzpatrick   Phone: 802.451.3086

Controlling Document: PP 7028   Frequency: Quarterly

Date:	22-Jun-04
Quarter:	2004-Q1
Program Color:	White
Trend:	Steady

2003-Q1	2003-Q2	2003-Q3	2003-Q4

Current Status Basis:

Program is White, based on 20 Green; 1 White; 1 Yellow; and 0 Red

Current Activities:

Attended the EPRI Checworks Users Group Meeting, January 12-14.

Addressed NRC RAIs relating to FAC for the VY Power Uprate Submittal.

Completed writeup for 2003 Focussed Self Assessment for Design Engineering Manager review and approval on 1/30/04.

FAC Program Coordinator participated in JAF FAC Program Self Assesment at WPO 2/9 to 2/13.

viewd draft of Revision 1 changes to ENN-DC-133, for Structural evaluation of worn piping components.

RFO 24 Outage Support for FAC Inspections. Tasks included outage review of Work Order packages, planning, training, data evaluation, turbine crossaround piping visual inspections, and interface with management.

Developed EWC Program Scope Memo (ENN-DC-183) for remander of 2004 and for 2005.

ENN FAC Working group assigned to an expedited adoption of a new ENN Standard FAC Program. Participated in working group developing a draft of new procedure ENN-DC-315 and new Gridding Standard ENN-EP-S-005 (6/2 to 6/4)

Significant Accomplishments:

RFO 24

Actions To Return To Green:

Ensure that ongoing program tasks which wer rescheduled for remainder of 2004 per ENN-DC-183 Program Scope Memo are in fact preformed on or near to schedule. This reqiuires adquate time & personeel alloted to perform program tasks.

Exceptions To Grading Criteria:

REGULATORY:

LERs: 0

No FAC Program Related LERs this quarter.

INPO Findings: 0

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det: 0

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance: 0

No Regulatory Compliance issues related to the FAC Program this quarter.

New RRs and Code Cases: 1

ASME Code Case N-597 was incorporated into R.G 1.147. This will affect DP-0072 and transition to ENN-DC-133. WPO controls ENN-DC-133.

ADMINISTRATIVE:

Procedure, Program Compliance Issues: 0

There are no procedure/program compliance issues associated with the FAC Program.

Budget, Resources: Rating

2003-2004 Budget per supervisor Schedule was set prior to EPU. For reaminder of 2004 and 2005 scheduling of FAC Program per ENN-DC-183 Program *Scoping Memo.*

FAC Program personnel were utilized on EPU related design changes and calculations.

Audits: Rating

A NRC Inspection of ISI Program Activities was performed during the beginning of RFO 24. The inspection included an interview of the FAC Program Coordinator on program issures and planned inspections. The inspection report is pending.

Open Action Items: 1

LO-VTYLO-2003-00327 (1 extesion during period)

BenchMarking, SelfAssessment: Rating

Participated in Fcused Self Assessment of JAF FAC Program per ENN-LI-104 week of 2/9 to 2/13

Planned benchamarking trip to FP&L in 3rd Qtr. (July 12-16)

Planned participation if Fcused Self Assessment ofPNPS FAC Program per EN-LI-104 3rd Qtr. (Aug. 8-13)

Milestones, new:

Outage suppport for RFO 24 completed. Ongoing program tasks were rescheduled for remainder of 2004 per ENN-DC-183 Program Scope Memo.

Engineering Issues, new: 1

ASME Code Case N-597 was incorporated into R.G 1.147. (DP0072) this will affect transition to ENN-DC-133. Previously planned working group meetings scheduled for 1st qtr 2004 were not held. WPO has control of ENN-DC-133

Administrative Backlog:

CORRECTIVE ACTIONS:

Significant CRs: 0

No significant CR's were written against the FAC program for this quarter. Existing VY commitments are equivalent to LO-CAs.

Open CR CAs: 1

CR-VTY-2002-2568 (5/4/04)

EQUIPMENT:

Open Eng Req: 1

ER 04-0964 for replacement of small bore piping on Turbine Bypass Valve 1st Seal Leakoff lines with FAC Resitant materials

Operator Work Arounds: 0

N/A - There are no operator works around related to the FAC program.

Prog Related LCOs: 0

N/A - There are no LCOs related to the FAC program this qtr.

PMs Within Due Date:

N/A - There are no PMs associated with the FAC program.

Repetitive Failures:

N/A - There are no repetitive equipment related issues for the FAC program this quarter.

Unanticipated Failures: 0

Trending Results: Supv. Rati

Open Work Requests: 0

N/A - There are no work requests over 2 yrs old.

Surveillances Within Due Date: 100

All inspections scheduled in the RFO 2004 inspection scope were completed during RFO 24.

Significant Parts Issues: N/A

N/A - There are no parts issues associated with the FAC program this quarter

Identified Concerns: 1

ɟnificant Concern: Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. (Action Plan: Activities were rescheduled in EWC into 3rd/4th qtr. 2004) Same concern from 4th qtr. 2003. This is an ongoing issue and may requie realignment of porgram resouces to insure program activities take priority.

ORGANIZATION:

Staff Qual and Trng: Rating

The program owner and Backup engineer are qualified to perform FAC Program tasks.

Bench Strength: 1

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

Program Ownership: Rating

Based on pending results form recent SA the answer is yes.

HU Errors: 0

There were no human performance errors associated with the FAC program this qtr.

P0098 Expectations: Supv. Rating

Operating Experience: Number

See 2004 RFO FAC Program Scoping Worksheets for detailed list.

CPIs: Number

None

Outage Health:

Outage Perf: Rating

Outage Preparation: Rating

RFO-24 Outage Milestones met.

Generation Health:

Generation Health: Rating

No adverse impact on generation by FAC Program issues or component failures. No transients or power reductions were reported as a result of a FAC Program issue this quarter.

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion Program (FAC)

FAC | Owner: Jim Fitzpatrick | Phone: 802.451-3086

Controlling Document: PP 7028 | Frequency: Quarterly

Date: 16-Jan-04
Quarter: 2003-Q4
Program Color: White
Trend: Declining

2002-Q4	2003-Q1
N/A	N/A
2003-Q2	**2003-Q3**
green	green

Current Status Basis:

Current Status: Program is Green, based on 20 Green; 2 White; 1 Yellow; and 0 Red.

Current Status Basis:

Current Program Trend: Steady

Current Activities:

ENN FAC Working group formed (two meetings held). Standardization of ENN AC Programs is a focus of the group. Each plant is to have a focused self assessment performed. A significant effort was required to develop the standardized evaluation criteria to perform these SAs per new ENN procedure ENN-LI-104.

Qualitative studies & evaluations were performed in support of September EPU submittal.

Significant Accomplishments:

A Focused Self Assessment (per ENN-LI 104) of the VY FAC Program was started on 9/29/03. Results will be incorporated into the 4th Qtr Health Report.

REGULATORY:

LERs: 0 Green

No FAC Program Related LERs this quarter.

INPO Findings: 0 Green

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det: 0 Green

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance: 0 Green

No Regulatory Compliance issues related to the FAC Program this quarter.

New RRs and Code Cases: N/A N/A

ASME Code Case N-597 was incorporated into R.G 1.147. This will affect DP-0072 and transition to ENN-DC-133. Additional ENN meetings to be scheduled for 1st QTR 2004 to evaluate.

ADMINISTRATIVE:

Procedure, Program Compliance Issues: 0 Green

There are no procedure/program compliance issues associated with the FAC Program.

Budget, Resources: Rating White

2003-2004 Budget per supervisor Schedule was set prior to EPU. For 2003 scheduling of FAC Program activities has been shifted to allow for engineering support off EPU and emergent work. FAC Program personnel were utilized on EPU related design changes and calculations.

Audits: Rating Green

There were no Audits performed for this quarter. There are no open issues.

Open Action Items: 4, 2 ext. Green

LO-VTYLO-2002-00341
LO-VTYLO-2002-00568 (1 extension during qtr.)
LO-VTYLO-2003-00327
LO-VTYLO-2002-00528 (1 extension.during qtr.)
Note both extensions during qtr. are due to EPU work.

BenchMarking, SelfAssessment: Rating Green

S.A. VYM SA 2002-003 on Davis Besse Issues performed in Nov.2002.

Focused Self Assessment of VY FAC Program per ENN-LI-104 week of 9/29 to 10/2. Draft report complete, final report deffered untill 2004 for EPU related work (LO-VTYLO-2003-00327 CA-0001)

Milestones, new: 0 N/A

None This Qtr.

Engineering Issues, new: 1 N/A

ASME Code Case N-597 was incorporated into R.G 1.147. (DP0072).
Transition to ENN-DC-133. Meetings scheduled for 1st qtr 2004 to evaluate Standardization for ENN FAC Programs

Administrative Backlog: N/A

CORRECTIVE ACTIONS:

Significant CRs: 0 Green

No significant CR's were written against the FAC program for this quarter. Existing VY commitments are equivalent to LO-CAs.

Open CR CAs: 1 N/A

CR-VTY-2002-2568 (5/4/04)

EQUIPMENT:

Open Eng Req: N/A N/A

N/A; Engineering Requests not yet implemented at Vermont Yankee.

Operator Work Arounds: 0 Green

N/A - There are no operator works around related to the FAC program.

Prog Related LCOs: 0 Green

N/A - There are no LCOs related to the FAC program this qtr.

PMs Within Due Date: N/A Green

N/A - There are no PMs associated with the FAC program.

Repetitive Failures: 0 Green

N/A - There are no repetitive equipment related issues for the FAC program this quarter.

Unanticipated Failures: 1 White

Turbine Bypass Valve Steam Seal Piping. Additional inspections scheduled for 2004RFO, Also scoping to replace with FAC resistant material.

Trending Results: N/A

Open Work Requests: 0 N/A

N/A - There are no work requests over 2 yrs old.

Surveillances Within Due Date: 100% Green

All inspections scheduled in previous outages were performed. RFO 2004 scope is currently being scheduled.

FAC | Owner: Jim Fitzpatrick | Phone: 802.451-3086

Controlling Document: PP 7028 | Frequency: Quarterly

Significant Parts Issues: N/A N/A

N/A - There are no parts issues associated with the FAC program this quarter

Identified Concerns: Rating Yellow

Leak in TBV Steam Seal Leakoff piping has elevated the need to complete the update of the small bore piping database (Action Plan: Currently on EWC FAC Program schedule).

Significant Concern: Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. (Action Plan: Activities were rescheduled in EWC into 1st. qtr. 2004) Same concern from 3rd qtr. 2003.

Potential Issue: Based on experience to date, the transition to ENN procedures is trending toward standardization in name only. The concern is that previous efficiencies at VY will be lost when new ENN procedures modeled on large utility organizations, which require an army to nplement, are imposed on the program. (Proposed Action Plan is to participate in transition working groups to control direction of transition or alert management to start hiring.)

ORGANIZATION:

Staff Qual and Trng: Rating Green

The program owner is qualified to perform FAC Program tasks.

Bench Strength: 2 Green

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

Program Ownership: Rating Green

Based on pending results form recent SA the answer is yes.

HU Errors: 0 Green

There were no human performance errors associated with the FAC program this qtr.

AP0098 Expectations: Rating

Operating Experience: N/A N/A

ee 2004 RFO FAC Program Scoping Worksheets for detailed list.

CPIs: N/A N/A

None

Outage Health:

Outage Perf: Rating N/A

Outage Preparation: Rating Green

RFO-24 Outage Milestones met.

Generation Health:

Generation Health: Rating Green

No adverse impact on generation by FAC Program issues or component failures. No transients or power reductions were reported as a result of a FAC Program issue this quarter.

ENTERGY NORTHEAST, VERMONT YANKEE
ENGINEERING PROGRAM HEALTH
Flow-Accelerated Corrosion Program (FAC)

FAC | **Owner: Jim FitzPatrick** | **Phone: 802.451-3086**

Controlling Document: PP 7028 | Frequency: Quarterly

Date: 18-Nov-03
Quarter: 2003-Q3
Program Color: Green
Trend: Steady

2002-Q3	2002-Q4
N/A	N/A

2003-Q1	2003-Q2
N/A	Green

Current Status Basis:

Current Status: Program is Green, based on 19 Green; 3 White; 0 Yellow, and 0 Red.

Current Status Basis:

Current Program Trend: Steady

Current Activities:

ENN FAC Working group formed (two meetings held). Standardization of ENN FAC Programs is a focus of the group. Each plant is to have a focused self assessment performed. A significant effort was required to develop the standardized evaluation criteria to perform these SAs per new ENN procedure ENN-LI-104.

Qualitative studies & evaluations were performed in support of September EPU submittal.

Significant Accomplishments:

A Focused Self Assessment (per ENN-LI 104) of the VY FAC Program was started on 9/29/03. Results will be incorporated into the 4th Qtr Health Report.

REGULATORY:

LERs: 0 — Green

No FAC Program Related LERs this quarter.

INPO Findings: 0 — Green

No NRC Findings
No INPO Findings or AFIs.

GL 91-18 and Op Det: 0 — Green

No GL 91-18 issues or operability evaluations related to the FAC Program this quarter.

Regulatory Compliance: 0 — Green

No Regulatory Compliance issues related to the FAC Program this quarter.

New RRs and Code Cases: N/A — N/A

ASME Code Case N-597 was incorporated into R.G 1.147. This will affect DP-0072 and transition to ENN-DC-133. Meetings scheduled for 4th qtr. to evaluate.

ADMINISTRATIVE:

Procedure, Program Compliance Issues: 0 — Green

There are no procedure/program compliance issues associated with the FAC Program.

Budget, Resources: Rating — White

2003-2004 Budget per supervisor Schedule was set prior to EPU. For 2003 scheduling of FAC Program activities has been shifted to allow for engineering support off EPU and emergent work. FAC Program personnel were utilized on EPU related design changes and calculations.

Audits: Rating — Green

There were no Audits performed for this quarter. There are no open issues.

Open Action Items: 4; 5 ext. — Green

LO-VTYLO-2002-00441 (2 extensions.)
LO-VTYLO-2002-00568 (1 extension)
LO-VTYLO-2003-00327 (1 extension)
LO-VTYLO-2002-00528 (1 extension.)
Note all 5 extensions during qtr. are due to EPU work.

BenchMarking, SelfAssessment: Rating — Green

S.A. VYM SA 2002-003 on Davis Besse Issues performed in Nov.2002.

Focused Self Assessment of VY FAC Program per ENN-LI-104 started 9/29/03. Significant effort was required to develop evaluation criteria was required by FAC Working Group.

Milestones, new: 0 — N/A

None This Qtr.

Engineering Issues, new: 3 — N/A

ASME Code Case N-597 was incorporated into R.G. 1.147. (DP0072).
Transition to ENN-DC-133. Meetings scheduled for 4th qtr. to evaluate.
Standardization ENN FAC Programs

CORRECTIVE ACTIONS:

Significant CRs: 0 — Green

No significant CR's were written against the FAC program for this quarter. Existing VY commitments are equivalent to LO-CAs.

Open CR CAs: 1 — N/A

CR-VTY-2002-2568 (5/4/04)

EQUIPMENT:

Open Eng Req: N/A — N/A

N/A; Engineering Requests not yet implemented at Vermont Yankee.

Operator Work Arounds: 0 — Green

N/A - There are no operator works around related to the FAC program.

Prog Related LCOs: 0 — Green

N/A - There are no LCOs related to the FAC program this qtr.

PMs Within Due Date: N/A — N/A

N/A - There are no PMs associated with the FAC program.

Repetitive Failures: 0 — Green

N/A - There are no repetitive equipment related issues for the FAC program this quarter.

Unanticipated Failures: 1 — White

Turbine Bypass Valve Steam Seal Piping. Additional inspections scheduled for 2004RFO. Also scoping to replace with FAC resistant material.

Trending Results: N/A

NEC038448

FAC — Owner: Jim FitzPatrick — Phone: 802.451-3086

Controlling Document: PP 7028 — Frequency: Quarterly

Open Work Requests: 0 — N/A

N/A - There are no work requests over 2 yrs old.

Surveillances Within Due Date: % — Green

All inspections scheduled in previous outages were performed. RFO 2004 scope is currently being scheduled.

Significant Parts Issues: N/A — N/A

N/A - There are no parts issues associated with the FAC program this quarter

Identified Concerns: Rating — White

Leak in TBV Steam Seal Leakoff piping has elevated the need to complete the update of the small bore piping database (Action Plan: Currently on EWC FAC Program schedule).

Scheduled FAC program activities for qtr. were not performed due to resources spent on EPU related work. (Action Plan: Activities were rescheduled in EWC into 4th qtr. 2003 & 1st qtr. 2004)

Potential Issue: Based on experience to date, the transition to ENN procedures is trending toward standardization in name only. The concern is that previous efficiencies at VY will be lost when new ENN procedures modeled on large utility organizations, which require an army to implement, are imposed on the program. (Proposed Action Plan is to participate in transition working groups to control direction of transition or alert management to start hiring.)

ORGANIZATION:

Staff Qual and Trng: Rating — Green

The program owner is qualified to perform FAC Program tasks.

Bench Strength: 2 — Green

The program owner for and backup (T. O'Connor) are FAC qualified personnel. An additional engineer in M/S (R. Omer) has FAC related experience.

Program Ownership: Rating — Green

Based on pending results form recent SA the answer is yes.

HU Errors: 0 — Green

here were no human performance errors associated with the FAC program this qtr.

AP0098 Expectations: Rating

Operating Experience: N/A — N/A

See 2004 RFO FAC Program Scoping Worksheets for detailed list.

CPIs: N/A — N/A

None

Outage Health:

Outage Perf: Rating — N/A

Outage Preparation: Rating — Green

RFO-24 Outage Milestones met.

Generation Health:

Generation Health: Rating — Green

No adverse impact on generation by FAC Program issues or component failures. No transients or power reductions were reported as a result of a FAC Program issue this quarter.

This Exhibit Contains Proprietary Information

Entergy	QUALITY ASSURANCE DIVISION VERMONT YANKEE NUCLEAR POWER PLANT

AUDIT NO.: QA-8-2004-VY-1

TITLE: Engineering Programs

ACTION ORGANIZATIONS:

Design Engineering
System Engineering

AUDIT TEAM:
B. E. Hall, *ENNNY/QA*, ATL
H. Heilman, *ENNNY/QA* ATM
Nick Love, Constellation Tech Specialist

AUDIT DATES: 9/20/04 – 9/30/04 Exit: 10/07/04

PREPARED BY:

B. E. Hall 11/22/04 B E Hall
Audit Team Leader /Date

APPROVED BY:

Thomas P. White 11/22/04 Thomas P. White
Quality Assurance Manager / Date

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Echelon- QA Manager, Wenstrom Edge

EXECUTIVE SUMMARY

The audit team concluded that the four engineering programs evaluated during this audit, Reactor Vessel Internals, Check Valve, Relief Valve, and Environmental Qualification Programs were effective and were being administered and maintained in a manner that meets regulatory requirements/commitments and supports safe and reliable plant operation.

The team concluded that while the Flow Accelerated Corrosion Program was technically sound, a number of the administrative/documentation issues identified did not meet regulatory requirements.

The following table summarizes results for evaluated elements:

Elements	Result	Number of CRs/AFIs
EQ Program	Satisfactory	2 CRs 2 AFIs
Check Valve Program	Satisfactory	1CR 3 AFIs
Flow Accelerated Corrosion Program	Unsatisfactory	2 CRs
Relief Valve Program	Satisfactory	1 CR 1 AFI
Reactor Vessel Internals Program	Satisfactory	1CR 1 AFI

Overall Results

The audit team identified five findings, two compliance CRs, and seven areas for improvement. None of the findings or areas for improvement, individually or in the aggregate, were indicative of significant programmatic weaknesses which would impact the overall effectiveness of the Engineering Programs assessed. However, as previously noted, there were administrative / documentation issues with the Flow Accelerated Corrosion Program which need to be corrected.

Findings

RFO 24 FAC documentation not yet completed.
(CR-VTY-2004-03061 Cat C – Design Engineering M&S)

QA records not handled in accordance with procedures.
(CR-VTY-2004-03062 Cat C – Design Engineering M&S)

Multiple versions of MOVATS software in Check Valve Program.
(CR-VTY-2004-03087 Cat C – System Engineering Components)

Relief valve as-found testing near miss.
(CR-VTY-2004-03039 Cat B – Work Control)

QDR 8.6 does not clearly document how Amphenol connectors with Rexolite are qualified.
(CR-VTY-2004-03032 Cat C – Design Engineering EI&C)

Compliance

LO-CA issued instead of CR during IVVI Self-Assessment.
(CR-VTY-2004-03086 Cat D – System Engineering Code Programs)

Master EQ List references deleted QDR 8.9.
(CR-VTY-2004-03106 Cat D – Design Engineering EI&C)

Areas for Improvement

LO-VTYLO-2004-00512

CA - 1 The following documents need to be updated: OP 4223 needs to reflect new equipment, software, and practices. Vendor Manual VYEM 0250 needs to be evaluated to determine if it should be retained and updated or deleted.

CA – 2 ESP training activities should be developed for the Check Valve Program similar to those for the MOV/AOV Program

CA - 3 Submit VYAPF 0700.03 to training to get training credit for the two component engineers who completed off-site check valve diagnostic training.

CA - 4 A maximum and minimum examination distance for the camera is established at the time of resolution demonstration check. Each examination record should indicate the distance the camera was from weld or verify that the camera was within the resolution range. The distance of the lens to the examination surface cannot be determined from the current QA records.

CA – 5 The relief valve scheduling spread sheet should use the installation date rather than the as-found testing date to schedule the next test since the as-found test can be performed up to 90 days or one year after the valve is replaced. This can lead to incorrect due dates for the 48 month interval and the ten year mandatory test dates.

CA - 6 The EQ Health Report should include all outstanding corrective actions related to EQ, not just those assigned to the EQ Coordinator. The current EQ Health report indicates no corrective actions are outstanding against the program. However, there are open corrective actions open to other departments for EQ issues. (CR-VTY-2001-00983 "EQ MCC Component Replacements Not Performed by End of EQ Life," Corrective Actions 1,4,8,9, 13)

CA – 7 The EQ Coordinator should note in the program health report the OEs that he had seen during the period of the report. Currently if no actions are taken there is no documentation that he has reviewed any OEs.

AUDIT PURPOSE, SCOPE, AND METHODOLOGY

Purpose:

The purpose of this audit was to detennine whether selected Engineering Programs have been adequately maintained and administered to effectively meet regulatory requirements/commitments and support safe and reliable plant operation.

Scope:

The selected engineering programs included the Environmental Qualification (EQ) Program, the Check Valve Program, the Flow Accelerated Corrosion (FAC) Program, the Relief Valve Program, and the Reactor Vessel Internals Program. Each program was checked to verify that it was being maintained current, that software used by the program was current and in the SQA program if applicable, and that required inspections/surveillances have been identified and implemented. In checking that the program was current, the impact of design changes, Extended Power Uprate (EPU), regulatory changes, deviations from codes and standards, industry positions, and industry experience was considered.

Methodology:

The audit was perfonned through interviews with engineering personnel and others as appropriate and through the examination of procedures and documentation.

AUDIT DETAILS

Program Maintenance / Instructions, Procedures, Drawings

Plant Modifications

The audit team members concluded that adequate programmatic "hooks" existed to ensure that program engineers would be included in reviews of design changes affecting their programs and that programs have been adequately updated to reflect design changes. There was an exception noted in the EQ Program which is discussed below.

Environmental Qualification

During a review of several Qualification Documentation Review (QDR) Packages, it was noted that inboard electrical penetration Amphenol connectors were included in the Victoreen HRRM Package (QDR 8.6). The qualified life of these connectors was identified as 2.61 years. During a review of work orders to verify that the connectors had been replaced at the required frequencies, it was detennined that new connectors were evaluated for this application per Equivalency Evaluation (EE) 1101. QDR 8.6 had not been adequately updated to reflect the new component with a longer qualified life. EE-1101 was considered inadequate because it did not reference the test report, a lOCFR50.49 requirement, needed to qualify the new connectors to IEEE-323. Thus, EE-1101 did not provide for an adequate evaluation of a critical characteristic for this EQ application. The EQ Program owner was unaware that these connectors had been replaced with a longer life component and wrote CR-VTY-2004-03032 to document the issue. An operability detennination concluded that this issue was not an operability concern. This modification was not recent and changes made to the EE process should preclude recurrence.

The auditor also noted during the QDR reviews that the EQ Master List still referenced QDR 8.9.1 which had been previously deleted. CR-VTY-2004-03106 documented this issue.

Check Valve Program

Based upon a review of ENN and VY procedures, the auditor verified that the responsibilities of the Check Valve Program Coordinator (CVPC) included a review of plant design changes involving the addition, deletion, or change in station check valves. Although the CVP was not specifically included on the distribution of pending design changes, Component Engineering and/or the IST Coordinator were. Based on a discussion with the IST Program Coordinator, he has a good working relationship with the CVPC for interface of all aspects of the two programs. The review of design changes for program impact was discussed with the CVPC who stated that he would be included for review if a check valve was affected. He was included in the review of the EPU design change which added a third safety valve (he is also the Relief Valve Program Coordinator).

Flow Accelerated Corrosion

Section 3.2.12 of PP 7028 identified that one of the responsibilities of the FAC Inspection Program Coordinator is to "update/maintain the 'FAC Susceptible Piping Identification' document to reflect plant changes as required." Section 0.5 requires revision of the CHECWORKS module to reflect current plant design and operation. AP 6008 requires the Mechanical & Structural Group to review all VYDCs. AP 0020 also requires MMs to be reviewed by Mechanical & Structural unless it is checked NA for their review.

Relief Valve Program

Procedures PP 7204 and OP 4261 for IST and BOP valves include notes relative to changes to the program and equipment and the associated reference to the design document.

One pending change to the Safety & Relief Valve (S&RV) Program under ER-04-1222 was not routed to the program engineer for required review; however, the IST Engineer was a required reviewer for the change. The S&RV Program Engineer became involved when questioned on the need for pre-installation setpoint verification and provided input to the change originator by e-mail on 09/22/04. This omission was discussed with the originator who assumed that IST was the proper individual to respond. A further review revealed that ENN-DC-115, "ER Response Development," includes Programs and Component Engineering for impact screening. This appeared to be a misunderstanding and not a programmatic issue.

The auditor verified that procedure OP 4201 was revised by Maintenance Support to reflect the addition of a third safety valve installed for EPU.

Both procedure changes had the required documentation packages with approvals retained in Curator.

Reactor Vessel Internals Program

The Reactor Vessel Internals Program is driven primarily through the implementation of Procedure PP 7027, which maintains the inspections and examinations that are required under the BWRVIP Program. Although there are no current plant modifications that would affect this program, steam dryer cracking was being evaluated for scope increase. This was based upon the industry issues involving steam dryer cracking and the VY steam dryer cracks that were identified and repaired during RFO 24.

Extended Power Uprate

Section 10, of Volume 2 of the "Vermont Yankee Nuclear Power Station Extended Power Uprate BOP Engineering Report" addresses the impact of the Extended Power Uprate (EPU) on various programs. Four of the five programs selected for this audit were addressed explicitly in section 10. The auditor considered that the fifth, Safety & Relief Valve was implicitly addressed as part of the 1ST Program. Based upon reviews of these sections and discussions with the program engineers, the auditors concluded that the impact of the EPU on Engineering Programs was being adequately addressed.

Environmental Qualification

Due to temperature and radiation increases during accident scenarios, 181 pieces of equipment would need to be requalified and 1 modification was required. The EQ Coordinator stated that he was actively working on completing the required requalifications. As a check the auditor reviewed QDR 6.14, Rome XLPE/PVC Cable, which would be impacted. This review found the manner of evaluating qualification for radiation dose to be adequate and appropriate to assess increased dose from the power up-rate. No issues were identified with EPU impact.

Check Valve Program

The main impact of the EPU would be on feedwater flow, steam flow and the generator. The report concluded that there would be no programmatic effect on the Check Valve Program, but that degradation rates could be affected by the EPU. Although it concluded that the normal inspection process should be adequate to identify changes in the valve degradation rate, it recommended that the program coordinator review the parameter changes caused by the EPU to identify any recommended testing or inspection frequency changes. The Check Valve Engineer has requested infonnation on any velocity changes resulting from the EPU for further consideration of PM changes. The auditor had no further issues.

Flow Accelerated Corrosion

The impact on the FAC Program of changes in the temperature, pressure, and velocity due to the power uprate were considered. Based upon evaluations of individual system impacts, it was concluded that there would be minimal impact on FAC and that no additional systems would need to be added to the FAC Program. The report also recommended new CHECWORKS runs to identify possible changes in FAC concerns (increased erosion rates, reduced useful components life, etc.). The new flows will be included in the new CHECWORKS model once version 1.0G is approved.

Relief Valve Program

The EPU impact on the 1ST Program would be evaluated as part of the EPU change process. Modifications/changes are evaluated as part of the modification process for changes in system/component design requirements.

The Safety & Relief Valve Engineer indicated that he had been involved with EPU changes and had reviewed the design change packages. He has been satisfied with the interface between himself and the EPU staff. Pending procedure changes have been made to reflect the modifications made during RF024.

Reactor Vessel Internals Program

The report noted that the In Vessel Visual Inspection (IVVI) Program was revised prior to each refueling outage. Since the EPU would be implemented following an outage, the program update prior to the outage should include any required EPU information [Dryer inspections and repairs were completed during RFO 24]. GE Task Report T0302, "Reactor Vessel Integrity Stress Evaluation," evaluated the expected EPU stress in many components/locations.

The auditor obtained and reviewed a copy of the "Licensee Identified Commitment Form" in accordance with ENN-LI-106, which demonstrated that a process was in place for preparing an action plan for the monitoring of the Steam Dryer. This document outlined a number of one-time commitment actions relative to the analysis, inspection and reporting actions and their respective scheduled completion dates. It was noted that several of the commitment actions had near term completion dates as well as indeterminate dates. A search of LOCRs using a key word of "steam dryer" showed that LOCRs had been written to track various steam dryer requirements.

Regnlatory Changes

The auditors concluded that regulatory changes were being adequately addressed. No issues were identified by the auditors.

Environmental Qualification

There have been no recent regulatory changes impacting the VY EQ Program.

Check Valve Program

Regulations mandating elements and testing of the Check Valve Program are Technical Specifications, the 1ST Program, and ASME OM-1998 Edition through ASME OMb-2000 Addenda. The Check Valve Program procedure has been revised for the new code requirements of the 4th 1ST interval.

Relief Valve Program

Current 4th interval 1ST requirements for test frequency and expansion testing have been included in the Program procedure, PP 7204, "Safety & Relief Valve Program." Procedures have been revised to reflect the correct codes for the 4th 1ST interval.

Reactor Vessel Internals Program

Program procedure PP 7027 "Reactor Vessel Internals Management Program" was reviewed, and was determined to address the necessary requirements for adequately implementing the BWRVIP Program. The procedure provides the necessary direction for the responsible individuals to review and initiate actions that may be required upon the issuance of NRC correspondence, information notices, BWRVIP documents and G.E. bulletins, etc., as they apply to Vermont Yankee. In tum, the information obtained from these documents is incorporated into the various inspection plans that are implemented during refueling outages.

To determine the adequacy of the prepared inspection plan, a comparison between PP 7027, Appendix A "Reactor Vessel Internals Components Inspection Scope and Schedule" and the RFO 24 Reactor Vessel Services In Vessel Visual Inspection Final Report was performed. Both were obtained from Curator. A sample of activities was randomly selected from the RFO 24 schedule, with respect to the method of examination and the relative frequency of the examination. These activities were compared with the RFO final report to determine if the appropriate examinations were performed. In all instances reviewed, the report confirmed that the required examination method and frequency were correct. In several instances, due to limited accessibility of the examined component, a partial examination was performed and documented as such. The assessor had contacted the Site Reactor Internals Engineer, to ascertain whether or not the examination sufficiently evaluated the component under examination. The engineer indicated that the inspection of the accessible portion of the component revealed no recordable indications, and was therefore deemed acceptable until such time that the reactor internals are accessible due to disassembly. The auditor subsequently confirmed that Technical Justification No. 2004-02, dated March 26, 2004 was issued for the deferral of inspection of inaccessible welds and Technical Evaluation No. 2004-0018 dated April 2004 addressed inspection of portions of shroud horizontal welds.

Code and Standards Deviations

Deviations from codes and standards, where applicable, have been adequately addressed. No issues were identified by the auditors.

Environmental Qualification

Based on discussion with the EQ Program owner, VY has not requested any deviations from NRC EQ Program requirements.

Check Valve Program

The Check Valve Program does not have deviations from approved codes and standards but implements and tracks deviations developed and approved under the 1ST Program. Several changes which were noted to valve testing/inspection frequencies were verified to be addressed with document changes, PM Basis Database changes, and EMPAC Asset schedule changes.

Changes from regulatory standards relative to the 4th interval 1ST Program and implemented or tracked through the CVP have been approved under NRC Letter NVY 03-078.

Flow Accelerated Corrosion

By letter dated March 19,2001, VY requested approval from the NRC to use Code Case N-597 which was an alternative approach to evaluating components when the section thickness has been reduced below code minimum thickness. NRC approval was received by letter dated July 21, 2001.

Relief Valve Program

The 1ST 4th interval code deviations have been approved and accepted under NRC Letter NVY 03-078. The auditor verified that procedure OP 4201 referenced the proper codes for the 4th 1ST interval.

Reactor Vessel Internals Program

Based upon spot checks the auditor confirmed that exceptions made due to weld accessibility and deferrals were documented and justified.

Industry Alignment

In general, the auditors concluded that the programs reviewed were acceptably aligned with industry positions. As discussed below, VY's approach to the EQ Program is more fragmented than others, but this was discussed with engineering management who had already recognized some of these issues and was evaluating approaches to resolve them.

Environmental Qualification

The QDR Packages reviewed had strong technical content and were organized in a manner that made the required information easy to find. This provides a strong basis for the program. Current industry efforts are focused on internal communications and retention of configuration control.

Based on review of procedure ENN-LI-IOO, ENN-DC-115 and ENN-DC-329, the recent implementation of these procedures at VY would appear to offer some enhancement to the oversight and feedback available to program owners. This may mitigate some of the potential for future disconnects between the maintenance organization's component replacements and engineering's oversight responsibilities.

However, these procedures which impact the EQ Program are partitioned in a manner that fragments program oversight accountability between licensing, engineering, and maintenance. ENN-LI-IOO makes no reference to the EQ Program and ENN-DC-115 is a classification and screening process for engineering aspects only. The applicable procedures, including VY AP's offer only very limited flow charts identifying how the programs processes are supposed to work or how the various parts of the organization interface with each other. These issues were discussed with Engineering management.

Program health is a significant aspect of the INPO EQ Program Guideline currently in preparation. Audit health reports for quarter 2003-Q4 and 2004-QI were reviewed. The 2004-QI report indicates no CR CA's open against the EQ Program at this time. In fact, this is because the applicable performance indicator has been interpreted to apply only to CR CA's assigned to the EQ Program owner as opposed to those impacting the program as a whole. The industry position would be that the health report is intended to capture full program scope at the plant. CR-VTY-2001-0983 has five open items against it relating to non-performance of EQ component replacements. This issue was documented as CA6 of LO VTYLO-2004-00512.

Check Valve Program

This scope element was discussed with the Check Valve Engineer. The program was originally developed based on the industry documents as identified in the program procedure purpose section and references. The review and inspection processes used in the development of the program are documented in curator under SOER 86-03. Corrective maintenance is factored into the program and subsequent PMs revised based on findings. Additional balance-of-plant check valves which were considered a risk to generation, but were not originally covered in the SOER 86-03, have also been included in the program. Based on a review of the type valves tested, the test methods, maintenance, intrusive and non intrusive inspections, the program and test methods appear to be in alignment with industry expectations.

Flow Accelerated Corrosion

Surveillance 99-016 verified that the VY FAC Program met both NRC expectations and industry guidelines as defined in Generic Letter 89-08, "Erosion/Corrosion - Induced Pipe Wall Thinning

Program uses CHECWORKS, an EPRI sponsored code, as a tool for prioritizing inspections and tracking data. VY also participates in CHUG, an EPRI sponsored CHECWORKS user's group.

Relief Valve Program

The S&RP was developed based upon EPRIINMAC guidance with recommendations from INPO included for balance-of-plant valves. The inputs and methodologies used in the development are discussed in the procedure as a historical reference. There have been no new initiatives in the area that are not included in the current program..

Reactor Vessel Internals Program

Program procedure PP 7027 "Reactor Vessel Internals Management Program" was reviewed, and was determined to address the necessary requirements for adequately implementing the BWRVIP Program. The procedure provides the necessary direction for the responsible individuals to review and initiate actions that may be required upon the issuance ofNRC correspondence, information notices, BWRVIP documents and G.E. bulletins, etc., as they apply to Vermont Yankee. In tum, the information obtained from these documents is incorporated into the various inspection plans that are implemented during the respective refueling outage.

During documentation reviews, it was noted that it could not be determined how the IVVI examinations were conducted, with respect to the measured distance between the lens of the camera and the examination surface. Procedure NE 8048, Rev. 1, paragraph 4.1.2 states in part, that"...the lens to object distance required to discern the target on the Sensitivity, Resolution, and Contrast Standard (SRCS) becomes the maximum distance examinations can be performed from the examination surface." Although the distance/range of the camera lens to the examination surface is determined and documented during the sensitivity, resolution and contrast standard, it cannot be readily determined how the distance is determined/maintained during actual visual examinations. This was addressed in CA 4 ofLO VTYLO-2004-00512.

Industry Events

All of the program engineers were receiving OE relevant to their program and were aware of significant industry events involving their programs. The auditors concluded that industry events were being adequately addressed.

Environmental Qualification

As a part ofthe program health assessment, industry operational experience (OE) and NRC Information Notices (IN's) are to be screened for EQ Program impact. A sample offour recent OE's and three NRC IN's with potential EQ Program applicability were submitted to the Technical Support OE Coordinator to determine specifically how they had been addressed. All of the IN's were found in the Technical Support files with documentation to address the extent of their VY applicability including two which were evaluated to actually have direct EQ impact. One of these was entered in QDR 8.6 to address its specific applicability at VY.

Ofthe four OE's, all were distributed. Two were recognized as having potential EQ impact and sent to I&ClElectrical. None ofthe IN's and OE's reviewed by the auditor originated during the most recent two health report periods. However, while five additional OE's were issued during the 2003-Q4 and 2004-QI periods, none are noted as having been reviewed in the health reports. In discussions with the EQ Coordinator, he indicated that he does not normally identify OEs that he reviewed unless they required action. Ifno actions were taken, he does not document that he has reviewed the OE. The auditor recommended identifying in the program health report the OEs that he had reviewed during the reporting period even ifno action was required. This was documented as CA 7 of LO VTYLO-2004-00512.

The EQ Program owner was very knowledgeable ofindustry events, and ofthe general applicability of operational experience at other plants to VY equipment.

Check Valve Program

The CV Program Engineer receives OE from the Entergy OE distribution as well as the System EPIX Coordinator. The OE evaluated each quarter is documented on the CV Program Health Report. A review ofthe last two health reports indicated that twelve OE related to check valves were reviewed. There were no specific changes to equipment, inspections or testing required from the reviews and no commitments resulted.

Flow Accelerated Corrosion

Industry events are identified and the bases for performing or not performing additional inspections were documented in the VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage." The Coordinator was aware ofthe details ofthe piping failure that occurred in Japan and indicated that he has an action item (LO-OEN-2004-00272 CA-00003) to look for similar piping arrangements at VY.

ReliefValve Program

OE was discussed with the site OE coordinator, System Engineering EPIX Coordinator and the S&RV Program Engineer. OE that has been reviewed is documented in the Program Health Report. There has been no OE that required specific program changes or commitments generated. However, OP 4200 was revised based upon a concern received from Pilgrim Station involving hydrogen entrapment in the piping downcomer region. The S&RV Program Engineer receives OE for review from the ENN distribution as assigned by the morning screening as well as from the System Engineering OE screener. Seventeen OE reviews were documented in the health report.

Reactor Vessel Internals Program

Steam dryer cracking is currently the most significant industry OE issue in this area. This issue will drive further examination ofthis component in future examination/inspection activities. A Licensee Identified Commitment Form per Procedure ENN-LI-106 was initiated to identify specific actions that will be required to assist in the assessment ofthis component. This document contained commitments that will incorporate augmented examinations into the Vessel Internals Inspection Program.

Software/ Software Quality Control

With the exceptions noted below, the auditors considered that software was being adequately controlled. There were several issues identified with software QA, but none ofthem directly compromised the integrity ofthe results.

Environmental Qualification

VY had EPRI's System 1000 software for materials library reference, but it was not yet in use because it had not been through the SQA Program. The EQ Database, which was developed in 1997, was included in the SQA Program as Level A software. However, the EQ Coordinator indicated that there had been a data corruption problem which IT had been unable to recover. The verified hard copy of the database is considered the Q copy. Since none of the EQ software was being used for Q purposes, this was considered acceptable.

Check Valve Program

Check Valve Program software is classified as Category A and has been controlled through the procurement process. It has been approved and tested for verification. All paperwork for compliance was available as quality records in FYI.

Multiple versions of MOVATS software (4.6.b and 4.5) were still in use to support older equipment (Maintenance Support lap top computer). SQA paperwork for new versions state old versions are retired. The computer and software should be removed from use or the SQA should be resubmitted to define and allow conditional use of older versions (CR-VTY-2004-03087). Based on discussion with the MOVATS Component Engineer who was involved with all six RFO 24 non-intrusive check valve tests, the MOVATS computer with version 4.6.b software was used to perform diagnostic data collection and analysis.

The ENN web software catalog for VY, which is considered non Q, was not up-to-date for MOVATS software. It listed versions 4.0.0.0, 4.5, and 4.6. As mentioned before, version 4.6.b is the software of record and Curator records show that previous revisions are retired.

Based on discussion with the previous and current CV Program Engineers, one Signature Analysis Module (SAM) notebook computer is not capable of running the newer software. Version 4.6.b is capable of being used with the Viper and UDS systems. A potential area for improvement exists by updating OP 4223 to allow the performance of check valve diagnostics using any of the available systems. This was documented as CA 1 of LO-VTYLO-2004-00512.

Flow Accelerated Corrosion

The Software QA Program identified CHECWORKS version 1.OF and CHECWORKS Application Manager Version 1.00 as approved software. The FAC Program Coordinator stated that he was in the process of upgrading to version LOG, but had not completed the software QA process. He had been using version 1.0F, but it was approved for a Windows 98 platform which was no longer available. Version LOG supports a Windows XP platform. Once the new version is approved, it can be used to confirm RFO 25 inspection selections and assist in the assessment of EPU impacts. The auditor considered this acceptable.

Relief Valve Program

S&RV Program 1ST Scheduling software has been controlled and is appropriately classified as Type B in support of Technical Specifications. A review of the software qualification package revealed that all procedural requirements were met and are documented as QA records. No concerns were identified relative to Software QA requirement implementation. For the relief valve scheduling, the auditor noted an area for improvement in the use of the spreadsheet. There are no instructions for the spreadsheet use and currently, the date of as-found testing is inputted instead of the installed date. The as-found test date (performed subsequent to replacement) could cause the next test to exceed the 48 month or 10 year requirement to be exceeded (LO-VTYLO-2004-00512 CA 5).

Reactor Vessel Internals Program

There were no specific software programs unique to the RVI Program.

Inspections/Surveillances

The auditors concluded that required inspections and surveillances were being performed, although issues were identified with the completion of documentation in the FAC Program and with a scheduling error which could have led to missing a 90 day requirement in the S&RV Program.

Maintenance of EQ Requirements

Based upon a review of Qualification Documentation Review (QDR) Packages to determine if adequate end of life replacements are being performed for components with qualified lives of less than 40 years, two examples were identified, one each for QDR's 8.8 and 35.3, where adequate replacements were made for items with qualified lives of 17.6 years and 3.3 years, respectively.

As discussed earlier, the review of QDR 8.6 identified that it had not been appropriately updated following an equivalent component replacement. A review of work orders verified that the new longer life components had been installed in the plant and was therefore not outside of its EQ lifetime.

Check Valve Program

Required inspections and testing requirements are identified in the program procedure. The performance of the 2004 specified testing was evaluated through the review of 30 EMPAC work orders. All scheduled inspection and testing was performed, rescheduled with appropriate change documentation, or deleted from the 1ST/Check Valve Programs with justification documented. No concerns were noted

Flow Accelerated Corrosion

"VY Piping FAC Inspection Program PP 7028 - 2004 Refueling Outage" identified the inspections that were to be conducted during RFO 24. The Post outage report for RFO 24 had not been written at the time of the audit, although the program procedure requires that the report be issued within 90 days. The report for RFO 23, issued on 1/22/02 was reviewed by the auditor and found to be complete, thorough and met the expectations of PP 7028. However, this document had not yet been sent to RIMs. Based upon a search of CURATOR and discussions with the FAC Engineer, it was concluded that a significant amount of FAC Program documentation had not been sent to RIMS. These issues were documented in CR-VTY-2004-03061 and CR-VTY-2004-03062.

Relief Valve Program

Required testing to meet code or program BOP valve expectations have been defined and tracked in the program procedure. A sample of nine 1ST valves scheduled for testing during 2004/2005 was selected for review. During the review of work orders and the P3 Work Week Schedule for the as-found testing, it was discovered that this activity was scheduled for 02/22/05 which would have been past the 90 day requirement. This had occurred in the past, with 4 CRs written in 2003. The corrective actions from these CRs did not prevent the potential recurrence of the same issue in this instance. CR-VTY-2004-03039 was written to address the near miss.

Reactor Vessel Internals Program

On a sampling basis, the auditor verified that the scope of examinations/inspections required by the program procedure was performed during the In-Vessel Visual Inspection performed by AREVA. Of the components reviewed, the corresponding requirements were found to be consistent with the scope of work performed. No unsatisfactory conditions were noted.

Personnel certifications were also reviewed to verify that required personnel qualifications were current. All of the individuals responsible for performing the VT-1 and 3 Level II examinations were found to be qualified to perform these tasks during the duration of the RFO, and demonstrated the required visual acuity required to interpret their observations.

Additionally, the auditor verified on a sampling basis, that the individual in-vessel examinations did receive the required sensitivity, resolution and contrast verifications/calibrations. A comparison between the inspection data sheet and the resolution verification log was performed, which confirmed that the necessary resolution was maintained throughout the examination duration. It was observed in some instances, that the individual performing the calibration differed from the person who performed the examination. Upon investigating this concern, it was determined that this practice was acceptable, as none of the key elements of the examination, i.e. water clarity, lighting, nor equipment were affected, which would influence the video image. All of the individuals involved with the examination equipment calibration, performance and interpretation of results were verified to be qualified Level II or higher in the examination method used.

Self Evaluation and Corrective Action Effectiveness

Corrective Action Effectiveness

Based upon a review of the corrective actions associated with the Check Valve and the Safety & Relief Valve Programs, the auditor concluded that corrective actions were acceptable.

Check Valve Program

Three QAD CRs that had been generated from surveillances were reviewed to determine if the corrective actions were acceptable, effective, and timely. Equipment issues were also reviewed. One level C and two Level B CRs were reviewed with no issues identified. Overall, CR dispositions were thoroughly performed with corrective actions assigned to address the most probable or apparent causes. Corrective action disposition has been timely with extensions minimal and approvals granted and justified when required.

Safety & Relief Valve Program

Corrective actions from CRs and recommendations issued as a result of a 2002 QA assessment of the Safety and Relief Valve Program were also reviewed for acceptability, effectiveness, and timeliness. No concerns were identified.

ER-2003-1910 (Level I) for program deficiencies identified during the 2003 NRC PI&R Inspection was reviewed. The root cause investigation was performed to the AP 0009 requirements and commitments were established for the findings of the investigation. Corrective actions relative to the S&RV Program were reviewed

Condition Reports have been issued for each relief valve failure and programmatic issues. Since the NRC finding on the program and the corrective actions of CR-VTY-2003-1910, equipment failures have been assigned as Level "B." Improvements in the content of the evaluation and subsequent disposition are evident.

Based upon the CRs and corrective action reviewed above, the auditor concluded that commitments were tracked to completion with extensions documented and approved. Overall, corrective actions were considered timely and where delays existed, appropriate justification was provided.

Self Evaluation Effectiveness

Based upon a review of selected self-assessments/benchmarks, it was concluded that the self assessments were of acceptable depth and were adequately intrusive. Recommendations were being tracked. It was noted that LOCRs were used in two instances where CRs would have been more appropriate.

Check Valve Program

A benchmarking trip was performed on OS116/04 to compare VY's Check Valve Program to that of Seabrook Station and included the CV Program Engineer, 1ST Program Engineer, and a mechanical maintenance support engineer. A review of the preliminary draft of the report revealed corrective actions would be issued for the evaluation of enhancements to the program. These included employing non-intrusive digital radiography methods, procedure enhancement for dimensional checks during disassembly and inspections, development of a condition monitoring process in support of IST, the use of leak rate testing results as a trending tool for determining check valve degradation, and an effectiveness of corrective actions review.

Relief Valve Program

An on-going Self Assessment (MSA 2003-015) was performed under commitment OPVY-2003-065_01. Recommendations resulting from the assessment were documented in the assessment and were entered into the corrective action process. The assessment included team members from the 1ST, Component Engineering, and Maintenance Support. The S&RV Program Engineer was aware of the status of all open items and is tracking the items under the program improvement plan.

Reactor Vessel Internals Program

During the course of this assessment, a review of the BWRVIP Program Self Assessment that occurred following RFO 24, was performed. Although this assessment was found to be quite comprehensive, there were at two instances noted where LOCRs were written when CRs were the appropriate documents. Both examples involved the use of an incorrect examination method and frequency which were not in accordance with BWRVIP guidelines (VT-3 versus VT-1 visual exams). A failure to comply with BWRVIP guidance should have triggered a CR, not an LOCR. CR-VTY-2004-03086 was initiated to address this issue.

In both instances, the VT-1 examinations produced acceptable results. Recommendations within the self assessment indicate that the applicable tables in Procedure PP 7027 will be revised to capture the correct examination method and frequency requirements.

Training/Qualifications

One of the five program engineer positions, EQ, had a qualification card item directly related to their EQ position at the time of the audit. The VY ESP Qualification Matrix indicated that position specific qualifications for all of the positions except the Reactor Internals Program Engineer were being developed for implementation across Entergy North. There is an ISI Engineer Qualification Card to be developed which could be used for the Vessel Internals. All of the current program engineers have had background, experience, and training relevant to their areas of responsibility.

Based upon a review of the training provided on check valves the auditor recommended that an ESP Qualification activity be established for check valve diagnostics and analysis equivalent to that for the MOV/AOV Programs. Also, since two component engineers had received off-site check valve diagnostic training, 0700.03 forms should be submitted to training to get training credit.
(LO VTYLO-2004-0512 CA 2 and CA 3)

RecordslDocument Control

While QA records and document control was acceptable within the Check Valve and Safety & Relief Valve Programs, temporary and permanent storage issues were identified within the FAC Program.

Check Valve Program and Safety & Relief Valve Programs:

Records reviewed from QA record files, packages in process, and CuratorlFYI were legible and retrievable. Work order package records were legible with entries made in ink. Two instances were noted where a write-over or cross-out without initials occurred. However, this was a significant improvement over the condition of maintenance records reviewed on previous audits.

Work Order records that were completed and not transferred to RIMS were stored in the locked Work Control QA Records fire proof file cabinets. Incomplete records that have completed procedure data-sheets attached are not treated as QA records until complete. This was discussed with QA Records personnel in RIMS and is consistent with all records at the site for in-process work such as design changes and procedures where the package is not treated as a QA record until complete with the last signature. This interpretation is consistent with the QAPM and with ANSI 45.2.9.

FAC

Based upon a review of data sheets from RFO 23, and 24 and documents retrieved from CURATOR, the records are legible. However, several issues were identified with document storage and transferal to RIMs.

Although the current records from RFO 24 were being maintained in a fire proof cabinet, other QA records such as the 2002 Refueling Outage Inspection Report (RFO 23 - Fall 2002) and supporting documentation were being maintained by the FAC Program Coordinator on a bookshelf.

As discussed earlier in "Inspections / surveillances, a significant amount of FAC Program documentation had not been sent to RIMS. These issues were documented in CR-VTY-2004-03061 and CR-VTY-2004-03062.

LIST OF ATTACHMENTS

ATTACHMENT 1 - Personnel Contacted

ATTACHMENT 1 - PERSONNEL CONTACTED

Name	Department or Title	Contact
I. Dreyfuss	Director Engineering	1,3
J. Callaghan	Manager Design Engineering	1,3
J. Wierzbowski	Manager System Engineering	1, 3
A. Haumann	EQ Program Coordinator	1
E. Luciano	PM Coordinator, *(C)*	1
C. Rose	EPU, VY	1
I. Fitzpatrick	Senior Eng ME&S	1
S. Goodwin	Supervisor ME&S	1
J. Apostoles	Sr. Plant Mechanic, VY	1
W. Aho	VY OE Coordinator	1
T. Underkoffler	Appendix J Program Coordinator, VY	1
M. Garland	Mechanical Maintenance Supervisor, VY	1
J. Golonka	EPIX Coordinator, VY	1
R. Penny	Mgr, Eng Programs WPO	1
I. Lafferty	Sr Engineer (Nuc) WPO, VY IVVI Coord	1
W. Fields	Technical Spec IV (Nuc)	1
C. Larson	PNPS	1
J. Devincentis	Licensing Manager VY	1
L. Lukens	ISTPC, VY	1,3
B. Smith	Maint. Support Eng., VY	1
R. Booth	Check Valve Program Coordinator	1
T. Derting	IT SQA Program Administrator, VY	1
P.Longo	MOVATS Engineer, VY	1
M. Faunce	MOV Group Engineer	1
R. Wanczyk	Director, NSA	3
I. O'Connor	QA	3
S. DiMauro	QA	3
T. White	QAManager	3

1 – Contact
2 – Pre-Audit Conference - Informal
3 - Post-Audit Conference 10/07/04)

Entergy	CONDITION REPORT	CR-VTY-2004-03062

Originator: Hall,Bruce E
ginator Group: Eng DE Manager
Supervisor Name: Callaghan,James H
Discovered Date: *10104/2004 13:24*

Originator Phone: 5587
Operability Required: N
Reportability Required: N
Initiated Date: *1010412004 13:28*

Condition Description:

QA records not handled in accordance with procedures

During Audit QA-8-2004-VTY-1, Engineering Programs, a number of noncompliances with plant procedures were noted, these included:

There is a significant backlog of FAC documents that have not been sent to RIMS, AP 6807, step 4.1.11.4 requires that QA records not be in temporary storage for more than 6 months.

Some QA documents that have not been sent to RIMS are not being stored in fireproof cabinets. AP 6807, section 4.1.1.1 requires completed QA records to be stored in 1 hr fire proof repositories.

CHECKWORKS predictive models have not been sent to RIMS for permanent storage as required by PP 7028, steep 6.1.2

Immediate Action Description:

gested Action Description:

TRENDING (For Reference Purposes Only):

Trend Type	Trend Code
KEYWORDS	KW-HU CLOCK RESET DEPT
CAUSE DEPT	CD-MECHANICAL - CIVIL/STRUCTURAL ENG.
HOW IDENTIFIED	HI-QAD
KEYWORDS	KW-PROCEDURE ADHERENCE
HUTYPE	HU-PRECURSOR
KEYWORDS	KW-DOCUMENTATION PROBLEM
CAUSAL FACTOR CODES	CFC-F4B4
HU EVALUATION FORM	HU-WB-PROCEDURE USE
KEY ACTIVITY	KA-DS
WORK PROCESS	WP-DM

Entergy **ASSIGNMENTS** | CR-VTY-2004-03062

Version:

Significance Code: C - MPC & CORRECT

:lassification Code: C

Owner Group: Eng DE Mech Civil Struct Mgmt

Performed By: Burger,Frederick J 10/05/2004 13:44

Assignment Description:

CR-VTY-2004-3062
Screening Data
□Significance□C - MPC & CORRECT
□Owner: □Eng DE Mech Civil Struct Mgmt
□Presented By: □Goodwin, Scott
Comments:
□A Human Performance Evaluation VYAPF 0009.05 is required for all HU identified CRs
Trending Items
DOCUMENTATION PROBLEM
ERRORPRECURSOR-HU
HU CLOCK RESET DEPT
PROCEDURE ADHERENCE
QAD Identified
All paperwork that is planned to be transferrred to RIMS has been temporarily placed in fire prrof cabinets.

Entergy	ADMIN	CR-VTY-2004-03062

Initiated Date: 10/4/2004 13:28 **Owner Group** :Eng DE Mech Civil Struct Mgmt

Current Contact: FJB

Current Significance: C - MPC & CORRECT

Closed by: Felumb,Rhonda 3/22/20059:23

Sununary Description:

QA records not handled in accordance with procedures

During Audit QA-8-2004-VTY-1, Engineering Programs, a number of noncompliances with PP were noted these included:

There is a significant backlog ofFAC documents that have not been sent to RIMS. AP 6807, step 4.1.11.4 requires that QA records not be in temporary storage for more than 6 months.

Some QA documents that have not been sent to RIMS are not being stored in fireproof cabinets. AP 6807, section 4.1.1.1 requires completed QA records to be stored in 1 hr fire proof repositories.

CHECKWORKS predictive models have not been sent to RIMS for permanent storage as required by PP 7028, steep 6.1.2

Remarks Description:

Closure Description:

Condition Report Closure Review IAW LI-102 Section 5.9.1 Completed

Entergy	CORRECTIVE ACTION	1 CR-VTY-2004-03062

CA Number:

	Group	Name
Assigned By:	*CRG/CARB/OSRC*	
Assigned To:	Eng DE Mech Civil Struct Mgmt	Goodwin,Scott D
Subassigned To:	Eng DE Mech Civil Struct Staff	Fitzpatrick,James C
Originated By:	Burger,Frederick J	*10/0512004* 13:48:5S
Performed By:	Goodwin,Scott D	1110212004 15:24:21
Subperformed By:	Goodwin,Scott D	*11102/2004* 15:23:2E
Approved By:		
Closed By:	Felumb,Rhonda	1110212004 15:57:03

Current Due Date: 1110212004 **Initial Due Date:** *11102/2004*

CA Type: CR DISPOSITION

Plant Constraint: 0 NONE

CA Description:

CR Disposition
OQA records not handled in accordance with procedures
O(Review CR for Full Details)

CR- VTY-2004-3062
OReview Screening Comments on the Assignment Tab
O
OThe CRG has initially classified this CR as
JClassification Code - "C"
JSignificance Code - "MPC & CORRECT"
O
LJFollow the process provided in AP 0009 Appendix K. If during your investigations into this event it is determined
Dthat the classification should be changed, contact the CA&A representative for re-consideration by the CRG.
⌐j
OPerform Most Probable Cause Evaluation. Issue the appropriate CAs. (per LI 102)
O
OCR Disposition Guidelines: This is only a guide. It is not a substitute for the applicable procedures.
LI
OAll Attachments are to be in PDF format
O
OoAttach Most Probable Cause Investigation Report or Document in the Response or Sub response field
OoEnsure all Screening Comments have been addressed in the investigation - (CR assignment tab)
OoDevelop adequate corrective actions and issue CAs. (Due Dates per LI 102 Attachment 9.5)
Do LT CAs Require Approval from *Managerl* GMPO or Director prior to initiating
OoAttach completed VYAPF 0009.02 (CR Trend Input Data Sheet) in accordance with Appendix E.
OoAttach completed VYAPF 0009.05 (Human Performance Evaluation) if required. Include Cause Dept
OooAttach completed EN-LI-118 Attachment 9.17 (Equipment Failure Evaluation Checklist) .if assigned.
OoSpecify any references needed and enter into Ref. Items.

Response:

Review CRG Screening comments on Initiation Tab for inclusion in the report.

Subresponse :

QA records not handled in accordance with procedures.

'PC-1 *[F.4.bA]* Documents not followed correctly. FAC documents such as worksheets, reports, and CHECWORKS predictive models have not been sent to RIMS for permenant storage. Also, documents not sent to RIMS are to be stored in a fireproof cabinet until they have been transmitted

ImmediatelInterim Actions Completed
Item #0 Action Taken
MPC-1 □Placed documentation in fireproof cabinet until they are transmitted to RIMS.
□
□

Proposed! Assigned Corrective Actions

Item #OActionO CA Type□Assigned Department Due Date CA #
MPC-1 □Transmit FAC documentation to RIMSOCAODE Mech StructO 3-18-05000002
□□
ClosureofCROOOCA DEMechStruct 4-1-05 00003

Closure Comments:
Trending data entered and additional CAs have been generated.

Attachments:

Subresp Description
Trend and HU

Attachment Header

Document Name:

!cR-VTY-2004-03062 CA-00001

Document Location

Subresp Description

Attach Title:

Trend and HU

ENVY HUMAN PERFORMANCE EVALUATION FORM

CR No: CR VTY-2004-03062	Dispositioning Dept: MSD
	Cause Department: MSD

Applicable HU TRAPs:

O Time Pressure O Vague Guidance O Physical Environment
O Distraction/Interruption D First Shift/Late Shift O Mental Stress
O MUltiple Tasks D Peer Pressure
O Overconfidence O Change/Off-Normal

Description of Inappropriate Act(s):	Assoc Process/Prog/Org Issue(s): X N/A
FAC personnel have not complied with procedures regarding the storage and/or transmittal of QA documents.	

Worker Behaviors:

☒ Procedure Use/Adherence D Self-Checking D Fitness for Duty
O Placekeeping O Peer Checking O Turnover/Handoff
D Spoken Communication O Knowledge D Problem Solving Method
O Written Communication O Skill

Supervisor Behaviors:

O Spoken Communication O Task Allocation O Pre-Job Brief
O Written Communication O Clear Expectations

Management Behaviors:

O Communications O Change Management 0 Scheduling/Sequencing
D Resource Allocation O Conservative Decision Mkg 0 Clear Expectations

Process/ProgrammaticlOrganizatlonalIssues:

O Ergonomic/Human Factors 0 Housekeeping O ProcedureNVk Pkg Quality
O Environmental Conditions D Equipment Labeling O Training

Dispositioner: T. M. O'Connor **Date Completed: 11-2-04**

VYAPF 0009.05
AP 0009 Rev. 17
Page 1 of1

CR TRENDING INPUT DATA SHEET

CR No: CR-VTY-2004-03062	Dispositioning Dept: MSD
	Cause Department (if HU): MSD

NOTE

See Appendix E (CR Trending) for instructions on how to obtain information with which to com lete this form

CAUSE CODES			
MPC-1 [F.4.b.4]			

KEYWORDS			
Documentation	Procedure Adherence		

WORK PROCESS	OM
KEY ACTIVITY	DS

VYAPF 0009.02
AP 0009 Rev. 17
Page 1 of 1

Entergy	CORRECTIVE ACTION	CR-VTY-2004-03062

CA Number: 2

	Group	Name
Assigned By:	Eng DE Mech Civil Struct Staff	O'Connor,Thomas M
Assigned To:	Eng DE Mech Civil Struct Mgmt	Goodwin,Scott D
Subassigned To:	Eng DE Mech Civil Struct Staff	Fitzpatrick,James C

Originated By:	O'Connor,Thomas M	11/02/2004 14:04:41
Performed By:	Goodwin,Scott D	031161200515:14:4S
Subperformed By:		
Approved By:		
Closed By:	Goodwin,Scott D	03116/200515:14:4S

Current Due Date: 03/1812005 **Initial Due Date:** 0311812005

CA Type: CORRECTIVE ACTION

Plant Constraint: 0 NONE

CA Description:

Transmit FAC documentation to RIMS

Response:

Transmittal is complete. Refer to e-mail enclosed as Att 1. No further actions required for this CA.

Subresponse :

Closure Comments:

Attachments:

Resp Description

FAC Doc Transmittal E-mail

Attachment Header

Document Name:

luntitled

Document Location

/Resp Description

Attach Title:

IFAC Doc Transmittal E-mail

Goodwin, Scott

From: Graves, Amy
Sent: Wednesday, March 16,20052:43 PM
To: Goodwin, Scott
Cc: Fitzpatrick, Jim; O'Connor, Tom
SUbject: FW: FAC INFO to RIMS for CR-VTY-2004-3062 CA2

Scott - Records indicated below have been transferred to RIMS in checklist number 02668. This transfer has been completed. Therefore, enabling you to close this commitment.

From: Fitzpatrick, Jim
Sent: Monday, March 14,20058:24 PM
To: Graves, Amy
Cc: Goodwin, Scott; O'Connor, Tom
Subject: FAC INFO to RIMS for CR-VTY-2004-3062 CA2

Amy,

I have a CA to transmit FAC Program Inspection data and CHECWORKS Model data to RIMS by 3/18/03 (CR-VTY-2004-0362 CA2). There is a lot of data to be scanned.

The QA records for the 2004 RFO for the FAC Inspection program as required by PP 7028 have been assembled and indexed. They are located in the top drawer of the fire proof file in the PSB NW corner. The 2004 data package is similar to the 2001 RFO & 2002 RFO files previously sent to RIMS. These are originals so they should stay in the file.

In addition to the 2004 RFO inspection data there are 5 new documents to go to RIMS:

1. 1996 CHECWORKS Models & Results
2. 1996 EPRI CHECWORKS Database
3. 2001 EPRI CHECWORKS Database
4. EPRI CHECWORKS Wear Rate Analysis Results Cycles 20 &21
5. EPRI CHECWORKS Wear Rate Analysis Results Cycles 22B

These are also in the top drawer of the fire proof file.

Please have these scanned and sent to RIMS. I will be out of the office the remainder of this week but can be reached at 603-778-1144. Also Tom O'Connor can help to identify items. Please tell Scott when the data has been transmitted so he can close out the CA or if you need more help.

Thanks,
(Sorry for the data dump)

Jim Fitz.

Thanks,

Jim Fitz.

Entergy	CORRECTIVE ACTION	CR-VTY-2004-03062

CA Number: 3

	Group	Name
Assigned By:	Eng DE Mech Civil Struct Mgmt	
Assigned To:	Eng DE Mech Civil Struct Mgmt	
Subassigned To :		

Originated By:	Goodwin,Scott D	11102/2004 15:09:4C
Performed By:	Goodwin,Scott D	0311612005 19:31:43
Subperformed By:		
Approved By:		
Closed By:	Goodwin,Scott D	0311612005 19:31:43

Current Due Date: 04/0112005 **Initial Due Date:** 04/0112005

CA Type: EN CA

Plant Constraint: 0 NONE

CA Description:

Perform CR Closure review IAW EN-LI-102 requirements.

Response:

CR Disposition and all CAs have been reviewed and are considered closed. No further actions are required. IAW LI-102 requirements for closure, this CR should be closed.

Subresponse :

sure Comments:

Entergy **ADMIN** **CR-VTY-2004-03061**

Initiated Date: 10/412004 13:23 **Owner Group** :Eng DE Mech Civil Struct Mgmt

Current Contact: FJB

Current Significance: C - MPC & CORRECT

Closed by: Felumb,Rhonda 2/16/2005 16:37

Sununary Description:

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days.

Remarks Description:

Closure Description:

Condition Report Closure Review IAW LI-102 Section 5.9.1 Completed

Entergy	CONDITION REPORT	CR-VTY-2004-03061

Originator: Hall,Bruce E

ginator Group: Eng DE Manager

Supervisor Name: Callaghan,James H

Discovered Date: 10/0412004 13:21

Originator Phone: 5587

Operability Required: N

Reportability Required: N

Initiated Date: 10/04/2004 13:23

Condition Description:

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days. This condition report documents a QA identified issue. This issue was identified during the performance of Engineering Program Audit number QA-8-2004-VTY-1.

Immediate Action Description:

Suggested Action Description:

TRENDING (For Reference Purposes Only):

Trend Type	Trend Code
KEYWORDS	KW-HU CLOCK RESET DEPT
KEYWORDS	KW-PROCEDURE ADHERENCE
HOW IDENTIFIED	HI-QAD
HUTYPE	HU-PRECURSOR
CAUSE DEPT	CD-MECHANICAL - CIVIL/STRUCTURAL ENG.
HU EVALUATION FORM	HU-TRAP-MULTIPLE TASKS
WORK PROCESS	WP-DM
HU EVALUATION FORM	HU-TRAP-DISTRACTION
KEYWORDS	KW-DOCUMENTATION PROBLEM
CAUSAL FACTOR CODES	CFC-E3Z4
CAUSAL FACTOR CODES	CFC-F4B4
KEY ACTIVITY	KA-AN
HU EVALUATION FORM	HU-WB-PROCEDURE USE

Entergy ADMIN CR-VTY-2004-03061

Initiated Date: 10/412004 13:23 **Owner Group** :Eng DE Mech Civil Struct Mgmt

Current Contact: FIB

Current Significance: C - MPC & CORRECT

Closed by: Felumb,Rhonda 2/1612005 16:37

Sununary Description:

RFO 24 FAC documentation not yet completed

Formal documentation of FAC erosion rate on analysis/worksheets has not been completed for the data taken during RFO 24. The FAC Coordinator indicated that the Ultrasonic data had been reviewed, but the worksheets have not yet been completed to document the wear rate. Since the wear rates are not yet completed, the post outage FAC report has also not yet been completed although PP 7028, section 4.4.12 requires that the report be issued within 90 days.

Remarks Description:

Closure Description:

Condition Report Closure Review IAW LI-102 Section 5.9.1 Completed

Version:

Significance Code: C - MPC & CORRECT

21assification Code: C

Owner Group: Eng DE Mech Civil Struct Mgmt

Performed By: Burger,Frederick J *10/0512004 13:32*

Assignment Description:

CR-VTY-2004-3061
Screening Data
OSignificanceDC - MPC & CORRECT
DOwner: 0 Eng DE Mech Civil Struct Mgmt
DPresented By: o Goodwin, Scott
Comments:
DA Human Performance Evaluation VYAPF 0009.05 is required for all HU identified CRs
Trending Items
Cause Department -DE Mech Civil Structural
ERRORPRECURSOR-HU
HU CLOCK RESET DEPT
PROCEDURE ADHERENCE
Self-Identified
Discussed with FAC Coordinator. All RFO inspections have been evaluated and have been IR. There are no outstanding issues related to plant ops. Issue is administrative and relates to timely closure of paperwork.

Entergy	CORRECTIVE ACTION	CR-VTY-2004-03061

CA Number:

	Group	Name
Assigned By:	*CRG/CARB/OSRC*	
Assigned To:	Eng DE Mech Civil Struct Mgmt	Goodwin,Scott D
Subassigned To:	Eng DE Mech Civil Struct Staff	Fitzpatrick,James C
Originated By:	Burger,Frederick J	*10/051200413:41:55*
Performed By:	Goodwin,Scott D	*1110212004* 15:27:19
Subperformed By:	O'Connor,Thomas M	*11/02/2004* 15:09:38
Approved By:		
Closed By:	Felumb,Rhonda	*1110212004* 15:50:51

Current Due Date: *1110212004* **Initial Due Date:** *11102/2004*

CA Type: CR DISPOSITION

Plant Constraint: 0 NONE

CA Description:

OCR Disposition
10RFO 24 FAC documentation not yet completed
O(Review CR for Full Details)

CR-VTY-2004-3061
OReview Screening Comments on the Assignment Tab
O
OThe CRG has initially classified this CR as
OClassification Code - "C"
OSignificance Code - " MPC & CORRECT"
[J
OFollow the process provided in AP 0009 Appendix K. If during your investigations into this event it is determined
[Jthat the classification should be changed, contact the CA&A representative for re-consideration by the CRG.
O
OPerform Most Probable Cause Evaluation. Issue the appropriate CAs. (per LI 102)
O
OCR Disposition Guidelines: This is only a guide. It is not a substitute for the applicable procedures.
O
OAll Attachments are to be in PDF format
O
OoAttach Most Probable Cause Investigation Report or Document in the Response or Sub response field
OoEnsure all Screening Comments have been addressed in the investigation - (CR assignment tab)
OoDevelop adequate corrective actions and issue CAs. (Due Dates per LI 102 Attachment 9.5)
00 LT CAs Require Approval from Managerl GMPO or Director prior to initiating
OoAttach completed VYAPF 0009.02 (CR Trend Input Data Sheet) in accordance with Appendix E.
OoAttach completed VYAPF 0009.05 (Human Performance Evaluation) if required. Include Cause Dept
OooAttach completed EN-LI-118 Attachment 9.17 (Equipment Failure Evaluation Checklist) .if assigned.
OoSpecify any references needed and enter into Ref. Items.

Response:

Review CRG Screening notes on Initiation Tab for inclusion in report.

Subresponse :

FAC paperwork for RF024 not completed within 90 days of outage as required by procedure.

1PC-I *[FA.bA]* Documents not followed correctly; Procedure requires summary report to be issued within 90 days of Jutage completion. Although all data was evaluated and independently reviewed all formal worksheets had not been completed and hence the final report was not issued within the required time frame. Completion of formal worksheets is in progress with report to follow.

MPC-2 *[E.3.zA]* Contributing to the problem was ongoing work and emergent issues.

Proposed!Assigned Corrective Actions
Item #0 Action0 CA Type Assigned DepartmentDDue Date CA #
MPC-I oComplete FAC Worksheets and Issue Final ReportDCAODE Mech StructD 12-6-04000002

Closure Comments:

Trending data entered and additional CAs have been generated.

Attachments:

Subresp Description
trend and hu

Attachment Header

Document Name:

CR-VTY-2004-03061 CA-00001

Document Location

ISUbresp Description

Attach Title:

trend and hu

ENVY HUMAN PERFORMANCE EVALUATION FORM

CR No: CR-VTY-2004-03061	Dispositioning Dept: MSD
	Cause Department: MSD

Applicable HU TRAPs:

D Time Pressure	D Vague Guidance	D Physical Environment
☒ Distraction/Interruption	D First ShifULate Shift	D Mental Stress
☒ Multiple Tasks	D Peer Pressure	
D Overconfidence	D Change/Off-Normal	

Description of Inappropriate Act(s):	Assoc Process/Prog/Org issue(s): *NJA*
FAC personnel did not comply with procedure to complete RFO associated paperwork within 90 days of outage completion.	**Multiple ongoing tasks and emergent issues contributed to paperwork not being completed in a timely fashion.**

Worker Behaviors:

☒ Procedure Use/Adherence	D Self-Checking	D Fitness for Duty
D Placekeeping	D Peer Checking	D Turnover/Handoff
D Spoken Communication	D Knowledge	D Problem Solving Method
D Written Communication	D Skill	

Supervisor Behaviors:

D Spoken Communication	D Task Allocation	D Pre-Job Brief
D Written Communication	D Clear Expectations	

Management Behaviors:

D Communications	D Change Management	D Scheduling/Sequencing
D Resource Allocation	D Conservative Decision Mkg	D Clear Expectations

Process/Programmatic/OrganizationalIssues:

D Ergonomic/Human Factors	D Housekeeping	D ProcedurelWk Pkg Quality
D Environmental Conditions	D Equipment Labeling	D TraininQ

Dispositioner: T. M. O'Connor **Date Completed: 11-2-04**

CR TRENDING INPUT DATA SHEET

CR No: CR-VTY-2004-03061	Disposltioning Dept: MSD
	Cause Department (if HU): MSD

NOTE

See Appendix E (CR Trending) for instructions on how to obtain infonnation with which to com lete this fonn

CAUSE CODES

MPC-1[FAbAI	MPC-2[E3ZAI 1	

KEYWORDS

Documentation	Procedural Adherence		

WORK PROCESS	AN

KEY ACTIVITY	OM

Entergy	CORRECTIVE ACTION	CR-VTY-2004-03061

CA Number: 2

	Group	Name
Assigned By:	Eng DE Mech Civil Struct Staff	O'Connor,Thomas M
Assigned To:	Eng DE Mech Civil Struct Mgmt	Goodwin,Scott D
Subassigned To:	Eng DE Mech Civil Struct Staff	Fitzpatrick,James C

Originated By:	O'Connor,Thomas M	11I021200414:30:IS
Performed By:	Goodwin,Scott D	*0211512005 16:08:37*
Subperformed By:	Fitzpatrick,James C	021151200516:00:15
Approved By:		
Closed By:	Goodwin,Scott D	*02115/2005 16:08:37*

Current Due Date: *0211512005* Initial Due Date: *12/0612004*

CA Type: CORRECTIVE ACTION

Plant Constraint: 0 NONE

CA Description:

Complete Formal FAC worksheets and Issue Final Report

Response:

Concur with response. No further actions required for this item. SDG 2-15-05

Subresponse :

Attached .PDF file of 2004 RFO Outage FAC Inspection Report No. VY-RPT-04-00010 Rev.O.
Note the CD containing cross around piping photos is not included here. The CD and any other ENN DC-xx process forms are filed separately in the documemt control system as required by procedure.

..osure Comments:

Approval attached to DDE #2.

