August 25, 2009

Mr. Gene St. Pierre
Vice President, North Region
Seabrook Nuclear Power Plant
NextEra Energy Seabrook, LLC
c/o Mr. Michael O'Keefe
P.O. Box 300
Seabrook, NH 03874

SUBJECT: SEABROOK STATION - NRC EXAMINATION REPORT 05000443/2009301

Dear Mr. St. Pierre:

On July 19, 2009, the U.S. Nuclear Regulatory Commission (NRC) completed an examination at Seabrook Station. The enclosed report documents the examination findings, which were discussed on August 12, 2009, with Mr. Kerry Wright of your staff.

The examination included the evaluation of four applicants for reactor operator licenses, seven applicants for instant senior operator licenses and two applicants for upgrade senior operator licenses. The written and operating examinations were developed using NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," Revision 9, Supplement 1. The license examiners determined that five of the thirteen applicants satisfied the requirements of 10 CFR Part 55, and the appropriate licenses were issued on July 31, 2009.

Two applicants for instant senior operator licenses passed their exams but their licenses are being held based on their written exam grades. Licenses for applicants with written exam passing grades of 82 percent or below are normally held for review until those applicants who failed the examination have had an opportunity to appeal their license denials. Also, one of these two instant senior operator license applicants will not be issued a license until you certify in writing that he has acquired all of the training and experience for which he was previously granted a waiver. The remaining six applicants (one reactor operator applicant, four instant senior operator applicants and one upgrade senior operator applicant) failed the written portion of their exams and were denied a license.

No findings of significance were identified during this examination.

In accordance with 10 CFR 2.390 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/

Samuel L. Hansell, Jr., Chief
Operations Branch
Division of Reactor Safety

Enclosure:
NRC Examination Report 05000443/2009301

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Sincerely,

/RA/

Samuel L. Hansell, Jr., Chief
Operations Branch
Division of Reactor Safety

Enclosure:
NRC Examination Report 05000443/2009301

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A. Khanpour, Vice President, Engineering Support
M. Warner, Vice President, Nuclear Plant Support
M. Mashhadi, Senior Attorney, Florida Power & Light Company
M. Ross, Managing Attorney, Florida Power & Light Company
M. O’Keefe, Manager, Licensing Manager
P. Freeman, Plant General Manager
K. Wright, Manager, Nuclear Training
S. Colman, FEMA, Region I
Office of the Attorney General, Commonwealth of Mass
K. Ayotte, Attorney General, State of NH
O. Fitch, Deputy Attorney General, State of NH
P. Brann, Assistant Attorney General, State of Maine
R. Walker, Director, Radiation Control Program, Dept. of Public Health, Commonwealth of MA
C. Pope, Director, Homeland Security & Emergency Management, State of NH
R. Hughes, Director, Licensing and Performance Improvement
J. Giarrusso, MEMA, Commonwealth of Mass
D. O'Dowd, Administrator, Radiological Health Section, DPHS, DHHS, State of NH
J. Roy, Director of Operations, Massachusetts Municipal Wholesale Electric Company
T. Crimmins, Polestar Applied Technology
R. Backus, Esquire, Backus, Meyer and Solomon, NH
Town of Exeter, State of New Hampshire
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S. Comley, Executive Director, We the People of the United States
R. Shadis, New England Coalition Staff
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EXAMINATION REPORT

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Dockets:	50-443
Licenses:	NPF-86
Report :	05000443/2009301
Licensee:	NextEra Energy Seabrook, LLC
Facility:	Seabrook Station
Location:	P.O. Box 300, Lafayette Road Seabrook, NH 03874
Dates:	June 12, 2009 (Written Exam Administration June 15 – 19, 2009 (Operating Test Administration) July 20 – 31, 2009 (NRC Examination Grading)
Inspectors:	P. Presby, Chief Examiner, Operations Branch D. Silk, Senior Operations Engineer G. Johnson, Operations Engineer S. Garchow, Senior Operations Engineer
Approved By:	Samuel L. Hansell, Jr., Chief Operations Branch Division of Reactor Safety

SUMMARY OF FINDINGS

ER 05000443/2009301; June 12-19, 2009; Seabrook Station; Initial Operator Licensing Examination Report.

NRC examiners evaluated the competency of four applicants for reactor operator (RO) licenses, seven applicants for instant senior reactor operator (SROI) licenses and two applicants for upgrade senior reactor operator (SROU) licenses at Seabrook Station. The facility licensee developed the examinations using NUREG-1021, "Operator Licensing Examination Standards for Power Reactors," Revision 9, Supplement 1. The written examination was administered by the facility on June 12, 2009. NRC examiners administered the operating tests on June 15 - 19, 2009. The license examiners determined that three RO license applicants, one SROI license applicant and one SROU license applicant satisfied the requirements of 10 CFR Part 55, and the appropriate licenses have been issued.

Two SROI license applicants passed their exams but their licenses are being held based on their written exam grades. Licenses for applicants with written exam passing grades of 82 percent or below are normally held for review until those applicants who failed the examination have had an opportunity to appeal their license denials. Also, one of these two SROI license applicants will not be issued a license until the facility certifies in writing that the applicant has acquired all of the training and experience for which he was previously granted a waiver. The remaining six applicants (one RO, four SROI and one SROU) failed the written portion of their exams and were denied a license.

A. NRC-Identified and Self-Revealing Findings

No findings of significance were identified.

B. Licensee-Identified Violations

None.

REPORT DETAILS

4. OTHER ACTIVITIES (OA)

4OA5 Other Activities (Initial Operator License Examination)

.1 License Applications

a. Scope

The examiners reviewed all thirteen license applications submitted by the licensee to ensure the applications reflected that each applicant satisfied relevant license eligibility requirements. The applications were submitted on NRC Form 398, "Personal Qualification Statement," and NRC Form 396, "Certification of Medical Examination by Facility Licensee." The examiners also audited three of the license applications in detail to confirm that they accurately reflected the subject applicant's qualifications. This audit focused on the applicant's experience and on-the-job training, including control manipulations that provided significant reactivity changes.

b. Findings

No findings of significance were identified.

.2 Operator Knowledge and Performance

a. Examination Scope

On June 12, 2009, the licensee proctored the administration of the written examinations to all thirteen applicants. The licensee staff graded the written examinations, analyzed the results, and presented their analysis to the NRC on July 17, 2009.

