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Duane Arnold Energy Center
Operated by Nuclear Management Company, LLC

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REPORT OF FACILITY CHANGES, TESTS AND EXPERIMENTS, FIRE PLAN CHANGES AND COMMITMENT CHANGES

In accordance with the requirements of 10 CFR Section 50.59(d)(2), please find enclosed the subject report covering the time period from November 1, 2001 through September 30, 2003. A summary of changes to the Duane Arnold Energy Center Fire Plan during the same time period is included, as well as a summary of commitment changes.

Should you have any questions regarding this matter, please contact this office.

Sincerely,

Mark A. Peifer
Site Vice President

Enclosure: Report of Facility Changes, Tests and Experiments, Fire Plan Changes and Commitment Changes

cc: Regional Administrator, USNRC, Region III
Project Manager
NRC Resident Inspector

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October 20, 2003
Enclosure to NG-03-0697

Report of Facility Changes, Tests and Experiments, Fire Plan Changes and Commitment Changes

Table of Contents

Section A - Plant Design Changes

This section contains brief descriptions of plant design changes completed during the period of November 1, 2001 through September 30, 2003 and summaries of the evaluations for the changes, pursuant to the requirements of 10 CFR Section 50.59(d)(2). All changes were reviewed against 10 CFR 50.59 by the Duane Arnold Energy Center (DAEC) Operations Committee.

The basis for inclusion of an Engineering Change Package (ECP) in this report is operational release of the associated modification at the DAEC during the period of November 1, 2001 through September 30, 2003. The basis for inclusion of an Engineered Maintenance Action (EMA) is completion of all the changes described in the evaluation, during the period of November 1, 2001 through September 30, 2003.

SE 98-097 (Revision 1) ECP 1610 - Radwaste Surge Tank And Ultraviolet Ozone Treatment System Addition

Description and Basis of Change

Since the DAEC committed to a policy of zero discharge of liquid radioactive effluent, a number of situations have arisen which have resulted in reduced Radwaste System capability. Often these situations have threatened to cause the plant to shutdown because sufficient open tank capacity or processing capability was not available to allow normal plant leakage to be processed and returned to the Condensate Storage Tanks. Changes were implemented to aid in dealing with the challenges of processing water generated from plant leakage while maintaining zero discharge and meeting more restrictive limits on reactor water purity. Condensate resins which were transferred to the Condensate Phase Separator Tanks have been used to remove turbidity and conductivity from floor drain water prior to processing through the radwaste filters and demineralizers. This is accomplished by "blowing down" high turbidity, high conductivity water to the Condensate Phase Separators and recirculating this water with the Spent Condensate Resins, completely utilizing the remaining ion exchange capacity of the resin and increasing the crud loading on the resin. Influent sources have been strictly controlled as well. Mop water, which is a significant source of Total Organic Carbon (TOC), conductivity, and turbid water, was barreled and evaporated in the Low Level Radwaste Processing and Storage Facility (LLRPSF) using drum heaters. While this process was extremely effective, it was very labor intensive.

ECP 1610 installed a 70,000 gallon capacity tank in the LLRPSF. The new tank has a parallel connection with the existing surge tank. An Ultraviolet Ozone (UVO_3) Treatment System was also installed in the LLRPSF and a holding tank of about 600 gallons capacity was installed in the LLRPSF Sump Room.

The following additional activities were also performed:

- Removed (abandoned in place) Centrifuge System equipment from the Centrifuge Room.
- Ozone generators of the UVO_3 System require a cooling water flow of 3 GPM at 55 ^{0}F. This was accomplished by connecting to the existing Well Water Cooling System in the Radwaste Building.
- Installed a (chain link) barrier in the Centrifuge Room, in front of the resin transfer valve station, to allow reduction in the Locked High Radiation Boundary.
- A portion of the LLRPSF's north wall was removed to gain access to the room for the tank and the UVO_3 System installation. These removable portions of the walls were constructed with hollow masonry blocks which were solid filled and reinforced. Upon completion of the installation activities, this wall was reinstalled back to its original configuration. Barriers were installed on room penetrations per directions from Plant Security for the interim period of equipment installation.