Attachments:

Subresp Description

VY-RPT-04-00010 RevO

Attachment Header

Document Name:

Document Location

ISUbresp Description

Attach Title:

iVV-RPT-04-0001O ReVO

Engineering Report No. VY-RPT-04-o0010 Rev. 0

Page 1 of 20

Plus attached CD

Entergy

ENTERGY NUCLEAR NORTHEAST

Engineering Report Cover Sheet

Engineering Report Title:

VERMONT YANKEE PIPING FLOW ACCELERATED CORROSION INSPECTION PROGRAM (PP 7028)
2004 REFUELING OUTAGE INSPECTION REPORT
(RFO 24- Spring 2004)

Engineering Report Type:

New ☒ Revision 0 Cancelled 0 Superceded 0

Applicable Site(s)

IP1 D IP2 D IP3 D JAF D PNPS D VY ☒

Quality-Related: ☒ Yes 0 No

Prepared by: James C. Fitzpatrick [signature] Date: 2/15/05
Responsible Engineer (Print Name/Sign)

Verified/ Reviewed by: Thomas M. O'Connor [signature] Date: 2/15/05
Design Verifier/Reviewer (Print Name/Sign)

*Reviewed by: N/A Date: N/A
Authorized Nuclear In-service Inspector (ANII)

Approved by: Scott D. Goodwin [signature] Date: 2-15-05
Supervisor (Print Name/Sign)

Multiple Site Review (10)

Site	Design Verifier/Reviewer (Print Name/Sign)	Supervisor (Print Name/Sign	Date
	N/A	N/A	N/A

*: For ASME Section XI Code Program plans per ENN-DC-120, if required.

NEC038554

Entergy	CORRECTIVE ACTION	CR-VTY-2004-03061

CA Number: 3

	Group	Name
Assigned By:	Eng DE Mech Civil Struct Staff	O'Connor,Thomas M
Assigned To:	Eng DE Mech Civil Struct Mgmt	Goodwin,Scott D
Subassigned To :		

Originated By:	O'Connor,Thomas M	11/02/200415:07:5S
Performed By:	Goodwin,Scott D	02/16/2005 12:57:4S
Subperformed By:		
Approved By:		
Closed By:	Goodwin,Scott D	0211612005 12:57:4S

Current Due Date: 03/04/2005 **Initial Due Date:** 1212012004

CA Type: CR CLOSURE REVIEW CA

Plant Constraint: 0 NONE

CA Description:

Ensure all Corrective Actions are closed out and close CR.

Response:

CR Disposition and associated CAs reviewed. All actions required complete. No further actions are required. IAW Section 5 of LI-102 this CR should be closed.

Subresponse :

osure Comments:

NEC038555

Entergy	**CONDITION REPORT**	**CR-VTY-2005-02239**

Originator: Fitzpatrick,James C
uriginator Group: Eng DE Mech Civil Struct Staff
Supervisor Name: Goodwin,Scott D
Discovered Date: *07/28/2005* 10:26

Originator Phone: 3086
Operability Required: N
Reportability Required: N
Initiated Date: *07/2812005 10:43*

Condition Description:
CHECWORKS predictive models for Piping FAC Inspection Program not updated as required per Appendix D ofPP 7028.

The CHECWORKS predictive models for the Piping FAC Inspection Program were not updated after the 2002 and 2004 refueling outages as required per Appendix D of PP 7028. Section 4.4.13 of PP 7028 states the FAC Program Coordinator will as applicable, incorporate the inspection results into the CHECWORKS models for use in planning the scope of the next refueling outage. However, Appendix D Section D.5 of PP 7028 states that the CHECWORKS models shall be updated after each refueling outage to incorporate inspection data taken during the outage for use in planning inspections for the following outages.

There are no operability concerns. The CHECWORKS model results along with previous inspection data and industry operating experience are inputs to determining the scope of inspections for each refueling outage. Scoping for FAC inspections for RFO 24 and RFO 25 was based on CHECWORKS predicted wear rates from the 2000 and 2001 CHECWORKS model updates. Actual measured wear rates from 2001,2002 and 2004 RFO inspections are an order of magnitude less than the CHECWORKS predicted wear rates. If the 2002 and 2004 inspection data were incorporated into the models the CHECWORKS predicted wear rates would be reduced.

Use of the non-updated CHECWORKS model results as a basis for inspection planning is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS predicted wear rates significantly greater than actual measured wear rates.

Immediate Action Description:
Update of the CHECWORKS models is in progess.
There is no impact on planned RFO 25 inspection scope. Use of the non-updated CHECWORKS model results as a basis for inspection planning for RFO 25 is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS predicted wear rates significantly greater than actual measured wear rates.

Suggested Action Description:

REFERENCE ITEMS:

Type Code	Description
PROCEDURE	PP 7028

Initiated Date: 7/28/2005 10:43 **Owner Group** :Eng DE Mech Civil Struct Mgmt

Current Contact:

Current Significance: C - CORRECT ONLY

Closed by:

Summary Description:

CHECWORKS predictive models for Piping FAC Inspection Program not updated as required per Appendix D ofPP 7028.

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Use of the non-updated CHECWORKS model results as a basis for inspection planning is conservative in that scoping decisions documented in the Inspection Location Worksheets were based on the CHECWORKS predicted wear rates significantly greater than actual measured wear rates.

Remarks Description:

Closure Description:

Version: 1

Significance Code: C - CORRECT ONLY

Classification Code: C

Owner Group: Eng DE Mech Civil Struct Mgmt

Performed By: Rogers,James G *07/28/2005 13:26*

Assignment Description:

WX - Procedure Non-Compliance
ESDE
KW-HU Precursor; HU Clock Reset Dept

Official Transcript of Proceedings ACRST-3397

NEC-UW_11

NUCLEAR REGULATORY COMMISSION

Title: Advisory Committee on Reactor Safeguards Subcommittee on Plant License Renewal

Docket Number: (not applicable)

PROCESS USING ADAMS
TEMPLATE: ACRS/ACNW-005

SUNSI REVIEW COMPLETE

Location: Rockville, Maryland

Date: Tuesday, June 5,2007

Work Order No.: NRC-1602

Pages 1-167

[ORIGINAL]

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UNITED STATES NUCLEAR REGULATORY COMMISSION'S

ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

June 5, 2007

The contents ofthis transcript ofthe proceeding ofthe United States Nuclear Regulatory Commission Advisory Committee on Reactor Safeguards, taken on June 5, 2007, as reported herein, is a record ofthe discussions recorded at the meeting held on the above date.

This transcript has not been reviewed, corrected and edited and it may contain inaccuracies.

of License Renewal.

Your observation is actually very correct, and very on the point. We have observed this same phenomena also, and in the past that's why we tried to update GALL, and in 2005 we updated GALL. The hope was that we would be able to eliminate many of the exceptions that we have -- you have been talking about.

And recently, in a couple of the most recent reviews, we find that, again, there were a lot of exceptions, more than what we would like to see.

So, thisis the one thing that we are working on that. We will be working with the industry. We will actually bring this very subject to the industry and see if there's any ways that we can reduce the number of exceptions.

With the number of exceptions we see right now, it doesn't make sense anYmore to have the GALL report there with the program, and then, you know, everybody is taking exceptions, and then why there's no reason for the GALL to exist anYmore.

CHAIRMAN BONACA: For example, on the containment issue, if I remember, there is a statement that says exceptions are so many that there was no point in listing them, otherwise it would have been confusing. Therefore, there is a description of the problem separate from GALL.

So, that, to me, was a clear indication we had to talk about where GALL is going.

MR. KUO: Yes, I fully agree with that assessment, and like I said we plan to work with the industry, and at some point we will come back to the committee and give you a status report on this.

As far as the audit report, I think we have come back to the committee about, I forget how long ago, about a few months ago. We told you that we are going to change from writing the 700 or 800 page report to what we call database.

What the database is, really, is something that when we go to the -- when the audit team goes to the site and audits the on-site design basis document, the applicant will create a question and answer database, and this database is evolving during the audit, so it's changing. Whenever we have a question, they have an answer, and that database has got to be revised.

But, at the end of the audit, we expect the applicant to submit this database, question and answers, to us, and their information, that becomes a formal document. Okay.

Then, the staff will take that database and build on it to actually provide a write-up similar to SER, basically, providing technical justification to the database and the status, whether it is still under discussion, open, or closed.

So, we are going to build, if you will, an audit report on the question and answer database submitted to us, and then provide the write-up on the technical justifications, and every time we will indicate what the status of that is.

So, that becomes, actually, the main body of the future audit report.

At the end of audit, okay, when everybody is ready to close out the audit status, then we will put a very simple description on top of this database, and then that becomes the audit report.

CHAIRMAN BONACA: Thank you, appreciate the explanation.

MR. KUO: So, that's what we are doing right now.

CHAIRMAN BONACA: Thank you. Okay.

So, I'll turn the meeting over to you, Dr. Kuo, for the Vermont Yankee application.

MISS KIMBALL: Well, yes, we have completed our safety evaluation, and we have an issue there to report to you. About a month ago, you have it in your hand, and I believe in that safety evaluation report we have the four confirmatory items that is, basically, about the boundary of the non-safety-related structures over safety-related structures. Okay. We were -- because of the spatial relationship, we have asked our regional staff to help us to walk down the plant, and so that they can have a better assessment of that.

We haven't been able to get input from the region yet, but this is something that we are going to have it, so we make it the confirmatory item in the report. As soon as we get input from the region, we will be able to hopefully close that out.

Recently, it has caught our attention about a dam, their own dam, and that, the issue, it was closed in the SER, but we noticed lately that this dam was owned by Trans-Canada, and because of the different ownership there is a question who is really responsible for the management of the dam. Okay. So, we have some ongoing discussion with the applicant, and I'm sure today they will address that, too. So that, we think, is resolved, but we will treat it as a confirmed item, too, so that is a new item added to the original SER that you had.

And, that is, really, the review status right now. Right now I'm turning to the applicant to make their application, and then the staff presentation will follow.

With that, I turn to the applicant.

MR. SULLIVAN: Good morning, I'm Ted Sullivan, I'm the 2nd Vice President for Vermont Yankee, and I'd like to thank the ACRS for allowing us to present the license renewal application here today.

I'd like to introduce John Dreyfuss. John is the Director of Nuclear Safety Assurance at Vermont Yankee, and he'll be lead presenter today, and I'd like the Vermont team to introduce themselves, and then I'll turn it directly over to John to make the presentation.

Thank you.

MR. RADEMACHER: Norm Rademacher, I'm the Director of Engineering.

MR. MANNAI: Dave Mannai, Entergy Vermont Yankee Licensing Manager.

MR. COX: I'm Alan Cox with the Entergy License Renewal Team.

MR. METELL: Mike Metell, Vermont Yankee License Renewal Project Manager.

MR. FITZPATRICK: Jim Fitzpatrick, Vermont

Yankee Design Engineering & Civil Structural Group.

MR. UNDERKOFFLER: Ted Underkoffler, I'm a Co-Program Engineer, I am the responsible individual for the Section 11 Containment Inspection Program.

MR. LUKENS: Larry Lukens, vermont Yankee in Programs and Components Engineering Department. I'm the Supervisor of Code Programs.

MR. McCANN: Good morning. My name is John McCann. I ,m the Director of Licensing for the Entergy Fleet.

MR. THAYER: I'm Jay Thayer, I'm Vice President of Operations for Entergy Nuclear. I'm on loan to the Nuclear Energy Institute.

MR. GOODWIN: Good morning. I'm Scott Goodwin, Entergy Design --

CHAIRMAN BONACA: You are going to have to corne to a microphone if we are going to go around the room.

MR. GOODWIN: Good morning. I'm Scott Goodwin, Entergy Vermont Yankee Design Engineer and Civil Structural Supervisor.

MR. HOFFMAN: Good morning. My name is John Hoffman. I'm currently retired from Entergy. I was the previous Site License Renewal Proj ect Manager.

MR. LACH: Good morning. My name is Dave

Lach. I'm the Entergy Corporate License Renewal Services Project Manager for the VY License Renewal Project.

MR. YOUNG: I'm Gary Young with Entergy, and I'm the Manager of the License Renewal Group for Entergy.

MR. STROUD: My name is Mike Stroud with the Entergy Corporate Group for License Renewal, and I am the Electrical Lead for Electrical Programs and Review.

MR. AHRABIA: My name Reza Ahrabia, I'm the SI, Civil Structural Lead for License Renewal.

MR. IVY: And, my name is Ted Ivy, I'm with the Entergy Corporate License Renewal Services Group. I'm the Mechanical Lead.

MR. JOHNSON: I'm Paul Johnson at Vermont Yankee. I'm Electrical Design Engineer.

MR. DREYFUSS: All right.

MEMBER BARTON: I'm glad you left somebody there behind to run the plant. I was getting a little nervous about that.

MR. DREYFUSS: Gentlemen, good morning, John Dreyfuss, Director of Nuclear Safety Assurance for Vermont Yankee. I'm responsible for, among other things, the Regulatory, Compliance and Licensing

Group. I'm also the Project Sponsor for the License Renewal Project for Vermont Yankee.

Where we are at right now, and we'll talk about it a little bit as we go through recent plan performance and current plan status, but we are, as we speak, turning the moats switch after a refuel outage, and we are going to plant start up.

So, we appreciate being here, thank you for entertaining us here at the ACRS meeting.

I did want to point out a couple of quick features here. Here's the Connecticut River. Here's the plant. There's the stack back here. We have the intake and the discharge. I think what you'll find is that the plant has been very well maintained over the years. We will talk about some of the capital improvements that we have been making to the plant over the years, in accordance with our long-range plan, and a big investment by Entergy in the plant over the last several cycles. We'll talk about that as well.

We've done the introductions.

Agenda is, we'll talk a little bit about the site description, touch on licensing history and some of the big plant improvements that we have made recently and over the years. We'll talk about recent plant performance and the project itself and team composition. We'll also discuss the cost beneficial severe accident management alternatives that we identified during the course of license renewal. None of them are age related, but they are interesting to speak about.

Additionally, we have a number of presentation topics we've prepared for you on the containment integrity, both the dry well and torus shell, and as P.T. Kuo mentioned, we will also discuss the Vernon Hydroelectric Station.

One thing that we have done is in these presentations we have put together an awful lot of detail, and we also have some hyperlinks and back-up slides. If at any point you want more information, we can provide that for you. If you have seen enough in the way of information, please say so, we will move on to any topic that interests you.

And, of course, we'll entertain any questions that you have during the course of the presentation here.

Site description, the plan is a 125-acre site on the banks of the Connecticut River. It's a very lovely site. General Electric was the NSSS vendor, and Ebasco was the AE and builder of the plant. It is a BWR, Mark I containment. We'll be discussing that a bit during the course of the presentations here today.

The plant is now rated at 1912, 1912 megawatts thermal, with a 650 megawatt electric output.

MEMBER BARTON: Is that original, or is that an upgrade?

MR. DREYFUSS: That is, during the past cycle we implemented a power uprate. We had put the modifications in over the prior two cycles, and in March of this year got the license up -- I'm sorry, 2006, got the license to do the 20 percent uprate.

MEMBER BARTON: Thank you.

MR. DREYFUSS: Very good.

The cooling is a hybrid cycle condenser with forced draft cooling, cooling towers. You saw a little bit of the cooling towers, we have a better shot of that later as well in the presentation slides, and we are currently at a staff of 650 people. That includes our contractors of supplemental work force.

Here are some of the licensing highlights. The plant did go on line in 1972, in March. The expiration of the operating license is March 21, 2012. Thus, we are here.

I did want to point out, in July of 2002 the plant was acquired by Entergy from Vermont Yankee Nuclear Power Corporation, and that really marked the beginning of a number of substantial capital upgrades and major projects, the power uprate project that we talked about, the 20 percent power uprate, dry fuel storage on site at the facility, as well as the License Renewal Project kicked off after Entergy acquired the plant.

I'll go through some of the major plant improvements that we've had. We did replace core spray piping back in 1978. We did the full bevy of modifications to the Mark I containment in the '78 to '82 time frame, new saddles, the hold downs, the shortening of the downcomers to alleviate some of the Mark I containment loading. All of that work was done during that period of time.

In 1986, we replaced our recirc piping with low carbon steel, 316 low carbon steel.

In 1998, we put in our new suction strainers, resulting as a result of some of the industry operating experience that was out there. We also took that opportunity to recoat our torus. We'll be talking about that a little bit later in the presentation as well.

2001, we applied noble chemistry for the first time at the plant, successful application. We most recently reapplied or put our second application on in the past refueling outage. Again, a successful application. And, we've also gone to hydrogen water chemistry, and, of course, those two in combination really do provide for the asset protection and IGSCC mitigation.

MEMBER BARTON: What's your hydrogen water chemistry designed to protect? I mean, how much -- you know, it can vary on the amount of hydrogen depending on what you are trying to protect in the core internals. What are you trying to protect?

MR. DREYFUSS: We protect the full asset and the recirc loop as well.

MEMBER ARMIJO: How do you monitor that? Do you have online ECP monitoring, or just do it --

MR. RADEMACHER: This is Norm Rademacher.

Yes, we do have an online ECP monitor, and we just -- as a matter of fact, as a result of this outage we put in a new one just for ongoing cycling.

MEMBER SHACK: What fraction of the cycle is it operable for?

MR. RADEMACHER: We are also investigating other alternatives to the General Electric supplied

ECP monitor, to improve the reliability.

MR. DREYFUSS: We have had them fail after two months of operation. We have replaced them as well. We've had them work for quite a while, and we are working, as Norm said, on doing an upgrade.

MEMBER BARTON: What's your success rate with operation of hydrogen water chemistry as a system, 95 percent of the time? How much?

MR. RADEMACHER: 98 percent.

MEMBER BARTON: 98 percent of the time?

MR. RADEMACHER: That's correct.

MEMBER BARTON: Okay, good.

Thank you.

MR. ARMIJO: This is maybe a little bit off base, but have you made any adjustment in your hydrogen water chemistry when you went from 100 percent to 120 percent --

MR. DREYFUSS: Yes.

MR. ARMIJO: or did you notice an ECP change?

MR. DREYFUSS: Originally, at the previous license conditioning, we were running about 3 SCFM and now we are on a 3.5.

MR. ARMIJO: Okay.

MR. DREYFUSS: Not a substantial change.

This is not necessarily in the slide that you have in front of you, but we thought it was worthwhile to mention. We did implement zinc injection at Vermont Yankee during this past cycle.

And, as far as power uprate, equipment upgrades, I did want to talk some about that. Can we go to the hyperlink there?

MR. ARMIJO: Before you go to that, you didn't do zinc injection earlier, but you used to have a brass condenser. Do you still have brass condensers?

MR. DREYFUSS: That's correct. We have the Admiralty brass condenser, and there is some natural zinc that we do get as a result of the condenser that we have.

MR. ARMIJO: But, you still keep the Admiralty brass condenser, or have you changed that?

MR. DREYFUSS: We have not changed that, that's correct.

MR. ARMIJO: Okay.

MR. RADEMACHER: It is in our long-range plan after 2010 to change that up.

MR. ARMIJO: That would be titanium or --

MR. RADEMACHER: We haven't made the selection of materials at this time.

MR. ARMIJO: Okay.

MR. DREYFUSS: I did want to touch on some of the major equipment changes that we made that we believe position us well for extended operation and good plant reliability into that period.

We did a change out of the high pressure turbine, the LP turbines were replaced earlier, prior to our power uprate, not associated with the power uprate, so that train is all new.

MEMBER BARTON: Was that the rotor cracking issue?

MR. DREYFUSS: No.

MEMBER BARTON: Okay.

MR. DREYFUSS: No, we had a rotor -- we had a rotor insulation issue.

MEMBER BARTON: Okay.

MR. DREYFUSS: And, we did fully reinsulate the rotor to enable us to stay away from any kind of thermal sensitivity and vibration on the power train.

MEMBER BARTON: All right.

MR. DREYFUSS: We additionally replaced, rewound the stader. That's all new copper, and reinsulated the boiler as well.

Feedwater heaters, we do have new high

pressure feedwater heaters. We had replaced the LP heaters in cycles previous to the power uprate modifications.

Switchyard improvements, we, essentially, replaced the switchyard. We put in lots of new protective features and redundant protection schemes. All of the 345, 3-4-5 KV breakers, are new. That was not driven by uprate, that was driven by our long-range plan as well.

We replaced a number of control systems, feedwater, level control, the feedwater heater level control system. The reactor pressure regulator has gone to digital. We are digital on most of these control systems, and they are working very fine for us.

And, one of the other big challenges that we had in going to power uprate was, we went from two feed pump operation with one in standby, to three feed pump operation, and we had to make a number of modifications to be able to address in the event that we would lose a condensate pump, what would happen to the feedwater system, and this was an area of interest during the power uprate proceedings. So, we put in modifications to provide for auto tripping of a feedwater pump in the event of a trip of a condensate pump. Also, an automatic runback of our recirc system, to maintain power, and additionally, a level setdown, ultimately, very well analyzed and our goal was, one, ensure, primarily, that we would maintain feedwater flow to the reactor vessel, and that we would not have an inadvertent scram on low level or a high level trip on the turbine.

MEMBER BARTON: On the loss of feedwater pump you runback or scram?

MR. DREYFUSS: Correct, loss of feedwater pump will do a runback.

MEMBER BARTON: Runback.

MR. DREYFUSS: Right, and we did an analysis using some sophisticated modeling. Ultimately

MEMBER ABDEL-KHALIK: What did you do to the condenser? You didn't say.

MR. DREYFUSS: To the condenser, we did some reinforcement in staking to avert any issues that we might have with vibration, due to the higher flows. We did take a look at the condenser this refuel outage, and we see no issues with the condenser, as a result of the power uprate.

This shows here, up top there is Wayne Manning, one of our operator, as we did reach the new power level. The slide below there, or the picture below, is our Power Ascension Control Center. We did a deliberate slow power ascension, never going backwards, but methodical step by step changes in power, at small increments, analyzed. At the very end here we did a big integrated plant test, where we actually did manually trip one of the condensate pumps and this is the Power Ascension Control Center, the brain of the power ascension operation, and all of us sitting around watching the traces and transients.

If you are astute, you can see that the rods remain out, and these are the traces here. Let's go to that next slide. This was a really nice result. W e had great results from this transient test. Classic quarter wave dampening on level, you can see the tripping of a pump here, and the tripping of the feed pump as far as the changes in feedwater flow, and this test matched perfectly with our analyzed projections for the test. So, a testament to, I think, the engineering staff for the work that they did in analyzing for this transient as well.

MEMBER SHACK: And, your secondary system piping, has much of that been replaced, or is it still all carbon steel?

MR. DREYFUSS: Go ahead, Norm.

MR. RADEMACHER: A lot of the high usage areas, drains and such where they go back to the condenser is chrome-moly. That was the original design.

MEMBER SHACK: Oh, the original design.

MR. RADEMACHER: And so, we haven't had to replace much of that.

MR. DREYFUSS: As far as recent plant performance, current plan performance, current plan status right now is, we are mode switch to start-up. We will be withdrawing control rods for start-up from our refueling outage.

Cycle 25, where we did the 20 percent power uprate, was a 549-day safe, continuous run. We had shut down for our prior refueling outage, did all of the maintenance, did some additional power uprate modifications, started the plant up, and it maintained -- we maintained it in service during the cycle, as well as doing the power uprate and power increase during the wave. So, a good, safe run, and a testament to the quality of the work that was done.

We started our refuel outage on May 12, 2007. Safe shutdown from that outage. We are starting up as we speak.

And, for key outage summary, one thing

that I did want to say, as far as the power uprate went, we were a full year operation at the extended uprate level with no challenges to the operators and good, safe performance of the unit.

A couple of key things as far the outage summary goes, some of the big things that we got done is, we did replace one of our large feedwater motors, the size of a walk-in kitchen, I would characterize it, pretty good size motor. That worked well, and it was fine. We did replace the last of the 345 KV breakers that we were seeking to replace. Again, that was driven by our long-range plan. We have a 15-year capital plan, and we have a large motor program, we are replacing and refurbishing motors as we go, and laying them out in a logical sequence based on priority.

MEMBER BARTON: Does that include your recirc motors as well?

MR. DREYFUSS: We are looking at the recirc motors as well, and that's a relatively high priority one for us as well. It's a big job.

MEMBER BARTON: Yes.

MR. DREYFUSS: The feedwater motor was a big job, had to cut a hole in the turbine building, cut a hole in the turbine building floor --

UNITED STATES OF AMERICA

NUCLEAR REGULATORY COMMISSION

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ADVISORY COMMITTEE ON REACTOR SAFEGUARDS (ACRS)

MEETING OF THE SUBCOMMITTEE ON PLANT LICENSE RENEWAL

+ + + + +

TUESDAY,

JUNE 5, 2007

The meeting was convened in Room T-2B3 of Two White Flint North, 11545 Rockville Pike, Rockville, Maryland, at 10:30 a.m., Dr. Mario Bonaca, Chairman, presiding.

MEMBERS PRESENT:

MARIO BONACA Chair
WILLIAM J. SHACK
J. SAM ARMIJO
SAID ABDEL-KHALIK
OTTO MAYNARD
JOHN BARTON

MEMBER BARTON: Roof, yes.

MR. DREYFUSS: -- it was a big deal, but very well done.

Service water, we replaced the discharge valve and check valve on our service water D train, our delta train of service water. Again, that was work that we are looking to do. We have the other trains laid out in our long-range plan that we'll be doing over the course of the next several years.

We did replace a HPCI high pressure cooling injection turbine exhaust and check valve, that we had had some history with leak rating. We put a new check valve in, it's working beautifully.

So, some of the highlights from the outage.

MEMBER ABDEL-KHALIK: Now, you've been operating with a MELLLA power flow limit line?

MR. DREYFUSS: We are, we are operating under the MELLLA operating regime, and we are -- we did some gamma scanning for this refuel outage in support of the GE application for the MELLLA+.

MEMBER ABDEL-KHALIK: And, your operators have had no problems operating with MELLLA in terms of the range of control that they have?

MR. DREYFUSS: That's correct. There

have been no problems. Ideally, the MELLLA+ will provide some additional operational flexibility, so that we have a larger flow window, in particular, end-of-cycle, so that we don't have to make as many pattern adjustments to the --

CHAIRMAN BONACA: You say a larger flow window, I mean, you have some flow window now?

MR. DREYFUSS: Yes.

CHAIRMAN BONACA: With the MELLLA?

MR. MANNAI: Yes, this is Dave Mannai, we have about a 4 to 5 percent flow window. It's a little bit larger than Brunswick's. We did some industry comparisons with them when we were going to implement uprate, and I'm pleased to report that over the last cycle we had a number of rod adjustments toward the end of the cycle, you know, as is typical, but not having MELLLA+ at a full EPU condition we did have to do more rod adjustments, but they are all done safely with excellent focus on reactivity management and performance. We had no issues as a result of that.

MEMBER ABDEL-KHALIK: And, you can enter into higher than 100 percent flow range?

MR. MANNAI: Yes, we implemented increased core flow back in late '99, early 2000 time frame, and we went -- you know, we had the full 107 percent increase core flow. As you implement power uprate you lose some of that margin, so we went from 107 percent down to about 104.5, so our flow window is from 99 percent to, roughly, 104.5 percent flow, so we had a little bit more margin than one of the Brunswick units.

MEMBER ABDEL-KHALIK: Thank you.

MR. DREYFUSS: As far as an overall summary, excellent plant material condition. We did do a lot of looking as a result of a power uprate and the changes that we had made, and we found the plant to be in excellent health. We'll talk a little bit more about that.

We did not identify any significant equipment issues, routine items, routine added out of scope, and well managed and addressed. No generic issues.

Outage items of interest, a lot of interest from everybody on the steam dryer and its performance, as well as the performance of flow accelerated corrosion under the uprate power levels. I'd like to talk a little bit about both of those topics as well.

MEMBER MAYNARD: You said you are going to talk more about your first bullet there, excellent plant material condition?

MR. DREYFUSS: Yes, sir.

MEMBER MAYNARD: Okay, because that's an easy -- that's a statement to make, but it doesn't really give me a feel. You obviously have some issues and some things that you are dealing with, I'd like to get a feel for kind of what level of items that you do have on your list of things to do.

MR. DREYFUSS: All right, very good, thank you.

As far as the steam dryer went, during start up from the last refuel outage we did do extensive monitoring of the steam dryer to validate that we are going to remain within the low profile, code low profiles, and we did do that.

But also, during the course of the cycle we did online monitoring to a high degree. Additionally, during this last outage, lots of interest in terms of the steam dryer condition as we pulled it out of the vessel.

So, from an online monitoring standpoint, we have been monitoring, we saw no changes in reactor water level that we couldn't explain. Similarly, steam dome pressure, no changes there that would prompt us or kick us into any off-normal procedure that we have for actual steam dryer issues.

Additionally, we do monitor moisture carryover, and we had no unexplained changes with moisture carryover. It tracked as predicted, with changes in power or changes in rod sequences, which, again, those were all anticipated.

MEMBER ABDEL-KHALIK: How is that measured?

MR. DREYFUSS: We use -- Norm, can you speak to this?

MR. RADEMACHER: Sure. We use sodium-24 testing. The chemistry performs the testing, and use a radioactive sample and verify. And, they do on a weekly basis, and we monitor statistically and see if there's any statistic changes, statistically unusual changes, every week.

And, the performance of that has been -- you could see the change with our uprate, as we increased steam flow you get more carryover, but then it stays relatively constant through the rest of the year for the cycle.

MR. DREYFUSS: It probably averages about .12 percent.

MEMBER ABDEL-KHALIK: And, the uncertainty in that is how much?

MR. RADEMACHER: I don't know the answer to that question.

MR. MANNAI: We'll get that information and get back to you.

MR. DREYFUSS: It's very predictable. We'll get the numbers on the uncertainty for you.

For outage monitoring as well, we did take a look and found that there were no fatigue indications that have been seen elsewhere in the industry. I happened to be at one facility when they removed the dryer from the reactor vessel, and there were obvious flaws in that steam dryer, in particular, some of the areas where reinforcement and strengthening modifications were made. We took a look at all of those areas, and the steam dryer looks there were no indications, and the steam dryer is in very good health.

MEMBER BARTON: Are there any cracks at all in your steam dryer?

MR. DREYFUSS: There were some indications that we identified as well. We'll talk a little bit about that. We characterized them as IGSCC as well --

MEMBER BARTON: Okay.

MR. DREYFUSS: -- and dispositioned them

with General Electric as use as is. I'll explain some of those as well as we go forward.

MEMBER BARTON: All right, thank you.

MR. DREYFUSS: Go to the hyperlink here. This is a shot of the steam dryer here, and we did find these are the lifting lugs for the steam dryer. We found that on a tap weld on two of these lifting lugs, there's a structural weld underneath here, that was fine, but the tack weld, that's, essentially, anti-rotation for the lifting lugs, we did find a couple of small indications there, and they may be service-induced from lifting, lifting the dryer.

Where we did find IGSCC is, this shows here, we have two steam dams, and they are about half an inch wide, 12 feet long, six inches high, and during the visual inspection, we did very high-quality visual inspections of this outage as well as last outage, we saw three indications right along one edge of the steam dam. They didn't turn the corner whatsoever, and they look like classic IGSCC-type indications, dispositioned as use as is. We concurred with that in our Civil Structural Group, and we will inspect them next outage.

CHAIRMAN BONACA: You didn't see them in

the previous outage?

MR. DREYFUSS: We did not see them in the previous outage.

CHAIRMAN BONACA: So, this is indications that developed over this period of operation.

MR. DREYFUSS: That's correct. What we had done, in 2004, two cycles ago, is we did do some strengthening modifications here, some weld build up at this particular area, as well as putting in a couple of gussets along the length of the steam dam to improve its strength, and we found that in the heat affected zone, where we did that work, that's where the IGSCC showed up.

MR. ARMIJO: So, you believe it's residual stress from your welding that caused the cracking to initiate there?

MR. DREYFUSS: Yes, sir.

MR. ARMIJO: Do you have any micro structural confirmation that it was IGSCC and not something else?

MR. DREYFUSS: No.

MR. ARMIJO: So, it's just -- is there water up there? How can you have a cracking in a steam dryer? Is there liquid bays up there?

MR. MANNAI: A fraction of a percent.

MR. LUKENS: It's very low moisture content at that part of the dryer.

MR. ARMIJO: But, there was no metallographic sample taken to verify its intergranulars?

MR. DREYFUSS: That is correct.

MR. ARMIJO: So, it's an indication, and you concluded with G.E. that it was IGSCC.

MR. DREYFUSS: Right, and we will again look at it next outage to confirm that.

MEMBER MAYNARD: Can you explain to me what you mean by a very high-quality visual inspection?

MR. DREYFUSS: Yes, the standard that we used was G.E. SIL, Service Information Letter 644 requires visual examination. The technology that was used, the cameras that were used, the speed at which the cameras moved, the clarity of the water was very high as well.

MR. RADEMACHER: And the lighting.

MR. DREYFUSS: And the lighting was very good.

MR. RADEMACHER: It was almost EVT -- met EVT standards, the enhanced visual requirements.

MEMBER SHACK: Now, how do you disposition this curve crack? You know, what's the process?

What's the acceptance criteria for the dispositioning?

MR. RADEMACHER: General Electric evaluates it. Well, first off, just to remind you, this is on the end of the steam dam, it's a ½ inch wide, just on the face of the steam dam.

Then they evaluate the condition, where it is, and whether it impacts the structural capability of the steam dryer, and then they provide a response to us that is reviewed by our structural folks to verify that it's acceptable.

And --

Larry, do you have anything to add to that?

MR. LUKENS: This is Larry Lukens.

We spent a lot of time on the phone with General Electric, both their metallurgist and their analysis folks, on this particular set of indications, and the cracks are consistent with IGSCC. The history on this particular spot in the dryer is that in 2004 there were a number of welds that were put on because of cracks found in structural parts in the vicinity of that steam dam.

This particular spot in the steam dam is not a structural part of the steam dam. It's about a 3-inch high piece of this 6-inch stainless plate, and

ACRS STAFF PRESENT:

MICHAEL JUNGE Designated Federal Officer

NRC STAFF PRESENT:

P.T. KUO

MICHAEL MODES

RICHARD CONTE

JONATHAN ROWLEY

LAMBROSE LOIS

JIM MEDOFF

ROBERT HSU

DUK NGUYEN

ALSO PRESENT:

TED SULLIVAN

JOHN DREYFUSS

PAUL JOHNSON

NORM RADEMACHER

DAVE MANNAI

ALAN COX

MIKE METELL

JIM FITZPATRICK

TED UNDERKOFFLER

LARRY LUKENS

JOHN McCANN

these cracks are characteristic of stress relief. And, in 2004, when the original indications in these areas -- this area was identified, there was a lot of discussion in that analysis about the stress induced by the welding, by the original manufacturing process.

There are four symmetrical locations to this specific spot, and only one of the four has these indications.

MR. ARMIJO: So, G.E. dispositioned that by saying, and correct me if I'm not saying what they told you, but these cracks were caused by residual fabrication stresses caused by the welding.

MR. LUKENS: That's correct.

MR. ARMIJO: And, they must have assessed that these cracks wouldn't propagate and leave you with a loose part.

MR. LUKENS: That was our big concern, yes.

MR. ARMIJO: Okay, and that's been reviewed with the staff.

MR. LUKENS: No, the staff --

MR. DREYFUSS: Well, we did do a -- we had a telecon with Tom Scarborough and a number of the consultants that were involved in the steam dryer work, as a courtesy call, and did explain to them what we saw and what we had identified as well.

MR. RADEMACHER: And, in addition, we forwarded our detailed report to the staff for their review, as part of our license conditions, after each inspection of the dryer wall, for the next -- this cycle, as well as the next two refueling cycles, we'll be continuing to monitor the steam dryer, and we'll prepare a report for the staff for their review.

MR. LUKENS: That's a 60-day report.

MR. MANNAI: Yes, this is Dave Mannai. I think it's worth noting, we had set up that courtesy teleconference with the NRC staff ahead of time, even before we noted these indications, and we discussed those indications fully with the staff at that telecon, and much of the questions that you are asking now were similar to the questions they asked, and staff, I believe, was satisfied at the end of that teleconference. We owed them the formal reports in accordance with our license condition, 60-day report.

MR. DREYFUSS: And, some of the industry operating experience that we had followed is, there were substantial flaws here along the lower plate, along the gussets and shoes, as well as the gussets pulling away from the actual base plate here. Again, we looked at all of those areas, all of the preemptive strengthening modifications that we had done, and found them to be in good order, no indications there.

MR. RADEMACHER: We performed over 460 inspections, both inside and out, and there was no change in any of the previously identified indications, and just the new ones that we have mentioned during our conversation here today.

MR. DREYFUSS: Any other questions on the steam dryer?

CHAIRMAN BONACA: Just the question I had was, you will inspect again at the end of the new cycle, and for how long do you plan to do inspections?

MR. DREYFUSS: We will follow the SIL-644 guidance. However, we did have a license condition that, rather than every other outage that we would do three successive --

CHAIRMAN BONACA: Yes.

MR. DREYFUSS: -- full inspections of the susceptible, accessible welds. So, this outage and the next two, we will also do the same type of high-quality visual inspection.

CHAIRMAN BONACA: So, the dispositioning was, essentially, for a cycle length, or a disposition that's acceptable for a cycle of operation.

MR. DREYFUSS: That's correct.

CHAIRMAN BONACA: And, they will be

inspected again.

MR. DREYFUSS: Inspect again next cycle, correct.

CHAIRMAN BONACA: Thank you.

MR. RADEMACHER: In addition now, as part of license renewal, we have an ongoing commitment to meet SIL-644 for the license extension period.

MEMBER SHACK: And, it is sort of a rock in a hard place. Every strengthening operation you make to protect against fatigue just gives you a new ISSC location.

MR. DREYFUSS: That was one of the concerns that we had, in terms of the modeling that we did on the steam dryer, to make sure that we had mesh sizes small enough to really get a good understanding of what the stresses were at those key locations. That did prove to have been accurate, and we don,t see any indications.

MEMBER SHACK: Now, the fluids is up here low enough, you don't have to worry about helium in the stainless steel?

MR. DREYFUSS: Right, yes.

MEMBER ABDEL-KHALIK: Was the steam pressure monitored during the power uprate to detect any sort of high-frequency variations in steam pressure?

MR. DREYFUSS: Yes, we had highly instrumented both the steam lines, feedwater lines as well, and looked at steam dome pressure, and we monitored any fluctuations there.

What we had learned from the industry is that there were some signals, acoustic signals, that were being brought from the main steam lines back to the steam dryer, that's what we monitored.

MEMBER ABDEL-KHALIK: And, what,were the results of those monitoring activities?

MR. DREYFUSS: We stayed well within the loads. We never -- it went as we predicted, and did not approach the ASME loads.

MEMBER ABDEL-KHALIK: And, what were the dominant frequencies?

MR. DREYFUSS: We had a frequency at 137 Hertz, and another one -- and we'll give you the exact numbers, but a little bit -- I think it was 148, 148 Hertz, and they coincided with the SRB branch line connections off the main steam lines. We had predicted we would see a spike there, we did see it there, it grew and then mitigated, and stayed within the limits.

MEMBER ABDEL-KHALIK: Thank you.

MR. DREYFUSS: Okay. Flow accelerated corrosion, this was another area that we paid particular attention to under the uprate conditions. We did increase the number of FAC inspections by 50 percent from what we typically do during outages. We did do 63 inspections overall. They were satisfactory and, in fact, they were consistent with your analytical predictions that we use in our modeling for FAC.

One area that, Jim, maybe you can talk about, the cross-around piping inspection that we did. It's one of the susceptible areas.

MR. FITZPATRICK: We've got one remaining carbon steel cross-around. Jim Fitzpatrick. It's the only thing left in the system that is still susceptible, so we use that as an indicator, and we've been doing visual inspections of that almost every outage. And, it's, essentially, the same condition it was in 1996, even with the power uprate.

We have visual marks on the inside, and they are still there after this cycle.

MEMBER SHACK: Okay, that's how you do the visual, it's still there.

MR. FITZPATRICK: Well, we did UTs, and we have a mat on the inside, and you go inside the pipe and see if it's still there.

MEMBER SHACK: There's no wall thinning.

MR. FITZPATRICK: No, and that's surprising.

MR. LUKENS: This is Larry Lukens, maybe, maybe the gentleman didn't completely understand what you said, there were marks -- marks we put on the inside --

MR. FITZPATRICK: Yes.

MR. LUKENS: to make sure that we understood

MEMBER SHACK: I was sort of wondering how you were going to do the visual, you know.

MR. ARMIJO: Poke in your head.

MR. LUKENS: Actually crawl down the pipe.

MEMBER SHACK: No, but I mean, you have marks, and if they are still there that's an indication you are not losing metal, yes.

MEMBER MAYNARD: The 50 percent increase in number of FAC inspections, is that just the number of inspections, or did you also increase number of locations that you are looking at?

MR. DREYFUSS: Jim?

MR. FITZPATRICK: A mixture of both. We do repeat inspections. We do some new areas, try to mix it up, try to add more areas on the same system, look at the models, get more data for the check-works models we are using.

MR. ARMIJO: Now you used you have chrome-moly most here.

MR. FITZPATRICK: In the extraction steam system it's all chrome-moly. The heated drain systems, everything downstream of the local control valves are chrome-moly or stainless, except for the lowest load pressure here.

MEMBER SHACK: Do you have a feel for the amount of margin you have with this material compared to the carbon steel, as far as FAC resistance?

MR. FITZPATRICK: EPRI publishes 34 times more resistant than the carbon.

MEMBER SHACK: Order of magnitude at least, huh?

MR. FITZPATRICK: Well, we are not seeing -- we've done some monitoring in the past 15 years on the chrome-moly and haven't seen anywhere at all.

MEMBER SHACK: And, this is 2-1/4 chrome-1-moly or what?

MR. FITZPATRICK: Some 2-1/4, some 1-1/4, EPRI rec -- even if you have a carbon steel that's got more than .1 percent it works.

CHAIRMAN BONACA: Going back to the 50 percent increase, what was the criteria used? I mean, you looked for still susceptible locations, right?

MR. DREYFUSS: Go ahead, Jim.

MR. FITZPATRICK: Jim Fitzpatrick.

Just for planning, going to the power uprate, we had pretty good confidence in what was going on prior to power uprate, and we figured we'd do 50 percent more inspections to get more data, just to get it back into the check-works models, and then at the end of the three cycles we'll be assessing where to go from there.

We've been on a trend of small in order inspections over time, and most of the industry is, too.

MR. DREYFUSS: Okay, and again, we'll continue to ,do the increased scope of these inspections for two more cycles.

Now, moving on to the license renewal project itself. As you have heard from introductions, we have a multi-discipline team, a good blend of people from both our Corporate staff, as well as at the site. At the site, we have personnel, not just from the key engineering programs, programs and components and system engineering, design engineering, we also had operations, maintenance and other groups participate, so that we would get that synergy and make sure everybody sees what's coming here with license renewal.

We did, as far as the Revision 1 to the Standard Review Plan in GALL, it's noteworthy that both Pilgrim and VY were the first to go that route, and we are going to talk more about GALL exceptions. I know you are interested in that, but general overall -- over-arching philosophy on the GALL is that we comply with the GALL.

There were a number of areas where there -- I'd characterize them as technical exceptions for the GALL that we needed to take, but we were conservative in the development of the GALL, and I think you'll find that these are relatively minor exceptions, and we'll speak to them in detail as well.

Of course, we incorporated industry lessons learned, both at Pilgrim and other fleet plants that have undergone license renewal, and others in the industry.

As far as the exception types, we have overall 30 exceptions to the GALL. As far as the types of exceptions, you know, for example, if we were committed to a different version of an ASME code, we

ALSO PRESENT: (CONT.)

JAY THAYER

SCOTT GOODWIN

JOHN HOFFMAN

DAVE LACH

GARRY YOUNG

MIKE STROUD

REZA AHRABIA

TED IVY

did take exception to the GALL. So, we've broken down the exceptions that we took into six categories that we'll describe to you, and I'd like to ask Alan Cox to brief you on that.

MR. COX: These six categories -- this is Alan Cox -- the six categories was our -- to try to characterize these exceptions, and you can draw the lines in different places, they are somewhat arbitrary, I guess, and there's some overlap between them. So, there's not a real clear-cut line.

The first category we've got there is where an activity is not applicable to the plant design. That was pretty straightforward. We may have -- I think we took an exception to metal enclosed bus program, where it talked about insulation between phases, we didn't have insulation between phases. In our bus, we had insulation or insulators that supported the bus, but we didn't have any insulation between phases.

So, we took, I guess, an overall philosophy on these exceptions, we took a pretty conservative or a literal interpretation of what was in GALL. If it said do an inspection, we did have an inspection, we tended to call that out as an exception. I think if you compare applications from plant to plant you'll see that there's different degrees of that, there's different levels of conservatism or how literal you take things, so you'll see differences in numbers probably because of those factors.

The second category we've got there is an alternative that's consistent with approved methods. I guess one of the other philosophies that we took was, if we had a -- as you know, GALL says that that's one way of doing things, if we had an existing plant program that had proven within the, you know, the circumstances of our plant, our people, our training programs, if that existing program had proven effective over the years in dealing with that aging effect, we didn't make the change in the program just to say that we were consistent with GALL. We felt like it was more important to use what's already in place and what's establish and proven for our plant, for our circumstances.

The third category is programs based on different code --

MEMBER MAYNARD: Excuse me, alternative, consistent with approved methods, from what I understood you to say, I'm not sure what the approved methods are. Is it approved method just because it has worked for you, or is it other things in the regulations that --

MR. COX: In some cases it's -- the most obvious thing that comes to mind is the BWR VIP program. A lot of times you have specifics there that are -- maybe we've got an approved exception to the BWR VIP program because of plant unique circumstances, and we would take that approach.

MR. DREYFUSS: You know, Alan, we have an example that we could go to here.

MR. COX: Right.

This is one that dealt with the frequency, and we had approval of the Generic Letter 89-13, to do things at a refueling frequency, and I think the GALL report may have been more specific than that, it may have said annually. In some cases it was not practical to do it annually, you had the access to the system, you had plans to do things during refueling outages.

MEMBER BARTON: Your refueling outages are how often?

MR. COX: Eighteen months.

MEMBER BARTON: Eighteen months?

MR. COX: Right.

MEMBER BARTON: Okay.

MR. COX: That's an example of that category. Again, there are others. There was, oh, seven or eight examples I think that we had in that category.

The third one, different ASME code edition, that's pretty straightforward. There's been a lot of discussion about that. There's was a handful of things that fell in that category.

Again, this category met the equal to or better than the NUREG 1801 method, that's a little bit of, you know, the second category that we talked about earlier is a little bit of the same thing, but we've got an example of that -- can you click on the example there?

MR. DREYFUSS: Yes, let's look at that.

MR. COX: The GALL analysis program, the GALL program, you know, again, was a program that was developed off of somebody -- some specific plant that was reviewed and accepted. Well, it turns out that that particular plant program had flashpoint testing in there. We have a practice at vy to do a fuel dilution test, which is considered to be a better indicator of the contamination of the lube oil with fuel oil than a flashpoint test. So again, it's an alternative that's equally effective, if not better, than what was in the NUREG, and it's a fairly minor thing, it took pretty little interpretation and decided that that was something we needed to flag as an exception.

MR. DREYFUSS: Okay.

MR. COX: The experience justifies exception.

MEMBER BARTON: That's a scary one.

MR. COX: It really kind of ties back in to the philosophy that we were talking about earlier, where you've got an established program that's been proven effective under the plant specific circumstances that it's applicable to, and just go and click on the example of that, if you will.

Diesel fuel additives is specified in the particular GALL program. At VY, there's a long history of not requiring any additives beyond those which are provided as part of the manufacturing process by the fuel vendor, and we've had very good operating experience with the existing process. We didn't feel like it was appropriate to change that.

MEMBER BARTON: How about how about containment leak rate tests ten to 15 years, where did that one come from?

MR. UNDERKOFFLER: We presently Ted

Underkoffler -- we presently test containment on a ten-year basis.

MEMBER BARTON: Right.

MR. UNDERKOFFLER: We are right in a five-year extension right now.

MEMBER BARTON: About what?

MR. UNDERKOFFLER: On the analysis of the uprate analysis. We did the extension for five years.

MEMBER BARTON: One time?

MR. UNDERKOFFLER: One time only, and we'll be doing our integrated test in 2010.

MR. DREYFUSS: Go ahead.

MR. COX: I'd say there's only a couple exceptions that we considered in that fifth category.

The final one is the NUREG 1801 method is not feasible, and again, this examples that we had in that category were all related to the BWR VIP program, where the VIP program recognizes that some of the inspections that they called for are not technically feasible at this time, and, you know, they have some allowances in there. Larry could probably speak further to this, but that was -- all three of the items we put into that category were BWR VIP items, where the technology is not there to allow you to do the particular inspection.

MR. LUKENS: This is Larry Lukens.

Probably the classical example of this is the so-called P9 weld and the core spray shroud the collar, the P9 weld is inaccessible, it's not visible, can,t get there. Several years ago, we got a technique approved by EPRI to interrogate this weld by UT, and that technique was subsequently disqualified because nobody currently believes we can come up with a UT technique to interrogate that weld.

So, that weld is inaccessible, and that weld is redundant to other welds, which we can examine, and which we have examined, we do examine those at the frequency specified by the BWR VIP, so that our inability to examine that weld doesn't affect structural integrity of the connection, it is an artifact of the way the plant was built, as all BWRs we build.

MEMBER BARTON: I think the concern I've got about this whole issue is that there were -- you explained your reasoning for not complying with all the GALL issues, but yet the audit team did find, when you did divert to your own program for whatever reason it was, that you did have to make additional commitments to that program that you were using, even though it wasn't a GALL program. So, that kind of says, hey, how smart was the NRC team that was there that did the audit that picked these up that made you do -- that you then did agree to do some additional commitments to what you were doing. And, there were several of those in this whole stack of exceptions, and I guess that was the thing that was most concerning to me. Suppose somebody didn't pick this up, and you guys agreed to do additional things to the program you were doing. And, I don't specifically remember which ones they were, but there were a few of those like that.

MR. LUKENS: This is Larry Lukens.

I remember a few of those.

MEMBER BARTON: Yes.

MR. LUKENS: They dealt, in my area they dealt with things like frequency of inspections in fire protection systems.

MEMBER BARTON: Yes, that's one.

MR. LUKENS: And, the intervals that we have used are currently in our TRM, they were derived from are the same intervals that used to be in tech specs. They were the intervals that we've used successfully for as long as we've had a fire protection program.

And, we -- our preference would have been

A-G-E-N-D-A

P-R-O-C-E-E-D-I-N-G-S

10:28 a.m.

CHAIRMAN BONACA: Good morning. The meeting will now corne to order. This is a meeting of the Plant License Renewal Subcommittee. I'm Mario Bonaca, Chairman of the Plant License Renewal Subcommittee for this plant.

ACRS members in attendance are William Shack, Otto Maynard, Said Abdel-Khalik, Sam Armijo, and John Barton. Michael Junge, of the ACRS Staff is the Designated Federal Official for this meeting.

The purpose of this meeting is to review the license renewal application for the Vermont Yankee Nuclear Power Station, the draft SER, and associated documents.

We will hear presentations from representatives of the Office of Nuclear Reactor Regulation, NRR, the Region 1 office, and Entergy Nuclear Operations, Incorporated.

The subcommittee will gather information, analyze relevant issues and facts, and formulate proposed position and action as appropriate for deliberation by the full committee.

Rules of participation in today's meeting were announced as part of the notice of the meeting previously published in the Federal Register. We have received no requests for time to make oral statements, and we have received no written comments from members of the public regarding today's meeting.

A transcript of the meeting is being kept, and will be made available as stated in the Federal Register notice. Therefore, we request that participants in this meeting use the microphones located throughout the meeting room when addressing the subcommittee. Participants should first identify themselves, and speak with sufficient clarity and volume so that they can be readily heard.

We will now proceed with the meeting, and before I call upon Dr. Kuo, of the Office of Nuclear Regulation, to begin I would like to make a couple of general observations regarding this application.

The first is really a recurrent theme, I guess, and the question regarding GALL, and one thing what we notice is that there is an increasing number of exceptions being taken on the GALL, and this is not an issue only for Vermont Yankee. We've seen it coming, and I have raised a number of questions in the past regarding whether or not GALL should be updated to be less descriptive, and to incorporate some of this that are really not exceptions, they are just alternatives. For example, in some cases to ASME code on the report, and to have their views regarding, you know, how do we reduce the number of exceptions being taken. I mean, GALL was originally a cooperative effort between the industry and the staff, to see that there is, you know, 70 percent of the programs take exceptions from GALL says something that has to be looked at.

The second issue I would like to raise is the one of the audit report. The audit report is growing, and it's becoming almost a duplicate of the portion of the SER, but it's not written the same way. So, a reviewer, like the ACRS members, is puzzled by, you know, what information is there in one that is not in the other. Typically, there is none, but in some cases there is. So, you know, is there any way in which that two things can be meshed together and become one document only in the future.

So, these are the two issues I would like to raise, and again, the first one that I talked about may be significant enough to deserve a meeting at some point in the future, because it's not specific to Vermont Yankee, it's more generic to GALL.

MR. KUO: Thank you, Dr. Bonaca.

I'm P.T. Kuo, the Director of the Division

Title: **Flow Accelerated Corrosion Program**

Procedure Owner:	Oscar Limpias / Vice President Engineering
	(Print Name / Title)
Approved:	(Procedure Owner Signature) — 3/09/06 (Date)

Effective Date				Effective Date Exception				
	EN Common	☐			ANO		PNPS	
	ENN	☒	3/15/06		ECH		RBS	
	ENS	☐			GGNS		VY	
					IPEC		W3	
					JAF		WPO	

Procedure Contains NMM REFLIB Forms: YES ☐ NO ☐

Basis Statement

Re-defined Significant wall thinning
Deleted superseded procedure ENN-DC-133 from text and replaced with ENN-CS-S-008.
Added EPRI CHUG position Paper No.4 to references
Added "CHECWORKS Steam /Feedwater Application, Guidelines for Plant Modeling and Evaluation of Component Inspection Data to references.
Added Passport to text in section 4.4.11.
Added "degraded and deficient" components to text of section 4.4.16
Added threshold for generating condition reports to section 5.11.3
Added "except as provided below" and "Reference section 5.12.2" to section 5.12.1.
Added text "and it is determined that sample expansion" to section 5.12.2.
Added "deficient" to section 5.13.1
Edited various typos to section 8.
Edited logic diagram in attachment 9.3.
Re-indexed section 5.2 to 5.17
Add VY to ENN Fleet procedure.

This procedure supersedes the following site procedures:

- **ENN DC-315 Rev.0**
- **VY – PP7028**

Site and NMM Procedures Canceled or Superseded By This Revision

ENN-DC-315 Rev.0

Process Applicability Exclusion (ENN-LI-100) / Programmatic Exclusion (ENS-LI-101)

All Sites: ☐ Specific Sites: ANO ☐ GGNS ☐ IPEC ☐ JAF ☐ PNPS ☐ RBS ☐ VY ☐ W3 ☐

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1.0 PURPOSE

[1] The purpose of this procedure is to provide requirements for establishing and maintaining an effective Flow Accelerated Corrosion (FAC) Program that will standardize Entergy Nuclear Northeast Fleet's approach towards mitigating FAC damage.

[2] This procedure uses a systematic approach for long term monitoring to enhance the reliability of the affected FAC components by reducing the probability of failures and reduces maintenance costs associated with unplanned or unnecessary repairs.

[3] This procedure provides criteria and methodology for selecting components for inspection, performing inspections, gridding, evaluating inspection data, disposition of results, sample expansion requirements, piping repair /replacement criteria, program responsibilities and documentation requirements.

[4] This program is applicable to plant piping systems and feed water heater shells susceptible to FAC.

[5] This procedure may be used a guide for evaluating systems and components that don't meet the criteria of the FAC program.

2.0 REFERENCES

[1] NRC Generic Letter 89-08, Erosion/Corrosion Induced Pipe Wall Thinning.

[2] NUREG-1344, "Erosion/Corrosion-Induced Pipe Wall Thinning in U.S. Nuclear Power Plants."

[3] NSAC 202L, latest revision, EPRI Document, "Recommendations for an Effective Flow Accelerated Corrosion Program"

[4] EPRI Technical Report, TR-106611, "Flow-Accelerated Corrosion in Power Plants"

[5] NRC Bulletin No. 87-01, "Pipe Wall Thinning."

[6] ENN-LI-102, "Corrective Action Process."

[7] EPRI CHECWORKS FAC Application User's Guide/ CHECWORKS computer models.

[8] ENN-NDE-9.05,"Ultrasonic Thickness measurement"

[9] ANSI B31.1 "Power Piping", (For applicable code year see individual plant FSAR).

[10] ENN-DC-126, "Calculations".

[11] ENN-CS-S-008, "Pipe Wall Thinning Structural Evaluation".

[12] Site ASME XI Repair / Replacement Program as applicable.

[13] ENN-EP-S-005 "Flow Accelerated Corrosion Component Scanning and Gridding Standard".

[14] EPRI Report, "Single-Phase Erosion/Corrosion of Carbon Steel Piping", February 1987.

[15] EPRI Report - "Practical Consideration for the Repair of Piping Systems Damaged by Erosion/Corrosion", dated 10/5/87

[16] NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repairs of ASME Code Class 1, 2 &3 Piping".

[17] INPO SOER 87-3, "Piping Failures in High-Energy Systems Due to Erosion/Corrosion", March 1987.

[18] INPO Significant Operating Experience Report (SOER) 82-11, "Erosion of Steam Piping and Resulting Failure", February 1982.

[19] EPRI CHUG Position Paper #3, "A Summary of Tasks and Resources Required to Implement an Effective Flow Accelerated Corrosion Program."

[20] Entergy Quality Assurance Manual

[21] ENN FAC Qualification Card ENN-TK-ESPG-042, "Implementing the Flow Accelerated Corrosion Program ".

[22] JAF-SPEC-MISC-03290 Rev.0, "Specification for Evaluation and Acceptance of Local Areas of material, parts and components that are less than the specified thickness." By REEDY Engineering.

[23] IP3-SPEC-UNSPEC-02996 Rev.0, "Specification for Evaluation and Acceptance of Local Areas of material, parts and components that are less than the specified thickness." By REEDY Engineering.

[24] EPRI CHUG Position Paper No. 4, "Recommendations for Inspecting Feedwater Heater Shells for Flow Accelerated Corrosion Damage", February 2000.

[25] "CHECWORKS Steam /Feedwater Application, Guidelines for Plant Modeling and Evaluation of Component Inspection Data", EPRI No. 1009599, Final Report, September 2004.

3.0 DEFINITIONS

[1] Base Line Inspection – An initial wall thickness measurement of a component taken prior to being placed in service.

[2] Basis Document - Program documents that define the scope, attributes, commitments, evaluation reports and predictive models that forms the basis of the FAC program (i.e., System Susceptibility Evaluation reports). These documents contain the basis for the plant piping in the CHECWORKS model, the susceptible-not-modeled (SNM) piping and those that are non-susceptible.

[3] EPRI CHUG – EPRI CHECWORKS USERS GROUP.

[4] Code Minimum Thickness (Tmin) – The minimum required global wall thickness based on hoop stress.

[5] Critical Thickness (Tcrit) - The minimum required wall thickness per code of construction required to meet all design-loading conditions.

[6] Deficient Component - A component identified by examination to be below Taccpt wall thickness or projected to be below Taccpt wall thickness by the next refueling outage.

[7] Degraded component – A component identified as being below the screening criteria that is acceptable for continued operation.

[8] Examination - Denotes the performance of all visual observation and nondestructive testing, such as radiography, ultrasonic, eddy current, liquid penetrant and magnetic particle methods.

[9] Examination Checklist/ Traveler – A data sheet developed for the components being inspected and may contain but is not limited to the following: Tnom, Tmeas, Tmin, Screening criteria, components name, system number, previous data, inspection datasheet number, grid size, examination extent, work order and affiliated minimum wall calculation.

[10] Flow Accelerated Corrosion (FAC) - Degradation and consequent wall thinning of a component by a dissolution phenomenon, which is affected by variables such as temperature, steam quality, steam/fluid velocity, water chemistry, component material composition and component geometry. Previously known as Erosion/Corrosion.

[11] Grid - A pattern of points or lines on a piping component, where UT thickness measurements will be made. Grid may be permanently marked with circumferential and longitudinal grid lines.

[12] Grid Point – A Specific location on a piping component, where a UT thickness measurement will be made. Grid points are at the intersections of the circumferential and longitudinal grid lines.

[13] Grid Point Reading – UT reading taken at the intersection of the grid location.

[14] Grid Scan– 100% scan of the area between the grid lines. The lowest measurement in each area to be recorded as the measured thickness.

[15] Grid Size - The distance between grid points in the circumferential or longitudinal direction. Also called grid space or grid spacing.

[16] Initial Thickness (Tinit): The thickness determined by ultrasonic examination prior to the component being placed into service (baseline) or the first ultrasonic examination during its service life. If an examination has not previously been performed on the component, the initial thickness shall be determined by reviewing the initial ultrasonic data for that component. The area of maximum wall thickness within the same region as the worn area shall be identified and compared to Tnom. If the thickness is greater than Tnom, the maximum wall thickness within that region shall be used as Tinit. If that thickness is less than Tnom, Tnom shall be used as Tinit. Initial thickness for pipe may also be calculated as the nominal thickness multiplied by a factor of 1.125 (1.125*Tnom) for conservatism.

[17] Inspection Location - A specific component (i.e., elbow, tee, reducer, straight pipe section).

[18] Inspection Outage - the outage during which the component was inspected.

[19] Large-bore Piping - Piping generally greater than 2" nominal pipe size with butt-weld fittings.

[20] Line Scans– piping segments broken into one-foot lengths (Small-Bore pipe).

[21] Minimum acceptable wall thickness (Taccpt) – Maximum value of Tmin or Tcrit.

[22] Minimum Measured Thickness - (Tmeas or Tmm) as identified by ultrasonic thickness examination, the present thickness at the thinnest point on a component.

[23] Minimum required thickness – (Taloc) Minimum required pipe wall thickness for internal pressure based on local thinning requirements.

[24] Next Scheduled Inspection (NSI) -The outage at which an inspection will be performed on a given component.

[25] Nominal Thickness (Tnom) - Wall thickness equal to ANSI standard thickness.

[26] PASS 1 Analysis - Runs modeled in CHECWORKS that either have no inspection data, an insufficient number of inspections to provide a proper calibration, or where there is no expectation of ever developing a proper calibration.

[27] PASS 2 Analysis - The process of utilizing UT inspection data thickness measurements in CHECWORKS to predict wear and wear rates for components.

[28] Piping Segment - A run of piping that consists of inspection locations which have common operating parameters (i.e., temperature, pressure, flow rate, Oxygen content and pH level).

[29] Predicted Thickness (tp, Tpred) -The calculated thickness of a component based upon a rate of wear to some point in time (e.g., next refueling, next scheduled examination).

[30] Quadrant Scan– Piping segments divided in quadrants A, B, C, D that are 90 degrees apart and broken into one-foot lengths, or as specified by the FAC engineer.

[31] Qualified FAC Engineer- Individual who has completed the FAC Qualification Card, who participates in the Engineering Support Personnel (ESP) training program and demonstrates knowledge required for the use of the CHECWORKS computer program.

[32] Reference Point - The point on a piping component where the longitudinal and circumferential grid lines originate.

[33] Remaining Service Life (RSL) - The amount of time remaining based upon an established rate of wear at which the component is anticipated to thin to Taccpt.

[34] Safety Factor – A Margin of Safety used to account for inaccuracies in wear rate evaluation.

[35] Sample Expansion - The addition of inspection locations based on significant or unexpected wall thinning during planned inspection(s).

[36] Significant wall thinning - Wall thinning to a thickness less than 60% of pipe nominal wall thickness or wall thinning to a thickness that is half the remaining margin of the piping /component which is above Taccpt. [½ (0.875Tnom + Taccept)] or (Taccpt + 0.020) which ever is greater.

[37] Small-bore Piping - Piping that is generally 2" or less nominal diameter and that typically uses socket welded fittings.

[38] Subsequent Inspection - Inspection of components that have had a baseline inspection and/or an initial operational inspection.

[39] Susceptible Line - Piping determined to be susceptible to FAC using the EPRI susceptibility criteria in NSAC 202L, industry experience and as documented in the System Susceptible Evaluation.

[40] Susceptible Non-Modeled (SNM) Piping - A subset of the FAC susceptible lines that cannot be modeled using the EPRI CHECWORKS software.

[41] Time - Time in service shall be actual hours on line or of operation and/ or hours critical. Calendar hours may be used for conservatism.

[42] UT Datasheets - Paperwork that documents the results of the ultrasonic thickness inspections.

[43] Wear (W) - The amount of material removed or lost from a components wall thickness since baseline or subsequent to being placed in service.

[44] Wear Rate (WR) - Wall loss per unit time.

4.0 RESPONSIBILITIES

4.1 MANAGER, ENGINEERING PROGRAMS (ENNE FLEET PROGRAM OVERSIGHT)

[1] Providing a single point of accountability and is responsible for the overall health and direction of the FAC programs.

[2] Ensuring that the ENN FAC programs are effectively developed and implemented.

[3] Providing oversight for implementing the FAC programs.

[4] Co-ordinate FAC working group meetings.

[5] Co-ordinate ENN FAC Self-Assessments.

4.2 SUPERVISOR, CODE PROGRAMS

[1] Designate responsible engineer/Personnel from the Code Programs Engineering Group for the implementation and maintenance of the Flow Accelerated Corrosion Program.

[2] Ensure that the Flow Accelerated Corrosion Program activities are conducted in accordance with this procedure.

[3] Shall ensure that repair procedures are in place to support any planned repairs or replacements.

[4] Ensure audits and surveillance of selected Flow Accelerated Corrosion (FAC) activities are performed to verify compliance with applicable codes, procedures and drawings.

[5] Provides personnel to perform NDE during normal plant operation and unscheduled outages.

[6] Shall provide qualified Non-Destructive Examination personnel to perform flow accelerated corrosion inspections during scheduled refueling and maintenance outages.

[7] Provides personnel to perform reviews of all final FAC UT data sheets.

[8] Provides personnel to review vendor procedures, personnel certifications and equipment certifications.

[9] Assuring adequate technical personnel are available to provide required support services prior to the outage.

4.3 NDE LEVEL III OR DESIGNEE

[1] Reviews and approves FAC personnel and equipment certifications, and NDE procedures including revisions.

[2] NDE Level II or Level III reviews and signs all final FAC UT data sheets to ensure appropriate NDE examinations have been completed in accordance with the FAC program. The NDE level III review of Risk Informed examination shall be performed in accordance with the site ISI program requirements.

[3] Resolution of anomalies found in inspection data.

[4] Identify discrepancies or deficiencies and initiates condition report in accordance with FAC program or site protocols as appropriate.

[5] Performs oversight of selected FAC examinations to verify vendor procedure compliance.

[6] Performs functions in accordance with applicable procedures including the Entergy Quality Assurance Program.

4.4 FLOW ACCELERATED CORROSION ENGINEER

[1] Shall determine scope of inspections. The FAC Engineer shall develop a list of components/piping segments to be inspected prior to each outage using the criteria of NSAC-202L and CHECWORKS Pass1 and Pass 2 output as a guide. Previous

outage inspection results shall be reviewed prior to development of the inspection list. This list shall be based on the susceptibility to flow accelerated corrosion and the severities of wear identified from previous inspection results.

[2] Review and/or perform an engineering evaluation for all Flow Accelerated Corrosion inspections where pipe wall thinning has been identified and concur on any recommended action. Calculations shall be done in accordance with ENN-DC-126 & ENN-CS-S-008.

[3] Shall ensure that appropriate inspections are performed in accordance with the scope of the Flow Accelerated Corrosion Program.

[4] Shall review and may sign all inspection data and make recommendations for repair/replacement of piping materials in accordance with applicable site protocols.

[5] Shall provide NDE data for review and signature to the ANII, if requested by the ANII.

[6] Shall provide Risk Informed Inspection to the ANII for review and signature, if applicable.

[7] Develops or reviews program basis documents.

[8] Shall revise and/or expand the scope of the Flow Accelerated Corrosion inspection program to incorporate industry and in-house experiences and track/trend inspection results.

[9] Shall maintain records of all inspection results and inspection database.

[10] Develop a FAC examination checklist/traveler that contains Tnom, screening criteria, Taccpt, line number, etc. for the components being inspected.

[11] Shall initiate request for engineering services in accordance with the MAXIMO/PASSPORT or site specific work control system for piping replacement or engineering evaluations as required. This request should include recommended materials for replacement and configuration changes, if applicable, to reduce the effects of flow accelerated corrosion.

[12] The FAC Engineer shall periodically review completed plant modifications to assess their effect on the scope of the flow accelerated corrosion program.

[13] The FAC Engineer shall assist in vendor oversight as required.

[14] Maintaining control of the predictive models (CHECWORKS), which includes any development, updates or revisions to the models.

[15] Developing, revising, and issuing FAC program documents.

[16] Initiating and/or responding to Condition Reports and Engineering Requests for evaluating degraded and deficient components or other discrepancies or deficiencies within the scope of the FAC program.

[17] Developing post outage inspection summary reports.

[18] Review and disposition Operating Event (OE) notices for applicability to the FAC program.

[19] Analyzing inspection data to determine component acceptability for continued service and to determine the need for sample expansion.

[20] Prioritizing and ranking inspection in terms of susceptibility and consequence of failure.

[21] Develop and maintain the System Susceptibility Evaluation report.

4.5 DESIGN ENGINEERING/RESPONSIBLE ENGINEER

[1] Provide minimum acceptable wall thickness (Taccpt) to the FAC Engineer. Responsibility may be delegated to another department or qualified personnel.

[2] Perform local wall thinning evaluations for components having UT measurements that are below or are projected to go below the minimum acceptable wall thickness (Taccpt) or administrative wall thickness requirement.

[3] Prepare and issue engineering response packages for component requiring replacement. Responsibility may be delegated to another department or qualified personnel.

[4] Perform remaining service life evaluation for components in the FAC program as required.

4.6 MAINTENANCE SUPERVISOR/DESIGNEE

[1] The maintenance supervisor or designee will ensure that adequate craft personnel are available to support the FAC program. The supervisor shall ensure that scaffolding is erected, when needed, and insulation removed from components/piping segments that will be inspected and that the piping is prepared for inspection. Scaffolding erection in safety related areas should be in accordance with site procedures.

[2] The maintenance supervisor or designee shall inform the FAC engineer when it is necessary to remove a pipe support for inspection. An engineering evaluation is required if a pipe support requires removal.

[3] The maintenance supervisor must ensure that surfaces to be inspected are free from all foreign materials that would interfere with the inspections, i.e., dirt, rust, paint, etc. If cleaning is required, this may be accomplished by power sanding, flapper wheel only) hand wire brushing, or hand sanding in accordance with site procedures/protocols.

[4] The maintenance supervisor shall ensure restoration of lines, i.e. insulation replaced, scaffolding removed, upon completion of the FAC inspection.

4.7 FAC INSPECTION COORDINATOR

[1] A FAC coordinator may be chosen to Implement the activities of the inspection plan, the duties may include but is not limited to the following activities:

(a) Performing component walk downs

(b) Generating NDE inspection packages

(c) Defining NDE staffing as required

(d) Scheduling of inspections

(e) Acquiring data as required

(f) Providing field coordination to ensure timely inspection are accomplished

(g) Tracking progress of the FAC inspection project

(h) Transmitting inspection results to the FAC Engineer

5.0 DETAILS

5.1 PRECAUTIONS AND LIMITATIONS

None.

5.2 ANALYSIS/PRE-EXAMINATION

[1] The criteria contained in NSAC-202L, latest revision, shall be used to perform the System Susceptibility Evaluation (SSE).

[2] The System Susceptibility Evaluation report shall be developed and peer checked in accordance with ENN procedures.

[3] Non-typical operation of systems should be taken into consideration and if necessary factored into the FAC program.

[4] The susceptible small-bore piping inspection priority ranking should consider personnel safety, consequence of failure and plant unavailability.

[5] Industry and plant experiences relating to FAC will be factored into the program.

[6] The CHECWORKS model should be used for guidance in determining inspection priority based on relative ranking for specific locations to be examined for FAC damage.

5.3 PREPARATION OF OUTAGE INSPECTION PLAN

[1] The FAC Program Engineer shall prepare an Outage Inspection Plan prior to the outage to meet site milestones.

[2] The Outage Inspection Plan should consider the cost of repair/replacement versus inspection.

[3] The Outage Inspection Plan should consider inspection priority based on relative ranking for specific locations to be examined for FAC damage.

[4] Each identified location shall be documented in the inspection plan, along with the component number and reason for selection.

[5] The inspection plan shall be reviewed.

[6] Component Selection

(a) The FAC engineer shall prepare a FAC Outage Inspection scope as directed by plant milestones or as directed by Station management.

(b) Inspection selections shall be made in accordance with the requirements of this procedure and shall be identified based on CHECWORKS results, industry/station/utility experience, required re-inspections, the non- modeled program piping and engineering judgment.

(c) If a selected inspection location is determined to be excessively difficult, impractical or costly to examine due to inaccessibility, temperature, ALARA concerns, scaffolding requirements, or other factors, then an equivalent alternate inspection location may be selected.

(d) Components selected shall be formally documented.

(e) The criteria for component selection should consider the following:

(1) Components selected from measured or apparent wear found in previous inspection results.

(2) Components ranked high for susceptibility from current CHECWORKS evaluation.

(3) Components identified by industry events/experience via the Nuclear Network or through the EPRI CHUG.

(4) Components selected to calibrate the CHECWORKS models.

(5) Components subjected to off normal flow conditions. Primarily isolated lines to the condenser in which leakage is indicated from the turbine performance monitoring system.

(6) Engineering judgment / Other

(7) Piping identified from Work Orders (malfunctioning equipment, leaking valves, etc.).

(8) Susceptible piping locations (groups of components) contained in the Small Bore Piping database, which have not received an initial inspection.

(9) Piping identified from Condition Reports/ Corrective action, Work Orders (malfunctioning equip, leaking valves, etc.).

(10) Feed water Heater Shells

[7] Inspection schedule

(a) Inspection sequence and schedule should be developed based on priority established by the FAC engineer considering repair/scope expansion potential. Consideration will also be incorporated based on other outage work priorities, job conflict and system window duration.

(b) The FAC outage schedule should contain sufficient time for analysis and evaluations of the components being inspected.

[8] Drawing Preparation

(a) For each component scheduled for inspection, an isometric or other acceptable location drawing should be prepared prior to the outage that identifies the component to be examined. When applicable ensure the component number is shown on the drawing.

[9] Obtain Minimum Acceptable Wall Thickness (Taccpt)

(a) Obtain Taccpt (maximum of Tmin or Tcrit) values for each component to be inspected. Those values may be obtained as required, prior to or during an outage.

(b) These criteria may be obtained from engineering calculations or by other approved methods.

[10] Component Identification

(a) Inspected components should have a unique identifier to allow for the tracking of inspection data.

(b) Component identifiers may allow for the identification of the Unit, system, sub-system, line number and corresponding location of that component within a sub-system.

(c) Components in the CHECWORKS non-modeled piping may be identified by using line numbers.

[11] Pre-inspection Activities

(a) Review inspection schedule, inspection requirements and sequence with appropriate plant personnel to ensure requirements for the completion of the FAC inspection are understood.

(b) The FAC engineer should participate in the preparation of FAC inspection work packages as required.

5.4 GRIDDING

[1] Gridding of components shall be performed in accordance with recommendation of NSAC 202L, ENN-EP-S-005 or as specified by the FAC engineer.

[2] Gridding information shall be documented on the appropriate NDE UT data sheet; a sketch may also be required.

5.5 NDE TEST METHODS AND DOCUMENTATION

[1] Components can be inspected for FAC wear using ultrasonic testing (UT), radiography testing (RT), visual observation or other approved methods.

[2] UT thickness measurement is the primary method of determining pipe wall thickness.

(a) Inspections will be performed by using one of the following techniques:

(1) Grid Point Reading

(2) Grid Scan

(3) Quadrant Scan

(4) Line Scan

[3] Ultrasonic Thickness measurement shall be performed in accordance with ENN-NDE-9.05 or other approved site or vendor procedures.

[4] UT Data sheets

(a) A data sheet for components inspected shall be prepared. The information included in the sheet should contain but is not limited to the following:

(1) Plant's name/unit

(2) Components name

(3) Component sketch

(4) NDE technician signature/ date

(5) Grid size

(6) Axial and radial grid boundaries

(7) Calibration information

(8) Level II or Level III signature/date

(9) Work order information

(10) Nominal & Measured thickness

(11) 87.5% nominal thickness screening criteria

(12) Scanning method

5.6 EVALUATION OF UT INSPECTION DATA

> **NOTE**
>
> Historically, typical manufacturing practice has been to supply fittings (especially tees, elbows and reducers) with wall thickness significantly larger than the piping nominal thickness.

