UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION II
101 MARIETTA ST., N.W., SUITE 3100
ATLANTA, GEORGIA 30303

Report Nos. 50-324/82-25 and 50-325/82-25

Licensee: Carolina Power & Light Company
411 Fayetteville Street
Raleigh, NC 27602

Facility Name: Brunswick

Docket Nos. 50-324 and 50-325

License Nos. DPR-62 and DPR-71

Inspection at Brunswick site near Wilmington, North Carolina

Inspectors: C. K. Harden for — 8/12/82
D. O. Myers — Date Signed

C. K. Harden for — 8/12/82
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T. Peeples — Date Signed

Approved by: C. W. Burger for — 8/12/82
C. Burger, Section Chief, Division of Project and Resident Programs — Date Signed

SUMMARY

Inspection on June 15 - July 15, 1982

Areas Inspected

This routine inspection involved 277 inspector-hours on site in the areas of plant operations, procedure review, followup of plant transients, review of LER's, maintenance observations, surveillance testing, and operational safety verification.

Results

Of the areas inspected, one violation was identified (Failure to implement and maintain procedure, paragraph 5) and applies to both units.

DETAILS

1. Persons Contacted

Licensee Employees

J. Boone, Engineering Supervisor
J. Cook, E&RC Foreman
*C. Dietz, General Manager, Brunswick
J. Dimmette, Mechanical Maintenance Supervisor
E. Enzor, I&C Electrical Maintenance Supervisor
M. Hill, Maintenance Manager
*B. Tucker, Manager of Operations
M. Long, Manager, Special Projects
*R. Morgan, Plant Operations Manager
*D. Novotny, Regulatory Specialist
G. Oliver, E&RC Manager
A. Padgett, Assistant to General Manager
*R. Poulk, Regulatory Specialist
W. Tripplett, Administrative Manager
L. Tripp, RC Supervisor
*A. Bishop, Technical and Administrative Manager
V. Wagner, Director, Planning and Scheduling

Other licensee employees contacted included technicians, operators and engineering staff personnel.

*Attended exit interview

2. Exit Interview

The inspection scope and findings were summarized on July 15, 1982, with those persons indicated in paragraph 1 above. Meetings were also held with senior facility management periodically during the course of this inspection to discuss the inspection scope and findings.

3. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable or may involve violations or deviations. New unresolved items identified during this inspection are discussed in paragraph 9.

4. Licensee Action on Previous Inspection Findings

(Closed) Inspector Followup Item Revision 17 was issued on February 24, 1982 to remove discrepancies between Tables I and I.A of Plant Operating Manual Volume XI, Book 2.

5. Plant Operations Procedure Review

a. A special inspection was conducted during the week of June 21-24 to determine if current plant operating and emergency procedures are suitable for plant operation.

To accomplish this inspection, the procedures were reviewed to assure that procedure interface is adequate to provide continuity between procedures, that current design and as-built plant conditions are incorporated, and that personnel are able to effectively utilize the procedures to accomplish plant operations. To this end, the procedures were compared to the following criteria: General Electric "GEK" Manuals; Process and Instrumentation Drawings (P&ID's); Actual as-built conditions (as determined during fluid system and control panel walkdowns); Plant Technical Specifications (TS's); and, Operator and plant personnel interviews.

The inspection consisted of a sampling of 26 Emergency Instructions (EI's), 2 Operating Guidelines (OG's), 1 General Procedure, and 9 Operating Procedures (OP). The following procedures were reviewed:

(1) GP-1, General Plant Operating Procedure, Rev. 71

Section A, Master checklist; Section B, Approach to Criticality; Section C, Startup and Synchronization of the Unit; and, Section D, Increase of Power to Rated.

(2) Operating Procedures (OP's)

OP-1, Nuclear Boiler System, Rev. 16; OP-11, Radiation Monitoring System, Rev. 6; OP-16, Reactor Core Isolation Cooling (RCIC) System, Rev. 24; OP-17, Residual Heat Removal (RHR) System, Rev. 37; OP-19, High Pressure Coolant Injection (HPCI) System, Rev. 29; OP-22, Rod Sequence Control System, Rev. 6; OP-24, Containment Atmospheric Control System, Rev. 40; OP-25, Main Steam System, Rev. 12; OP-41, Fire Protection System, Rev. 10.

(3) Operating Guidelines (OG's)

OG-3, Primary Containment Access Control, Rev. 10; and, OG-6, Radioactive Gaseous Release Control, Rev. 12.

