ENCLOSURE 1

U.S. NUCLEAR REGULATORY COMMISSION
REGION I

Docket/Report No. 50-244/89-18 Licensee No. DPR-18

Licensee: Rochester Gas and Electric Corporation
49 East Avenue
Rochester, New York

Facility: R. E. Ginna Nuclear Power Plant

Location: Ontario, New York

Inspection Conducted: June 26-30, 1989; July 17 - August 24, 1989

Inspectors: N. S. Perry, Resident Inspector, Ginna
P. D. Drysdale, Reactor Engineer, Region I, DRS
R. A. Laura, Resident Inspector, Nine Mile Point

Approved by: Eric C McCabe Jr 9/8/89
E. C. McCabe, Chief, Reactor Projects Section 3B Date

Summary:

Areas Inspected: Special inspection (107 hours) of May and June 1989 events (Table 1) which occurred during the annual refueling outage and subsequent plant start-up.

Results: Adequacy of control of modifications (Sections 10, 11, 12) and of non-safety, non-plant personnel work which could adversely impact plant safety (Section 7) is in question. Failure to follow procedures produced a safety injection signal (Section 3). The licensee did not implement effective corrective actions for failure to perform weekly rodding of boric acid tank level bubbler tubes (Section 5). There was a failure to obtain a grab sample of the containment atmosphere as required (Section 9). An independent verification deficiency was noted (Section 8). A waste gas release performed outside the specified time limit (Section 4) and incorrect setting of intermediate range detector trip setpoints (Section 6) were evaluated as being of minimal safety significance.

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DETAILS

1. Persons Contacted

During this inspection period, inspectors held discussions with and interviewed operators, technicians, engineers and supervisory level personnel. The following people were among those contacted:

R. Baker, Electrical Engineer
J. Bergstrom, Nuclear Engineer
D. Berry, Shift Supervisor
J. Bodine, Nuclear Assurance Manager
D. Filkins, HP & Chemistry Manager
T. Harding, Modification Support Coordinator
G. Hermes, Engineer, Nuclear Safety Licensing
*T. Marlow, Superintendent, Ginna Support Services
A. Morris, Maintenance Manager
M. Ruby, Shift Supervisor
T. Schuler, Operations Manager
*S. Spector, Plant Manager, Ginna Station
J. St. Martin, Corrective Action Coordinator
*J. Widay, Superintendent, Ginna Production
G. Wrobel, Manager of Nuclear Safety and Licensing

All persons listed above attended the interim exit meeting on June 30, 1989.

*Attended the supplemental exit meeting on August 24, 1989.

2. Introduction

Within a five week period prior to, during, and after start-up from the 1989 annual refueling outage, Ginna experienced several problems (see Table 1). Most of these were related to recent modifications and system lineups. The 1989 refueling outage was 74 days long and included the ten-year inservice inspection (ISI), extensive steam generator work, and plant modifications. This special NRC inspection examined ten events (Table 1), all of which were licensee identified, to assess licensee performance, especially determination of root causes and corrective actions, and to determine if programmatic weaknesses caused the high number of events. In particular, the design change and modification programs and processes were examined. Specific attention was given to the recent modifications of the Safety Injection System and the ATWS (Anticipated Transient Without Scram) Mitigation System Actuation Circuitry (AMSAC). Related operational and preoperational problems led to a reactor trip and a plant shutdown.

3. Unanticipated Safety Injection Signal

With the plant shut down, and while performing the Plant Safeguard Logic Test on May 18, 1989, an unanticipated Safety Injection (SI) signal occurred. During review of plant response, control room personnel noted a containment ventilation isolation signal should have been generated, but was not.