Evaluation Summary

These changes enhanced DAEC's performance in the areas of liquid radwaste storage and treatment in TOC reduction. The equipment introduced by this modification is not an initiator of any accident. This modification did not increase the probability of occurrence of an accident evaluated previously in the Safety Analysis Report (SAR). The tank and the pressure retaining components of the UVO_3 System including associated piping were designed, fabricated, and installed to be consistent with the design requirements of safety class 3 components. Therefore, there is reasonable assurance that these components will not result in any leakage and the modifications will not increase the consequences of an accident evaluated previously in the SAR. The probability of occurrence of a malfunction of equipment important to safety evaluated previously in the SAR was not increased. The integrity of

liquid radwaste is required to prevent an excessive rate of leakage of liquids to the environs. Protection against accidental discharge is provided by instrumentation for the detection and alarm of abnormal conditions and procedural controls. Since these controls were not changed, this modification did not increase the consequences of a malfunction of equipment important to safety evaluated previously in the SAR. The Radwaste and the LLRPSF buildings are able to handle a major leak in the largest tank without permitting significant quantities of the liquid to escape off the site. These modifications did not create the possibility of an accident of a different type than any evaluated previously in the SAR, and the possibility of a malfunction of equipment important to safety of a different type than any evaluated previously in the SAR was not created. The Technical Specifications do not specify any margin of safety for the Liquid Radwaste System or its components. Also, no surveillance tests are specified for the existing components or the components added by this modification. There were no changes required to the Offsite Dose Assessment Manual (ODAM). Therefore, this activity did not reduce the margin of safety as defined in the basis for any Technical Specification. No unreviewed safety question was identified.

SE 99-011 Replacement of Main Steam Line Temperature Indicating Switches

Description and Basis of Change

The analog Main Steam Line Steam Leak Detection temperature indicating switches were replaced under an EMA with digital switches. This change was made due to the analog switches reaching the end of their useful life. The temperature indicating switches are designed to detect a leak in the main steam line piping that does not produce a high enough flow rate to trip the main steam line high flow switches or sufficiently depressurize the steam line to trip the main steam line low pressure switches. The temperature indicating switches are located outside of the main control room, and do not require operator intervention or affect the operator burden during normal or off-normal conditions. The new digital switches are designed to have low malfunction and failure rates as a result of the increased reliability of the digital components, and are qualified for the environmental and seismic conditions. The new digital switches also use printed-circuit boards and connectors only, eliminating the wiring harness which is subject to age-related degradation and shorts.

Evaluation Summary

Replacement of the analog temperature indicating switches with digital temperature indicating switches did not affect the probability of occurrence of a main steam line leak or break evaluated previously in the SAR. The temperature indicating switches are designed to detect a leak in the main steam line piping and initiate isolation prior to the leak increasing to the point of a line break. Additionally, a control room alarm is initiated based on high ambient or high differential temperature in the steam tunnel to alert operators of a condition that may indicate a steam leak. A steam line break would still be detected and isolated by the main steam line high flow switches or the main steam line low pressure switches. The temperature indicating switches are located outside of the main control room, and do not require operator intervention or affect the operator burden during normal or off-normal conditions. This activity did not increase the consequences of an accident evaluated previously in the SAR. The digital switches contain filtering on the input power line, and relay spike suppression on the output relay coils, so that electromagnetic interference will not be transmitted through the input or output cabling. The digital switches also have the firmware permanently stored on a programmable read-only memory (PROM), which is not user-alterable, and contains a watchdog timer that monitors the operation of the unit. If the unit's self-test sequence does not see the expected signals, a command is issued to initiate a system reset. Based on the installed experience base and the extensive qualification testing, the replacement temperature indicating switches are expected to be as reliable or more reliable than the analog instruments. Therefore, the probability of occurrence of a malfunction in the main steam line temperature indicating switches is not increased. The inadvertent closure of all MSIVs is analyzed each operating cycle as part of the reload analysis. This activity did not increase the consequences of a malfunction previously evaluated. The analog switches were and the replacement digital switches are configured to trip on loss of power or burnout of a sensor. The temperature indicating switches are powered from the Group 1 isolation logic, which in turn is powered by the Reactor Protection System (RPS) motor-generator (M-G) sets and/or the alternate supply. The loads receiving power from the RPS power supplies are protected against degraded electrical conditions by the electrical protection assemblies (EPAs). The possibility of an accident of a different type than any evaluated previously in the SAR is not created. The design of the digital temperature indicating switches has been thoroughly reviewed and evaluated. The