The NRC examination team administered the various portions of the operating examination to all thirteen applicants on June 15-19, 2009. Three RO license applicants participated in three dynamic simulator scenarios and the fourth RO applicant participated in two dynamic simulator scenarios. All four RO applicants also participated in a control room and facilities walkthrough test consisting of eleven system tasks and an administrative test consisting of four administrative tasks. Five SROI license applicants participated in three dynamic simulator scenarios and two SROI applicants participated in two dynamic simulator scenarios. All seven SROI license applicants also participated in a control room and facilities walkthrough test consisting of ten system tasks and an administrative test consisting of five administrative tasks. One of the two SROU license applicants participated in two dynamic simulator scenarios and the other SROU applicant participated in one dynamic simulator scenario. Both of the SROU license applicants also participated in a control room and facilities walkthrough test consisting of five system tasks and an administrative test consisting of five administrative tasks.

b. Findings

All thirteen of the applicants passed all parts of the operating test. Six applicants (one reactor operator license applicant, four instant senior operator license applicants and one upgrade senior operator license applicant) failed the written examination. For the written examinations, the reactor operator applicants' average score was 83.78 percent and ranged from 77.02 to 90.54 percent, the senior operator applicants' average score was 72.88 percent and ranged from 64.00 to 84.00 percent. The overall written examination average was 82.65 percent. The text of the examination questions, the licensee's examination analysis, and the licensee's post-examination comments may be accessed in the ADAMS system under the accession numbers noted in the attachment.

Chapter ES-403 and Form ES-403-1 of NUREG 1021 require the licensee to analyze the validity of any written examination questions that were missed by half or more of the applicants. The licensee conducted this performance analysis for thirteen questions that met these criteria and submitted the analysis to the chief examiner. This analysis concluded that eight of the thirteen questions were technically valid as administered. The licensee submitted five post-examination question comments on July 17, 2009. The NRC reviewed the facility's post-exam comment submittal package and accepted the facility recommendations on three of the five questions. One question was deleted from both the reactor operator and senior reactor operator written exams. The senior reactor operator written exam key was also modified to accept two correct answers on two questions. The remaining two questions with post-exam comments were left unchanged on the answer key. The post-exam comments, including NRC responses, are included in an attachment to this report.

Seabrook Station is performing a root cause analysis to determine the cause of the examination results. Seabrook Station is adopting a newly developed fleet standard exam development procedure. This procedure will be updated based on the lessons learned from the root cause analysis. This written exam performance issue has been captured in the site corrective action program under Condition Report 00199879.

.3 Initial Licensing Examination Development

a. Examination Scope

The facility licensee developed the examinations in accordance with NUREG-1021, Revision 9, Supplement 1. All licensee facility training and operations staff involved in examination preparation and validation were listed on a security agreement. The facility licensee submitted both the written and operating examination outlines on March 31, 2009. The chief examiner reviewed the outlines against the requirements of NUREG-1021, Revision 9, Supplement 1, and provided comments to the licensee. The facility licensee submitted the draft examination package on May 4, 2009. The chief examiner reviewed the draft examination package against the requirements of NUREG-1021, Revision 9, Supplement 1, and provided comments to the licensee on the examination on May 11, 2009. The NRC conducted an onsite validation of the operating examinations and provided further comments during the week of May 14, 2009. The licensee satisfactorily completed comment resolution on June 8, 2009.

b. Findings

The NRC approved the initial examination outline and advised the licensee to proceed with the operating examination development.

The examiners determined that the written and operating examinations initially submitted by the licensee were within the range of acceptability expected for a proposed examination.

No findings of significance were identified.

.4 Simulation Facility Performance

a. Examination Scope

The examiners observed simulator performance with regard to plant fidelity during the examination validation and administration.

b. Findings

No findings of significance were identified.

.5 Examination Security

a. Examination Scope

The examiners reviewed examination security for examination development and during both the onsite preparation week and examination administration week for compliance with NUREG-1021 requirements. Plans for simulator security and applicant control were reviewed and discussed with licensee personnel.

b. Findings

No findings of significance were identified.

4OA6 Meetings, Including Exit

The chief examiner presented the examination results to Mr. Kerry Wright on August 12, 2009. The licensee acknowledged the results.

The licensee did not identify any information or materials used during the examination as proprietary.

4OA7 Licensee-Identified Violations

No findings of significance were identified.

ATTACHMENTS:
- Attachment 1, Supplemental Information
- Attachment 2, Written Examination Post-Exam Submittal

ATTACHMENT 1

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

K. Wright, Training Manager
K. Browne, Assistant Operations Manager
T. Cassidy, Simulator Support Section Leader
P. Leary, Nuclear Training Instructor – Exam Developer

NRC Personnel

W. Raymond, Senior Resident Inspector
J. Johnson, Resident Inspector

ITEMS OPENED, CLOSED, AND DISCUSSED

Opened

None

Opened and Closed

None

Closed

None

Discussed

None

ADAMS DOCUMENTS REFERENCED

Accession No. ML092240554 – FINAL-Written Exam
Accession No. ML092240469 – FINAL-Operating Exam
Accession No. ML092360643 – FINAL-Post Exam Comments

WRITTEN EXAMINATION POST-EXAM SUBMITTAL

Exam Question Number	Facility Recommendation	Final Resolution
RO and SRO 25	Delete question	No change
RO and SRO 43	Delete question	Deleted question
SRO 82	Accept A and D	Accepted A and D
SRO 83	Accept A and D	Accepted A and D
SRO 100	Delete question	No change

Question 25:

The following plant conditions exist:

- The plant has experienced a small break LOCA.
- Total EFW flow has been throttled to 550 GPM based on RCS temperature less than 557 degrees.
- The Crew has transitioned from E-0, "Reactor Trip or Safety Injection" to E-1, "Loss of Reactor or Secondary Coolant" and now to ES-1.1, "SI Termination" in order to reduce ECCS flow.
- Plant parameters are as follows:
  - Containment pressure is 1.5 psig and slowly decreasing.
  - Pressurizer level is 40% and increasing.
  - RCS Subcooling is 43º and stable.
  - RCS pressure is 1950 psig and stable.
- The crew is terminating SI.
- After placing the first CCP in standby, RCS pressure starts to slowly decrease.

Which of the following describes the correct procedural response to these conditions?

A. Restart the CCP and go to E-0, "Reactor Trip or Safety Injection".

B. Transition to ES-1.2, "Post LOCA Cooldown and Depressurization".

C. Restore normal charging path and control charging flow to maintain Pressurizer Level.

D. Initiate Safety Injection and transition to E-1, "Loss of Reactor or Secondary Coolant".

Answer: B

Facility Comments:

ES-403 D.1.c Re-grade criteria: Two answers are determined to be correct, however both answers contain conflicting information, accordingly this question should be deleted.