(4) Emergency Instructions (EI's)

EI-1.1, Primary System Rupture Inside Drywell (Leaks), Rev. 13; EI-1.2, Rupture Inside Drywell, Rev. 14; EI-1.3, Small Break Outside Drywell, Rev. 3; EI-2.0, Loss of Control Rod Shutdown Capability, Rev. 7; EI-3.1, Control Rod Drop, Rev. 2; EI-3.2, Rod Uncoupled, Rev. 3; EI-3.3, Control Rod Drift; Rev. 5; EI-3.4, Inability to Move Control Rods, Rev. 3; EI-3.5, RPIS Failure, Rev. 3; EI-4.1, MSIV Closure, Rev. 6; EI-4.2, Moderator Temperature

Decrease, Rev. 8; EI-4.4, Continuous Rod Withdrawal During Power Range Operation, Rev. 2; EI-4.4, Continuous Rod Withdrawal During Reactor Start-up, Rev. 3; EI-4.5, Recirculation Flow Control Failure - Decreasing Flow, Rev. 6; EI-4.6, Recirculation Flow Controller Failure - Increasing Flow, Rev. 2; EI-4.7, Improper Start-up of Idle, Recirculation Pump, Rev. 2; EI-5.1, Loss of Primary Containment (Normal Operation), Rev. 7; EI-5.2, Loss of Primary Containment (Accident Conditions) Rev. 3; EI-6, High Pressure Coolant System Failure, Rev. 8; EI-7, Reactor Core Isolation Cooling System Failure, Rev. 6; EI-8, Abnormal Reactor Water Levels, Rev. 8; EI-9, Condensate and Feedwater Failure, Rev. 4; EI-10, Recirculation Pump Trip, Rev. 11; EI-15.1, Station Blackout Operation, Rev. 8; EI-15.2, Degraded Auxiliary Electrical Power Operation, Rev. 6; and, EI-31, Reactor Scram, Rev. 21.

b. As a result of this inspection, a Violation and Inspector Followup Item were identified.

(1) Procedure GP-1 is supposed to provide an outline to start up and shut down the plant. The procedure contains signature blanks and check-off lists to ensure that each step in the procedure is completed and to provide the various operating shifts continuity while performing the procedure. Procedure GP-1 refers operators to various OP's that are supposed to provide startup/operating instructions for the various systems needed for plant operation.

The review of GP-1, selected OP's and interviews with various licensee personnel identified the following items:

(a) OP's are not written in the format required by ANSI 18.7-1976. The ANSI standard requires check-off lists for "extensive or complex jobs", "tasks that are infrequently performed", and "tasks in which operations are to be performed in a specified sequence". The OP's do not contain such check-off lists. In addition the standard requires procedures to contain a reference section, prerequisite section, and precaution section. The OP's and GP do not contain any references and the prerequisite and/or precaution sections are either non-existent or are insufficient for the evolution performed. For example, OP-17, which provides the procedure for draining the reactor vessel, has only one precaution for performing this evolution which states "Notify radwaste prior to draining". Discussions with operating personnel revealed that the OP's are only utilized for initial system lineup and are not routinely used for system operation.

(b) The valve lineups (VLU's) and electrical circuit breaker lineups (BLU's) that affect safety-related systems require independent verification of their positions. The OP's that affect these systems have additional signature blocks on the lineup sheets to reflect this independent verification. Review of the OP's indicates that while the initial system lineups provide for independent verification, subsequent lineups that place various systems in their standby modes are not independently verified thereby defeating the purpose of such verification. Examples of this finding were evident in paragraph O of OP-17 for placing the RHR system in standby, paragraph A of OP-19 for placing HPCI system in standby, and paragraph A of OP-16 for placing RCIC system in standby. In addition, as mentioned in the previous paragraph, there are no checkoff lists required to accomplish these evolutions.

(c) There are numerous examples in procedure GP-1 where the steps utilized to perform an evolution are inconsistent with the steps provided in an OP for the same evolution. This was evident in step B.4.5.12.2 of GP-1 for warming up of the HPCI and RCIC steamlines. Paragraph G of OP-16 and paragraph E of OP-19 provide different steps than those provided in GP-1.

(d) Procedure GP-1 refers to various OP's to accomplish specific operations but in many cases the OP's do not direct these operations. For example: Master checklist step A.3.1.1.e, requires Main Steam (MS) to be "ready for operation as per OP-25". OP-25 does not direct completion of the valve lineup and also requires many systems to be in service that have not yet been addressed by GP-1.

Master Checklist step A.3.1.1.1 requires the Automatic Depressurization System (ADS) to be placed in standby readiness in accordance with OP-1. OP-1 does not direct the performance of this activity.

Master checklist step A.3.1.8.d, e, f, g, and h refer to OP-11 for the various radiation monitoring systems starups, however, OP-11 provides insufficient direction to perform these startups.

(e) The licensee changed the reactor vessel level reference points such that a former normal level of +32 to +42 inches now +182 to +192 inches. This modification was completed some time ago, however, GP-1 has not been completely revised. Some steps of the GP refer to the old level and some steps refer to the new level.