software has been independently verified for use. The software is not user-alterable, and is monitored during operation, so that software common-cause failure is not credible. The digital units are fully qualified for the environment in which they will be installed and operated, and will not have an adverse effect on any other equipment. The possibility of a malfunction of equipment important to safety of a different type than any previously evaluated was not created. This activity did not reduce the margin of safety as defined in the basis for any Technical Specification. The number of temperature elements providing signals to the temperature indicating switches is unchanged. The replacement digital temperature indicating switches are configured in the same one-out-of-two-twice logic as the analog switches, with identical set points. The replacement switches, which have a user-definable time delay were verified to have that trip time delay set to zero. The configuration settings are demonstrated through the normal surveillance process. The switches also have an inherent time delay that results from polling the inputs. This time delay, approximately 1.5 seconds, does not affect any margin of safety, because the time required to initiate a trip varies with the size of the leak and there is no specified response time associated with the leak detection system. Therefore, the margin of safety to 10 CFR 20 and 10 CFR 100 dose limits is unchanged. No unreviewed safety question was identified.

SE 00-014 ECP 1630 – Penetration Upgrade/Replacement

Description and Basis of Change

This change replaced low voltage power and control drywell electrical penetrations. Two of the four original construction low voltage power and control drywell electrical penetrations exhibited degradation. This degradation was in the form of short circuit failures between conductors within the penetration assemblies. These failures were self-identifying and rendered associated circuits inoperable. The basic function of these penetrations is to provide means for the passage of electrical power, control, and instrumentation signals through the containment wall while maintaining containment integrity. The replacement assemblies are more flexible in design, have a track record of proven reliability, and are fully qualified to modern standards of the nuclear industry and are designed to meet the standards required by DAEC.

Evaluation Summary

The probability of occurrence of an accident evaluated previously in the SAR was not increased. The replacement penetration assemblies meet the required design criteria to perform during normal and defining accident conditions (Loss Of Coolant Accident). Plant conditions are maintained within the range of conditions assumed by DAEC Accident Analyses. This change did not increase the consequences of an accident previously evaluated in the SAR and the probability of occurrence of a malfunction of equipment important to safety evaluated previously in the SAR was not increased. Since conditions resulting from this change are an improvement in reliability and are within the range of initial conditions assumed by DAEC transient analyses, the consequences of a malfunction of equipment important to safety evaluated previously in the SAR were not increased. No new means for bypassing or failing radiological barriers that could result in off-site doses were created. Therefore, the possibility of an accident of a different type than those described in the SAR was not introduced. No physical change was made to other system components or to control devices that would cause them to fail in a manner different than already postulated. The equipment installed fulfills all the required safety functions for accidents previously evaluated in the SAR. This change did not add equipment with any new failure modes. Therefore, the possibility of a malfunction of equipment important to safety of a different type than described in the SAR was not introduced. Since this activity involved only the replacement of penetration assemblies with more reliable and qualified penetration assemblies, the margins of safety as defined in the basis for Technical Specifications were not reduced. No unreviewed safety question was identified.

SE 00-023 (Revision 1) Replacement of Offgas Hydrogen Analyzers

Description and Basis of Change

The purpose of this Safety Evaluation was to evaluate the installation of replacement offgas hydrogen analyzers. The Offgas System does not provide a nuclear safety function. The Offgas and Recombiner System receives the noncondensible gases removed from the main condenser during operation. The recombination process of the Offgas System recombines the radiolytic hydrogen and oxygen to eliminate potential downstream hydrogen gas explosions and to reduce the gas volume to be treated. The function of the offgas hydrogen analyzer is to monitor hydrogen in the Offgas System downstream of the recombiner to ensure that an

explosive concentration does not go undetected. This also ensures the recombiner is functioning properly. An EMA was used to replace the hydrogen analyzers.