The first Charging pump is secured in ES-1.1, “SI Termination”, step 2. Step 3 checks RCS pressure “STABLE or INCREASING…”. If RCS pressure is determined to be “STABLE” then normal charging is restored using step 4. When the first Charging pump is secured RCS pressure will initially decrease. If the remaining ECCS flow provides adequate inventory makeup then the RCS will stabilize at a lower pressure and an attempt is made to realign the normal charging flowpath. If the remaining ECCS flow does NOT supply enough inventory then RCS pressure will continue to decrease and a transition is made to ES-1.2, “Post LOCA Cooldown and Depressurization”. No information concerning the duration of the “slow pressure drop” was provided in the question. Both answer “B” and “C” are correct depending on the assumed time frame of the plant conditions.

During the exam administration a candidate (docket number 055-63183) asked: “Over what time frame is the last bulleted item (“After placing the first CCP in standby, RCS Pressure starts to slowly decrease”) assumed to occur? Is this the expected initial pressure drop when the first CCP is stopped, or is this slow pressure decrease continuing?”

The student question was discussed with the Chief Examiner via phone during the exam. The exam writer and the Chief Examiner explored adding some additional pressure trends to the question, but decided to NOT add any clarifying information because ~ ½ of the candidates had already finished the exam and left the room.

Additional Facility Comments:

Question 25 concerned the expected plant response and correct procedural guidance during SI flow reduction during a small break LOCA. The conditions stated established initial Reactor Coolant conditions as follows:

The given conditions as:

- Pressurizer level is 40% and increasing.
- RCS Subcooling is 43º and stable.
- RCS pressure is 1950 psig and stable.

The assumed condition of:

- All ECCS equipment in service

The question concerns the decision point after the recovery procedure has placed the first High Head Centrifugal Charging Pump to standby. RCS pressure response to this action was stated as: “starts to slowly decrease”. The original regrade request submitted that two answers were correct, but the answers were mutually exclusive, so the question should be deleted from the exam.

The original answer for the question was:

B. Transition to ES-1.2, “Post LOCA Cooldown and Depressurization”.

This answer is based on ES-1.1, “SI termination”, step 3. This step checks that RCS pressure is stable or increasing after stopping the CS pump and, if not, directs a transition to ES-1.2. This answer is the correct flowpath for “smart” leak sizes that are smaller than the combined capacity of 2 CS pumps running in the ECCS injection mode, but larger than the capacity of 1 CS pump running in that same mode.

The regrade request asserted that under other plausible conditions answer “C” was also correct. This answer stated the correct response for the conditions given were to:

C. Restore normal charging path and control charging flow to maintain Pressurizer Level.

This answer would be correct if an applicant assumed that the RCS pressure response (“starts to slowly decrease”) after the first CS pump was secured was the expected plant response to securing the first CS pump, and that RCS pressure would stabilize at a new equilibrium pressure below the starting point. The Seabrook SI flow reduction methodology uses a “stepped” method of flow reduction. In this method the high head injection ECCS pumps are secured one at a time and plan response is evaluated. As each pump is secured there is a stepped decrease in RCS pressure but, provided that sufficient makeup inventory was still provided, the RCS pressure should stabilize and the next step in flow reduction is attempted. For Seabrook the optimal reduction scheme is as follows:

- Both High head injection pumps (CS pumps) are initially running in the ECCS injection line up.
- The First High Head injection pump is secured.
- RCS pressure should decrease, then stabilize at a new equilibrium.
- If RCS pressure does not stabilize then transition to ES-1.2, “Post LOCA Cooldown and Depressurization.”
- If RCS pressure stabilizes then the normal charging flowpath is established for the remaining High Head injection pump (the new flowpath is aligned in parallel with the High Head ECCS injection flowpath).
- The High head ECCS injection flowpath is secured, leaving just the normal charging flowpath. RCS pressure should decrease, then stabilize at a new equilibrium pressure.
- If RCS pressure does not stabilize then transition to ES-1.2, “Post LOCA Cooldown and Depressurization.”

During the exam administration a candidate asked:

“Over what time frame is the last bulleted item (“After placing the first CCP in standby, RCS Pressure starts to slowly decrease”) assumed to occur? Is this the expected initial pressure drop when the first CCP is stopped, or is this slow pressure decrease continuing?”

The student question was discussed with the Chief Examiner via phone during the exam. The exam writer and the Chief Examiner explored adding some additional pressure trends to the question, but decided to NOT add any clarifying information because ~ ½ of the candidates had already finished the exam and left the room. Although additional information seemed merited, it would cause an unfair advantage for the students still remaining in the room. Appendix “E” of NUREG 1021, part B, item 7, 1st paragraph states:

> “If you have any questions concerning the intent or the initial conditions of a question, do *not* hesitate to ask them before answering the question. Note that questions asked during the examination are taken into consideration during the grading process and when reviewing applicant appeals.”

The question asked by the student appears to be directly germane to the crux of the question: is the pressure drop the EXPECTED, initial drop in RCS pressure while new equilibrium conditions are established or does this pressure drop continue past that point? The two answers determined to be correct state the proper response to these two choices.

Conclusion:

The facility feels that information concerning the size and duration of the RCS pressure drop was lacking in the question as given. Both answers B and C are correct answers based on reasonable assumptions drawn from the limited information provided to the students.

Facility Recommendation: Delete question.

Technical Reference(s):

ES-1.1 “SI TERMINATION”, steps 1, and 2

NRC Resolution:

Choice B will remain the only correct answer for Question 25.

The licensee contends that two answers, containing conflicting information, are correct and therefore, the question should be deleted from the exam. The question stem describes RCS pressure slowly decreasing following a reduction in ECCS flow during SI termination and asks for the correct procedural response. Key Answer 'B' ("Transition to ES-1.2, Post LOCA Cooldown and Depressurization") is based on indications of pressure not stable or increasing after stopping the first charging pump. This answer is correct for the conditions given. ES-1.1, SI Termination, Step 3 has the operator check for RCS pressure stable or increasing and, if not, directs the action specified in the key answer.

The licensee contends that Distractor Choice 'C' ("Restore normal charging path and control charging flow to maintain Pressurizer Level") is also correct. ES-1.1, SI Termination, Step 4 directs the operator to restore normal charging path. However, the RCS pressure indication given in the question stem requires exiting the procedure at Step 3, prior to implementing Step 4. The basis for these steps is that if the leak is small or non-existent, normal conditions can be re-established. But, if not, LOCA mitigation response actions are appropriate. In order for Distractor Choice 'C' to also be a correct answer, the applicant must assume RCS pressure will stabilize after securing one of two running charging pumps. The information provided in the question stem that relates to RCS pressure does not support this assumption. The question stem only states that RCS pressure starts to slowly decrease.