The licensee attributed the unanticipated SI signal to lack of detailed procedural guidance. Technicians were accustomed to placing bistables in the tripped condition prior to insertion of a test signal. However, the Plant Safeguard Logic Test procedure did not instruct technicians to trip the bistables in this case. The technicians, after questioning the procedure step and getting no additional direction, assumed tripping the bistables was intended and caused the SI signal by placing the bistables in trip. The licensee attributed the cause to procedure inadequacy, provided clarification to the technicians, and the Plant Safeguard Logic Test was satisfactorily completed. The NRC concluded that the proximate cause of the unanticipated SI was failure to literally follow procedures. This violates Technical Specification 6.8.1, which requires procedures for surveillance and test of safety related equipment to be established, implemented, and maintained. Other than the importance of literally following procedures for safety systems, there was no safety significance to this SI signal. Most safeguards equipment was out of service and the test is only performed with the plant shutdown (50-244/89-13-06).

The licensee determined that the failure of the SI signal to generate a containment ventilation isolation signal was due to a wire missing from the logic circuitry. The wire was missing due to a system modification not yet completed. The licensee concluded that failure of containment ventilation isolation to occur was an expected result considering the in-progress modification. Post-modification testing was adequate to insure the containment ventilation isolation signal functioned as required. The modification was subsequently completed and successfully tested. The inspectors concluded that licensee review of failure of the SI signal to generate a containment ventilation isolation signal was thorough and appropriate. Minimal safety significance was attributed to the absence of the ventilation isolation signal since operability of that isolation was not required at the time. The inspectors had no further questions regarding this item.

4. Waste Gas Release

On May 29, 1989, the waste gas decay tank was sampled at 6:43 a.m. and a release permit was initiated. The release was initiated at 8:40 p.m. and completed at 1:57 a.m. on May 30, 1989. The tank was isolated per procedure from the time of the sample through the release. Additionally, the release was monitored by radiation monitors and no alarms were received. Technical Specification Table 4.12-2 requires the sample to be taken with-

in 12 hours prior to the release. In this case, the release was initiated approximately 14 hours after the tank was sampled. The release was later than expected due to operations personnel being unavailable to perform the release while they were controlling plant start-up. The error was identified during the licensee's normal permit review. No similar late releases were identified. The licensee counseled personnel involved and informed all shift supervisors of the event and the need to verify strict compliance with technical specifications. At the close of the inspection period the licensee was reviewing the release process.

Because the tank was isolated from the time of the sample through the release, and no additional radioactivity was introduced to the tank prior to release, and the release was monitored, the release was within release limits on radioactivity. This apparent violation (50-244/89-18-01) had minimal safety/environmental significance, and licensee corrective actions were assessed as acceptable.

5. Cleaning of Boric Acid Tank Sensing Lines

On June 7, 1989, the licensee discovered that Periodic Test PT-21, Cleaning Boric Acid Tank Sensing Lines, was not performed as required on June 1, 1989. The sensing lines are cleaned weekly as preventive maintenance to ensure operability of the level instruments by removing any boron build-up in the level bubbler tubes. In this case, the boric acid tank level indication remained operable and there was no safety significance to the missed weekly cleaning. PT-21 also was not performed when required on October 21, 1988. Corrective action taken included altering the schedule for performing PT-21 to weekly on Thursday rather than Friday to allow for timely verification of completion.

Although there was no safety significance to the missed weekly cleaning in this instance, the failure to adequately correct a previously identified problem indicates a weakness in the oversight and assurance of quality. 10 CFR 50, Appendix B, Criterion XVI requires correction of conditions adverse to quality. The Ginna Quality Assurance Manual, Section 16, Corrective Action, Paragraph 2.0, requires, in part, that the licensee identify, report and correct conditions adverse to quality, that Ginna Station correct conditions adverse to quality, and that the Plant Operations Review Committee (PORC) recommend interim corrective actions. Corrective actions for failing to perform weekly rodding of boric acid tank level bubbler tubes on October 21, 1988 were inadequate to prevent recurrence on June 1, 1989. This is an apparent violation (50-244/89-18-02).

6. Intermediate Range Detector Trip Setpoints

During the start-up on June 1-2, 1989 the two intermediate range detector high level trips were set at 32 percent and 40 percent current equivalent of rated power. Procedure P-1, Reactor Control and Protection System, specifies a trip setpoint of 25 percent of rated power. The inspectors

noted that trip setpoint accuracy is not assured until a calorimetric has been performed and the 25 percent trip setpoint cannot be accurately set before start-up after refueling.