(f) Procedure GP-1 has a number of areas where the steps conflict with each other. For example, the authorization for plant startup is different between checklist step A.3.3.9.b and step A.3.1.13.c.

(g) Review of procedure OP-41 indicated that:

The procedure does not address startup and operation of the motor-driven fire pump;

The initial conditions for the fire service tank required levels that were less conservative than those stated in the facility

Technical Specifications and that the demineralized water tank level requirement is not listed; and,

The VLU for the fire pumps located in the Water Treatment Building had valves missing, incorrect valve descriptions, and incorrect valve numbers.

(h) Procedure OP-22 for Unit 1 had incorrect component descriptions for the Breaker Line Up. When the inspector requested plant operator assistance to complete the Breaker Line Up, the plant operators had considerable difficulty locating and identifying the required breakers. In addition, procedure GP-1 did not refer to procedure OP-22 at all for plant startup even though the Rod Sequence Control System must be operational for plant start-up. Failure to implement and maintain the facility Operating and General Procedures and failure to meet the format requirements of ANSI N18.7-1976 are contrary to the requirements of Technical Specification 6.8.1a and the accepted quality assurance program required by 10 CFR 50, Appendix B, Criterion II. This item is a Violation.

Violation: Failure to implement and maintain GP's and OP's and failure to meet procedure format requirements of ANSI N18.7-1976. (Other examples of this violation appear in paragraphs 9 and 10).

In NRC Inspection Report 50-324, 325/82-05, the licensee was cited for a similar violation for failure to properly implement facility procedures. In the licensee's response to this Violation dated April 30, 1982, the licensee stated that "the examples presented in this violation are viewed as isolated in nature" and that "In an effort to identify other problems which may exist in plant operating procedures, a review of all operating and annunciator procedures is planned... The review and rewrite of the operating and annunciator procedures should be completed during the summer of 1983".

Operating Instruction (OI) OI-10 and Maintenance Procedure (MP) MP-14 were identified by the inspector as inadequately identifying valves requiring local leakage rate (LLRT) testing. OP-10, revision 14, does not identify all the valves listed in PT-20.3 that require LLRT. Examples of these valves are B22-F019, F0-20; B21-F010 A and B; G31-F039; CAC V4, V15, V55, V56; G16-F03, F04, F19, F20. Additionally, MP-14, revision 12 does not identify all valves listed in PT-20.3 which require LLRT. Examples of these valves requiring LLRT's are B22; V30; CAC-V16, 17. These procedures identify to operations and maintenance personnel which valves should be identified on trouble tickets as requiring LLRT's in accordance with PT-20.3. This is another example of failure to implement and maintain procedures.

This inspection indicates that procedural violations are not isolated and that a major procedure rewrite effort is required. Therefore this violation is considered to be recurrent and uncorrected.

(2) During walkdowns of the various plant systems, it was noted that a number of valves and circuit breakers were not tagged or labeled for identification. The licensee has attempted to replace missing valve tags but apparently has not been able to keep up with the loss rate. The inspector stated that the licensee needs to develop and implement a program that will insure that missing valve tags and circuit breaker labels are replaced on a timely basis. The licensee acknowledged the inspector's remarks and the inspector will establish an Inspector Followup Item (324, 325/82-25-01): Review licensee's activities to establish and implement a valve tag/circuit breaker label replacement program.

6. Followup of Plant Transients and Safety System Challenges

During the period of this report, a followup on plant transients and safety system challenges was conducted to determine the cause; ensure that safety systems and components functioned as required; corrective actions were adequate; and the plant was maintained in a safe condition.

a. On June 28, 1982 at 1:59 a.m., Unit 1 reactor experienced a main steamline isolation valve (MSIV) less than 90% open scram from 80% of full power. Relief valve B21-F013G was manually opened to control vessel pressure and the High Pressure Coolant Injection (HPCI) system was used to maintain vessel level until the MSIV's were reset and normal cooldown initiated approximately 15 minutes after the trip. Reactor pressure did not exceed 1075 psig. Reactor level remained above 140 inches during the event.

At the time of the scram both HPCI and the reactor core isolation cooling (RCIC) systems auto started but neither injected into the vessel. Subsequent testing demonstrated that HPCI and RCIC were operational and would inject per design. Apparently a low level signal existed long enough to start the HPCI and RCIC turbines but was not of sufficient duration to allow all of the injection valves open permissives to be satisfied simultaneously.

At the time of the event diesel generators 1 and 2 loaded their respective emergency power buses. In addition, reactor protection system (RPS) motor generator set "1A" tripped causing all RPS scram channel A relays to trip. Subsequent investigation revealed that circulating water pump "1A" had failed to synchronized during starting and had tripped. This apparently caused a degraded voltage condition on the balance of plant buses which are the normal supply to the emergency buses. Degraded voltage on the emergency buses caused the normal supply breakers to open and the diesel generators to start and load on loss of emergency bus voltage. The momentary loss of power to the emergency bus caused RPS motor generator set "1A" to trip.