Further, centrifugal charging pump (CCP) curves show RCS leakage in the approximate range of 500 to 700 gpm for the given conditions of stable pressure at 1950 psi and stable subcooling at 43°F. Stopping a single CCP under these conditions would result in a significant RCS pressure drop prior to stabilization. The “response not obtained” response for ES-1.1 Step 3 requires transition to ES-1.2, “Post LOCA Cooldown and Depressurization”, which is Choice B.

The NRC disagrees with the licensee’s recommendation to delete the question because of two (divergent) correct answers being possible. The NRC contends that there is only one correct answer for the conditions provided in the question. The answer key will remain as is with Choice B being the only correct answer.

Question 43:

Given the following plant conditions:

- The reactor is operating at full power near end of life.
- A Large Feedwater Line break downstream of the Feed Line check valves inside containment occurs.

Which of the following parameter trends would initially distinguish the Large Feedwater Line break from a Large Main Steam Line break inside containment?

A. Reactor Power prior to the reactor trip.

B. Containment pressure after the reactor trip.

C. Affected Steam generator pressure after the reactor trip.

D. Affected Steam Generator narrow range level after the reactor trip.

Answer: __A___

Facility Comments:

ES-403 D.1.b Re-grade criteria; newly discovered technical information that contradicts the answer key. Based on Seabrook Simulator response (See attached data) original answer is not correct. There is no correct answer.

The original explanation for answer “A” postulated that Reactor Power should initially increase for a steam line break due to the positive reactivity added as Tavg drops with the increased steam demand. For a feed line break Reactor Power will remain the same initially, then start to decrease as SG inventory is depleted and less heat is removed from RCS and Tavg begins to rise. These conclusions were based largely on the information presented in the Westinghouse owners group background document for E-2, “Faulted Steam Generator Isolation”.

Simulator data concludes that for both a large feed line break and a large steam break (with break flows peak at ~8,000 lbm/sec – to match UFSAR case studies) a safety injection and reactor trip on containment pressure > 4.3 psig occur almost instantaneously after the initiation of the break, so the hypothetical changes in reactor power are not seen. The attached trends provide break flow, NI indicated power, containment pressure response, and the simulator instantaneous core power. Note that the current simulator modeling of containment response is based on a Westinghouse simulator analysis performed as part of the plant power up-rate done in 2007. This model uses plant “best case” expected response to provide the most realistic model of containment performance to the students.

The discussion section of E-2 bounds intermediate size breaks as between those that could be handled by normal plant controls to those that do not generate any protective actions until greater than 5 minutes from break initiation. The discussion on large breaks is only focused on double-ended breaks. The background document does not contain a graph of the expected response of core power during a large feed break: just RCS pressure response, Pressurizer level response, RCS loop temperature response, and SG pressure response. The background document does not provide any graphs of expected plant response during a large steam break. The discussion section of E-2 does discuss that either type of large break inside containment would cause changing containment pressure and temperature but does not discuss the magnitude or expected plant protective actions of those changes. The original answer “A” was based on exam writer extrapolation of the expected response of core power based on that provided information.

The UFSAR was reviewed to ensure no contradictory information to the conclusion that containment pressure rapidly increases above the Safety Injection actuation pressure of 4.3 psig. Containment response to accident conditions is discussed in the UFSAR in section 6.2, Containment Systems, and chapter 15, Accident Analysis. In section 6.2 Feed line breaks are bounded by the more limiting steam line breaks (UFSAR 6.2.1.4, page 37). Analysis information for the large steam line breaks assumes a full double-ended rupture, with additional discussion of small double ended ruptures which are large enough to generate a Main Steam Line Isolation signal because they present the most limiting conditions of containment temperature rise. This analysis was performed using the worst case failure criteria, in this case either the broken loop Main Steam Isolation valve fails to close, or one train of CBS fails to actuate. The attached table 6.2.-69 shows that for these worse case failures that break flow peaks at ~ 8600 lbm/sec, then decreases as SG pressure decreases. The attached tables 6.2-20 and 6.2-22 shows that containment pressure reaches 10 psig almost instantaneously at the onset of the failure. This does not contradict the trends obtained from simulator performance. UFSAR section 15.1.5 discusses Steam System Piping failures. The focus of this discussion is the possible return to power operation based on the excessive RCS cooldown. This accident analysis credits a safety injection signal actuated from Containment pressure reaching 4.3 psig (Section 15.1, page 11). The discussion is focused on the more limiting plant conditions of hot, zero power which is different that the initial conditions of the question of 100% power. No tables or figures are provided for this section that characterize the expected containment pressure response. Section 15.2.8 discusses a Feedwater System Pipe Break. This discussion does state that a containment high pressure safety injection would provide protection for main feedwater piping system failure, but the affects on containment pressure are not discussed because the main steam line rupture in containment is a more limiting accident condition. No tables or figures are provided for this section which characterize the expected containment pressure response

Conclusion: None of the choices presented to the students created clearly distinct trends that could be used by an operator to differentiate between a Large Feed line Break and a Large Steam Line Break.

Facility Recommendation: Delete this question.

Technical Reference(s):

Simulator performance curves, UFSAR section 6.2, Containment systems, and Chapter 15, accident analysis

NRC Resolution:

Question 43 will be deleted from the examination.

Answer Key Choice A was based on an incorrect extrapolation of information provided in an EOP basis document. Although Choice A is conceptually correct when comparing smaller steam and feed line breaks, a detailed post-exam comparison of equivalent size large steam and feed breaks shows that an automatic reactor trip on high containment pressure shuts the reactor down almost immediately following either break, such that reactor power response prior to the trip will not distinguish between the two break types. Therefore, there was no correct answer provided and the question will be deleted from the examination.

QUESTION 82:

The following conditions exist:

- The plant is at 100% power.
- Two Control Rods drop into the core.
- The crew has entered OS1210.05, "Dropped Rod'.

Why does OS1210.05, "Dropped Rod', direct a manual Reactor Trip if more than one control rod has been dropped?

A. Unanalyzed Rod configurations invalidates the assumed rod worth used in the safety analyses.

B. Multiple rod drops will cause the heat flux hot channel factor to exceed the design limits on peak local power density.

C. The value of predicted Moderator Temperature Coefficient CANNOT be assured to remain within the limiting condition assumed in the FSAR accident and transient analysis.

D. Multiple rod drops or partial rod drops beyond those limited variations that allow continued power operation in Technical Specifications may produce power distributions outside of design limits.

Answer: _D____

Facility Comments :

ES-403 D.1.c Re-grade criteria; newly discovered technical information shows that two answers are correct. Answer "A" is also a correct answer as explained below.