In this case, there was little safety significance since the trip is blocked when above 10 percent reactor power, the trip does not provide a primary safety function (it is a backup to the power range detector trip), and credit is not taken for the trip in the licensee's accident analysis. The licensee determined that they were not in compliance with P-1, and is evaluating resetting the intermediate range trip setpoint at an earlier point during initial plant start-up. The inspectors had no further concerns. This apparent violation (50-244/89-18-05) is considered an isolated instance for which appropriate corrective action has been initiated and which has minimal safety/environmental significance.

7. Main Generator Current Transformer Sliding Links

While placing the main generator on the grid during plant start-up on May 30, 1989, the generator breaker was closed. It immediately tripped open, resulting in a main turbine trip. Since reactor power was less than 50 percent, approximately 17 percent, no reactor trip occurred. All turbine trip responses functioned properly.

Licensee investigation revealed that six sliding links in the generator current transformer were incorrectly open. During the 1989 refueling outage, offsite RG&E personnel conducted maintenance and testing of the main transformer. That work was not controlled by plant management. The cognizant substation crew supervisor stated that the cause of the links being out of position could not be determined since some activities performed were not specifically procedurally controlled. During discussions with the licensee on August 24, 1989, the NRC was informed that the gasket condition indicated the enclosure had not been reopened since the work in question. This indicated that the mispositioning occurred during the authorized work.

This is the second example of non-safety-related equipment outside the plant impacting plant operation; a substation breaker bushing failure caused a loss of offsite power on July 16, 1988. In that case, the bushing failure was attributed to low cooling oil level with the level gauge stuck high. The NRC concluded that the control over electric power system equipment needs to be addressed by licensee management.

Absent information on electric power breaker maintenance controls and corrective actions, and absent information showing adequate control and corrective actions on deficiencies such as the sliding link mispositioning, these conditions appear to violate 10 CFR 50, Appendix A, Criteria 1 and 17 requirements for assuring that electric power systems will satisfactorily perform their safety function (50-244/89-18-07).

8. Average Temperature Channel 403 Sliding Link

On June 13, 1989, the licensee identified that the average temperature channel 403 sliding link was inadvertently left open following an alignment. Instrumentation and Control (I&C) technicians had opened the link, performed an alignment and failed to return the link to the closed position as specified in Calibration Procedure CP-7, T AVG and DELTA T Alignment at 70 Percent Power or Greater, Loop B, Unit 1, Channel 3. This link is located in a cabinet in the back of the control room. The average temperature instrument is safety-related and provides inputs to the reactor protection system. The safety significance of the link being out of position was minimal; it functions to connect the correction for lead resistance changes due to temperature changes. The error introduced did not affect system operability.

The inspector found that the I&C technicians had an independent verifier reviewing status of the links. However, the procedure lacked a second signoff provision for documentation of the independent verification. Plant management acknowledged that procedures were previously identified as weak. A Procedure Upgrade Program in process includes reworking all procedures. Licensee management committed to have two independent technicians initial each critical step regarding equipment status as an interim measure until the Procedure Upgrade Program is completed.

The inspectors concluded that the licensee's policy on independent verification needs to be reviewed by licensee management to determine whether the second check is sufficiently independent of the first. The licensee committed to further define the independent verification process. The inspectors had no further questions about this specific occurrence. The weakness identified does, however, reinforce the concerns generated about procedure adequacy and adherence elsewhere in this report.

9. Containment Radiation Monitors R-10A, 11, 12

On June 16, 1989, the licensee identified that radiation detectors R-10A, 11, 12 for the containment atmosphere were not returned to service properly after routine calibration. The detectors were removed from service for calibration and a grab sample was obtained on June 14, 1989 at 8:30 a.m. After the calibrations were completed on June 15, 1989 at 4:30 p.m., the detectors were not restored to their required condition. Another grab sample of the containment atmosphere was not obtained because it was assumed that the monitors were continuously monitoring the containment atmosphere. On June 16, 1989 at 12:57 a.m., the licensee discovered that the radiation detectors were aligned for continuous recirculation, which samples ambient air.