Evaluation Summary

None of the criteria specified in the Design Basis Documents (DBDs) were affected by this activity. All of the accidents in the Updated Final Safety Analysis Report (UFSAR) were reviewed with respect to this activity and none of the accidents were affected. The offgas hydrogen analyzers are passive components that monitor the hydrogen concentration in the Offgas System downstream of the offgas recombiner. The Offgas System and the offgas hydrogen analyzers have no nuclear safety functions. The replacement offgas hydrogen analzyers perform the same function as the original analyzers. Therefore, there are no credible ways of increasing either the probability of occurrence of an accident or the consequences of any of the accidents evaluated in the SAR. The offgas hydrogen analyzers provide indication and alarm of hydrogen concentration in the Offgas System downstream of the recombiner. This ensures that the recombiner is functioning properly. There are no credible failures that could increase either the probability of occurrence or the consequences of a malfunction of equipment important to safety as evaluated in the SAR. Since there is no tie to any safety systems by the passive offgas hydrogen analyzers, there is no possibility of the replacement of the offgas hydrogen analyzers affecting the operation of any safety systems. There are no credible failures that could create the possibility of an accident not previously evaluated or increase the possibility of malfunction to any equipment important to safety not previously evaluated. The replacement of the offgas hydrogen analyzers did not adversely impact the operation of the Offgas System. This activity did not affect Technical Specifications. The margin to safety as defined in the basis of any Technical Specification was not reduced. No unreviewed safety question was identified.

SE 00-033 Relocation of Reactor Water Cleanup (RWCU) Filter Demineralizer (F/D) Temperature Switch

Description and Basis of Change

Per an EMA, a thermowell was installed downstream of the RWCU non-regenerative heat exchanger outlet isolation valve and the temperature switch for RWCU F/D inlet high temperature was

relocated to the new thermowell. This switch actuates an annunciator in the Control Room for RWCU F/D inlet water high temperature. The annunciator gives the Control Room indication that temperature is increasing before RWCU isolates. The temperature switch was previously located upstream of the RWCU non-regenerative heat exchanger outlet isolation valve, which was a stagnant part of the RWCU System. This prevented the switch from monitoring the true inlet temperature for the RWCU F/D.

Evaluation Summary

The F/D portion of RWCU has no safety function. All of the design criteria were reviewed with respect to this activity. None of the criteria specified in the DBDs were affected by this activity and the modification meets or exceeds all of the design requirements. None of the accidents previously evaluated in the SAR were affected by the installation of a thermowell and relocation of the RWCU F/D inlet high temperature switch. The probability of occurrence of an accident and the consequences of any of the accidents evaluated in the SAR were not increased as a result of this activity. The thermowell is only required for pressure boundary when the RWCU Inlet Inboard Isolation, RWCU Suction Outboard Isolation, and RWCU Return Header Outboard Isolation valves are open. Both the thermowell and temperature switch are non-safety related and can in no way impact the operation of any safety related equipment. This activity could not increase either the probability of occurrence or the consequences of a malfunction of equipment important to safety as evaluated in the SAR. The only possible failure modes would be for the thermowell to leak and the temperature switch to fail. The thermowell was designed to the required specifications. This failure type would not create an unanalyzed accident. The temperature switch actuates an annunciator in the control room and does not perform any automatic functions. Therefore the failure of the temperature switch could not cause an accident. The possibility of an accident of a different type than any previously evaluated, and the possibility of a malfunction of equipment important to safety of a different type than any evaluated previously in the SAR were not created. There is no reference to RWCU F/D inlet high temperature or the RWCU System in the basis for any Technical Specification. Therefore, installing a thermowell and relocating the temperature switch for RWCU F/D inlet high temperature did not reduce the margin of safety as defined in the basis for any Technical Specification. No unreviewed safety question was identified.

03-001 (Revision1) Modification To Allow For Monitoring Biofouling Growth In The River Water Supply System

Description and Basis of Change

This activity completed a design document change for the River Water Supply (RWS) System by altering the RWS pumps' Discharge Sample Line Supply Isolation Valves from normally closed to normally open. This allows the Zebra Mussel Monitor Holding Tank, to be used to monitor for growth of Bryozoa. In addition, an Operating Instruction was also changed and a Plant Chemistry Procedure was written to allow operation of these valves as necessary to support sampling operations. These changes allow use of the Zebra Mussel Monitoring Tanks to monitor for growth of Bryozoa as an early warning to allow remedial actions before this growth can threaten to plug the safety related raw water systems, Residual Heat Removal Service Water (RHRSW) and Emergency Service Water (ESW).