Answer A has been identified as correct: When a rod or rods drops into the core the neutron flux profile will be suppressed in those areas, but increase in the rest of the core. This increase in flux level in the rest of the core will change the rod worth of control rods in those regions. This conclusion is discussed in detail in the included technical reference material.

Original answer D is correct. The TS bases for 3.1.3, Movable Control Assemblies, states in the second paragraph that "ACTION statements which permit limited variations from the basis requirements are accompanied by additional restrictions which ensure the original design criteria are met… ..In addition, those safety analyses affected by a misaligned rod are reevaluated to confirm that the results remain valid during future operation." The station specific AOP for dropped rods has determined that operating outside those limited variations that allow continued power operation in Technical Specifications may produce power distributions outside of design limits. The Dropped Rod procedure conservatively trips the plant when it has been determined that multiple dropped rods has occurred because the required safety analysis may not support continued operation and the evaluation could not reasonably be expected to be performed within the 1 hr TS limit to recover the rods.

Additional Facility Comments:

When a rod or rods drops into the core the neutron flux profile will be suppressed in those areas, but increase in the rest of the core. This increase in flux level in the rest of the core will change the rod worth of control rods in those regions. This conclusion was supported in detail in the previously included technical reference material, GFES lesson L8125I, “Control Rods”.

Technical Specification 3.1.3.1, “Movable Control Assemblies”, provides the operating limitations associated with Control Rod misalignment, as would be the case in a dropped rod or multiple dropped rods. Action b.3.a, provides a direct reference to the safety analysis that are related to Control Rod operability; Table 3.1-1. (included in attached reference material). This tie between Control Rod operability and accident analysis is also restated in the T.S. bases discussion for 3/4.1.3, but without referencing the Table by title. (see attached reference material). The accident analyses that require re-evaluation in the event of an inoperable full length rod are as follows:

- Rod Cluster Control Assembly Insertion Characteristics
- Rod Cluster Control Assembly Misalignment
- Loss of Reactor Coolant from Small Ruptured Pipes or from Cracks in
- Large Pipes Which Actuates the Emergency Core Cooling System
- Single Rod Cluster Control Assembly Withdrawal at Full Power
- Major Reactor Coolant System Pipe Ruptures (Loss-of-Coolant Accident)
- Major Secondary Coolant System Pipe Rupture
- Rupture of a Control Rod Drive Mechanism Housing (Rod Cluster Control Assembly Ejection)

These accident analyses are described in UFSAR chapter 15.

UFSAR section 15.4.3, “Rod Cluster Control Assembly Misoperation” provides the most direct discussion of the potential effects of multiple dropped rods. This section provides information on the following control rod misalignment combinations:

a. One or more dropped RCCAs within the same group
b. A dropped RCCA bank.
c. Statically misaligned RCCA
d. Withdrawal of a single RCCA.

NO specific analysis has been performed for multiple dropped rods in multiple core location, and that is the bases for tripping the plant if it is in that configuration in the first place. The analysis for the adverse affects of multiple rod drops within a group state that the more limiting condition is a “Dropped RCCA bank” so this becomes the bounding analysis. The discussion of the affects of the “Dropped Rod bank” hinges on a comparison of the worth of the dropped bank as compared to the worth of control bank D rods (which are assumed to withdraw in automatic). When rod worths change as a result of a neighboring dropped rod, as proven in the GFES Control Rod lesson, the assumed rod initial rod worths used to analyze those affects would be invalid.

Other UFSAR chapter 15 accident analyses affected by a changed assumed rod worth:

UFSAR section 15.4.1, “Uncontrolled Rod Cluster Assembly withdrawal from a Subcritical or Low power startup condition”, 3rd paragraph, states that “The maximum (positive) reactivity insertion rate analyzed in the detailed plant analysis is that occurring with the “simultaneous withdrawal of the combination of two sequential control banks having the maximum combined worth at maximum speed”. This same bounding parameter is also used in UFSAR section 15.4.2, “Uncontrolled Rod Cluster Assembly withdrawal at power”, as stated in subsection 15.4.2.2, item 4 and 5. In these two accident conditions any condition that changes rod worths (i.e. multiple rods dropped) would differ from the assumptions in the original accident analysis.

UFSAR section 15.4.8.1, “Spectrum of Rod Cluster Control Assembly Ejection Accidents”, subsection 15.4.8.2. “Calculation of Basic parameters”, a, Ejected Rod Worths and Hot Channel Factors states that “The calculation (for ejected rod worths) is performed for the maximum allowed bank insertion at a given power level, as given by the rod insertion limits”. For a case where one or more rod has dropped, those rods will be below their rod insertion limits, therefore the estimated rod worths of the OTHER rods are DIFFERENT than as assumed for the UFSAR accident analysis starting point.

Subsection e., Trip Reactivity Insertion”, of this same section states that the Trip reactivity assumed is given in table 15.4-2 and included the effect of one stuck RCCA adjacent to the ejected rod. The table lists the assumed rod worth of the ejected rod at various power levels and times in core life. For a case where one or more rod has dropped, the worth of a postulated rod adjacent to an ejected rod will be DIFFERENT than as assumed for the UFSAR accident analysis starting point.

Subsection g. “Results”, also provides specific reactivity values assigned to the hypothetical ejected rod worth for various points in core life and power levels.

Facility Recommendation: Accept two answers, A and D.

Technical Reference(s)

GFES Lesson L8125I, “Control Rods”, pages 27, 28, and 29. This lesson specifically states:

NRC Resolution:

The NRC will accept both Choices A and D as correct answers for Question 82.

The licensee contends that Distractor Choice 'A' is also a correct answer. The licensee describes how rod worth will change according to changes in neutron flux that would occur due to the presence of a dropped rod or rods. The information provided by the licensee indicates that various reactivity effects were analyzed in scenarios that assumed the drop of a single rod. There were no analyses performed for two dropped rods at random locations. Thus, given that dropped rods cause shifts in neutron flux that in turn impact reactivity analyses and, that no analyses were performed for two dropped rods, it is reasonable to also accept Choice A (“Unanalyzed Rod configurations invalidates the assumed rod worth used in the safety analyses”) as a correct answer. Thus, Choices A and D will both be accepted as correct answers.

Question 83:

The following conditions exist:

- The plant was operating in Mode 1 at 100% power.
- A fire in the Seismic Monitoring Cabinet has forced an evacuation of the Control Room.
- The Crew is responding to the Remote Safe Shutdown (RSS) Panels.