The inspectors reviewed CP-211, Calibration and/or Maintenance of RMS Channel R-11 (Containment Particulate), and found that the restoration section contained inadequate instructions. The procedure required notification to operations and assumed Administrative Procedure A-52.4, Control

of Limiting Conditions For Operating Equipment, would properly restore the system. The licensee issued a procedure change to provide step-by-step restoration to service instructions. Long term correction involves rewriting all maintenance procedures as part of the Procedure Upgrade Program.

Technical Specification 3.1.5.1.1 requires that, with Reactor Coolant System (RCS) temperature greater than 350 degrees Fahrenheit, two of the listed leak detection systems, including one system sensitive to radioactivity, shall be in operation. Since the R-10A, 11, 12 radiation monitors were not placed back in service, the licensee did not have any leak detection system sensitive to radioactivity in operation. Technical Specification 3.1.5.1.2 allows a system sensitive to radioactivity to be inoperable provided grab samples of the containment atmosphere are obtained and analyzed at least once every 24 hours. Due to the inadequate restoration, the containment atmosphere was not sampled for about 32 hours.

Although the safety significance of this event was low because the containment was not purged during this time period, the inspectors concluded that there was an apparent violation of Technical Specification 3.1.5.1.1: the RCS temperature was greater than 350 degrees, no system sensitive to radioactivity was in operation, and the compensatory action of drawing and analyzing a grab sample of the containment atmosphere at least every 24 hours was not accomplished (50-244/89-18-03).

10. <u>Safety Injection System Recirculation Valves</u>

On June 19, 1989, the control room shift foreman identified that two of the three Safety Injection (SI) system recirculation valves were out of their required position. The licensee commenced a shutdown until SI system recirculation flow was restored to the specified value by throttling these valves from locked fully open to locked approximately 80 percent shut.

During the 1989 refueling outage, the licensee implemented an SI modification which required throttling the recirculation valves to obtain the desired performance characteristics (see section 11). Prior to this modification, the valves were required to be locked full open. The inspectors found that, during post modification testing, the recirculation valves were throttled to approximately 80 percent shut, and this change in required position was not incorporated into the applicable SI system lineup procedures (i.e., S-30.1, S-16.A).

Licensee management and the security department investigated to determine how the valves were mispositioned and were unable to determine the cause. These valves were procedurally controlled under a locked valve list and a key is required to unlock the valves. Several members in the operations staff were unaware of the change in required position of the recirculation valves. Station management stated the reason why the valves were out of

position is still under investigation. The inspectors concluded that the impact of the modification was neither properly communicated from engineering and the test group to operations nor followed to resolution.

Administrative Procedure A-52.2, Control of Locked Valve and Breaker Operation, required two of the three SI recirculation valves to be throttled. On June 19, 1989, all three SI recirculation valves were found in the full open position. This is another example of the violation cited in Section 11 of this report (50-244/89-18-04).

Subsequently, the licensee determined that, if the SI system automatically initiated while the recirculation valves were out of position, the required SI core delivery flow would have been attained. This is due to a 20 percent error in the conservative direction made during the SI flow transmitter calibration. Although the licensee thought they were in an unanalyzed condition regarding the valves out of position, they later determined they were not due to sufficient flow always being available. The NRC concluded that, although the violation did not result in inability to meet design requirements, it represented an unacceptable practice.

11. Safety Injection System Modifications (Engineering Work Request EWR-3881)

The Safety Injection (SI) system modifications were designed to increase the piping size for the pump recirculation lines and replace three SI recirculation valves. The increase in recirculation flow for the SI pumps was to reduce the likelihood that pump damage might occur if operated against deadhead pressure for an extended time. The recirculation flow was designed to be increased from approximately 35 gpm to 100 gpm for a single pump. A new flow gauge (FI-916, 0-350 gpm) was installed to allow direct reading of the recirculation and test flows.