[1] The data review should consider screening for further evaluation. Factors that should be considered when reviewing the inspection data include unknown initial thickness (especially fittings), counter-bore, obstructions, and manufacturing wall thickness variations.

[2] For each component that is examined and is below the screening criteria of 87.5% of nominal wall, the wear, wear rate, remaining service life shall be calculated.

[3] The FAC Program Engineer or designee shall review the UT data to ensure that the data is complete and corresponds to the requirements specified on the inspection data sheet (i.e., grid size, spacing, flow direction, starting and ending locations, obstructions, missing data, suspect readings and orientation).

[4] If low readings are determined from repeat inspections that are due to counter-bore, then those areas shall be noted and additional inspections are not required.

[5] Grid Refinement

(a) A grid reduction / refinement may used if the minimum measured thickness is less than the minimum required wall thickness, severe wall thinning is detected, engineering judgment, or the projected thickness is less than the minimum required wall thickness or as directed by the FAC engineer.

(b) The results of the grid refinement or scan shall be documented on an inspection data sheet.

[6] Grid Extension

(a) If measurement indicates wall loss at either edge of the grid, then the grid should be extended until the entire wear pattern is mapped.

[7] Determination of Initial Wall Thickness

(a) For fittings, the band, area and blanket methods calculate wear. Initial Thickness (Tinit): *The thickness determined by ultrasonic examination prior to* the component being placed into service (baseline) or the first ultrasonic examination during its service life. If an examination has not previously been performed on the component, the initial thickness shall be determined by reviewing the initial ultrasonic data for that component. The area of maximum wall thickness within the same region as the worn area shall be identified and compared to Tnom. If the thickness is greater than Tnom, the maximum wall thickness within that region shall be used as Tinit. If that thickness is less than Tnom, Tnom shall be used as Tinit.

(b) Initial thickness for pipe may be calculated as the nominal thickness multiplied by a factor of 1.125 (1.125Tnom) for conservatism.

[8] Determination of Wear

(a) Wear of piping components may be evaluated using the band, area, blanket or point-to-point method as defined in NSAC-202L, latest revision.

(b) Evaluation of inspection data that is determined to require wear evaluation shall be documented and reviewed.

[9] Wear rate Determination

(a) Wear rate is determined by wear/ unit time (Units to be consistent with thickness evaluation).

(b) A reasonable safety factor may be applied to the wear rates to account for inaccuracies in the FAC wear rate calculations.

(c) Wear rate evaluation should be evaluated on a component evaluation sheet.

[10] Predicted Thickness (tp, Tpred)

(a) The projected or predicted thickness to the next schedule refueling outage.

Tpred = Tmeas – Safety factor x Wear Rate x Time

A safety factor of 1.1 may be applied to ENN plants. If a value other 1.1 is used the reason shall be documented.

[11] Determination of Remaining Service Life (RSL)

(a) Remaining service life (RSL) shall be evaluated as follows, units to be consistent with thickness evaluation:

RSL = (Tmeas – Taccpt) / (Safety Factor x Wear Rate)

5.7 EVALUATION OF RT INSPECTION DATA

[1] Qualified NDE personnel shall interpret the film and report the examination result to the FAC engineer.

[2] Appropriate conservatism should be used to determine if a component requires replacement or re-inspection as a consequence of qualitative nature of RT.

[3] RT inspection shall be recorded on a data sheet.

5.8 EVALUATION OF VISUAL INSPECTION DATA

[1] Where accessible, visual inspections may be performed on two-phase flow lines.

[2] Follow-up UT inspection is required for locations showing evidence of extensive wear.

[3] Due to the qualitative nature of visual inspections, appropriate conservatism should be used when determining whether a component is acceptable to return to service and when establishing a re-inspection frequency.

5.9 DISPOSITION OF INSPECTION RESULTS

[1] The following are used to disposition component inspection results. Reference attachment 9.3 for logic diagram

NOTE

Certain components may have very little margin remaining as a consequence of high stresses in the line even though Tpred ≥ 0.875Tnom and therefore may require evaluation, for example Feedwater, Condensate, RHR, etc.

[2] If Tpred ≥ 0.875 Tnom the component is acceptable as is and may be returned to service.

[3] If Tpred is ≤ 0.875 Tnom Evaluate for sample expansion (Reference section 5.12).

[4] If Tpred ≤ 0.3 Tnom for safety related piping repair or replacement is required.

[5] If Tpred < 0.2 Tnom, for non-safety related, repair, replace or evaluate as warranted.

[6] If Tpred ≥ Taccpt the component is acceptable for continued operations, however monitoring is required.

[7] *Tpred is <Taccpt a structural evaluation per ENN-CS-S-008 is required, also a sample* expansion evaluation is required or repair or replace in accordance with the requirements of ASME Section XI Repair and Replacement Program.

[8] If Tmeas is <Taccpt a structural evaluation per ENN-CS-S-008 is required.

5.10 RE-INSPECTION REQUIREMENT

[1] If the remaining service life of a component is greater than or equal to the number of hours in the next operating cycle, then the component may be returned to service.

[2] If the component's remaining life is greater than the number of hours in the next operating cycle but is less than the number of hours in the next two operating cycles, then the component should be considered for re-inspection, repair or replacement during the next scheduled outage.

[3] If the component is acceptable for continued service, then it shall be re-examined before or during the outage immediately prior to the cycle during which it is projected to wear to the minimum allowable wall thickness.

5.11 COMPONENTS FAILING TO MEET INITIAL SCREENING CRITERIA

[1] If the results of the remaining life evaluation are shorter than the amount of time until the next scheduled inspection, there are several options for disposition of the component, as follows:

(a) *Shorten the inspection interval (for components that can be inspected online)*

(b) Refine the Taccpt value through a detailed stress analysis, which should be provided by Design Engineering.

(c) Repair or replace the component

(d) *Safety class components that are less than or equal to 0.3Tnom must be* replaced or further structural evaluation is required.

[2] Wall thinning resulting in less than Taccpt shall be reported immediately to the FAC engineer by verbal or written communications.

[3] A condition report shall be generated when significant wall thinning or unexpected wear is detected in a system or component.

[4] A condition report shall be generated for wall thinning below Taccpt or other site established limit and a subsequent structural evaluation performed to disposition the line for continued service.

[5] If a previous condition report was generated for a component with wall thinning then no new condition report is required provided that the associated structural evaluation is current and applicable.

5.12 SAMPLE EXPANSION

[1] If a component is discovered that has a current or projected wall thickness less than the minimum acceptable wall thickness (Taccpt), then additional inspections of identical or similar piping components in a parallel or alternate train shall be performed to bound the extent of thinning except as provided below. Reference section 5.12.2

[2] When inspections of components detects significant wall thinning and it is determined that sample expansion is required, the sample size for that line should be increased to include the following:

(a) Components within two diameters downstream of the component displaying significant wear or within two diameters upstream if the component is an expander or expanding elbow.

(b) A minimum of the next two most susceptible components from the relative wear ranking in the same train as the piping component displaying significant wall thinning.

(c) Corresponding components in each other train of a multi-train line with a configuration similar to that of the piping component displaying significant wall thinning.

[3] If the expanded inspection scope detects additional degradation, the sample expansion should continue until no additional components with significant wear are detected.

[4] Sample expansion is not required if the thinning was expected or if the thinning is unique to that component (e.g., degradation downstream of a leaking valve).

[5] Inspections of components from the current or past outages may satisfy the sample expansion criteria, therefore, some of the sample expansion requirements can be met without performing additional inspections.

[6] Sample expansion is not required for components that are being re-inspected if normal or expected wear is detected or wear unique to that component. All other wear patterns encountered shall be evaluated by the FAC Engineer to determine if sample expansion is required.

5.13 REPAIR / REPLACEMENT OF DEGRADED COMPONENTS

[1] The FAC engineer shall generate applicable documents to facilitate repair or replacement of degraded or deficient components.

[2] Components experiencing severe or unacceptable wear should be replaced with corrosion resistant material. However like in kind may be appropriate if procurement of a resistant material would delay plant restart.

[3] Replacing fitting-by-fitting that have experienced significant wear is a satisfactory approach to reducing wear if the wear is very localized (i.e., wear is concentrated downstream of a flow control valve or orifice).

[4] Repairs and replacements to piping and components within the scope of Class 1, 2, 3 shall be performed in accordance with the requirements of ASME Section XI Repair and Replacement Program.

[5] All temporary non-code repairs to ISI Class 1, 2, 3 shall comply with NRC Generic Letter 90-05.

5.14 COMPONENT EVALUATION PACKAGES

[1] The FAC Engineer or designee shall assemble a component evaluation package for each examined component which may contain some of, but is not limited to the following:

(a) UT DATA Sheet

(b) Isometric drawing(s), sketches, flow diagram and digital photo.

(c) Reference to Structural /Minimum wall evaluation

(d) Component evaluation data sheet.

5.15 POST- INSPECTION ACTIVITIES

[1] The FAC Program Engineer shall prepare an Outage Summary report to document the outage FAC activities and submit to Records for retention in accordance with applicable procedures.

[2] Update CHECWORKS models with inspection data.

[3] Update small bore susceptible report as applicable

[4] Update all applicable FAC reports.

[5] Update FAC System Susceptible Report as required.

5.16 LONG TERM STRATEGY

[1] The ENNE long-term strategy for increased safety, reduced costs and reduced FAC rates is accomplished through optimization of the inspection planning process, the use of improved materials for replaced components, improved water chemistry, and appropriate design changes.

5.17 METHODS OF DETERMINING PLANT PERFORMANCE

[1] Program performance indicators, self- assessments and bench marking are utilized as methods for monitoring program and plant performance.

6.0 INTERFACES

[1] ENN-CS-S-008, "Pipe Wall Thinning Structural Evaluation".

[2] ENN-EP-S-005 "Flow Accelerated Corrosion Component Scanning and Gridding Standard".

7.0 RECORDS

[1] Record retention shall be in accordance with site procedures.

8.0 OBLIGATION AND REGULATORY COMMITMENT CROSS-REFERENCES

[1] OBLIGATIONS AND COMMITMENTS IMPLEMENTED OVERALL

Document	Document Section	NMM Procedure Section	Site Applicability
QAPM	A6a, A6b, A6c, A6e	All	All
QAPM	B12a, b, c, d, e,f	All	All
QAPM	B15 a, c	All	All
8.0[1](a)	All		JAF
8.0[1](b)	All	All	JAF
8.0[1](c)	All		IPEC Unit 3
8.0[1](d)	All	All	IPEC Unit 3
8.0[1](e)	All	5.12	All
8.0[1](f)	All		IPEC Unit 2
8.0[1](g)	All	All	Pilgrim
8.0[1](h)	All	All	Vermont Yankee
8.0[1](i)(j)	All		Vermont Yankee

(a) JAFP 87-0737, JAFNPP Docket No. 50-333, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants.

(b) JPN-89-051, JAFNPP Docket No. 50-333. Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.

(c) IP3-87-055Z, Docket No. 50-286, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants.

(d) IPN-89-044, Docket No. 50-286. Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.

(e) NRC Generic Letter 90-05, "Guidance for Performing Temporary Non-Code Repairs of ASME (ISI) Code Class 1, 2, 3 Piping".

(f) Mr. Murray Selman (Con Edison) to Mr. William Russell (NRC) "Response to NRC Bulletin No. 87-01, Letter dated September 11, 1987.

(g) BECo 89-107, Docket 50-293, Response to NRC Generic Letter 89-08 Erosion/ Corrosion Induced Pipe Wall Thinning.

(h) Vermont Yankee letter to USNRC, FVY-89-66, Docket No. 50-271. Vermont Yankee Response to NRC Generic Letter 89-08," Erosion/ Corrosion Induced Pipe Wall Thinning", Dated July14, 1989.

(i) Vermont Yankee letter to USNRC, FVY-87-94, Docket No. 50-271, Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants. Dated September 11, 1987.

(j) Vermont Yankee letter to USNRC, FVY-87-121, Docket No. 50-271, Supplement to Vermont Yankee Response to NRC IE Bulletin 87-01 Thinning of Pipe Walls in Nuclear Power Plants. Dated December 24, 1987.

9.0 ATTACHMENTS

Guidance on Parameters affecting FAC.

Flow Accelerated Corrosion Program Attributes.

Wall Thinning Evaluation Process Map.

GUIDANCE ON PARAMETERS AFFECTING FAC

Listed below are factors to be considered when reviewing work requests, component replacements and modification packages for possible impact on the content of the FAC Program governed by DC-315. All Design Change Packages (DCP's) are required to be evaluated for impact to the FAC Program. This list is not intended to be all-inclusive or to limit the number of items an individual would consider when performing this impact assessment. It is intended as a reasonable list of items to consider for potential program content updates.

1. Water Chemistry. Many water chemistry parameters have been shown to contribute to FAC.

    a. pH Control Amine – pH is the primary chemistry parameter affecting FAC rates in PWRs. However, the amine used to control pH also plays an important role. Amines such as ammonia tend to separate more into the steam phase in two-phase flow conditions, and therefore provide less protection in the drains. Amines such as morpholine and especially ethanolamine have better partitioning characteristics for FAC.

    b. In a BWR, pH has much less of a role since the pH is stable and there are no amine's added to control the pH. FAC rates decrease as pH level increases. FAC rates seem to drop considerably at pH values of greater than 9.3 - 9.5.

    c. Oxygen Content - FAC rates decrease as oxygen concentration increases. Values that typically result in minimum FAC rates are approximately 15 to 20 ppb.

    d. Hydrogen Water Chemistry – BWR Plants that do not have hydrogen addition normally have a main steam oxygen content near 18 ppm. Plants with hydrogen water chemistry typically have an oxygen content from 3 to 12 ppm. This has a potential to impact the corrosion rates in the LP steam systems; mainly the first and second stage reheater drains based on industry experience.

    e. Hydrazine Injection - Hydrazine is added to the feed train of PWRs as an oxygen scavenger and to maintain a reducing environment in the steam generators. From zero to approximately 150 ppb,an increase in hydrazine concentrations seems to increase rates of FAC. Higher concentrations seem to result in no further increase in FAC rates. EPRI recommends the use of high levels of hydrazine (>100 ppb) to protect steam generator tubes; however, this can result in accelerated rates of FAC in the feed train. Although CHECWORKS does not currently model high hydrazine conditions, any model updates performed after the release of version 1.0F should carefully consider hydrazine concentrations.

f. Zinc Injection - Industry experience has shown that zinc injection decreases corrosion and FAC wear rates due to the concentration of zinc at the oxide surface. The amount of reduction depends on the amount of zinc at the surface.

2. Piping Geometry - Piping geometry is one of the most important factors in FAC. Generally, geometries that produce the greatest turbulence also produce the highest FAC rates. Listed below are examples of obvious items that should be considered in any assessment:

a. Addition or replacement of fittings, bends and branch connections.

b. Like for like replacement of any fitting in a system that is susceptible to FAC damage or is part of system that is already part of the FAC Program.

c. Alterations or repairs encountered in the nozzles or walls of FW heaters, MSR, Drain Tanks, FW Pumps, HD Pumps or CD/CB Pumps.

d. Throttled Valves.

3. Piping Material Composition - Alloying elements improve the resistance of piping systems to FAC. In ascending order of resistance, the following table presents the degree of improvement over carbon steel:

Material	Nominal Composition	Rate (carbon steel) / Rate (alloy)
P11	1.25% Cr, 0.50% Mo	34
P22	2.25% Cr, 1.00% Mo	65
304	18% Cr	>250

4. In-Line Components - Addition or replacement of such components as thermowells, flow elements and pressure-reducing orifices should be evaluated. The local effects caused by these components can generate FAC damage in areas where overall conditions don't indicate the need for inspections.

5. Component Supports - Additions or deletions of components supports which could result in the need for a review of the existing code minimum wall value or a new code minimum wall calculation.

6. Operational Changes - System operational changes such as the normal operation of emergency heater drains, switching of spare components, extended use of normal start-up or by-pass lines, etc.

7. Component Replacements – Records should be updated for like for like replacement of fittings already in the program including new baseline data, changing next scheduled inspection due date, etc. Note and track whether the replacement components have had surface preparation and a UT grid applied for future outage planning.

8. External Sources – Information concerning FAC Inspection results from other stations and Nuclear Plants operated by others. General information distributed by EPRI Reports, INPO & NRC Bulletins, etc. should also be considered.

9. Maintenance History – A review of the maintenance performed on valves, orifices, steam traps, etc. should be considered. Valves that have had seat leakage can cause very localized wear in systems normally exempted. Plugged traps create water pockets in steam systems that accelerate metal loss. Eroded orifices can cause increased metal loss due to decrease in back pressure and increase in flow rates.

PROGRAM ATTRIBUTES

Attributes:

Program Infrastructure

(a) Program Structure: Roles & Responsibilities, Program Ownership, Organizational Interfaces, etc.
(b) Flow Accelerated Corrosion Program Document.
(c) Flow Accelerated Corrosion System Susceptibility Review, Latest Revision.
(d) Report(s) Summarizing the Augmented portion of the FAC Inspection program, Latest Revision.
(e) CHECWORKS models

Program Staffing and Experience

(a) Background and Expertise.
(b) Qualification and training.
(c) Bench Strength.
(d) Industry Participation.

Program Implementation

(a) Inspections
(b) Maintenance and Repairs
(c) Control of Changes and Deferrals
(d) Review of INPO Operating Experience documents, CHUG operating experience, NRC notices.

Health Monitoring:

(f) System Engineering Health reports.
(g) FAC Quarterly Health Reports.

Effective Assessment:

(h) Perform FAC Self-Assessment on a periodic basis or as defined by applicable procedures.

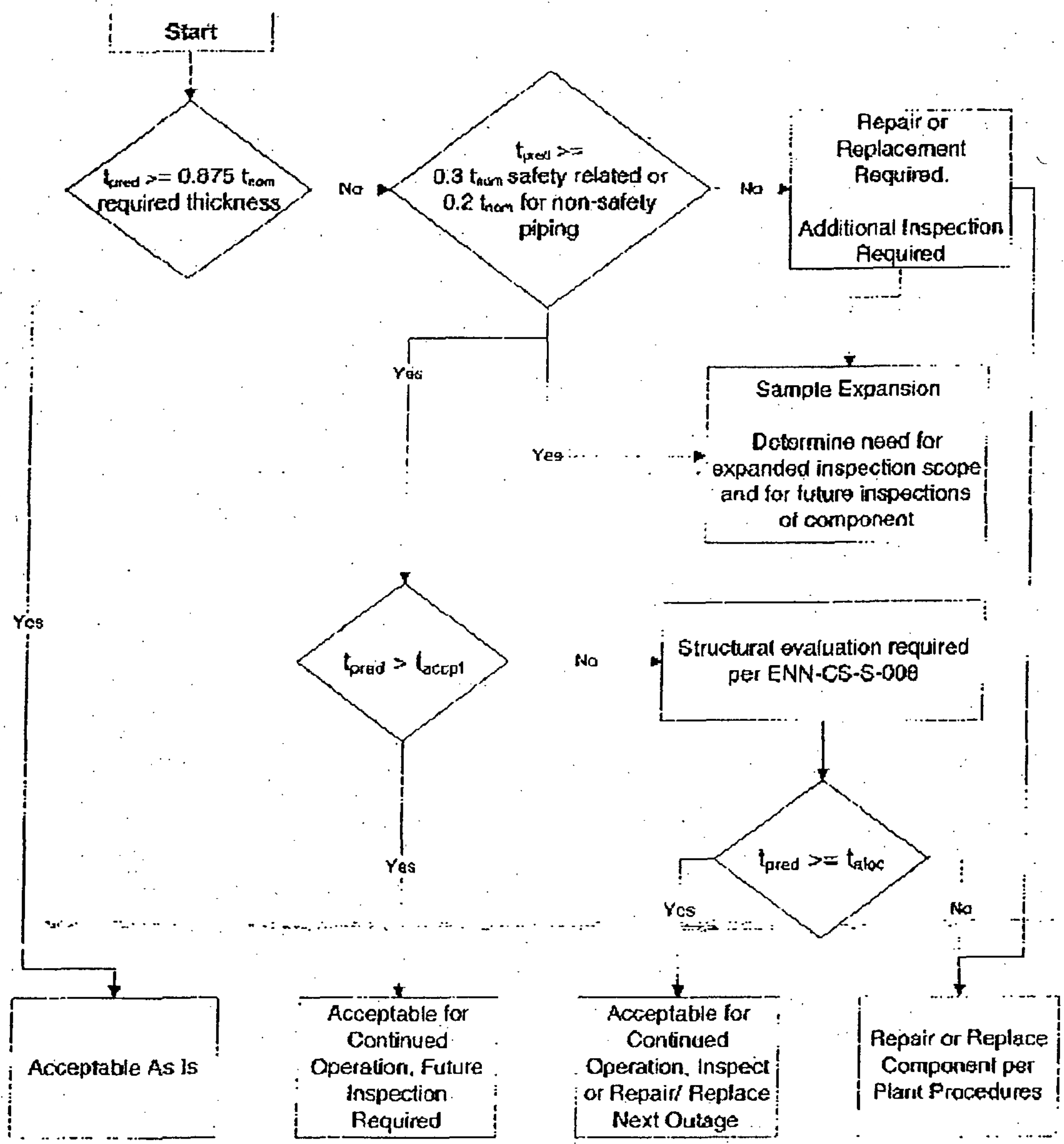
Oversight:

(k) Effective assessment, Benchmarking or Audits.

ATTACHMENT 9.3 — WALL THINNING EVALUATION PROCESS MAP

Sheet 1 of 1

Logic Diagram - Evaluation of Pipe Wall Thinning



Chockie Group International, Inc.

Aging Management and Life Extension in the US Nuclear Power Industry

October 2006

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PSA Project Reference Number: NO 99B16

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Executive Summary

All systems and equipment degrade over time. However, the nature and the rate of degradation depend on such factors as the design, material, construction, mode of operation, and operating environment. With effective inspection and maintenance practices aging degradation can be managed and operational life can be extended well beyond what was originally planned. For over 25 years the United States (US) nuclear power industry and the US Nuclear Regulatory Commission (USNRC) have worked together to develop aging management programs that ensure the plants can be operated safely well beyond their original design life.

This report was prepared by the Chockie Group International to provide an overview of the aging management and life extension programs and regulations within the US commercial nuclear power industry and their possible applicability to the petroleum industry in Norway. It was prepared as part of the project for the Petroleum Safety Authority (PSA) Norway entitled, *Design Life Extension Regulations* (PSA Project Reference Number: NO 99B16).

Associated with this report are two companion briefing reports that provide focused examinations of two important aspects of life extension requirements. These are *Performance Monitoring of Systems and Active Components* (CGI Report 06.21) – an examination of the Maintenance Rule requirements for effective maintenance programs, and *Condition Monitoring of Passive Structures and Components* (CGI Report 06.22) – a review of the License Renewal Rule requirements and process for aging management of passive and long-lived structures and components.

There are three important principles associated with aging management. These are:

- maintaining the structures, systems, and components (SSCs) in "as new" condition – with no reduction in performance or safety margins
- preventing failures of critical SSCs
- understanding and managing the age-related degradation mechanisms

During the operating life of a plant these aging management principles should be an integral part of the maintenance program. However, when contemplating life extension another set of issues must be considered. As the US nuclear industry and the USNRC concluded, in order to extend the operating life beyond the original design life additional economic and technical factors need to be considered.

Although the possibility of life extension for nuclear plants in the US has existed for more than 50 years, the industry and regulator have been actively developing life extension requirements for only the last 25 years. In 1954 the original licensing requirements for US nuclear power plants set a 40-year limit for operating licenses. This 40-year limit was selected based on economic considerations rather than technical limitations. However, even at that time, the Atomic Energy Act was set up to allow renewal of the operating licenses.

In the late 1970s the USNRC and the nuclear industry began to address the issues concerning life extension. The first initiatives were directed at determining whether or not the safe operation of the plant beyond its 40-year operating limit could be technically justified. That is, could the aging effects be adequately managed so the plant could be operated within the original safety margins during the period of extended operation?

To answer this question both the USNRC and the industry initiated a number of aging research programs. One of the largest aging research efforts was the Nuclear Plant Aging Research (NPAR) Program. This 10-year, multi-million dollar effort was sponsored by the USNRC and produced over 150 aging research reports. Other aging research programs by the industry complimented the work of the NPAR program. Based on the results of these programs it was concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. As long as there are effective inspection and maintenance practices the plant life is simply limited by the economic cost of repair or replacement of any components that do not meet specified acceptance criteria.

The USNRC then moved forward with the development of license renewal requirements and published the initial License Renewal Rule in 1991.

For over fifteen years the USNRC and the nuclear industry have been continuously refining both the license renewal requirements and the renewal process. There are many aspects of these efforts and lessons learned that can be of potential value to the PSA and the Norwegian petroleum industry.

The following are some of the key lessons from the development and implementation of aging management programs and life extension requirements that could be applicable to the PSA and the Norwegian petroleum industry in their consideration of life extension and aging management.

Aging Research Information

The wealth of aging related information produced by the NPAR and industry aging research programs remains a useful resource for both nuclear and non-nuclear organizations. Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors.

Continuous Improvement

Over the years both the USNRC and the industry have been working to make the license renewal requirements and the renewal process more efficient and effective. For example, the initial version of the License Renewal Rule did not provide a predictable nor stable process – it was too open ended and too broad a scope. It was determined that many aging effects were already adequately addressed during the initial operating license period. Also, the initial Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena as part of the on-going maintenance program tasks.

The resulting revised Rule established a simpler, more stable, and more predictable regulatory process. The key changes that were made included:

- focusing on the adverse effects of aging rather than identification of all aging mechanisms such that identification of individual aging mechanisms is not required
- simplifying the integrated plant assessment process and making it consistent with the revised focus on the detrimental effects of aging
- adding an evaluation of time-limited aging analyses (TLAA)
- requiring only passive, long-lived structures and components to be subject to an aging management review for license renewal, thus removing active SSCs from license renewal

Passive Versus Active

An important aspect of the US nuclear plant life extension requirements is the distinction between passive and active systems, structures, and components. Passive SSCs are those that do not move to function (such as structures, heat exchangers, cables, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements).

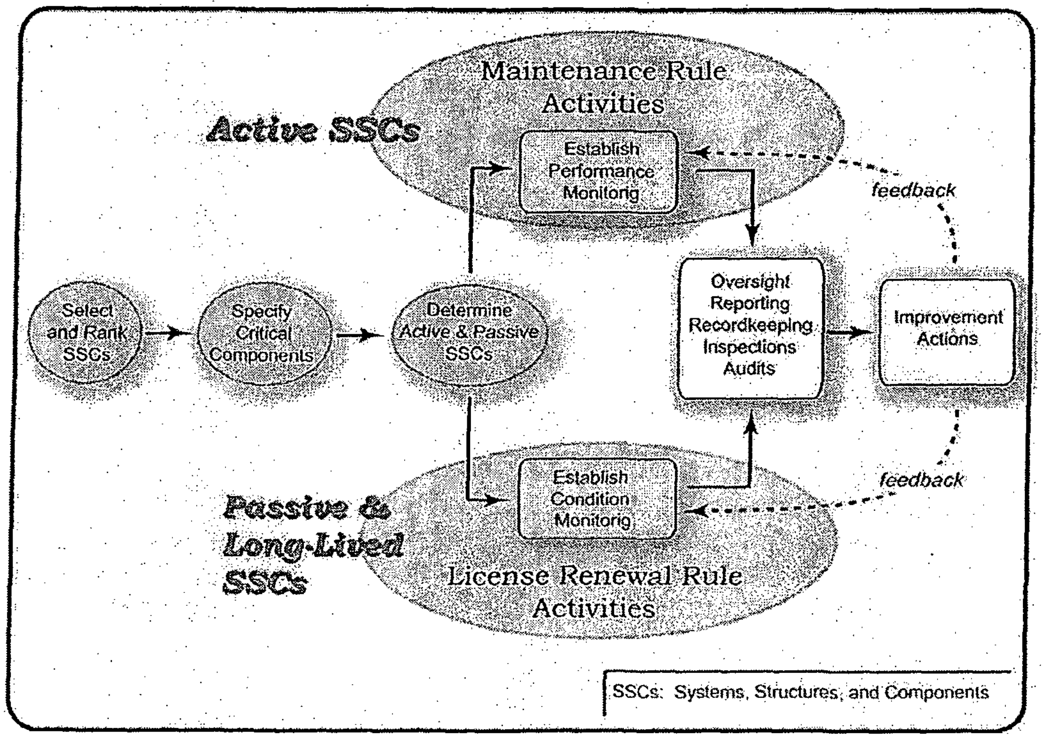
By focusing the license renewal process on safety critical passive and long-lived components the process has been reduced to manageable proportions – licensees are not required to consider all SSCs in order to justify extended operations.

A diagram of the relationship of the License Renewal and Maintenance Rules to the aging management of active and passive SSCs is shown in the figure on the next page.

During the renewal process, the licensee must confirm whether the original design assumptions will continue to be valid throughout the period of extended operation or whether aging effects will be adequately managed. The licensee must demonstrate that the effects of aging will be managed in such a way that the intended functions of passive or long-lived structures and components will be maintained during extended operation.

Need for Guidance

One of the key lessons has been the need to provide clear guidance and support to all involved parties. Both the USNRC and the industry have developed guidance documents to assist in the development of aging management programs, the preparation of the renewal application, and the review of the application. As lessons are learned these guidance documents are revised to capture new insights or address emerging issues. Along with the guidance documents, training programs and support activities have greatly reduced the time and expense in preparing, reviewing, and approving the license renewal applications.



Other Aging Management Lessons Learned

In reviewing the aging management and life extension efforts of the nuclear industry there are several areas where the experiences of the US nuclear power plants and USNRC could be of value to the PSA and the petroleum industry. These include:

- integrating aging management and maintenance requirements – careful management to avoid duplication of effort and non-effective maintenance tasks
- developing a long-term maintenance strategy – linking asset management to maintenance strategy with the objective to preserve the assets as long as economically feasible
- reducing component failures – being proactive to identify incipient failures, precursors, and age related degradation.
- effectiveness of condition monitoring – improving the application of diagnostic analysis to prevent failures.
- establishing appropriate inspection procedures
- aging management of inaccessible equipment (since replacement and repair is not usually an economically feasible option)
- sharing experiences by tracking generic failures and monitoring effectiveness of aging management activities
- implementing pilot projects to evaluate the effectiveness of new requirements and processes

- properly quantify consequential failure costs – to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy

Conclusions

The aging management and life extension process for the US nuclear industry has been refined and improved over the years. It has become an efficient and effective method to ensure that the nuclear plants in the United States can be safely operated beyond their original 40-year operating license. By dividing the safety critical systems, structures, and components into passive and active categories the industry and regulator have reduced the potentially overwhelming analysis effort to a reasonable and manageable size.

By working together, the nuclear industry and the US Nuclear Regulatory Commission (USNRC) have been able to technically justify life extension. The process has been structured to not be an economic or resource burden on either the licensees or the USNRC. However, all parties are continually reviewing the process and results to identify where improvements can be made.

The process has been selected as a viable method by many international regulatory and nuclear industry organizations, including those in Spain, Taiwan, and Korea. The International Atomic Energy Agency in Vienna has also adopted the process as the model for ensuring safe extended life operations.

The aging management and life extension process can be easily adapted to other industries. The development strategy, research material, specific elements of the process, and many of the lessons learned can all be of potential value to the PSA and Norwegian petroleum industry in ensuring safe extended operations of the facilities.

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Aging Management and Life Extension in the US Nuclear Power Industry

Background

This report on aging management and life extension actions within the United States (US) nuclear power industry was prepared by the Chockie Group International as part of the project for the Petroleum Safety Authority (PSA) Norway entitled, *Design Life Extension Regulations* (PSA Project Reference Number: NO 99B16).

Report Objective

The objective of the report is to provide an overview of the development and application of aging management and life extension programs and regulations within the US commercial nuclear power industry.

This report is a companion to two previous briefing reports that the Chockie Group International prepared for the PSA. The first, entitled, *Performance Monitoring of Systems and Active Components* (CGI Report 06.21), examined the requirements and activities associated with aging management of active systems and components. The second briefing report, *Condition Monitoring of Passive Systems, Structures, and Components* (CGI Report 06.22), addressed the programs and regulations for aging management of passive systems, structures and components for extended operation.

Information from these two briefing reports has been incorporated into this overview report.

The Principles of Effective Aging Management

It is a well-established fact that mechanical and electrical equipment can be maintained over long periods of time, using refurbishment, partial/complete replacement and reconditioning. There are some automobiles from the early 1900's that now look better and work better than when they were made. The technology to maintain equipment in an "*as new*" condition is called effective aging management. There are three basic principles that form the foundation of aging management programs.

The first principal is that there can be not reduction in the safety margins over the useful life of the plant. With respect to commercial nuclear power plants, the Nuclear Regulatory Commission (USNRC) does not permit reduction in safety margins. This implies that the plant licensees must maintain the plants in as new condition.

The second major principal is to avoid failures. The reliability of the plant will never be better than its worst performing system or component. To avoid failures, one must have the skills, knowledge, and experience to recognize pending failures and take timely corrective actions for all structures, systems, and components that are critical to the safe operation of the plant.

The third principal is to understand the behavior of materials when exposed to certain stressors (in other words, to understand the applicable aging mechanisms). This knowledge helps focuses attention on the "right places and at the right time". This also provides the information necessary for addressing the aging degradation situation with the right tools and developing effective actions to mitigate or prevent the problem from affecting safe plant operations.

Since the beginning of nuclear power in the US the industry and regulator have embraced these principles and have worked to ensure that the plants are properly maintained and operated over their operating life.

The Push for Life Extension

The operating life of the US plants has been limited to 40-years as is discussed in more detail in the following section. However, almost twenty-five years ago both the industry and the USNRC began to address the possibility of life extension. The first question they need to answer was whether it was technically justifiable and economically feasible to operate the plant beyond the original 40-year limit? If so, then what should the life extension approval process? The results of hundreds of aging research studies and many years of work have convinced all parties that life extension is both economically and technically viable. To ensure that the plants continue to operate within their design safety margins during extended operation, the USNRC in coordination with the nuclear industry had developed an effective and efficient license renewal process. The License Renewal Rule is discussed in detail in the CGI Report 06:22 and is summarized in later sections of this report.

Report Content

The first section of the report provides a brief historical perspective of the rationale for the life extension requirements and how the process has been split along the lines of active and passive systems, structures, and components.

The second section examines the key organizations that have been instrumental in the development of aging management programs. Included is an overview of how the various programs relate and complement each other.

The third section provides a discussion of the principal aging management and life extension program. The following sections examine the two key aging management requirements, the USNRC License Renewal Rule and Maintenance Rule.

The importance of industry developed aging management programs and the support and sponsorship of aging research by both the USNRC and industry is reviewed next. In the following sections a number of relevant issues and activities including early license renewal and international applications are examined.

The last part of the report discusses the lessons that have been learned over the twenty plus years in developing and implementing the aging management and life extension programs and requirements. Also as part of this later section is a summary of information, tools, strategies, and lessons that may be applicable to the PSA and Norwegian petroleum industry – how the PSA and the industry can take advantage of the extensive work and lessons to develop "focused" life extension requirements to ensure that adequate levels of safety are maintained during extended operation.

Historical Perspective

The 40-Year Operating License

When the original licensing requirements for United States commercial nuclear power plants were developed it was agreed to limit the licenses for a 40-year operating period. The 40-year limit was selected based on economic considerations rather than technical limitations.

The 40-year limit was specified by the US Congress in the Atomic Energy Act of 1954. The law was modeled on the Communications Act of 1934. This Act set up the conditions for radio stations to be licensed and operate for several years. Then the stations would be allowed to renew their licenses as long as they continued to meet their charters. Similarly, the Atomic Energy Act allows for the renewal of operating licenses for the nuclear power plants.

Congress selected 40 years for nuclear power plant licenses based on the view that this was the time required to pay off the plant investments through the anticipated income from the electrical rate base. The 40-year license term was not based on safety, technical, or environmental factors.

As specified in the Atomic Energy Act, the plants can reapply for a new operating license after 20-years of operation. If granted, the new license covers the remaining term of the 40-year operation plus up to a 20-year extension. The regulations do not set any limit on the number of renewals that a plant can apply for.

Renewal is voluntary. The decision is primarily economical and whether the licensee believes they can continue to meet NRC requirements. By June 2006, 21 nuclear plants have received regulatory approval for 20-years of extended operation. Another nine plant applications are being reviewed.

The Importance of Passive versus Active

The US Nuclear Regulatory Commission (USNRC) and the nuclear industry have developed a strategy to ensure the extended safe operation of the plants. An important element of the US strategy is the distinction between passive and active systems, structures, and components (SSCs). As a general definition, passive SSCs are those that do not move to function (such as, structures, heat exchangers, transformers, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements). An aging evaluation is typically required to identify the degradation mechanisms and to select the effective inspections and tests.

In order to ensure that the US nuclear power plants continue to maintain adequate levels of safety during extended operation beyond their original license period the USNRC has developed two important sets of requirements. These are the:

- Maintenance Rule
- License Renewal Rule

The requirements for the aging management of "active" systems and components are addressed by the Maintenance Rule (as discussed in CGI Report 06.21). The aging management of active SSCs should be part of the plant maintenance program. Good maintenance practices should identify and correct any aging degradation issues of the active SCCs and that no special license renewal aging management requirements are necessary for extended operational approval.

The focus of the License Renewal Rule is on the management of aging degradation of safety critical "passive" and long-lived systems, structures, and components (SSCs) at the nuclear power plants (as discussed in CGI Report 06.22). Long-lived items are those that are not subject to replacement based on a qualified life or specified time period.

Copies of the Maintenance Rule and the License Renewal Rule are provided in Appendices A and B, respectively.

Benefits of Life Extension

The industry and government have assessed the potential economic and environmental impact of life extension. Extending the useful plant life by 20 years for the 104 operating US plants is the equivalent of building 52 new plants. It would be most likely that these 52 replacement power plants would be coal fired. The avoidance of harmful plant emissions (SO_x, NO_x, heavy metals, and ash) is a significant environmental accomplishment (see Figure 1). Additionally, life extension is a way of minimizing the current bottleneck for the disposal of used spent fuel. Over the years, there have been numerous delays in the development of a final national repository for spent nuclear fuel. The extension of the operating licenses will allow the plants to continue to store the material on-site until the repository becomes available.

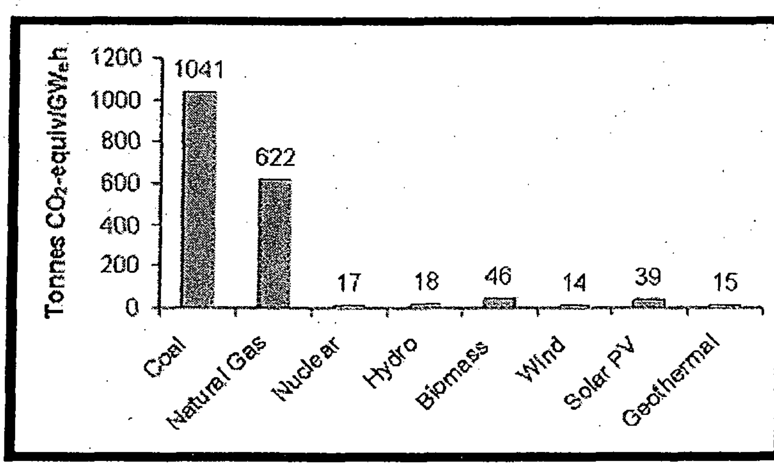

Figure 1: *Comparison of Life-Cycle Emissions*

On the economic scale, each plant represents an asset value of between $1 billion to $2 billion.

The largest part of the operating costs comes from the depreciation of the original investment over the first 40 years and the decommissioning fees. After 40 years, the only remaining capital costs are those associated with refurbishment and replacement of aging components. The fuel and operations and maintenance costs are much lower than comparable size coal or oil fired plants. The overall benefit-to-cost ratios are on the order of 2:1 to 4:1 (a saving of between \$500 and \$1000 million) over the period of extended operation. According to the Nuclear Energy Institute:

> *... the economic value of the U.S. nuclear fleet over the remaining 40-year life of the plants is approximately \$65 billion, and, over a 60-year life, assuming license renewal, is \$76 billion. (Economic value is net present value of future revenue stream net of fuel and O&M costs, capital additions, etc., expressed in 2002 dollars.)*

Life extension also brought into focus the value of increasing capacity factors and the possibility of power uprate. Many plants have already completed significant power uprates, gaining 10% to 15% additional capacity with little investment. In fact, the equipment reconditioning and replacements performed as a result of life extension are made to also satisfy the needs of power uprate that is new equipment is purchased with additional capacity or upgraded. Capacity factors for the operating plants have been increasing over the last ten years, mostly by reducing the number of outage days for refueling and avoiding plant shutdowns. The average fleet capacity factor has increased about 10% to the present value of around 90%. The combined effect of power uprate and capacity factor increase has provided the equivalent electric output of about 26 additional nuclear plants. These efforts were made possible by the prospect of life extension and the attendant economic savings.

Because most of the cost of electric production from nuclear plants in the US is regulated at the state level, the net savings by the plant operators are ultimately passed on to the consumer. As a result, the economic benefits from more efficient extended operation should be realized by the utility customers.

Development of Aging Management Programs

This section examines the key organizations that have been involved in the development and improvement of programs to identify and manage the effects of aging on plant systems, structures, and components (SSCs). Also briefly discussed is the relationship among the many industry and regulatory aging management related programs.

Key Organizations Involved in Nuclear Plant Aging Management

There have been a number of industry and governmental organizations involved for over twenty-five years in the development of aging management programs and requirements for the extended operation of US nuclear plants. The key organizations are:

- Industry Organizations
  - Electric Power Research Institute (EPRI)
  - Institute of Nuclear Power Operations (INPO)
  - Nuclear Energy Institute (NEI)
  - Boiling Water Reactor Owners Group
  - Westinghouse Owners Group
  - Babcock and Wilcox Owners Group
  - Combustion Engineering Owners Group
- Governmental Organizations
  - US Department of Energy (DOE)
  - US Nuclear Regulatory Commission (USNRC)

The principal aging related activities of these various organizations are summarized below.

EPRI Aging Research

EPRI, the research arm of the electric utilities, sponsored life extension pilot plant and demonstration projects. These studies provided the initial technical and economic impetus for individual plant owners to look at plant life extension as a serious option for their long-term generation planning. EPRI aging research projects established the basic aging assessment technology and aging management principles. EPRI programs concerning mechanical, electrical, and structural equipment identified potential aging mechanisms and the effects of aging degradation (those that manifest themselves and can be visually or otherwise observed).

EPRI and various nuclear plant owners groups also sponsored the development of Industry Reports on Component Aging. Aging Management Tools for mechanical, electrical and structural equipment were produced to provide guidance to the plant licensees.

A similar effort was undertaken to deal with the aging management of the non-safety related portion of the plant. EPRI initiated the Preventive Maintenance Basis project to develop an industry consensus of best practices for maintenance and aging management. This project was closely followed by the EPRI Life Cycle Management program to create long-term maintenance strategies on the basis of highest reliability at the lowest costs.

INPO Maintenance Management Guidance

Initially there were no uniform implementation procedures for the aging management programs related to non-safety structures, systems, and components (SSCs). INPO lead the development of an equipment reliability guide [AP-913] that incorporating the preventive maintenance (PV) basis, life cycle management (LCM) programs, and reliability centered maintenance (RCM) programs. AP-913 has become the standard to measure plant excellence.

NEI Aging Guidelines

The Nuclear Energy Institute has been responsible for taking the lead in the development of the guidelines to assist licensees prepare the license renewal applications. The NEI-95-10 document, entitled *Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule,* provides licensees with an acceptable approach for implementing the requirements of the USNRC License Renewal Rule. This is a living document and is continuously updated based on NEI's monitoring of licensees experiences with the license renewal process. NEI continues to be the focus for interaction between the industry and the USNRC and serves as a spokesperson for the industry when new life extension or aging management issues emerge.

DOE Aging Research

The US Department of Energy (DOE) is responsible for national long-term energy planning. DOE has supported a number of the EPRI programs including those addressing mechanical, electrical, and structural equipment aging degradation. Follow-on research by DOE has included the Aging Management Guides for major components and commodities and the concrete aging research conducted by the DOE Oak Ridge National Laboratory.

USNRC License Renewal Research & Regulations

In the early 1980s the USNRC initiated a major aging research program to investigate the aging degradation of safety related equipment. This program, entitled the Nuclear Plant Aging Research (NPAR) program, examined aging degradation in both passive and active structures, systems, and components. This was a major multi-million dollar research effort lasting almost 10 years and sponsoring more than 100 aging research studies. The Program eventually generated over 150 technical reports.

The findings from the NPAR Program provided the basis for determining that extended operations of the nuclear power plants were technically justifiable. It also provided the foundation for the license renewal requirements and renewal process.

In 1991, the safety requirements for license renewal (entitled, Requirements for Renewal of Operating Licenses for Nuclear Power Plants) were adopted by the USNRC. These requirements, known as the License Renewal Rule, established the procedures, criteria, and standards governing the renewal of nuclear power plant operating licenses. These were made mandatory requirements as part of the United States Code of Federal Regulations (commonly referred to as 10 CFR Part 54).

For the next few years the USNRC in cooperation with the nuclear industry conducted a demonstration program to apply the Rule to pilot plants. The objective was to assess the effectiveness of the requirements and the application/review process. The USNRC also undertook a number of activities related to the implementation of the Rule. These included:

- developing a draft regulatory guide
- developing a draft standard review plan for license renewal
- reviewing generic industry technical aging information

Based on discussions with industry and results from the demonstration program the USNRC determined that revisions to the Rule were needed. The USNRC found that many aging effects are dealt with adequately during the initial license period. In addition, the USNRC found that the review did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which also helps manage plant aging phenomena.

In summary, the amended Rule established a regulatory process that is simpler, more stable, and more predictable than the initial License Renewal Rule. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived structures and components

Relationship of Aging Management Programs

The original life extension pilot plant studies performed in the 1980's did not differentiate among passive and active components or the safety and non-safety related portions of the plant. The focus of these studies was to determine the critical components and life ending scenarios as a result of progressive unmitigated degradation and from this to establish a realistic attainable plant life. When the USNRC started to develop the License Renewal Rule, they had the benefit of the pilot studies results and included the passive and active components within the scope of the Rule. This turned out to be a bad decision, as industry tried to cope with very costly implementation costs and impractical application of the requirements. Because the Maintenance Rule was being prepared by the USNRC in the same timeframe and dealing exclusively with the performance monitoring of active components and systems, the License Renewal Rule was revised to only encompass long-lived passive components and structures. Notably, the USNRC regulations only apply to the regulated safety related portions of the plants, about one-third of the total plant. (A detailed review of the Maintenance Rule is provided in CGI Report 06:21.)

When life extension or license renewal is considered, the entire plant needs to be assessed and prepared to meet its extended life goal. To this end the industry sponsored a number of equipment reliability research studies concerning the aging degradation for the non-safety portions of the plant. The initial focus was the development of Reliability Centered Maintenance (RCM) to identify critical component/parts. It was followed by the Preventive Maintenance Basis (PMB) to collect and document industry "best practices" for the maintenance of equipment. The relationship of the various industry and USNRC programs is shown in Figure 2.

However, the early aging studies and the license renewal efforts quickly pointed to a maintenance gap. Plants did not have, nor were they developing, and long-term aging management programs. As a result, EPRI sponsored the development of a Life Cycle

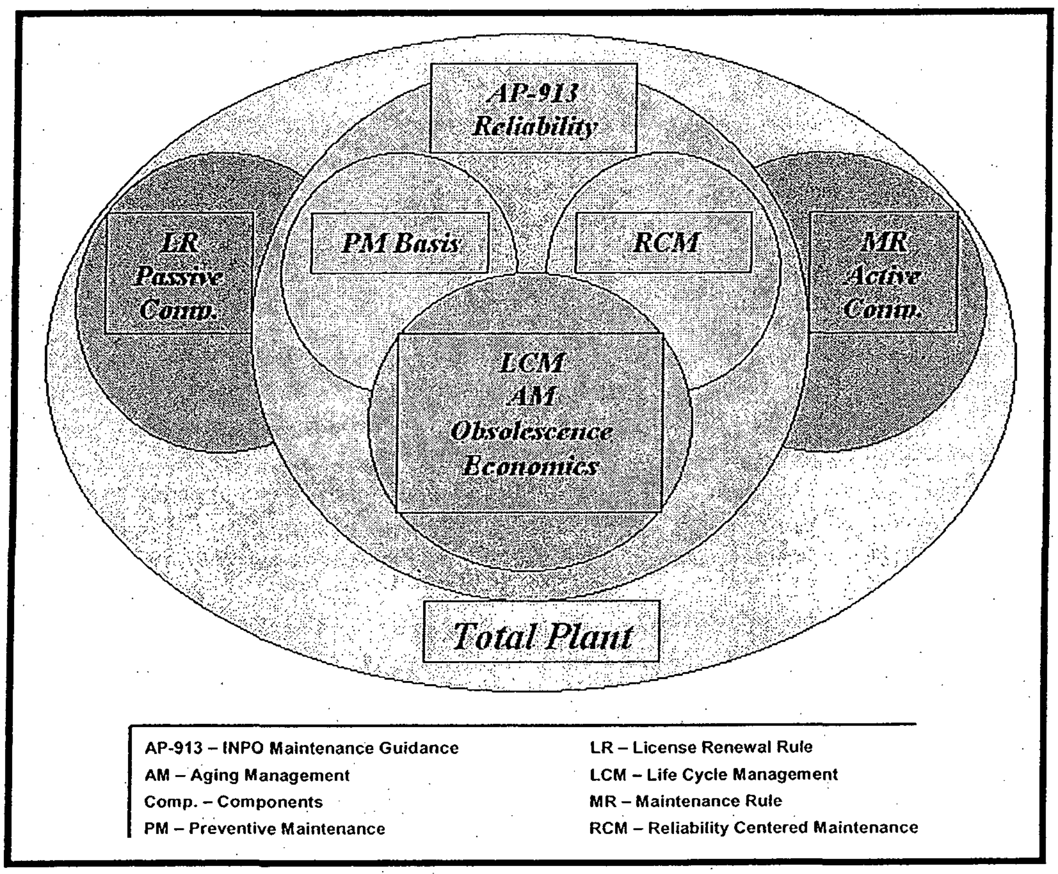

Figure 2: *The Relationship of Aging Management Programs*

Management (LCM) methodology for the plants to use to determine the most effective alternative from a number of scenarios. As defined by AP-913, life cycle management (LCM) is:

> *... the process by which nuclear power plants integrate operations, maintenance, regulatory, environmental, and business activities that manage plant condition (by means of aging and obsolescence management), optimize operating life (including the options of early retirement and license renewal), and maximize plant value while maintaining plant safety.*

LCM can provide a basis for a long-term maintenance strategy with the highest reliability at the least cost. LCM makes use of RCM and PMB in addition to addressing technical obsolescence, aging management and the generic and plant-specific operating experience. The LCM program also considers economics to select the optimum long-term maintenance strategy.

INPO lead the development of the "umbrella" process that incorporates the various maintenance and aging management programs and requirements. This resulting industry guidance document, entitled, *Equipment Reliability Process Description* (AP-913), has become the industry standard by which plant maintenance performance is currently judged.

A related maintenance oversight activity is exercised by the insurance companies, such as Nuclear Equipment Insurance Limited. These insurance companies have created similar maintenance standards to be followed with the objective of minimizing their liability exposure. A benefit-penalty system has been applied by which the insurance premiums are determined based on the level of compliance with their maintenance standards.

The Industry "Umbrella" Program (AP-913)

The *Equipment Reliability Process Description* (AP-913) developed by INPO has become the industry umbrella for effective plant maintenance practices. Many plants have adopted all or portions of AP-913, including the applicable parts of the regulatory programs, such as the aging management and performance monitoring parts of the License Renewal Rule and Maintenance Rule, respectively. It is important to note that the AP-913 is an industry initiative and is not a mandatory requirement. However, INPO's role as an industry oversight organization for utility corporate and plant performance assures that most plants implement part or all of the recommended equipment reliability program guidance.

Large utilities with a substantial number of plants are creating their own organizational standards that essentially mirror the AP-913 program features.

The AP-913 process, as shown in Figure 3, consists of six basic elements. Each element, as briefly described below, has a series of considerations or tasks, which should be part of an effective maintenance program.

<u>**Scoping and Identification of Critical Components**</u>
There are basically three categories of components within the plant. First, and most important, are the critical components that would shut down the plant or initiate safety

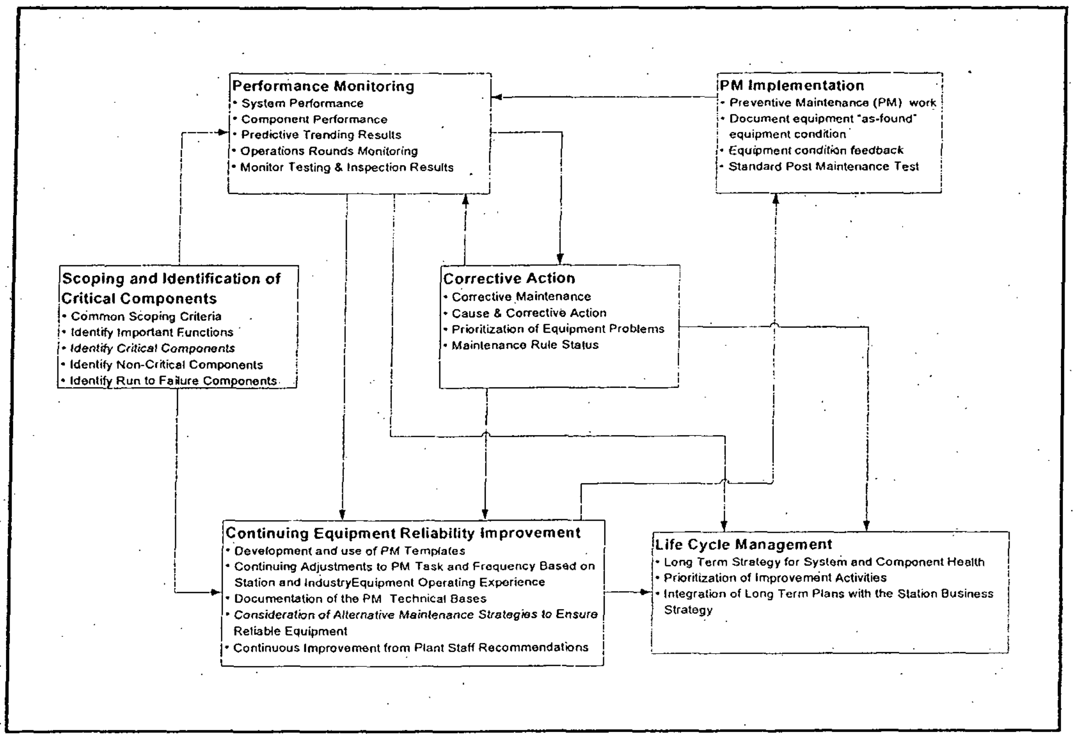

Figure 3: *Equipment Reliability Process (Source: INPO AP-913)*

systems if they were to fail their functions. The second category is the non-critical components that are being maintained by regular or vendor recommended maintenance. The third category is the run-to-failure components for which maintenance is not economically justifiable. These components are replaced on a set time schedule or following their failure.

<u>Performance Monitoring</u>

For the critical and non-critical components, performance monitoring as required by the USNRC Maintenance Rule is applied at the system or component level (reliability and availability). Performance trending is conducted to assure that mitigative or corrective actions are contemplated prior to the component or system exceeding its performance limits.

The routine system of engineer and operator rounds is one example of recommended performance monitoring tasks. The rounds are undertaken frequently (such as daily or weekly) to detect minor changes in equipment behavior. Tasks to be administered during the rounds may include visual observation of the equipment looking for missing/loose parts, leakage, noise, fumes/smell, missing insulation, construction debris, abnormal vibration, discoloration and rusting, deformation, and cracking of foundations. Operators are required to confirm the correct position of breakers and switches, read local instrumentation, and verify position of fire and security barriers/doors.

At the crafts level, a "*condition code*" process has been implemented by most plants to facilitate condition feedback for the equipment being worked on. This condition code typically includes three to five levels of equipment conditions as observed by the maintenance personnel. Typical levels of condition codes may be:

- Condition 1: As New
- Condition 2: Meets or exceeds expectations
- Condition 3: Shows signs of acceptable wear/degradation
- Condition 4: Should be scheduled for overhaul, replacement
- Condition 5: Found in failed condition

These conditions are simple observations and are recorded on a standard form with the work package to be evaluated by the system engineer. A more detailed condition code table, using a 10-point graduation, is included in AP-913 presented in Table 1.

Other recommended considerations for performance monitoring include:

- use of equipment history and the corrective action database to perform equipment failure trending for components used across several systems
- specific alert values for condition-monitoring data in the component performance criteria

Table 1: *Equipment Condition Codes* (Source: AP-913)

CONDITION 1
Unanticipated Failure Failure not associated with normal wear or aging discovered at time of activity Condition Report required to address condition Potentially misapplied structure, system, or component requiring engineering resolution
CONDITION 2
Repair/Replacement Required, Not Necessarily Due to Normal Wear or Aging Failure not definitely attributable to normal wear or aging; can be repaired with replacement in kind material, parts, or components May require engineering resolution
CONDITION 3
Repair/Replacement Required, Due to Normal Wear or Aging Failure that is obviously due to normal wear or aging that can be repaired without engineering evaluation Consider performing the PM task more frequently
CONDITION 4
Measured Parameter Outside Specified Tolerance Component has not failed, but adjustment is required No replacement parts other than those dictated by the PM task required Consider performing the PM task more frequently
CONDITION 5
Reliability Degraded Component has not failed, but replacement or repairs recommended due to normal wear or aging to ensure reliable operation until the next inspection Consider performing the PM task more frequently
CONDITION 6
Measured Parameter Within Tolerance, but Adjustment Required Adjustments required due to normal wear, aging, or drift No replacement parts other than those dictated by the PM task required
CONDITION 7
Satisfactory Observed wear considered normal No adjustments required No replacement parts other than those dictated by the PM task required
CONDITION 8
Superior Observed wear less than would be expected No adjustments required No replacement parts other than those dictated by the PM task required Consider performing the PM task less frequently
CONDITION 9
Like New - Component is in "like new" condition Consider performing the PM task less frequently
CONDITION N
As-Found Condition Not Applicable Administrative task One-time performance Condition monitoring task

- trending of as-found equipment condition codes to:
  - identify patterns of degradation by component type and the need to adjust preventive maintenance (PM) tasks or frequencies
  - update PM templates based on station equipment operating experience
  - to identify PM outliers for additional evaluation

- use industry event database (EPIX) to identify component trends being experienced by other plants, and take proactive measures to avoid similar failures
- identify aging or obsolescence issues
- evaluate the relationship between component performance and effect on system functional performance
- trend key data collected on operator rounds
- consult non-nuclear sources of component failure information and trending parameters/strategies

Corrective Actions

This is perhaps the most important element, in that it directs the plant to perform a rigorous root cause evaluation of equipment failure. It also requires management actions to develop a plant culture of preventing future failures. According the AP-913:

> *This is one of the hard links management can establish to reinforce an intolerance for unexpected equipment failures. By establishing management expectations that evaluations of unexpected failures include the question of why the failure occurred and what process should have prevented it, instead of just repairing it, continuous equipment reliability improvement initiatives become a way of life. This is also an opportunity to revisit a previous decision to run to failure.*

An evaluation is required to determine if the failure was preventable, using the following considerations:

- What existing barriers should have prevented the failure (procedure completeness, procedure implementation, craft training, post-maintenance testing, tag-out restoration, use of operating experience, troubleshooting, unavailability management, and human performance)?
- What barriers should be implemented to prevent recurrence? Consider the risk/benefit of the change.
- What other components are susceptible to this failure mechanism; what is the extent of this condition?
- How did the continuing equipment reliability improvement process miss this?
- Could more frequent implementation of existing preventive maintenance actions prevent recurrence?
- Should the scope of the preventive maintenance tasks be increased?
- Is there an aging or obsolescence concern that should be addressed in the corrective actions?
- Is additional corrective maintenance needed?
- Is the failed component in USNRC Maintenance Rule scope or did the failure cause a significant power reduction?
- Provide equipment root cause training and qualification, including the requirement to participate in a certain number of root cause analyses per year.

- Develop root cause specialists or mentors, with additional training and experience, in departments that frequently participate in this activity.
- Use a graduated approach for root cause determination commensurate with the level of consequences of the failure. Examples include trending only, apparent cause determination, root cause determination by an individual, and forming a root cause team.
- Establish clear methods to obtain vendor expertise or increased failure analysis for equipment failures whose root cause cannot be determined by a team.
- Search in-house and industry operating experience, including EPIX, to determine if similar failures have occurred.
- Are similar components affected by the same problem?

Continuing Equipment Reliability Improvement

This element is the focus of the INPO equipment reliability strategy. It is structured to reflect a living maintenance program with continuous feedback, enhancements based on equipment performance, adjustments to PM frequencies to compensate for poor or excellent performance, to look for alternative solutions, recognize application of new technologies/diagnostics and to eliminate low value tasks and/or add new tasks where the need arises. Equipment reliability is tightly coupled to the need to identify incipient failures, monitor failures at other plants and look for precursors. This means that we know the locations, susceptibility to failure and the potential degradation, such that effective monitoring methods can be engaged. This element suggests that the following monitoring methods be considered:

- Degradation can be monitored by installed instrumentation.
- Degradation can be detected by a predictive maintenance technique such as vibration, oil sampling, thermography, or motor signature analysis.
- Degradation can be visibly observed during operator rounds or system engineer walkdowns.
- Degradation can be measured by surveillance testing.

Long-Term Planning and Life-Cycle Management

With the event of power uprate (increasing the power output beyond the design levels, e.g., 115 to 120%) and life extension for the nuclear plants, it became evident that long-term plans needed to be developed to support cost-benefit assessments of these major capital projects and to formulate a lifetime maintenance strategy for the plants. The utilities were used to strategic planning with respect to power need forecasts, selecting the type of power generation and revenue projections, however, the nuclear plants needed a more sophisticated asset management tool, taking into account the unique life cycle and major capital expenditures for these plants. The Life Cycle Management (LCM) methodology and process was developed to fit this gap and was subsequently integrated with AP-913. This integration specifically recognizes the need to merge the long-term maintenance strategy with the station business plan.

Preventive Maintenance Implementation

Lastly the program addresses implementation issues of the equipment reliability process. Plants are expected to have a rigorous work order system by which maintenance activities can be scheduled, implemented and recorded. The work order database provides a historic record of all work performed and includes data fields for the type of activity (preventive, corrective, design change, surveillance testing, operations test, etc) for each component, the date, required hours and in many cases also the labor and material costs. The data such constitutes a significant element for the reliability assessment in that the number of failures (each component and all similar components) can be sorted by year, cost and type, from which failure rates can be computed. Trending of the number of preventive and corrective work orders can be performed to ascertain whether the trend is stagnant, positive or negative. The effectiveness of the maintenance program can therefore be measured over time.

The License Renewal Rule

In 1954 the original licensing requirements for US nuclear power plants set a 40-year limit for operating licenses. This 40-year limit was selected based on economic considerations rather than technical limitations. However, even at that time, the Atomic Energy Act was set up to allow renewal of the operating licenses.

In the late 1970s the USNRC and the nuclear industry began to address the issues concerning life extension. The first initiatives were directed at determining whether or not the safe operation of the plant beyond its 40-year operating limit could be technically justified – could the aging effects be adequately managed so the plant could be operated within the original safety margins during the period of extended operation?

To answer this question both the USNRC and the industry initiated a number of aging research programs. One of the largest aging research efforts was the Nuclear Aging Plant Research (NPAR) Program. This 10-year, multi-million dollar effort provided the basis for determining that extended operations were technically justifiable. It also provided the foundation for the license renewal requirements and renewal process.

The NPAR Program identified aging as the cumulative, time-dependent degradation of a systems, structures, and components (SSCs) that, if unmitigated, could compromise continuing safe operation of the plant. Mitigating measures are therefore needed to ensure that aging does not reduce either the operational readiness of a plant's safety systems or the defense-in-depth through common-mode failures of redundant, safety-related equipment.

The main goals of the NPAR Program were to understand aging and to identify ways to manage aging of safety-related SSCs. The specific technical objectives were to:

- identify and characterize aging effects which, if unmitigated, could cause degradation of SSCs and impact plant safety
- develop supporting data to facilitate management of age-related degradation
- identify methods of inspection, surveillance, and monitoring, or of evaluating residual-life of SSCs, which will ensure timely detection of significant aging effects before loss of safety function
- evaluate the effectiveness of storage, maintenance, repair, and replacement practices in mitigating the effects of aging and diminishing the rate and extent of degradation caused by aging
- provide technical bases and support for the License Renewal Rule and the license renewal process

During the mid-1980s the USNRC initiated two other aging assessment programs as companions to the NPAR Program. One focused on the aging of nuclear plant vessels, piping, steam generators, and nondestructive examination techniques. The other involved the assessment of age-related degradation on plant civil structures. These three programs provided a wealth of information and insights on aging and aging management that formed the basis for the License Renewal Rule.

The NPAR Program alone produced over 150 technical reports and numerous papers and proceedings concerning aging characteristics and aging management of safety-related SSCs. The major subjects examined by the NPAR and related aging research programs are shown in Table 2.

Table 2: *Subjects Examined by the NPAR and Related Aging Research Programs*

Air operated valves	Chillers
Auxiliary feedwater pumps	Heat exchangers
Batteries	Large electric motors
Bistables/switches	Main steam isolation valves
Cables	Motor operated valves
Chargers/inverters	Piping
Check valves	Power operated relief valves
Civil structures	Small electric motors
Circuit breakers/relays	Snubbers
Compressors	Solenoid valves
Connectors, terminal blocks	Steam generators
Diesel generators	Transformers
Electrical penetrations	Vessels

Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors. A list of selected aging reports from the NPAR program is provided in Attachment of the CGI Report 06-22, *Condition Monitoring of Passive Systems, Structures, and Components*.

Based on industry initiatives started in 1985, two pilot plants were chosen to conduct life extension investigations and feasibility assessments. The principal objectives were to find answers to a number of questions, including:

- What defines the ultimate life of a plant?
- What are the events that lead to final plant shutdown?
- What is a realistic and achievable operating life?
- What type of repair and replacement capital projects would be required?
- Are there any technical or economic obstacles or limits?

These studies introduced the concept of "critical components". These are components that if they were allowed to degrade unimpeded would constitute a safety concern and lead to shutdown. An importance ranking process was developed to identify the critical components and perform a relative importance ranking, using a Delphi process. The result was a list of the top 24 components, all passive components and structures. These components were then selected for a detailed aging assessment to investigate the plausible aging mechanisms, identify the associated aging effects that have been observed and to formulate a strategy for effective aging management, using preventive and mitigative maintenance or corrective repair and replacement options. These efforts were later extended to cover a host of other components and commodities, including active components, to create a more complete picture of the plant's aging concerns.

While the studies for the two pilot plants were carried out by completely separate research teams, the results and conclusions were very similar. A byproduct of the pilot studies were the identification of a host of additional aging research tasks, a need to better understand certain aging phenomena, the recognition that aging management needs to start at the beginning of the life cycle and the need to perform some maintenance tasks to better monitor material conditions, such as inspections, tests, fatigue cycle counting, measuring environmental conditions in electrical enclosures, testing soil and water for aggressiveness (chlorides, phosphates, pH) with respect to concrete and instituting structures inspections.

A technical review group examined the aging research findings and concluded that many aging phenomena are readily manageable and do not pose technical issues that would preclude life extension for nuclear power plants. They also stated that as long as there are effective inspection and maintenance practices, the plant life is simply limited by the economic cost of repair or replacement of any components that don't meet specified acceptance criteria.

With the technical and economic feasibility of life extension demonstrated, the industry started working with the USNRC to develop a License Renewal Rule that would provide a formal process to allow extended operation beyond the original 40-year license.

In 1991, the safety requirements for license renewal (entitled, *Requirements for Renewal of Operating Licenses for Nuclear Power Plants)* were adopted by the USNRC. These requirements, known as the License Renewal Rule, established the procedures, criteria, and standards governing the renewal of nuclear power plant operating licenses. These were made mandatory requirements as part of the United States Code of Federal Regulations (commonly referred to as 10 CFR Part 54).

The scope of this initial version of the Rule included both passive and active components for the safety related systems of the plant.

Revisions to the Rule – Lessons Learned

Again, the Monticello plant volunteered to be the demonstration plant to test the Rule. The objective was to assess the effectiveness of the requirements and the application and review process. Once completed, it became apparent that the provisions of the original Rule required changing – particularly the requirements for commitments and additional maintenance tasks to be implemented. Cost estimates ranged from to $100 to $500 Million for a plant to comply with rule requirements.

The Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena on an on-going basis. The initial License Renewal Rule also did not provide a predictable nor stable process. Industry point out, and the USNRC agreed, that it is essential to have a predictable and stable regulatory process that clearly and unequivocally defines the regulatory expectations for license renewal.

The revised Rule was published in 1995. A copy is provided in Appendix B. The new amended Rule established a regulatory process that is simpler, more stable, and more predictable. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived systems, structures and components.[1]

The relationship of the regulatory requirements for the Maintenance and License Renewal Rules is shown in Figure 4.

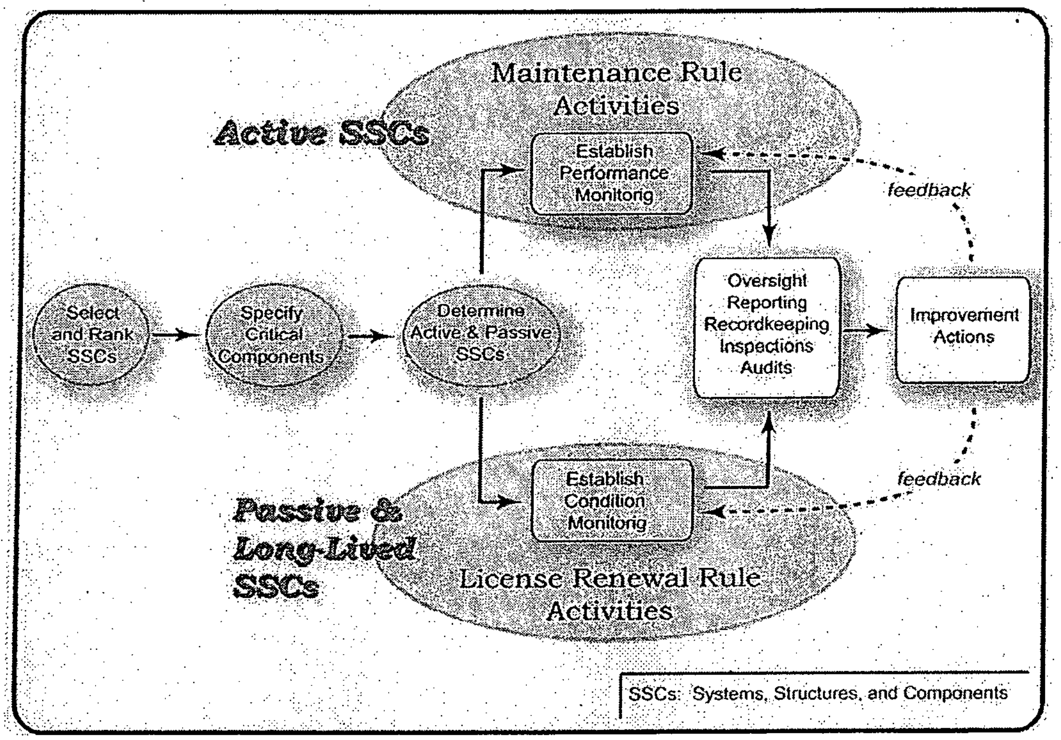

Figure 4: *Relationship of Maintenance and License Renewal Rules*

The License Renewal Process

The license renewal process proceeds along two tracks – one for the review of safety issues and another for environmental issues. The safety requirements, as noted above,

[1] An extensive discussion of the revisions and the USNRC's license renewal philosophy can be found in the Statement of Considerations that accompanied the License Renewal Rule as published in the US Federal Register, Vol. 60, No. 88, page 22461, May 8, 1995.

are addressed in 10 CFR Part 54. The environmental requirements are found in 10 CFR Part 51.

The USNRC developed a generic environmental impact statement (GEIS) which covered impacts that were common to most all nuclear power plants. During the review process the USNRC focuses on the important environmental issues specific to each plant.

The license renewal review process (Figure 5) is intended to identify any additional actions that will be needed to maintain the functionality of the SSCs for the extended operation. The USNRC determined that the following can be excluded from the license renewal aging management review:

- those structures and components that perform active functions
- structures and components that are replaced based on qualified life or specified time period.

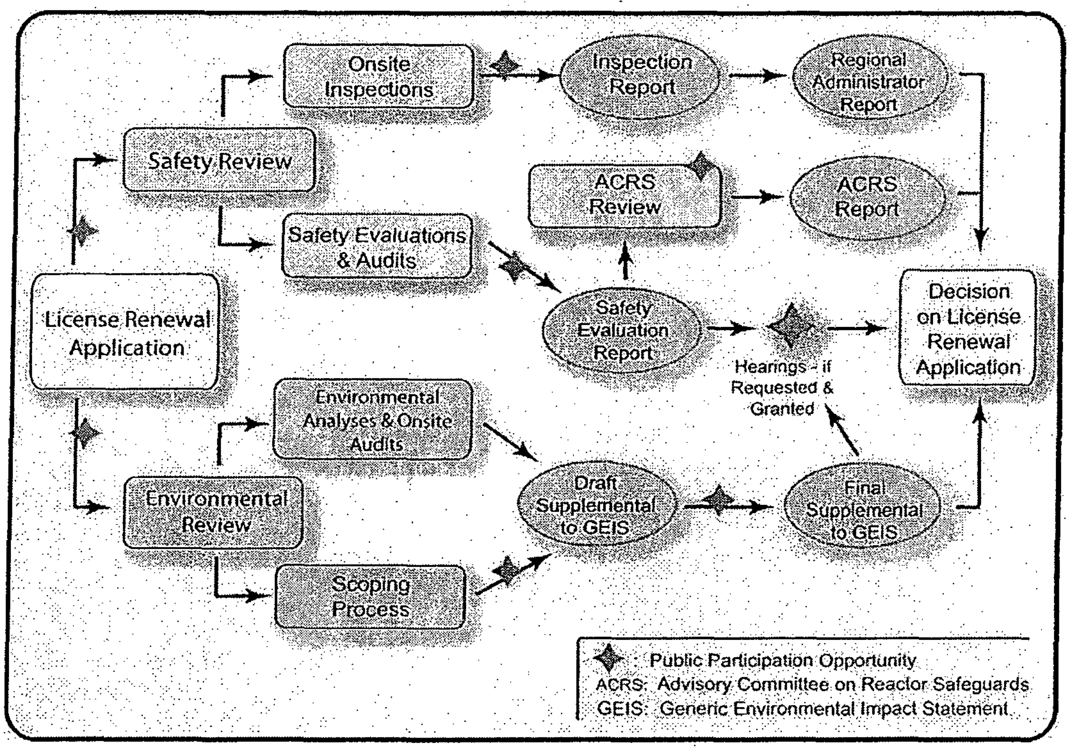

Figure 5: *Simplified Flow Chart of the License Renewal Process (source: USNRC)*

License Renewal Principles

The license renewal requirements for nuclear power plants are based on two key principles:

- the existing USNRC regulatory process (such as the Maintenance Rule) is adequate to ensure that currently operating plants will continue to maintain adequate levels of safety during extended operation – however, license renewal requirements are needed to address age-related degradation unique to life extension for certain passive and long-lived SSCs as well as a few other issues that may arise during the period of extended operation

- each plant's licensing basis is required to be maintained during the renewal term in the same manner and to the same extent as during the original licensing term

The License Renewal Application

Two important items that are required to be included in the application are:

- an integrated plant assessment
- an evaluation of time-limited aging analyses

The application development process involves the following actions:

- identification of the SSCs within the scope of License Renewal Rule
- identification of the intended functions of SSCs
- identification of the structures and components subject to aging management review and intended functions
- assurance that effects of aging are managed
- development and application of new aging management programs and inspections
- identification and resolution of time-limited aging analyses
- identification and evaluation of exemptions containing time-limited aging analyses

Scoping

The scoping phase requires the licensee to identify all plant systems, structures and components that are safety-related or whose failure could affect safety-related functions, or that are relied on to demonstrate compliance with the several specific USNRC's regulations (such as, for fire protection and plant blackout).

The scoping or categorization process can be rather complicated and requires careful review of the nature and function of the various SSCs being considered. For example in the case of valves and pumps, the valve bodies and pump casings may perform an intended function by maintaining the pressure-retaining boundary and therefore would be subject to aging management review.