In accordance with OS1200.02, "Safe Shutdown and Cooldown From the Remote Safe Shutdown Facilities", which of the following is the prescribed method of ensuring sufficient RCS boration for Cold shutdown in this condition?

A. At the RSS panels shift CS pump suction to the RWST. Start borating using a Boric Acid Transfer Pump and the Emergency Boration valve. Inject Boric Acid required for Cold Shutdown by calculation or sample.

B. Prior to leaving the Control Room start a boration using a Boric Acid Transfer Pump and the Emergency Boration valve. Monitor WR Excore Neutron Flux less than 1.0 E-3% at RSS panel throughout the cooldown to ensure sufficient boration.

C. Prior to leaving the Control Room start a boration using a Boric Acid Transfer Pump and the Emergency Boration valve. Verify sufficient Boric Acid for cold shutdown injected by sample or calculated volume when the RSS panels are manned.

D. At the RSS panels shift CS pump suction to the RWST. Start borating using a Boric Acid Transfer Pump and the Emergency Boration valve. Monitor WR Excore Neutron Flux remains less than 1.0 E-3% at RSS panel throughout the cooldown to ensure sufficient boration.

Answer: _A____

Facility Comments:

ES-403 D.1.b Re-grade criteria; newly discovered technical information shows that two answers are correct. Answer "D" is also a correct answer as explained below.

The stem of the question intended to test the students knowledge of the method used to ensure sufficient boration has been added to the plant to achieve cold shutdown conditions when operating from the Remote Safe Shutdown (RSS) panel.

In a normal plant shutdown and cooldown from the Main Control Room the plant is borated to meet the shutdown margin requirements for cold shutdown condition prior to the initiation of the cooldown. This boration must be verified by direct sample of the RCS before proceeding. In a RSS shutdown the cooldown is initiated before the boration is started, so verification of adequate shutdown margin is managed under more dynamic conditions.

In OS1200.02 the boration is initiated as described in the first and second sentences of both answer "A" and answer "D". The procedure starts this boration in two different steps, step 4 or step 14. Step 4 of the procedure is a continuous action step that directs the operators to monitor WR Excore Neutron Flux level less than 1.0 E-3%. The RNO for flux level greater than 1.0 E-3% directs shifting CS pump suction to the RWST and starting a boration. Step 14 records initial boric acid storage tank levels, then aligns the charging system suction to a borated water source. A plant cooldown is then initiated in step 17. Boron (via the aligned borated water suction source) is then added as necessary as the RCS volume contracts during the cooldown to maintain Pressurizer level between 20% and 80% (step 15) or WR Excore Neutron Flux level less than 1.0 E-3% (step 4). An attempt is made to verify RCS boron concentration is greater than the concentration required by RE-18, “Shutdown Margin Values” by RCS sample (Step 24 c) before the plant is aligned to RHR. If accident conditions prevent verification by sample then an indirect determination of RCS boron concentration is utilized. The amount of boric acid that has been pumped from the boric acid storage tanks is used to calculate the inferred change in RCS boron concentration. This measurement can not verify that the volume that left the boric acid storage tanks has been successfully added to the RCS, but the expected results are backed up by the provided RSS process monitoring instrumentation.

UFSAR section 7.4, “Systems Required for Safe Shutdown”, subsection 7.4.5.6 (Section 7.4, page 4), Process Monitoring states that “Monitoring of various vital plant parameters relied on to achieve and verify safe shutdown is available from redundant instrumentation in the main control room and the RSS locations. This instrumentation is listed in Table 7.4-1.”. The Excore Wide Range Neutron detectors referred to in OS1200.02, step 4 are identified in Table 7.4-1 as used for “Reactivity Monitoring and Control”.

Subsection 7.4.6, “Design Basis and Analysis” (Section 7.4, page 8) states: “In the unlikely event that the main control room is uninhabitable, alternate control provisions are provided at the RSS locations. Safety is not adversely affected by Event 1, uncontrolled boron dilution (see Subsection 15.4.6)”. The Boron dilution monitors are only available in the main control room, so a boron dilution event can only be detected by monitoring of the WR Excore Neutron Flux detectors.

An addition caution prior to step 29 also warns the operators to monitor plant conditions for insufficient boron addition. The caution states: “SDM (Shutdown margin) should be monitored during initial RHR recirculation to the RCS.” The can only be accomplished by monitoring of the Excore Wide Range Neutron detectors to verify that the core is protected from an inadvertent dilution when RHR is placed in service.

Answer A remains correct. The remote safe shutdown procedure directs shifting CS pump suction to the RWST, and step 14 of OS1200.02 starts a Boric Acid Transfer Pump and opens the Emergency Boration valve. The required amount of Boric acid can be added until it is verified by sample or, if that is not available, by calculated volume. Step 13 of OS1200.02 performs the initial sample of RCS boron, a caution prior to step 17 warn that boron greater than RE-18 requirements must be added, and step 24 provides the “loop” to check the amount of boron added by sample or by calculation.

Additional Facility Comments:

Question 83 established some initial conditions that (1) A fire in the Seismic Monitoring Cabinet has forced an evacuation of the Control Room and (2) The Crew is responding to the Remote Safe Shutdown (RSS) Panels.

The question then asks: “In accordance with OS1200.02, “Safe Shutdown and Cooldown From the Remote Safe Shutdown Facilities”, which of the following is the prescribed method of ensuring sufficient RCS boration for Cold shutdown in this condition?”

The request for a regrade has asserted that answer D is also a correct answer so two answers should be credited. Answer D states:

D. At the RSS panels shift CS pump suction to the RWST. Start borating using a Boric Acid Transfer Pump and the Emergency Boration valve. Monitor WR Excore Neutron Flux remains less than 1.0 E-3% at RSS panel throughout the cooldown to ensure sufficient boration.

The initial request for regrade differentiated between the methodology of a normal plant shutdown, as opposed to the accelerated shutdown and cooldown used at the RSS panel. The request also used the design bases discussion provided in UFSAR chapter 7.4, “Systems required for Safe Shutdown”.

The design bases of the Remote safe shutdown facilities are further discussed in Appendix R of the UFSAR. The introduction section provides a description of the purposes of the sub systems credited for Remote Safe shutdown function. In this section it establishes that: “reactivity control function(s) shall be capable of achieving and maintaining cold shutdown reactivity conditions” and that “the process monitoring functions shall be capable of providing direct readings of the process variables necessary to perform and control the (above) functions. (see excerpt on next page). Note that, for the concept of “Remote Safe Shutdown” two separate and distinct end conditions are described: achieving and maintaining cold shutdown.