Engineering aspects of the system design modifications were completed by the corporate engineering group. Installation was performed by the modification project construction group during the 1989 refueling outage. System instrumentation was adjusted and calibrated by the site I&C department during the outage. Prior to plant start-up, modification functional testing was performed by the Results and Test group with recirculation flow set at 100 gpm through each recirculation valve.

During plant startup after the 1989 refueling outage, operational system testing was performed with RCS pressure greater than 1000 psig. The results indicated that the modified system was unable to produce the SI flow delivery to the reactor as specified by the FSAR injection flow curve. The SI system was reconfigured to throttle two of the SI recirculation valves to 35-50 gpm (approximately 80 percent closed) to achieve acceptable recirculation flow and the required injection flow. System recirculation flow was established by monitoring the new flow gauge, FI-916. An Engineering Change Notice (ECN 3881-16) was issued by the responsible engineer to authorize a revision of the system preoperational test specification (MET-024) to require the recirculation valves to be throttled.

The system lineup sheets required the recirculation valves to be Locked Open (LO) because the modification was not carried through to change the position of these valves from LO to throttled or locked/throttled. Approximately three weeks after the plant was operating, a Procedure Change Notice (PCN) was written to change the designated position of the SI pump recirculation valves to throttled. Since the operations shift supervisor knew the valves were full open, the pumps were declared inoperable due to inability to confirm required SI injection flow and a technical specification LCO was entered on June 19, 1989. A reactor shutdown was begun. The recirculation valves were reconfigured to the designated throttled position, and normal operation resumed.

During the monthly SI system operational surveillance test on June 21, 1989, inconsistent and unrepeatable flow results were obtained with the recirculation valves throttled to 80 percent shut. The test results indicated flows from 50 to 70 gpm on several trials. The reactor was manually shut down after the SI pumps were declared inoperable due to the inability to obtain repeatable flow rates. During the efforts to analyze the inconsistent flow results, the RG&E modification design consultant (NUS Corp.) informed the engineering group that the Flow Transmitters (FTs) in the SI injection piping may be calibrated incorrectly for the installed Flow Elements/orifices (FEs). Available vendor information indicated that the flow transmitters could be matched with several different orifice designs (with different calibration characteristics), but no specific information was available on the orifices installed in the SI system (FT-924/FE-924 & FT-925/FE-925). The orifices were removed and found to be of a design with a calibration curve different from the one the plant has used since 1971. The curve error resulted in the actual SI injection flow being approximately 20 percent greater than the indicated flow. Engineering personnel installed a new orifice design which provided more accurate FE/FT calibration data. On June 24, 1989, the SI system was retested with the SI system recirculation valves fully open. The required reactor delivery curves were met with SI recirculation flow at the original design value for the modified system (approximately 100 gpm each with two pumps running).

Site operations participated in SI modification preoperational testing and signed verification steps in the test procedure which reconfigured (i.e., throttled) the recirculation valves. No related information was entered into the control room logs, the operations required reading program, or other plant notifications. The ECN was issued by the responsible engineer to allow throttling of the recirculation valves, but operations was not on distribution and did not receive a copy. Approximately three weeks transpired before a PCN was initiated to change the valve lineup sheets to reflect locked throttled recirculation valves. No interim drawing change was made by the liaison engineer to reflect the correct throttled position of the recirculation valves. There was no indication that the liaison engineer was made aware of the change in the valves' positions or that he was aware of the existence of the ECN. This demonstrated a lack of effective communication between corporate and onsite groups.

Engineering did not have verifiable information on the exact design of the original injection flow orifices. Design information from the original construction plans listed the orifice sizes only. According to the vendor, different orifice shapes could have been used with the specific FT model installed. The new orifices installed were the same size and had the same flow characteristics, but had a different shape which was able to provide more accurate calibration data. The revised data were used to confirm that FSAR-required injection flow was met with the recirculation valves fully open as originally designed.