Integrated Plant Assessment (IPA)

The integrated plant assessment (IPA) is the core of the license renewal application (Figure 6). The purpose of the IPA is to demonstrate that the structures and components requiring aging management (within the scope of the Rule) have been identified and the effects of aging on their functionality will be managed to maintain an acceptable level of safety during extended operations

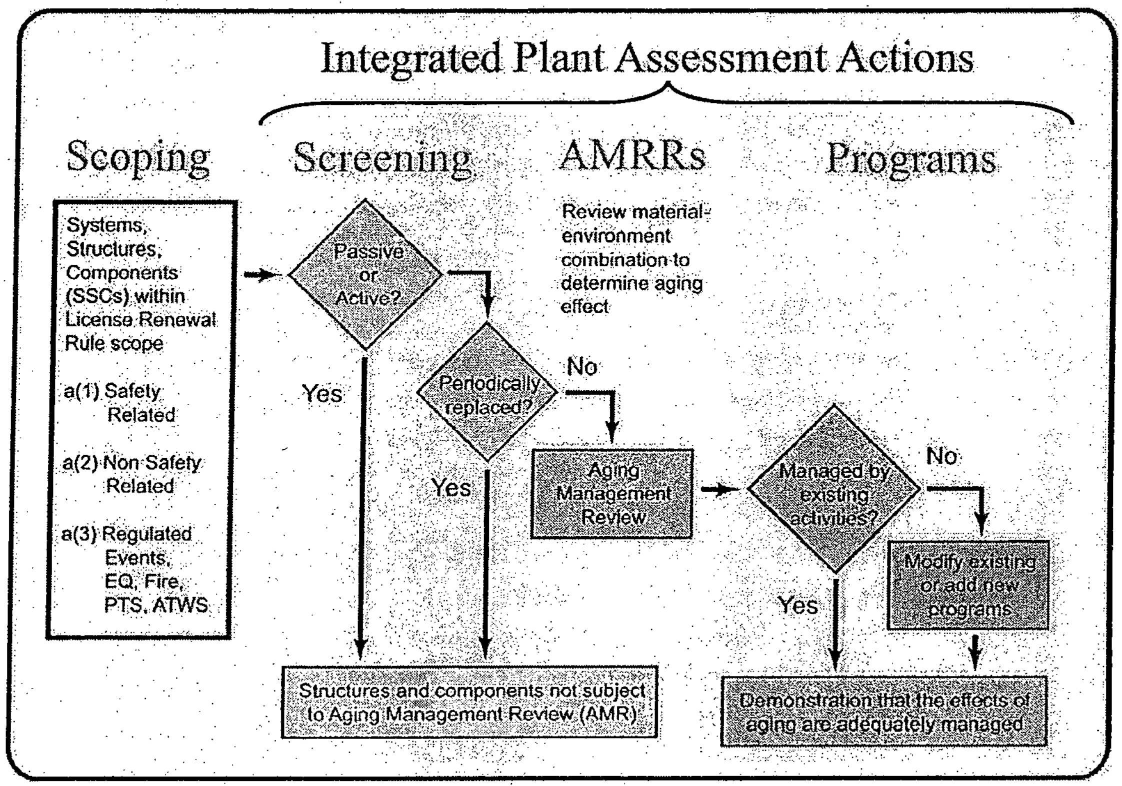

Figure 6: *License Renewal Application Activities*

The first part of the IPA process is to determine which of the structures and components within the scope of the Rule are passive and long-lived. Passive structures and components are those that perform their function without a change in configuration or properties. Long-lived items are those that are not subject to replacement based on a qualified life or specified time period. An example list of such structures and components is provided in Table 3.

The objective of this screening exercise is to determine which components and structures require aging management review to determine whether or not some form of aging management is necessary.

There are a number of different techniques that can be used to identify and assess aging effects. The NEI guidance document (NEI 95-10) lists several approved techniques. These include material-environment-stressors analysis, analysis based on common setting or location, plant specific aging analysis based on loss of intended function, and the use of similar aging management reviews approved by the USNRC.

The licensee must demonstrate that the effects of aging will be managed in such a way that the intended functions will be maintained for the extended operation period. Where the licensee can demonstrate that the existing programs provide adequate aging management throughout the period of extended operation, no additional action may be required. However, if additional aging management activities are warranted, it will be up to the licensee to define these actions. This can include such activities as developing new monitoring programs or increasing current inspections. Licensees should consider all programs and activities associated with the component or structure to determine to what degree they already manage the aging degradation. The four general types of aging management programs are:

- Prevention – to preclude certain levels of aging degradation from occurring (e.g., coating programs to prevent external corrosion of a tank)
- Mitigation – to reduce or slow aging effects (e.g., chemistry programs to mitigate internal corrosion of piping)
- Condition monitoring – to inspect for the presence of and extent of aging effects (e.g., visual inspection of concrete structures for cracking and ultrasonic measurement of pipe wall for erosion-corrosion induced wall thinning
- Performance monitoring – to test the ability to perform its function (e.g., heat balances on heat exchangers for the heat transfer intended function of the tubes)

Table 3: *Examples of Structures and Components included in, or excluded from, the License Renewal Rule Scope* (Source: 10 CFR 54)

Passive Structures & Components Included in Rule Scope (Example List)	Active Structures & Components Excluded from Rule Scope (Example List)
cable trays	air compressors
component supports	batteries
containment	battery chargers
containment liner	breakers
core shroud	circuit boards
electrical and mechanical penetrations	cooling fans
electrical cabinets	diesel generators
electrical cables and connections	motors
equipment hatches	power inverters
heat exchangers	power supplies
piping	pressure indicators
pressure retaining boundaries	pressure transmitters
pressurizer	pumps (except casing)
pump casings	relays
reactor coolant system pressure boundary	snubbers
reactor vessel	switches
seismic Category I structures	switchgears
steam generators	the control rod drive
valve bodies	transistors
ventilation ducts	valves (except body)
	ventilation dampers
	water level indicators

To assist the licensees in perform their plant-specific aging assessments and avoid duplication of work from one plant to another the USNRC developed a comprehensive guidance document entitled, *Generic Aging Lesson Learned Report* (GALL) NUREG-1801. The document provides aging management matrixes for the various passive mechanical, electrical and structural components found in a nuclear plant. The GALL report also provides links and references to acceptable aging management programs inclusive of specific program attributes. An example of a typical aging matrix from the GALL report is shown in Table 4.

Table 4: *Typical Aging Matrix from GALL Report* (Source NUREG-1801)

NUREG-1801, Rev. 1

VII AUXILIARY SYSTEMS
C1 Open-Cycle Cooling Water System (Service Water System)

Item	Link	Structure and/or Component	Material	Environment	Aging Effect/ Mechanism	Aging Management Program (AMP)	Further Evaluation
VII.C1-14 (AP-59)	VII.C1.	Piping, piping components, and piping elements	Stainless steel	Lubricating oil	Loss of material/ pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis" The AMP is to be augmented by verifying the effectiveness of the lubricating oil analysis program. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated
VII.C1-15 (A-54)	VII.C1.2-a VII.C1.6-a VII.C1.1-a VII.C1.4-a	Piping, piping components, and piping elements	Stainless steel	Raw water	Loss of material/ pitting and crevice corrosion, and fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No
VII.C1-16 (AP-56)	VII.C1.	Piping, piping components, and piping elements	Stainless steel	Soil	Loss of material/ pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant-specific
VII.C1-17 (AP-30)	VII.C1.	Piping, piping components, and piping elements	Steel	Lubricating oil	Loss of material/ general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis" The AMP is to be augmented by verifying the effectiveness of the lubricating oil analysis program. See Chapter XI.M32, "One-Time Inspection," for an acceptable verification program.	Yes, detection of aging effects is to be evaluated

VII C1-4

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The licensee has a choice to utilize the generic findings of the GALL report as a technical basis for his plant, subject to verification of applicability. If the plant-specific conditions, materials, components or aging management programs are different, a plant-specific assessment is required. The GALL report relies heavily on a condition directed maintenance program (inspection, analysis and testing) for effective aging management that is to monitor the material conditions.

The aging management programs to be credited for license renewal, must meet a rigorous 10-point acceptance criteria shown in Table 5.

The GALL Report includes a comprehensive listing of all the plausible aging effects and mechanisms, with a definition and explanation of applicability. The basis for these aging effects and mechanisms are contained in the numerous references form the wealth of the aging research conducted by the industry, EPRI, DOE, and the USNRC. With the exception of a few industry-specific or unique degradation mechanisms, these aging effects and mechanisms are applicable to almost any industrial facility and are not specific to power plants. An edited version was extracted from the GALL report is provided in Appendix B.

The last important tool provided with the GALL report, is a series of aging management programs (AMPs), targeting the specific aging mechanisms and affected materials. Licensees are expected to implement these aging management programs as part of their maintenance program without much deviation. If plant-specific changes are required, they must be identified to the USNRC for approval. Each of the aging management programs has been developed with substantial industry input to reflect current aging

Table 5: *Aging Management Activity Program Elements* (Source, NUREG-1801)

Element	Description
1. Scope of the activity	Scope of the program/activity should include the specific structures and components subject to an aging management review for license renewal.
2. Preventive actions	Preventive actions should mitigate or prevent aging degradation.
3. Parameters monitored or inspected	Parameters monitored or inspected should be linked to the degradation of the particular structure or component intended function(s).
4. Detection of aging effects	Detection of aging effects should occur before there is a loss of structure or component intended function(s). This includes aspects such as method or technique (i.e. visual, volumetric, surface inspection), frequency, sample size, data collection and timing of new/one-time inspections to ensure timely detection of aging effects.
5. Monitoring and trending	Monitoring and trending should provide predictability of the extent of degradation and provide timely corrective or mitigating actions.
6. Acceptance criteria	Acceptance criteria, against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all current licensing basis design conditions during the period of extended operation.
7. Corrective actions	Corrective actions, including root cause determination and prevention recurrence, should be timely.
8. Confirmation processes	Confirmation processes should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.
9. Administrative controls	Administrative controls should provide a formal review and approval process.
10. Operating experience	Operating experience of the aging management activity, including past corrective actions resulting in program enhancements or additional programs or activities, should provide objective evidence to ensure that the effects of aging will be adequately managed so that the intended functions of the structure or component will be maintained during the period of extended operation.

management practices and to maintain effectiveness. There are 39 AMPs for mechanical component aging management, eight structural programs and six electrical programs. An example of an aging management program for concrete structures is provided in Appendix D.

As with the aging mechanisms and aging effects, the AMPs are equally applicable to other industrial facilities, with perhaps a minimized formality and quality control.

Much of the contents contained in the GALL report are repeated in a companion document called the License Renewal Standard Review Plan (SRP-LR), NUREG-1800. This document is for the use by the USNRC staff to assist in the review of the License Renewal applications and to assure consistency among the reviewers. The SRP-LR also provides guidance regarding components, aging mechanisms and aging effects not addressed in the GALL but which require plant-specific aging evaluations.

While the aging management programs are not mandatory, they represent one acceptable method to perform effective aging management under the license renewal rule. Licensees may deviate and apply their own versions. However, such programs are subject to acceptance by the USNRC and usually require a substantial justification to deviate from the standards. In this way, the AMPs constitute a near-mandatory status and the specific activities referred to the programs, become licensing commitments for the extended operating period. For components that are not covered by the GALL report or for which no standard AMPs are applicable, the applicant must perform a detailed documented aging management review.

For the typical plant, the aging management review resulted in the identification of about 200 to 400 specific aging management activities. The activities range from completely new programs to changes to existing programs (scope for additional components, more frequent inspections, different technology, new locations, etc) and administrative tasks to document activities, quality control and training. Most of the impact comes from the additional inspections and testing requirements to monitor the degradation and engineering analyses to demonstrate that existing design margins have not eroded and are adequate for the extended operating period. Examples of updated and new aging management activities and programs are shown in Table 6.

TABLE 6: *Typical New and Updated Aging Management Activities and Programs*

Updated Programs (examples):	New Programs (examples):
Boric Acid Corrosion Prevention Program	Alloy 600 Aging Management Program
Fire Protection Program	Buried Piping Inspection Program
Instrument Air Quality Program	Cast Austenitic Stainless Steel (CASS) Evaluation Program
Maintenance Program	Heat Exchanger Monitoring Program
Service Water System Reliability Program	Cable Management Programs
Structures Monitoring	Reactor Vessel Internals Programs
System Testing Program	Small Bore Piping Program
System Walkdowns Program	Wall Thinning Monitoring Program
	Water Chemistry Control - Chemistry One-Time Inspection Program

Time Limited Aging Analysis

One of the major provisions of the Rule is the identification and analysis of Time Limited Aging Analyses (TLAA). The licensee must identify and update time-limited aging analyses. During the design phase for a plant, certain assumptions about the length of time the plant will be operated are incorporated into design calculations for various SSCs. In order to obtain approval for a renewed license, these calculations must be shown to be valid for the period of extended operation, or the affected SSCs must be included in an appropriate aging management program.

In essence, the USNRC requires the licensee to go back to the original plant design documents and determine if the design criteria included specific time limited assumptions or criteria. Once identified, the original calculations or qualification tests must be updated for the new extended operating life. This process may be a simple ratio method to establish a new value for fatigue cycles, or it may involve a complex fatigue analysis, considering the used-up cycles and extended operating life.

A comprehensive review was performed by the industry to identify potential time limited aging analyses (TLAAs) that may be part of the original design basis, the underlying design codes and standards, and the qualifications tests (i.e. environmental exposure of cables, corrosion tests) that were performed in support of the original design life calculations. The principal issues identified by this industry review are (NUREG-1800 & NEI-95-10):

- reactor vessel neutron embrittlement
- prestressed concrete containment tendon prestress
- metal fatigue
- environmental qualification of electrical equipment
- metal corrosion allowance
- inservice flaw growth analyses
- inservice local metal containment corrosion
- high-energy line break postulated on fatigue cumulative usage factor

Once the licensee has identified their specific TLAAs, analysis must be performed to extend the design basis for the extended operating period or compensatory measures must be implemented. The licensee must demonstrate one of the following:

- The analyses remain valid for the period of extended operation or;
- The analyses have been projected to the end of the extended period of operation; or
- The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

These options clearly include full or partial replacement of the component, requalification by testing, more sophisticated analyses (i.e. finite element analysis and fracture mechanics) or use of mitigative measures to impede or avoid degradation. Some plants have chosen to implement stricter preventive and predictive maintenance, one-time inspections to assess used-up margins, monitoring of the environments to recalculate cable life, new inspections to quantify degradation and installation of coupons to monitor corrosion and cracking.

The Maintenance Rule

Because active components in mechanical and electrical systems are normally operating, their performance can be monitored and trended to detect incipient degradation. Representative parameters that can be measured must be established for both the local components and for the complete system. Examples of local component parameters include flow, differential pressure, vibration, and delta temperature. Reliability and availability are examples of typical system performance parameters.

Within the nuclear power generation industry in the United States, the US Nuclear Regulatory Commission (USNRC) has promulgated a "Maintenance Rule" for the purpose of improving the performance monitoring of critical systems at all nuclear power plants in the United States.

Regulatory Requirements

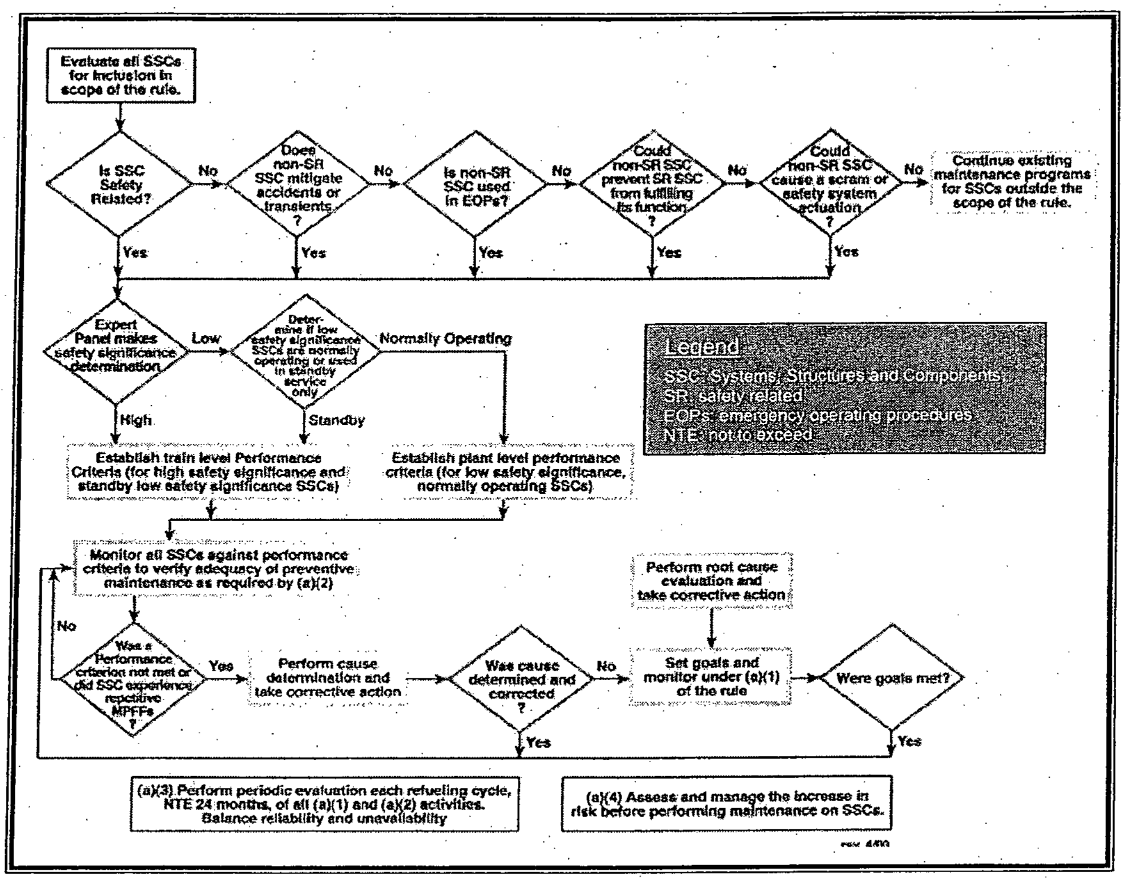
During the 1980s, the USNRC became concerned with the maintenance of nuclear power plants and the attendant decline in reliability. No regulatory provisions were in force to require uniform application of maintenance, except for the Technical Specifications, which required periodic surveillance testing, and the ASME Code, which required periodic inspections of the safety-related pressure boundary components. With the assistance of a number of volunteer plant owners, the USNRC conducted a survey of utility practices in an effort to establish the effectiveness of various maintenance programs (i.e. experience based, vendor recommended, preventive, corrective, run-to-failure), allocation of utility resources among safety and non-safety (power production) equipment and utility methods of monitoring and benchmarking performance. The survey results led the USNRC to conclude that more consistent and rigorous monitoring and reporting of individual system performance parameters was needed. Using industry input, to the USNRC developed a performance-based regulation that would allow individual plants to define the scope of the program, the performance parameters and the acceptance criteria. The plant specific application and implementation would be subject to inspection by the USNRC. The original Rule was issued in July 1991 and became effective in July of 1996 and the USNRC began their implementation inspections. The Rule was revised a number of times to incorporate lessons learned, clarifications and new requirements.

The Maintenance Rule Provisions

The Maintenance Rule was issued under the United States Code of Federal Regulations. This is a mandatory rule that all commercial nuclear power plants must follow. A copy of the full text of the Maintenance Rule is provided in Appendix A. Although the Rule consists of only a single page, the underlying documentation, interpretations, and guidance reports amounts to thousand of additional pages of material and information.

The Maintenance Rule analysis process is shown in Figure 7.

Figure 7: *Simplified Flow Chart of the Maintenance Rule* (Source: USNRC)



The key provisions of the Rule are:

- defining systems monitoring requirements
- preventive maintenance versus availability/reliability
- corrective action goal setting
- operating experience considerations
- demonstrations of preventive maintenance (PM) effectiveness
- bi-annual performance reviews
- quantification of on-line risk

Systems Monitoring Requirements

The Rule makes a significant distinction between important systems that need to be performance monitored at the train level and those systems that can be monitored at the plant level. The systems that are considered to be safety significant with equally or diversely redundant safety systems typically have two or three trains or channels.

Standby systems (systems that are activated in response to an accident or fire or are required to mitigate accident consequences) are monitored using reliability as a performance parameter. Reliability can be measured by such indicators as fail-to-start or fail-to-run per 100 attempts.

Normally operating systems are monitored using availability as a performance measure. Availability is determined as the fraction of system available hours during the mission time divided by the mission time. When assessing reliability and availability, the success or ability of accomplishing the defined safety functions is considered. This permits some level of degradation, as long as the system's functions are not compromised.

Preventive Maintenance versus Availability/Reliability

The Rule recognizes the conflict between performing preventive (invasive) maintenance that requires the system or component to be removed from service and the need to maintain satisfactory availability and/or reliability. One of the requirements mandates that an adequate balance of the two be maintained and reported.

Corrective Action Goal Setting

If a system cannot meet its performance criteria over a period not exceeding 24 months, corrective action is required and a new and more specific performance criteria must be established (Goal Setting) to demonstrate that the corrective action has been effective. This Goal Setting assures that recurring problems are fixed.

Operating Experience Considerations

Operating experience must be considered when establishing the performance parameters and criteria. This experience may be based on generic industry experience or the historical plant performance, failure rates, or reliability / availability values assumed in the plant's probabilistic risk analysis (PRA).

Demonstrations of PM Effectiveness

Systems that are monitored at the plant level require demonstration that the preventive maintenance programs are effective. Plant level performance criteria can include repetitive failures, plant shutdowns, initiation of safety systems and lost production. If the established criteria levels are exceeded, the system must be elevated to "system level monitoring".

System level monitoring requires that an elevated level of monitoring must continue until it can be demonstrated that the system has achieved its new system level performance, before the system is returned to plant level.

Bi-Annual Performance Reviews

The result of the system monitoring and trending activities is subject to bi-annual review to highlight the:

- performance problems
- corrective actions taken
- changes in performance parameters or criteria

- assessment of the balance between maintenance outages and system availability
- evaluation of industry operating experience

The evaluation of industry operating experience is an attempt to identify precursors or incipient failures that may have occurred at other plants and may have generic implications.

Quantification of On-Line Risk

A new paragraph was added to the Rule in 2000 to address the risk associated with plant configuration changes made during operation. This includes systems that are taken out-of-service for maintenance or due to failure/degradation. The on-line risk is influenced by the importance of the unavailable system, the period of time that it is not available, as well as the status of other safety related systems. As a consequence, the USNRC now requires that the on-line risk must be quantified to support continued operation of the plant.

Modifications/Improvements to the Rule

Following the original issue of the rule in 1991, the Nuclear Energy Institute (NEI) formed a utility task group to develop an industry guide, NEI-93-01, to assist the plants with the implementation. The USNRC conducted a number of early plant implementation audits in 1996 and based on these audits it was determined that some interpretations and improvements were desirable. The nuclear industry, represented by the Nuclear Energy Institute (NEI), discussed the implementation issues with the USNRC and subsequently generated a Revision 1 to NEI-93-01 in 1996.

The USNRC reviewed the revised NEI-93-01 for generic acceptability. In 1997 the guide was endorsed with some additional provisions (USNRC Regulatory Guide 1.160 Revision 2). The most significant addition was the inclusion of structures including concrete and steel structures that house or protect equipment covered within the scope of the Rule.

In 2000 the Rule was modified again to address on-line risks associated with maintenance activities. The USNRC added a new paragraph A-4 that then required the NEI to revise NEI-93-01. The new Section 11 provides guidance to the industry on how best to assess on-line risk associated with their maintenance activities. The USNRC endorsed the changes to NEI-93-01 in the USNRC Regulatory Guide 1.180.

Regulatory Inspections and Guidance

The USNRC started plant-specific inspections and audits in 1996 and 1997 to verify the acceptability of methods and procedures and the programmatic approaches taken. Because the rule is performance based, these inspections were unique and required substantial guidance and training of the inspector teams. The training guides and inspection procedures were made available to the industry. This allowed self-assessments and readiness reviews to be conducted prior to USNRC on-site inspections. Lessons learned from the inspections were communicated to the industry in a number of workshops and seminars.

Monitoring Issues

Monitoring important systems at the train level is considered an effective way to identify poorly performing equipment. A redundant high performance train could otherwise shadow the poorly performing train. Performance monitoring at the train or channel level is therefore mandated for risk significant systems. The USNRC was also concerned that generic problems in cross-system component groups (valves, motors, pumps, solenoids) would not be readily identified. As a result all plants are now tracking functional failures, which are periodically reviewed to identify trends of multiple component failures. A definition for a "Repetitive Functional Failure" was crafted to include: "Failures of another same component with identical cause".

Determining meaningful performance parameters for structures became a difficult task. A "Structures Monitoring Program" was created and implemented to periodically inspect (i.e. five to ten year intervals) for functional degradation. The acceptance criteria were defined in the American Concrete Institute (ACI) standards or the American Institute of Steel Construction (AISC) standards. If performance problems are identified, corrective action is required and the structure must be re-inspected at shorter intervals until it can be demonstrated that the fix was effective.

Industry Aging Management Programs (PM Basis and LCM)

The EPRI PM Basis Program

Recognizing the license renewal and maintenance rules as effective aging management tools for the safety-related systems and components in the plants, the industry needed to develop commensurate programs to be applied for the traditional part of the plants, the power production equipment. It is obvious that these systems must also undergo a transformation to support an extended operation. The first of these comprehensive efforts was the development of the Preventive Maintenance Basis Program (PM Basis) by EPRI to cover the majority of generic components and commodities found in the plants. The objective was to research and document the "Industry Best Practices" with respect to effective maintenance and aging management practices. Previously, plant maintenance was largely based on the equipment vendor recommendations, often without a solid technical basis for the requirements, except to protect the equipment warranty provisions.

Table 7: *EPRI PM Basis Component Listing* (Source EPRI TR106857)

Component Description	Volume
Air Operated Valves	V1
Medium Voltage Switchgear	V2
Low Voltage Switchgear	V3
Motor Control Centers	V4
Check Valves	V5
Motor Operated Valves	V6
Solenoid Operated Valves	V7
Low Voltage Electric Motors (600V and below)	V8
Medium Voltage Electric Motors (between 1kV and 5kV)	V9
High Voltage Electric Motors (5kV and greater)	V10
Direct Current Electric Motors	V11
Vertical Pumps	V12
Horizontal Pumps	V13
Reciprocating Air Compressors	V14
Rotary Screw Air Compressors	V15
Power Operated Relief Valves - Solenoid Actuated	V16
Power Operated Relief Valves - Pneumatic Actuated	V17
Pressure Relief Valves - Spring Actuated	V18
HVAC - Chillers and Compressors	V19
HVAC - Dampers and Ducting	V20
HVAC - Air Handling Equipment	V21
Inverters	V22
Battery Chargers	V23
Battery - Flooded Lead-Acid	V24
Battery - Valve-Regulated	V25
Battery - Nickel-Cadmium (NICAD)	V26
Liquid-Ring Rotary Compressor and Pump	V27
Positive Displacement Pumps	V28
Relays- Protective	V29
Relays- Control	V30
Relays- Timing	V31
Heat Exchangers	V32
Feedwater Heaters	V33
Condensers	V34
Main Feedwater Pump Turbines	V35
Terry Turbines	V36
Main Turbine EHC Hydraulics	V37
Transformers- Station Type Oil Immersed	V38
I&C Components	V39

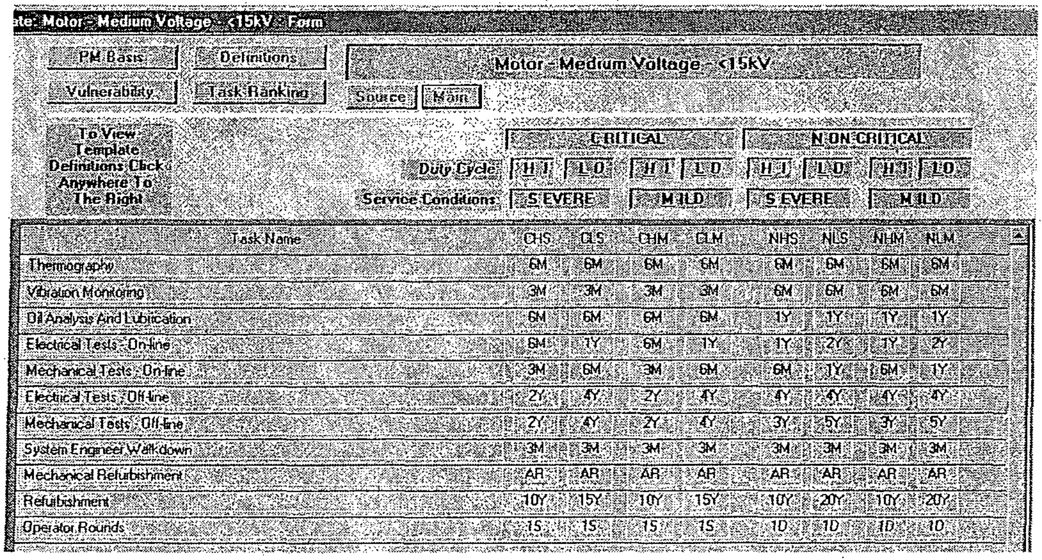
The PM Basis program initially included 39 component templates, each documented in a separate report volume (see Table 7). The program scope was later expanded to add a variety of instrumentation groups. For each component, the program determined the appropriate maintenance activities, the recommended frequency for the activity and the effectiveness of the action. The program also provided a first attempt at correlating PM frequency with reliability, i.e. the more often a component is tested or inspected, the more reliable it is supposed to be and the corollary, what is the reliability reduction if the PM task is eliminated. In many cases, a single task will not provide a major improvement in reliability, but a combination of PM tasks can make a major difference.

In addition to the individual component reports, EPRI converted the templates to electronic format, so that they can be accessed via computer and component reliability manipulations can be exercised on the ACCESS based software. The best practices are captured on a summary template for each component. The templates recognize the fact that not all components are of equal importance and therefore the level of preventive maintenance may be significantly different, dependant on the components service duty, environmental exposure and functional importance. The different levels of recommended PM for the various categories (there are eight different categories to choose from) are shown on the templates. An example template for large electric motors is shown in Figure 8.

The Life Cycle Management Planning (LCM) Process

The Life Cycle Management planning methodology was developed under EPRI and utility sponsorship to create a tool for the long-term maintenance planning, using both, technical and economic measures to find the maintenance plan that will give the highest reliability at the lowest cost. The LCM process is fairly complex in that it requires a relatively accurate representation of the plant's historic performance, component failures, failure consequences, such as lost power generation, regulatory scrutiny, corrective maintenance costs, and the impact of a poor plant performance on the corporate image and financial picture. However, given the eventual possibility that the

Figure 8: *EPRI PM Basis Template Example*


ate: Motor - Medium Voltage - <15kV : Form

PM Basis | Definitions | Vulnerability | Task Ranking | Source | Main

Motor - Medium Voltage - <15kV

To View Template Definitions Click Anywhere To The Right

	CRITICAL				NON CRITICAL			
Duty Cycle:	HI	LO	HI	LO	HI	LO	HI	LO
Service Conditions:	SEVERE		MILD		SEVERE		MILD	
Task Name	CHS	CLS	CHM	CLM	NHS	NLS	NHM	NLM
Thermography	6M	6M	6M	6M	6M	6M	6M	6M
Vibration Monitoring	3M	3M	3M	3M	6M	6M	6M	6M
Oil Analysis And Lubrication	6M	6M	6M	6M	1Y	1Y	1Y	1Y
Electrical Tests - On-line	6M	1Y	6M	1Y	1Y	2Y	1Y	2Y
Mechanical Tests - On-line	3M	6M	3M	6M	6M	1Y	6M	1Y
Electrical Tests - Off-line	2Y	4Y	2Y	4Y	4Y	4Y	4Y	4Y
Mechanical Tests - Off-line	2Y	4Y	2Y	4Y	3Y	5Y	3Y	5Y
System Engineer Walkdown	3M	3M	3M	3M	3M	3M	3M	3M
Mechanical Refurbishment	AR	AR	AR	AR	AR	AR	AR	AR
Refurbishment	10Y	15Y	10Y	15Y	10Y	20Y	10Y	20Y
Operator Rounds	1S	1S	1S	1S	1D	1D	1D	1D

plants will operate for 60 years or longer, it was necessary to change the maintenance planning horizon and to be able to forecast major capital projects with respect to timing and cost for the foreseeable future. The following is a quote taken from the EPRI summary report for LCM planning:
"Life Cycle Management planning is intended to provide an effective long-term planning tool for minimizing unplanned capability loss and optimizing maintenance programs and capital investments consistent with plant safety and an identified plant operating strategy. Such an operating strategy might include license renewal and/or plant power uprating. An LCM Plan addresses such issues as aging management, preventive maintenance, obsolescence, and the replacement or redesign of a structure, system or component (SSC) important to safety and plant operation. In short, LCM Planning is viewed as a viable process to systematically identify and examine the important SSCs, optimize their contribution to plant performance, reliability, safety and value, and prepare long-term maintenance management plans and resource projections."

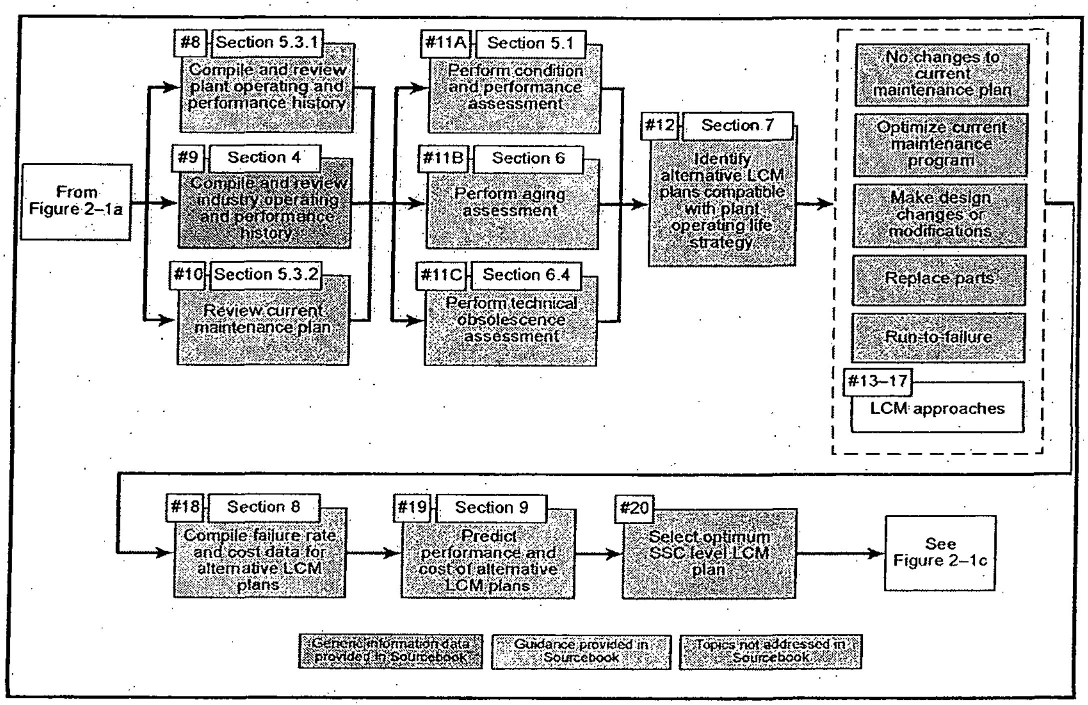
The basic steps of the LCM process are delineated on the simplified diagram, shown in Figure 9. The major steps are briefly reviewed to help understand the interrelationship and task objectives.

Compiling Performance and Operating History

Some plants have included cost data in their WO database, which when trended over time, provides an additional parameter to measure maintenance effectiveness. More money does not always lead to better reliability. To benchmark the plant's performance, similar operating data, including generic failure rates, is assembled from the EPIX

Figure 9

LCM Planning Flowchart – Technical and Economic Evaluation



database and other sources (such as the French EDF Eireda database). Benchmarking has the principal objective to place the specific plant performance relative to its peers. If the plant experiences a failure rate of twice the industry average, there is ample room for improvement and investments are economically justified. If the plant turns out to be already a leader in performance, additional improvements are difficult to sell.

Another aspect of this performance compilation task is the review of the plant's *maintenance programs and procedures and to compare the list with the industry* "Best Practices", such as the EPRI PM Basis Templates, to identify specific shortcomings and gaps that can be closed to enhance the plant performance.

Condition Assessment

In order to establish a baseline for the plant's equipment performance and reliability, the operating history over the last 5 to 10 years is reviewed and trended. Typically, the plant will have a work order database from which the preventive and corrective work orders can be accessed. A simple count per year will provide a meaningful trend to see if the maintenance activities are increasing, decreasing or portray a stable trend. Also, the ration of preventive to corrective work orders will provide some indication for a successful maintenance program (corrective work orders are decreasing), or the trend will point to problems, that is failures are increasing as an indication of progressive aging problems.

The age of the plant can have a profound effect on the performance and condition of its components; therefore it is necessary to have a good understanding of the material condition of the components at the time the assessment is made. Material conditions are determined from the review of maintenance history, such as inspection reports, test data, *diagnostic data, craft feedback, spare parts use, operating records and a plant walkdown.* From this an estimate can be rendered if the plant age is commensurate with its condition, that is, if its useful life has been expended faster than expected or the current condition is better than anticipated.

Aging Evaluation

Next is the aging evaluation to be performed for each major component or commodity group. Here the work performed by the industry groups and USNRC in support of the license renewal represents a basis to start the assessments. Typically a matrix is constructed, showing the basic component parts and materials, their applicable aging effects and associated aging mechanisms and the effective aging management programs. A typical aging matrix (this one for electric motors) is shown in Table 8.

For each line item, the plant's matching aging management program is identified and reviewed to determine if the effective attributes are included and to highlight any gaps that need to be addressed. The previous review of the operating history and plant condition records also contributes to this task to ascertain applicability and to assure that plant specific conditions are not overlooked.

Table 8: *Typical Aging Management Evaluation Matrix (Electric Motor)*

Structure or Components	Component/ Material Grouping	Plausible Aging Effects	Potential Aging Mechanisms	Present Plant Aging Management Programs
Rotor and Stator Windings End turns	Copper and Insulation	Discoloration, Burning, melting	Winding Shorts, Moisture Intrusion, Aging, Dirt, High Temperature	Motor Status Monitor. Refurbishment Consider internal inspection
		Overheating	Aging, Dirt	See above
Rotor Bars	Steel	Loose	Vibration, Age, Fatigue	Vibration monitoring On-line electrical tests
Rotor Shaft	Steel	Deformation, cracking	Vibration, fatigue, corrosion	Vibration monitoring Bearing temp. monitoring Internal visual inspection
Bearings	Various	Loss of Material, Cracking	Friction, Wear, Loss of lubrication	Vibration monitoring Temperature monitoring Oil sampling, analysis Thermography Internal inspection
Wiring, Terminations	Copper, Insulation	Loss of Contact, Cracking	Pinched, crimped, loose wire, Aging, corrosion	Thermography Visual inspection High pot tests
Frame, Base Plate	Carbon Steel	Loss of Material, Cracking, Deformation	Corrosion, Vibration, Loose Bolts	Vibration monitoring Visual inspections Recoating MR Structures Monitoring
Cooling Coils, Oil and water piping/reservoirs	Carbon Steel, SS	Leakage, Cracking	Corrosion, Wear, Vibration, Fatigue	Oil sampling, testing Visual inspection (E/I) Operator/SE rounds
Oil sight glass, Oil seals	Various non-metallic	Leakage	Corrosion, aging, wear, fatigue	Visual inspection Operator/SE rounds Periodic replacement
Sensors (RTDs, TCs, LVDTs, level, pressure, DP)	Various	Loss of signal, Drifting	Vibration, aging, corrosion	Calibration Replacement
Space heaters	Copper, insulation	Loss of continuity	Loose, broken wire, Moisture accumulation	Winding temp. monitoring Functional testing Thermostat calibration

Obsolescence Assessment

An obsolescence assessment provides a critical review of the potential technical obsolescence of the equipment. The industry is experiencing a serious exodus of original equipment vendors, many vendors do no longer support warranty and equipment services or have terminated production of spare parts. This puts the plant into a vulnerable position, leaving few of acceptable options, including re-engineering or reverse engineering, substituting newer models that often do not fit the original configuration envelope, upgrading technology (analog to digital) creating electronic-computer interface problems or scavenging parts from abandoned plants. The obsolescence assessment criteria and the relative ranking applied by a number of plants are shown on Table 9.

The first step is to assess the exposure level to obsolescence. Typically the electrical-electronic and instrumentation and control components are affected most prominently.

Obsolescence is ranked by applying a set of questions and ranking the applicability of each question. The total numerical value is compared to a traffic light scale to indicate the eminence of obsolescence. While this may not be a true scientific process, it nevertheless provides a timeframe for corrective or mitigative action.

The "traffic light" ranking for obsolescence is:

- Total Score is < 6.0, RED and the SSC obsolescence is serious. Potential options to deal with obsolescence and contingency planning should be identified. Guidance on the modeling, timing and costs of these contingencies and the associated risks should be provided.
- Total Score is between 6.0 and 10.0, YELLOW and the SSC may have longer-term concerns for obsolescence. Contingency planning and options should be considered.
- Total Score is > 10, GREEN and the SSC is not likely affected by obsolescence.

TABLE 9: *Technical Obsolescence Evaluation Criteria (Breakers)*

	Technical Obsolescence Evaluation Criteria	Base Score Yes=5 No=0	GE AKR	GE AM	W DHP	ABB K-line
1	Is the SSC still being manufactured and will it be available for at least the next five years?	5	0	0	0	5
2	Is there more than one supplier for the SSC for the foreseeable future?	3	0	0	0	0
3	Can the plant or outside suppliers manufacture the SSC in a reasonable time (within a refueling outage)?	3	0	0	0	3
4	Are there other sources or contingencies (from other plants, shared inventory, stock-piled parts, refurbishments, secondary suppliers, imitation parts, commercial dedications, etc) available in case of emergency?	3	3	3	3	3
5	Is the SSC frequency of failure/year times the number of the SSCs in the plant times the remaining operating life (in years) equal or lower than the number of stocked SSCs in the warehouse?	3	0	0	0	0
6	Can the spare part inventory be maintained for at least the next five years?	3	3	3	1	3
7	Is the SSC immune to significant aging degradation?	1	0	0	0	0
8	Can newer designs, technology, concepts be readily integrated with the existing configuration (hardware-software, digital-analog, solid-state, miniaturized electronics, smart components, etc)?	3	1.5	0	3	3
	Total Obsolescence Score	24	7.5	6	7	17

Determining LCM Planning Options and Plant Strategies

At this point in the LCM planning process, all the potential enhancements should be identified, such that a concise list of new or modified maintenance activities can be compiled, along with their costs and timing of implementation. Each goal can be met by a number of different options, called Alternatives in the LCM process. The Alternatives include:

- Maintain the Current Maintenance Program

  This is considered the base case against which other options are compared. The model assumes that current maintenance practices are continued and failure rates will gradually increase commensurate with progressive aging. Equipment replacement at time of failure is the planned corrective action.

- Optimize the PM Program

  Low cost PM activities are implemented on the basis of their cost effectiveness. Existing tasks are fine tuned or modified to be more effective and tasks with little payback are eliminated. A variant to the PM program is preventive replacement of components that have reached their predetermined useful life.

- Make Design Changes and Modifications

  Typically this option is a more costly alternative and makes sense for long-term operation if the design change avoids costly failures and lost power generation. There is a caution though in that design changes are often not proven concepts and may turn out worse for the plant.

- Designate Components as Run-to-failure

  For many unimportant components this is a reasonable alternative. In order to be effective, there must be a task that determines when failure has occurred so that a replacement can be installed.

Plant operating strategies need to be established, such that the LCM planning can consider the appropriate planning horizon, which is the remaining operating life, whether the plant is base loaded or cycled and if a power uprate is contemplated.

Economic Analysis of LCM Alternatives

The last step of the LCM process is to consolidate the technical data, failure data and financial/cost data to be loaded into financial analysis software, called LcmVALUE, to perform the Net Present Value (NPV) and Benefit to Investment Ratio (BIR) calculations that provide the measure of economic feasibility. The Alternative with the lowest NPV cost and the highest BIR is the preferred option. If the results are very close (i.e. within 1% of each other) additional sensitivity and uncertainty analysis are typically performed to render a confident recommendation. Results are highly dependant on long-term financial assumptions (such as discount rate, inflation rate, cost of power generation, cost of labor/materials, etc) and small changes cause large fluctuations in the results.

The Use of Probabilistic Risk Analysis for Maintenance

The probabilistic risk analysis (PRA) was initially developed for the safety related part of the nuclear power plant to facilitate simulation of various accident scenarios. Over time, plant-specific failure data became available and Bayesian updating brought about much more accurate modeling of the plant. With the promulgation of the Maintenance Rule, the PRA was expanded to now also include the power generation part of the plant, such that on-line risk modeling has become feasible and is performed on a routine basis. Outage times associated with preventive maintenance and surveillance testing as well as unanticipated equipment failures (emergent events) can be modeled and the risk impact associated with maintenance activities can be assessed on a continual basis. As plants continue to age, the increased equipment failures, if any, will be captured and the overall plant risk changes will have to be managed within the acceptance limits. This is another form of aging management trending at a higher level.

This PRA fidelity has led to new uses of the PRA, including risk ranking (RRW and RAW) of individual systems, evaluation of configuration and design changes prior to actual implementation and risk informed inspection plans (locations and frequency). Most recently, the USNRC has issued guidance for plant owners to apply PRA to fire protection and quality assurance programs.

Regulatory and Industry Aging Research

Early EPRI Pilot Plant and Demonstration Projects for License Renewal

As noted previously, the EPRI and DOE co-sponsored life extension pilot plant projects were initiated to study the feasibility and boundaries of nuclear plant life extension beyond the licensed 40-year life. With the new construction of power plants virtually coming to a halt after the 1979 Three Mile Island event, the electric generation industry and the US Department of Energy (DOE) were looking at long-term solutions to a looming energy crisis. Extending the plant life by some 20 years is equivalent of building 50 new power plants. The objectives of these early studies, as quoted in the Phase 1 BWR Pilot Plant Life Extension Report were:

> *To determine a realistic life goal for BWR plants, to identify major degradation mechanisms and potential technical obstacles to life extension, and to provide a methodology for BWR life extension programs.*

As the project was nearing completion and confidence in life extension was assured, economic obstacles and limits became an additional concern, as the list of potential new aging management activities and component replacements grew. The projects did develop the concept of "Critical Components" to delineate those that are essential to function and must be carefully managed to achieve the new life goals. It was also discovered that steel and concrete structures are not immune to aging and require aging management, largely through preventive techniques such as sealing, protective coatings and cathodic protection.

With the success of the pilot plants, a Phase 2 project was initiated to begin aging assessment of most of the plant components and commodity groups (cable, piping, structures, pressure boundary components, batteries, diesel generators, power generation equipment, etc). Among the top twelve critical components, all but two were passive components, the control center and diesel generators being the only active components. The Phase 2 report laid the foundation for identifying potential aging effects and mechanisms, their rate of degradation, manifestation of degradation and vulnerable locations. The studies also provided a first glance at potential aging management tactics from preventive/predictive maintenance, mitigation techniques, replacement options and repair feasibility.

The demonstration projects were initiated following the USNRC promulgation of the original License Renewal Rule in December 1991. The principal objective was to test the Rule's provisions and to generate the first license renewal application. It turned out not to be feasible and became unworkable in addition to plant owners concerns for an unstable licensing environment with open interpretation of the actual requirements. The license renewal application was never filed and the action prodded the NRC to revise and simplify the rule in 1995.

DOE-Sandia Aging Management Guides (AMG)

During the license renewal demonstration project phase, a need arose to study the critical components in more detail and to generate a generic AMG that could be used by other plants in their applications as well as be subjected to NRC review. The USDOE through the Sandia National Laboratory contracted for the development of ten individual AMGs, using a standard format and content guide. The ten critical components to be covered were chosen by an industry consortium and included the following reports:

- Electrical Switchgear (SAND93-7027)
- Pumps (SAND93-7045)
- Battery Chargers, Inverters & Uninterruptible Power Supplies (SAND93-7046)
- Power and Distribution Transformers (SAND93-7068)
- Motor Control Centers (SAND93-7069)
- Heat Exchangers (SAND93-7070)
- Stationary Batteries (SAND93-7071)
- Tanks and Pools (SAND96-0343)
- Electrical Cable and Terminations (SAND96-0344)
- Non-Reactor Pressure Boundary Piping (Draft) (TR-88953

While these reports cover both, passive (Heat Exchangers, Piping, Tanks/Pools, Cable) and active components (batteries, inverters/UPS, pumps, transformers, switchgear and motor control centers) they have become a valuable industry reference for the assessment of power production equipment. The AMGs contain a comprehensive review of industry operating experience, failure data, aging management techniques, and aging management options. The Cable AMG has become the industry bible on cable degradation, cable life determination and cable aging management.

EPRI Generic License Renewal Industry Reports for Major Components

In parallel to the DOE-Sandia AMGs EPRI also produced ten License Renewal Industry Reports. The EPRI addressed issues related to both the boiling water reactors (BWR) and the pressurized water reactors (PWR).

The EPRI reports were developed with participation from the General Electric BWR and Westinghouse PWR Owners Groups. The objectives of the EPRI reports were to provide the nuclear industry with aging technical basis documents and to support the technical review of license renewal applications by the USNRC.

The long-lived passive components and structures examined in the reports included:

- BWR plant primary containment
- PWR containment structures
- Class 1 structures
- PWR reactor coolant system
- low voltage, in-containment, environmentally-qualified cable

- BWR primary coolant pressure boundary
- BWR and PWR reactor vessels
- BWR and PWR reactor vessel internals

These reports are in-depth studies of historical performance and operating experience, failures and failure history, aging effects, and aging mechanism. The reports also provided information on aging management technologies and programs and discussed the aging management options for component parts and aging mechanisms that are not currently being managed or are not accessible (such as, underground structures, embedded steel and piping, and cable in conduits).

Over the years these reports have been of significant value for both the US nuclear industry and regulator as well as for nuclear plant operators and regulators in other countries. In particular, the reports on structures and containments have formed the basis of similar aging reports developed by the International Atomic Energy Agency in Vienna.

Much of the information in the reports on Class 1 structures and cables is application to both nuclear and non-nuclear facilities.

NRC Nuclear Plant Aging Research (NPAR) Program

To compensate for and to supplement the industry research of component aging, the USNRC funded a large multimillion-dollar research program to study aging of more than 100 different topics and components. Most of the actual research was conducted by the national laboratories (Oakridge, Argonne, Pacific Northwest, Sandia, and Idaho). The USNRC managed the program and provided for the technical review of selected reports by industry experts and users. A summary report (NUREG- 1377) was generated and updated annually to maintain an overview of the program status, components and topics being studied, short briefing reports and summaries for those reports completed. The reports for the selected components included passive and active components, as well as special topics, such as fatigue, material embrittlement, monitoring for aging, maintenance issues, seismic effects, and operating experience. Most of these reports are readily available from the NRC website. A more detailed discussion of the NPAR Program can be found in the companion briefing report *Condition Monitoring of Passive Systems, Structures, and Components* (CGI Report 06:22).

EPRI Generic Aging Management Tools

As a follow-up to the earlier industry reports for critical component aging, EPRI consolidated the research conducted within those reports, other owner's group initiatives, the NRC NPAR program and the early LICENSE RENEWAL applications in a series of Aging Management Tools. The three documents provide specific guidance in matrix format (similar to the later GALL report) to license renewal applicants for the applicable aging effects, mechanisms, exposure environments, affected materials and effective aging management programs. The tools are as follows:

- *Mechanical Implementation Guideline And Mechanical Tools* – contains a number of individual reports to cover the applicable service conditions and environments for:
  - treated water conditions
  - raw water
  - oil containing systems
  - gas containing systems
  - external surfaces
  - bolting
  - heat exchangers
  - fatigue affected systems
- *License Renewal Electrical Handbook* – contains aging management guidance for electrical cable and terminations, penetrations, buses, conductors and insulators.
- *Aging Effects for Structures and Structural Components (Structural Tools)* -- contains aging management guidance for steel and concrete structures (beams, columns, floors, walls, foundations, roofs, etc), above and below grade, underwater, in freeze-thaw climate, indoors and outdoors. Also covered are piping and cable tray supports, electrical and control cabinets, racks and enclosures, fire barriers, elastomer seals and barriers, galvanized steel and threaded fasteners. An example of the aging matrix for steel components is shown on Table 10.

The INPO AP-913 Equipment Reliability Program

The Nuclear Plant Reliability Data Search (NPRDS) database was created by INPO following the Three Mile Island event to respond to NRC requests for generic operating experience accumulation and assessment. Each plant provided input of component failures and causes to facilitate searches and to identify precursors to potential failures. With the promulgation of the maintenance rule, a new software tool was required to manage the failures associated with the equipment included under the Maintenance Rule. These failures are considered "Maintenance Preventable Functional Failures" (MPFFs) and repeat failures and are reportable under the Maintenance Rule. In operation since 1996, the database now contains more than 100,000 failure events and descriptions and as such is a credible basis for establishing component failure rates. One major shortcoming is the absence of component populations, such that component estimates need to be made for the 104 operating plants. For some commodities, such as valves, breakers or cables, uncertainties are encountered. Nevertheless, the database has become a very useful tool to examine operating experience and failure modes. Another caution for the use of the data is the fact that reporting of failures is only required for systems and components included in the scope of the Maintenance Rule, that is largely safety related equipment.

Table 10: *Applicable Aging Effects for Structural Steel Components and Materials*

APPLICABLE AGING EFFECTS	CARBON STEEL	LOW-ALLOY STEEL	GALVANIZED STEEL	STAINLESS STEEL
Loss of Material				
General Corrosion	Y	Y	N-protected atmosphere/weather Y-exposed atmosphere/weather	N
Galvanic Corrosion	N	N	N	N
Crevice Corrosion	N	N	N	N
Pitting Corrosion	N	N	N	N
Erosion and Erosion Corrosion	NA	NA	NA	NA
Microbiologically Induced Corrosion	N	N	N	N
Wear	N	N	N	N
Cracking				
Hydrogen Damage	N	N	N	N
Stress Corrosion	N	N	N	N
Fatigue	N	N	N	N
Mechanical Distortion				
Creep	N	N	N	N
Fatigue	N	N	N	N
Change in Material Properties				
Elevated temperatures	N	N	N	N
Irradiation Embrittlement	N*	N*	N*	N*
Intermetallic Embrittlement	NA	NA	N-provided temperature < 400 °F	NA

Key: Y- aging mechanism is applicable.
N- aging mechanism is not applicable
NA- Not Applicable to this chapter
*- Outside Primary Shield Wall.

While not a bona fide research program, this INPO developed reliability management guide provides plant owners with a structured methodology to more effectively apply and manage their maintenance programs. The guide is not mandatory and plant owners can customize their programs to incorporate existing programs and procedures, as long as the principal objective of improving equipment reliability is met. The programmatic details are discussed in an earlier section of this report.

NEI Guidelines

The Nuclear Energy Institute (NEI) has accepted the responsibility of developing industry guidelines for the implementation of new regulatory requirements and other topics not addressed by EPRI or INPO, such as business planning. The three most prominent guides associated with aging management of plant systems, structures, and components are:

- NEI-95-10, *Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule Plants* – this guide is discussed in the License Renewal Rule section of this report and in the companion briefing report CGI 06:22
- NEI-93-01, *Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants* – this guide is discussed in the Maintenance Rule section of this report
- NEI-AP-940, *Nuclear Asset Management Process Description and Guideline*:

In NEI-AP-940 asset management process guidance includes strategic and generation planning, project evaluation and ranking, long range planning, budgeting, and plant / fleet valuation. The process deals with the high-level business management of a fleet or a single plant. The most interesting section of this guide is the topic of project evaluation and ranking. Industry surveys showed that there is no consensus with respect to the method of selecting and ranking specific projects from a multiple projects listing and being restrained by a fixed budget. Many different methods have been proposed, from risk ranking, expert panel (Delphi), cost-benefit, operational priorities, safety considerations and the rucksack method (what to take with you in a fixed volume rucksack for a one week survival trip).

Ongoing EPRI Aging Research

A lesson learned about aging management, is that no matter how precise and detailed the aging studies are performed, there is always the unexpected, often a combination of events that surprises the engineers. In the nuclear industry there is no exception and unknown material behavior, degradation mechanisms and aging effects are discovered as the plants age. Largely due to the inspection programs in place today, these "surprises" are discovered in time to facilitate timely corrective actions.

During the last ten years, accelerated degradation associated with crack initiation was discovered in the stainless steel reactor vessel internals. The cause was determined to be stress corrosion cracking, assisted by fatigue and un-annealed weldments. A major research project was initiated by the industry and managed by EPRI to find solutions, mitigation techniques and new inspection methods to investigate, size, and analyze the cracks. Just recently another new issue emerged concerning the cracking of Alloy 600 and similar Inconel alloys. This also is attributed to stress corrosion cracking, aggravated by the unique water environment (high hydrogen levels and borated water) in the PWR reactors. As before, the industry convened a large task force to deal with the issue and EPRI again is managing the project for the plant owners. These two projects and others are now combined under the EPRI Materials Research Program (MRP).

Code and Standards Perspective of Aging Management

In principle, Codes and Standards are voluntary, unless mandated by a government authority. The ASME Boiler and Pressure Vessel Code (ASME-BPVC) is mandated by the state authorities and the NRC for safety related pressure vessels, while the Electrical

Code (IEEE) and Fire Protection Codes are enforced by national building codes (NFPA). The American Concrete Institute Codes are mandated by the building codes for residential and commercial construction, however for power plants and other industrial facilities the Engineer/Designer is responsible for Code compliance. For the safety related portion of the nuclear plant, the USNRC mandates certain ACI Codes, including ACI-349. A brief description of the code activities involving aging management is presented below.

ASME-BPVC PLEX Working Group

Section XI, "Inservice Inspection of Nuclear Power Plant Components" of the ASME Boiler Code is the applicable Code specifying inspection and testing requirements for the nuclear plant components, as well as frequency of inspections, personnel qualifications and inspection techniques to be applied. A special working group was established within Section XI to accommodate the eventual integration of aging management into the Code. As a first action, the committee removed the 40-year inspection schedule (four 10-year cycles) from the Code to permit continued 10-year intervals until the plant shuts down for decommissioning. In the interim the Working Group monitors technical issues as they emerge from the license renewal process for future integration. The Code does not react to new issues very quickly and purposely takes its time to test implementation problems before codifying them.

IEEE Working Group for Aging Management of Electrical and I&C Equipment

The Institute of Electrical and Electronics Engineers (IEEE) generated a guide for aging management of electrical and instrumentation equipment, P-1205 (draft), "IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class IE Equipment Used in Nuclear Power Generating Stations". The guide contains a comprehensive aging effects and mechanisms matrix and the associated effective aging management methods. It is *not certain if this guide was ever formally issued.*

ACI Standards for Evaluation of Existing Concrete Structures

The American Concrete Institute (ACI) had a working condition survey standard for concrete inservice since 1968, ACI-201.1R, "Guide for Making a Condition Survey of Concrete Inservice". The Code addresses some 38 degradation effects, including ten types of cracking. For most of the degradation effects, reference photographs are provided for the inspector to discern the exact nature of the defects. The code has been updated a number of times, the 1996 version being the latest. The code has been widely in use for municipal and public use structures (garages, bridges, event buildings, etc), but has also been applied to power plants, including the nuclear facilities.

More recently, ACI issued a new Code with specific application to safety related structures, ACI-349-3R, "Evaluation of Existing Nuclear Safety Related Concrete Structures". In addition to the condition survey requirements as defined in ACI-201, this standard provides definitive acceptance criteria at two levels, Acceptance without further evaluation and acceptance with review. The acceptance criteria for concrete inspections are provided in Table 11.

Table 11: *Concrete Inspection Acceptance Criteria (from ACI-349), Edited*

Concrete Defect Description	Acceptance Criteria Without Review	Acceptance Criteria With Review
Leaching and Chemical Attack	None permitted	None permitted
Abrasion, Corrosion, Cavitation	None permitted	Evaluate Defects
Drummy Areas, Poor Concrete	None permitted	<Cover Concrete
Popouts, Voids	<20mm diameter or Equiv. Area	<50mm diameter or Equiv. Area
Scaling	<5mm in depth	<30mm in depth
Spalling	<10mm in depth, <100mm in any dimension	<20mm in depth, <200mm in any dimension
Passive Cracks	<04mm in width	<1.0mm in width
Passive Deflection, Settlement	None permitted	Within design limits
Loss of Coatings	<4000mm^2 for any area	>4000mm^2 for any area
Leakage	None permitted	Evaluate any leakage

Lessons Learned from the Initial License Renewals

The license renewal process has been a 25-year learning curve. The initial version of the Rule in 1991 was found to be open-ended with an overwhelming program scope. The nuclear industry and the USNRC staff identified many problems with the initial Rule. The amended Rule in 1995 established a regulatory process that is simpler, more stable, and more predictable than the initial License Renewal Rule. It put the focus of the license renewal assessment on the licensees aging management activities concerning passive and long-lived SSCs. It also clarified the focus on managing the adverse effects of aging rather than identification of all aging mechanisms. The changes to the integrated plant assessment (IPA) process were to make it simpler and more consistent with the revised focus on passive, long-lived systems, structures and components. However there remained a number of areas where further improvements were needed in the application process.

In the late 1990's the Calvert Cliffs plant announced its plan to file an application using the revised Rule and the NEI license renewal application guide, NEI 95-10. NEI 95-10 provides an approach that the USNRC has found to be acceptable and has endorsed for implementing the requirements of the License Renewal Rule. The guidelines in the NEI 95-10 report are based on industry experience in implementing License Renewal Rule.

The review of the Calvert Cliffs applications by the USNRC staff revealed some serious problems. These included the fact the staff had very little guidance, no training, and a diverse view of what the regulations actually meant. Also, questions were raised with respect to the license renewal application costs, utility commitment, and effectiveness of the Rule. Senior management from both the USNRC and the nuclear industry worked to address these and other weaknesses with the license renewal process. This involved numerous site visits to familiarize the USNRC staff with site conditions and to conduct scope audits.

It became apparent that much of the information to be developed for an application is of a generic nature. It was determined that standards and guidance were needed to avoid unnecessary duplication of work. Guidance was also needed to avoid technical inconsistencies so that there are not different interpretations of the technical findings and conclusions from one application reviewer to another.

To address these and other issues the USNRC and the nuclear industry developed a number of guidance documents. One of the key documents has been the Generic Aging Lessons Learned (GALL) Report (NUREG-1801). The GALL report provides a template of aging management programs that have been determined to be acceptable by the USNRC to manage the aging effects of safety critical passive and long-lived SSCs. The GALL Report documents the USNRC's basis for determining which existing programs are adequate without modification and which existing programs should be augmented for license renewal. A complimentary Standard Review Plan (NUREG-1800) was developed as a guide to the USNRC staff for their review of the application information.

Strong emphasis has been placed on training NRC staff and plant owners to assure that all stakeholders are aware of the process, requirements, tools and reference guides. The NRC implemented an extensive training program for their staff members and assigned additional inexperienced staff to their site audit teams to observe and learn the process. Training modules also were developed by the owners groups and EPRI to be conducted at the plant sites for different levels of staff, management briefings and working level indoctrinations.

The next license renewal applicants were able to use these guidance documents in the development of their applications. Major cost reductions were realized with the streamlined process. Savings were estimated to be in the range of 50% to 75% with respect to the Calvert Cliffs project costs. Further improvements were initiated by the USNRC to shorten the review process from three years to less than two years, to deal with staff shortages and reflect the learning curve. The nuclear industry and NEI also sponsored development of the Aging Management Tools, a commitment database (to assure that applicants do not over-commit or fail to address previous USNRC issues), and a searchable database for NRC generic communications.

The lessons learned from these efforts and the continued review process has been incorporated into the latest revision of the GALL report and the Standard Review Plan. The process has matured to a point were the USNRC has been able to review multiple plant applications in parallel. Utilities have seen major cost and schedule reductions for the license renewal process; fewer site visits and experienced significantly less interaction with the USNRC during the review process.

Some to the key documents that are used by both the licensees and the USNRC during the license renewal process are listed in Table 12. These are all “living documents”. Revised versions of the reports are routinely produced that incorporate changes based on experience gained from numerous license renewal application reviews by USNRC staff and from insights identified by the industry. For example, the, NEI 95-10 is currently in its sixth revision.

Table 12: *License Renewal Support and Guidance Documents*

Document Title	Document Identifier
Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants	NUREG-1800 (USNRC)
Generic Aging Lessons Learned (GALL) Report	NUREG-1801 (USNRC)
Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses	Regulatory Guide 1.188 (USNRC)
License Renewal Inspections	Inspection Manual 71002 (USNRC)
Policy and Guidance for License Renewal Inspection Programs	MC-2516 (USNRC)
Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 - The License Renewal Rule	NEI 95-10 (Nuclear Energy Institute)

Reaching Process Consensus among Stakeholders

As described above, the license renewal process has undergone substantial evolution. This implies recognition of the need to and willingness to change by all parties involved. Pressure was applied on the regulator to keep the process on track, simplify it and make it effective for all stakeholders. The mistakes made with the initial rule could not be repeated and a stable and workable process had become essential for success. Such a proven process also lends itself to standardization, further assuring consistency and efficiency. One of the key concerns with new regulations is the threat of "Rule Creep", that is the ever-changing interpretations of the regulations, issuance of new guidance, raising of new issues, different treatment of the same issue for other applicants and the constant desire to invent new wheels. In this case, the NRC and utilities were jointly motivated to develop a streamlined and stable methodology. The development of the GALL report and NEI license renewal Guide, NEI 95-10, are considered major tools to achieve those objectives.

The process has by no means found its end point, additional lessons learned, improvements and experience feedback are being monitored and revisions of the key references are planned to capture process changes. The most recent evidence of the continuing consensus evolution is an EPRI project to prepare so-called "Road Maps" for generic technical issues and associated aging management programs. This project evolved from the tallying and review of individual plant commitments and to sort those that are common to many plants and therefore deserve identical treatment and resolution. These road maps are to assist plant owners to develop implementation tasks for their license renewal commitments at least costs and assuring acceptability of implementation. The road maps also identify technical issues that are not fully resolved yet and require research to facilitate task implementation prior to the start of the license renewal period. The NRC is expected to audit these implementation activities in the future and they are tracking compliance with the applicant's commitments.

Another method to communicate current development, lessons learned and ideas of process improvement is facilitated through frequent workshops sponsored by the NRC and the industry. These workshops encourage presentations from all stakeholders and the public to solicit input and opinions. They are also a vehicle to share information with management, vendors, suppliers of services, inspectors, public members and other interested parties. All or most of the license renewal information, including the complete application packages, USNRC application reviews (SER), rules and regulations and guidance documents (GALL, SRP-LR, NEI-95-10, Regulatory Guides, Interim Staff Guidance) are available on the USNRC website (www.nrc.gov).

Life Extension Implementation at the Plants

The Two-Step Process

Life Extension for a plant is considered a two-step process. The initial step is to secure regulatory approval through license renewal application process. The second step is to actually implement life extension for the plant. Although the approval of a license renewal allows continued operation for 20-years it does not require such operation. The decision to actually operate beyond the current license period is up to the licensee. It is dependent on such factors as power generation planning, economic justification, and prevailing condition of the plant.

The aging management requirements of the license renewal application only apply to the safety-related scope under the License Renewal Rule – about one-third of the plant equipment. In order to prepare the plant for life extension, the remaining power production part of the plant has to be upgraded and evaluated to assure that the equipment can support reliable operation for an extra 20 years. Many plants will wait until about five years before the extended license becomes effective (at year 35 of the plant life) to avoid large capital investments that may become stranded if the plant owners decide not to implement life extension. Often these objectives are compromised, because the plant may need a new turbine generator or main transformer at year 34, without life extension such an investment would not be cost beneficial such that the extended life period is needed in the cost benefit analysis.

Proactive Implementation Tasks

While most of the license renewal commitments for the plant apply only for the extended operating period, there are a number of preparatory and mitigative actions taken by the plants to reduce future costs and to collect the information needed for future assessments. The following are some of the proactive, diagnostic, preventive, predictive and investigative activities performed by plants in preparation for license renewal:

- Temperature Survey of Spaces for EQ
  - Initial survey with Pyrometer or Thermography to locate "Hot Spots", actual temperature variations within the space, room or enclosure, locations with temporary elevated temperature and containing vulnerable electrical equipment
- Fatigue Cycle Counting and Monitoring
  - Simple cycle counting and transient categorization to be compared to the design basis assumptions and projected for 60 years. Thermal transient monitoring to determine the rate of transients for future reclassification and margin hunting.
- Biological Essays (Tests) of Water Sources
  - Sampling and testing for MIC of all water sources (Service Water, raw water, demineralized water, closed loops, sumps, storage tanks, lube oil, fuel oil)

- Visual Inspection of Inaccessible Areas
    - When opening up equipment (pumps, valves, heat exchangers, tanks/vessels) or removing insulation, perform a visual (VT-1 or VT-3) inspection of the normally inaccessible surfaces and record the conditions (corrosion, cracking, loss of material, staining, etc). When excavating buried/embedded pipe, steel and concrete structures, trenches, cable ducts, perform a VT-1 or VT-3 and take good pictures of the normally inaccessible surfaces.
- Wall Thickness Measurements
    - When possible, conduct sample UT wall thickness measurements on carbon steel piping, valve bodies, pump casings, heat exchanger and vessel shells, tank walls and bottoms, etc. Identify and record abnormal conditions.
- Underwater Inspections
    - When using divers in the intake, fuel pools, etc, train divers for VT-1 examinations and debrief afterwards. Document conditions and take photos if possible.
- Soil and Groundwater Tests
    - Take soil and groundwater samples and test for chlorides, sulfates, silica, cement paste, iron oxides. Take samples as near to the structure as possible from test wells, borings, and excavations. Monitor groundwater level and variations at least over a few years.
- Settlement Monitoring
    - If the plant sits on soil or piles, consider installing, reactivating or updating the settlement monitoring system for the principal structures (Containment, Auxiliary or Reactor Building, Intake).
- Air Sampling and Testing
    - Sample and test the external plant air to determine the extent and type of air pollution at the site, measure chlorides, CO, SOX, NOX, particulates to establish aggressiveness. For ocean plants, measure the concentration of NaCl (salt) for various weather and wind conditions in the ventilation intakes.
- Beltline Material Surveillance
    - Review the material test coupon withdrawal schedule and make adjustments as early as possible to accommodate a 60-year (and possibly 80 year) operating period. Consider reinsertion of the material, using miniaturization and reconstitution of the coupons for future embrittlement tests.

License Renewal Commitment Implementation after Year 40

Once the plant approaches the end of the current operating license and decided that economics dictate continuation of operation and that an extended life is warranted and desirable, the commitments made in the license renewal application become mandatory and full implementation must be achieved before the plant can continue to operate past

40 years. Plants consider it unwise to wait to the last minute, particularly for new inspection programs, such as certain one-time inspections, where surprises could occur in that unexpected degradation is found. In such case, the aging management program for the affected components would not be effective and would require changes and regulatory review prior to continued operation. Other programs that merely require procedure changes or administrative actions could be delayed to the last year. Another aspect of the implementation process is to consider the generic guidance developed by NEI and EPRI, such as the "Road Maps" discussed earlier. It is important to implement tasks that are acceptable to the regulator, feature the attributes and requirements as well as scope committed to in the application.

Typically a plant will have between 200 and 400 individual license renewal tasks to implement. To assure that the tasks are all properly scheduled for completion and documentation is generated, a computerized database is normally used to track responsibility, schedule, completion status and associated design and quality assurance records/references. Many tasks require follow-up actions or re-inspections at a predetermined interval and inspection results must be evaluated and documented. The plant has to be able to verify implementation to the regulator's onsite inspectors.

A new Appendix to the License Renewal Guide, NEI 95-10, has been drafted and issued. The purpose of this Appendix is to provide guidance to utility personnel for the follow-up actions after receipt of a renewed license.

In parallel, the USNRC has also developed inspection guidance for their onsite inspectors, as well as training programs to get ready for the extended operating period. The applicable inspection program policy document is embodied in the USNRC's "Policy and Guidance for License Renewal Inspection Programs", MC-2516. Because of its relevance an edited copy of this policy document has been included in Appendix E.

International Applications and Interaction

The US has taken an active role in transferring the aging management and life extension technology to other countries and international organizations. This has taken place at all levels, starting with the NRC participation in IAEA working groups to draft international standards, to individual consultants assisting foreign countries and organizations to develop their own programs. Many international conferences on nuclear technology, such as ICONE, SMIRTand IPLEX, have carried specific sessions to address life extension, aging management and operational issues. US corporations and government agencies have extensively participated in these sessions and shared their experiences and processes with the international community. Additionally, the USNRC website provides most of the regulatory guidance documents and licensing proceedings without restrictions. The following specific examples of technology transfer provide just a small piece of the word wide application of this US technology.

- The Spanish regulator required the Spanish utilities to implement the Maintenance Rule as defined in the US regulations. Assistance was provided to the utilities in shaping a program tailored to their needs and unique circumstances. Spanish regulatory representatives cross trained with the USNRC in their Washington headquarters to learn about the implementation process and the procedures.
- The IAEA relied on US participation to draft License Renewal and Aging Management standards, using US precedents, methodology and references. This has led to the development of international policy documents and generation of a number of Aging Management Standards (Containment, Reactor Vessel)
- Japan having some of the oldest nuclear plants in the world, has benefited from the early aging studies conducted in the US. Aging analysis reports have been made available to Japanese utilities through a number of technology exchange channels.
- South Korea has applied US life extension technology to their plants, both in the aging evaluations and degradation assessments/inspections.
- France (EDF) through a technology exchange agreement with EPRI has acquired the US life extension technology and life cycle management processes. A number of training seminars and workshops were held in France to present the technology.
- Switzerland, through their utility owners group, has made use of the life extension and aging management technology, specifically the identification of applicable aging effects and mechanisms and their aging management programs. Following a successful national referendum on the continuation of nuclear power, the Swiss plants are preparing their license renewal applications.

Lessons Learned – Possible Petroleum Industry Application

For over fifteen years the USNRC and the nuclear industry have been continuously refining both the license renewal requirements and the renewal process. There are many aspects of these aging management and life extension efforts and the lessons that have been learned that can be of potential value to the PSA and the Norwegian petroleum industry.

Aging Research Information

The wealth of aging related information produced by the NPAR and industry aging research programs remains a useful resource for both nuclear and non-nuclear organizations. Although the aging studies examined SSCs with respect to their operation in the nuclear plants, much of the aging degradation and aging management information is applicable to the petroleum and other industrial sectors.

Continuous Improvement

Over the years both the USNRC and the industry have been working to make the license renewal requirements and the renewal process more efficient and effective. For example, the initial version of the Rule did not provide a predictable nor stable process – it was too open ended with too broad a scope. It was determined that many aging effects were already adequately addressed during the initial operating license period. Also, the initial Rule did not allow sufficient credit for existing programs, particularly those under the USNRC Maintenance Rule, which help manage plant aging phenomena as part of the on-going maintenance program tasks.

The resulting revised Rule established a simpler, more stable, and more predictable regulatory process. The key changes that were made included:

- focusing on the adverse effects of aging rather than identification of all aging mechanisms – identification of individual aging mechanisms is not required
- simplifying the integrated plant assessment process and madding it consistent with the revised focus on the detrimental effects of aging
- adding an evaluation of time-limited aging analyses (TLAA)
- requiring only passive, long-lived structures and components to be subject to an aging management review for license renewal – removing active SSCs from license renewal

Passive versus Active SSCs

An important aspect of the US nuclear plant life extension requirements is the distinction between passive and active systems, structures, and components. Passive SSCs are those that do not move to function (such as, structures, heat exchangers, cables, valve and pump bodies, and piping). Their age related degradation can only be monitored and trended by performing periodic condition assessments (such as inspections, testing, and measurements).

By focusing the license renewal process on safety critical passive and long-lived components the process has been reduced to a manageable proportions – licensees are not required to consider all SSCs in order to justify extended operations.

Guidance and Training

One of the key lessons has been the need to provide clear guidance and support to all involved parties. Both the USNRC and the industry have developed guidance documents to assist in the development of aging management programs, the preparation of the renewal application, and the review of the application. As lessons are learned these guidance documents are revised to capture new insights or address emerging issues. Along with the guidance documents, training programs and support activities have greatly reduced the time and expense in preparing, reviewing, and approving the license renewal applications. The training must be supplemented with guides, pilot studies, working examples, and procedures to assure consistency of application.