A specific discussion of the Bases and Positions of Safe Shutdown Capabilities is provided in sub-section 3.1. Section 3.1.2 defines Safe Shutdown as follows:

"Safe Shutdown" for purposes of the review is defined as a capability to bring the reactor from a 100 percent power operating condition to a "cold shutdown" condition. Included in this are conditions "hot standby," "hot shutdown," "cold shutdown," and maintenance of "cold shutdown." Note again there is a distinction in this definition between achieving cold shutdown and maintenance of cold shutdown. The term “shutdown margin” is also not discussed in this definition, as it would be for a normal reactor shutdown and cooldown evolution.

Appendix R discusses the criteria used to determine what equipment is required to satisfy the Safe Shutdown function. This is given in section 3.1.5. The equipment is broken down into two broad functional areas; Hot Standby and Cold Shutdown. Included in the listed criteria for determination of this equipment is the qualifier: “The equipment is required to operate to permit a safe shutdown system to perform its safe shutdown function”.

The equipment required to both achieve and MAINTAIN cold shutdown from the Remote Safe Shutdown Panel (the location stipulated in the question) is listed Table RSS 3.1.3.4-3. This table identifies whether the equipment is required to achieve hot standby or to either achieve or maintain cold shutdown. In this list the Wide Range Ex Core Neutron detectors are identified as “Required for: Cold Shutdown” (See attached table excerpt).

Conclusion:

As restated, the question asked:

- What is a prescribed method described in the Remote Safe Shutdown procedure…

- ..that utilizes equipment at the Remote Safe Shutdown panels…
- ..to ensure the plant is sufficiently borated to Cold Shutdown conditions…
- .. for the conditions of plant shutdown and cooldown from the remote safe shutdown facilities.

Appendix R equipment is required to satisfy a definition of Cold Shutdown that is different and unique from the classic definition. The RSS cold shutdown definition has two elements: achieving and maintaining Cold Shutdown. Appendix R of the UFSAR clearly identifies the Ex Core Wide Range Neutron detectors as process monitoring equipment required for Cold Shutdown. The Design criteria for the RSS equipment clearly states that the process monitoring functions shall be capable of providing direct readings of the process variables necessary to perform and control whatever functions are REQUIRED to achieve AND MAINTAIN cold shutdown conditions. No other process instrumentation is available in the list of credited equipment that provides direct readings of the ability to MAINTAIN the plant in Cold Shutdown.

Answer D provides a valid description of the methodology used to perform the addition of negative reactivity to the core from the Remote Safe Shutdown panel, and provides a valid, credited method to DIRECTLY observe the effectiveness of the reactivity addition.

Answer D is correct.

Facility Recommendation: Accept two answers, A and D.

Technical Reference(s)

OS1200.02, “ Safe Shutdown and Cooldown From the Remote Safe Shutdown Facilities”._UFSAR Section 7.4, “Systems Required for Safe Shutdown” including UFSAR table 7.4-1, “Equipment Required for Safe Shutdown”

NRC Resolution:

The NRC will accept both Choices A and D as correct answers for Question 83.

The licensee contends that Choice D is also a correct answer. Resolution of the licensee’s comment hinges upon the interpretation of the word “sufficient.” The question asks “…which of the following is the prescribed method of <u>ensuring sufficient RCS boration for Cold shutdown in this condition</u>?” Choice D contains the phrase “Monitor WR Excore Neutron Flux remains less than 1.0 E-3% at RSS panel throughout the cooldown to <u>ensure sufficient boration</u>.” OS1200.02 does direct boration if monitored wide range excore nuclear instruments do not continue to indicate less than 1E-3% reactor power.

The NRC concedes that ambiguity can exist in the meaning of the phrases about “ensuring sufficient RCS boration.” The phrase in Choice D can be interpreted to mean the amount needed to achieve CSD while maintaining the reactor shutdown or can also be interpreted to mean the amount of boration directed by the procedure. Therefore, depending on applicant interpretation of meaning of 'sufficient', both answers are correct since both methods are prescribed in the procedure. Therefore, the NRC will accept Choices A and D as correct responses.

QUESTION 100:

The following plant conditions exist:

- A SITE AREA EMERGENCY was declared 37 minutes ago.
- The Emergency Response plan facilities have NOT been activated yet.
- The on shift Work Control Supervisor has made the Notification to the States and NRC.
- Conditions have stabilized and the event no longer meets the Emergency Action Level criteria.

Who is responsible for termination of the classification?

A. ONLY the Response Manager

B. Response Manager or Site Emergency Director.

C. Response Manager or Short Term Emergency Director.

D. Site Emergency Director or Short Term Emergency Director.

Answer: _B____

Facility Comments:

ES-403 D.1.b Re-grade criteria; Question had unclear conditions and did not provide the necessary information to answer the questions. No correct answer.

Initial Conditions stated in the question establish that a Site Area Emergency was declared 37 minutes ago. At this point the Shift Manager assumes the dual role of the Short Term Emergency Director (STED). The second bullet of the question specifically state that the site emergency facilities are not manned. Without the Emergency Off-site Facility (EOF) or the Technical Support Center (TSC) the Response Manager (RM) and the Site Emergency Director (SED) positions are not filled so no turnover of responsibilities can occur. ER-1.1, “Classification of Emergencies”, Section 2.2, “Shift Manger Responsibilities” states “Responsibility for classifying observed station conditions in accordance with the emergency classification system specified in this procedure and reclassifying the emergency as necessary until relieved by the SED”.

ER-1.1, “Classification of Emergencies”, Section 1.1 Discussion, 11th paragraph also states “If emergency conditions are initially classified as an Alert or higher, and then subsequently reclassified to an Unusual Event, all ERO members should continue to report to their facilities. Although *activation of the Technical Support Center, Operational Support Center, and Emergency Operations Facility are not required* (italics added), the ERO staff will be available to assist with event recovery efforts, interface with State emergency response personnel, and respond to information requests from the media, elected officials and industry organizations.” No further discussion is provided concerning the case of an emergency condition that is classified above an alert, but subsequently cleared. ER-1.2, “Emergency Plan Activation”, Section 1.1 Discussion, restates this in the 3rd paragraph.

The 4th paragraph of ER-1.2, “Emergency Plan Activation”, Section 1.1 Discussion states “Once the initial emergency declaration is made, the associated ER 1.2 checklist for the Short Term Emergency Director (ER 1.2A, B, C or D) shall be implemented at least through to the completion of state notifications prior to terminating the emergency classification or reclassifying the emergency”.

In order to have a correct answer for this question, a choice must be given that either states the event can not be terminated at this point, or, the EOF and/or the TSC must be activated in order to terminate the event.