The inspectors questioned the original engineering department assumption that the modified SI system could be reconfigured with recirculation valves throttled nearly closed and 35-50 gpm as indicated on FI-916. FI-916 is not a linear gauge and there is no incremental mark at 35 gpm. The inspectors checked the calibration data for FI-916 and it was noted that FI-916 was least accurate in the low range where the initial incremental markings are spaced at 25 gpm and where the gauge is more nonlinear. This item is not being separately pursued. It is, however, another indication of lack of thorough design control of field changes to modifications.

The new recirculation valves had to be throttled to approximately 80 percent shut to achieve measured flows in the 35 gpm range. The responsible engineer stated that these valves were not designed to be throttled in this region because of the unknown consequences from flow instabilities induced by a two piece stem and disc. Also, the long term consequences from high velocity flow were not known for a nearly closed valve. This question on the part of the responsible engineer also showed existence of failure to thoroughly review and resolve a field change to a modification. Inasmuch as the valves did not remain throttled, this issue is not being separately addressed. It is, however, another pertinent input in considering the extent of the modification control problem.

The joint modification follow group is constituted primarily to verify that a modification is complete and ready for installation in the plant. All activities associated with preparing a design package are usually completed in time for the construction, and for site training and operations groups to prepare documents required to integrate the modification into plant operations. The modification follow group provides the primary interface for all principal groups dealing with the design, installation, testing, and operation of a modification. The formal business of the group is completed when turnover to the site groups begins. The inspectors concluded that this happens too early in the modification process, because of the ongoing need for design engineering involvement in modification installation, testing, and initial operation, and because of the need for more effective communication between the modification follow group members.

Site Administrative Procedures, A-301 series, Control of Station Modifications, allow informal turnover of control of plant modifications. Also, turnover punchlists were found to be unofficial, uncontrolled documents without binding requirements on the parties who produce them. Group managers are responsible for resolving punchlist items before final system turnover, but there is no accountability system for ensuring that punchlist items are resolved to the satisfaction of the parties involved. This condition increases the possibility of missing the transfer of design information and/or required action items.

Acceptance of a plant modification is accomplished by the modification design coordinator and liaison engineers who do not have defined design responsibility for modifications. Most of the system design and testing information is accepted from corporate engineering and the Results and Test (R&T) group. The R&T group does not participate in the preparation of operations procedures which may be developed from or affected by operational testing. Operations does not always participate fully in preoperational or operational acceptance testing. In this case, the inspectors found no effective operations participation in SI modification functional testing. SI operational procedures were developed after the modification follow group closed out formal activities early in the modification installation process. Information given to operations during modification training was based upon a system configuration with fully open recirculation valves. Most operations personnel assumed the valves should always be open. They did not functionally participate in the system testing and modification field change processes.

The liaison engineer is responsible for issuing interim drawing changes to the plant system P&IDs in a timely manner so that control room operators are informed of changes to system and component configurations while P&ID changes are in progress. The interim drawing changes for the SI system were reviewed. One SI system P&ID (33013-1262) had been used to indicate system changes for three separate P&IDs (33013-1261, -1262, and -1266). Although the changes were not complex, the areas of the SI system on each plan were represented differently and the potential for misunderstanding was clear. No administrative controls were found to effectively control this practice and the liaison engineer stated that this case was not in accordance with standard practice at Ginna Station. This drawing change control inadequacy was assessed as another indicator of inadequate overall control of modifications.

The Ginna Quality Assurance Manual, Section 3, Configuration Control, Paragraph 2.3, requires, in part, that Ginna Station prepare or revise plant procedures or documents as necessary to reflect modifications. Procedures requiring SI recirculation valves to be verified full open were not revised to require the valves to be throttled in accordance with the design change. This is an apparent violation (50-244/89-04).

12. ATWS/AMSAC Modification (Engineering Work Request EWR-4230)

AMSAC is a Westinghouse Plant Owner's Group system upgrade designed to comply with the ATWS rule of 10 CFR 50.62. The system is designed to initiate auxiliary feed flow and trip the main turbine when turbine header pressure exceeds 40 percent of full power turbine header pressure and a loss of main feed flow is anticipated. AMSAC mitigates plant transient consequences if no reactor trip occurs.