Evaluation Summary

This change did not affect any accident initiators. The change did not affect the ability of the RWS System to fulfill its safety function and therefore did not increase the frequency of occurrence of an accident previously evaluated in the UFSAR. Although this change increased the potential for a leak out of the non-safety related, non-seismic piping downstream from the River Water Supply pumps' Discharge Sample Line Supply Isolation Valves during an earthquake, this amount of leakage would not threaten the ability of the RWS System to perform its safety function. Therefore, the likelihood of a failure of the RWS System was not increased. If the non-seismic, nonsafety-related piping downstream of the now normally open valves were to fail, equipment in close proximity could be sprayed with the water leakage. Because an 18 inch pipe would shield most of the water spray from any leakage that occurred (except for the security card readers and emergency lighting) and because of the distance from these components and the low pressure of the water spray, there is no more than a minimal increase in the likelihood of a malfunction of this equipment. Additionally, no area flooding would occur because of the drain area provided by the deck plating around the RWS pump suction pipes. Since the RWS System is still able to perform its safety function for every accident for which it is credited even with a break in the piping downstream of the RWS pumps' Discharge Sample Line Supply Isolation Valves, there is no increase in the consequences of any accident. This change did not increase the

amount of fuel failures likely to occur if the RWS System were to fail to perform its safety function. This change did not result in any increase in the consequences of a malfunction of a Structure, System or Component (SSC) important to safety. This change merely opened two small (one inch) previously closed valves to allow a small amount of sample flow (no more than 10 gpm) through the Zebra Mussel Monitoring Tanks in the Intake Structure. A failure of the RWS System could still occur but this change will not increase that likelihood of failure. Therefore, this change did not create the possibility of a different type of accident from that previously evaluated in the UFSAR. The possibility for a malfunction of a SSC important to safety with a different result than previously evaluated in the UFSAR was not created. This change did not affect any Design Basis Limit for Fission Product Barrier (DBLFPB)s. The RWS System supports the Containment Cooling and Emergency Service Water Systems. This change does not prevent the RWS System from providing the required flow rate to these systems. This change did not result in any DBLFPB being exceeded or altered. This change did not affect any method of evaluation. Therefore, this activity did not require prior NRC approval.

Section B - Procedure/Miscellaneous Changes

This section contains brief descriptions of Procedure/Miscellaneous changes completed during the period November 1, 2001 through September 30, 2003 and summaries of the evaluations for those changes, pursuant to the requirements of 10 CFR Section 50.59(d)(2). All changes were reviewed against 10 CFR 50.59 by the Duane Arnold Energy Center (DAEC) Operations Committee.

02-001 Revisions To Environmental Qualification (EQ) Program Documents

Description and Basis of Change

The purpose of this evaluation was to review the changes to two EQ Program documents: (1) Environmental Service Conditions Analysis, and (2) Environmental and Seismic Service Conditions. This activity only incorporated the changes in the environmental conditions due to the extended power uprate (EPU) to 120% original rated thermal power (ORTP). While the EPU changes were reviewed in the NRC SER, some calculations and analyses for the EPU involved a change of methodology that needed to be explained. The methodology used in the analyses for high-energy line break outside containment was a departure from the method used before, and it is not explicitly stated in the safety evaluation for the EPU. This evaluation only addressed the change of methodology.

Evaluation Summary

High Energy Line Break (HELB) Outside Containment:

For the liquid line breaks, the calculation of record prior to EPU assumed saturated liquid blowdown conditions for all postulated line breaks including critical cracks (CCs). Based on the evaluation of saturated liquid blowdown, the calculations for all double-ended breaks (DEBs) prior to EPU (at 104.1% ORTP) bounds those at 120% ORTP. This is because the dome pressure remains unchanged from 104.1% ORTP to 120% ORTP.