Additional Facility Comments:

Question 100 established initial conditions that (1) A Site Area Emergency was declared 37 minutes ago, (2) The Emergency Response plan facilities have NOT been activated and, (3) the conditions no longer meet the Emergency Action Level.

The initial request for a regrade pointed out that the initial conditions created unclear conditions so that no correct answer was available. The crux of this conclusion was the statement that “the Emergency Response plan facilities have not been activated”. When the emergency condition was discovered the Shift Manager had assumed the E-plan position of the “Short Term Emergency Director” (STED), but neither the “Station Emergency Director” (SED) nor the “Response Manager” (RM) positions are filled. At this moment in time it is clear that no one is available with the authority to terminate the event until the Technical Support Center (TSC) has activated and a turnover of responsibilities has occurred between the STED and SED, or the Emergency Off-site facilities have activated and the RM has assumed incident command. Appendix “E” of NUREG 1021, part B, item 7, 2nd paragraph states:

> ”When answering a question, do *not* make assumptions regarding conditions that are not specified in the question unless they occur as a consequence of other conditions that are stated in the question. For example, you should not assume that any alarm has activated unless the question so states or the alarm is expected to activate as a result of the conditions that are stated in the question. Similarly, you should assume that no operator actions have been taken, unless the stem of the question or the answer choices specifically state otherwise.”

No information was provided to the students that allowed them to assume that E-plan activation would successfully occur (i.e.: “no operator actions have been taken”), and their answer should be based on that expected outcome. Instead the question clearly states that emergency condition occurred 37 minutes ago, the Emergency Facilities have NOT been activated, and the condition has cleared. This is the frozen moment that the students felt they should be evaluating.

During the post exam review it was noted that clear direction to process the given emergency plan chain of events is not available in ER 1.2, “Emergency Plan Activation”. Section 1.1, “Discussion”, provides clarification for responding to other, similar chains of events:

> If an Unusual Event is declared, Primary Responders shall respond per Procedure ER 1.2, Section 5.0, even if notified of the termination of the Unusual Event. (2nd paragraph, section 1.1).

> If emergency conditions are initially classified as an Alert or higher, and then subsequently reclassified to an Unusual Event, all ERO members should continue to report to their facilities. (3rd paragraph, section 1.1).
>
> If the emergency classification is terminated or if reclassification of the emergency is made after completion of the state notifications, the initial NRC notification must still be made within one hour of the initial classification; however, the initial NRC notification will be for the termination of the emergency or for the emergency classification currently in effect (i.e., the reclassification). (3rd paragraph, section 1.1).

These clarifications do provide useful information for the cases stated, but the case presented in the initial question, "An Alert or Higher (i.e. Site Area Emergency) has been declared, but conditions have completely cleared prior to E-plan activation" is not discussed. A procedure change request has been implemented to add the conditions that occurred in this case with the expected response by the station staff to ER 1.2.

There are two other statements made ER 1.2, section 1.1, "Discussion", that further served to create unclear directions for the expected response to the stated conditions:

The 1st sentence of the 4th paragraph states:

> Once the initial emergency declaration is made, the associated ER 1.2 checklist for the Short Term Emergency Director (ER 1.2A, B, C or D) shall be implemented at least through to the completion of state notifications prior to terminating the emergency classification or reclassifying the emergency.

The state notifications are made in step 8 of each respective STED checklist. The turnover of command and control of the emergency does not occur until step 16. The emergency termination is not made until step 17. The direction in section 1.1 states that a reclassification or an event termination could occur any time after step 7 of the checklist.

The 2nd sentence of the third paragraph states:

> Although activation of the Technical Support Center, Operational Support Center and Emergency Operations Facility are not required, the ERO staff will be available to assist with event recovery efforts, interface with state emergency response personnel and respond to information requests from the media, elected officials and industry organizations.

This direction is given for emergency conditions that have been initially classified as an Alert or higher, then subsequently reclassified to an Unusual Event. Because no clear directions that cover the better condition (the event condition has completely cleared), this direction gives the conflicting guidance to consider not activating the Emergency Response Organizations. The procedure change request referenced earlier will also resolve this conflicting guidance issue.

Conclusion:

For the conditions given in the question, the only way to procedurally terminate the event would be to move past the moment in time given as a condition of the question. The question clearly froze a moment in time during E-plan activation and asked the students to determine who could terminate the event at that moment. The current Seabrook procedure provides the conflicting guidance that:

(1) The E-plan can be terminated any time after the state notification is made without continuing to activate the emergency facilities, with a follow up notification to the NRC

that the EAL was exceeded, but is now clear. This guidance is incomplete and will be fixed using the Procedure change process

(2) The E-plan can only be terminated by either the SED or the RM, but only after their respective emergency facilities are activated. This condition was not clearly available to the students as a condition of Appendix E of NUREG 1021.

There is no correct answer for the question as written

Facility Recommendation: Delete question

Technical Reference(s):

ER 1.1, section 1.1, section 2.2 and ER 1.2, section 1.1

NRC Resolution:

Choice B will remain the only correct answer for Question 100.

This question asks for who has authority for terminating the emergency classification following an event that resulted in declaring a Site Area Emergency. It is challenged on the basis of no correct answers for the given conditions. The licensee contends that the information in the stem provides conditions at a specific time in the event and, as such, implies that the question is asking who has the authority at this point in time to terminate the event. The stem does provide time of event information relative to initial declaration of the EAL, but that information does not affect the validity of the answer.

The question asks the applicant to identify "Who is responsible for termination of the classification?" This authority rests with the Response Manager or the Site Emergency Director. These are the individuals, by position, responsible to terminate the classification. The Short Term Emergency Director (STED) is prohibited from terminating an event classified at an Alert or higher level. Station Procedure ER-1.2, "Emergency Plan Activation", Attachment C, "Site Area Emergency Checklist - Short Term Emergency Director", Step 17 states, "A Site Area Emergency cannot be terminated by the STED except as discussed in Precaution 3.5. The emergency shall be terminated by either the Site Emergency Director or the Response Manager."

The applicants did not ask for any clarification of this question during exam administration. Understanding of the emergency plan requirements would preclude selection of Choice D, regardless of time in the event, since the STED is prohibited from terminating a Site Area Emergency. Choice D was selected as the correct answer by 5 of the 9 SRO applicants, indicating a lack of understanding of plan requirements related to event termination.

The licensee contends that vague information elsewhere in the activation procedure and step sequencing problems unfairly challenged the applicants' ability to determine the correct answer. However, the activation procedure does make absolute statements regarding termination authority in the STED checklists for Alert, Site Area and General Emergency levels. Knowledge of these statements would enable an applicant to identify the single correct answer for this question.