Integration of Aging Management Program Requirements

From the description of the many diverse aging management programs it becomes clear that plants have a difficult time to integrate all the different requirements and to avoid duplication and non-effective maintenance tasks. Too much maintenance can lead to reliability and availability concerns and it is necessary to strive for an adequate balance. Other drivers are manpower, costs, prioritization of activities and consolidation of tasks. As part of the Maintenance Rule, the plants already have established a 13-week schedule, that is each system or train (where systems have redundant trains) will be taken out of service for one week every 13 weeks, or four times a year. During this one-week system outage, all the preventive and corrective maintenance tasks are to be completed, including invasive inspections, tests, calibrations, repairs and replacements. Once license renewal activities begin, additional tasks will have to be squeezed into the maintenance week, likely at the expense of other similar tasks.

Long-term Maintenance Strategy

When contemplating aging management for a facility, the useful life expectancy and associated planning horizon must be established first, to provide a basis for the long-term maintenance strategy. The ultimate operating life has a profound impact on the selection of appropriate and economic maintenance alternatives. It is prudent to link asset management to maintenance strategy with an objective to preserve the assets as long as economically feasible. A lesson learned from the aging management projects is that most components can be replaced and that good aging management can preserve structures for decades if not centuries (the B-52 aircraft are over 50 years old and are still flying).

Reducing Component Failures

No other maintenance action taken in the plant will have as much impact on equipment reliability and plant availability as reducing the failure rates of components. The plant or system performance cannot be better than the worst performing critical component. All efforts must therefore be directed to identify incipient failures, precursors and age related degradation. This implies that inspections and diagnostics must be employed in areas where failure knowledge and prediction is inadequate. In general plants are not aggressive enough to reduce failures and to invest in predictive maintenance. Even though some plants have a "Zero Failure Tolerance" policy, when it comes to making investments, replacements are preferred.

Effectiveness of Condition Monitoring

It is not unusual to find that plants have implemented predictive maintenance tools to monitor equipment conditions, but the diagnostics are not effective in preventing failures. One example is vibration monitoring of rotating equipment, when data is read infrequently (once a month) with portable equipment. Bearing degradation can progress, and often will, from minor imbalance to catastrophic failure within minutes or hours. Continuous monitoring with alert and warning levels is significantly more effective. Another example is oil analysis and ferrography performed at certain intervals is mostly used to justify an increase in the oil change interval. Installing oil reservoir breather caps and filters will be more effective to keep contaminants out of the oil. Thermography has slowly made inroads in detecting degradation and incipient failures, even though the surveys are done typically only annually and only for readily accessible equipment. More aggressive and effective thermography can be performed for electrical equipment inside enclosures, using infrared windows. Enclosed motors also can be surveyed internally using infrared windows on the casing to measure rotor and stator, slip ring and bearing temperatures to identify hot spots.

Establishing Appropriate Inspection Procedures

The two major questions concerning an effective inspection program are: What and how often to inspect? For components such as cable, piping, valves, pumps, motors a sampling program is the most effective means of inspection. Sampling rates must be representative with respect to component size, vendor, materials, service and environmental exposure. An example is to start with a 10% sampling rate and decreasing the rate after five years if nothing is found. Or doubling the rate if defective equipment is found. If more than one deficiency is found, a 100% inspection would be justified.

If a risk analysis is available, component selection and prioritization can be made by using risk measures. If aging evaluations have been performed, the most vulnerable components and locations should be known and become the focus of inspections. The frequency of inspections depends on the degradation one is looking for. If the known degradation is a fairly rapid and aggressive process, inspection periods of one to two years are not uncommon, while inspections of steel and concrete structures are undertaken at ten-year intervals. If acceptable defects are found or if repairs have been performed, the inspection periods should be shortened, commensurate with the rate of degradation or on an annual basis.

Just because nothing has been found for 20 or 30 years does not imply that degradation is absent, it may just be slow or takes a long time to crack initiation and propagation. The most troubling degradation issues in the nuclear plants became apparent after more 20 years of operation and exposure.

Aging Management of Inaccessible Equipment

A major concern in the license renewal process is equipment that is not readily accessible to inspection, testing or diagnostics. Underground piping and cable, embedded steel, underwater structures are examples of these cases. Unique programs were developed to deal with these components and to assure that degradation is adequately managed. Onetime inspections, selected excavations, use of test coupons and monitoring of the service environment (soil and water chemistry, evidence of corrosion products) were employed to indicate when and where degradation becomes active. Managing these inaccessible components and structures should be a priority, because replacement and repair is not usually a feasible option.

Sharing Experiences

An effective failure reduction strategy is to access, review and analyze equipment failures at other facilities. Problems and difficulties at older facilities or those that have greater operating hours can be a valuable source of leading indicators of what to watch out for. Generic failures may point out particularly vulnerable parts, impact of abnormal operation, failure indicators, methods of detection and actual service hours to failure.

Another important source of information is gained by monitoring of other plant's experience and programs to identify those activities that work and those that do not work. The sharing of best practices, however has been impeded by the deregulation of the nuclear power industry. Unfortunately, in certain cases, information that provides an economic advantage to one plant becomes a valuable commodity that is likely not to be shared with others.

Manufactures usually do not have a good understanding of the operational performance of their equipment in the field and are only performing root cause assessments when they receive a warranty claim. Maintenance recommendations from the manufacturer must be taken with great caution and only if a technical basis exists for their recommendations, such as operational failure rate trends and component life expectancies.

Pilot Projects

When attempting to create new regulations with complex processes, it is imperative to test the regulations and processes in a real application environment. The first License Renewal rule failed as a result of applying it to a demonstration project. All stakeholders must participate in this test program to understand the implications and be willing to search for acceptable compromise. The revised rule was a success because of frequent interaction among the stakeholders, participation of and guidance from senior management representatives and a willingness to change and adapt during the development process.

Properly Quantify Consequential Failure Costs

Often when cost benefit analyses are performed to justify corrective or preventive actions following equipment failures, the consequential failure costs are not adequately incorporate into the analyses. This can lead to erroneous assumptions and conclusions.

Failure costs can include lost production, personnel injury, lost work time, and medical costs. The more serious the failure the greater the impact on the plant and the organization. Some plants have been forced to shutdown for several years because of equipment failures and human errors. It is therefore important to identify and quantify the consequential failure costs to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy

Quantify Consequential Failure Costs

Often when cost benefit analyses are performed to justify corrective or preventive actions following equipment failures, the consequential failure costs are not adequately incorporate into the analyses. This can lead to erroneous assumptions and conclusions. As stated earlier, the value of one day's lost power production approaches one Million Dollars for most plants. In addition, some failures cause personnel injury, lost work time, medical costs and inquiries by the safety authorities. Other failure consequences may even be more drastic, including fires, flooding, steam escape, explosions, radioactive contamination or releases. The more serious the failure, the more impact there will be on the corporate well being, from an impact on the stock price, annual dividend and earnings, public image and potential regulatory actions and fines. Some plants have been forced to shutdown for periods up to two years, because of equipment failures and human errors. It is therefore important to identify and quantify the consequential failure costs to support reliable conclusions and to justify implementation of a predictive maintenance and effective aging management strategy.

Conclusions

The aging management and life extension process for the US nuclear industry has been refined and improved over the years. It has become an efficient and effective method to ensure that the nuclear plants in the United States can be safely operated beyond their original 40-year operating license. By dividing the safety critical systems, structures, and components into passive and active categories the industry and regulator have reduced the potentially overwhelming analysis effort to a reasonable and manageable size.

By working together, the nuclear industry and the US Nuclear Regulatory Commission (USNRC) have been able to technically justify life extension. The process has been structured to not be an economic or resource burden on either the licensees or the USNRC. However, all parties are continually reviewing the process and results to identify where improvements can be made.

The process has been selected as a viable method by many international regulatory and nuclear industry organizations, including those in Spain, Taiwan, and Korea. The International Atomic Energy Agency in Vienna has also adopted the process as the model for ensuring safe extended life operations.

The aging management and life extension process can be easily adapted to other industries. The development strategy, research material, specific elements of the process, and many of the lessons learned can all be of potential value to the PSA and Norwegian petroleum industry in ensuring safe extended operations of the facilities.

Appendices

A The Maintenance Rule: Title 10 of the US Code of Federal Regulations, Part 50.65 (10 CFR 54.65)

B The License Renewal Rule: Title 10 of the US Code of Federal Regulations, Part 54 (10 CFR Part 54)

C USNRC Guidance Concerning Aging Effects and Aging Mechanisms

D Aging Management Program Example – Concrete Structures Monitoring: GALL Report-(NUREG-1801 Vol 2)

E License Renewal Inspection Policy and Guidance: USNRC Inspection Manual Chapter (MC) 2516 – Policy and Guidance for the License Renewal Inspection Programs

F Nuclear Related Aging Management and Life Extension Abbreviations and Acronyms

G Bibliography of Selected Nuclear Aging Management and Life Extension Reports

Appendix A

The Maintenance Rule

Title 10 of the US Code of Federal Regulations, Part 50.65
(10 CFR 54.65)

Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants

The requirements of this section are applicable during all conditions of plant operation, including normal shutdown operations.

(a)(1) Each holder of a license to operate a nuclear power plant under Secs. 50.21(b) or 50.22 shall monitor the performance or condition of structures, systems, or components, against licensee-established goals, in a manner sufficient to provide reasonable assurance that such structures, systems, and components, as defined in paragraph (b), are capable of fulfilling their intended functions. Such goals shall be established commensurate with safety and, where practical, take into account industry-wide operating experience. When the performance or condition of a structure, system, or component does not meet established goals, appropriate corrective action shall be taken. For a nuclear power plant for which the licensee has submitted the certifications specified in Sec. 50.82(a)(1), this section only shall apply to the extent that the licensee shall monitor the performance or condition of all structures, systems, or components associated with the storage, control, and maintenance of spent fuel in a safe condition, in a manner sufficient to provide reasonable assurance that such structures, systems, and components are capable of fulfilling their intended functions.

(2) Monitoring as specified in paragraph (a)(1) of this section is not required where it has been demonstrated that the performance or condition of a structure, system, or component is being effectively controlled through the performance of appropriate preventive maintenance, such that the structure, system, or component remains capable of performing its intended function.

(3) Performance and condition monitoring activities and associated goals and preventive maintenance activities shall be evaluated at least every refueling cycle provided the interval between evaluations does not exceed 24 months. The evaluations shall take into account, where practical, industry-wide operating experience. Adjustments shall be made where necessary to ensure that the objective of preventing failures of structures, systems, and components through maintenance is appropriately balanced against the objective of minimizing unavailability of structures, systems, and components due to monitoring or preventive maintenance.

(4) Before performing maintenance activities (including but not limited to surveillance, post-maintenance testing, and corrective and preventive maintenance), the licensee shall assess and manage the increase in risk that may result from the proposed maintenance activities. The scope of the assessment may be limited to structures, systems, and components that a risk-informed evaluation process has shown to be significant to public health and safety.

(b) The scope of the monitoring program specified in paragraph (a)(1) of this section shall include safety related and nonsafety related structures, systems, and components, as follows:

(1) Safety-related structures, systems and components that are relied upon to remain functional during and following design basis events to ensure the integrity of the reactor coolant pressure boundary, the capability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposure comparable to the guidelines in Sec. 50.34(a)(1), Sec. 50.67(b)(2), or Sec. 100.11 of this chapter, as applicable.

(2) Nonsafety related structures, systems, or components:

(i) That are relied upon to mitigate accidents or transients or are used in plant emergency operating procedures (EOPs); or

(ii) Whose failure could prevent safety-related structures, systems, and components from fulfilling their safety-related function; or

(iii) Whose failure could cause a reactor scram or actuation of a safety-related system.

(c) The requirements of this section shall be implemented by each licensee no later than July 10, 1996.

Appendix B

The License Renewal Rule

Title 10 of the US Code of Federal Regulations, Part 54
(10 CFR Part 54)

Requirements for Renewal of Operating Licenses for Nuclear Power Plants

General Provisions

§ 54.1 Purpose.

This part governs the issuance of renewed operating licenses for nuclear power plants licensed pursuant to Sections 103 or 104b of the Atomic Energy Act of 1954, as amended (68 Stat. 919), and Title II of the Energy Reorganization Act of 1974 (88 Stat. 1242).

§ 54.3 Definitions.

(a) As used in this part,

Current licensing basis (CLB) is the set of NRC requirements applicable to a specific plant and a licensee's written commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71 and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

Integrated plant assessment (IPA) is a licensee assessment that demonstrates that a nuclear power plant facility's structures and components requiring aging management review in accordance with § 54.21(a) for license renewal have been identified and that the effects of aging on the functionality of such structures and components will be managed to maintain the CLB such that there is an acceptable level of safety during the period of extended operation.

Nuclear power plant means a nuclear power facility of a type described in 10 CFR 50.21(b) or 50.22.

Time-limited aging analyses, for the purposes of this part, are those licensee calculations and analyses that:

(1) Involve systems, structures, and components within the scope of license renewal, as delineated in § 54.4(a);
(2) consider the effects of aging;
(3) Involve time-limited assumptions defined by the current operating term, for example, 40 years;
(4) Were determined to be relevant by the licensee in making a safety determination;
(5) Involve conclusions or provide the basis for conclusions related to the capability of the system, structure, and component to perform its intended functions, as delineated in § 54.4(b); and

(6) Are contained or incorporated by reference in the CLB.

(b) All other terms in this part have the same meanings as set out in 10 CFR 50.2 or Section 11 of the Atomic Energy Act, as applicable.

§ 54.4 Scope.

(a) Plant systems, structures, and components within the scope of this part are--

(1) Safety-related systems, structures, and components which are those relied upon to remain functional during and following design-basis events (as defined in 10 CFR 50.49 (b)(1)) to ensure the following functions--

(i) The integrity of the reactor coolant pressure boundary;

(ii) The capability to shut down the reactor and maintain it in a safe shutdown condition; or

(iii) The capability to prevent or mitigate the consequences of accidents which could result in potential offsite exposures comparable to those referred to in § 50.34(a)(1), § 50.67(b)(2), or § 100.11 of this chapter, as applicable.

(2) All nonsafety-related systems, structures, and components whose failure could prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(1)(i), (ii), or (iii) of this section.

(3) All systems, structures, and components relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the Commission's regulations for fire protection (10 CFR 50.48), environmental qualification (10 CFR 50.49), pressurized thermal shock (10 CFR 50.61), anticipated transients without scram (10 CFR 50.62), and station blackout (10 CFR 50.63).

(b) The intended functions that these systems, structures, and components must be shown to fulfill in § 54.21 are those functions that are the bases for including them within the scope of license renewal as specified in paragraphs (a)(1) - (3) of this section.

[60 FR 22491, May 8, 1995, as amended at 61 FR 65175, Dec. 11, 1996; 64 FR 72002, Dec. 23, 1999]

§ 54.5 Interpretations.

Except as specifically authorized by the Commission in writing, no interpretation of the meaning of the regulations in this part by any officer or employee of the Commission other than a written interpretation by the General Counsel will be recognized to be binding upon the Commission.

§ 54.7 written communications.

All applications, correspondence, reports, and other written communications shall be filed in accordance with applicable portions of 10 CFR 50.4.

§ 54.9 Information collection requirements: OMB approval.

(a) The Nuclear Regulatory Commission has submitted the information collection requirements contained in this part to the Office of Management and Budget (OMB) for approval as required by the Paperwork Reduction Act (44 U.S.C. 3501 et seq.). The NRC may not conduct or sponsor, and a person is not required to respond to, a collection of information unless it displays a currently valid OMB control number. OMB has approved the information collection requirements contained in this part under control number 3150-0155.

(b) The approved information requirements contained in this part appear in §§ 54.13, 54.15, 54.17, 54.19, 54.21, 54.22, 54.23, 54.33, and 54.37.

[60 FR 22491, May 8, 1995, as amended at 62 FR 52188, Oct. 6, 1997; 67 FR 67100, Nov. 4, 2002]

§ 54.11 Public inspection of applications.

Applications and documents submitted to the Commission in connection with renewal applications may be made available for public inspection in accordance with the provisions of the regulations contained in 10 CFR Part 2.

§ 54.13 Completeness and accuracy of information.

(a) Information provided to the Commission by an applicant for a renewed license or information required by statute or by the Commission's regulations, orders, or license conditions to be maintained by the applicant must be complete and accurate in all material respects.

(b) Each applicant shall notify the Commission of information identified by the applicant as having, for the regulated activity, a significant implication for public health and safety or common defense and security. An applicant violates this paragraph only if the applicant fails to notify the Commission of information that the applicant has identified as having a significant implication for public health and safety or common defense and security. Notification must be provided to the Administrator of the appropriate regional office within 2 working days of identifying the information. This requirement is not applicable to information that is already required to be provided to the Commission by other reporting or updating requirements.

§ 54.15 Specific exemptions.

Exemptions from the requirements of this part may be granted by the Commission in accordance with 10 CFR 50.12.

§ 54.17 Filing of application.

(a) The filing of an application for a renewed license must be in accordance with Subpart A of 10 CFR Part 2 and 10 CFR 50.4 and 50.30.
(b) Any person who is a citizen, national, or agent of a foreign country, or any corporation, or other entity which the Commission knows or has reason to know is owned, controlled, or dominated by an alien, a foreign corporation, or a foreign government, is ineligible to apply for and obtain a renewed license.
(c) An application for a renewed license may not be submitted to the Commission earlier than 20 years before the expiration of the operating license currently in effect.
(d) An applicant may combine an application for a renewed license with applications for other kinds of licenses.
(e) An application may incorporate by reference information contained in previous applications for licenses or license amendments, statements, correspondence, or reports filed with the Commission, provided that the references are clear and specific.
(f) If the application contains Restricted Data or other defense information, it must be prepared in such a manner that all Restricted Data and other defense information are separated from unclassified information in accordance with 10 CFR 50.33(j).
(g) As part of its application, and in any event before the receipt of Restricted Data or classified National Security Information or the issuance of a renewed license, the applicant shall agree in writing that it will not permit any individual to have access to or any facility to possess Restricted Data or classified National Security Information until the individual and/or facility has been approved for such access under the provisions of 10 CFR Parts 25 and/or 95. The agreement of the applicant in this regard shall be deemed part of the renewed license, whether so stated therein or not.
[60 FR 22491, May 8, 1995, as amended at 62 FR 17690, Apr. 11, 1997]

§ 54.19 Contents of application--general information.

(a) Each application must provide the information specified in 10 CFR 50.33(a) through (e), (h), and (i). Alternatively, the application may incorporate by reference other documents that provide the information required by this section.
(b) Each application must include conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license.

§ 54.21 Contents of application--technical information.

Each application must contain the following information:
(a) An integrated plant assessment (IPA). The IPA must--

(1) For those systems, structures, and components within the scope of this part, as delineated in § 54.4, identify and list those structures and components subject to an aging management review. Structures and components subject to an aging management review shall encompass those structures and components--

(i) That perform an intended function, as described in § 54.4, without moving parts or without a change in configuration or properties. These structures and components include, but are not limited to, the reactor vessel, the reactor coolant system pressure boundary, steam generators, the pressurizer, piping, pump casings, valve bodies, the core shroud, component supports, pressure retaining boundaries, heat exchangers, ventilation ducts, the containment, the containment liner, electrical and mechanical penetrations, equipment hatches, seismic Category I structures, electrical cables and connections, cable trays, and electrical cabinets, excluding, but not limited to, pumps (except casing), valves (except body), motors, diesel generators, air compressors, snubbers, the control rod drive, ventilation dampers, pressure transmitters, pressure indicators, water level indicators, switchgears, cooling fans, transistors, batteries, breakers, relays, switches, power inverters, circuit boards, battery chargers, and power supplies; and

(ii) That are not subject to replacement based on a qualified life or specified time period.

(2) Describe and justify the methods used in paragraph (a)(1) of this section.

(3) For each structure and component identified in paragraph (a)(1) of this section, demonstrate that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation.

(b) CLB changes during NRC review of the application. Each year following submittal of the license renewal application and at least 3 months before scheduled completion of the NRC review, an amendment to the renewal application must be submitted that identifies any change to the CLB of the facility that materially affects the contents of the license renewal application, including the FSAR supplement.
(c) An evaluation of time-limited aging analyses.

(1) A list of time-limited aging analyses, as defined in § 54.3, must be provided. The applicant shall demonstrate that--

(i) The analyses remain valid for the period of extended operation;

(ii) The analyses have been projected to the end of the period of extended operation; or

(iii) The effects of aging on the intended function(s) will be adequately managed for the period of extended operation.

(2) A list must be provided of plant-specific exemptions granted pursuant to 10 CFR 50.12 and in effect that are based on time-limited aging analyses as defined in § 54.3. The applicant shall provide an evaluation that justifies the continuation of these exemptions for the period of extended operation.

(d) An FSAR supplement. The FSAR supplement for the facility must contain a summary description of the programs and activities for managing the effects of aging and the evaluation of time-limited aging analyses for the period of extended operation determined by paragraphs (a) and (c) of this section, respectively.

§ 54.22 Contents of application--technical specifications.

Each application must include any technical specification changes or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. The justification for changes or additions to the technical specifications must be contained in the license renewal application.

§ 54.23 Contents of application--environmental information.

Each application must include a supplement to the environmental report that complies with the requirements of Subpart A of 10 CFR Part 51.

§ 54.25 Report of the Advisory Committee on Reactor Safeguards.

Each renewal application will be referred to the Advisory Committee on Reactor Safeguards for a review and report. Any report will be made part of the record of the application and made available to the public, except to the extent that security classification prevents disclosure.

§ 54.27 Hearings.

A notice of an opportunity for a hearing will be published in the Federal Register in accordance with 10 CFR 2.105. In the absence of a request for a hearing filed within 30 days by a person whose interest may be affected, the Commission may issue a renewed operating license without a hearing upon 30-day notice and publication once in the *Federal Register* of its intent to do so.

§ 54.29 Standards for issuance of a renewed license.

A renewed license may be issued by the Commission up to the full term authorized by § 54.31 if the Commission finds that:

(a) Actions have been identified and have been or will be taken with respect to the matters identified in Paragraphs (a)(1) and (a)(2) of this section, such that there is reasonable assurance that the activities authorized by the renewed license will continue to be conducted in accordance with the CLB, and that any changes made to the plant's CLB in order to comply with this paragraph are in accord with the Act and the Commission's regulations. These matters are:

(1) managing the effects of aging during the period of extended operation on the functionality of structures and components that have been identified to require review under § 54.21(a)(1); and

(2) time-limited aging analyses that have been identified to require review under § 54.21(c).

(b) Any applicable requirements of Subpart A of 10 CFR Part 51 have been satisfied.

(c) Any matters raised under § 2.335 have been addressed.

[69 FR 2279, Jan. 14, 2004]

§ 54.30 Matters not subject to a renewal review.

(a) If the reviews required by § 54.21 (a) or (c) show that there is not reasonable assurance during the current license term that licensed activities will be conducted in accordance with the CLB, then the licensee shall take measures under its current license, as appropriate, to ensure that the intended function of those systems, structures or components will be maintained in accordance with the CLB throughout the term of its current license.

(b) The licensee's compliance with the obligation under Paragraph (a) of this section to take measures under its current license is not within the scope of the license renewal review.

§ 54.31 Issuance of a renewed license.

(a) A renewed license will be of the class for which the operating license currently in effect was issued.

(b) A renewed license will be issued for a fixed period of time, which is the sum of the additional amount of time beyond the expiration of the operating license (not to exceed 20 years) that is requested in a renewal application plus the remaining number of years on the operating license currently in effect. The term of any renewed license may not exceed 40 years.

(c) A renewed license will become effective immediately upon its issuance, thereby superseding the operating license previously in effect. If a renewed license is subsequently set aside upon further administrative or judicial appeal, the operating license previously in effect will be reinstated unless its term has expired and the renewal application was not filed in a timely manner.
(d) A renewed license may be subsequently renewed in accordance with all applicable requirements.

§ 54.33 Continuation of CLB and conditions of renewed license.

(a) Whether stated therein or not, each renewed license will contain and otherwise be subject to the conditions set forth in 10 CFR 50.54.
(b) Each renewed license will be issued in such form and contain such conditions and limitations, including technical specifications, as the Commission deems appropriate and necessary to help ensure that systems, structures, and components subject to review in accordance with § 54.21 will continue to perform their intended functions for the period of extended operation. In addition, the renewed license will be issued in such form and contain such conditions and limitations as the Commission deems appropriate and necessary to help ensure that systems, structures, and components associated with any time-limited aging analyses will continue to perform their intended functions for the period of extended operation.
(c) Each renewed license will include those conditions to protect the environment that were imposed pursuant to 10 CFR 50.36b and that are part of the CLB for the facility at the time of issuance of the renewed license. These conditions may be supplemented or amended as necessary to protect the environment during the term of the renewed license and will be derived from information contained in the supplement to the environmental report submitted pursuant to 10 CFR Part 51, as analyzed and evaluated in the NRC record of decision. The conditions will identify the obligations of the licensee in the environmental area, including, as appropriate, requirements for reporting and recordkeeping of environmental data and any conditions and monitoring requirements for the protection of the nonaquatic environment.
(d) The licensing basis for the renewed license includes the CLB, as defined in § 54.3(a); the inclusion in the licensing basis of matters such as licensee commitments does not change the legal status of those matters unless specifically so ordered pursuant to paragraphs (b) or (c) of this section.

§ 54.35 Requirements during term of renewed license.

During the term of a renewed license, licensees shall be subject to and shall continue to comply with all Commission regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, and 100, and the appendices to these parts that are applicable to holders of operating licenses.

§ 54.37 Additional records and recordkeeping requirements.

(a) The licensee shall retain in an auditable and retrievable form for the term of the renewed operating license all information and documentation required by, or otherwise necessary to document compliance with, the provisions of this part.
(b) After the renewed license is issued, the FSAR update required by 10 CFR 50.71(e) must include any systems, structures, and components newly identified that would have been subject to an aging management review or evaluation of time-limited aging analyses in accordance with § 54.21. This FSAR update must describe how the effects of aging will be managed such that the intended function(s) in § 54.4(b) will be effectively maintained during the period of extended operation.

§ 54.41 Violations.

(a) The Commission may obtain an injunction or other court order to prevent a violation of the provisions of the following acts--
(1) The Atomic Energy Act of 1954, as amended.
(2) Title II of the Energy Reorganization Act of 1974, as amended or
(3) A regulation or order issued pursuant to those acts.
(b) The Commission may obtain a court order for the payment of a civil penalty imposed under Section 234 of the Atomic Energy Act--
(1) For violations of the following--
(i) Sections 53, 57, 62, 63, 81, 82, 101, 103, 104, 107, or 109 of the Atomic Energy Act of 1954, as amended;
(ii) Section 206 of the Energy Reorganization Act;
(iii) Any rule, regulation, or order issued pursuant to the sections specified in paragraph (b)(1)(i) of this section;
(iv) Any term, condition, or limitation of any license issued under the sections specified in paragraph (b)(1)(i) of this section.
(2) For any violation for which a license may be revoked under Section 186 of the Atomic Energy Act of 1954, as amended.

Appendix C

USNRC Guidance Concerning Aging Effects & Aging Mechanisms

Table C-1: *Aging Effects* (Source: GALL Report - NUREG-1801)

Selected Definitions & Use of Terms for Describing and Standardizing Aging Effects	
Changes in dimensions	Changes in dimensions can result from void swelling.
Concrete cracking and spalling	Concrete cracking and spalling can result from freeze-thaw, aggressive chemical attack, and reaction with aggregates.
Crack growth	Increase in crack size, attributable to cyclic loading.
Cracking	This term is used in this document to be synonymous with the phrase "crack initiation and growth" in metallic substrates. Cracking in concrete can be caused by restraint shrinkage, creep, and aggressive environment.
Cracking, loss of bond, and loss of material (spalling, scaling)	Cracking, loss of bond, and loss of material (spalling, scaling) can be caused by corrosion of embedded steel in concrete.
Cracks; distortion; increase in component stress level	Within concrete structures, cracks, distortion, and increase in component stress level can be caused by settlement. Although settlement can be occur in a soil environment, the symptoms can be manifested in either an air-indoor uncontrolled or air-outdoor environment.
Cumulative fatigue damage	Cumulative fatigue damage is due to fatigue, as defined by ASME Boiler and Pressure Vessel Code.
Degradation of insulator quality	The decrease in insulating capacity can result from the presence of salt deposits or surface contamination. Although this derives from an aging mechanism (presence of salt deposits or surface contamination) that may be due to temporary, transient environmental conditions, the net result may be long lasting and cumulative.
Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance; electrical failure	Embrittlement, cracking, melting, discoloration, swelling, or loss of dielectric strength leading to reduced insulation resistance, electrical failure can result from mechanisms such as thermal or thermoxidative degradation of organics; radiation-induced oxidation, radiolysis and photolysis (UV sensitive materials only) of organics; moisture intrusion; and ohmic heating.
Expansion and cracking	Within concrete structures, expansion and cracking can result from reaction with aggregates.
Fatigue	Fatigue in copper fuse holder clamps can result from ohmic heating, thermal cycling, electrical transients, frequent manipulation, vibration, chemical contamination, corrosion, oxidation.
Fretting or lockup	Fretting is an aging effect due to accelerated deterioration at the interface between contacting surfaces as the result of corrosion and slight oscillatory movement between the two surfaces. In essence, both fretting and lockup are due to mechanical wear.
Hardening and loss of strength	Hardening and loss of strength can result from Eastover degradation of seals and other elastomeric components. Elastomers can experience increased hardness, shrinkage, and loss of strength, due to weathering.
Increase in porosity and permeability, cracking, loss of material (spalling, scaling), loss of strength	Concrete can increase in porosity and permeability, cracking, loss of material (spalling, scaling) due to aggressive chemical attack. In concrete, loss of material (spalling, scaling) and cracking can result from freeze-thaw processes. Loss of strength can result from leaching of calcium hydroxide in the concrete.
Increased resistance of connection	Increased resistance of connection in electrical transmission conductors and connections can be caused by oxidation or loss of preload.
Ligament cracking	Steel tube support plates can experience ligament cracking due to corrosion.
Localized damage and breakdown of insulation leading to electrical failure	Localized damage in polymeric electrical conductor insulation leading to electrical failure can be due to a number of aging mechanisms including moisture intrusion, and the formation of water trees. Based on operating experience, localized damage

Selected Definitions & Use of Terms for Describing and Standardizing Aging Effects	
	and breakdown of insulation may be exacerbated by manufacturing defects in the insulation of older electrical conductors, external damage, or damage due to poor installation practices.
Loosening of bolted connections	The loosening of bolted bus duct connections due to thermal cycling can result from ohmic heating.
Loss of fracture toughness	Loss of fracture toughness can result from various aging mechanisms including thermal aging, thermal aging embrittlement, and neutron irradiation embrittlement.
Loss of leak tightness	Steel airlocks can experience loss of leak tightness in closed position resulting from mechanical wear of locks, hinges, and closure mechanisms.
Loss of material	Loss of material may be due to general corrosion, boric acid corrosion, pitting corrosion, galvanic corrosion, crevice corrosion, erosion, fretting, flow-accelerated corrosion, MIC, fouling, selective leaching, wastage, wear, and aggressive chemical attack. In concrete structures, loss of material can also be caused by abrasion or cavitation or corrosion of embedded steel. For high voltage insulators, loss of material can be attributed to mechanical wear or wind-induced abrasion and fatigue due to wind blowing on transmission conductors.
Loss of material, loss of form	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, and seepage.
Loss of preload	Loss of preload due to gasket creep, thermal effects (including differential expansion and creep or stress relaxation), and self-loosening (which includes vibration, joint flexing, cyclic shear loads, thermal cycles) is an aging effect/mechanism accepted by industry as being within the scope of license renewal.
Loss of prestress	Loss of prestress in structural steel anchorage components can result from relaxation, shrinkage, creep, or elevated temperatures.
Reduction in foundation strength, cracking, differential settlement	*Reduction in foundation strength, cracking, and differential settlement can result* from erosion of porous concrete subfoundation.
Reduction of heat transfer	Reduction of heat transfer from fouling by the buildup, from whatever source, on the heat transfer surface. Although in heat exchangers, the tubes are the primary heat transfer component, heat exchanger internals including tubesheets and fins contribute to heat transfer and may be affected by the reduction of heat transfer due to fouling.
Reduction of strength and modulus	In concrete, reduction of strength and modulus can be attributed to elevated temperatures (>150°F general; >200°F local).
Reduction or loss of isolation function	Reduction or loss of isolation function in polymeric vibration isolation elements can result from elastomers exposed to radiation hardening, temperature, humidity, sustained vibratory loading.
Wall thinning	This is the term used to describe the specific type of loss of material due to flow-accelerated corrosion.

Table C-2: *Aging Mechanisms* (Source: GALL Report - NUREG-1801)

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	**Aging Mechanism Definition as used in the GALL Report**
Abrasion	As water migrates over a concrete surface, it may transport material that can abrade the concrete. The passage of water may also create a negative pressure at the water/air to concrete interface that can result in abrasion and cavitation degradation of the concrete. This may result in pitting or aggregate exposure due to loss of cement paste.
Aggressive chemical attack	Concrete, being highly alkaline (pH >12.5) is degraded by strong acids. Chlorides and sulfates of potassium, sodium, and magnesium may attack concrete, depending concentration in soil/ground water. Exposed surfaces of structures may be subject to sulfur-based acid-rain degradation. Minimum degradation thresholds are 500 ppm chlorides and 1500 ppm sulfates.
Boric acid corrosion	Corrosion by boric acid, which can occur where there is borated water leakage in an environment described as air with borated water leakage. See also Corrosion.
Cavitation	Formation and instantaneous collapse of innumerable tiny voids or cavities within a liquid subjected to rapid and intense pressure changes. Cavitation caused by severe turbulent flow can potentially lead to cavitation damage.
Chemical contamination	*Degradation due to presence of chemical constituents.*
Corrosion	Chemical or electrochemical reaction between a material, usually a metal, and its environment that produces a deterioration of the material and its properties.
Corrosion of embedded steel	If pH of the concrete in which steel is embedded is reduced (pH < 11.5) by intrusion of aggressive ions (e.g., chlorides > 500 ppm) in the presence of oxygen, embedded steel corrosion may occur. A reduction in pH may be caused by the leaching of alkaline products through cracks, entry of acidic materials, or carbonation. Chlorides may also be present in the constituents of the original concrete mix. The severity of the corrosion is affected by the properties and types of cement, aggregates, and moisture content.
Creep	Creep, for a metallic material, refers to a time-dependent continuous deformation process under constant stress. It is an elevated temperature process and is not a concern for low alloy steel below 700°F, for austenitic alloys below 1000°F, and for Ni-based alloys below 1800°F. Creep, in concrete, is related to the loss of absorbed water from the hydrated cement paste. It is a function of modulus of elasticity of the aggregate. It may result in loss of prestress in the tendons used in prestressed concrete containment.
Crevice Corrosion	Localized corrosion of a metal surface at, or immediately adjacent to, an area that is shielded from full exposure to the environment, because of close proximity between the metal and the surface of another material. *Crevice corrosion occurs in a wetted or buried environment when* a crevice or area of stagnant or low flow exists that allows a corrosive environment to develop in a component. It occurs most frequently in joints and connections, or points of contact between metals and non-metals, such as gasket surfaces, lap joints, and under bolt heads. Carbon steel, cast iron, low alloy steels, stainless steel, copper, and nickel base alloys are all susceptible to crevice corrosion. Steel can be subject to crevice corrosion in some cases after lining/cladding degradation.
Cyclic loading	*One source of cyclic loading is due to periodic application of pressure loads and forces due to* thermal movement of piping transmitted through penetrations and structures to which penetrations are connected. The typical result of cyclic loads on metal components is fatigue cracking and failure; however, the cyclic loads may also cause deformation that results in functional failure.
Deterioration of seals, gaskets, and moisture *barriers (caulking,* flashing, and other sealants)	Seals, gaskets, and moisture barriers (caulking, flashing, and other sealants) are subject to loss of sealing and leakage through containment caused by aging
Distortion	The aging mechanism of distortion can be caused by time dependent strain, or gradual elastic and plastic deformation of metal that is under constant stress at a value lower than its normal yield strength.
Elastomer degradation	Elastomer materials are substances whose elastic properties are similar to that of natural rubber. The term elastomer is sometimes used to technically distinguish synthetic rubbers and rubber-like plastics from natural rubber. Degradation may include cracking, crazing, fatigue breakdown, abrasion, chemical attacks, and weathering. [20, 21] Elastomer hardening refers to the degradation in elastic properties of the elastomer.

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	**Aging Mechanism Definition as used in the GALL Report**
Electrical transients	An electrical transient is a stressor caused by a voltage spike that can contribute to aging degradation. Certain types of high-energy electrical transients can contribute to electromechanical forces ultimately resulting in fatigue or loosening of bolted connections. Transient voltage surges are a major contributor to the early failure of sensitive electrical components
Elevated temperature	In concrete, reduction of strength and modulus can be attributed to elevated temperatures (>150°F general; >200°F local).
Erosion	Progressive loss of material from a solid surface due to mechanical interaction between that surface and a fluid, a multi-component fluid, or solid particles carried with the fluid.
Erosion settlement	Erosion (as defined above). Settlement of containment structure may occur during the design life due to changes in the site conditions, e.g., due to erosion or changes in the water table. The amount of settlement depends on the foundation material, and is generally determined by survey. Another term is erosion of the porous concrete sub-foundation.
Erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	In earthen water-control structures, the loss of material and loss of form can result from erosion, settlement, sedimentation, frost action, waves, currents, surface Run-off, and seepage.
Fatigue	A phenomenon leading to fracture under repeated or fluctuating stresses having a maximum value less than the tensile strength of the material. Fatigue fractures are progressive, and grow under the action of the fluctuating stress. Fatigue due to vibratory and cyclic thermal loads is defined as the structural degradation that can occur as a result of repeated stress/strain cycles caused by fluctuating loads, e.g., from vibratory loads, and temperatures, giving rise to thermal loads. After repeated cyclic loading of sufficient magnitude, micro-structural damage may accumulate, leading to macroscopic crack initiation at the most vulnerable regions. Subsequent mechanical or thermal cyclic loading may lead to growth of the initiated crack. Vibration may result in component cyclic fatigue, as well as in cutting, wear, and abrasion, if left unabated. Vibration is generally induced by external equipment operation. It may also result from flow resonance or movement of pumps or valves in fluid systems. Crack initiation and growth resistance is governed by factors including stress range, mean stress, loading frequency, surface condition, and the presence of deleterious chemical species.
Flow-accelerated corrosion (FAC)	Also termed erosion-corrosion. A co-joint activity involving corrosion and erosion in the presence of a moving corrosive fluid, leading to the accelerated loss of material.
Fouling	An accumulation of deposits. This term includes accumulation and growth of aquatic organisms on a submerged metal surface and also includes the accumulation of deposits, usually inorganic, on heat exchanger tubing. Biofouling, as a subset of fouling, can be caused by either macro-organisms (such as barnacles, Asian clams, zebra mussels, and others found in fresh and salt water) or micro-organisms, e.g., algae. Fouling can also be categorized as particulate fouling (sediment, silt, dust, and corrosion products), marine biofouling, or macrofouling, e.g., peeled coatings, debris, etc. Fouling in a raw water system can occur on the piping, valves, and heat exchangers. Fouling can result in a reduction of heat transfer, loss of material, or a reduction in the system flow rate (this last aging effect is considered active and thus is not in the purview of license renewal).
Freeze-Thaw, frost action	Repeated freezing and thawing is known to be capable of causing severe degradation to the concrete characterized by scaling, cracking, and spalling. The cause of this phenomenon is water freezing within the pores of the concrete, creating hydraulic pressure that, if unrelieved, will lead to freeze-thaw degradation. Factors that enhance the resistance of concrete to freeze-thaw degradation are a) adequate air content (e.g., within ranges specified in ACI 301-84), b) low permeability, c) protection until adequate strength has developed, and d) surface coating applied to frequently wet-dry surfaces.
Fretting	Aging effect due to accelerated deterioration at the interface between contacting surfaces as the result of corrosion, and slight oscillatory movement between the two surfaces.
Galvanic corrosion	Accelerated corrosion of a metal because of an electrical contact with a more noble metal or nonmetallic conductor in a corrosive electrolyte. Also called bimetallic corrosion, contact corrosion, dissimilar metal corrosion, or two-metal corrosion. Galvanic corrosion is an applicable aging mechanism for steel materials coupled to more noble metals in heat exchangers; galvanic corrosion of copper is of concern when coupled with the nobler stainless

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	**Aging Mechanism Definition as used in the GALL Report**
	steel.
General corrosion	Also known as uniform corrosion, corrosion proceeds at approximately the same rate over a metal surface. Loss of material due to general corrosion is an aging effect requiring management for low alloy steel, carbon steel, and cast iron in outdoor environments.
Intergranular stress corrosion cracking (IGSCC)	SCC in which the cracking occurs along grain boundaries.
Leaching of calcium hydroxide	Water passing through cracks, inadequately prepared construction joints, or areas that are not sufficiently consolidated during placing may dissolve some calcium containing products, of which calcium hydroxide is the most-readily soluble, in concrete. Once the calcium hydroxide has been leached away, other cementatious constituents become vulnerable to chemical decomposition, finally leaving only the silica and alumina gels behind with little strength. The water's aggressiveness in the leaching of calcium hydroxide depends on its salt content and temperature. This leaching action is effective only if the water passes through the concrete.
Mechanical loading	Applied loads of mechanical origins rather than from other sources, such as thermal.
Microbiologically influenced corrosion (MIC)	Any of the various forms of corrosion influenced by the presence and activities of such microorganisms as bacteria, fungi, and algae, and/or the products produced in their metabolism. Degradation of material that is accelerated due to conditions under a biofilm or microfouling tubercle, for example, anaerobic bacteria that can set up an electrochemical galvanic reaction or inactivate a passive protective film, or acid-producing bacterial that might produce corrosive metabolites.
Moisture intrusion	Influx of moisture through any viable process.
Ohmic heating	Ohmic heating is induced by current flow through a conductor and can be calculated using first principles of electricity and heat transfer. Ohmic heating is a thermal stressor and can be induced in situations, such as conductors passing through electrical penetrations. Ohmic heating is especially significant for power circuit penetrations.
Overload	Overload is one of the aging mechanisms that can cause loss of mechanical function in piping and components, such as constant and variable load spring hangers, guides, stops, sliding surfaces, design clearances, vibration isolators, fabricated from steel or other materials, such as Lubrite
Oxidation	Two types of reactions a) reaction in which there is an increase in valence resulting from a loss of electrons, or b) a corrosion reaction in which the corroded metal forms an oxide.
Photolysis	Chemical reactions induced or assisted by light.
Pitting corrosion	Localized corrosion of a metal surface, confined to a point or small area, which takes the form of cavities called pits.
Plastic deformation	Time-dependent strain, or gradual elastic and plastic deformation, of metal that is under constant stress at a value lower than its normal yield strength.
Presence of any salt deposits	The surface contamination resulting from the aggressive environment associated with the presence of any salt deposits can be an aging mechanism causing the aging effect of degradation of insulator quality. Although this aging mechanism may be due to temporary, transient environmental conditions, the net result may be long-lasting and cumulative for plants located in the vicinity of saltwater bodies.
Radiolysis	Chemical reactions induced or assisted by radiation. Radiolysis and photolysis aging mechanisms can occur in UV-sensitive organic materials.
Reaction with aggregate	The presence of reactive alkalis in concrete, can lead to subsequent reactions with aggregates that may be present. These alkalis are introduced mainly by cement, but also may come from admixtures, salt-contamination, seawater penetration, or solutions of deicing salts. These reactions include alkali-silica reactions, cement-aggregate reactions, and aggregate-carbonate reactions. These reactions may lead to expansion and cracking.
Restraint shrinkage	Restraint shrinkage can cause cracking in concrete transverse to the longitudinal construction joint.
Selective leaching	Also known as dealloying, e.g., dezincification or graphitic corrosion. Selective corrosion of one or more components of a solid solution alloy.
Settlement	Settlement of structures may occur during the design life due to changes in the site conditions, e.g., the water table. The amount of settlement depends on the foundation material and is

Selected Definitions & Use of Terms for Describing and Standardizing Aging Mechanisms	
Term	**Aging Mechanism Definition as used in the GALL Report**
	generally determined by survey.
Stress corrosion cracking (SCC)	Cracking of a metal produced by the combined action of corrosion and tensile stress (applied or residual).
Stress relaxation	Many of the bolts in reactor internals are stressed to a cold initial preload. When subject to high operating temperatures, over time, these bolts may loosen and the preload may be lost. Radiation can also cause stress relaxation, in highly stressed members such as bolts. Relaxation in structural steel anchorage components can be an aging mechanism contributing to the aging effect of loss of prestress.
Thermal aging embrittlement	Also termed thermal aging or thermal embrittlement. At operating temperatures of 500 to 650°F, cast austenitic stainless steels (CASS) exhibit a spinoidal decomposition of the ferrite phase into ferrite-rich and chromium-rich phases. This may give rise to significant embrittlement, i.e., reduction in fracture toughness, depending on the amount, morphology, and distribution of the ferrite phase and the composition of the steel. Thermal aging of materials other than CASS is a time- and temperature-dependent degradation mechanism that decreases material toughness. It includes temper embrittlement and strain aging embrittlement. Ferritic and low alloy steels are subject to both of these embrittlement, but wrought stainless steel is not affected by either of the processes.
Thermal effects, gasket *creep, and self-loosening*	Loss of preload due to gasket creep, thermal effects (including differential expansion and *creep or stress relaxation*), and *self-loosening* (*which includes vibration, joint flexing, cyclic* shear loads, thermal cycles) is within the scope of license renewal.
Thermal and mechanical loading	Loads (stress) due to mechanical or thermal (temperature) sources.
Thermal fatigue	Thermal (temperature) fatigue can result from phenomena such as thermal loading, thermal cycling, where there is cycling of the thermal loads and thermal stratification. Thermal stratification is a thermohydraulic condition with definitive hot and cold water boundary inducing thermal fatigue of the piping. Turbulent penetration is a thermo-hydraulic condition where hot and cold water mix as a result of turbulent flow conditions, leading to thermal fatigue of the piping.
Water trees	Water trees occur when the insulating materials are exposed to long-term, continuous electrical stress and moisture; these trees eventually result in breakdown of the dielectric and ultimate failure. The growth and propagation of water trees is somewhat unpredictable. Water treeing is a degradation and long-term failure phenomenon.
Wear	Wear is defined as the removal of surface layers due to relative motion between two surfaces or under the influence of hard abrasive particles. Wear occurs in parts that experience intermittent relative motion, frequent manipulation, or in clamped joints where relative motion is not intended but may occur due to a loss of the clamping force.
Weathering	Degradation of external surfaces of materials when exposed to outside environment.

Appendix D

Aging Management Program Example – Concrete Structures Monitoring

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XI.S2 ASME SECTION XI, SUBSECTION IWL

Program Description

10 CFR 50.55a imposes the examination requirements of the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel (B&PV) Code, Section XI, Subsection IWL for reinforced and prestressed concrete containments (Class CC). The scope of IWL includes reinforced concrete and unbonded post-tensioning systems. This evaluation covers both the 1992 edition with the 2001 edition[1] including the 2002 and 2003 Addenda, as approved in 10 CFR 50.55a. ASME Code Section XI, Subsection IWL and the additional requirements specified in 10 CFR 50.55a(b)(2) constitute an existing mandated program applicable to managing aging of containment reinforced concrete and unbonded post-tensioning systems for license renewal.

The primary inspection method specified in IWL is visual examination (VT-3C, VT-1, VT-1C). For prestressed containments, tendon wires are tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is analyzed for alkalinity, water content, and soluble ion concentrations. Prestressing forces are measured in selected sample tendons. IWL specifies acceptance criteria, corrective actions, and expansion of the inspection scope when degradation exceeding the acceptance criteria is found.

The evaluation of 10 CFR 50.55a and Subsection IWL as an aging management program (AMP) for license renewal is provided below.

Evaluation and Technical Basis

1. *Scope of Program:* Subsection IWL-1000 specifies the components of concrete containments within its scope. The components within the scope of Subsection IWL are reinforced concrete and unbonded post-tensioning systems of Class CC containments, as defined by CC-1000. Subsection IWL exempts from examination portions of the concrete containment that are inaccessible (e.g., concrete covered by liner, foundation material, or backfill, or obstructed by adjacent structures or other components).

   10 CFR 50.55a(b)(2)(viii) specifies additional requirements for inaccessible areas. It states that the licensee is to evaluate the acceptability of concrete in inaccessible areas when conditions exist in accessible areas that could indicate the presence of or result in degradation to such inaccessible areas. Steel liners for concrete containments and their integral attachments are not within the scope of Subsection IWL, but are included within the scope of Subsection IWE.

2. *Preventive Action:* No preventive actions are specified; Subsection IWL is a monitoring program. If a coating program is currently credited for managing the effects of aging of concrete surfaces, then the program is to be continued during the period of extended operation.

3. *Parameters Monitored or Inspected:* Table IWL-2500-1 specifies two categories for examination of concrete surfaces: Category L-A for all concrete surfaces and Category L-

[1] An applicant may rely on a different version of the ASME Code, but should justify such use. An applicant may wish to refer to the SOC for an update of 10 CFR § 50.55a to justify use of a more recent edition of the Code.

B for concrete surfaces surrounding tendon anchorages. Both of these categories rely on visual examination methods. Concrete surfaces are examined for evidence of damage or degradation, such as concrete cracks. IWL-2510 specifies that concrete surfaces are examined for conditions indicative of degradation, such as those defined in ACI 201.1R-77. Table IWL-2500-1 also specifies Category L-B for test and examination requirements for unbonded post tensioning systems. Tendon anchorage and wires or strands are visually examined for cracks, corrosion, and mechanical damage. Tendon wires or strands are also tested for yield strength, ultimate tensile strength, and elongation. Tendon corrosion protection medium is tested by analysis for alkalinity, water content, and soluble ion concentrations.

4. *Detection of Aging Effects:* The frequency and scope of examinations specified in 10 CFR 50.55a and Subsection IWL ensure that aging effects would be detected before they would compromise the design-basis requirements. The frequency of inspection is specified in IWL-2400. Concrete inspections are performed in accordance with Examination Category L-A. Under Subsection IWL, inservice inspections for concrete and unbonded post-tensioning systems are required at one, three, and five years following the structural integrity test. Thereafter, inspections are performed at five-year intervals. For sites with two plants, the schedule for inservice inspection is provided in IWL-2421. In the case of tendons, only a sample of the tendons of each tendon type requires examination at each inspection. The tendons to be examined during an inspection are selected on a random basis. Table IWL-2521-1 specifies the number of tendons to be selected for each type (e.g., hoop, vertical, dome, helical, and inverted U) for each inspection period. The minimum number of each tendon type selected for inspection varies from 2 to 4%. Regarding detection methods for aging effects, all concrete surfaces receive a visual VT-3C examination. Selected areas, such as those that indicate suspect conditions and areas surrounding tendon anchorages, receive a more rigorous VT-1 or VT-1C examination. Prestressing forces in sample tendons are measured. In addition, one sample tendon of each type is detensioned. A single wire or strand is removed from each detensioned tendon for examination and testing. These visual examination methods and testing would identify the aging effects of accessible concrete components and prestressing systems in concrete containments.

5. *Monitoring and Trending:* Except in inaccessible areas, all concrete surfaces are monitored on a regular basis by virtue of the examination requirements. For prestressed containments, trending of prestressing forces in tendons is required in accordance with paragraph (b)(2)(viii) of 10 CFR 50.55a. In addition to the random sampling used for tendon examination, one tendon of each type is selected from the first-year inspection sample and designated as a common tendon. Each common tendon is then examined during each inspection. This procedure provides monitoring and trending information over the life of the plant. 10 CFR 50.55a and Subsection IWL also require that prestressing forces in all inspection sample tendons be measured by lift-off tests and compared with acceptance standards based on the predicted force for that type of tendon over its life.

6. *Acceptance Criteria:* IWL-3000 provides acceptance criteria for concrete containments. For concrete surfaces, the acceptance criteria rely on the determination of the "Responsible Engineer" (as defined by the ASME Code) regarding whether there is any evidence of damage or degradation sufficient to warrant further evaluation or repair. The acceptance criteria are qualitative; guidance is provided in IWL-2510, which references ACI 201.1R-77 for identification of concrete degradation. IWL-2320 requires that the Responsible Engineer be a registered professional engineer experienced in evaluating

the inservice condition of structural concrete and knowledgeable of the design and construction codes and other criteria used in design and construction of concrete containments. Quantitative acceptance criteria based on the "Evaluation Criteria" provided in Chapter 5 of ACI 349.3R may also be used to augment the qualitative assessment of the responsible engineer. The acceptance standards for the unbonded post-tensioning system are quantitative in nature. For the post-tensioning system, quantitative acceptance criteria are given for tendon force and elongation, tendon wire or strand samples, and corrosion protection medium. 10 CFR 50.55a and Subsection IWL do not define the method for calculating predicted tendon prestressing forces for comparison to the measured tendon lift-off forces. The predicted tendon forces are to be calculated in accordance with Regulatory Guide 1.35.1, which provides an acceptable methodology for use through the period of extended operation.

7. *Corrective Actions:* Subsection IWL specifies that items for which examination results do not meet the acceptance standards are to be evaluated in accordance with IWL-3300 "Evaluation" and described in an engineering evaluation report. The report is to include an evaluation of whether the concrete containment is acceptable without repair of the item and if repair is required, the extent, method, and completion date of the repair or replacement. The report also identifies the cause of the condition and the extent, nature, and frequency of additional examinations. Subsection IWL also provides repair procedures to follow in IWL-4000. This includes requirements for the concrete repair, repair of reinforcing steel, and repair of the post-tensioning system. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions.

8. *Confirmation Process:* When areas of degradation are identified, an evaluation is performed to determine whether repair or replacement is necessary. As part of this evaluation, IWL-3300 specifies that the engineering evaluation report include the extent, nature, and frequency of additional examinations. IWL-4000 specifies the requirements for examination of areas that are repaired. Pressure tests following repair or modifications are in accordance with IWL-5000. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the confirmation process.

9. *Administrative Controls:* IWA-1400 specifies the preparation of plans, schedules, and inservice inspection summary reports. In addition, written examination instructions and procedures, verification of qualification level of personnel who perform the examinations, and documentation of a quality assurance program are specified. IWA-6000 specifically covers the preparation, submittal, and retention of records and reports. As discussed in the appendix to this report, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the administrative controls.

10. *Operating Experience:* ASME Section XI, Subsection IWL was incorporated into 10 CFR 50.55a in 1996. Prior to this time, operating experience pertaining to degradation of reinforced concrete and prestressing systems in concrete containments was gained through the inspections required by 10 CFR Part 50, Appendix J and ad hoc inspections conducted by licensees and the Nuclear Regulatory Commission (NRC). Recently, NRC Information Notice (IN) 99-10 described occurrences of degradation in prestressing systems. The program is to consider the degradation concerns described in this generic communication. Implementation of Subsection IWL, in accordance with 10 CFR 50.55a, is

a necessary element of aging management for concrete containments through the period of extended operation.

References

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10 CFR 50.55a, Codes and Standards, Office of the Federal Register, National Archives and Records Administration, 2005.

ACI Standard 201.1R-77, *Guide for Making a Condition Survey of Concrete in Service*, American Concrete Institute.

ACI Standard 349.3R-96, *Evaluation of Existing Nuclear Safety-Related Concrete Structures*, American Concrete Institute.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, Subsection IWA, *General Requirements*, 2001 edition including the 2002 and 2003 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, Subsection IWE, *Requirements for Class MC and Metallic Liners of Class CC Components of Light-Water Cooled Power Plants*, 2001 edition including the 2002 and 2003 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

ASME Section XI, *Rules for Inservice Inspection of Nuclear Power Plant Components*, Subsection IWL, *Requirements for Class CC Concrete Components of Light-Water Cooled Power Plants*, 2001 edition including the 2002 and 2003 Addenda, The ASME Boiler and Pressure Vessel Code, The American Society of Mechanical Engineers, New York, NY.

NRC Information Notice 99-10, Revision 1, *Degradation of Prestressing Tendon Systems in Prestressed Concrete Containment*, U.S. Nuclear Regulatory Commission, October 7, 1999.

Appendix E

License Renewal Inspection Policy and Guidance[*]

USNRC Inspection Manual Chapter (MC) 2516 – Policy and Guidance for the License Renewal Inspection Programs
(Edited)

2516-01 PURPOSE

The purpose of MC 2516 is to document policy and guidance for review and inspection activities associated with the License Renewal Inspection Program (LRIP). The LRIP is the process used by Nuclear Regulatory Commission (NRC) staff, region, and consultants to verify the accuracy of the aging management programs and activities associated with an applicant's request for a renewed license for a commercial nuclear power plant beyond the initial licensing period under Title 10 of the Code of Federal Regulation, (10 CFR) Part 54.

2516-02 POLICY AND OBJECTIVES

02.01 The basic policies, excerpted from the Statements of Consideration of the License Renewal Rule, and objectives used in the development and implementation of the LRIP are as follows:

a. *The NRC exists to assure that the public health and safety, the common defense and security,* and the environment are protected.

b. With respect to license renewal of a commercial nuclear power plant, the NRC has established the following two basic principles:

   1. The first principle of license renewal is that with the exception of age-related degradation and possibly a few other issues related to safety only during extended operation of nuclear power plants, the existing regulatory process is adequate to ensure that the licensing bases of all currently operating plants provide and maintain an acceptable level of safety so that operation will not be inimical to public health and safety or common defense and security.

   2. The second and equally important principle of license renewal holds that the plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term. This would be accomplished, in part, through a program of age-related degradation management.

c. An applicant for license renewal should rely on the plant's current licensing basis (CLB), actual plant-specific experience, industry-wide operating experience, as appropriate, and existing engineering evaluations to determine those systems, structures, and components that are the initial focus of the license renewal review.

d. The detrimental effects of aging affecting passive structures and components are less apparent than the detrimental effects of aging affecting structures and components that perform their intended functions with moving parts or a change in configuration or properties (active structures and components). Therefore, the aging management review of passive structures and components is needed to provide reasonable assurance that their intended functions are maintained consistent with the CLB during the period of extended operation.

e. For the purpose of license renewal, an applicant can generically exclude, from its integrated plant assessment, the aging management review of the following: 1) active structures and components, and 2) structures and components that are replaced, based on qualified life or specified time period, when the replacement frequency is less than 40 years ("short-lived"). In addition, some components are both active and passive. Components that are passive, or both active and passive, must be included within the scope of components requiring an aging management review based on the intended function(s) that is performed without moving parts or change in configuration or properties.

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[*] Note: A copy of the related USNRC License Renewal Inspection Procedure 71002 is provided in Attachment D of the CGI Report 06-22, *Condition Monitoring of Passive Systems, Structures, and Components*

f. Postulated failures that could result from system interdependencies that are not part of the CLB *and that have not been previously experienced need not be considered as part of a license* renewal application (LRA). However, for some license renewal applicants, postulated failures that are part of the CLB may require consideration of more than the first level support systems.

02.02 The objectives of the LRIP are as follows:

a. The LRIP will provide the guidance for the inspection of license renewal programs, documentation, and activities necessary for the staff to make a finding that an applicant's LRA, aging management programs (AMPs), implementation activities, and on-site documentation provide reasonable assurance that the effects of aging will be effectively managed consistent with the CLB during the period of extended operation.

b. The LRIP will also provide the guidance for assessing the adequacy of implemented AMPs to effectively manage the effects of aging, consistent with the licensee's CLB, after the renewed license is issued.

2516-03 DEFINITIONS

Current licensing basis is the set of NRC requirements applicable to a specific plant and a licensee's written regulatory commitments for ensuring compliance with and operation within applicable NRC requirements and the plant-specific design basis (including all modifications and additions to such commitments over the life of the license) that are docketed and in effect. The CLB includes the NRC regulations contained in 10 CFR Parts 2, 19, 20, 21, 26, 30, 40, 50, 51, 54, 55, 70, 72, 73, 100 and appendices thereto; orders; license conditions; exemptions; and technical specifications. It also includes the plant-specific design-basis information defined in 10 CFR 50.2 as documented in the most recent final safety analysis report (FSAR) as required by 10 CFR 50.71; and the licensee's commitments remaining in effect that were made in docketed licensing correspondence such as licensee responses to NRC bulletins, generic letters, and enforcement actions, as well as licensee commitments documented in NRC safety evaluations or licensee event reports.

Regulatory Commitment is an explicit statement made by a licensee (or applicant) to take a specific action agreed to or volunteered by a licensee, and that has been submitted in writing on the docket to the Commission.
Integrated Plant Assessment (IPA) is a licensee assessment that demonstrates that a nuclear power plant facility's structures and components requiring aging management review in accordance with §54.21(a) for license renewal have been identified and that the effects of aging on the functionality of such structures and components will be managed to maintain the CLB such that there is an acceptable level of safety during the period of extended operation.

Nuclear power plant means a nuclear power facility of a type described in 10 CFR 50.21(b) or 50.22.

2516-06 LICENSE RENEWAL INSPECTION PROGRAM

06.01 Purpose.

The fundamental task of the LRIP is to ensure that there is reasonable assurance that the effects of aging will be managed consistent with the CLB during the period of extended operation. The program objectives derived from that task are as follows:

a. To provide a basis for recommending issuance or denial of a renewed license.

b. To identify weaknesses within an applicant's overall license renewal program or an individual AMP that fail to provide reasonable assurance that the applicable aging effects will be adequately managed during the period of extended operation.

c. To determine the status of compliance with 10 CFR Part 54 and other areas relating to maintaining and operating the plant such that the continued operation beyond the current licensing term will not be inimical to the public health and safety.

06.02 Independent Inspection Policy.

These inspections should be conducted in accordance with inspection procedure IP 71002. However, it is not possible to anticipate all the unique circumstances that might be encountered during the course of a particular inspection and, therefore, individual inspectors are expected to exercise initiative in conducting *inspections based on their expertise and experience to assure that all the inspection objectives are met.* If in the course of conducting an inspection, current potential safety concerns or compliance issues outside the scope of the procedure being executed are identified, the concerns should be pursued to the extent necessary to understand the issue and then they will be turned over to the Senior Resident Inspector for further follow-up inspection.

06.03 License Renewal Review Program.

The license renewal review program consists of an LRA review and site inspections. The LRA review is primarily a headquarters review performed by NRR to ensure that the applicant meets the technical and regulatory requirements of the rule, and to verify that the format and content of the application meet the requirements of the rule. The regional staff and inspection team members will become familiar with the LRA in preparation for inspections to provide operational and performance input in the application review, to assess the applicant's commitments against their past performance and experience, and in preparation to provide a regional recommendation to grant or deny approval for the applicant's request for a renewed license.

06.04 Site-Inspections.

The site inspections are assessments of an applicant's implementation of and compliance with 10 CFR Part 54 requirements. All inspection teams will be led by the regions and any NRR supporting staff will be detailed to the region for the period of time necessary to prepare, inspect, and document inspection activities. The site inspections will be performed by a team inspection in the areas of the scoping and screening activities, observation of the condition of plant equipment, and implementation of the aging management programs and review of associated documentation. By observing the current condition of plant equipment in the scope of license renewal, inspectors may identify the effects of aging not previously recognized. Such observations allow the inspectors to evaluate the success of previously implemented plant programs, which are being credited for license renewal AMPs. The site-inspection activities will be performed using IP 71002 "License Renewal Inspections."

06.05 Post Renewal Site-Inspections.

Site inspections of AMP implementation conducted after the approval of the renewed license will be conducted in accordance with IP 71003 "Post-Approval Site Inspection for License Renewal." These inspections will verify the licensee's continued compliance with 10 CFR Part 50 and implementation of commitments related to the LRA.

06.06 Inspection Documentation.

Inspections will be documented with inspection reports sent to the applicant and made publicly available in ADAMS. Attachments to IMC 2516 provide guidance on the preparation of documents related to the site inspection. Attachment 1, "Region Notification of Plant Readiness For License Renewal," provides a region with guidance on how to prepare its overall evaluation of inspection activities performed on an applicant for license renewal. Attachment 2, "Sample License Renewal Inspection Letter," is a sample letter of an overall evaluation of the inspection completion. The results of site team inspections will provide major input for the staff and regional recommendations to grant or deny an applicant's request for a renewed license.

Appendix F

Nuclear Related Aging Management and Life Extension Abbreviations and Acronyms

Abbreviation or Acronym	Description
AMP	*Aging Management Program*
AMR	Aging Management Review
ANSI	American Nuclear Standards Institute
ASME	American Society of Mechanical Engineers
BAW	Babcock and Wilcox
BIR	Benefit to Investment Ratio
BOP	Balance of Plant
BWROG	Boiling Water Reactor Owners Group
CBA	Cost Benefit Analysis
CDF	Core Damage Frequency
CFR	Code of Federal Regulations
CLB	Current Licensing Basis
CUF	Cumulative Usage Factor
DBD	Design Basis Document
DOE	U.S. Department of Energy
EPIX	Equipment Performance and Information Exchange
EPRI	Electrical Power Research Institute
EQ	Environmental Qualification
ER	Environmental Report
FHA	Fire Hazards Analysis and Fire Protection Program
FSAR	Final Safety Analysis Report
FSD	Functional System Description
GALL	Generic Aging Lessons Learned
IOE	Industry Operating Experience
INPO	Institute of Nuclear Power Operations
ISG	Interim Staff Guidance
ISI	In-Service Inspection
LCM	Life Cycle Management
LRA	License Renewal Application
LRR	License Renewal Rule
MIC	Microbiological Influenced Corrosion
MPFF	Maintenance Preventable Functional Failure
MR	Maintenance Rule
NEI	Nuclear Energy Institute
NMAC	Nuclear Maintenance Assist Center
NPAR	Nuclear Plant Aging Reports
NPV	Net Present Value
NRC	Nuclear Regulatory Commission (also USNRC)
O&M	Operation and Maintenance
OEM	Original Equipment Manufacturer
PdM	Predictive (diagnostic) Maintenance

Abbreviation or Acronym	Description
PM	Preventive Maintenance
PRA	Probabilistic Risk Analysis
RAI	Request for Additional Information (NRC Questions)
RAW	Risk Achievement Worth
RMPFF	Repetitive MPFF
RRW	Risk Reduction Worth
SER	Safety Evaluation Report
SOC	Statement of Considerations
SPV	Single Point Vulnerability
SRP	Standard Review Plan
SRP-LR	Standard Review Plan for License Renewal
SSC	Systems, Structures and Components
TLAA	Time Limited Aging Analyses
USNRC	United States Nuclear Regulatory Commission
WANO	World Association of Nuclear Operators

Appendix G

Bibliography of Selected Nuclear Aging Management and Life Extension Reports

Regulatory Requirements

- The License Renewal Rule, Title 10 of the United States Code of Federal Regulations, Part 54 (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants"
- The Maintenance Rule, Title 10 of the United States Code of Federal Regulations, Part 50.65 (10 CFR 54.65), "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"

US Nuclear Regulatory Commission Selected Documents

- EGG/SSRE-10039, "An Evaluation of the Effects of Valve Body Erosion on Motor-Operated Valve Operability"
- Inspection Manual Chapter 2516, "Policy and Guidance for License Renewal Inspection Programs," February 3, 1999
- Inspection Procedure 71002, "License Renewal Inspections", February 3, 1999
- NUREG/CR-4257, "Inspection, Surveillance, and Monitoring of Electrical Equipment Inside Containment of Nuclear Power Plants – With Applications to Electrical Cables," August 1985
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- NUREG/CR-4652, "Concrete Component Aging and Its Significance Relative to Life Extension of Nuclear Power Plants," September 1986
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- NUREG/CR-4747, "An Aging Failure Survey of Light Water Reactor Safety Systems and Components," Vols. 1 and 2, July 1987
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- NUREG/CR-5314, "Life Assessment Procedures for Major LWR Components," Vol. 3, "Cast Stainless Steel Components"
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- NUREG/CR-5419, "Aging Assessment of Instrument Air Systems in Nuclear Power Plants," January 1990
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- NUREG/CR-5546, "An Investigation of the Effects of Thermal Aging on the Fire Damageability of Electrical Cables"
- NUREG/CR-5779, "Aging of Non-Power-Cycle Heat Exchangers Used in Nuclear Power Plants," Vol. 1, April 1992
- NUREG/CR-6052, "Methodology for Reliability Based Condition Assessment-Application to Concrete Structures in Nuclear Plants"
- NUREG/CR-6679, "Assessment of Age-Related Degradation of Structures and Passive Components for U.S. Nuclear Power Plants"
- NUREG-1568, "License Renewal Demonstration Program: NRC Observations and Lessons Learned." December 1996
- NUREG-1611, "Aging Management of Nuclear Power Plant Containments for License Renewal." September 1997
- NUREG-1800 "Standard Review Plan for the Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR)
- NUREG-1801, "Generic Aging Lessons Learned (GALL) Report"
- ORNL/NRC/LTR-91/25, "Throttled Valve Cavitation and Erosion"
- PNL-5722, "Operating Experience and Aging Assessment of ECCS Pump Room Coolers"
- PNL-SA-18407, "Understanding and Managing Corrosion in Nuclear Power Plants"
- Regulatory Guide 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses."
- SECY-01-0074, "Approval to Publish Generic License Renewal Guidance Documents," dated April 26, 2001

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- B&W Owners Group, "Aging Effects for Structures and Structural Components (Structural Tools)", BAW-2279, December 1997
- BWR Owners Group License Renewal Committee, "Aging Management Review of the BWR Reference Plant Primary Containment for License Renewal", BWROG-12-15980, Revision 0, March 1996

* EPRI reports are available from the Electric Power Research Institute, Inc., Publications Department, 3420 Hillview Avenue, Palo Alto, California 94304

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- EPRI TR-103841, "The Low Voltage, In-Containment, Environmentally-Qualified Cable License Renewal Industry Report," July 1994
- EPRI TR-103842, "Class I Structures License Renewal Industry Report," July 1994
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- EPRI TR-103893, "BWR Primary Coolant Pressure Boundary License Renewal Industry Report," July 1994
- Nuclear Energy Institute, NEI 95-10, "Industry Guidelines for Implementing the Requirements of 10 CFR Part 54 – The License Renewal Rule," Revision 3, dated March 2001
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- SAND 93-7070, "Aging Management Guideline for Commercial Nuclear Power Plants – Heat Exchangers," June 1994
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UNITED STATES
NUCLEAR REGULATORY COMMISSION

ATOMIC SAFETY AND LICENSING BOARD

Before Administrative Judges:

Alex S. Karlin, Chairman
Dr. Richard E. Wardwell
Dr. William H. Reed

In the Matter of	)	
	)	
ENTERGY NUCLEAR VERMONT YANKEE, LLC	)	**Docket No. 50-271-LR**
and ENTERGY NUCLEAR OPERATIONS, INC.	)	**ASLBP No. 06-849-03-LR**
	)	
(Vermont Yankee Nuclear Power Station)	)	

NEW ENGLAND COALITION, INC.

CONTENTION 3

PREFILED EXHIBITS

NEC-JH_54 – NEC-JH_61

April 28, 2008

NEC-JH_54

Assessment of Proposed Program to Manage Aging of the Vermont Yankee Steam Dryer Due to Flow-Induced Vibrations

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April 25, 2008

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I. Basic Concepts

NEC's Contention Three addresses Entergy's plan to manage aging of the Vermont Yankee (VY) steam dryer due to flow-induced vibration, mechanical vibration resulting from interactions between the elastic forces in the dryer and the dynamic forces of the flowing steam. Such vibrations can result when the dryer or one of its components sheds vortices due to boundary layer flow separation at the surface. These vortices create pressure oscillations near the dryer, causing the dryer to vibrate. When the natural frequency of the dryer or one of its components is close to the shedding frequency of the vortex, the resulting vibrations can cause catastrophic damage to the dryer.

The frequencies at which vortices are shed from a structure are correlated with a nondimensional number called the Strouhal number; $S = f D/V$, f is the frequency, D is a dimensional length, V is the flow velocity, S is an empirical number that depends on the Reynolds number. For high Reynolds numbers and simple geometries, such as a cylinder, S is approximately a constant, making the frequency directly proportional to the flow velocity. For a given structure, a small change in velocity may cause the vortex shedding frequency to increase and approach the natural frequency of the structure.

II. Background.

The steam dryer has no safety functions. However, the structural integrity of the dryer must be maintained such that the generation of loose parts is prevented during normal operation, transients[1] and accident events. A public safety hazard would result if the dryer was damaged and some of its parts broke loose and were transported by flow or gravity to other areas of the reactor system. Loose parts may block flow channels in the reactor core, block spray cooling nozzles, or prevent the main steam isolation valves ("MSIVs") from isolating the system during loss of coolant accidents ("LOCA"). This is a direct threat to public health and safety and in violation of General Design Criteria GDC 1 and Draft GDC -40 and -42, 10 CFR Part 50, Appendix A insofar as they require that protection must be provided against the dynamic effects of loss of coolant accidents, LOCA.

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[1] A "transient" is the plant response to a change in power level.

At the beginning of 2006, the operating power at the Vermont Yankee plant was increased by 20%. This also increased the velocities by 20%. Other plants where the velocity was increased experienced crack formation in the steam dryer as described in GE SIL No. 644[2], as discussed further below. Consequently, Entergy installed strain gauges to monitor the condition of the dryer during accession to power. The strain gauges were installed in the main steam line (MSL) to monitor pressure fluctuations within the main steam flow. The data were then used as inputs to an acoustic circuit model (ACM) to calculate pressure loads on the steam dryer and the resulting stress in steam dryer components using a finite element model (FEM).[3]

III. Dryer Failures

GE Nuclear Entergy Service Information Letter, SIL No. 644, Revision 1 (November 9, 2004) provides a summary of experience with dryer failures following power uprates. [4] Failures due to both localized high and low frequency pressure loading occurred on dryers at two different power plants. In both cases, the failures at different locations on the dryer occurred from high cycle fatigue. The small pressure fluctuations in the steam lines (3-4 psi) indicate that even small pressure fluctuations on the dryer can generate altering stresses that exceed the endurance limit at some dryer locations.[5] This is important because it indicates that in order to predict whether the dryer will crack one must first know what the loads are on the dryer at various locations.

The history of steam dryer cracking at the VY plant indicates that Entergy's program to date of visual inspection and moisture monitoring have

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[2] Exhibit NEC-JH_55.

[3] See, ML060050028, Safety Evaluation by Office of Nuclear Reactor Regulation Related to Amendment No. 229 to Facility Operating License No. DPR28, Entergy Nuclear Vermont Yankee, LLC and Entergy Nuclear Operations, Inc., Vermont Yankee Nuclear Power Station Docket 50-271 at § 2.2.6.2.1.

[4] Exhibit NEC-JH_55 at 1-5, Appendices A, B; See also, Exhibit NEC-JH_56.

[5] Exhibit NEC-JH_55.

been ineffective in identifying cracking at the time it occurs, when it occurs in between inspections.[6] General Electric evaluated crack formation in the dryer during the last refueling outage RF026.[7] GE believes that all the cracks were caused by intergranular stress corrosion cracking ("IGSCC"). However, GE did not rule out the possibility of continued crack growth by fatigue.

IV. Entergy's Proposed Steam Dryer Aging Management Plan Program

Entergy has represented that its aging management program for the steam dryer during the period of extended operations will consist exclusively of periodic visual inspection and monitoring of plant parameters as described in GE-SIL-644, and will not involve the use of any analytical tool to estimate stress loads on the steam dryer.[8] Entergy described its proposed program as follows:

> The aging management program for the VY steam dryer during the twenty-year license renewal period will consist of well-defined monitoring and inspection activities that are defined in GE SIL-644 guidelines and are identical to those being conducted during the current post-EPU phase. Steam dryer integrity will be monitored continuously via operator monitoring of certain plant parameters. VY Off-normal Procedure ON-3178 alerts the operators that any of the following events could be indicative of reactor internals damage and/or loose parts generation: a) a sudden drop in main steam line flow > 5%; b) > 3 inch difference in reactor vessel water level instruments; c) sudden drop in steam dome pressure > 2 psig. In addition, periodic measurements of moisture carryover will be evaluated in accordance with the requirements of GE-SIL-644. This monitoring program will continue for the entire license renewal period. The inspection activities will include

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6 Exhibit NEC-JH_57; Exhibit NEC-JH_58 at 4-5; Exhibit NEC-JH_59; Exhibit NEC-JH_60.

7 Exhibit NEC-JH_59.

8 Exhibit NEC-JH_61 at ¶¶ 23-24.

visual inspections of the steam dryer every two refueling outages consistent with GE and BWR Vessel Internals Program (VIP) requirements. The inspections will focus on areas that have been repaired, those where flaws exist, and areas that have been susceptible to cracking based on reactor operating experience throughout the industry.