For the RWCU CCs, it was determined that the analyses should be based on subcooled liquid condition in accordance with the currently accepted methods. (Also, DAEC calculation shows that the liquid is at subcooled condition for CCs at the time of blowdown). The environmental conditions resulting from RWCU critical crack analysis for the EPU are based on the above change

in the assumption. The new assumption is more conservative than the earlier assumption because the calculated break flow with subcooled liquid is larger than that calculated with saturated fluid. In addition, the EPU analyses used GOTHIC computer code while the previous analyses used PCFLUD code. GOTHIC is approved for use in safety related applications under the DAEC Software Quality Assurance Program. Benchmarking of this software was performed by DAEC against a previous HELB analysis using PCFLUD. It was concluded that the results of the GOTHIC model were in close agreement with the results of PCFLUD.

DBA LOCA and HELB Inside Containment:

The UFSAR subsection for pipe ruptures within the reactor shield indicates that the differential pressure analyses were made with Bechtel computer program COPRA to calculate the transient pressure responses of two containment compartments during a LOCA.

For the EPU, the short-term containment analysis was performed using the DAEC design and licensing bases methodology that was used prior to EPU. However, the long-term containment analysis was performed using the same methodology as was used for other power uprates, which had been reviewed and approved by the NRC. The analyses were performed in accordance with NRC guidance using GE codes and models. The M3CPT code to model the short-term, and the SHEX code to model the long-term containment pressure and temperature response were used for the EPU. The analyses using the above codes and models were acceptable to the NRC as documented in the Safety Evaluation for License Amendment No. 243.

It was concluded that the change in the method of analysis is either more conservative (for HELB outside containment) or is acceptable to the NRC (DBA LOCA & HELB inside containment), and does not adversely affect the safety analysis. No activity requiring prior NRC approval per 10 CFR 50.59 was identified.

02-002 Residual Heat Removal Service Water (RHRSW) System Strainer Bypass

Description and Basis of Change

Plant procedures did not provide clear direction for use of the RHRSW strainer bypass lines to assist in maintaining RHRSW strainer differential pressure within limits while delivering the

required RHRSW System flowrate. This resulted in RHRSW loops being declared inoperable when the RHRSW strainer differential pressure exceeded procedural limits. The scope of this activity is to provide direction to plant operators to bypass the RHRSW strainer, during severe water fouling conditions as necessary to maintain the RHRSW System flow or strainer differential pressure requirements within design limits.

Evaluation Summary

The RHRSW System and Residual Heat Removal (RHR) System (suppression pool cooling mode) are not accident initiators and do not contribute to the frequency of occurrence of an accident previously evaluated. Therefore, this activity did not result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated. The RHRSW System is a SSC important to safety. The ability to pass the minimum required flowrate through the RHR heat exchanger, and indirectly remove the required heat load, is a safety function in support of the RHR containment cooling mode. Criteria have been established to ensure heat exchanger effectiveness will be maintained above that assumed in the accident analysis, whenever the RHRSW strainer is bypassed. In addition, long-term heat exchanger effectiveness is assured through augmented performance testing, inspection and cleanings, whenever the RHRSW strainer is bypassed. Therefore, bypassing of the RHRSW strainer does not result in more than a minimal increase in the likelihood of occurrence of a malfunction of a SSC important to safety previously evaluated. This activity did not result in more than a minimal increase in the consequences of an accident previously evaluated, and it did not result in more than a minimal increase in the consequences of a malfunction of a SSC important to safety previously evaluated. The RHRSW System is a manually initiated support system for the RHR System. Its only safety function is to mitigate an event that is already in progress. The only other times the system is routinely operated during power operations is for surveillance testing or to support a Technical Specification Limiting Condition For Operation and its Required Actions during periods of high suppression pool temperature. In none of these activities will the RHRSW System be operated in a fundamentally different way (i.e., higher discharge pressure or flowrate). Therefore, this activity did not create the possibility for an accident of a different type than previously evaluated. The existing safety analysis was considered to be bounding, as it assumes the complete loss of one train/subsystem of RHRSW. Therefore, this activity did not create the possibility for a malfunction of a SSC

important to safety with a different result than any previously evaluated. The RHRSW System functions to support heat removal from the Primary Containment during the Design Basis Accident to maintain the containment temperature, and ultimately pressure, within their design limits. Adequate compensatory measures have been put into place to ensure that the RHRSW System continues to meet its safety analysis assumptions with the strainer(s) bypassed. RHRSW System operation with the strainer bypassed will continue to ensure that this design differential pressure between the RHRSW and RHR Systems is maintained. Therefore, the DBLFPB will not be exceeded or altered. This activity did not affect the existing method of evaluation of the RHR System heat removal function. The design basis for the system was not modified. Therefore, the evaluations used to develop the acceptance criteria for allowable operation with the strainer bypassed do not constitute new or different methods from those used in the UFSAR for establishing the design basis. Therefore, this activity did not require prior NRC approval.