The AMSAC modification was installed and functionally tested. Acceptance testing was accomplished prior to plant start-up by R&T and I&C personnel. During plant startup on June 1, 1989, the system was placed into operation with reactor power at approximately 53 percent and turbine header pressure greater than 40 percent. When AMSAC was "unblocked" to bring it on-line, the main turbine tripped. The reactor also tripped since power was greater than 50 percent.

Once again, the inspectors concluded that the modification follow group had completed its business too early. During the modification follow group meetings, uncontrolled and unofficial design information drafted on RG&E title block drawing paper was distributed to the site operations and training departments. These drawings were AMSAC logic diagrams which contained incorrect design information. They were used by site groups to develop operating procedures and training packages for the modification. This condition is another example of inadequate design control.

The AMSAC responsible engineer stated that he often distributed uncontrolled and/or unverified design information for general purposes and did not know specifically what it was used for, or if it was used for any official purpose. In this case, he did not know he was putting out incorrect logic information. The responsible engineer also stated that RG&E purchased the design package for the AMSAC and that corporate engineering had no real direct need for the system logic. There does not appear to have been any licensee engineering effort to ensure that the system configuration matched the system logic. This is another example of inadequate design control.

The site I&C group participated in AMSAC operational testing. Technicians reportedly understood that, when the test procedure removed the conditions which initiated the trip signals, the relays would maintain a trip signal if the system was deactivated before allowing the 200 second timer to run out. The test procedure did not require a 200 second wait time to permit the trip signals to clear. The operating procedure assumed the system was clear of any trip signals. The procedures were inadequate because the test procedure did not leave the system in the configuration the operating procedure assumed it to be in. It also left the system in a configuration that could not be cleared by resetting the system at the time specified by the operating procedure.

The AMSAC operations procedure was generated as a PCN to procedure O-1.2, titled Plant from Hot Shutdown to Full Load, and was sent to the Plant Operations Review Committee (PORC) without going through the normal pre-PORC process defined by Administrative Procedure A-601.2, Procedure Control - Permanent Changes, (i.e., without the specified technical reviews and approvals). PORC did not perform a technical review of this procedure. The inspectors and the licensee concluded that the operating and logic errors probably would not have been detected in the normal pre-PORC process. NRC review also concluded that, since the I&C department understood the problem of leaving the system with a trip signal locked in, the error could have been identified and associated problems prevented prior to system operation if I&C and operations had communicated effectively.

Operations did not participate in the preoperational acceptance testing to the extent necessary to fully understand that the assumed system logic was wrong. Current system drawings were not used during the preparation of the operational procedure for AMSAC. The system construction drawings were not part of any formal design package given to operations. The operational procedure was developed from the incorrect system logic and from operating information made available from the designer. Corporate engineering did not normally review operations procedures. In addition, engineering drawings were not normally being used to verify or validate changes to operating procedures. No formal check of the validity of the system logic was performed by the plant operations group.

The Ginna Quality Assurance Manual, Section 3, Configuration Control, Paragraph 2.3, requires, in part, that Ginna Station prepare or revise plant procedures or documents as necessary to reflect modifications. Procedures incorporating changes due to the AMSAC modification were not revised as necessary to reflect proper operation of the modified system. This is another example of the apparent violation (50-244/89-04) described in Section 11 of this report.

13. Exit Interviews

An interim exit interview was held with the licensee on June 30, 1989. After subsequent information development and review, another exit interview was held with the licensee on August 24, 1989. That second exit interview was held primarily to emphasize the seriousness with which the NRC regarded the design control inadequacies identified in this report.