The aging management plan for the license renewal period, consisting of the monitoring and inspection activities described above, does not depend on, or use, the CFD and ACM computer codes or the [finite element modeling] conducted using those codes.[9]

GE- SIL-644 recommends visual inservice inspections during each refueling outage, but does not require any measurements that could indicate whether existing cracks in the dryer grow in number or length. Visual inspection of the dryer is done with a camera only in accessible areas.

V. Assessment of Proposed Steam Dryer Aging Management Plan

A. Basic Considerations

The steam dryer is susceptible to two types of cracks, (a) stress corrosion cracks, ("SC") and (b) fatigue cracks. Even when one can measure with Eddy Current the density or depth of existing SC cracks, there is no way of predicting how fast such cracks would reach a critical size and then propagate through the wall very rapidly given the presence of sufficiently high loads. Fatigue cracks are usually initiated at points of high stress concentrations which were formed during the fabrication process. Fatigue cracks may be slow to initiate, but once initiated they propagate very fast when exposed to alternating stresses of sufficient magnitude and frequency. Because of the two-stage process of crack formation, when one does not find cracks during inspection, there is absolutely no reason why such cracks would not start propagating once the plant is restarted. The steam dryer problem at VY is serious because we already know that the 20%

[9] Id.; see also, License Renewal Application § 3.1.2.2.11.

increase in velocity increased the potential for the creation of fluctuating pressure loadings. Small changes in local velocity may cause pressure frequencies of local pressure fluctuations to approach the natural frequency of the dryer.

There were problems in the interpretation of the strain gauge data during the accession to 120% at VY and the ACRS questioned the validity of the analytical models.[10] Following the accession to power, Entergy removed the instrumentation that was used to monitor the pressure fluctuations within the dryer.[11]

B. Aging Management Requirements

A sufficient steam dryer aging management plan at VY must include both 1) visual inspection of the steam dryer, and 2) some means of estimating and predicting stress loads on the steam dryer, establishing dryer flow induced vibration load fatigue margins, and demonstrating that stresses on the dryer at selected locations will fall below ASME fatigue limits. The ability to accurately assess and predict stress loads that may act on the dryer during the fuel cycle is essential to ensure the dryer's structural integrity. The visual inspection program and any repairs to the dryer must be informed by knowledge of dryer loads. Plant experience (see Part III, above) demonstrates that an aging management plans that consists solely of parameter monitoring, and partial visual inspection, uninformed by knowledge of dryer loading, will not be sufficient.

Plant parameter monitoring is not effective to prevent the generation of loose parts that can damage safety-related plant components. Most parameter monitoring (moisture, steam flow, water level, dome pressure) may indicate the formation of only those steam dryer cracks that increase moisture carryover; those cracks that do not lead to significant moisture carryover may continue to grow undetected. Moisture monitoring only indicates that a failure has occurred; it does not prevent the failure from occurring. In fact, GE-SIL-644 states the limitations of parameter monitoring as follows: "monitoring steam moisture content and other reactor

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[10] See, ML060040431, Letter to Nils J. Diaz from Graham B. Wallis re. Vermont Yankee Extended Power Uprate (January 4, 2006) at 5.

[11] Exhibit NEC-JH_61 at ¶ 27.

parameters does not consistently predict imminent dryer failure nor will it preclude the generation of loose parts."[12]

VI. Conclusions

For the above-stated reasons, I believe that the operation of the steam dryer, as currently intended by Entergy, is a direct threat to public health and safety and is in violation of GDC 1 and Draft GDC -40 and -42 insofar as they require that protection must be provided against the dynamic effects of a LOCA. I also believe that it was a mistake to remove the instrumentation for the determination of the loads on the dryer. Instead of eliminating all instruments, VY should have improved the analytical tools for predicting, the loads on the dryer, perhaps by conducting additional scaling test at GE at the San Jose facility.

Entergy must formulate a new plan to manage steam dryer cracking before entering the extended period of operation. The plan should be reviewed by a competent party with no financial ties to Entergy.

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[12] Exhibit NEC-JH_ at 6.

GE Nuclear Energy

SIL
Services Information Letter

BWR steam dryer integrity

SIL No. 644
Revision 1

November 9, 2004

SIL No. 644 ("BWR/3 steam dryer failure"), issued August 21, 2002, described an event at a BWR/3 that involved the failure of a steam dryer cover plate resulting in the generation of loose parts, which were ingested into a main steam line (MSL). The most likely cause of this event was identified as high cycle fatigue caused by a flow regime instability that resulted in localized high frequency pressure loadings near the MSL nozzles. SIL No. 644 Supplement 1, issued September 5, 2003, described a second steam dryer failure that occurred at the same BWR/3 approximately one year following the initial steam dryer failure. This second failure occurred at a different location with the root cause identified as high cycle fatigue resulting from low frequency pressure loading. SIL No. 644 included focused recommendations. For BWR/3-style steam dryers, it recommended monitoring steam moisture content (MC) and other reactor parameters, and for those plants operating at greater than the original licensed thermal power (OLTP), it recommended inspection of the cover plates at the next refueling outage. SIL No. 644 Supplement 1 broadened the earlier recommendations for BWR/3-style steam dryer plants and provided additional recommendations for BWR/4 and later steam dryer design plants planning to or already operating at greater than OLTP.

Following this revised guidance, inspections were performed on plants operating at OLTP, stretch uprate (5%), and extended power uprate conditions. These inspections indicate that steam dryer fatigue cracking can also occur in plants operating at OLTP.

The purpose of this Revision 1 to SIL No. 644 is to describe additional significant fatigue cracking that has been observed in steam dryer hoods subsequent to the issuance of SIL No. 644 Supplement 1 and to provide inspection and monitoring recommendations for all BWR plants based on these observations. In that the occurrence of fatigue cracking has been observed in several BWRs, this revision contains inspection and monitoring recommendations that apply to all plants. SIL No. 644 Revision 1 voids and supercedes SIL No. 644 and SIL No. 644 Supplement 1.

Discussion

Instances of fatigue cracking in the steam dryer hood region have been observed recently in several BWR plants. The cracking has led to failure of the hood and the generation of loose parts in two BWR/3 plants. Details of the cracking in these plants are described below. These observations have potential generic significance for all BWR steam dryers that will be discussed in the generic implications section below.

BWR/3-Style Dryer Observations

Lower horizontal cover plate failure occurred in a BWR/3 in 2002. In this failure, almost the entire lower horizontal cover plate came completely loose, with some large pieces falling down onto the steam separators and one piece being ingested into the main steamline and lodging in the flow restrictor. This failure was accompanied by a significant increase in moisture content, along with changes in other monitored reactor parameters. The cause of this failure was attributed to the higher fluctuating pressure loads at extended power uprate (EPU) operation. In particular, there may have been a potential resonance condition between a high frequency fluctuating pressure loading (in the 120-230 Hz range) and the natural frequency of the cover plate. Appendix A provides a more detailed description of this event.

The same BWR/3 experienced extensive through-wall cracking in the outer bank hood on the 90° side in May 2003. On the opposite side of the steam dryer (270° side), incipient cracking was observed on the inside of the outer hood cover plate. Several internal braces were detached and found on top of the steam separators. No damage was found on the inner banks of the dryer. Again, the failure was accompanied by a significant increase in moisture content. Of the other monitored reactor parameters, only the flow distribution between the individual steamlines was affected. The cause of this failure was attributed to high cycle fatigue resulting from low frequency oscillating pressure loads (<50 Hz) of higher amplitude at EPU operation and the local stress concentration introduced by the internal brackets that anchor the diagonal internal braces to the dryer hoods. Appendix B provides a more detailed description of this event.

In November 2003, a hood failure occurred in the sister unit to the BWR/3 that had experienced the previously noted failures. This unit was also operating at EPU conditions. The observed hood damage and associated root cause determination were virtually the same as the May 2003 failure described above. During the event, the moisture content exceeded the previously defined action level. However, the monitored plant parameters (primarily individual steamline flow rates) showed only subtle changes and were well within the previously defined action levels for the plant. This failure resulted in the generation of loose parts from the outer vertical hood plate. In addition, inspections during the repair outage showed fatigue cracking in the inner hood vertical braces below where the lower ends of the diagonal braces were attached. The cracking of these braces was attributed to poor fit-up of the parts during the dryer fabrication. The diagonal braces should have terminated on the vertical braces where they were butted up against the drain trough, which would have transferred the diagonal brace loads directly to the drain trough. Instead, the diagonal braces terminated on the vertical braces above the top of the drain trough and the diagonal brace loads were transmitted through the unsupported section of the vertical braces, thus overstressing the vertical braces.

In October 2003 and December 2003, inspections were made of the steam dryers of the sister units to the BWR/3s described above at another site. These units had also been operating at EPU conditions. Incipient cracking was observed on the inside of the outer hood vertical plates on each of the outer dryer banks. At one location, the cracking had grown through-wall. The cracking was also attributed to high cycle fatigue resulting from low frequency pressure loading.

In March 2004, inspections were performed of the repairs made to the BWR/3 dryer in 2003. Incipient fatigue cracks were found at the tips of the external reinforcing gussets that were added as part of the 2003 repairs. Fatigue cracks were also found in tie bars that were reinforced during the 2003 repairs. The cracking in these repairs was attributed to local stress concentration introduced by the as-installed repairs. In both cases, the local stress concentrations had not been modeled in sufficient detail in the analyses that supported the repair design. Fatigue cracks were also found in perforated plate insert modifications that were made in 2002 as part of the extended power uprate implementation. These cracks were also attributed to the displacements and stresses imposed by the dryer banks that caused the tie bar cracking.

In April 2004, inspections were made of a BWR/3-style dryer (square hood) in a BWR/4 plant in preparation for implementing an extended power uprate during the upcoming cycle. This inspection found cracking at two diametrically opposed locations on the exterior steam dam near the lifting lug. Both cracks were similar in length. The cause of the cracking was not identified. It has been postulated that the crack initiation was due to high residual stresses generated during the dryer fabrication process. The structural analysis of the steam dryer for EPU conditions did not predict these locations as highly susceptible to fatigue cracking. Two other symmetrical locations in the steam dryer that experienced the same loading conditions did not exhibit any evidence of cracking. These observations point to the likelihood of the presence of an additional contributing factor aside from the pressure loads during normal operation. Specifically, the evidence indicates that a high residual stress condition was probably developed by the original dryer fabrication welding sequence. Other "cold spring" type loading could also have been generated during the fabrication process. After the cracking developed, the residual stresses would have been relieved and the crack growth would have subsided.

BWR/5-Style Dryer Observation

In March 2004, inspection of the steam dryer at a BWR/5 revealed a fatigue crack in the hood panel to end plate weld. The hood crack occurred in the weld joint between the 1/8" curved hood and the 1/4" end plate on the second dryer bank. This particular weld location is vulnerable to fatigue cracking because of the small weld size associated with the thin 1/8" hood material. Fabrication techniques (e.g., feathering the 1/8" plate during fit-up) may further reduce the weld size. Fatigue cracking has been observed in the second bank hood-end plate weld at several other plants with the curved BWR/4-5 hood design at OLTP power levels. An undersized weld was determined to be the root cause of the cracking observed in at least two of the plants. Incorporating lessons learned from the weld cracks at the other plants, the dryer for this BWR/5 was built with an additional 1/4" fillet weld on the inside of the hood-end plate joint. This weld extended as high up in the hood as was practical for the welder to make (approximately 50") and spanned the probable initiation location for the earlier cracks. The weld crack at the subject BWR/5 occurred in the upper part of the 1/8" weld, above this reinforced section.

The weld joint between the 1/8" curved hood and the 1/4" end plate on the second dryer bank is a known high stress location for the BWR/4-5 curved hood dryer design; therefore, periodic inspection of this location was recommended by SIL No. 644 Supplement 1. The hood cracks at the other four plants occurred early in plant life, within the first three or four cycles of operation. In-plant vibration testing of one of the cracked dryers showed that the dynamic pressure oscillations were high enough that the 1/8" hood to end plate weld was vulnerable to fatigue cracking at pre-uprate power levels. The hood crack at the subject BWR/5 occurred after approximately 16 years of operation, the last nine of which were at a 5% stretch uprate power level. While power uprate operation does increase the loading on the dryer, the length of operating time at uprated power levels before the cracking was observed indicates that the weld was not grossly overstressed and that power uprate was only a secondary factor in the cracking observed at the subject BWR/5.

BWR Fleet Operating History

Steam dryer cracking has been observed throughout the BWR fleet operating history. The operating environment has a significant influence on the susceptibility of the dryer to cracking. Most of the steam dryer is located in the steam space with the lower half of the skirt immersed in reactor water at saturation temperature. These environments are highly oxidizing and increase the susceptibility to IGSCC cracking. Average steam flow velocities through the dryer vanes at rated conditions are relatively modest (2 to 4 feet per second). However, local regions near the steam outlet nozzles may be continuously exposed to steam flows in excess of 100 feet per second. Thus, there is concern for fatigue cracking resulting from flow-induced vibration and fluctuating pressure loads acting on the dryer.

In addition to the recent instances described above, steam dryer cracking has been observed in the following components at several BWRs: dryer hoods, dryer hood end plates, drain channels, support rings, skirts, tie bars, and lifting rods. These crack experiences have predominately occurred during OLTP conditions, and are briefly described below.

Dryer Hood Cracking

As discussed above, outer hood cracking has occurred recently in square hood design dryers. Additionally, other hood cracking has occurred in the BWR operating fleet. Cracking of this type was first found in BWR/2s in the inner banks. These hood cracks were attributed to high cycle fatigue. Other cracking has since been observed in other types of dryers including BWR/4s and attributed to high cycle fatigue as well. Susceptible plants were typically reinforced with weld material or plates.

Dryer End Plate Cracking

Cracking has been detected in end plates of the dryer banks at several BWRs. These cracks have been attributed to IGSCC based on the location and morphology of the cracks. These cracks have been followed over several cycles and shown to be stable when operating conditions (power levels) are not changed. Typically no repairs have been necessary.

Drain Channel Cracking

Drain channel cracking has been found in all types of BWRs. This cracking has been primarily categorized as being attributable to fatigue, although many cracks have been attributed to IGSCC. The steam dryers were originally fabricated using Type 304 stainless steel, a material susceptible to sensitization by welding processes and prone to crack initiation in the presence of cold work. Drain channel cracking has been associated with at least 17 plants. The occurrence of the cracking prompted GE to issue SIL No. 474 ("Steam Dryer Drain Channel Cracking" issued October 26, 1988) after cracks were discovered in the drain channel attachment welds during routine visual examination of dryers at several BWR/4, 5 and 6 plants. The cracks generally were through the throat of vertical welds that attach the side of the drain channel to the exterior of the 0.25-inch thick dryer skirt. The cracks were as long as 21 inches. The cracks are thought to have originated at the bottom of the drain channel where there is maximum stress in the welds. The appearance of the cracking and analysis of potential sources of stress on the welds indicate that high cycle fatigue initiated the cracks in drain channel welds. With the internal dryer inspections performed following the issuance of SIL No. 644, similar cracking has been observed in the internal drain channels of BWR/3-type steam dryers. Typically, drain channel cracks have been repaired by replacing and adding reinforcement weld material, stop-drilling the crack tip, or by replacing the drain channels.

Support Ring Cracking

Support ring cracking has been found in many BWRs. Cracking has been found in at least 19 plants, ranging from BWR/4s to BWR/6s. The cause of cracking has been IGSCC with a potential contributor being the cold working of the support ring during the fabrication process. These cracks are typically monitored for growth. To date, no repairs have been necessary since cracks have reached an arrested state.

Skirt

Skirt cracking has been found along with drain channel cracking. These cracks are either due to IGSCC or could be related to fatigue due to imposed local loads on the dryer. The cracking has also been found in the formed channel section of the dryer. The complex structural dynamic mode shapes of the dryer skirt, the stiffness added by the drain and guide channels, and residual weld stresses all contribute to the cracking observed in these components. Cracking in the dryer skirt region has been observed in plants operating at both OLTP and uprated power levels. Typically, repairs have been implemented at the time that cracking was found.

Tie Bar Cracking

Fatigue cracking has been observed in tie bars of plants operating at both OLTP and uprated power levels. In most cases, the potential for cracking is related to the cross section of the tie bar itself because the tie bar must withstand the displacements and stresses imposed by the dryer banks. Typically, repairs have been implemented at the time that cracking was found.

Lifting Rod

Several plants have exhibited damage in the lifting rods. This cracking has often been in tack welds or in lateral brackets and has been attributed to fatigue.

Other Crack Locations

Other locations have also exhibited cracking. These locations include the level screws or leveling screw welds, seismic blocks, dryer bank end plates and internal attachment welds, vertical internal hood angle brackets and bottom plates.

Generic Implications

The steam dryer is a non-safety component. However, the structural integrity of the dryer must be maintained such that the generation of loose parts is prevented during normal operation, transients, and accident events. With the exception of the significant outer hood cracking at the two BWR/3 plants, the dryer cracking observed in the BWR fleet to date is unlikely to result in the generation of loose parts provided that a periodic inspection program is in place. However, given that the steam dryers operate in an environment that is conducive to crack initiation and that many plants are pursuing power uprates and operating license extensions, further cracking in steam dryers should be anticipated. Therefore, the material condition of the dryer should be actively managed to ensure that structural integrity is maintained throughout the life of the dryer.

The experience described above has several generic implications with respect to the susceptibility of steam dryers to fatigue or IGSCC cracking.

- Fatigue cracking may result from stress concentrations inherent in the design of the dryer. The design of the BWR/3-style steam dryers with a square hood and internal braces results in maximum stresses where the internal braces attach to the outer hood. The hood crack initiation at the BWR/3s described above occurred at these high stress locations. Also, the undersized hood-to-end plate welds on the BWR/5 curved hood dryers have cracked in several plants.
- The actual dryer fabrication may have introduced stress concentrations that may lead to fatigue cracking. The poor fit-up of the diagonal and vertical braces in the BWR/3 dryer led to the cracking of the vertical braces. Feathering of the 1/8" plate during fit-up, and the corresponding reduction in weld area, was considered a contributing factor in the through-wall cracking of the hood-end plate weld in one of the BWR/5-style dryers. Residual stresses or "cold spring" introduced during the fabrication sequence may also lead to crack initiation.
- The fabrication quality for each dryer may vary from one unit to the next, even if the dryers were built by the same fabricator to the same specifications.
- The design of dryer repairs and modifications should consider the local stress concentrations that may be introduced by the modification design or installation. Repairs and modifications to the dryer should be inspected at each outage following the installation until structural integrity of the repairs and modifications can be confirmed.
- Steam dryers are susceptible to IGSCC due to the material and fabrication techniques used in the dryer construction. Weld heat affected zone material is likely to be sensitized. Many dryer assembly welds have crevice areas at the weld root, which were not sealed from the reactor environment. Cold formed 304 stainless steel dryer parts were generally not solution annealed after forming and welding. Therefore, steam dryers are susceptible to IGSCC.

Parameter monitoring programs had been previously recommended with the intent of detecting structural degradation of the steam dryer during plant operation. The experience described above also has generic implications with respect to monitoring reactor system parameters during operation for the purposes of detecting steam dryer degradation.

- The November 2003 BWR/3 hood failure demonstrated that monitoring steam moisture content and other reactor parameters does not consistently predict imminent dryer failure nor will it preclude the generation of loose parts. Monitoring is still useful in that it does allow identification of a degraded dryer allowing appropriate action to be taken to minimize the damage to the dryer and the potential for loose parts generation.
- Monitoring the trends in parameter values may be more important than monitoring the parameter values against absolute action thresholds. An unexplained change in the trend or value of a parameter, particularly steam moisture content or the flow distribution between individual steamlines may be an indication of a breach in the dryer hood, even though the absolute value of the parameter is still within the normal experience range.
- Statistical smoothing techniques such as calculating running averages using a large quantity of samples may be necessary to eliminate the process noise and allow the changes in the trend to be identified.
- An experience base should be developed for each plant that correlates the changes in monitored parameters to changes in plant operation (rod patterns, core flow, etc.) in order to be able to distinguish the indications of a degraded dryer from normal variations that occur during the operating cycle.

Recommended Actions:

GE Nuclear Energy recommends that owners of GE BWRs consider the following:

A. For all plants:

A1. Perform a baseline visual inspection of all susceptible locations of the steam dryer within the next two scheduled refueling outages. Inspection guidelines showing the susceptible locations for each dryer type are provided in Appendix C.

a. Repeat the visual inspection of all susceptible locations of the steam dryer at least once every two refueling outages.

b. For BWR/3-style steam dryers with internal braces in the outer hood that are operating above OLTP, repeat the visual inspection of all susceptible locations of the steam dryer during every refueling outage.

c. Flaws left "as-is" should be inspected during each scheduled refueling outage until it has been demonstrated that there is no further crack growth and the flaws have stabilized.

Note: This recommendation does not supercede the inspection schedules for existing flaws for which plant-specific evaluations already exist.

d. Modifications and repairs to cracked components should be inspected during each scheduled refueling outage until the structural integrity of the modifications and repairs has been demonstrated. Once structural integrity of any modifications and repairs has been demonstrated, longer inspection intervals for these locations may be justified.

Note: This recommendation does not supercede the inspection schedules for existing modifications or repairs for which plant-specific evaluations already exist.

A2. Implement a plant parameter monitoring program that measures moisture content and other plant parameters that may be influenced by steam dryer integrity. Initial monitoring should be performed at least weekly. Monitoring guidelines are provided in Appendix D.

A3. Review drawings of the steam dryer to determine if the lower cover plates are less than 3/8 inch thick or if the attachment welds are undersized (less than the lower cover plate thickness). If this is the case, and the plant has operated above OLTP, review available visual inspection records to determine if there are any pre-existing flaws in the cover plate and/or the attachment welds.

B. In addition, for plants planning on increasing the operating power level above the OLTP or above the current established uprated power level (i.e., the plant has operated at the current power level for several cycles with no indication of steam dryer integrity issues), the recommendations presented in A (above) should be modified as follows:

B1. Perform a baseline visual inspection of the steam dryer at the outage prior to initial operation above the OLTP or current power level. Inspection guidelines for each dryer type are provided in Appendix C.

B2. Repeat the visual inspection of all susceptible locations of the steam dryer during each subsequent refueling outage. Continue the inspections at each refueling outage until at least two full operating cycles at the final uprated power level have been achieved. After two full operating cycles at the final uprated power level, repeat the visual inspection of all susceptible locations of the steam dryer at least once every two refueling outages. For BWR/3-style steam dryers with internal braces in the outer hood, repeat the visual inspection of all susceptible locations of the steam dryer during every refueling outage.

B3. Once structural integrity of any repairs and modifications has been demonstrated and any flaws left "as-is" have been shown to have stabilized at the final uprated power level, longer inspection intervals for these locations may be justified.

To receive additional information on this subject or for assistance in implementing a recommendation, please contact your local GE Nuclear Energy Representative.

This SIL pertains only to GE BWRs. The conditions under which GE Nuclear Energy issues SILs are stated in SIL No. 001 Revision 6, the provisions of which are incorporated into this SIL by reference.

Product reference

B11 — Reactor Assembly
B13 — Reactor System

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Appendix A
2002 BWR/3 Event

On June 7, 2002, while operating at approximately 113% of OLTP, the BWR/3 experienced a mismatch between the "A" and "B" reactor vessel level indication channels, a loss of approximately 12 MWt, and a reactor pressure decrease. Following the event, measurement indicated that the moisture content had increased by a factor of 10 (to a value of 0.27%). The reactor pressure decrease, reactor vessel level indication mismatch, and increase in moisture content comprised a set of concurrent indications suggesting a possible failure of the steam dryer. It was evaluated that there were no safety concerns associated with the observed conditions, and the plant continued to operate after implementing several compensatory measures (e.g., reactor water level setpoint adjustments, increased frequency of moisture content measurements).

Following the initial event, additional short duration (several minutes to ½ hour) perturbations occurred and the moisture content continued to increase. When the moisture content increased to approximately 0.7%, the power level was reduced to approximately 97% of OLTP. At this reduced power, the frequency of the plant perturbations decreased, along with the moisture content. Given the stable plant response at this lower power, the power was increased to 100% OLTP approximately one week later.

On June 30, subsequent to the power reduction to the OLTP level, a step change increase in the reactor steam dome pressure was noted. No changes in turbine control valve positions or pressure in the turbine steam chest were observed. Several additional perturbations occurred over the following week with the reactor steam dome pressure continuing to increase (to a total of 15 to 20 psi above normal conditions) along with a divergence of the measured total main steam line (MSL) flows compared to the total feedwater flow. The plant was shut down on July 12 to inspect the steam dryer.

Inspection Results:

Inspection of the steam dryer revealed that a ¼-inch stainless steel cover plate measuring approximately 120" x 15" had failed near the MSL "A" and "B" nozzles (Figure A-1). The failure of this cover plate allowed steam to bypass the dryer banks and exit through the reactor MSL nozzles, causing the observed increase in moisture content. The majority of the cover plate was found as a single piece on top of steam separators. However, a piece of the cover plate (approximately 16"x 6") had failed and was found lodged in and partially blocking the MSL "A" flow venturi contributing to the MSL flow imbalance and water level perturbations. Several smaller loose pieces (believed to have come from a startup pressure sensor bracket which may have been knocked off by the cover plate) were located at the turbine stop valve strainer basket. Minor gouges and scratches from the transport of foreign material were noted in the "A" steam nozzle cladding, the main steam piping and the MSL "A" flow venturi. All loose pieces were recovered. No collateral damage to other reactor vessel components was observed.

The cover plate was welded in place as part of the original equipment dryer assembly. No known prior repairs had been made to the cover plate. The cover plate is not connected or adjacent to the dryer modification performed at the previous outage; all flow distribution plates installed as part of the dryer modification were intact in the as-installed condition.

Metallurgical Evaluation:

Preliminary laboratory analysis has been completed. The main crack originated from the bottom side of the cover plate and propagated upward through both the plate base metal and weld metal. The transgranular, as opposed to intergranular, nature of the fracture surface and the relative lack of crack branching indicated that the failure was not caused by stress-corrosion cracking. The lack of macro and micro ductility features in and near the fracture indicated the cracking occurred over a period of time and not due to a mechanical overload. Additionally, there was no evidence that the failure was a result of an original manufacturing defect. Based on the available evidence, the most probable cause of the cover plate cracking was mechanical, high cycle fatigue.

Root Causes:

The results of the metallurgical analysis confirmed that the failure mechanism is high cycle fatigue. The cause of this high cycle fatigue is believed to be flow induced vibration. At this time there are two probable root causes of the cover plate failure:

1. Increased pressure oscillations on the steam dryer due to the increased steam flows at extended power uprate conditions, aggravated by the potential presence of a pre-existing crack in the cover plate.
2. A flow regime instability that results in localized, high cycle pressure loadings near the MSL nozzles. When the natural frequency of the installed cover plate coincides or nearly coincides with the frequency of the cyclic pressure forcing function, and the acoustic natural frequency of the steam zone, the resulting resonance or resonances can lead to high vibratory stresses and eventual high cycle fatigue failure of the cover plate.

Corrective Actions:

The cover plates on both sides of the dryer have been replaced with ½-inch continuous plates (this eliminates two intermediate welds on the original plates). The fillet weld connecting the plate to the support ring was increased to ⅜-inch and the weld to the vertical face of the dryer hood was increased to ½-inch. The plant has been returned to service with interim, enhanced monitoring of moisture content, reactor steam dome pressure, MSL flow rates and reactor water level. As an additional measure, the plant has implemented dynamic response monitoring of the MSLs to determine if higher flow induced vibration occurs as the steam flow is increased.

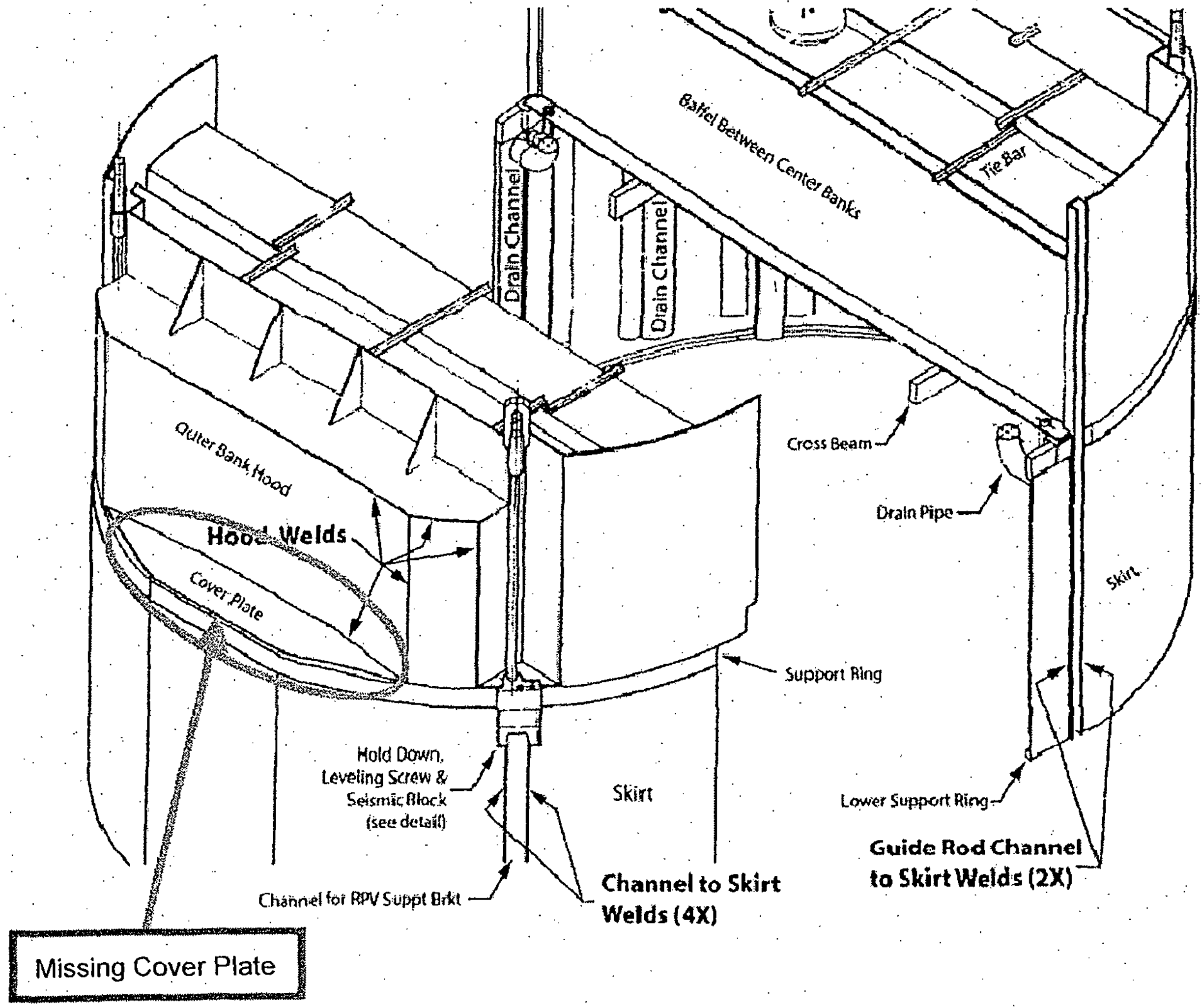


Figure A-1: Location of the 2002 Lower Cover Plate Failure

Appendix B

2003 BWR/3 Event

On April 16, 2003, with the plant operating at extended power uprate (EPU) conditions, an inadvertent opening of a pilot operated relief valve (PORV) occurred. The unit was shut down and the PORV replaced. On May 2, 2003, following return to EPU conditions, a greater than four-fold increase in the moisture content was measured. The moisture content continued to gradually increase until it exceeded a pre-determined threshold of 0.35% on May 28, 2003. The power level was reduced to pre-EPU conditions that resulted in a moisture content reduction to 0.2%. The moisture content remained steady at this value following the power reduction with no significant changes in other reactor operating parameters observed by the operators.

A detailed statistical evaluation of key plant parameters concluded that a subtle change in the MSL flows had occurred following the April 16, 2003 PORV event. Based on this information, concurrent with the moisture content increase, the utility elected to shut down the unit on June 10, 2003 and perform a steam dryer inspection.

Inspection results

A detailed visual inspection of the accessible external and internal areas of the steam dryer revealed significant steam dryer damage. The damage was most severe on the 90-degree side of the steam dryer, the side that was closest to the PORV that had opened. On the 90-degree side, a through-wall crack approximately 90 inches long and up to three inches wide was observed in the top of the outer hood cover plate and the top of the vertical hood plate (refer to Figures B-1 and B-2). Three internal braces in the outer hood were detached and one internal brace in the outer hood was severed. The detached braces were found on top of the steam separator. All detached parts were accounted for and retrieved. On the opposite side of the steam dryer (270-degree side), incipient cracking was observed on the inside of the outer hood cover plate and one vertical brace in the outer hood was cracked. No damage was found in the cover plates that had been replaced following the first steam dryer failure in 2002.

Three tie bars on top of the steam dryer connecting the steam dryer banks were also cracked. Tie bar cracking has been observed on several other steam dryers (including plants that have not implemented EPU); therefore, tie bar cracking is believed to be unrelated to the other damage noted above.

Root cause of steam dryer failure

Extensive metallurgical and analytical evaluations (e.g., detailed finite element analyses, flow induced vibration analyses, computational fluids dynamics analyses, $1/16^{th}$ scale model testing and acoustic circuit analyses) concluded that the root cause of the steam dryer failure was high cycle fatigue resulting from low frequency pressure loading. There are two potential contributing factors to the failure:

1. Continued operation for approximately 1 month following the failed cover plate in 2002 which resulted in additional stress loading on the vertical hood plate, and

2. Inadvertent opening of the PORV resulting in a decompression wave, which subjected the steam dryer to two to three times the normal pressure loading. (It is believed that there was incipient cracking in the steam dryer and the PORV event caused the cracks to open up).

The root cause identified in the first steam dryer failure was high cycle fatigue cause by high frequency pressure loading. The low frequency pressure loading was identified as the dominant cause in this failure. The low frequency pressure loading may have also been a significant contributing factor in the first failure.

Corrective Actions:

The following repairs and pre-emptive modifications were made to both the 90 and 270-degree sides of the steam dryer:

1. replaced damaged ½ inch outer hood plates with 1 inch plates
2. removed the internal brackets that attached the internal braces to the outer hood
3. added gussets at the outer vertical hood plate and cover plate junction
4. added stiffeners to the vertical welds and horizontal welds on the outer hood

The combined effect of these modifications was to increase the natural frequency of the outer hood, reduce the maximum stress by at least a factor of two, and reduce the pressure loading by reducing the magnitude of vortices in the steam flow near the MSLs.

Following the steam dryer modifications, the unit was returned to service on June 29, 2003.

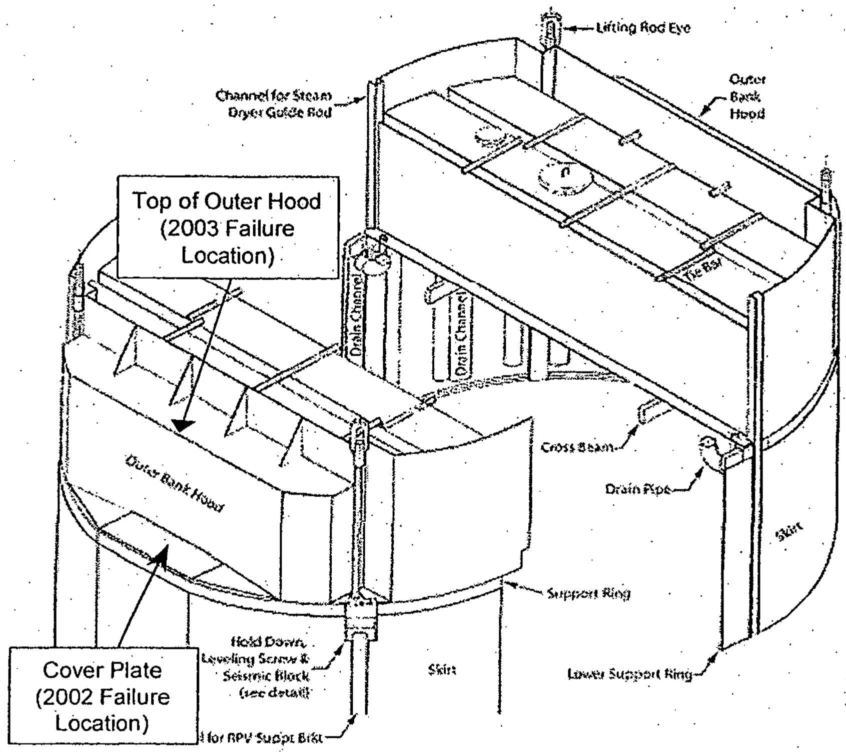


Figure B-1: Location of the 2003 Outer Hood Failure

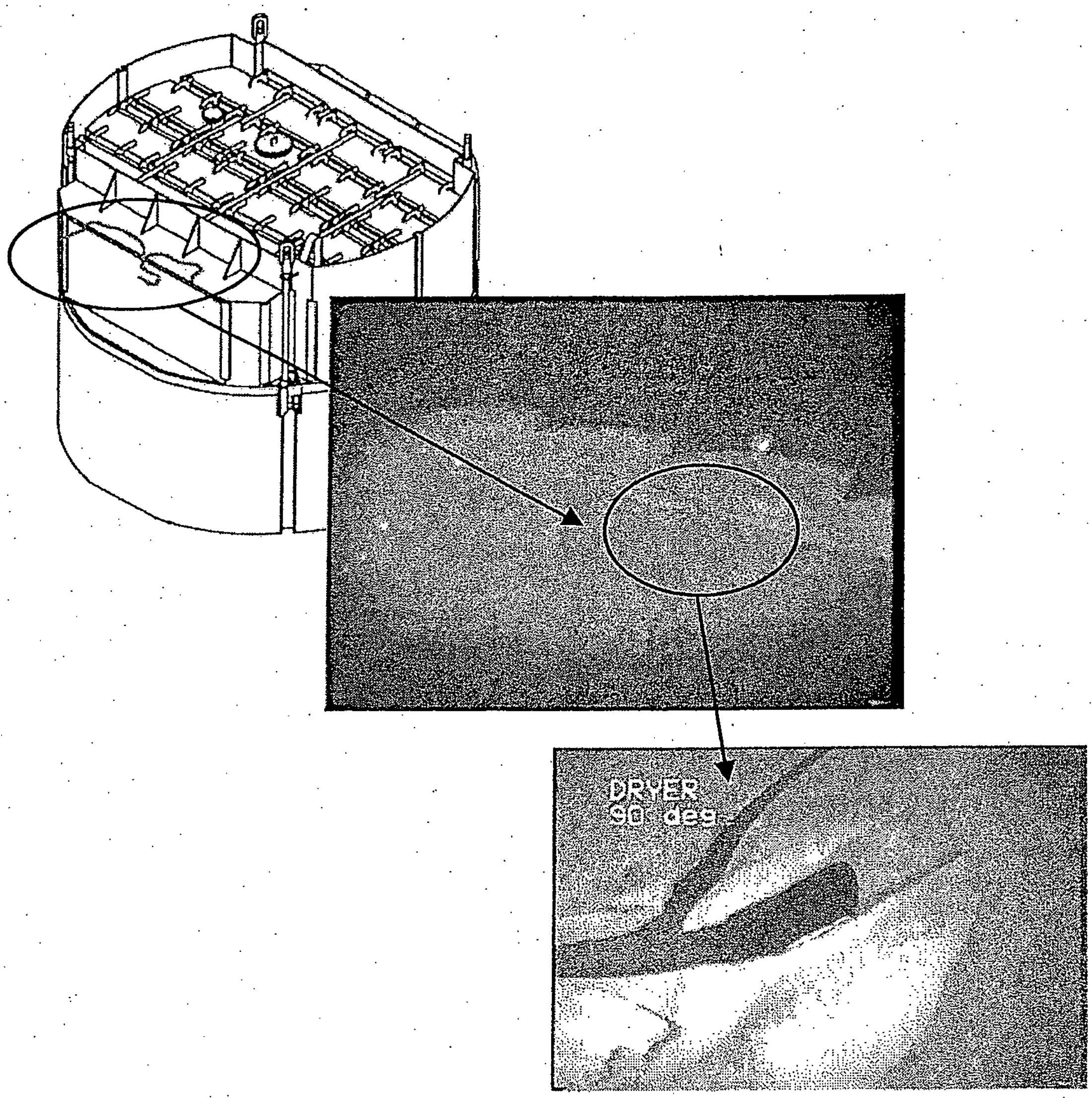


Figure B-2: Steam Dryer Damage 90 Degree Side

Appendix C
Inspection Guidelines

Overview

The steam dryers have been divided into four broad types with fourteen sub-groups: BWR/2 design, square hood design, slanted hood design and the curved hood design. The focus of the inspections for each dryer type is divided into two categories. The first category is directed at the outer surfaces of the dryer that are subject to fluctuating pressure loads during normal operation and are potentially susceptible to fatigue cracking. The second category is directed at the cracking that has been found in the drain channels and in inner bank end plates. These latter locations are not associated with any near term risk of loose part generation. They have often been associated with IGSCC cracking in the heat-affected-zones of stainless steel welds.

Inspection Techniques

Based on the current experience in inspecting the dryer components, VT-1 is the recommended technique to be employed for the inspections. VT-1 resolution, distance, and angle of view requirements should be maintained to the extent practical. In instances where component geometry or remote visual examination equipment limitations preclude the ability to maintain the VT-1 requirements over the entire length of the different weld seams, "best effort" examinations should be performed. In that cracking will be expected to have measurable length (several inches), field experience has confirmed that "best effort" approaches are sufficient to find the cracking that is present.

Steam Dryer Integrity Inspection Recommendations

The recommendations are divided into three categories: BWR/2 and square hood taken together, slanted hood and curved hood steam dryers. The inspection recommendations for each type of dryer will be detailed using schematics of the outer dryer structure. The key weld seams that must be inspected are outlined in red or green. High stress locations associated with structural integrity are outlined in red. Locations associated with field dryer cracking experience are outlined in green. Typical horizontal and vertical welds are shown thereby providing guidance for establishing a plant specific inspection plan. The weld numbering approach shown in the figures is only given as an example. Due to the many welds and size differences, each plant should employ their own weld numbering system. If an indication is detected, care should be exercised when inspecting the symmetrical locations on the dryer. If an indication is detected on the external surface of a plate or weld, consideration should be given to inspecting the location from the inside of the dryer in order to determine if the indication is through-wall.

Square Hood Design: applicable to BWR/2 plants and BWR/3 plants

Several square hood dryers were built with interior brackets and diagonal braces. These structures produce stress concentration locations, which have been found to aid in the initiation of fatigue cracking. These brackets exist in both the outer and the inner dryer banks. The recommended inspections follow.

Steam Dryer Bank Inspections

Figure C-1 provides the overview of the square dryer design. These dryers will require both an external and internal inspection. All dryers are symmetrical from this perspective. Outlined in red are the key weld seams that must be inspected. These welds, both horizontal and vertical outline the outer dryer bank. These locations considered as high stress locations. Figure C-2 displays a cross-section of the BWR/2 steam dryer with the outer bank peripheral welds highlighted. This configuration has no lower cover plate. However, the external locations that match those shown in Figure C-1 need to be inspected in a similar fashion to the other square hood dryers. Figures C-3 and C-4 provide the details of the weld seams as viewed from the dryer bank interior. As shown in Figure C-3, the outer bank welds need to be inspected from both the dryer exterior and the dryer interior. In addition, for the dryers where there are interior brackets that were present in the original design and are still present, the interior inspection must be conducted of the weld region where the bracket is joined to the hood vertical and top plates. Figure C-3 shows these locations for the outer banks hoods. Figure C-4 shows the brackets for the inner hood. In addition, Figure C-5 provides a cross section of the bracket-diagonal brace substructure. The intersection locations between the bracket and the top and outer hood are also outlined in red in these figures. In that the concern is primarily fatigue cracking, several inches of base material adjacent to welds should be examined as well as any obvious discontinuity, e.g., the exterior base material should be examined in the general area where there is an internal weld. This inspection examination region includes the heat-affected-zone and will therefore detect any IGSCC cracking. This figure also shows locations in green that exhibited cracking in the field. The region of inspection should be the same.

Tie Bar Inspections

In addition to the outer bank and interior bracket locations, tie bars also require inspection. Figure C-6 provides a schematic of the tie bars. These are located between each set of dryer banks.

Inspections Based on Field Experience

The other locations of interest are primarily associated with IGSCC in drain channels (shown for information in Figures C-7 and C-8). These components will be part of the internal examination. While these indications have been historically associated with BWR/4 through BWR/6 plants (SIL No. 474 "Steam Dryer Drain Channel Cracking" issued October 26, 1988), recent findings indicate that cracking can occur in these locations in square hood dryers. The additional weld seams associated with the outer side of the next set of inner banks should also be inspected in that this represents a steam path through the dryer. These areas are shown in green in Figure C-1. Cracking has been detected in these end panels in later design dryers. Finally, cracking at the steam dams as indicated in green in Figure C-6 has occurred in one BWR/4. These locations need to be included in the inspection plan for all of these plants. Finally, bank inner surface welds have cracked in the BWR/2. These locations, shown in Figure C-2 in green, also need to be inspected.

Slanted Hood Design: applicable to BWR/4 plants

The slanted hood steam dryers fall into three categories for which the primary difference is diameter and the number of banks. These dryers use 2 or 3 stiffener plates to strengthen each dryer bank. All inspections are on the external surface of the dryer. However, if an indication is detected on the external surface of a plate or weld, consideration should be given to inspecting the location from the inside of the dryer in order to determine if the indication is through-wall. The recommended inspections follow.

Steam Dryer Bank Inspections

Figure C-9 provides the overview of the slanted dryer design. All dryers are symmetrical from this perspective. Outlined in red are the key weld seams that must be inspected from the external surface. These welds, both horizontal and vertical outline the outer dryer bank as well as the cover plate between the outer hood vertical plate and the support ring. Additional red lines represent the outside projected location where the stiffener plates are welded to the outer hood vertical plate. These locations are considered as high stress locations. The man-way welds (on one side) are also shown as locations requiring inspection.

Tie Bar Inspections

In addition to the outer bank and interior bracket locations, tie bars also require inspection. Figure C-10 provides a schematic of the tie bar locations joining the tops of each set of banks. The primary concern is the presence of fatigue cracking through the bar base material cross-section at axial location where the tie bar is attached to the bank.

Inspections Based on Field Experience

Cracking has been detected in these end panels in later design dryers. Therefore, these additional weld seams associated with the outer side of the inner banks should also be inspected in that this represents a steam path through the dryer. These areas are shown in green in Figure C-9. Cracking has been observed in these locations in dryers of this design. The other locations of interest are primarily associated with IGSCC in drain channels (refer to SIL No. 474 "Steam Dryer Drain Channel Cracking" issued October 26, 1988), support ring, and lifting rod attachments.

Curved Hood Design: applicable to BWR/4-BWR/6 and ABWR plants

The curved hood steam dryers fall into five categories for which the primary differences are diameter and inner bank hood thickness. Similar to the slanted hood dryers, these dryers also have 2 or 3 interior stiffener plates to strengthen each dryer bank. All inspections are on the external surface of the dryer. However, if an indication is detected on the external surface of a plate or weld, consideration should be given to inspecting the location from the inside of the dryer in order to determine if the indication is through-wall. The recommended inspections follow.

Steam Dryer Bank Inspections

Figure C-11 provides the overview of the curved hood dryer design. All dryers are symmetrical from this perspective. Outlined in red are the key weld seams that must be inspected from the external surface. These welds, both horizontal and vertical outline the outer dryer bank as well as the cover plate between the outer hood vertical plate and the support ring. Additional red lines represent the outside projected location where the stiffener plates are welded to the outer hood vertical plate. Inspection locations also include outer plenum end plates and inner hood vertical weld seams for BWR/4 and BWR/5 plants with 1/8 inch thick hood plates on the inner banks. The location shown is the region where these thinner hood plates are attached to the stiffeners. All of these locations are considered as relative high stress locations. The man-way welds (on one side) are also shown as locations requiring inspection.

Tie Bar Inspections

In addition to the outer bank and interior bracket locations, tie bars also require inspection. Figure C-11 provides a schematic of the tie bar locations joining the tops of each set of banks. In that the attachment of the tie bars may have employed high heat input welds, the inspection should also include the entire welded region to assess the presence of IGSCC on the bank top plate. This region is adjacent to the region shown in red around the end of the inner bank tie bars.

Inspections Based on Field Experience

Cracking has been detected in the end panels in later design dryers. Therefore, these additional weld seams associated with the outer side of the inner banks should also be inspected in that this represents a steam path through the dryer. These areas are shown in green in Figure C-11. Cracking has been observed in these locations in dryers of this design. The other locations of interest are primarily associated with IGSCC in drain channels (refer to SIL No. 474 "Steam Dryer Drain Channel Cracking" issued October 26, 1988) and lifting rod attachments.

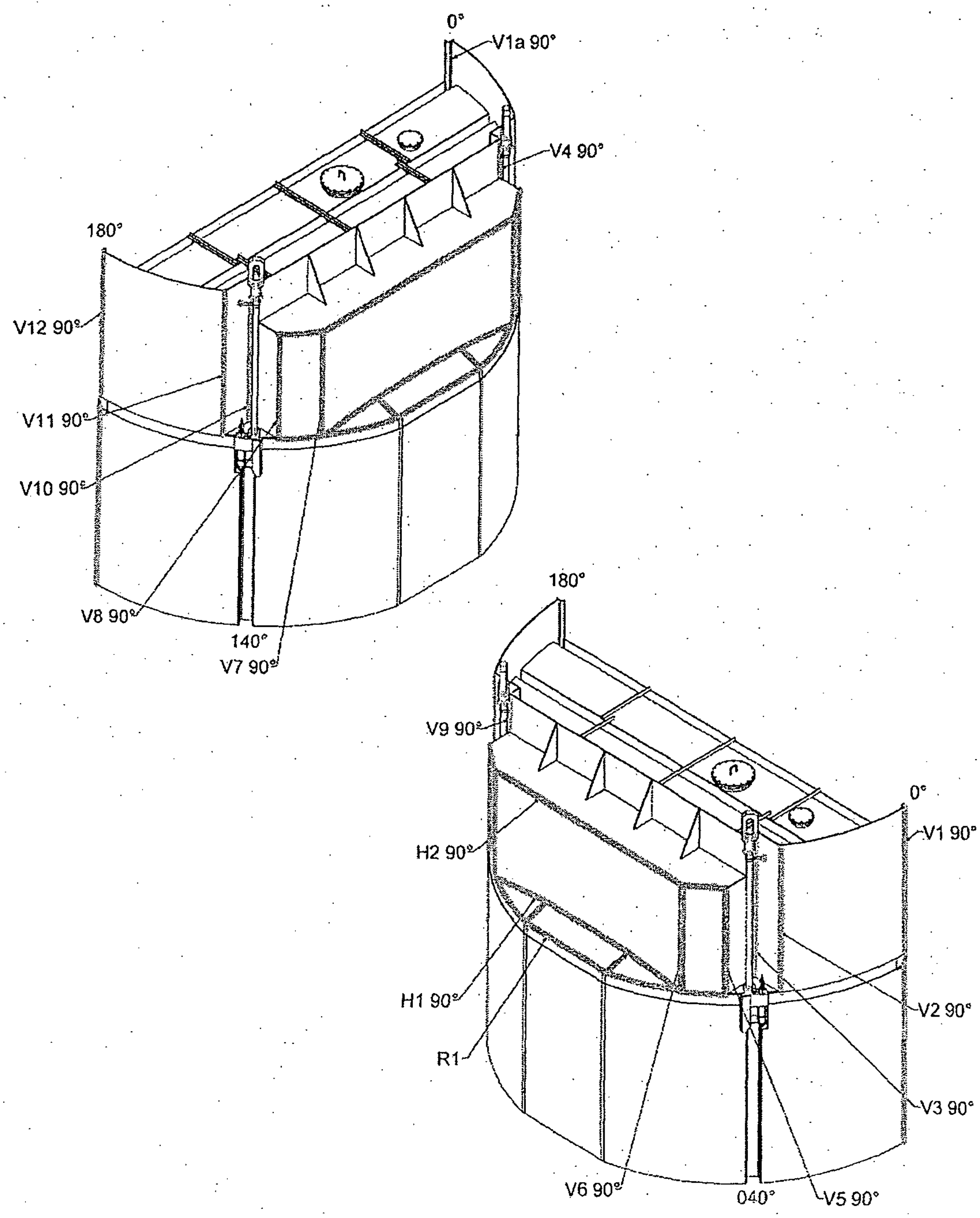


Figure C-1: Inspections: Outer Dryer Hood and Cover Plate (Square Hood Dryer)

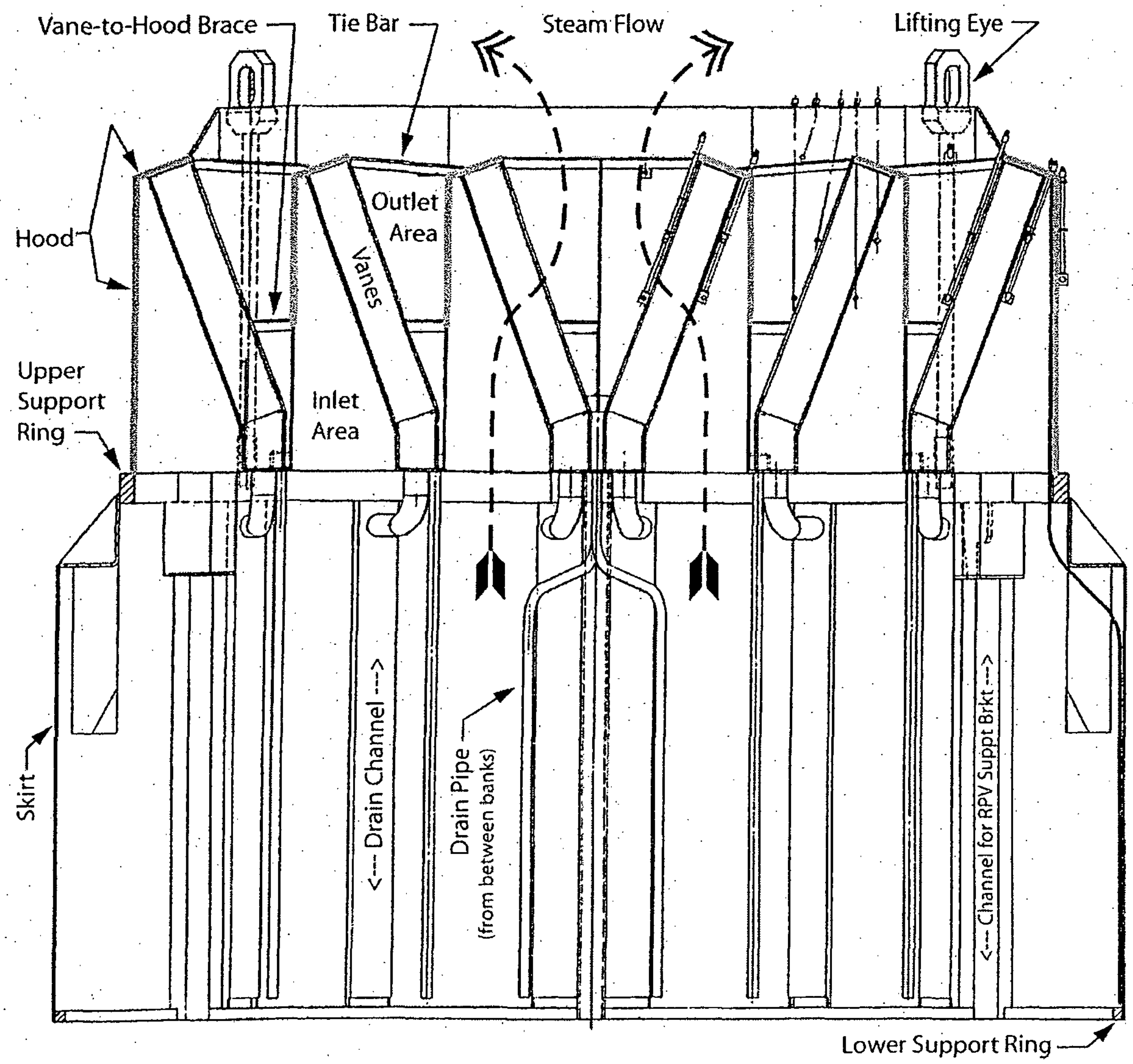


Figure C-2: Cross-Section of BWR/2 Steam Dryer

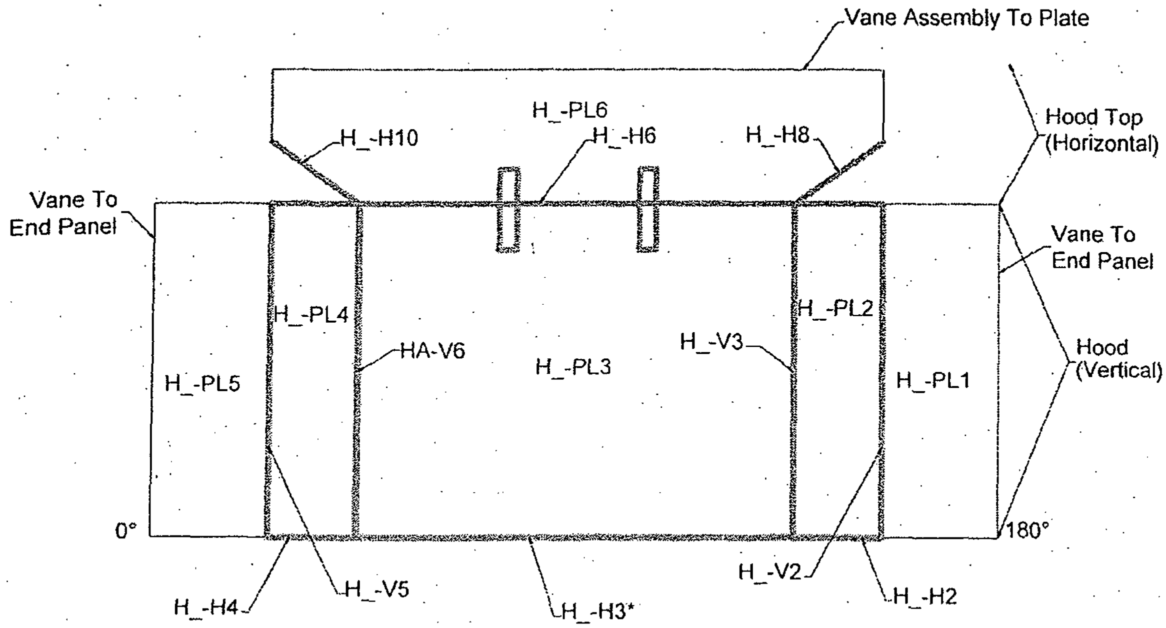
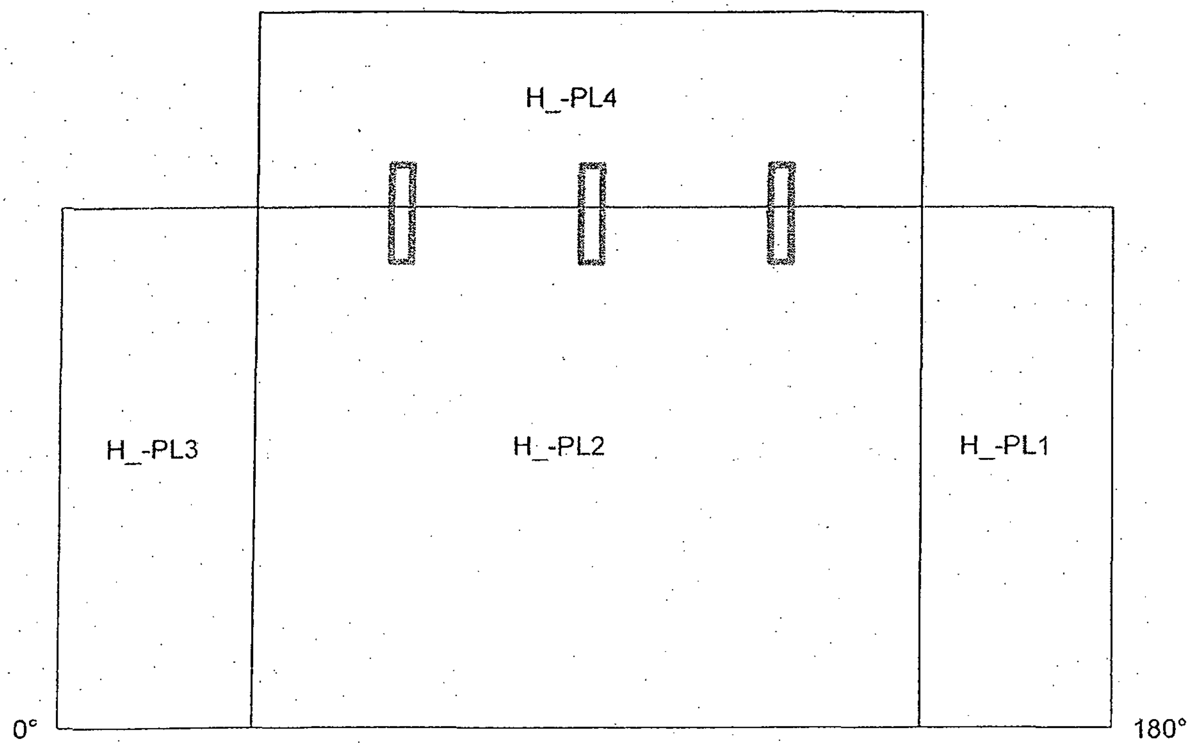


Figure C-3: Weld layout for interior of outer banks (Square Hood Dryer)

The brackets shown only exist in those plants where they were part of the original design and were not removed as part of dryer modifications.



H_-PL# = Plate (Bank B, C, D or E) (Ex. HB-PL1)
Internal View - View Is Looking Away From Vane Assembly

Figure C-4: Weld Rollout – Inner banks with internal brackets (Square Hood Dryer)

The brackets shown only exist in those plants where they were part of the original design and were not removed as part of dryer modifications.

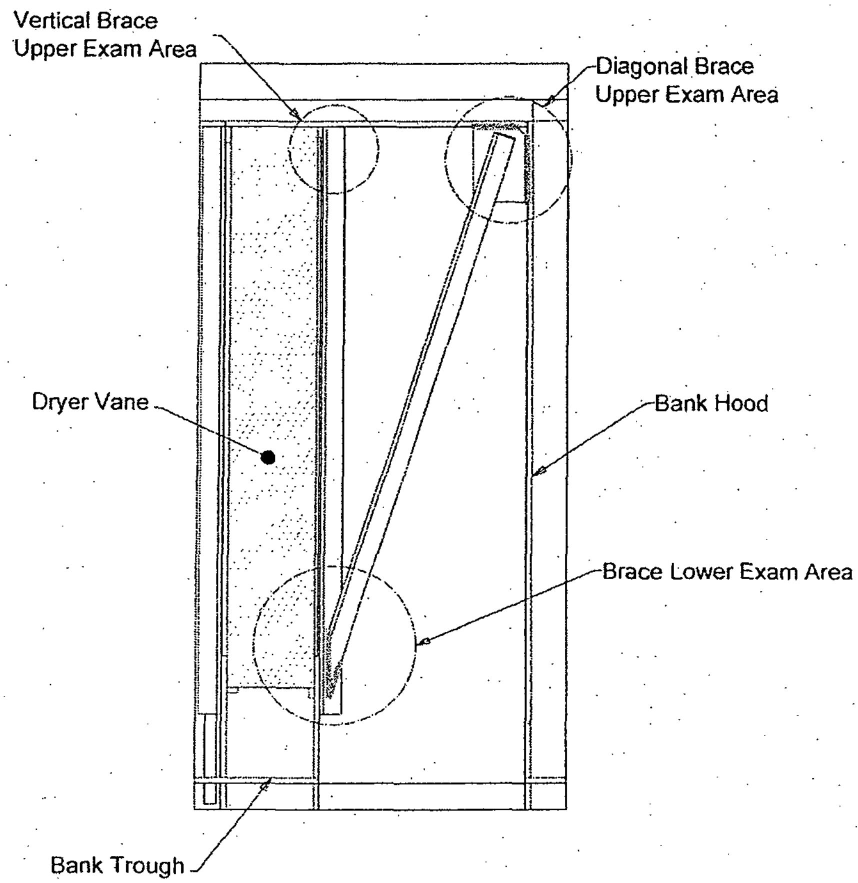


Figure C-5: Dryer Brace Detail (Square Hood Dryer)

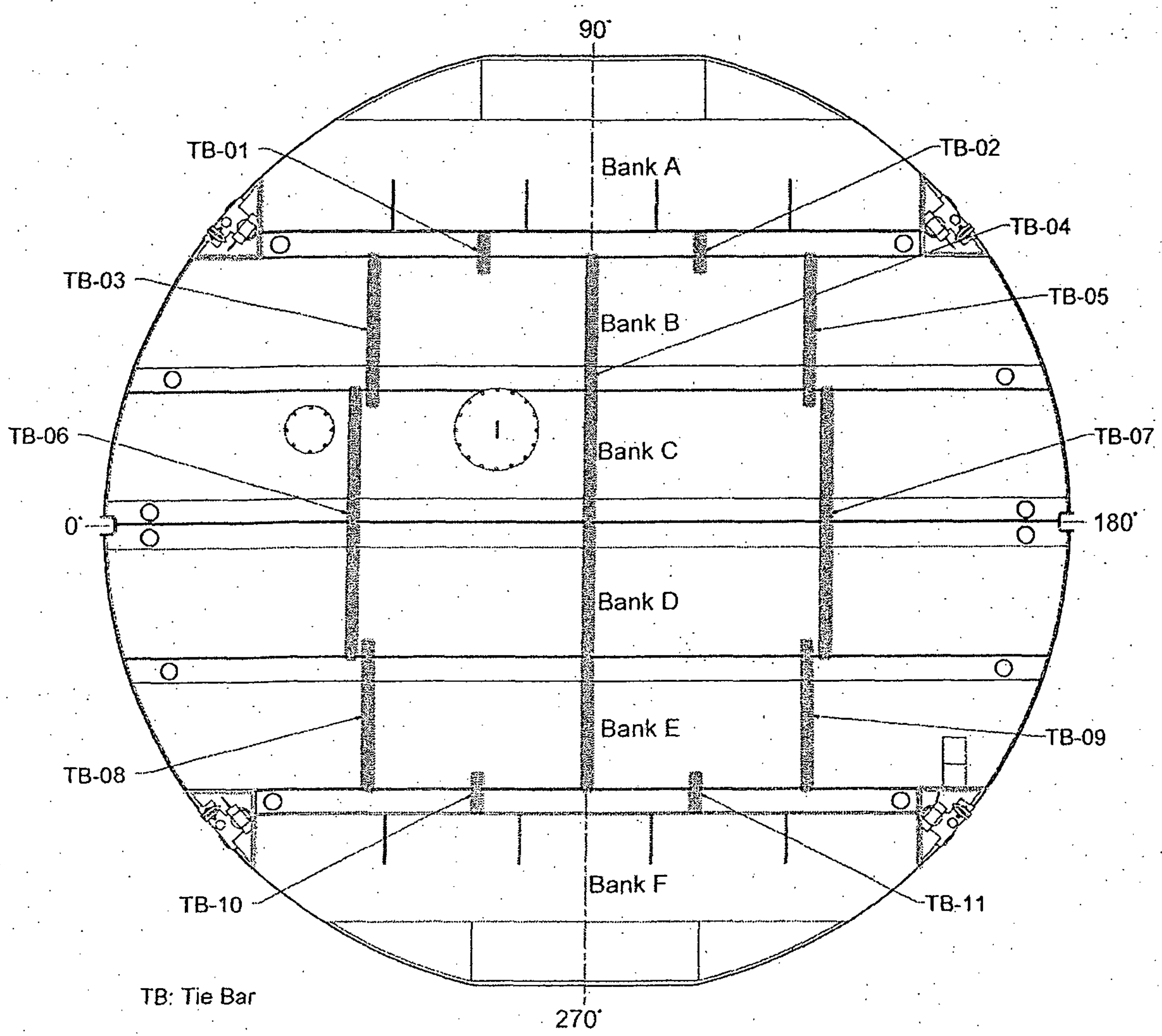
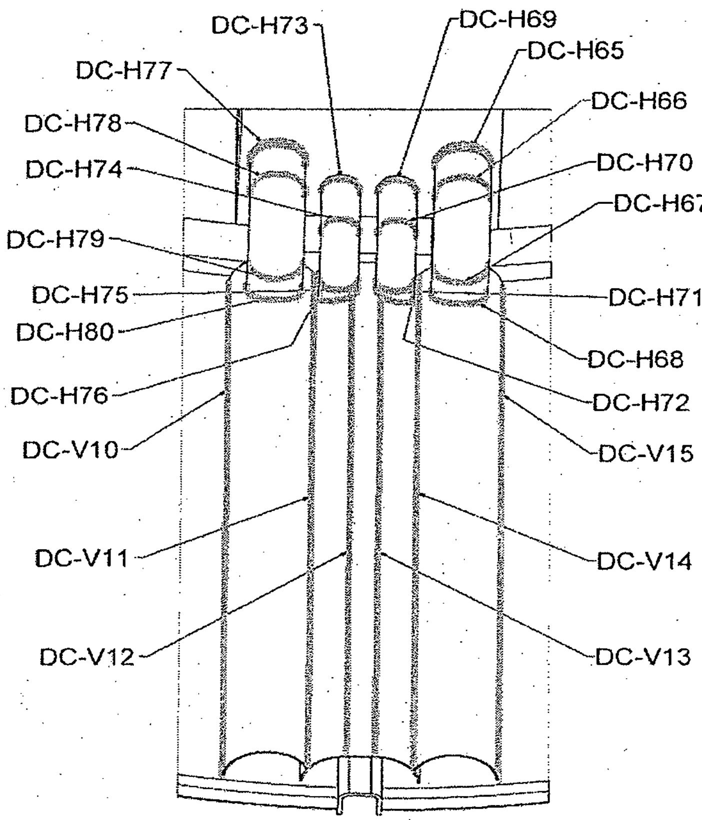


Figure C-6: Inspection Locations: Tie Bars and Steam Dam Inspections (Square Hood Dryer)



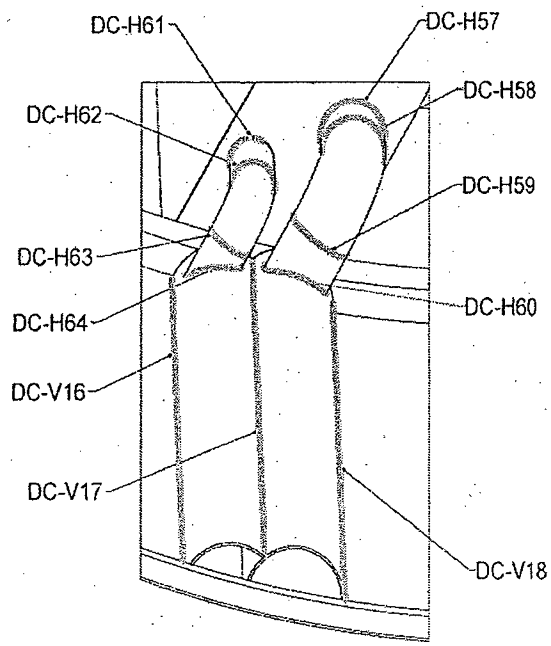


Figure C-7: Drain Channel Locations (Square Hood Dryer)

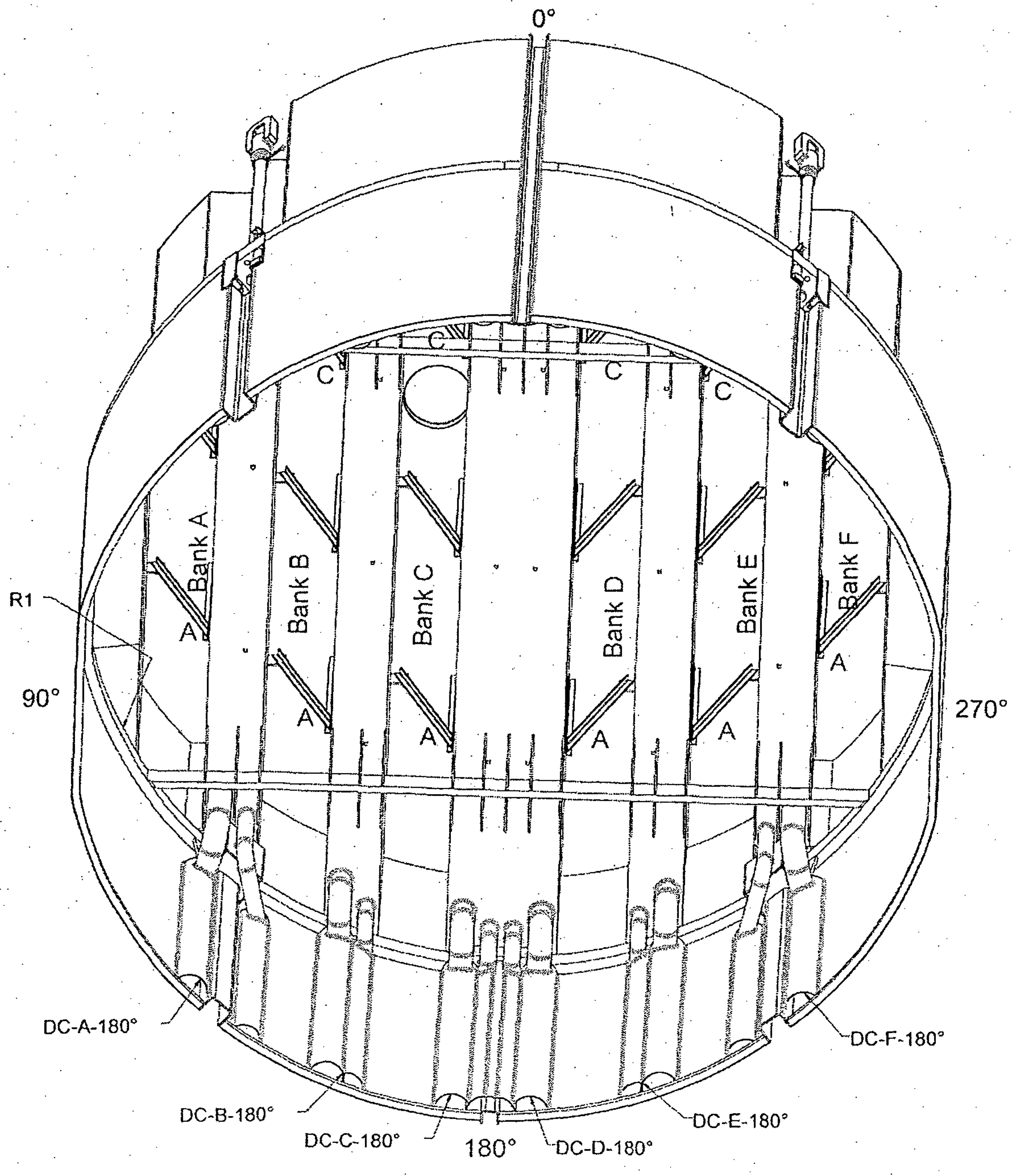


Figure C-8: Dryer Drain Channel, Guide channels and Guide Rod - Bottom View (Square Hood Dryer)

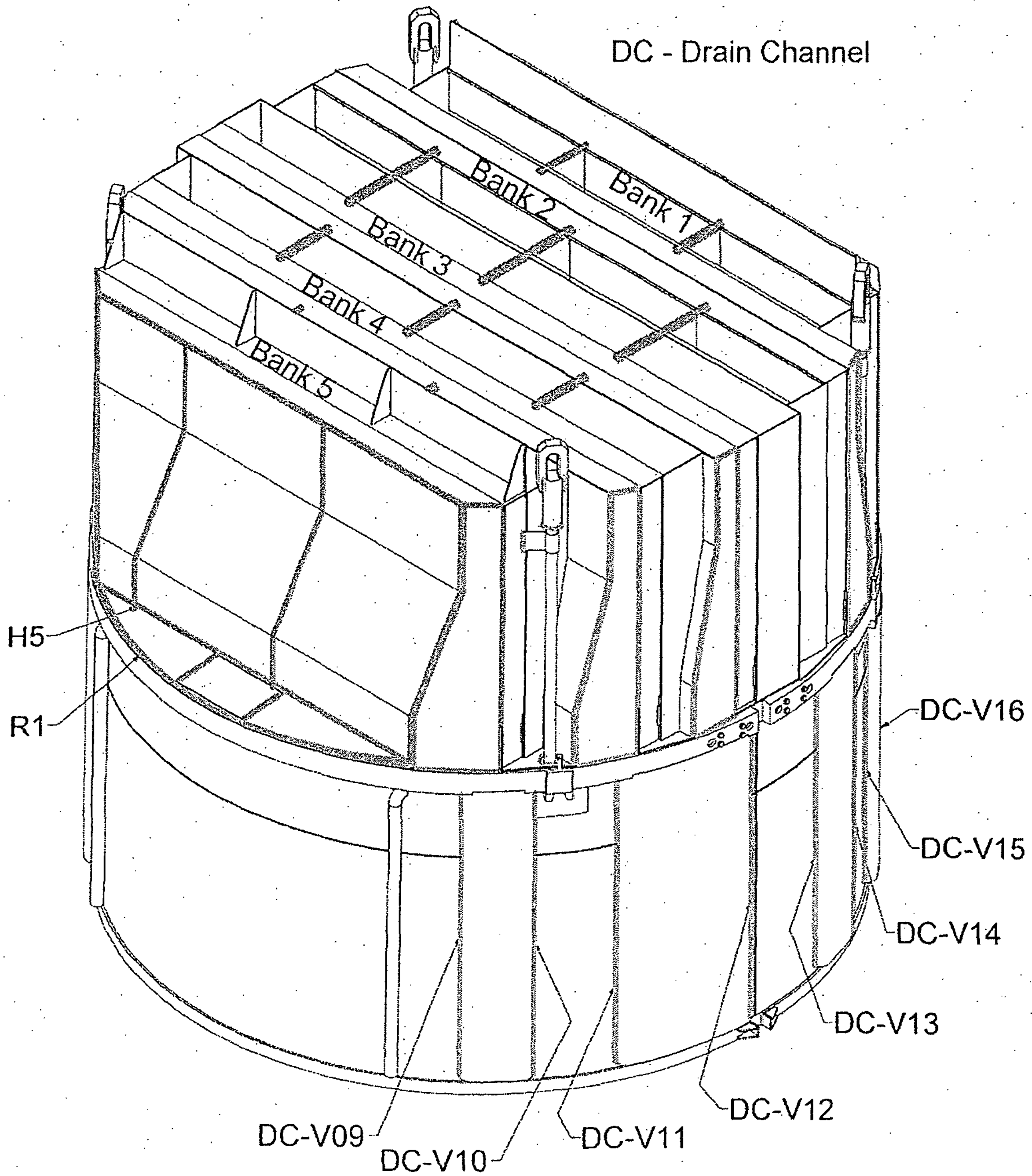


Figure C-9: Inspection Locations (Slanted Hood Dryer)

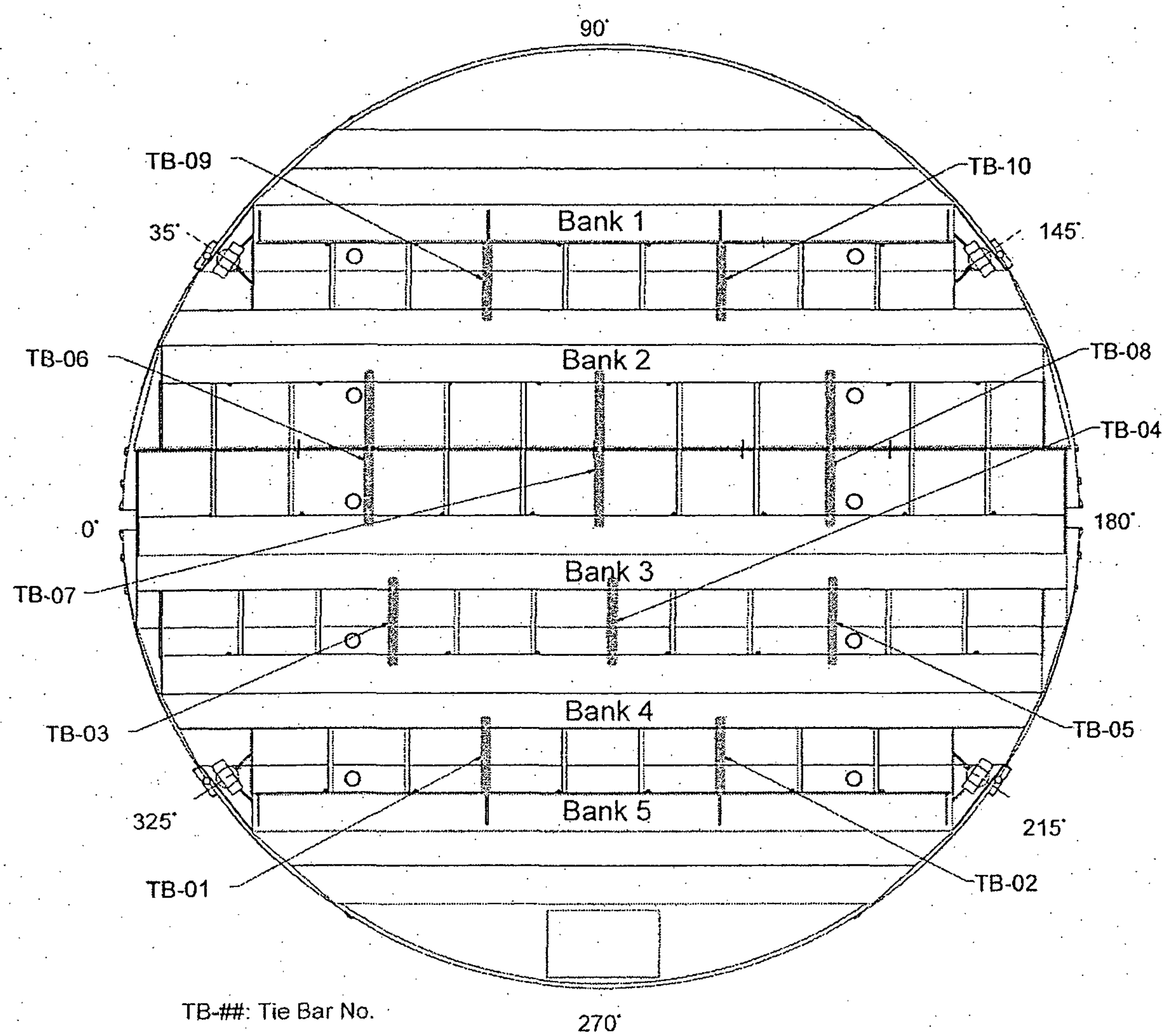


Figure C-10: Tie Bar Locations (Slanted Hood Dryers)

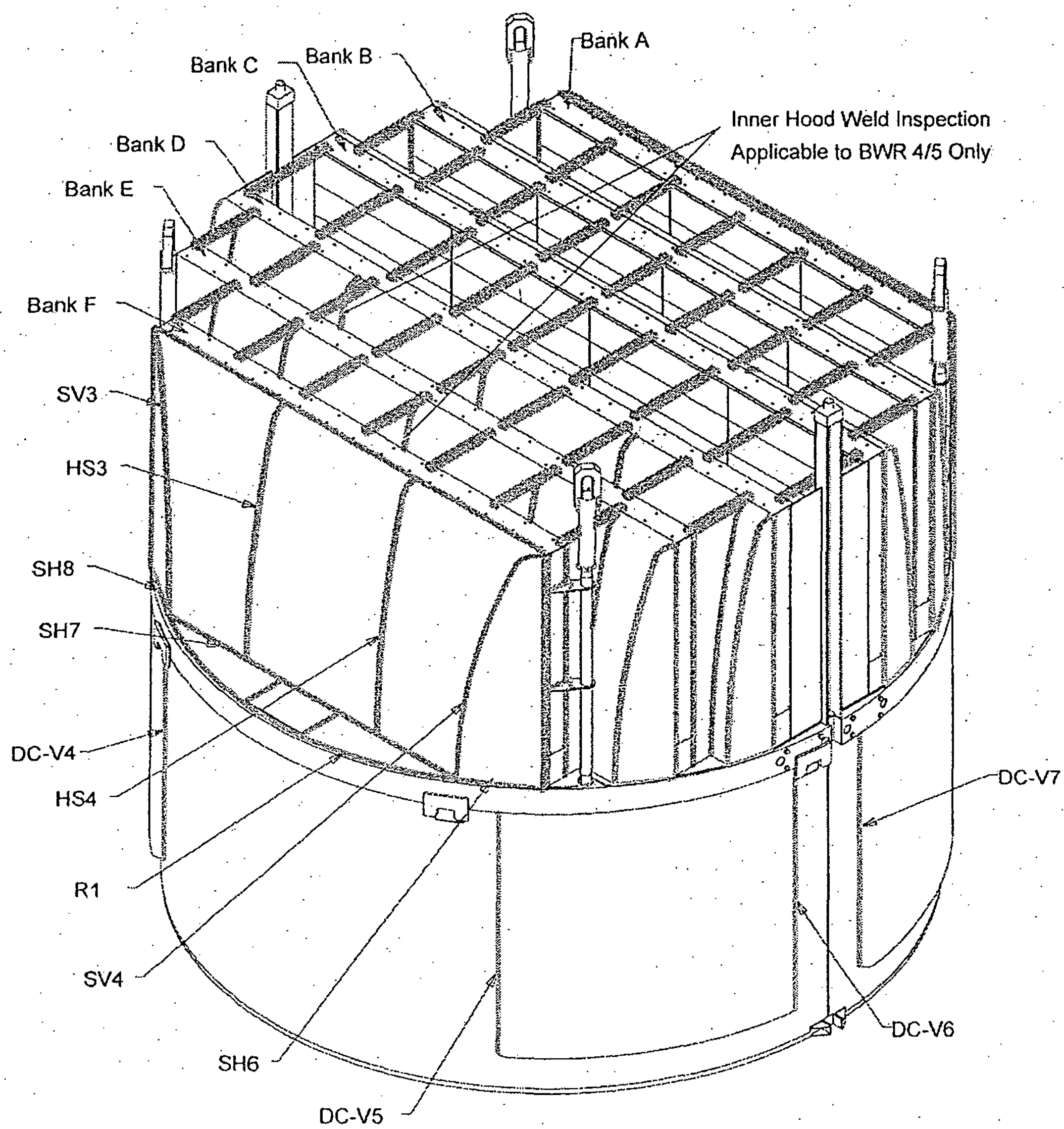


Figure C-11: Inspection Locations (Curved Hood Dryer)

Appendix D

Monitoring Guidelines

Applicability

In general, it is good practice to have access to as much performance data as practicable in order to make informed operational decisions. Therefore, GE recommends that all BWRs implement the moisture carryover and operational response guidance described here. However, plants that have sufficient baseline data and operating experience may elect to consider a less stringent monitoring program.