Section C – Tests and Experiments

This section contains a brief description of Tests completed during the period beginning November 1, 2001 through September 30, 2003. The Tests were reviewed against 10 CFR 50.59 by the DAEC Operations Committee. No experiments were conducted during this time period.

SE 01-026 (Revision 1) SpTP 202 Cycle 18 Power Ascension Test to 1790 MWth

Description and Basis of Change

This special test confirmed acceptable plant performance for operation at power levels up to 1790 MWth, following plant modifications in RFO17 installed to support uprated power levels to 1912 MWth. This test provided baseline testing up to 1790 MWth and will be used to predict the outcome of similar testing at uprated power levels of 1791 MWth to 1912 MWth. This testing is very similar to that performed as part of the original plant startup test program described in the UFSAR and nearly identical to that performed by SpTP 201, which provided baseline data collection at power levels up to 1658 MWth. Because no plant modifications are being made as part of this testing and no plant equipment is being operated outside its design envelope, this testing is consistent with the original plant design and licensing basis including Technical Specification Change Request (TSCR) 042 for power uprate.

Evaluation Summary

In general, these are routine testing and surveillance activities that pose no additional risk beyond that previously assumed. Strict controls were applied to any special testing requirements and limits were set to stop the test should unanticipated results be encountered. This activity did not result in more than a minimal increase in the frequency of occurrence of an accident previously evaluated in the UFSAR. No plant equipment was operated in an abnormal manner as part of any test sequence. No additional jumpers, lifted leads, or unique system/valve lineups were required by this testing. Therefore, this activity did not result in more than a minimal increase in the likelihood of occurrence of a malfunction of a SSC important to safety previously evaluated in the UFSAR. All Technical Specification limits approved by the NRC were maintained. Individual tests that manipulated plant equipment were performed independently from other such testing. Thus, the consequences of any unanticipated plant transient were bounded

by the analyses performed in support of TSCR-042 and approved by the NRC. Therefore, this activity did not result in more than a minimal increase in the consequences of an accident previously evaluated in the UFSAR. No plant equipment was operated in an abnormal manner, and all safety related equipment had been analyzed, in support of TSCR-042, to perform acceptably at power levels above 1658 MWth, up to 1912 MWth. If an equipment malfunction had occurred during this testing, the consequences would have been no worse than that analyzed in support of TSCR-042 and approved by the NRC for operation at power levels above 1658 MWth, up to 1912 MWth. Therefore, this activity did not result in more than a minimal increase in the consequences of a malfunction of a SSC important to safety evaluated previously in the UFSAR. This activity did not create a possibility for an accident of a different type than any evaluated previously in the UFSAR, and the possibility for a malfunction of a SSC important to safety with a different result than any evaluated previously in the UFSAR was not created. The effect of increasing reactor power above 1658 MWth, up to 1912 MWth was analyzed in support of TSCR-042 and reviewed and approved by the NRC as part of the License Amendment allowing Power Uprate. These analyses show that at power levels up to 1912 MWth, the DAEC Design Basis Limit Fission Product Barriers are not exceeded or altered. Therefore, this activity did not result in a design basis limit for a fission product barrier as described in the UFSAR being exceeded or altered. Performance of this test did not represent a change in any method of evaluation described in the UFSAR or described in TSCR-042. This activity did not require prior NRC approval.

Section D - Fire Plan Changes

The information contained in this section identifies and briefly describes changes to the DAEC Fire Plan during the time period beginning November 1, 2001 through September 30, 2003.

Revision 40

Changed Cardox surveillance requirement, FPSR 12.1.D.1.2, to perform functional test of Cardox CO2 thermal detectors frequency from 6 months to 1 year to reflect changes to NFPA standard and NEIL requirements.

Improved the examples that demonstrate the Improved Technical Specifications format to match those occurrences that could occur with fire protection systems.