TABLE 1

Date	Event
May 18, 1989	Containment ventilation isolation signal not generated during safety injection actuation due to missing wire.
May 29, 1989	Release of waste gas outside 12 hour Technical Specification limit.
May 30, 1989	Turbine trip due to current transformer open links.
June 1, 1989	Plant trip from 53 percent power due to AMSAC modification.
June 1, 1989	Surveillance PT-21 not performed as required.
June 13, 1989	Slide links feeding one Tavg and Delta T channel found open.
June 16, 1989	Radiation monitors R-10A, 11, 12 found misaligned to sample ambient air rather than containment air.
June 16, 1989	Intermediate range bistables' trip setpoints found set at 40 percent and 32 percent equivalent power.
June 19, 1989	Safety Injection recirculation valves 1820 B and C found locked full open.
June 21, 1989	Safety Injection recirculation flow found out of tolerance with nonrepeatable results.

ENCLOSURE 2

POTENTIAL ENFORCEMENT ITEMS

1. Contrary to Criterion III, Appendix B, 10 CFR 50 and Section 3 of the Ginna Quality Assurance Manual, measures to control design changes were inadequate for modifications accomplished during the 1989 refueling outage. Specifically, the following conditions indicate a breakdown in design control:

   On June 1, 1989, when the recently completed ATWS Mitigating System Actuating Circuitry modification was placed into operation during plant start-up, a main turbine and reactor trip resulted. This was due to incorrect system design information being used to develop operating procedures and training packages for the modification. Further, uncontrolled and unofficial modification information had been distributed to the operations and training departments.

   On June 19, 1989, about three weeks after the plant had been returned to operation after the outage during which Safety Injection (SI) system modifications were accomplished under Engineering Work Request EWR-3881 and Engineering Change Notice ECN 3881-16, and with two SI system recirculation valves required to be throttled to 80 percent closed, these valves were fully open. This condition was identified when the procedure change notice requiring the valves to be throttled was identified by the operating shift supervisor as not being complied with, and the system line-up sheets had not been modif ed to reflect the positioning change. Therefore, the as-prescribed design basis was not correctly translated into the operating procedures.

   On June 21, 1989, the SI system recirculation flow measuring orifice design calibration curve was found to be different than the one the plant has been using since 1971. Although this error resulted in SI injection flow being about 20 percent higher than indicated, it also showed that the design basis recirculation flow was not correctly translated into instructions, procedures, and drawings, in that the prescribed recirculation flow valve throtting to 80% shut was inappropriate.

   As of June 21, 1989, the modification control series A-301 procedures and the informal "punch list" of items to be completed for turnover of modified systems to Operations was found to not require completion of items necessary for turnover. Further, Operations was not properly involved in modification review and approval, inasmuch as documents (such as the Engineering Change Notice which prescribed throttling of the safety injection recirculation valves) were not distributed to or required to be reviewed by Operations. Also, although Operations personnel participated in testing the SI modification,

there was no indication of thorough Operations review of the modification prior to and during its accomplishment, or of Operations participation in the modification process to the extent that significant specified changes in safety-related valve positions were monitored and verified complete by the operating staff.

2. Contrary to Criteria 1 and 17, Appendix A, 10 CFR 50, based on the July 16, 1988 loss of offsite power and the May 30, 1989 turbine trip, the licensee did not exercise adequate control over and corrective action for electrical power supply distribution equipment.

3. Contrary to Technical Specification 6.8.1, and Criterion V, Appendix B, 10 CFR 50 and Section 5 of the Ginna Quality Assurance Manual, the Plant Safeguards Logic Test procedure was not implemented (literally followed) as prescribed on May 18, 1989, and an unanticipated safety injection signal was consequently generated.

4. Contrary to Corrective Action Criterion XVI, Appendix B, 10 CFR 50 and Section 16 of the Ginna Quality Assurance Manual requirements for prompt identification and correction of conditions adverse to quality, corrective actions for failure to perform weekly rodding of boric acid tank level bubbler tubes on October 21, 1988 were ineffective in preventing recurrence on June 1, 1989.

5. Contrary to Technical Specification 3.1.5.1.1, on June 16, 1989 reactor coolant system temperature was above 350 degrees Fahrenheit and no required reactor coolant leak detection system sensitive to radioactivity was in operation, and the compensatory requirement for sampling the containment every 24 hours was not met.