Background

A moisture carryover greater than 0.1% at the licensed power level is an indication of potential steam dryer damage, unless a higher threshold is established. A higher threshold may be warranted for a BWR with an unmodified square dryer hood (i.e., no addition of perforated plates) and/or operating with MELLLA+ at off-rated core flow.

If plants are reporting measured moisture carryover values of "less than" a value because of inability to measure Na-24 in the condensed steam sample and the "less than" value is greater than 0.025%, then the moisture carryover measurement process should be modified to reduce the minimum detectable threshold (preferably such that "less than" values are never reported). Without quantitative data, the plant staff will be unable to develop operational recommendations based on statistically valid moisture carryover and other plant data.

BWR moisture carryover may be impacted by: (1) reactor power level, (2) core flow and power distributions, (3) core inlet subcooling (which is related to final Feedwater temperature), and (4) reactor water level.

Moisture carryover is very sensitive to power level. Therefore, data should be collected during steady state operations at the highest possible power levels.

Moisture carryover has increased in cases where steam flow is increased towards the center of the core.

Moisture carryover has increased in cases where core inlet sub-cooling is decreased (i.e., final Feedwater temperature is increased).

Moisture carryover has increased in cases where reactor water level is increased (due to degraded separator performance).

Note that the standard deviation of moisture carryover measurements is not expected to change significantly following power distribution changes. However, if a significant condenser tube leak occurs, then the standard deviation of moisture carryover measurements may change significantly due to the resulting increased Na-24 concentrations.

Plants are recommended to accurately determine the flow distribution between individual steam lines. If significant steam dryer damage occurs, steam line flow distribution changes may result.

It may be helpful to have pressure data at each main steam flow element (venturi) to better understand the pressure drops and possible pressure changes due to moisture content changes in the steam line flow. This pressure data would have been beneficial at Quad Cities to help identify the flow blockage upstream of the flow element following significant steam dryer damage. Note that flow element performance calculations are based on the RPV steam dome pressure.

An increased feed-to-steam mismatch (i.e., total Feedwater flow plus CRD flow minus total steam flow, with reactor water level constant) may validate an increase in moisture carryover. Plant application has confirmed this correlation exists when the initial moisture carryover value is low (~0.01%), however the correlation showed significant scatter at higher initial moisture carryover values (0.04% to 0.10%).

Baseline Data

NOTE
Data should be collected during steady state operations at the highest possible power levels.

Moisture Carryover

Measure moisture carryover daily to obtain at least five (5) measurements.

Statistically evaluate the moisture carryover data (e.g., determine the mean and standard deviation for the data) to determine if there is a significant increasing trend. Qualitatively review the data to ascertain if there is a significant increasing trend. If there is an increasing trend in moisture carryover, review the changes in plant operational parameters to determine if there is an operational basis for the trend.

If an unexplained increasing trend is evident, then collect additional moisture carryover data with consideration for increasing the measurement frequency (e.g., from "once per day" to "once per 12 hours").

If an unexplained increasing trend is not evident, then begin collecting periodic data for moisture carryover.

Plant Operational Parameters

NOTE
Most plant operational data is available from the process computer, which can normally be input into an Excel spread sheet for evaluation and storage.

The following parameters should be measured under the same (or similar) plant conditions that existed during collection of moisture carryover baseline data:

Reactor power (MWt)

Core flow (Mlb/hr)

Core inlet sub-cooling (deg F)

Reactor water level, average of at least 1000 data points over a one to three hour time period.

Individual main steam line flows (Mlb/hr), average of at least 1000 data points over a one to three hour time period. Include pressure data at each MSL flow element (venturi), if available.

Total Feedwater flow (Mlb/hr), average of at least 1000 data points over a one to three hour time period.

CRD flow (Mlb/hr)

Periodic Data and Operational Response

NOTE

Data should be collected during steady state operations at the highest possible power levels.

If a moisture carryover measurement is suspect (e.g., less than "mean minus 2-sigma"), then repeat the moisture carryover measurement to verify sampling and analysis were performed correctly. Consider eliminating data shown to be incorrect/invalid.

Moisture carryover should be monitored weekly.

Statistically evaluate the moisture carryover data and qualitatively determine if there is a significant increasing trend that cannot be explained by changes in plant operational parameters.

If an unexplained increasing trend is evident, then collect additional moisture carryover data with consideration for increasing the measurement frequency (e.g., from "once per week" to "once per day").

If the latest moisture carryover measurement is greater than "mean plus 2-sigma" and this increase cannot be explained by changes in plant operational parameters, then obtain a complete set of data for the plant operational parameters (identified above). Compare the current plant operational data with the baseline data to explain the increased moisture carryover (i.e., is there steam dryer damage or not).

If an increase in moisture carryover occurs immediately following a rod swap, additional moisture carryover data should be obtained to assure that an increasing trend does not exist. Note that occurrence of steam dryer damage immediately following a rod swap would be highly unlikely.

If the increasing trend of moisture carryover cannot be explained by evaluation of the plant operational data, then initiate plant-specific contingency plans for potential steam dryer damage.

If the evaluation of plant data confirms that significant steam dryer damage has most likely occurred, then initiate a plant shutdown.

If there are no statistically significant changes in moisture carryover for an operating cycle, then decreasing the moisture carryover measurement frequency (e.g., from "once per week" to "once per month") may be considered, provided the highest operating power level is not significantly increased.

UNITED STATES
NUCLEAR REGULATORY COMMISSION
OFFICE OF NUCLEAR REACTOR REGULATION
WASHINGTON, D.C. 20555

January 9, 2004

NRC INFORMATION NOTICE 2002-26, SUPPLEMENT 2: ADDITIONAL FLOW-INDUCED VIBRATION FAILURES AFTER A RECENT POWER UPRATE

Addressees

All holders of an operating license or a construction permit for nuclear power reactors, except those that have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.

Purpose

The U.S. Nuclear Regulatory Commission (NRC) is issuing this supplement to a previously issued information notice (IN) to alert addressees to the failure of the steam dryer and other plant components at Quad Cities Nuclear Power Station, Unit 1 (QC-1), a boiling water reactor (BWR), during operations following a power uprate. The NRC expects that the recipients will review the information for applicability to their facilities and consider actions, as appropriate, to avoid similar problems. However, suggestions contained in this information notice are not NRC requirements. Therefore, no specific action or written response is required.

Description of Circumstances

As discussed in IN 2002-26, "Failure of Steam Dryer Cover Plate After a Recent Power Uprate" (ML022530291), a cover plate on the outside of the steam dryer at Quad Cities Nuclear Power Station, Unit 2 (QC-2), broke loose in June 2002 and caused pieces of the dryer to be swept down the main steamline. The failure followed completion of a refueling outage in March 2002 and subsequent implementation of an extended power uprate (EPU) from 2511 MWt to 2957 MWt (17.8% increase). Before the unit was shut down in 2002, steam dryer degradation was indicated by an increase in moisture carryover and minor perturbations in reactor pressure, water level, and steam flow. The licensee evaluated the cause of the steam dryer cover plate failure and determined that the failure of the plate was due to high-cycle fatigue. The licensee recovered all loose dryer pieces and did not identify any additional damage other than minor scratches and gouges to the main steamline. Prior to returning the unit to service, the licensee modified the steam dryer by installing thicker cover plates with higher strength welds, and implemented enhanced monitoring of steam moisture content, reactor steam dome pressure, main steamline flow rates, and reactor water level.

The second failure of the steam dryer in May 2003 at QC-2 was discussed in IN 2002-26, Supplement 1, "Additional Failure of Steam Dryer After a Recent Power Uprate" (ML031980434). In that case, the licensee again noted increasing moisture carryover in late May 2003; however, there were no discernible changes in other reactor parameters. On May 28, 2003, the licensee reduced power on QC-2 to the pre-EPU 100% power level. Moisture carryover levels remained above normal, and on June 11, 2003, the licensee shut down QC-2 to inspect the dryer. Inspection of the dryer revealed (1) through-wall cracks (about 90 inches long) in the vertical and horizontal portions of the outer bank hood, 90-degree side, (2) one vertical and two diagonal internal braces detached from the outer bank hood, 90-degree side, (3) one severed vertical internal brace on the outer bank hood, 270-degree side, and (4) three cracked tie bars on top of the dryer. The licensee believes the most probable cause of the failure of the steam dryer in QC-2 is low-frequency, high-cycle fatigue driven by flow-induced vibrations associated with the higher steam flows present during EPU operating conditions.

In late October 2003 at QC-1, the licensee observed changes in main steamline flows, steamline pressure drop, and increasing moisture carryover measurements. The symptoms observed were consistent with previous events at QC-2 that resulted in the discovery of damage to the steam dryer. The licensee subsequently reduced the power level of QC-1 to pre-EPU conditions. After power was reduced, the moisture carryover was lower than before the power reduction, but higher than the anticipated level. On November 12, the licensee shut down QC-1 to inspect the steam dryer and identified significant damage to several areas. For example, an identified crack was determined to have initiated at the top corner portion of the steam dryer hood and then extended horizontally toward the center of the hood and downward into the vertical section of the hood. The crack terminated in the vertical section where a portion of the dryer was missing. This missing piece of the steam dryer outer bank hood is approximately 6.5 inches (16.5 cm) by 9.0 inches (22.9 cm) and 0.5 inches (1.3 cm) thick. The licensee believes that a piece or pieces the size of this opening or smaller broke off due to fatigue cracking. The licensee performed an extensive but unsuccessful search for the lost part or parts. However, the licensee did identify impact marks on the impeller of the 1B recirculation pump that suggested that the missing part or parts passed through the pump. The licensee concluded that the missing part or parts migrated to the bottom head region of the reactor vessel. In addition to damage to the steam dryer at QC-1, the licensee identified significant flow-induced vibration damage to main steam line tieback supports and a main steam electromatic relief valve (including its attached drain line, actuator, and support), as well as loose clamps on the main steam line supports. Before restarting QC-1 on November 29, the licensee repaired the steam dryer and other damaged plant components identified during its inspections. With respect to the missing steam dryer metal plate, the licensee performed an operability evaluation for continued operation with the missing part or parts and will decide, prior to the next refueling outage, whether to continue efforts to locate and retrieve the missing dryer material.

Discussion

When operating above the original licensed thermal power (OLTP) level, BWR plants can experience a significant increase in the velocity of the steam generated from feedwater in the reactor core and directed through piping to the plant turbine generator. This increased steam velocity could damage plant components through flow-induced vibration. While major safety-related components undergo detailed review to demonstrate their capability to perform the applicable safety functions, nonsafety-related components and safety-related subcomponents have received less attention by the licensee and the NRC during preparation for nuclear power plant operation above the OLTP level.

Although performing a nonsafety-related function, the steam dryer in a BWR plant must maintain its structural integrity to avoid loose dryer parts from entering the reactor vessel or steam lines and adversely affecting plant operation. Industry representatives say that cracking occurred in steam dryers during the early operational phase of some BWR plants. The steam dryer failures at Quad Cities while operating at EPU conditions have led the BWR Owners Group (BWROG) to ask its BWR Vessel and Internals Project (BWRVIP) to develop inspection and evaluation guidelines for BWR steam dryers. In addition, General Electric (GE) Nuclear Energy issued Service Information Letter (SIL) 644, "BWR/3 steam dryer failure," on August 21, 2002, and Supplement 1 to SIL 644 on September 5, 2003, to provide monitoring and inspection recommendations for BWR plants that are operating, or plan to operate, at power levels greater than the OLTP.

In addition to the BWR steam dryers, flow-induced vibration during nuclear power plant operation above the OLTP level can potentially damage other plant components. For example, the QC-1 licensee identified significant flow-induced vibration damage to a main steam electromatic relief valve (including its attached drain line, actuator, and support), as well as main steam line support clamps and tieback supports. Therefore, information obtained from the review of the flow-induced vibration damage at QC-1 might also be applicable to other BWR plants with different steam dryer designs and to pressurized water reactor (PWR) plants operating at conditions above their OLTP level. The significance of the lessons learned is increased because operation of a nuclear power plant under conditions above the OLTP level might place additional reliance on the capability of plant equipment, such as relief valves or seismic restraints, to perform their intended functions as a result of higher reactor power levels and steam and feedwater flow rates.

The NRC staff is reviewing plant-specific and industry-wide activities to address the potential for flow-induced vibration damage to steam dryers and other plant components in BWR plants operating or planning to operate at conditions above the OLTP level. Although it is very unlikely that loose parts would adversely affect the safe shutdown of a plant, it is important to understand the extent of damage that might be caused by steam dryer failures and to identify the lessons learned from recent steam dryer failures for application to steam dryers at other BWR plants. It is also important to address the potential for similar failures in other plant components in BWR or PWR plants operating or planning to operate at conditions above the OLTP level.

Licensees should be alert to the possibility of unanticipated effects from increasing flow, power, or differential pressure associated with a major modification such as a power uprate. This information notice requires no specific action or written response. If you have any questions about the information in this notice, please contact one of the technical contacts listed below or the appropriate Office of Nuclear Reactor Regulation (NRR) project manager.

/RA/
William D. Beckner, Chief
Reactor Operations Branch
Division of Inspection Program Management
Office of Nuclear Reactor Regulation

Technical Contacts:

Karla Stoedter, Region III
(309) 654-2227
E-mail: kkb@nrc.gov

Jack Foster, NRR
(301) 415-3647
E-mail: jwf@nrc.gov

Larry Rossbach, NRR
(301) 415-2863
E-mail: lwr@nrc.gov

Thomas G. Scarbrough, NRR
(301) 415-2794
E-mail: tgs@nrc.gov

Attachment: List of Recently Issued NRC Information Notices

LIST OF RECENTLY ISSUED
NRC INFORMATION NOTICES

Information Notice No.	Subject	Date of Issuance	Issued to
2003-11, Sup 1	Leakage Found on Bottom-Mounted Instrumentation Nozzles	01/08/2004	All holders of operating licenses or construction permits for nuclear power reactors, except those that have permanently ceased operations and have certified that fuel has been permanently removed from the reactor.
2003-22	Heightened Awareness for Patients Containing Detectable Amounts of Radiation from Medical Administrations	12/09/2003	All medical licensees and NRC Master Materials License medical use permittees.
2003-21	High-Dose-Rate-Remote-Afterloader Equipment Failure	11/24/2003	All medical licensees.
2003-20	Derating Whiting Cranes Purchased Before 1980	10/22/2003	All holders of operating licenses for nuclear power reactors, except those who have permanently ceased operations and have certified that fuel has been permanently removed from the reactor vessel; applicable decommissioning reactors, fuel facilities, and independent spent fuel storage installations.

Note: NRC generic communications may be received in electronic format shortly after they are issued by subscribing to the NRC listserver as follows:

To subscribe send an e-mail to <listproc@nrc.gov >, no subject, and the following command in the message portion:

subscribe gc-nrr firstname lastname

OL = Operating License
CP = Construction Permit

From: Rick Ennis
To: Alan Wang; Allan Barker; Allen Howe; Anthony McMurtray; Brian Sheron; Cheng-Ih Wu; Christopher Grimes; David Terao; Diane Screnci; Donna Skay; Eric Leeds; Gene Imbro; James Clifford; Jim Dyer; John Craig; John Jolicoeur; Kamal Manoly; Neil Sheehan; Richard Barrett; Richard Borchardt; Scott Burnell; Tae Kim; Terrence Reis; Thomas Scarbrough; William Beckner; William Ruland
Date: 4/16/04 1:31PM
Subject: Fwd: VY Steam Dryer Crack Info

Attached is a little more detail on the steam dryer cracking at Vermont Yankee.

CC: Cliff Anderson; David Pelton

D-21

Mail Envelope Properties (40801878.B4F : 15 : 20516)

Subject:	Fwd: VY Steam Dryer Crack Info
Creation Date:	4/16/04 1:31PM
From:	Rick Ennis
Created By:	RXE@nrc.gov

Recipients	Action	Date & Time
kp1_po.KP_DO	Delivered	04/16/04 01:31PM
CJA CC (Cliff Anderson)	Opened	04/16/04 01:31PM
DLP1 CC (David Pelton)	Opened	04/19/04 07:13AM
DPS (Diane Screnci)	Opened	04/16/04 01:53PM
NAS (Neil Sheehan)	Opened	04/16/04 01:43PM
owf1_po.OWFN_DO	Delivered	04/16/04 01:31PM
SRB3 (Scott Burnell)	Opened	04/16/04 01:32PM
owf2_po.OWFN_DO	Delivered	04/16/04 01:31PM
ACM2 (Anthony McMurtray)	Opened	04/16/04 01:58PM
CIW1 (Cheng-Ih Wu)	Opened	04/17/04 10:14AM
DMS6 (Donna Skay)	Opened	04/16/04 03:12PM
DXT (David Terao)	Opened	04/16/04 01:48PM
EXI (Gene Imbro)	Opened	04/21/04 01:46PM
KAM (Kamal Manoly)		
RJB3 (Richard Barrett)	Opened	04/19/04 07:30AM
RWB1 (Richard Borchardt)	Opened	04/16/04 02:20PM
TGS (Thomas Scarbrough)	Opened	04/16/04 01:34PM
TXR (Terrence Reis)		
owf4_po.OWFN_DO	Delivered	04/16/04 01:31PM
ABW (Alan Wang)	Opened	04/16/04 02:02PM
AGH1 (Allen Howe)	Opened	04/19/04 07:24AM
ARB3 (Allan Barker)	Opened	04/16/04 01:31PM
BWS (Brian Sheron)	Opened	04/16/04 04:44PM
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JED2 (Jim Dyer)	Opened	04/16/04 01:43PM
JWC (James Clifford)	Opened	04/19/04 09:09AM
JWC1 (John Craig)	Opened	04/16/04 01:32PM
TJK3 (Tae Kim)	Opened	04/16/04 01:40PM
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WHR (William Ruland)	Opened	04/16/04 01:56PM
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JRJ1 (John Jolicoeur)	Opened	04/19/04 12:16PM

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MESSAGE	578	04/16/04 01:31PM

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Notify Recipients:	Yes
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Reply Requested:	No
Return Notification:	None
Concealed Subject:	No
Security:	Standard
To Be Delivered:	Immediate
Status Tracking:	Delivered & Opened

From: Cliff Anderson RI
To: Rick Ennis
Date: 4/16/04 12:59PM
Subject: Fwd: VY Steam Dryer Crack Info

fyi

From: Raymond Lorson RI
To: A. Randolph Blough; Brian Holian; Cliff Anderson; David Pelton; Hubert J. Miller; James Wiggins; Richard Crlenjak; Wayne Lanning
Date: 4/16/04 12:11PM
Subject: VY Steam Dryer Crack Info

FYI:

The attached write-up summarizes what we know about the VY steam dryer cracks to date.

Ray

While performing visual inspections of the reactor vessel steam dryer, Entergy and General Electric personnel identified several indications on both the interior and exterior surfaces of the dryer:

- Two external cracks were identified on outer plenum vertical welds (the longest crack was approximately 3 inches in length). The licensee plans to grind out, repair and install additional supports to reinforce these welds;

- Two internal cracks were identified in the drain channel weld. The longest crack was 14 inches in length. These cracks are inaccessible for repair. The licensee (based on input from GE) believes that they can demonstrate that operation with these cracks is acceptable

In addition to the cracks noted above, multiple axial indications were identified on the internal surface of the curved end plate of the dryer vane bank. The licensee has not determined whether these indications are cracks or manufacturing anomalies. The licensee (based on input from GE) believes that they can demonstrate that operation with these indications is acceptable.

The licensee is considering a press release on this topic and has indicated that the cracks are in low-stress, low-steam flow, areas of the dryer, and not in the areas affected at the EPU plants.

Region I reviewed the licensee's steam dryer inspection activities during a scheduled, routine ISI inspection and is continuing to monitor this situation. Similar external weld cracks were identified and repaired earlier this spring at Nine Mile Unit 2.

July 26, 2004

Mr. Jay K. Thayer
Site Vice President
Entergy Nuclear Operations, Inc.
Vermont Yankee Nuclear Power Station
P.O. Box 0500
185 Old Ferry Road
Brattleboro, VT 05302-0500

SUBJECT: VERMONT YANKEE NUCLEAR POWER STATION - NRC INTEGRATED INSPECTION REPORT 05000271/2004003

Dear Mr. Thayer:

On June 30, 2004, the US Nuclear Regulatory Commission (NRC) completed an inspection at your Vermont Yankee Nuclear Power Station (VY). The enclosed report documents the inspection findings which were discussed on July 12, 2004, with members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

This report documents one finding of very low safety significance (Green) which was also determined to involve a violation of NRC requirements. Because of the very low safety significance and because the finding was entered into your corrective actions program, the NRC is treating it as a non-cited violation (NCV), consistent with Section VI.A of the NRC's Enforcement Policy. If you contest this non-cited violation, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN.: Document Control Desk, Washington, D.C. 20555-0001; with copies to the Regional Administrator Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, D.C. 20555-0001; and the NRC Resident Inspector at the Vermont Yankee Nuclear Power Station.

In accordance with 10 CFR 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the Publicly Available Records (PARS) component of NRC's document system (ADAMS). ADAMS is accessible from the NRC Web site at http://www.nrc.gov/reading-rm/adams.html (the Public Electronic Reading Room).

Sincerely,

/RA/

Clifford J. Anderson, Chief
Projects Branch 5
Division of Reactor Projects

Docket No. 50-271
License No. DPR-28

Enclosure: Inspection Report 05000271/2004003
w/Attachment: Supplemental Information

Docket No. 50-271
License No. DPR-28

cc w/encl:
M. R. Kansler, President, Entergy Nuclear Operations, Inc.
G. J. Taylor, Chief Executive Officer, Entergy Operations
J. T. Herron, Senior Vice President and Chief Operating Officer
D. L. Pace, Vice President, Engineering
B. O'Grady, Vice President, Operations Support
J. M. DeVincentis, Manager, Licensing, Vermont Yankee Nuclear Power Station
Operating Experience Coordinator - Vermont Yankee Nuclear Power Station
J. F. McCann, Director, Nuclear Safety Assurance
M. J. Colomb, Director of Oversight, Entergy Nuclear Operations, Inc.
J. M. Fulton, Assistant General Counsel, Entergy Nuclear Operations, Inc.
S. Lousteau, Treasury Department, Entergy Services, Inc.
Administrator, Bureau of Radiological Health, State of New Hampshire
Chief, Safety Unit, Office of the Attorney General, Commonwealth of Mass.
D. R. Lewis, Esquire, Shaw, Pittman, Potts & Trowbridge
G. D. Bisbee, Esquire, Deputy Attorney General, Environmental Protection Bureau
J. Block, Esquire
D. Katz, Citizens Awareness Network (CAN)
M. Daley, New England Coalition on Nuclear Pollution, Inc. (NECNP)
R. Shadis, New England Coalition Staff
C. McCombs, Commonwealth of Massachusetts, SLO Designee
G. Sachs, President/Staff Person, c/o Stopthesale
J. Sniezek, PWR SRC Consultant
R. Toole, PWR SRC Consultant
J. P. Matteau, Executive Director, Windham Regional Commission
State of New Hampshire, SLO Designee
State of Vermont, SLO Designee

Distribution w/encl: H. Miller, RA/J. Wiggins, DRA (1)
C. Anderson, DRP
D. Florek, DRP
D. Pelton, Senior Resident Inspector
C. Miller, RI EDO Coordinator
J. Clifford, NRR
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D. Skay, Backup PM, NRR
Region I Docket Room (with concurrences)

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DATE	07/26/04		07/26/04		07/26/04					

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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No.	50-271
Licensee No.	DPR-28
Report No.	05000271/2004003
Licensee:	Entergy Nuclear Vermont Yankee, LLC
Facility:	Vermont Yankee Nuclear Power Station
Location:	320 Governor Hunt Road Vernon, Vermont 05354-9766
Dates:	April 1, 2004 - June 30, 2004
Inspectors:	David L. Pelton, Senior Resident Inspector Beth E. Sienel, Resident Inspector E. Harold Gray, Senior Reactor Inspector Todd J. Jackson, Senior Project Engineer James D. Noggle, Senior Health Physicist Larry L. Scholl, Senior Reactor Inspector Keith A. Young, Senior Reactor Inspector Amar C. Patel, Reactor Inspector Jennifer A. Bobiak, Reactor Inspector Thomas P. Sicola, Reactor Inspector
Approved by:	Clifford J. Anderson, Chief Projects Branch 5 Division of Reactor Projects

TABLE OF CONTENTS

SUMMARY OF FINDINGS

IR 05000271/2004003; 04/01/04 - 06/30/04; Vermont Yankee Nuclear Power Station; Refueling and Outage Activities.

This report covered a 13-week period of baseline inspection conducted by resident inspectors. Additionally, announced inspections were performed by regional inspectors in the areas of occupational radiation protection; evaluations of changes, tests, and experiments; in-service inspections; and permanent plant modifications. One Green non-cited violation (NCV) was identified. The significance of most findings is indicated by their color (Green, White, Yellow, Red) using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 3, dated July 2000.

A. NRC-Identified and Self-Revealing Findings

Cornerstone: Barrier Integrity

(Green) A self-revealing, non-cited violation (NCV) of 10 CFR 50 Criterion XVI was identified in that Entergy personnel did not develop effective corrective actions to prevent recurrence following a 2001 event wherein control room operators did not verify a suction path existed prior to starting the residual heat removal (RHR) system pump being used to support shutdown cooling (SDC) operations which caused the pump to trip. On April 10, 2004, an identical event occurred and again resulted in a trip of the RHR pump being used to support SDC operations.

The finding is greater than minor since it is associated with the Fuel Cladding Configuration Control Attribute of the Barrier Integrity Cornerstone and because it affects the associated Cornerstone objective. The inspectors conducted a SDP Phase 1 screening of the finding in accordance with IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process [SDP]." In accordance with the SDP, the inspectors determined that the finding was of very low safety significance (Green) since the RHR pump was restarted within 15 minutes of being tripped and an adequate SDC thermal margin was maintained as demonstrated by a calculated reactor coolant system (RCS) time-to-boil of greater than 24 hours.

A contributing cause of this finding is related to the Cross-Cutting area of Problem Identification and Resolution. As stated above, Entergy personnel did not develop effective corrective actions to prevent recurrence following a 2001 event wherein control room operators did not verify a suction path existed prior to starting the RHR system pump being used to support SDC operations which caused the pump to trip. Entergy's corrective actions relied on the operator's skill to verify a suction path was open prior to restarting the RHR pump rather than proceduralize the step. As a result, an identical event occurred in April 2004 again resulting in a trip of the RHR pump being used to support SDC operations. (Section 4OA3.1)

Summary of Findings (cont'd)

B. Licensee Identified Findings

None.

REPORT DETAILS

Summary of Plant Status

Vermont Yankee Nuclear Power Station entered the inspection period at or near full power. The reactor was shutdown on April 3, 2004, in support of planned refueling outage (RFO) 24. Reactor startup activities began on May 3, 2004, following the completion of RFO 24. The reactor was returned to full power operation on May 8, 2004. On June 18, 2004, an automatic reactor scram occurred as a result of a turbine trip following multiple faults-to-ground on the 22 kilovolt (KV) electrical system. The reactor remained shutdown for the rest of the inspection period.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity

1R01 Adverse Weather (71111.01)

a. Inspection Scope (one sample)

The inspectors reviewed measures established by Entergy for the restoration from cold weather operations. The inspectors reviewed Vermont Yankee Operating Procedure (OP) 2196, "Preparations for Cold Weather Operations," Form VYOPF 2196.02, "Cold Weather Restoration Operations Checklist," discussed the completion of items with operations personnel to confirm the items on the checklist had been completed or were appropriately tracked for completion, and independently walked down portions of the plant to verify selected actions to restore from cold weather operations had been completed appropriately.

b. Findings

No findings of significance were identified.

1R02 Evaluations of Changes, Tests, or Experiments (71111.02)

a. Inspection Scope (eight samples)

The inspectors reviewed the 10 CFR 50.59 safety evaluations or screening evaluations associated with plant modifications being installed during the current refueling outage to support a proposed power uprate. The inspectors assessed the adequacy of the safety evaluations through interviews with the cognizant plant staff and review of supporting documentation to verify the changes were performed in accordance with 10 CFR 50.59 and when required, NRC approval was obtained prior to implementation. The inspectors also reviewed a sample of changes the licensee had evaluated (using a screening process) and determined to be outside of the scope of 10 CFR 50.59, therefore not requiring a full safety evaluation. The inspectors performed this review to determine if Entergy conclusions with respect to 10 CFR 50.59 applicability were appropriate. A listing of the modifications for which associated safety evaluations, safety evaluation screenings, and other documents were reviewed is provided in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R04 Equipment Alignments

1. Complete Equipment Alignment (71111.04S)

a. Inspection Scope (one sample)

The inspectors performed a complete equipment alignment inspection of the accessible portions of the core spray (CS) system. The inspectors walked down the CS system, both inside and outside of the primary containment, and compared actual equipment alignment to approved piping and instrumentation diagrams, operating procedure lineups, the Vermont Yankee updated final safety analysis report (UFSAR), and the Vermont Yankee design basis document (DBD). The inspectors observed valve positions, the availability of power supplies, and the general condition of selected components to verify there were no unidentified deficiencies. The inspectors also confirmed that licensee-identified equipment problems had been entered into the corrective actions program.

b. Findings

No findings of significance were identified.

2. Partial Equipment Alignments (71111.04)

a. Inspection Scope (four samples)

The inspectors performed four partial system walkdowns of risk significant systems to verify system alignment and to identify any discrepancies that would impact system operability. Observed plant conditions were compared with the standby alignment of equipment specified in the licensee's system operating procedures and drawings. The inspectors also observed valve positions, the availability of power supplies, and the general condition of selected components to verify there were no obvious deficiencies. The inspectors verified the alignment of the following systems:

- The spent fuel pool (SFP) cooling system while the "A" train of the residual heat removal (RHR) system was unavailable to support shutdown cooling on June 6, 2004;
- The "B" train of the standby gas treatment (SBGT) system during planned maintenance on the "A" SBGT fan on June 7, 2004;

- The "A" train of SBGT during planned instrument calibrations on the "B" train of SBGT on June 8; and
- The emergency diesel generators (EDGs), start-up transformers, the diesel oil storage tank (DOST) following the main transformer fire on June 18, 2004.

b. Findings

No findings of significance were identified.

1R05 Fire Protection (71111.05Q)

a. Inspection Scope (nine samples)

The inspectors identified fire areas important to plant risk based on a review of Entergy's the Vermont Yankee Safe Shutdown Capability Analysis, the Fire Hazards Analysis, and the individual plant evaluation of external events (IPEEE). The inspectors toured plant areas important to safety in order to verify the suitability of Entergy's control of transient combustibles and ignition sources, and the material condition and operational status of fire protection systems, equipment, and barriers. The following fire areas were inspected:

- Reactor building, 252 foot elevation-S1 cable trays (CFZ-3/4);
- Reactor building, 252 foot elevation-S2 cable trays (CFZ-3/4);
- Reactor building, 252 foot elevation, North (FZ RB3);
- Reactor building, 252 foot elevation, South (FZ RB4);
- Reactor building, 280 foot elevation, Recirc MG set area (SZ RB-MG);
- Turbine building, all elevations (FA TB);
- Torus room, 213 foot elevation, North (FZ RB1);
- Torus room, 213 foot elevation, South (FZ RB2);
- 345 KV relay house.

b. Findings

No findings of significance were identified.

1R06 Flood Protection Measures (71111.06)

a. Inspection Scope (one sample)

The inspectors reviewed Entergy's established flood protection barriers and procedures for coping with internal flooding in the EDG rooms including Vermont Yankee Off-Normal Procedure (ON) 3148, "Loss of Service Water"; and ON 3158, "Reactor Building High Area Temperature/Water Level." The inspectors reviewed internal flooding information contained in Entergy's IPEEE, in the UFSAR, and in the Internal Flooding DBD as it related to the EDG rooms. Finally, the inspectors performed walk-downs of flood vulnerable portions of the EDG rooms to ensure equipment and structures needed to mitigate an internal flooding event were as described in the IPEEE and the DBD. Additionally, the inspectors reviewed condition reports (CRs) related to internal flooding and the EDG rooms to ensure identified problems were properly addressed for resolution.

b. Findings

No findings of significance were identified.

1R08 Inservice Inspection (71111.08G)

a. Inspection Scope (four samples)

The inspectors assessed the inservice inspection (ISI) activities using the criteria specified in the American Society of Mechanical Engineers (ASME) Boiler and Pressure Vessel Code, Section XI.

The inspectors observed selected in-process non-destructive examination (NDE) activities, reviewed documentation and interviewed personnel to verify that the activities were performed in accordance with the ASME Boiler and Pressure Vessel Code Section XI requirements. The sample selection was based on the inspection procedure objectives and risk priority of those components and systems where degradation would result in a significant increase in risk of core damage. The inspectors reviewed a sample of condition reports and quality assurance audit reports to assess the licensee's effectiveness in problem identification and resolution. The specific ISI activities selected for review included:

- Observation of the ultrasonic testing (UT) manual technique, UT procedure, weld overlay calibration test block, and performance of pre and post examination calibration for UT of the CS system N5A safe-end to nozzle structural weld overlay;
- Review of the computer based UT procedure and observation of its application for the reactor vessel welds and the eddy current (ET) examination method to quantify clad crack shadowing of volumetric vessel weld examinations and the results for the reactor vessel flange-to-vessel weld;
- Observation of the UT examination of a pre-existing reactor vessel weld indication for verification that the indication was appropriately characterized and had not increased in dimension since the previous examination;
- Review of CS system sparger video-visual examination records;
- Review of the inspection scope expansion and disposition of two small linear indications on a standby liquid control system socket weld (SL11-F12); and
- Review of the reactor vessel internals project (BWRVIP-03 Rev 6) procedure and observation of some of the initial visual examinations.

In response to Entergy's extended power up-rate request and recent industry operating experience, the inspectors observed portions of the steam dryer visual testing (VT) type

1 and type 3 examinations and reviewed the documented examination reports. The examination reports documented that cracks were identified on both the internal and external surfaces of the steam dryer. The inspectors reviewed Entergy's corrective actions for these indications to ensure that the actions were appropriate. Specifically, the inspectors reviewed the weld repair activities for the two cracks identified on the external surface of the steam dryer. The inspectors also reviewed the vendor technical reports which justified operation for the next operating cycle at the current maximum licensed power level without repair of the indications identified on internal portions of the steam dryer.

b. Findings

No findings of significance were identified.

1R11 Licensed Operator Requalification (71111.11Q)

a. Inspection Scope (one sample)

The inspectors observed simulator examinations for one operating crew to assess the performance of the licensed operators and the ability of Entergy's Training Department staff to evaluate licensed operator performance. Operating crew performance was evaluated during a simulated main steam line break inside the drywell coincident with a loss of normal power. The inspectors evaluated the crew's performance in the areas of:

- Clarity and formality of communications;
- Ability to take timely actions;
- Prioritization, interpretation, and verification of alarms;
- Procedure use;
- Control board manipulations;
- Oversight and direction from supervisors; and
- Group dynamics.

Crew performance in these areas was compared to Entergy management expectations and guidelines as presented in the following documents:

- Vermont Yankee Administrative Procedure (AP) 0151, "Responsibilities and Authorities of Operations Department Personnel";
- AP 0153, "Operations Department Communication and Log Maintenance"; and
- Vermont Yankee Department Procedure (DP) 0166, "Operations Department Standards."

The inspectors verified that the crew completed the critical tasks listed in the associated simulator evaluation guide (SEG). The inspectors also compared simulator configurations with actual control board configurations. For any weaknesses identified, the inspectors observed the licensee evaluators to verify that they also noted the issues to be discussed with the crew.

b. Findings

No findings of significance were identified.

1R12 Maintenance Effectiveness (71111.12Q)

a. Inspection Scope (three samples)

The inspectors performed three issue/problem-oriented inspections of actions taken by Entergy in response to the following issues:

- As-found local leakage rate testing (LLRT) failures of the high pressure coolant injection (HPCI) turbine exhaust vacuum breakers;
- Repeat failures of the "C" residual heat removal service water (RHRSW) system pump motor cooling solenoid valve; and
- A trend of unavailability associated with the diesel-driven fire pump.

The inspectors reviewed applicable system maintenance rule scoping documents, system health reports, corrective actions taken in response to the equipment problems, maintenance rule functional failure determinations, and applicable a(1) action plans. In addition, the issues were discussed with the responsible engineer.

b. Findings

No findings of significance were identified.

1R13 Maintenance Risk Assessment and Emergent Work Evaluation (71111.13)

a. Inspection Scope (seven samples)

The inspectors evaluated on-line and outage risk management for six planned and one emergent maintenance activities. The inspectors reviewed maintenance risk evaluations, work schedules, recent corrective actions, and control room logs to verify that other concurrent or emergent maintenance activities did not significantly increase plant risk. The inspectors also compared these items and activities to requirements listed in Vermont Yankee AP 0125, "Equipment Release"; AP 0172, "Work Schedule Risk Management - Online"; and AP 0173, "Work Schedule Risk Management - Outage." The inspectors reviewed the following work activities:

Online Risk:

- Planned maintenance on the service water (SW) system supply to turbine the building valve SW-19B breaker, resulting in Yellow online risk;
- Planned maintenance on the "A" train of SBGT; and
- Emergent work to implement minor modification on average power range monitors (APRMs), resulting in a ½ scram condition and "Yellow" online risk.

Outage Risk:

- Planned realignment and testing of offsite electrical power via the delayed backfeed through the auxiliary and main transformers;
- Planned maintenance resulting in 345 KV 340 line and "1T" breaker being out of service;
- Portions of planned maintenance on electrical buses 2, 4, and 9; and
- Planned performance of reactor pressure vessel leakage testing; considered by Entergy to be a "high risk evolution."

b. Findings

No findings of significance were identified.

1R14 Personnel Performance During Non-routine Plant Evolutions (71111.14)

a. Inspection Scope (two samples)

The inspectors assessed the control room operator performance during the following two non-routine evolutions:

- Entry into emergency operating procedure (EOP) 3, "Primary Containment Control," due to average torus temperature exceeding 90 degrees during HPCI system testing on May 26, 2004; and
- Reactor scram following the main transformer fire on June 18, 2004.

Specifically, the adequacy of personnel performance, procedure compliance, and use of the corrective action process were evaluated against the requirements and expectations contained in technical specifications and the following station procedures, as applicable:

- AP 0151, "Responsibilities and Authorities of Operations Department Personnel";
- AP 0153, "Operations Department Communication and Log Maintenance";
- Vermont Yankee DP 0166, "Operations Department Standards;"
- Vermont Yankee OP 105, "Reactor Operations"; and
- OP 2124, "Residual Heat Removal System."

b. Findings

No findings of significance were identified.

1R15 Operability Evaluations (71111.15)

a. Inspection Scope (five samples)

The inspectors reviewed five operability determinations prepared by the licensee. The inspectors evaluated the selected operability determinations against the requirements and guidance contained in NRC Generic Letter 91-18, "Resolution of Degraded and Nonconforming Conditions," as well as procedures AP 0167, "Operability Determinations," and ENN-OP-104, "Operability Determinations." The inspectors verified the adequacy of the following evaluations of degraded or non-conforming conditions:

- Flow noise from the "C" RHR system pump discharge orifice;
- Broken 4 KV breaker driving pawl;
- Missing "clam shell" from the control rod drive housing support system;
- Apparent non-conservative flow-biased scram setpoints; and
- Incomplete NDE for lifting and handling gear.

b. Findings

No findings of significance were identified.

1R16 Operator Workarounds (71111.16)

a. Inspection Scope (one sample)

The inspectors reviewed the cumulative effect of operator workarounds on the reliability, availability, and potential mis-operation of systems and the potential to affect the ability of operators to respond to plant transients and events. The inspectors reviewed identified operator burdens, control room deficiencies, disabled or illuminated control room alarms, and component deviations and discussed them with responsible operations personnel to ensure they were appropriately categorized and tracked for resolution. In addition, in-plant and control room tours were performed to identify any workarounds not previously identified in accordance with procure DP 0166, "Operations Department Standards."

b. Findings

No findings of significance were identified.

1R17 Permanent Plant Modifications

1. Annual Review (71111.17A)

a. Inspection Scope (one sample)

The inspectors performed an annual review of a permanent plant modification involving the installation of an additional main steam safety valve installed during RFO 24. The inspectors reviewed this modification to verify that the design bases, licensing bases, and performance capability of risk significant structures, systems, and components (SSCs) had not been degraded through the modifications. The review evaluated the impact of the modification on power operation at the current licensed power level and potential future operation at an increased power rating. This plant modification was selected for review based on risk insights for the plant and included SSCs associated with the initiating events, mitigating systems and barrier integrity cornerstones. The inspection included a walkdown of the modification, interviews with plant staff, and the review of applicable documents including procedures, Vermont Yankee Design Calculation (VYDC) 2003-013, the modification package, engineering evaluations, drawings, corrective action documents, the UFSAR and Technical Specifications. The inspectors verified that selected attributes were consistent with the current design and licensing bases. These attributes included component safety classification, energy requirements supplied by supporting systems, instrument set-points, and control system interfaces. Design assumptions were reviewed to verify that they were technically appropriate and consistent with the UFSAR. The inspectors verified that selected procedures, calculations and the UFSAR were properly updated with revised design information and operating guidance. The inspectors also verified that the as-built configuration was accurately reflected in the design documentation and that post-modification testing was appropriate.

b. Findings

No findings of significance were identified.

2. Biennial Review (71111.17B)

a. Inspection Scope (six samples)

The inspectors performed a biennial review of selected plant modifications that were being installed during RFO 24. The modifications support a proposed power uprate that is currently under review by the Office of Nuclear Reactor Regulation (NRR). The inspectors reviewed the modifications to verify that the design bases, licensing bases, and performance capability of risk significant SSCs had not been degraded through the modifications. The reviews evaluated the impact of the modifications on power operation at the current licensed power level and potential future operation at an increased power rating. Plant modifications were selected for review based on risk insights for the plant and included SSCs associated with the initiating events, mitigating systems and barrier integrity cornerstones. The inspection included walkdowns of selected plant systems and components, interviews with plant staff, and the review of applicable documents including procedures, calculations, modification packages, engineering evaluations, drawings, corrective action documents, the UFSAR and Technical Specifications. The inspectors verified that selected attributes were consistent with the current design and licensing bases. These attributes included component safety classification, energy requirements supplied by supporting systems, instrument set-points, and control system interfaces. Design assumptions were reviewed to verify that they were technically appropriate and consistent with the UFSAR. The inspectors verified that selected procedures, calculations and the UFSAR were properly updated with revised design information and operating guidance. The inspectors also verified that the as-built configuration was accurately reflected in the design documentation and that post-modification testing was appropriate. A listing of documents reviewed is provided in the Attachment to this report.

b. Findings

No findings of significance were identified.

1R19 Post Maintenance Testing (71111.19)

a. Inspection Scope (three samples)

The inspectors reviewed completed documentation for three post-maintenance test (PMT) activities to verify the test data met the required acceptance criteria contained in the licensee's Technical Specifications, UFSAR, and in-service testing program, and that the PMT was adequate to verify system operability and functional capability following maintenance. The inspectors reviewed the PMTs performed after the following maintenance activities:

- Installation of low feedwater pump suction pressure trip modifications in accordance with minor modification (MM) 2003-015;
- APRM flow control trip reference card replacement in accordance with MM 2003-028; and
- Disassembly and repair of HPCI turbine exhaust check valve V23-3 following failed as-found LLRT.

The inspectors verified that systems were properly restored following testing and that discrepancies were appropriately documented in the corrective action process. The inspectors also discussed the PMT results with the responsible engineers.

b. Findings

No findings of significance were identified.

1R20 Refueling and Outage Activities (71111.20)

1. Refueling Outage (RFO) 24

a. Inspection Scope (one sample)

The inspectors evaluated the following outage activities to verify that Entergy considered risk when developing outage schedules; that Entergy adhered to administrative risk reduction methodologies for plant configuration control; and to ensure that Entergy adhered to their operating license, Technical Specification requirements, and approved procedures:

- Review of the Outage Plan - The inspectors reviewed the RFO 24 shutdown risk assessment to verify that Entergy addressed the outage's impact on defense-in-depth for the five shutdown critical safety functions; electrical power availability, inventory control, decay heat removal, reactivity control, and containment. Adequate defense-in-depth was verified for each safety function and / or where redundancy was limited or not available, the existence of appropriate planned contingencies, to minimize the overall risk, was verified. Consideration of operational experience was also verified. The daily risk up-date, accounting for schedule changes and unplanned activities were also periodically reviewed;
- Monitoring of Shutdown Activities - The inspectors observed the shutdown of the reactor plant including reactor plant cooldown and transition to shutdown cooling operations. As soon as practical following the shutdown, the inspectors performed walkdowns of the primary containment;
- Electrical Power - The inspectors reviewed the status and configuration of safety-related buses throughout RFO 24. The inspectors ensured the electrical lineups met the requirements of Technical Specification and the outage risk control plan. The inspectors performed frequent walkdowns of affected portions of the electrical plant including startup transformers, the auxiliary transformer, and the emergency diesel generators;
- Decay heat removal (DHR) System Monitoring - The inspectors monitored decay heat removal status on a daily basis. Monitoring included daily reviews of residual heat removal system alignment, reviews of spent fuel pool cooling system alignment, and reviews of reactor coolant system (RCS) time-to-boil calculations and results;
- Inventory Control - The inspectors performed daily RCS inventory control reviews including reviews of available injection systems and flow paths to ensure consistency with the outage risk plan. The inspectors also ensured that operators maintained reactor vessel and/or refueling cavity levels within established ranges;
- Reactivity Control - The inspectors observed reactivity management actions taken by control room operators during refueling evolutions including procedure place keeping, communications with refueling floor personnel, the monitoring of source range nuclear instrumentation, and the monitoring of individual control rod positions;

- Containment Closure - The inspectors performed a torus internal cleanliness walkdown following completion of outage activities. The inspectors performed a primary containment closeout walkdown prior to final containment closure. Finally, the inspectors ensured secondary containment was maintained as required by Technical Specifications;
- Refueling Activities - The inspectors observed portions of refueling operations, including fuel handling and accounting in the reactor vessel and spent fuel pool. The inspectors also performed an independent core reload verification of approximately 34% of the core; and
- Heatup and Startup Activities - The inspectors observed portions of the heatup and startup of the reactor plant following the completion of RFO24.

The inspectors also verified that Entergy identified problems related to refueling activities and entered them into their corrective actions program.

b. Findings

Introduction: A very low safety significance (Green), self-revealing, non-cited violation (NCV) of 10 CFR 50 Criterion XVI was identified in that Entergy personnel did not develop effective corrective actions to prevent recurrence following a 2001 event wherein control room operators did not verify a suction path existed prior to starting a residual heat removal (RHR) system pump being used to support shutdown cooling (SDC) operations which caused the pump to trip. On April 10, 2004, an identical event occurred and again resulted in a trip of the RHR pump being used to support SDC operations.

Description: On April 10, 2004, control room operators realigned vital alternating current (AC) power from its normal power supply to the backup power supply to support planned maintenance on a vital AC motor generator. The reactor plant was in the refueling mode of operation at that time. In preparation for the vital AC realignment, operators temporarily secured the RHR system, which was running in the SDC mode of operation. One of the automatic actions that occurred during the vital AC alignment was the closure of the RHR pump suction valve V10-17 from a Group 4 containment isolation signal. Once the realignment of the vital AC power was completed, operators reset the expected partial Group 4 containment isolation signal, but did not recognize that this partial Group 4 containment isolation signal resulted in the closure of RHR system valve V10-17, isolating the suction path used for RHR system support of SDC. Operators subsequently attempted to reinitiate the RHR system in accordance with Vermont Yankee Operating Procedure (OP) 2124, "Residual Heat Removal System," Section J, "Short Term Shutdown Cooling Shutdown and Startup." When the "B" RHR pump was started, the pump's breaker immediately tripped open due to a designed electrical interlock requiring valve V10-17 to be open to provide a suction path for the RHR system. Operators investigated the cause of the pump breaker trip, identified that no suction path existed since valve V10-17 had closed, re-opened valve V10-17, and successfully restarted the "B" RHR pump within 15 minutes of the breaker trip.

SDC thermal margin was maintained throughout this event via continued operation of the spent fuel pool cooling system along with a calculated RCS time-to-boil value of greater than 24 hours.

In the apparent cause report for this event, Entergy identified that a nearly identical event had occurred during a refueling outage in May 2001. At that time, operators had performed a planned realignment of the vital AC power but did not recognize that valve V10-17 had closed which resulted in a trip of the "C" RHR pump breaker when operators attempted to reinitiate the RHR system. Entergy documented this previous event in event report (ER) 2001-01228. Corrective actions assigned at that time included discussions at shift supervisor meetings and the counseling of involved operators. In the apparent cause report, Entergy also concluded that the corrective actions taken to address the May 2001 event were insufficient to have prevented recurrence of the nearly identical April 2004 event. Specifically, no corrective actions were assigned to address the fact that OP 2124, Section J, did not specifically require operators to verify an adequate RHR system flow path to and from the reactor existed prior to reinitiating system operation.

Analysis: The performance deficiency associated with this finding is that Entergy personnel did not assign effective corrective actions to prevent recurrence as required by VY Administrative Procedure 0009 following a May 2001 trip of the "C" RHR pump which occurred when operations did not recognize that RHR system valve V10-17 had gone closed during a realignment of vital AC power. As a result, a similar event occurred in April of 2004 involving a trip of the "B" RHR pump resulting from operators again failing to recognize the closure of valve V10-17 during a realignment of vital AC power. The finding is greater than minor since it is associated with the Fuel Cladding Configuration Control Attribute of the Barrier Integrity Cornerstone and because it affects the associated Cornerstone objective. Specifically, the April 2004 trip of the "B" RHR pump, used to support SDC operations, reduced the assurance that the fuel cladding would protect the public from radio nuclide releases caused by accidents or events. The inspectors conducted a SDP Phase 1 screening of the finding in accordance with IMC 0609, Appendix G, "Shutdown Operations Significance Determination Process [SDP]." The inspectors determined that Entergy did not meet Item I.C. of Table 1, "BWR [Boiling Water Reactor] Refueling Operation with RCS Level > 23'" since the finding resulted in Entergy not having at least one RHR loop operating to support SDC. However, the inspectors also determined that the finding did not degrade Entergy's ability to recover SDC since the "B" RHR pump was restarted within 15 minutes of being tripped and an adequate thermal margin was maintained via a calculated RCS time-to-boil of greater than 24 hours. Therefore, in accordance with IMC 0609, Appendix G, the finding was of very low safety significance (Green).

A contributing cause of this finding is related to the Cross-Cutting area of Problem Identification and Resolution. As stated above, Entergy personnel did not develop effective corrective actions to prevent recurrence following a 2001 event wherein control room operators did not verify a suction path existed prior to starting the RHR system pump being used to support SDC operations which caused the pump to trip. Entergy's corrective actions relied on the operator's skill to verify a suction path was open prior to restarting the RHR pump rather than proceduralize the step. As a result, an identical event occurred in April 2004 again resulting in a trip of the RHR pump being used to support SDC operations.

Enforcement:

10 CFR 50, Appendix B, Criterion XVI states, in part, that measures shall be established to assure that conditions adverse to quality are promptly identified and corrected. Vermont Yankee AP 0009, "Event Reports," Revision 12, describes Entergy's requirements for the identification and correction of conditions adverse to quality including determining the cause(s) of the event and assigning corrective actions that prevent recurrence. Contrary to the above, in May 2001, Entergy did not assign effective corrective actions that prevent recurrence following a May 2001 trip of the "C" RHR pump which occurred when operators did not recognize that RHR system valve V10-17 had closed due to an expected partial Group 4 containment isolation during the realignment of vital AC power. As a result, a similar event occurred in April of 2004 involving the trip of the "B" RHR pump resulting from operators again failing to recognize the closure of valve V10-17 during a realignment of vital AC power. Because the finding is of very low safety significance and has been entered into the licensee's Corrective Actions Program (CR 2004-01005), this violation is being treated as an NCV, consistent with Section VI.A of the NRC Enforcement Policy: **NCV 0500271/2004003-01, Ineffective Corrective Actions Assigned Following a May 2001 Trip of the "C" RHR System Pump During SDC Operation.**

2. Forced Outage Following the Main Transformer Fire of June 18, 2004.

a. Inspection Scope (partial sample)

The inspectors evaluated the following forced outage activities to verify that Entergy considered risk when developing outage schedules; that Entergy adhered to administrative risk reduction methodologies for plant configuration control; and to ensure that Entergy adhered to their operating license, Technical Specification requirements, and approved procedures:

- Review of the Outage Plan - The inspectors reviewed the shutdown risk assessment to verify that Entergy addressed the outage's impact on defense-in-depth for the five shutdown critical safety functions; electrical power availability, inventory control, decay heat removal, reactivity control, and containment. The daily risk up-date, accounting for schedule changes and unplanned activities were also periodically reviewed;
- Monitoring of Shutdown Activities - The inspectors observed the shutdown of the reactor plant including reactor plant cooldown activities and transition to shutdown cooling operations. As soon as practical following the shutdown, the inspectors performed walkdowns of the primary containment;
- DHR System Monitoring - The inspectors monitored decay heat removal on a daily basis. Monitoring included daily reviews of residual heat removal system

alignment, reviews of spent fuel pool cooling system alignment, and reviews of RCS time-to-boil calculations and results; and

- Inventory Control - The inspectors performed daily RCS inventory control reviews including reviews of available injection systems and flow paths to ensure consistency with the outage risk plan. The inspectors also ensured that operators maintained RCS level within established ranges.

The inspectors also verified that Entergy identified problems related to the forced outage and entered them into their corrective actions program.

b. Findings

No findings of significance were identified.

1R22 Surveillance Testing (71111.22)

a. Inspection Scope (eight samples)

The inspectors observed surveillance testing to verify that the test acceptance criteria specified for each test was consistent with Technical Specification and UFSAR requirements, was performed in accordance with the written procedure, the test data was complete and met procedural requirements, and the system was properly returned to service following testing. The inspectors observed selected pre-job briefs for the test activities. The inspectors also verified that discrepancies were appropriately documented in the corrective action program. The inspectors verified that testing in accordance with the following procedures met the above requirements:

- OP 4031, "Type B and C Primary Containment Leak Rate Calculations and Evaluations";
- OP 4100, "ECCS Integrated Automatic Initiation Test";
- OP 4114, "Standby Liquid Control [SLC] System Surveillance," Section C, "Flow Test Directly into the Reactor Vessel," and Section I, "SLC Explosive Charge Continuity Check";
- OP 4121, "Reactor Core Isolation Cooling System Surveillance," Section B, "RCIC Injection Check Valve (RCIC-22) Test";
- OP 4142, "Vernon Tie and Delayed Access Power Source Backfeed Surveillance";
- OP 4424, "Control Rod Scram Testing and Data Reduction," Section B, "Single Rod Scrams Using ERFIS Data Collection";
- OP 4430, "Reactivity Anomalies/Shutdown Margin Check," Section 1, "Strongest Control Rod Withdrawn Subcritical Check; and
- Special Test Procedure (STP) 2003-004, "Power Ascension Test Procedure.

b. Findings

No findings of significance were identified.

1R23 Temporary Modifications (71111.23)

a. Inspection Scope (two samples)

The inspectors reviewed the following temporary modifications (TMs) to ensure that the modifications did not adversely affect the availability, reliability, or functional capability of any risk-significant structures, systems, and components:

- TM 2003-039, "Bottom Head Drain Line Freeze Seal"; and
- TM 2003-022, "Vibration Monitoring Equipment Installation on MS & FW Piping."

The inspectors compared the information in the TM packages to Entergy's TM requirements contained in AP 0020, "Control of Temporary and Minor Modifications." The inspectors also walked down accessible portions of these TMs to verify that required tags and markings were applied and that the TMs were properly maintained. The inspectors also reviewed a sample of TM-related problems identified in the Entergy's corrective action program to verify that they had identified and implemented appropriate corrective actions.

b. Findings

No findings of significance were identified.

Cornerstone: Emergency Preparedness

1EP6 Drill Evaluation (71114.06)

a. Inspection Scope (one sample)

On June 17, 2004, the inspectors observed an operating crew evaluate a simulator-based event using the station emergency action levels (EALs) during licensed operator requalification training activities. The inspectors discussed the performance expectations and results with the lead instructor and operations training manager. The inspectors focused on the ability of licensed operators to perform event classification and make proper notifications in accordance with the following station procedures and industry guidance:

- AP 0153, Operations Department Communications and Log Maintenance";
- AP 0156, "Notification of Significant Events";
- AP 3125, "Emergency Plan Classification and Action Level Scheme";
- DP 0093, "Emergency Planning Data Management";
- OP 3540, "Control Room Actions During an Emergency"; and
- Nuclear Energy Institute (NEI) 99-02, "Regulatory Assessment Performance Indicator Guideline," Revision 2.

b. Findings

No findings of significance were identified.

2. RADIATION SAFETY

Cornerstone: Occupational Radiation Safety

2OS1 Access Control to Radiologically Significant Areas (71121.01)

a. Scope (fourteen samples)

The inspectors conducted inspections to verify that Entergy was properly implementing physical, engineering, and administrative controls for access to high radiation areas, and other radiologically controlled areas, and that workers were adhering to these controls when working in these areas. Implementation of the access control program was reviewed against the criteria contained in 10 CFR 20, Technical Specifications, and approved Entergy procedures. The inspectors conducted independent radiation surveys and observed work area conditions, reviewed radiation surveys of these areas, and reviewed electronic dosimetry set points and other exposure controls specified in the radiation work permits (RWPs) that provided the access control requirements for the following radiologically significant work activities:

- Steam dryer underwater welding modifications;
- Drywell shielding installation;
- Drywell in-service inspection of core spray nozzle N5A;
- Drywell safety relief valve maintenance;
- Drywell main steam isolation valve maintenance; and
- Feedwater heater replacement modifications

b. Findings

No findings of significance were identified.

2OS2 ALARA Planning and Controls (71121.02)

Inspection Scope (four samples)

The inspectors reviewed Entergy's As Low As Reasonably Achievable (ALARA) Program performance against the requirements of 10 CFR 20.1101(b). The inspectors reviewed aspects of the implementation of exposure reduction requirements based on ALARA planning for the five highest exposure outage tasks. The ALARA-related work activities observed are listed in Section 2OS1 above. In addition, the following ALARA inspection activities were conducted:

- Independent shielding effectiveness radiation surveys conducted in the drywell;
- Observation of closed circuit television equipment and tele-dosimetry use in the drywell was conducted with respect to drywell remote health physics work surveillance capability and technical specification requirements; and

- Feedwater heater bay source term location was reviewed relative to worker occupancy areas.

b. Findings

No findings of significance were identified.

4. OTHER ACTIVITIES (OA)

4OA1 Performance Indicator Verification (71151)

a. Inspection Scope (two samples)

The inspectors sampled Entergy submittals for the performance indicators (PIs) listed below for the period from April 2003 to March 2004. The PI definitions and guidance contained in NEI 99-02 and AP 0094, "NRC Performance Indicator Reporting," were used to verify the accuracy and completeness of the PI data reported during this period.

Barrier Integrity Cornerstone

- Reactor Coolant System Specific Activity; and
- Reactor Coolant System Leakage.

The inspectors reviewed selected operator logs, plant process computer data, condition reports, and monthly operating reports for the period April 1, 2003, through March 31, 2004.

b. Findings

No findings of significance were identified.

4OA2 Identification and Resolution of Problems (71152)

1. Routine Review of Identification and Resolution of Problems

a. Inspection Scope

The inspectors routinely reviewed issues during baseline inspection activities and plant status reviews to verify they were being entered into Entergy's corrective action system at an appropriate threshold and that adequate attention was being given to timely corrective actions. Additionally, in order to identify repetitive equipment failures and/or specific human performance issues for follow-up, the inspectors performed a daily screening of items entered into Entergy's corrective action program. This review was accomplished by reviewing selected hard copies of condition reports (a listing of CRs reviewed is included in the Attachment to this report) and/or by attending daily screening meetings.

b. Findings

No findings of significance were identified.

2. Semi-Annual Trend Review

a. Inspection Scope

As required by Inspection Procedure 71152, "Identification and Resolution of Problems," the inspectors performed the semi-annual trend review to identify trends, either licensee or NRC identified, that might indicate the existence of a more significant safety issue. Included within the scope of this review were:

- CRs generated from January through May 2004;
- Corrective maintenance backlog listings from January through May 2004;
- The corrective action program 3rd and 4th quarter, 2003 trend report; and
- Daily review of main control room operator logs.

b. Findings

No findings of significance were identified.

3. Cross-Reference to PI&R Findings Documented Elsewhere

Section 1R20.1 describes a finding wherein Entergy personnel did not develop effective corrective actions to prevent recurrence following a 2001 event wherein control room operators did not verify a suction path existed prior to starting the RHR system pump being used to support SDC operations which caused the pump to trip. Entergy's corrective actions relied on the operator's skill to verify a suction path was open prior to restarting the RHR pump rather than proceduralize the step. As a result, an identical event occurred in April 2004 again resulting in a trip of the RHR pump being used to support SDC operations.

4OA3 Event Followup (71153)

1. Main Transformer Fire and Reactor Plant Scram

a. Inspection Scope (1 sample)

The inspectors evaluated Entergy's response to a main transformer fire and resultant reactor plant scram that occurred on June 18, 2004. The inspectors immediately responded to the main control room to observe reactor plant parameters, to evaluate individual safety system responses, and to evaluate licensed operator responses to the event. The inspectors evaluated the response of the reactor plant and the licensed operators against Entergy approved operating procedures, abnormal operating procedures, and emergency operating procedures. The inspectors evaluated Entergy's classification of the event (i.e., Unusual Event) in accordance with approved EAL procedures to ensure notifications were made to NRC and state/county governments as required. The inspectors also evaluated the ability of Entergy's fire brigade and automatic fire protection systems to extinguish the main transformer fire in a safe and timely manner.

The NRC Region I Office dispatched two inspectors, each a specialist in the areas of electrical and fire protection systems, to assist the resident inspectors with event follow-up activities. The inspectors monitored Entergy's efforts in determining the root cause of the event; monitored Entergy's efforts for the recovery, replacement, and repair of the effected portions of the 22KV electrical system; and monitored Entergy's reactor plant restart preparation activities.

b. Findings

Entergy has identified that the root cause of the main transformer fire relates to weaknesses with the preventive maintenance performed on the 22 KV electrical system. Because additional information is needed to determine if these issues are more than minor, they are considered to be an unresolved item (URI) pending completion of the inspectors review of Entergy's root cause analysis: **URI 0500271/2004003-02, Weaknesses Identified with the Preventive Maintenance Performed on the 22 KV Electrical System Resulted in Main Transformer Fire.**

4OA5 Other Activities

1. Temporary Instruction (TI) 2515/156, "Offsite Power System Operational Readiness."

a. Inspection Scope

The inspectors collected and reviewed information pertaining to the Vermont Yankee offsite power system as it related to the requirements of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"; 10 CFR 50.63, "Loss of All Alternating Current Power"; offsite power operability; and corrective actions. The inspectors also reviewed this data against the requirements of 10 CFR 50, Appendix A, General Design Criterion 17, "Electric Power Systems," and the Vermont Yankee Technical Specifications. This information was forwarded to NRR for further review. A listing of documents reviewed is included in the Attachment to this report.

b. Findings

No findings of significance were identified.

4OA6 Meetings, including Exit

Resident Exit

On July 12, 2004, the resident inspectors presented the inspection results to Mr. Kevin Bronson and members of his staff. The inspectors asked whether any materials examined during the inspection should be considered proprietary. No proprietary information was identified.