Improved wording in required actions to provide positive direction for Control Room actions and proper formatting.

Revision 41

Removed Level Indicators LI4396A, LI4396B, LI4541, and Pressure Indicators PI4590A and PI4590B from Table 12.1-2. The operability requirements for these instruments can be found within the Technical Requirements Manual or Technical Specifications and do not require duplicate operability requirements within the Fire Plan.

Revision 42

Revised the operability requirements for Temperature Recording Switch TRS1945 to identify that Temperature Element TE1945D is the only instrument required, the remaining instruments are not credited for 10 CFR 50 Appendix R compliance.

Revision 43

Removed the allowance to have individual fire detectors inoperable within the control room back panel cable spreading area and still consider the system operable to reflect the results of an evaluation to the NFPA code of record.

Revision 44

Eliminated portions of section 1.0 PURPOSE related to NRC commitments which are duplicated with the DAEC UFSAR, which is a higher level document.

Revision 45

Changed Reference 3.13 to DAEC Fire Protection Training Program Description deleting the reference to the Training Department Administrative Procedure (TDAP) 1863.

Revision 46

In section FP 11.4, *Fire Plan Frequency,* changed reference to section 3.0 and FPSR 3.0.1, 3.0.2 and 3.0.3. These were typographical errors and should be section 12.0 and FPSR 12.0.1, 12.0.2 and 12.0.3, respectively.

Revision 47

Added information to the BASES section regarding the exclusive use of fire watches as a compensatory measures to formalize the guidance and information provided by NRC Information Notice 97-48.

Section E - Commitment Changes

The information contained in this section identifies and briefly describes commitment changes that were made during the period beginning November 1, 2001 through September 30, 2003. The changes described are being reported per the Nuclear Energy Institute's "Guidelines for Managing NRC Commitment Changes", dated July 1999.

AR 28099 In NG-90-2088, *Root Cause and Corrective Action Plan regarding the Operator Requalifiction Training Program*, dated August 25, 1990, from D. Mineck (Iowa Electric Light and Power Company) to A.B. Davis (NRC), a corrective action taken was to provide 80 hours of simulator time per year during Licensed Operator Requalification training. It has since been determined that providing 80 hours of simulator training per year is difficult given the limitations of time and available resources. The emphasis is better placed on the quality of training, rather than the quantity. Industry standards, as outlined in INPO 86-025, *Guidelines for Continuing Training of Licensed Personnel*, require a minimum of 60 hours of time in the simulator for Licensed personnel. Subsequently, Licensed Operator Requalification Training now requires a minimum of 60 hours of training per year in the simulator.

AR 28100 In NG-86-1477, *Response to Generic Letter 86-04, Policy Statement on Engineering Expertise On Shift*, dated May 14, 1986, from D. Wilson (Iowa Electric Light and Power Company) to H. Denton (NRC), Response to Question 1 states, all Shift Technical Advisors (STAs) must successfully complete a forty-two (42) week hot licensing training course. This has since been revised to require all STAs must successfully complete an STA Training Course. As discussed in Generic Letter 86-04, each nuclear power plant was required to have on duty an STA whose function was to provide engineering and accident assessment advice to the Shift Supervisor in the event of abnormal or accident conditions. The STA was required to have specific training in plant response to transients and accidents. The STA-specific training course provides this training to the STA candidate in a more appropriate and effective manner by allowing the student to focus on these areas rather than operator skills.

AR 27456 A corrective action in LER 89-007-01, *Isolation of the High Pressure Coolant Injection System on High Steam Flow Due to an Improper Speed Control Signal From Turbine Governor (Woodward EG-M)*, required replacement of the High Pressure Coolant Injection (HPCI) and Reactor Core Isolation Cooling (RCIC) EG-M

boxes, chassis, and printed circuit boards every four refueling outages. Subsequently, this commitment has been revised to require replacement of the HPCI and RCIC EG-M boxes every ten years. The EG-M box includes the EG-M chassis and all the circuit boards. EPRI recommends a scheduled replacement frequency of seven to fourteen years based on the capacitor life. A ten year replacement frequency also matches the replacement frequency based on the capacitor replacement program. The probability of failure is decreased by this change since the probability of failure introduced by human error during replacement is higher than the probability of equipment failure had no replacement occurred.