Meeting with the State of Vermont Public Service Board

On June 28, 2004, Region I and NRR staff met with the Vermont State Public Service Board (PSB) regarding Vermont Yankee's request for a 20% extended power uprate. The NRC staff discussed the NRC's power uprate review process and details regarding a planned pilot engineering inspection slated for Vermont Yankee in August 2004.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel:

J. Thayer	Site Vice President
K. Bronson	General Plant Manager
J. Allen	Design Engineering
P. Corbett	Maintenance Manager
J. Dreyfuss	Project Engineering Manager
J. Devincentis	Licensing Manager
W. Fadden	Design Engineering
J. Geyster	Radiation Protection Superintendent
D. Giorowall	Programs Supervisor
Dennis Girrior	Programs Supervisor
S. Goodwin	Mechanical Design Department Manager
M. Gosekamp	Superintendent of Operations Training
M. Hamer	Licensing
D. Johnson	Design Engineering
Dave King	ISI Coordinator
R. Morissette	Principal As Low As Reasonably Achievable (ALARA) Engineer
M. Pletcher	Radiation Protection Supervisor - Instruments
P. Rainey,	Design Engineering
B. Renny	Supervisor, Access Authorization
K. Stupak	Technical Training
C. Wamser	Operations Manager
R. Wanczyk	Director of Nuclear Safety

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened and Closed

0500271/2004003-01 NCV	Ineffective Corrective Actions Assigned Following a May 2001 Trip of the "C" RHR System Pump During SDC Operation (Section 1R20.1)

Opened

0500271/2004003-02 URI	Weaknesses Identified with the Preventive Maintenance Performed on the 22 KV Electrical System Resulted in Main Transformer Fire (Section 4OA3.1)

LIST OF DOCUMENTS REVIEWED

Section 1R02: Evaluation of Changes, Tests, or Experiments

Power Uprate Modifications

TM 2003-022	Vibration Monitoring Equipment Installation on MS [Main Steam] & FW [Feedwater] Piping
MM 2003-015	Reactor Feed Pump Suction Pressure Trip
MM 2003-016	Reactor Recirculation System Runback"
MM 2003-026	AST [Alternate Source Term] Component Modification (OG-779 Installation)
MM 2003-028	APRM Flow Control Trip Reference Card Replacement
MM 2003-039	NSSS [Nuclear Steam Supply System]/BOP [Balance of Plant] Instrumentation Upgrades
MM 2003-054	381 Line Overload Relay Setting
VYDC 2003-013	Installation of Additional Main Steam Safety Valve

Section 1R08: Inservice Inspection

Procedures

ENN-NDE 9.29, Rev 0 for UT of structural overlay (weld N5A)
PDI-UT-8, Rev B. Generic Procedure for UT of Weld Overlaid Austenitic Pipe Welds
ISI - 254, Rev 5, for remote ISI of RPV Welds
NE 8048, Rev 1 - In Vessel Visual Inspection

Drawings

ISI-PPV-103, Rev 3. Reactor Vessel
ISI-SLC-Part 4, Rev 3. SLC Piping ISO
D-7983-621 Rev G. UT/ET clad crack calibration block
6D30047, Rev 0, Wesdyne Calibration Standard PDI-01

Miscellaneous Reports

QA (Quality Assurance) Audit Report AR-2003-22b&c, dated 11/13/2003
GE (General Electric) RICSIL No. 050 of 4/23/1990, and GE SIL NO. 539, dated 11/5/1991
GE Reports INR-VYR24-04-01R2, 02R2, 03, & 04R1 on Steam Dryer Visual Indications
GE Nuclear Engineering (GENE) 0000-0028-0130-01, Revision 3, dated April 2004 on Steam Dryer Unit End Plate Indications - Vermont Yankee R24
GENE-0000-0028-0130-02, Revision 3, dated April 2004 on Steam Dryer Drain Channel Indications - Vermont Yankee R24

Section 1R17: Permanent Plant Modifications

Power Uprate Modifications

MM 2003-015	Reactor Feed Pump Suction Pressure Trip
MM 2003-016	Reactor Recirculation System Runback
MM 2003-026	AST Component Modification (OG-779 Installation)
MM 2003-028	APRM Flow Control Trip Reference Card Replacement
MM 2003-039	NSSS/BOP Instrumentation Upgrades
MM 2003-054	381 Line Overload Relay Setting

Calculations

Vermont Yankee Calculation (VYC) 0693A Rev. 2 APRM Neutron Monitoring Trip Loops
VYC-2269 Rev. 0 Feedwater and Condensate Hydraulic Model Analysis
VYC-2309 Rev. 0 Steam Drain Line MS-189-D3 Check Valve Addition

License Amendment Documents

BVY 03-23	License Amendment Proposal for ARTS/MELLLA
BVY 03-39	Technical Specification Proposed Change # 257 (ARTS/MELLLA)
GE-NE-0000-0020	Entergy Nuclear Operations Incorporated Vermont Yankee Nuclear Power
GE-NE-1500-0001	Station MELLLA+ Transient Analysis
NEDO-33090	Safety Analysis Report for Vermont Yankee Nuclear Power Station Constant Pressure Power Uprate

NRC NRR Safety Evaluation for License Amendment No. 219 to DPR-28

Specifications/Procedures

AP 5226 Rev. 5	Calibration of Switchyard Breaker Failure Relays
VYSP-FS-074	Specifications for Safety Valves
VY IPE Vol 2	Individual Plant Examination for SRV/SV Reclosure

Section 4OA2.1: Routine Review of Problem Identification and Resolution

Condition Reports

2002-2581	RBCCW pumps failed to restart within time limit during ECCS [emergency core isolation cooling] test
2002-2584	ECCS test data was accepted as satisfactory when some data was outside of acceptance criteria
2003-1509	The “C” RHRSW pump cooling water supply solenoid valve failed to open as required on pump start
2003-2321	No indicated cooling flow upon “C” RHRSW pump start
2004-0700	While troubleshooting a 4KV breaker on Bus-2-7, the breaker driving pawl broke
*2004-0840	Incorrect status of Decay Heat Removal was logged on the Critical Outage Systems Status Form
*2004-0845	NRC resident question on RHR procedure wording
2004-0879	HPCI V23-845 failed IST testing
2004-0892	Water level in the reactor cavity exceeds limits during cavity floodup

*2004-0897	Incorrect start dates used in ORAM-Sentinel for alternate DHR capability determinations
2004-0918	Adverse trend - main steam isolation valve Appendix J test failures
2004-0942	HPCI V23-846 failed IST testing
2004-0955	As-found condition of V2-80 included a galled stem
2004-0968	Unsuccessful decon of diver
2004-0981	An observation was made from below vessel that a piece of control rod drive housing support (shoot-out steel) was missing
2004-0986	Instructions for RWP not adhered to
2004-0998	RHR-46A allowed to overflow while working on the valve
2004-1005	B RHR pump trip during restart due to no suction path
2004-1017	V2-13-3 failed Appendix J local leak rate test
2004-1058	Flow noise from RO-10-105C, "C" RHR pump discharge orifice
2004-1091	Rad survey maps indicate need to perform alpha survey
2004-1117	Flow noise from "C" RHR pump discharge orifice
2004-1160	ASME rejectable indication on SLC weld
2004-1190	Weld electrodeoven left unlocked and unattended
*2004-1339	Two fuel segments could not be confirmed in storage container
2004-1409	"A" RBCCW did not start within the allowed ECCS start time
2004-1426	ECCS test exceptions
2004-1428	Reactor water clean up pump started with no suction path
2004-1548	P-8-1A leaking oil from upper bearing reservoir area
2004-1653	Excessive overtime approved without documentation
2004-1665	Potentially non-conservative scram setpoint values
*2004-1916	#2 fan room has inadequate hose stream coverage due to modification to fan room door
*2004-1928	Slight leakage on "B" SBGT demister loop seal piping union
2004-1989	Generator Ground alarm came in
2004-2015	Reactor Scram
2004-2017	Notification of Unusual Event (NOUE) declared due to plant fire and automatic reactor scram
2004-2019	Main transformer fire
*2004-2022	Discrepancy in post scram rod position indication
*2004-2023	Torus-to-drywell vacuum breaker indicating lights and alarm indicate breakers may have cycled during the scram/transformer trip
*2004-2045	Repeat of P-8-1A leaking oil from upper bearing reservoir area
2004-2074	Failure to make timely notification of States upon declaration of unusual event on June 18, 2004

*Inspector-identified issues.

Section 4OA5.1: Temporary Instruction (TI) 2515/156, "Offsite Power System Operational Readiness."

Procedures

Vermont Yankee Operating Procedure Form (VYOPF) 0150.03, "CRO [Control Room Operator] Round Sheet
AP 0172, "Work Schedule Risk Management - On Line"
ISO New England Master/Satellite Procedure #1, "Nuclear Plant Transmission Operations," Revision 0
ISO New England Master/Satellite Procedure #2, "Abnormal Conditions Alert," Revision Dated 11/19/01

Licensee Event Reports (LERs)

Vermont Yankee Nuclear Power Station LER 87-008-00, "Loss of Normal Power During Shutdown Due to Routing All Off-Site Power Sources Through One Breaker"
Vermont Yankee Nuclear Power Station LER 84-022-00, "Diesel Generator Lockout Trip of Both Generators"

Maintenance Rule Documents

NRC Maintenance Rule Program Website Frequently Asked Questions (FAQs)
Vermont Yankee 10CFR50.65 NRC Maintenance Rule SSC Basis Document, "345K Volts AC Electrical (345KV)"
Vermont Yankee 10CFR50.65 NRC Maintenance Rule SSC Basis Document, "115K Volts AC Electrical (115KV)"

Operational Experience Documents

JA Fitzpatrick Operational Experience (OE) 16822, "Reactor Scram due to Grid Instability"
Significant Operating Experience Report (SOER) 9901, "Loss of Grid"

Miscellaneous Documents

Control room operator logs dated 8/17/87
VYC-1088, "Vermont Yankee 4160/480 Volt Short Circuit/Voltage Study," Revision 3

LIST OF ACRONYMS

AC	Alternating Current
ADAMS	Automated Document Access Management System
ALARA	As Low As Is Reasonably Achievable
AP	Vermont Yankee Administrative Procedure
APRMs	Average Power Range Monitors
ASME	American Society of Mechanical Engineers
CFR	Code of Federal Regulations
CR	Condition Report
CRO	Control Room Operator
CS	Core Spray
CY	Calendar Year
DBD	Design Basis Document
DHR	Decay Heat Removal
DOST	Diesel Oil Storage Tank
DP	Vermont Yankee Department Procedure
EALs	Emergency Action Levels
ECCS	Emergency Core Cooling System
EDGs	Emergency Diesel Generators
ET	Eddy Current Testing
EOP	Emergency Operating Procedure
ER	Event Report
FAQ	Frequently Asked Question
FW	Main Feedwater System
GE	General Electric
GENE	General Electric Nuclear Engineering
HPCI	High Pressure Coolant Injection
IMC	Inspection Manual Chapter
IPEEE	Individual Plant Examination External Events
IR	Inspection Report
ISI	Inservice Inspection
IST	Inservice Testing
KV	Kilovolt
LER	Licensee Event Report
LLRT	Local Leakage Rate Testing
MM	Minor Modification
MS	Main Steam System
NCV	Non-Cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Engineering Institute
NOUE	Notice of Unusual Event
NRC	Nuclear Regulatory Commission
NRR	NRC Office of Nuclear Reactor Regulation
OE	Operating Experience
ON	Vermont Yankee Off-Normal Procedure
OP	Vermont Yankee Operating Procedure

PI	Performance Indicator
PMT	Post Maintenance Testing
PSB	Public Service Board
QA	Quality Assurance
RCS	Reactor Coolant System
RCIC	Reactor Core Isolation Cooling
RFO	Refueling Outage
RHR	Residual Heat Removal
RHRSW	Residual Heat Removal Service Water
RPS	Reactor Protection System
RWP	Radiation Work Permit
SBGT	Standby Gas Treatment
SDC	Shutdown Cooling
SDP	Significance Determination Process
SEG	Simulator Evaluation Guide
SEN	Significant Event Notification
SFP	Spent Fuel Pool
SLC	Standby Liquid Control
SOER	Significant Operating Experience Report
SSC	Structures, Systems and Components
STP	Special Test Procedure
SW	Service Water
TI	Temporary Instruction
TM	Temporary Modification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Testing
VT	Visual Examination Testing
VY	Vermont Yankee
VYC	Vermont Yankee Calculation
VYDC	Vermont Yankee Design Calculation
VYOPF	Vermont Yankee Operating Procedure Form

Entergy	CONDITION REPORT	CR-VTY-2007-02133

Originator: Fales,Neil
Originator Group: Eng P&C Codes Staff
Supervisor Name: Lukens,Larry D
Discovered Date: 05/28/2007 17:06

Originator Phone: 8024513057
Operability Required: Y
Reportability Required: Y
Initiated Date: 05/28/2007 17:11

Condition Description:
Steam Dryer Inspection Indications

During RFO26 reactor vessel inspections, linear indications on the Steam Dryer Interior Vertical Weld HB-V04 were identified by General Electric. Most of these indications were previously identified in RFO25 with no discernable changes noted in RFO26. One new relevant indication was observed of similar appearance, orientation and size as those previously seen. These were documented via GE's process by INR-IVVI-VYR26-07-10. See attached GE INR's for details.

Immediate Action Description:
Notified Supervisor and generated CR.

Suggested Action Description:
The new indication will need to be evaluated.

EQUIPMENT:

Tag Name	Tag Suffix Name	Component Code	Process System Code
STEAM-DRYER	REACTOR	MR=Y	NB

TRENDING (For Reference Purposes Only):

Trend Type	Trend Code
KEYWORDS	KW-PRE-SCREENED FOR MRFF
INPO BINNING	ER1
KEYWORDS	KW-ISI
REPORT WEIGHT	1
EM	ESPC
HEP FACTOR	E

Attachments:
Condition Description
GE INR 10

Entergy	ADMIN	CR-VTY-2007-02133

Initiated Date: 5/28/2007 17:11 **Owner Group :**Eng P&C Codes Mgmt

Current Contact: vvv

Current Significance: C - INVEST & CORRECT

Closed by: Taylor,James M 6/18/2007 16:06

Summary Description:

Steam Dryer Inspection Indications

During RFO26 reactor vessel inspections, linear indications on the Steam Dryer Interior Vertical Weld HB-V04 were identified by General Electric. Most of these indications were previously identified in RFO25 with no discernable changes noted in RFO26. One new relevant indication was observed of similar appearance, orientation and size as those previously seen. These were documented via GE's process by INR-IVVI-VYR26-07-10. See attached GE INR's for details.

Remarks Description:

Closure Description:

CR closure review performed.

Attachment Header

Document Name:

untitled

Document Location

Condition Description

Attach Title:

GE INR 10

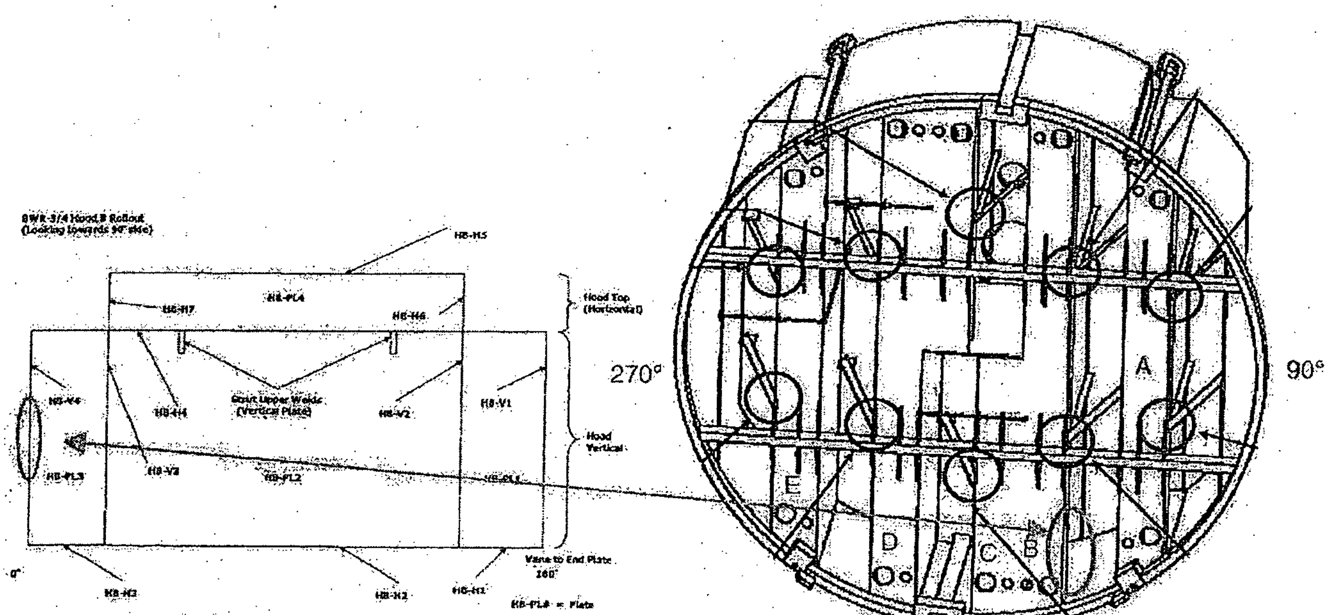
INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report

Plant / Unit	Component Description	Reference(s)
Vermont Yankee RFO26 Spring 2007	*Steam Dryer Interior Vertical Weld HB-V04*	DVD DISK IVVI-VYR26-07-58 Title 4 RFO-25 IVVI Report INF # 002.

Background

During the Vermont Yankee 2007 refueling outage, in accordance with the Vermont Yankee VT-VMY-204V10 Rev 2 Procedure, the Steam Dryer was inspected. The dryer inspection included inspection of the Steam Dryer interior welds and components. These inspections were done with GE's Fire Fly ROV with color camera. During the inspection of the HB-V04 weld (Dryer Unit Hood End Panel to HB-PL3 Plate weld), relevant linear indications were observed in the heat affected zone on the Dryer Unit side of the weld. Most of these linear indications were previously seen in RFO-25, Reference INF # 002. When comparing this outage with last outage, one new relevant indication is seen (3rd indication) of similar appearance, orientation and size as those previously seen; one indication was not seen (RFO25: 3th indication). No discernible change was noted in those indications which correlates to those of RFO26. See attached 2007 photos and sketches.



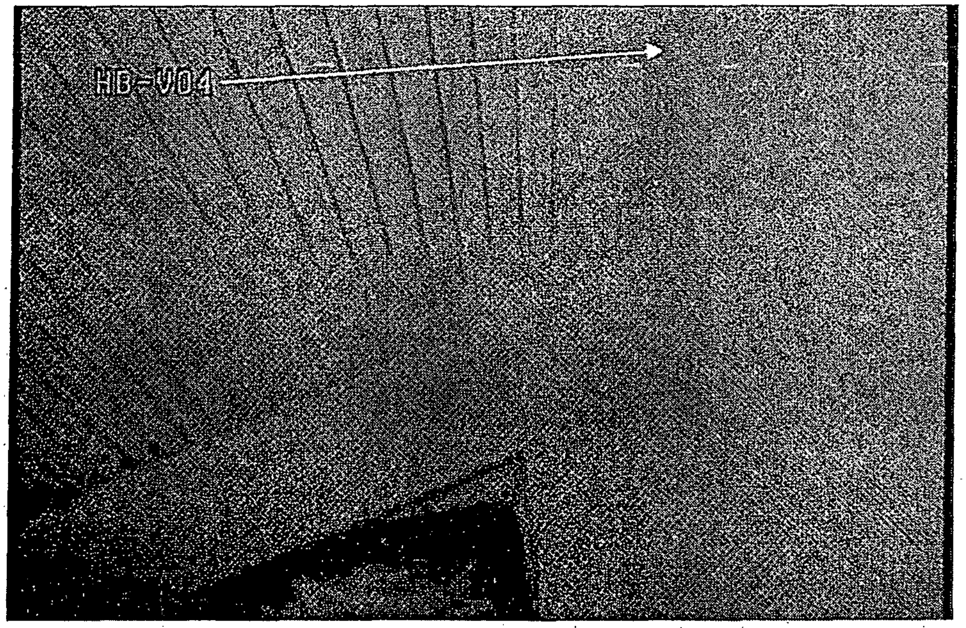
Sketch on the left shows the weld map rollout   The sketch on the right shows a bottom view of the dryer.

Prepared by: Dick Hooper   Date: *05/27/07*   Reviewed by: Rodney Drazich   Date: *05/27/07*

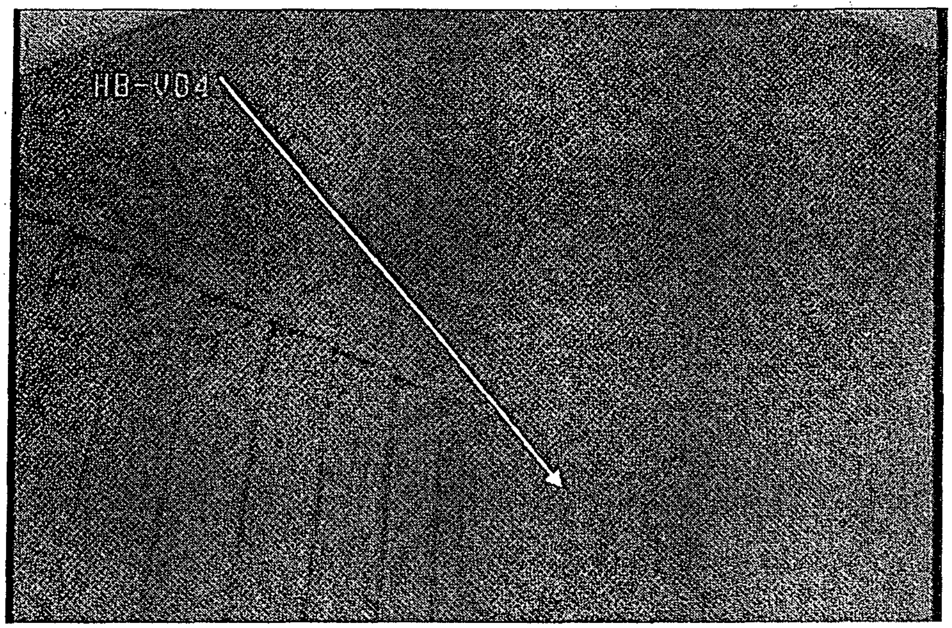
Utility Review By: R. Kudu   Date: 5/27/07

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



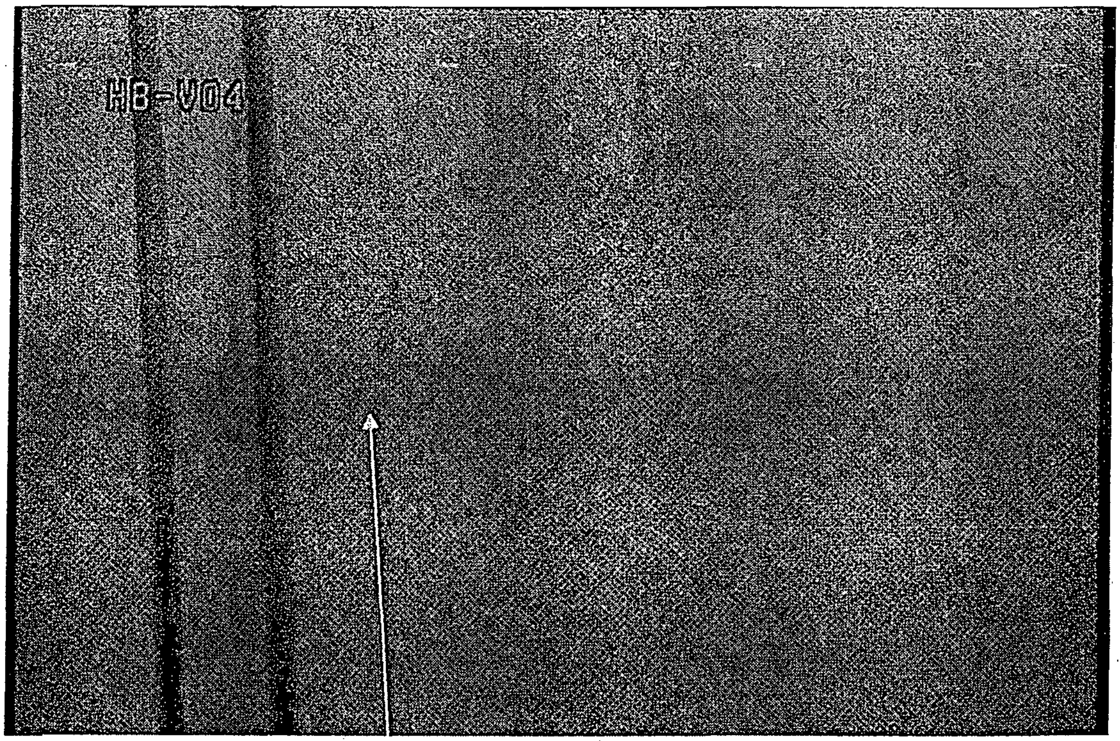
This 2007 photo shows the interior of the dryer and the location of HB-V04 vertical weld.



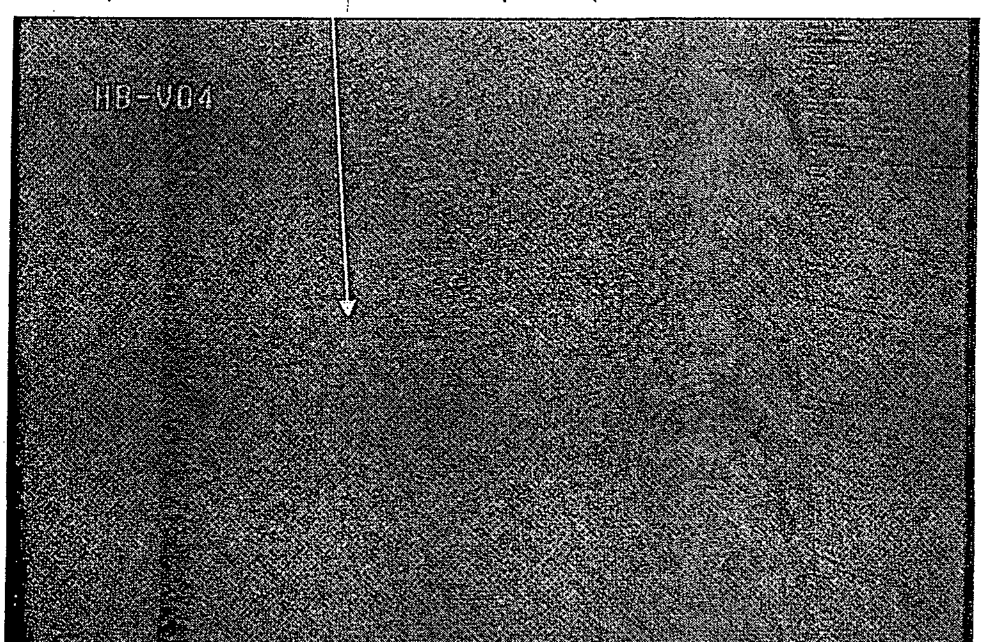
This 2007 photo shows the top of the vane bank (on the left) and the end panel (on the right) and the vertical weld in the center

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



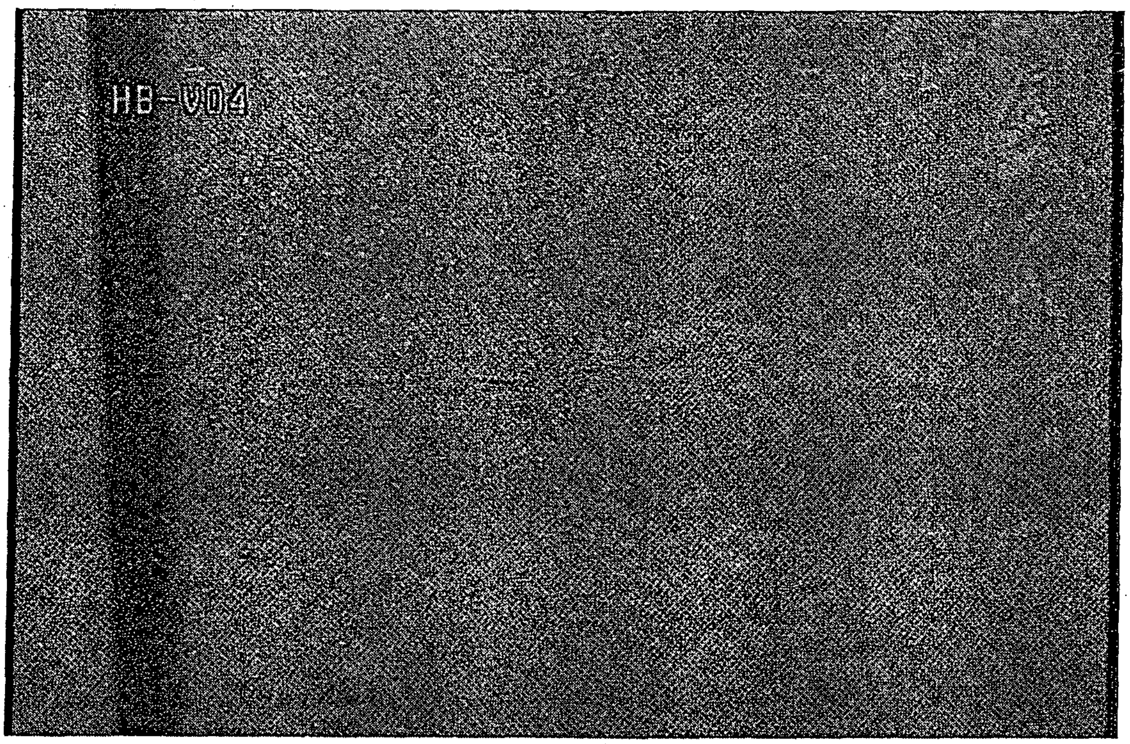
This 2007 photo is of the 1st indication from top down (Correlates to RFO25: 1st indication).



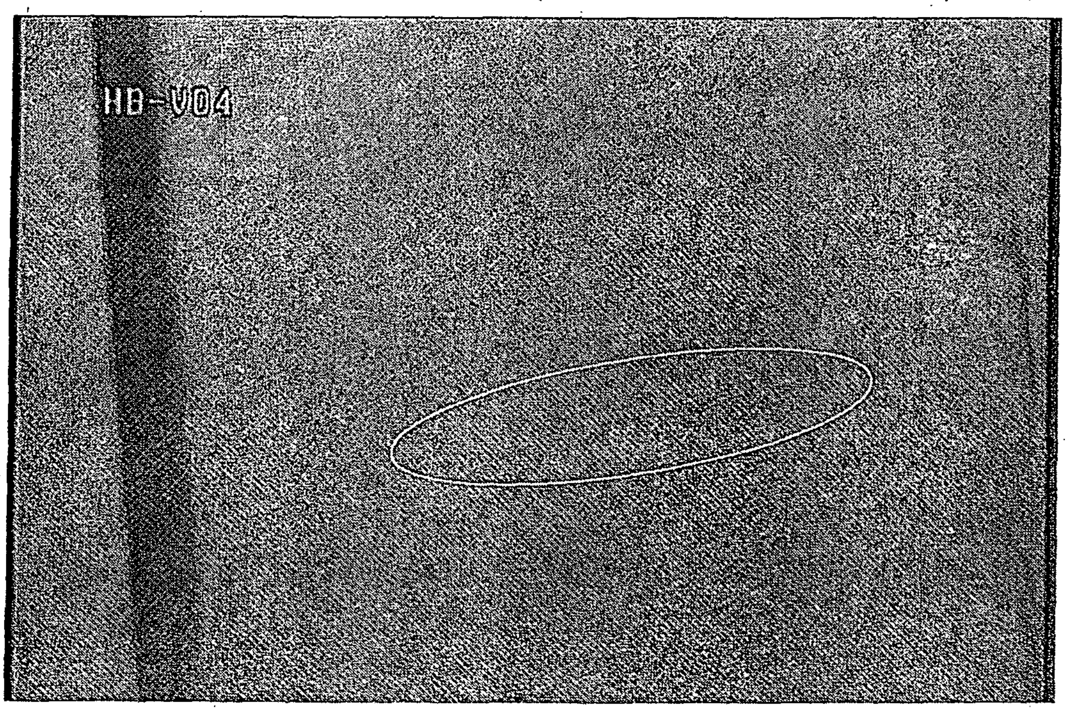
This 2007photo is a close-up of the 1st indication (Correlates to RFO25: 1st indication).

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



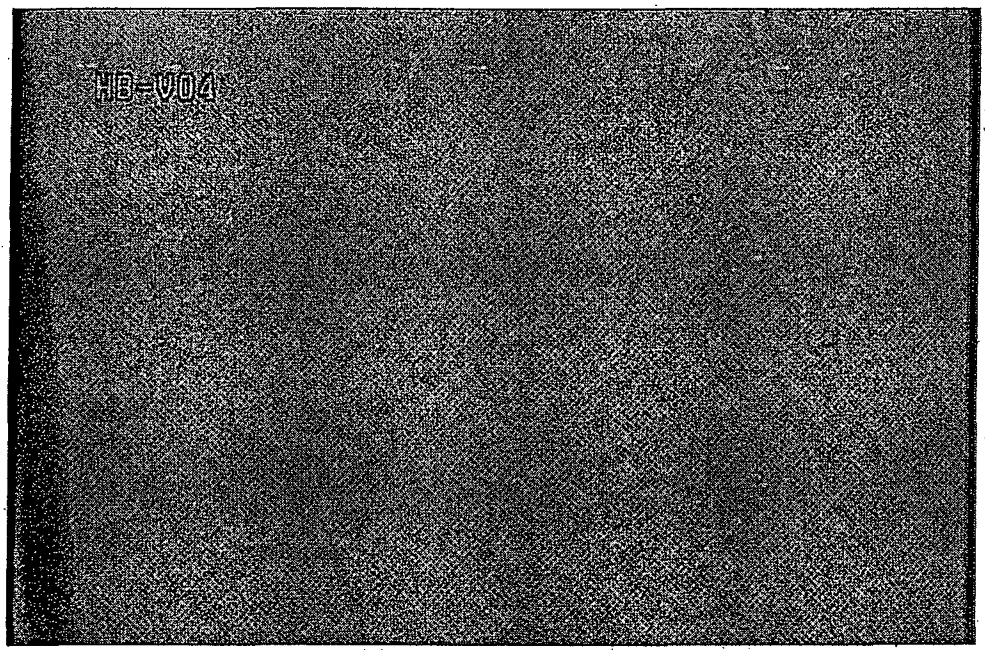
This 2007 photo is the 2nd indication (Correlates to RFO25: 2nd indication).



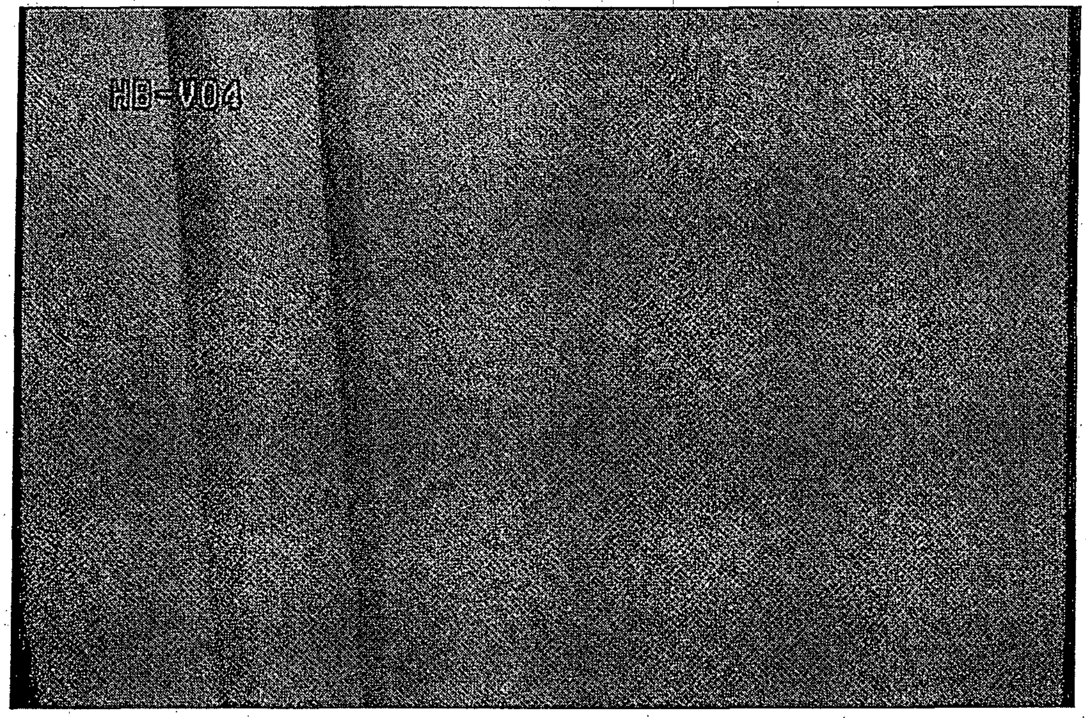
This is a 2007 photo of the 3rd indication and is a new RFO26 indication.

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



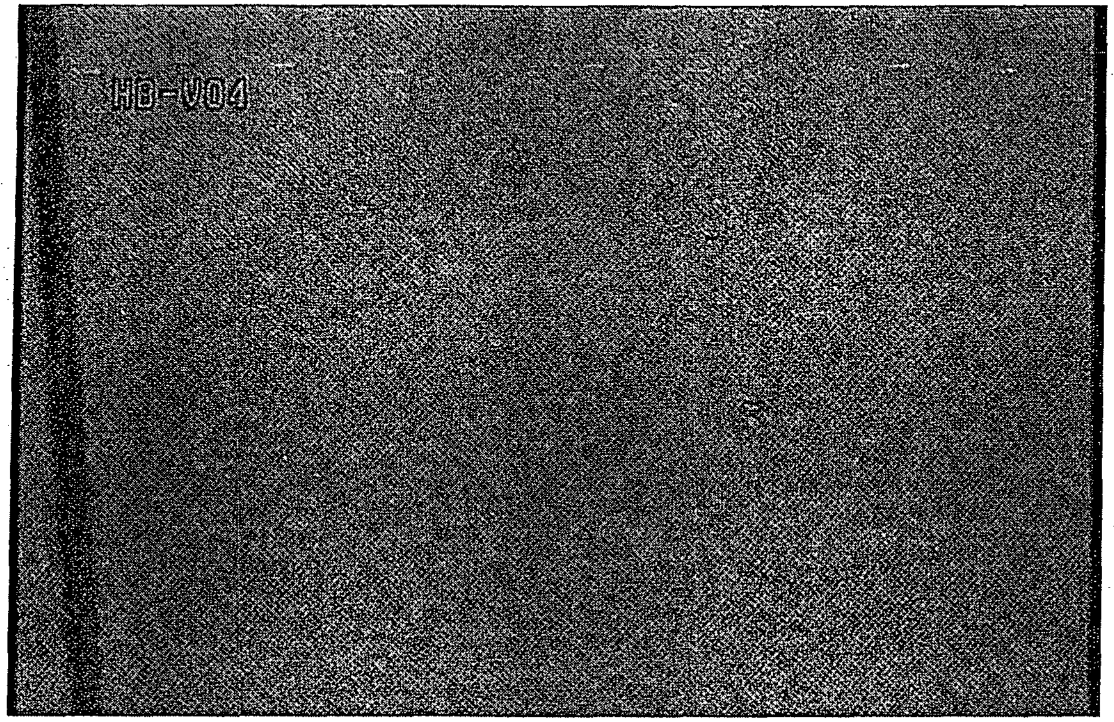
This is a 2007 photo of the 4th indication (Correlates to RFO25: 3rd indication)



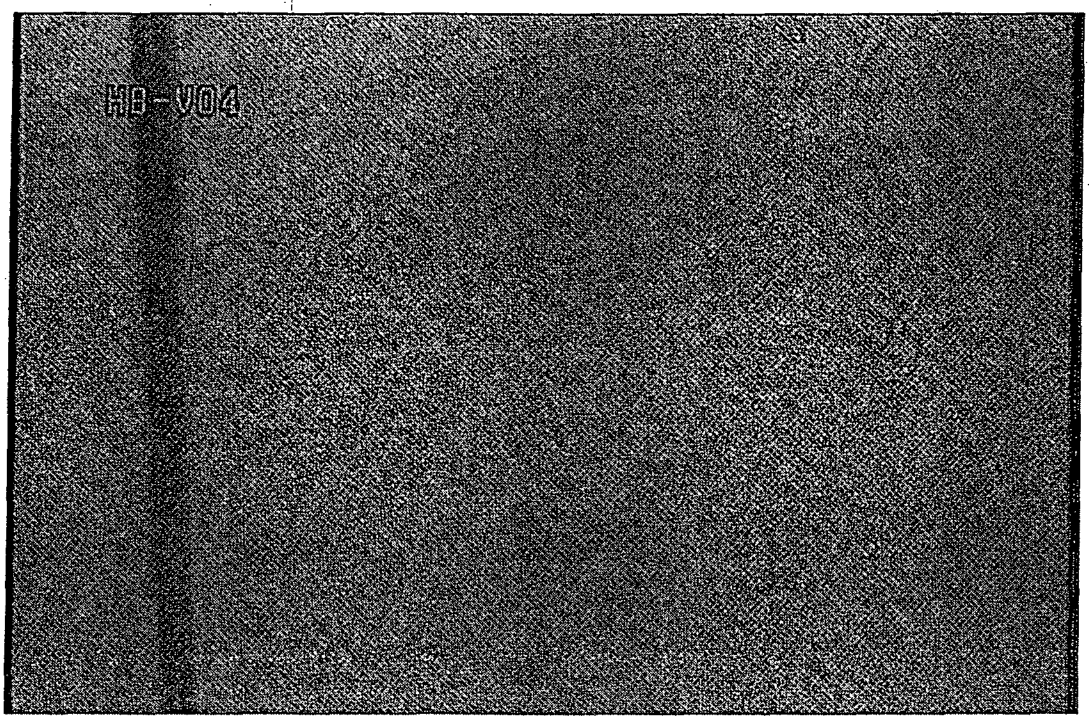
This is a 2007 photo of the 5th indication (Correlates to RFO25: 4th indication).

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



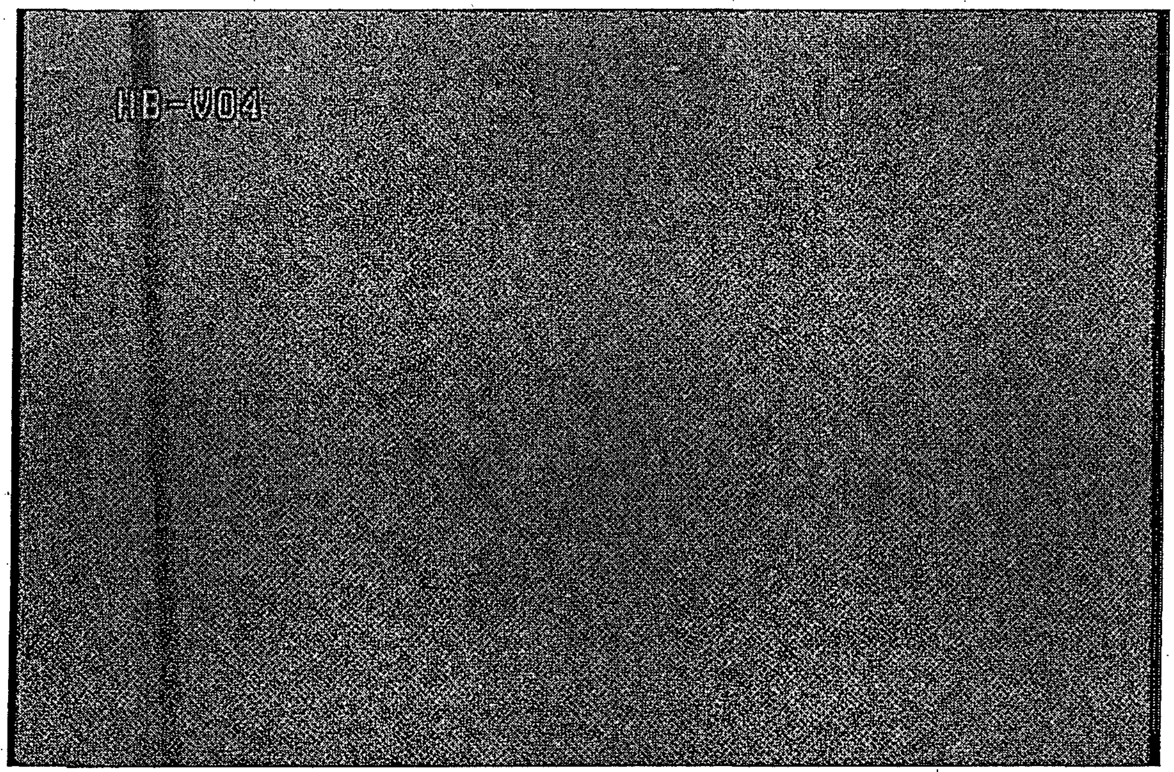
This is a 2007 photo of the 6th indication (Correlates to RFO25: 5th indication).



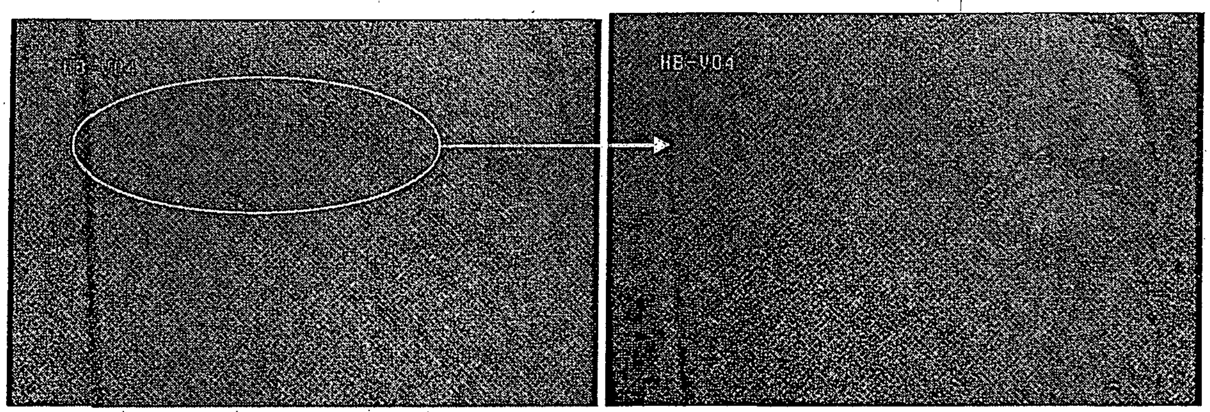
This is a 2007 photo of the 7th indication (Correlates to RFO25: 6th indication).

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



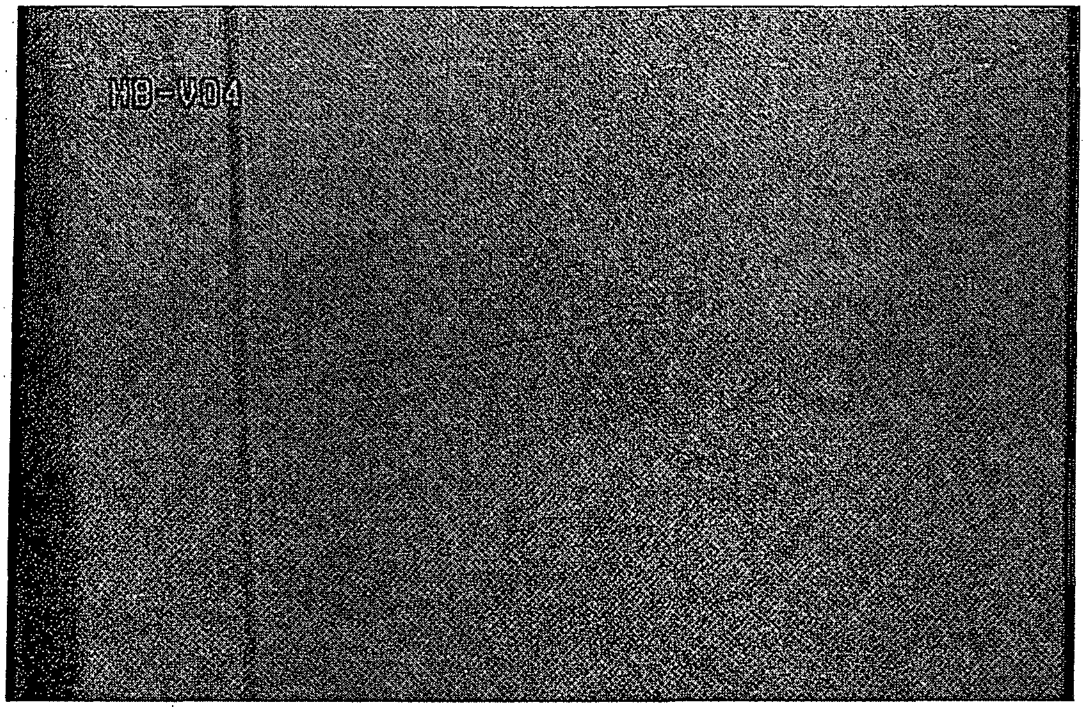
This is a 2007 photo of the 8th indication (Correlates to RFO25: 7th indication).



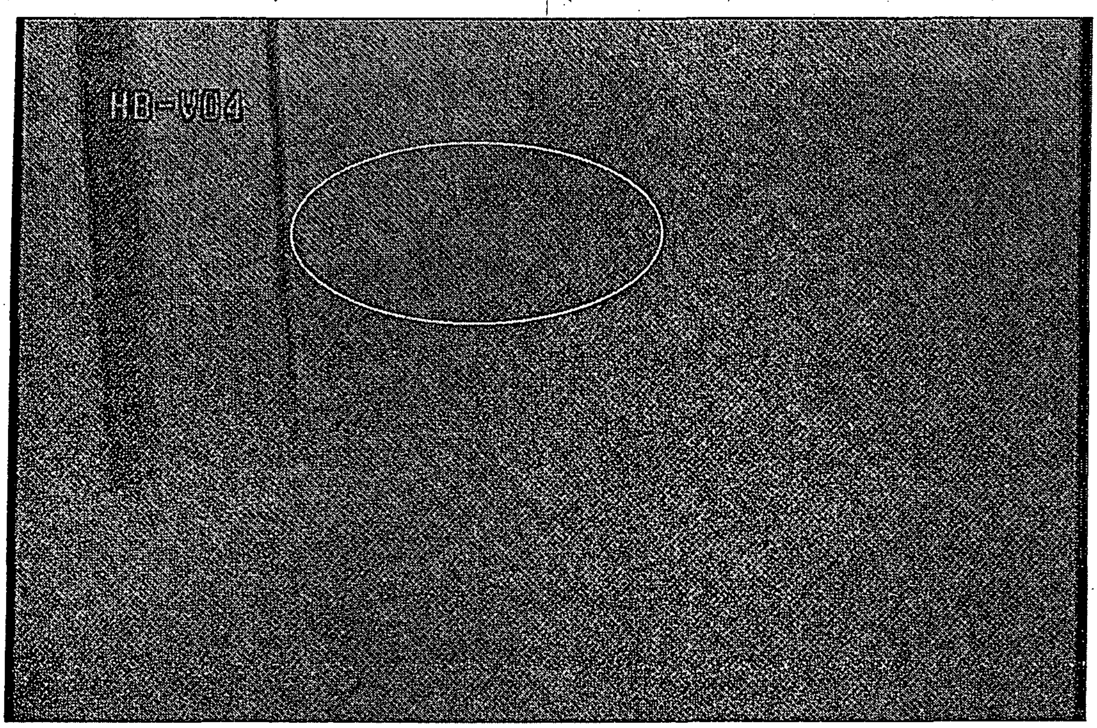
These 2007 photos show a linear indication and change of lighting and show a non-relevant indication (Correlates to RFO25: 9th indication).

INR-IVVI-VYR26-07-10- Steam Dryer Interior HB-V04

Indication Notification Report



This is a 2007 photo of the 9th indication (Correlates to RFO25: 10th indication).



This is a 2007 photo of the bottom weld area and crud line.

Entergy	**OPERABILITY**	**CR-VTY-2007-02133**

OperabilityVersion: 1

Operability Code: EQUIPMENT FUNCTIONAL

Immediate Report Code: NOT REPORTABLE

Performed By: Brooks,James C 05/29/2007 21:07

Approved By: Faupel,Robert F 05/30/2007 00:30

Operability Description:

Currently the plant is shutdown with the bolt in place. The bolt has one crimp fully engaged preventing the bolt from backing out. The need for having both crimps fully engaged will have to be evaluated prior to startup.

Approval Comments:

Entergy	**ASSIGNMENTS**	**CR-VTY-2007-02133**

Version: 2

Significance Code: C - INVEST & CORRECT

Classification Code: C

Owner Group: Eng P&C Codes Mgmt

Performed By: Wren,Vedrana 05/30/2007 13:04

Assignment Description:

Entergy	ASSIGNMENTS	CR-VTY-2007-02133

Version: 1

Significance Code: C - INVEST & CORRECT

Classification Code: C

Owner Group: Eng P&C Codes Mgmt

Performed By: Lukens,Larry D 05/29/2007 04:46

Assignment Description:

self identified
outage constraint

Entergy	REPORTABILITY	CR-VTY-2007-02133

Reportability Version: 1

Report Number:

Report Code: NOT REPORTABLE

Boilerplate Code: NOT REPORTABLE

Performed By : Devincentis,James M 05/29/2007 08:09

Reportability Description:

Not reportable - This condition does not meet the Reportability screening criteria contained in AP0010 or AP0156. The Steam Dryer is NNS and performs no safety releted functions. VY has a commitment to provide the results of the steam dryer inspections to the NRC following startup.

Entergy	**CORRECTIVE ACTION**	**CR-VTY-2007-02133**

CA Number: 1

	Group	Name
Assigned By:	CRG/CARB/OSRC	
Assigned To:	Eng P&C Codes Mgmt	Lukens,Larry D
Subassigned To :	Eng P&C Codes Staff	Fales,Neil

Originated By:	Wren,Vedrana	5/30/2007 13:00:53
Performed By:	Lukens,Larry D	6/15/2007 13:17:25
Subperformed By:	Fales,Neil	6/15/2007 11:49:49
Approved By:		
Closed By:	Taylor,James M	6/18/2007 16:02:38

Current Due Date: 06/28/2007 **Initial Due Date:** 06/28/2007

CA Type: DISP - CA

Plant Constraint: 0 NONE

CA Description:

C - INVEST & CORRECT (Review CR for full details)
□The CRG has initially classified this CR as "C" INVEST & CORRECT
□
□Per the CRG, Perform an Investigation of the issues identified in this CR and determine if additional actions are
□required within 30 days.
□
□Ensure all Screening Comments have been addressed in the investigation - (CR assignment tab)
□Develop adequate corrective actions and issue CAs. (Due Dates per LI 102 Attachment 9.4)
□LT CAs Require Approval from Site VP/ GMPO or Director prior to initiating. Completion of Attachment 9.9 LTCA
□Classification Form is required.

Response:

Approved. No additional corrective action required. Therefore, this CR may be closed. LI-102 Closure Statements follow:

CR CLOSURE STATEMENTS FROM LI-102:

o□The root cause or apparent cause is valid. VERIFIED
o□The specific condition is corrected or resolved. VERIFIED
o□Overall plant safety is not inadvertently degraded. VERIFIED
o□Generic implications of the identified condition are considered, as appropriate. VERIFIED
o□Actions were taken to preclude repetition, as appropriate. VERIFIED
o□Any potential operability or reportability issues identified during the resolution of the condition have been appropriately addressed. VERIFIED
o□All corrective action items are completed. VERIFIED
o□Effectiveness Reviews have been initiated via use of Learning Organization CR, when applicable. VERIFIED

Subresponse :

The new indication was evaluated by Code Programs, see the attached document. The evaluation accepts the indication as is with no repair required. The steam dryer will be inspected per the same scope in RFO27 and RFO28 per letter BVY 04-097, therefore the area of this indication will be inspected again during the next two outages.

Neil Fales 6/15/07

Closure Comments:

Entergy	**CORRECTIVE ACTION**	**CR-VTY-2007-02133**

Attachments:

Subresponse Description

Evaluation

Attachment Header

Document Name:

untitled

Document Location

Subresponse Description

Attach Title:

Evaluation

Engineering Report No. VY-RPT-07-00011 Rev 2

Entergy

ENTERGY NUCLEAR
Engineering Report Cover Sheet

Engineering Report Title:
EVALUATION OF NEW RFO26 STEAM DRYER INDICATION

Engineering Report Type:

New ☒ Revision ☐ Cancelled ☐ Superseded ☐

Applicable Site

IP1 ☐ IP2 ☐ IP3 ☐ JAF ☐ PNPS ☐ VY ☒ WPO ☐
ANO1 ☐ ANO2 ☐ ECH ☐ GGNS ☐ RBS ☐ WF3 ☐

DRN No. ☐N/A; ☒EC 1772

Report Origin: ☒ Entergy ☐ Vendor
Vendor Document No.:

Quality-Related: ☒ Yes ☐ No

Prepared by: Neil Fales/ N. F. Date: 6/15/07
Responsible Engineer (Print Name/Sign)

Design Verified/ N/A Date:
Design Verifier (if required) (Print Name/Sign)

Reviewed by: Scott Goodwin/ S D Goodwin Date: 6-15-07
Reviewer (Print Name/Sign)

Reviewed by*: N/A Date:
ANII (if required) (Print Name/Sign)

Approved by: Larry Lukens/ L Lukens Date: 6/15/07
Supervisor (Print Name/Sign)

*: For ASME Section XI Code Program plans per ENN-DC-120, if require

NEC-JH_60

STATE OF VERMONT
PUBLIC SERVICE BOARD
DOCKET NUMBER 7195

PETITION OF VERMONT DEPARTMENT OF PUBLIC SERVICE FOR AN INVESTIGATION INTO THE RELIABILITY OF THE STEAM DRYER AND RESULTING PERFORMANCE OF THE VERMONT YANKEE NUCLEAR POWER STATION UNDER UPRATE CONDITIONS.

Technical Hearing held before Board Members of the Vermont Public Service Board, at the Third Floor Conference Room, Chittenden Bank Building, 112 State Street, Montpelier, Vermont, on August 18, 2006, beginning at 9:30 a.m..

EXCERPT FROM PAGES 9-10 OF TRANSCRIPT

Redirect by John Marshall for ENVY

JOHN R. DREYFUSS- ENVY HEAD OF ENGINEERING- NOW HEAD OF NUCLEAR SAFETY ASSURANCE

SURREBUTTAL BY MR. MARSHALL:

Q. I have one question on live surrebuttal. Mr. Dreyfuss, Mr. Sherman testified yesterday that it can be difficult to distinguish IGSCC cracking related to uprate and uprate related fatigue cracking. He also testified with respect to the Department's recommendations concerning dispute resolution with respect to an extended ratepayer protection plan. Do you recall those questions and answers yesterday?

A. I do.

Q. My question is given his testimony about the difficulty of distinguishing IGSCC cracking and fatigue cracking related to uprate circumstances, does this give any concerns to the company about dispute resolution under an extended ratepayer protection plan?

A. Yes it does, and I do agree that you know it sometimes is very difficult to distinguish or differentiate between the type of cracking that you see with this intergranular stress corrosion cracking, IGSCC, and fatigue cracking. It can be particularly difficult when you're trying to do this work underwater as well.

So you know there are cases where it's clear and clean cut and the way that the kind of characteristics of this type of cracking where you can tell, but other cases that I have seen and have been brought to me you know it's less clear.

The other point that I think is important here too is that we are going to be shutting Vermont Yankee down for a refuel outage in May of next year and it's absolutely clear that we will see cracks. There were cracks before power uprate. You know we have evaluated all of them. They are not structurally significant, but there will be cracks and there can be debate about those cracks. If there's an IGSCC crack, there could be debate about whether it's IGSCC or otherwise or fatigue type of crack. So, you know, again these are not clear and easy distinctions to make in every case.

April 18, 2007

UNITED STATES OF AMERICA
NUCLEAR REGULATORY COMMISSION

Before the Atomic Safety and Licensing Board

In the Matter of	)	
	)	
Entergy Nuclear Vermont Yankee, LLC	)	Docket No. 50-271-LR
and Entergy Nuclear Operations, Inc.	)	ASLBP No. 06-849-03-LR
	)	
(Vermont Yankee Nuclear Power Station)	)	

DECLARATION OF JOHN R. HOFFMAN IN SUPPORT OF ENTERGY'S MOTION FOR SUMMARY DISPOSITION OF NEC CONTENTION 3

John R. Hoffman states as follows under penalties of perjury:

I. Introduction

1. Prior to September 2006 I was employed by Entergy Nuclear Operations, Inc. ("Entergy") and had, among other responsibilities, that of Project Manager for the License Renewal Project at the Vermont Yankee Nuclear Power Station ("VY"). I retired from Entergy's employment in September 2006. I am currently a consultant and provide this declaration in support of Entergy's Motion for Summary Disposition of New England Coalition's ("NEC") Contention 3 ("NEC Contention 3") in the above captioned proceeding.

2. My professional and educational experience is summarized in the *curriculum vitae* attached as Exhibit 1 to this declaration. Briefly summarized, I have over 37 years of nuclear power engineering experience, and have been associated with VY since 1971.

3. During my employment at VY I had no direct involvement with the power uprate implemented between 2003 and 2006. However, I have reviewed relevant materials and conducted interviews with plant personnel to familiarize myself with the manner in which steam dryer issues were addressed during the uprate process. I have personal knowledge of the manner in which VY intends to address the steam dryer during the period of extended operation.

4. NEC Contention 3 asserts that: "Entergy's License Renewal Application does not include an adequate plan to monitor and manage aging of the steam dryer during the period of extended operation." This contention lacks technical or factual basis.

5. I will demonstrate that the plan proposed by VY for monitoring and managing aging of the steam dryer during the period of extended operation is adequate and is consistent with manufacturer recommendations and the practice in the industry.

II. Background

6. In a boiling water reactor ("BWR"), the steam dryer is a stainless steel component whose function is to remove moisture from the steam before it leaves the reactor. The dryer is mounted in the reactor vessel above the steam separator assembly and is latched to the inside of the vessel wall below the steam outlet nozzles. Wet steam flows upward and outward through the dryer. Moisture is removed by impinging on the dryer vanes and flows down through drains to the reactor water in the downcomer annulus below the steam separators.

7. The steam dryer does not perform a safety function and is not required to prevent or mitigate the consequences of accidents. The VY steam dryer is a non-safety-related, non-Seismic Category I component. Although the steam dryer is not a safety-related component, the assembly is designed to withstand design basis events without the generation of loose parts and the dryer is designed to maintain its structural integrity through all the plant operating conditions.

8. On September 10, 2003, Entergy submitted its application to increase the maximum VY authorized power level from 1593 megawatts thermal ("MWt") to 1912 MWt. This power increase represented an increase of approximately 20% above original rated thermal power and was known as an "extended power uprate" or "EPU". Letter from J. Thayer to NRC, "Vermont Yankee Nuclear Power Station License No. DPR-28 (Docket No. 50-271) Technical Specification Proposed Change No. 263 Extended Power Uprate" (Sept. 10, 2003) ("EPU Application"), ADAMS Accession No. ML032580089.

9. In 2002, steam dryer cracking and damage to components and supports for the main steam and feedwater lines were observed at the Quad Cities Unit 2 nuclear power plant. These conditions were detected after implementation of an extended power uprate similar to the one proposed in 2003 for VY. It was determined that loose parts shed by the dryer due to flow-induced vibration had damaged the supports.

10. In response to this experience and to concerns about steam dryers at other nuclear power plants Entergy substantially modified the steam dryer at VY during the spring 2004 refueling outage to improve its capability to withstand potential adverse flow effects that could result from operation of the plant at EPU levels. The modifications, intended to increase the

structural strength of the dryer, are described in Attachment 2 to Supplement 8 (dated July 2, 2004) to the EPU Application, ADAMS Accession No. ML042090103.

III. VY Steam Dryer Analyses in Support of EPU

11. In addition to making substantial physical modifications to the VY steam dryer, Entergy conducted two categories of activities to assure that the structural integrity of the dryer would be maintained during EPU operations. The first category of activities included performing two types of complementary analyses to evaluate the pressure loads acting on the steam dryer during operation at EPU conditions: the computational fluid dynamics ("CFD") and acoustic circuit model ("ACM") analyses. The calculated loads obtained from the CFD and ACM analyses were inputs to a finite element model (FEM) that calculated peak stresses for specific steam dryer locations. This FEM output was then compared to the fatigue limits for the dryer material specified in the ASME Code.

12. The resulting maximum calculated stresses for EPU conditions were found to be well within the ASME fatigue endurance limit. (The endurance limit is the level of stress that a material can withstand over an infinite number of cycles without failure.) The analyses indicated that there is significant margin between the magnitude of the potential stresses imposed on the steam dryer and the level at which fatigue failure would occur.

13. Entergy also installed 32 additional strain gages on the main steam line piping during the fall 2005 refueling outage (beyond 16 strain gages installed previously). The data measured by the strain gages and other complementary instrumentation were monitored frequently during EPU power ascension to verify that the structural limits for the steam dryer were not reached. This data monitoring was accomplished as the power levels were increased towards EPU.

IV. Steam Dryer Monitoring and Inspection Program During Implementation of EPU

14. As a second set of activities intended to provide independent confirmation of the structural integrity of the steam dryer during operation at uprate levels, VY instituted a program of dryer monitoring and inspections to provide assurance that the structural loadings under EPU conditions did not result in the formation or propagation of vibration-induced cracks on the dryer. The program is described in Attachment 6 to Supplement 33 (dated September 14, 2005) to the EPU Application, ADAMS Accession No. ML052650122. The program was reviewed

and approved by the NRC and included as a license condition as part of the power uprate license amendment issued on March 2, 2006 (Exhibit 2 hereto).

15. The monitoring and inspection program measured the performance of the VY steam dryer during power ascension testing and operation as power was increased from the original licensed power level to full EPU conditions. The program included taking daily measurements of moisture carryover and periodic measurements of main steam line pressure. Pursuant to the program, following completion of EPU power ascension testing, moisture carryover measurements have continued to be made periodically, and other plant operational parameters that could be indicative of loss of steam dryer structural integrity continue to be monitored.

16. In addition to monitoring of plant operational parameters, the monitoring and inspection program calls for the steam dryer to be inspected during plant refueling outages in the fall of 2005, spring of 2007, fall of 2008, and spring of 2010. The inspections are conducted in accordance with the recommendations of General Electric's Service Information Letter ("SIL") No. 644, Revision 1 (Nov. 9, 2004), ADAMS Accession No. ML060120032 ("GE-SIL-644"). The provisions of GE-SIL-644 also govern the manner in which monitoring of plant parameters is being conducted since VY started operating at EPU levels. Plant procedures require that the periodic monitoring activities be conducted in a manner consistent with guidance in GE-SIL-644. See Exhibit 3 (VY Operating Procedure OP 0631, Appendix F).

17. The commitment to conduct dryer monitoring and inspections in accordance with the guidance of GE-SIL-644 is reflected in the above referenced license condition, proposed by Entergy in Attachment 1 to Supplement 36 to the EPU Application (October 17, 2005), ADAMS Accession No. ML052940225, and currently in effect. Entergy is committed to a program for ensuring the structural integrity of the VY steam dryer that consists of the following actions, specified in the VY operating license:

> 2e. Entergy Nuclear Operations, Inc. shall revise the SDMP [steam dryer monitoring program] to reflect long-term monitoring of plant parameters potentially indicative of steam dryer failure; to reflect consistency of the facility's steam dryer inspection program with General Electric Services Information Letter 644, Revision 1; and to identify the NRC Project Manager for the facility as the point of contact for providing SDMP information during power ascension.
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> 5. During each of the three scheduled refueling outages (beginning with the spring 2007 refueling outage), a visual inspection shall be conducted of all accessible, susceptible locations of the steam dryer, including flaws left "as is" and modifications.
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> 6. The results of the visual inspections of the steam dryer conducted during the three scheduled refueling outages (beginning with the spring 2007 refueling outage) shall be reported to the NRC staff within 60 days following startup from the respective refueling outage. The results of the SDMP shall be submitted to the NRC staff in a report within 60 days following the completion of all EPU power ascension testing.
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> 7. The requirements of paragraph 4 above for meeting the SDMP shall be implemented upon issuance of the EPU license amendment and shall continue until the completion of one full operating cycle at EPU. If an unacceptable structural flaw (due to fatigue) is detected during the subsequent visual inspection of the steam dryer, the requirements of paragraph 4 shall extend another full operating cycle until the visual inspection standard of no new flaws/flaw growth based on visual inspection is satisfied.
>
> 8. This license condition shall expire upon satisfaction of the requirements in paragraphs 5, 6, and 7 provided that a visual inspection of the steam dryer does not reveal any new unacceptable flaw or unacceptable flaw growth that is due to fatigue.

Exhibit 2 hereto at 2-4.

18. As required by the VY operating license, VY is operating under a program that provides for long-term monitoring of plant parameters potentially indicative of steam dryer failure plus inspections at three consecutive refueling outages, all in accordance with GE-SIL-644. The monitoring that has been performed since implementation of the EPU, and the inspections conducted to date, confirm that fatigue-induced cracking of the VY steam dryer is not occurring.

19. To summarize, Entergy performed two categories of activities in support of its EPU Application: on the one hand, the CFD/ ACM/ FEM and the associated measurement of stress levels by means of strain gages during power ascension; this set of activities has been completed. On the other hand, Entergy instituted a monitoring and inspection program, which was initiated during power ascension, is still ongoing, and will be in effect throughout EPU operations. The monitoring and inspection program does not rely on the CFD and ACM analyses.

V. Steam dryer aging management plan for license renewal period

A. Overview

20. In its License Renewal Application, Entergy addresses aging management of the VY steam dryer as follows:

> Cracking due to flow-induced vibration in the stainless steel steam dryers is managed by the BWR Vessel Internals Program. The BWR Vessel Internals Program currently incorporates the guidance of GE-SIL-644, Revision 1. VYNPS will evaluate BWRVIP-139 once it is approved by the staff and either include its recommendations in the VYNPS BWR Vessel Internals Program or inform the staff of VYNPS's exceptions to that document.

License Renewal Application, § 3.1.2.2.11 "Cracking due to Flow-Induced Vibration."

21. GE-SIL-644 recommends that BWR licensees institute a program for the long term monitoring and inspection of their steam dryers. It provides detailed inspection and monitoring guidelines (see SIL-644, ADAMS Accession No. ML050120032, Exhibit 4 hereto, Appendices C and D). With respect to monitoring, the guidelines call for the periodic monitoring of parameters that may be indicative of steam dryer failure, particularly moisture carryover:

> Moisture carryover should be monitored weekly:
>
> Statistically evaluate the moisture carryover data and qualitatively determine if there is a significant increasing trend that cannot be explained by changes in plant operational parameters. If an unexplained increasing trend is evident, then collect additional moisture carryover data with consideration for increasing the measurement frequency (e.g., from "once per week" to "once per day").
>
> If the latest moisture carryover measurement is greater than "mean plus 2-sigma" and this increase cannot be explained by changes in plant operational parameters, then obtain a complete set of data for the plant operational parameters (identified above). Compare the current plant operational data with the baseline data to explain the increased moisture carryover (i.e., is there steam dryer damage or not). If an increase in moisture carryover occurs immediately following a rod swap, additional moisture carryover data should be obtained to assure that an increasing trend does not exist. Note that occurrence of steam dryer damage immediately following a rod swap would be highly unlikely.

> If the increasing trend of moisture carryover cannot be explained by evaluation of the plant operational data, then initiate plant-specific contingency plans for potential steam dryer damage. If the evaluation of plant data confirms that significant steam dryer damage has most likely occurred, then initiate a plant shutdown.
>
> If there are no statistically significant changes in moisture carryover for an operating cycle, then decreasing the moisture carryover measurement frequency (e.g., from "once per week" to "once per month") may be considered, provided the highest operating power level is not significantly increased.

GE SIL-644, Rev. 1 (Nov. 2004), Appendix D at 32. As noted above, VY Operating Procedure OP 0631, Appendix F implements this guidance. This monitoring function is to continue for the balance of plant operations.

With respect to inspections, the GE guidelines establish a specific schedule for plants, like VY, that implement a power uprate:

> In addition, for plants planning on increasing the operating power level above the OLTP or above the current established uprated power level (i.e., the plant has operated at the current power level for several cycles with no indication of steam dryer integrity issues), the recommendations presented in A (above) should be modified as follows:
>
> B1. Perform a baseline visual inspection of the steam dryer at the outage prior to initial operation above the OLTP or current power level. Inspection guidelines for each dryer type are provided in Appendix C.
>
> B2. Repeat the visual inspection of all susceptible locations of the steam dryer during each subsequent refueling outage. Continue the inspections at each refueling outage until at least two full operating cycles at the final uprated power level have been achieved. After two full operating cycles at the final uprated power level, repeat the visual inspection of all susceptible locations of the steam dryer at least once every two refueling outages. For BWR/3-style steam dryers with internal braces in the outer hood, repeat the visual inspection of all susceptible locations of the steam dryer during every refueling outage.

> B3. Once structural integrity of any repairs and modifications has been demonstrated and any flaws left "as-is" have been shown to have stabilized at the final uprated power level, longer inspection intervals for these locations may be justified.

GE-SIL-644 at 7.

22. Because VY has a BWR-3 steam dryer, the details of the visual inspection program to be implemented are set forth in the corresponding section of GE SIL-644, which is Appendix C, p. 15-16. VY is implementing the above described applicable monitoring and visual inspection guidelines in GE-SIL-644.

B. Steam Dryer Monitoring and Inspection During License Renewal Period

23. The aging management program for the VY steam dryer during the twenty-year license renewal period will consist of well-defined monitoring and inspection activities that are defined in the GE SIL-644 guidelines and are identical to those being conducted during the current post-EPU phase. Steam dryer integrity will be monitored continuously via operator monitoring of certain plant parameters. VY Off-normal Procedure ON-3178 alerts the operators that any off the following events could be indicative of reactor internals damage and/or loose parts generation: a) sudden drop in main steam line flow >5%; b) >3 inch difference in reactor vessel water level instruments; c) sudden drop in steam dome pressure >2 psig. See Exhibit 5 hereto. In addition, periodic measurements of moisture carryover will be performed, and changes in moisture carryover will be evaluated in accordance with the requirements of GE-SIL-644. See Exhibit 3. This monitoring program will continue for the entire license renewal period. The inspection activities will include visual inspections of the steam dryer every two refueling outages consistent with GE and BWR Vessel Internals Program (VIP) requirements. The inspections will focus on areas that have been repaired, those where flaws exist, and areas that have been susceptible to cracking based on reactor operating experience throughout the industry.

24. The aging management plan for the license renewal period, consisting of the monitoring and inspection activities described above, does not depend on, or use, the CFD and ACM computer codes or the FEM conducted using those codes.

25. License Renewal Application, § 3.1.2.2.11 also commits to "evaluate BWRVIP-139 once it is approved by the staff and either include its recommendations in the VYNPS BWR Vessel Internals Program or inform the staff of VYNPS's exceptions to that document."

BWRVIP-139 is a 2005 industry standard developed by Electric Power Research Institute that provides steam dryer inspection and flaw evaluation guidelines. Those guidelines, currently issued in draft, are essentially the same as the ones contained in the GE SIL standard. BWRVIP-139 is currently under NRC Staff review, with an evaluation scheduled to be released in mid-2007. See http://www.nrc.gov/about-nrc/regulatory/licensing/topical-reports/under-review.html#boiling. If the guidelines in BWRVIP-139 are approved by the Staff, Entergy will evaluate any additional requirements that might result from the NRC's approval for applicability to VY. Any commitments made by Entergy will be consistent with the NRC regulatory requirements and guidance for aging management of plant components. VY has made a licensing commitment to "continue inspections in accordance with the Steam Dryer Monitoring Program, Revision 3 [i.e., the current inspection and monitoring program] in the event that the BWRVIP-139 is not approved prior to the period of extended operation." VY Licensing Renewal Commitment List, Commitment No. 37, Exhibit 6 hereto.

VI. Response to issues raised by NEC

26. NEC's consultant Dr. Joram Hopenfeld has addressed the steam dryer aging management commitment in the VY License Renewal Application as follows: "The license renewal application states at paragraph 3.1.2.2.11, and Table 3.1.2-2, that the management of cracking in the steam dryer will be in accordance with current guidance per NUREG 1801, GE-SIL-644 and possibly future guidance from BWRVIP-139, if approved by the NRC. No matter which guidance Entergy follows, the status of the existing dryer cracks must be continuously monitored and assessed by a competent engineer." Declaration of Dr. Joram Hopenfeld, dated May 12, 2006 at ¶ 19. Entergy's steam dryer aging management plan, however, does exactly what Dr. Hopenfeld requires, since it is based on continuous monitoring of plant parameters whose value is indicative of potential dryer cracking and crack propagation.

27. Dr. Hopenfeld also asserts that "Entergy's monitoring equipment does not measure crack propagation directly (because the strain gages are a distance away from the dryer) and therefore analytical tools would be required to interpret the data." Second Declaration of Joram Hopenfeld, dated June 27, 2006 at ¶ 14. The purpose of the monitoring equipment that was utilized during the EPU power ascension phase (strain gages installed on the main steam lines) was not to measure crack propagation, but to monitor pressure fluctuations in the steam piping that translate to pressure loads and ultimately to stresses on the steam dryer, to ensure that values

were below the maximum levels set by the ASME Code. The strain gages will not be used in the aging management program for the steam dryer during the license renewal period.

28. Dr. Hopenfeld also states that "Entergy has not demonstrated that the dryer will not fail and scatter loose parts in between the visual inspections, especially during design basis accidents, DBA." Id. at ¶ 15. The capability of the dryer to withstand design basis loads was demonstrated by the structural analyses and stress measurements performed as part of the EPU. It is important to note that only superficial cracks have been observed in the VY steam dryer and those cracks have not shown any measurable growth in the successive dryer inspections. Periodic visual examinations of the steam dryer in accordance with the license condition will continue to ensure that unacceptable flaw development or growth is not occurring.

29. It is also important to note that there are two types of loading imposed on the steam dryer (as well as other plant components.) There are the normal operating loads that are experienced day-in and day-out over the life of the plant. These loads are generally lower than the design basis accident loads, but because of the long time duration they can induce fatigue damage. The design basis loads are one-time loads. The purpose of the aging management process is to ensure that the condition of plant components is maintained in a status that is consistent with the design basis analyses for all plant conditions.

30. NEC asserts that "Entergy has previously used these computer models to establish a baseline for its steam dryer management program, and integrated code-based predictions into its aging management assessment. NEC's Contention 3 concerns regarding validity of these models are therefore current regardless of whether Entergy will make further use of them." New England Coalition, Inc's Opposition to Entergy's Request for Leave to File Motion for Reconsideration of NEC's Contention 3 (October 12, 2006) at 4. This assertion is incorrect. The purpose of the ACM and CFD analyses was to develop peak loads for the analysis of the steam dryer as a forward looking prediction that no unacceptable fatigue loadings would develop as a the power uprate was being implemented. The plant parameter monitoring and inspection program currently being conducted does not rely on the analyses performed during the implementation of the EPU and is sufficient to ensure satisfactory steam dryer performance during the license renewal period.

VII. Summary and Conclusions

31. My testimony in this Declaration justifies the following conclusions: (1) the steam dryer aging management plan for license renewal period proposed by Entergy is consistent with the vendor recommendations and industry guidance; (2) the monitoring and inspection activities called for in the plan are the same that the NRC has approved for assuring the structural integrity of the steam dryer during current post-EPU operation; and (3) the steam dryer aging management plan will adequately assure that the dryer's structural integrity will be maintained for all plant normal and transient operating conditions during the license renewal period.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on April 18, 2007

John R. Hoffman