During review of the loss of voltage and degraded voltage setpoints, it was determined that the surveillance required by Technical Specification 4.3.3.1 and Table 4.3.3-1 item 5.a and 5.b had never been implemented. This was the subject of a July 2 Confirmation of Action letter and a special inspection by Region II staff during the period July 12 through July 14, 1982. Their findings and/or enforcement action will be issued in a future inspection report.

b. On July 10, 1982 at 2:15 p.m., Unit 1 reactor experienced a turbine control valve and stop valve closure scram from 80% of full power. No engineered safeguard features were required. The reactor was cooled down using the main condenser and the reactor feedwater pumps per normal procedures.

Cause of the turbine trip was determined to be AC feedback by a malfunctioning lighting inverter onto the DC battery bus which supplies power to portions of the turbine control circuitry. This AC "ripple" caused a spurious load reject turbine trip.

The inspectors have no further questions at this time.

c. Inadvertent Core Spray Injection

On July 14, 1982 at 11:23 a.m., Unit 2 reactor experienced an injection into the vessel by core spray loop B. Vessel level increased from 185" to 192" before the unit operator manually de-energized the "B" core spray pump. At the same time the unit 1 reactor experienced a momentary partial opening of all four bypass valves. Unit 1 was operating at approximately 75% of full power. Power on Unit 1 fluctuated downward approximately 10% before returning to 75% of fullpower. Simultaneous to the preceeding items, control room annunciator "output breaker DG #2 open" actuated.

Prior to these events, a battery charger to Unit 2 battery 2B-2 output breaker had tripped. At that time the battery was out of service for maintenance; hence, all power was secured to one DC bus. When the charger breaker was closed to the DC bus the above mentioned events occurred.

Installation of a plant modification to trip the charger breaker had been completed this outage. Without the battery to act as a capacitor on the DC bus, varying loads on the DC bus caused the charger output voltage to spike; hence, the breaker to open. Re-energizing the bus which supplies power to the emergency core cooling system analog logic caused the core spray pump to start. Similar core spray injections on Unit 1 are discussed in Inspection Reports 325/82-08, 81-31, 81-24 and 81-20.

The 2B-2 battery is one of two supplies to the Unit 1 EHC cabinets. The closing of the breaker apparently caused a voltage spike in the bypass valve positioning logic of the EHC system. This initiated the rapid bypass valve opening and closing.

The diesel generator annunciator power is supplied from two sources. One of these is the 2B-2 battery. Thus the annunicator was spurious. No actual tripping of the generator output breaker would occur if Unit 2 battery bus is de-energized since the control circuitry for the breaker is powered from its associated Unit 1 battery bus and emergency bus.

7. Review of Licensee Event Reports

The below listed Licensee Event Reports (LER's) were reviewed to determine if the information provided met NRC reporting requirements. The determination included adequacy of event description and corrective action taken or planned, existence of potential generic problems and the relative safety significance of each event. Additional in-plant reviews and discussions with plant personnel, as appropriate, were conducted for those reports indicated by an asterisk.

Unit 1

1-82-32 (3L)	Primary Containment Temperature Recorder, 1-CAC-TR-1258, incorrect indications of Suppression Chamber Water Temperature.
1-82-38 (3L) and Supplement	The 125 Volt DC Battery Charger Output Breaker for Battery 1A-1, inadvertently opened and resulted in a reactor scram.
1-82-45 (3L)	The C12-LSH-129 Accumulator Leak Detectors of CRD Accumulators 30-11, 34-43, 22-27, 22-03 and 42-15, did not respond to applied test inputs and declared inoperable.
1-82-53 (3L)	Position indication problems with Control Rods 10-07 and 34-27, resulting from defective Rod Position Reed Switch.
1-82-55 (3L)	Discrepancy of Suppression Chamber Water Level Instrument indications on Remote Shutdown Panel Instrument 1-CAC-LI-3342 and Post-accident Monitoring Instruments, 1-CAC-LI-2601-3 and LR-2602
1-82-61 (3L)	Indication discrepancy between SRM "C" and SRM's "A" and "D", due to failure of Input Signal Preamplifier to SRM "C".

Unit 2

2-82-36 (3L)	Reactor Coolant activity exceeded Technical Specifications limit.
Supplement 2-82-48 (3L)	Post-accident Monitoring Control Room Recorder/Indicator, 2-CAC-AR-1263, observed exhibiting downscale indications of Drywell Oxygen Concentration.

8. Maintenance Observations

Maintenance activities were observed and reviewed throughout the inspection period to verify that activities were accomplished using approved procedures, the activity was within the skill of the trade and that the work was done by qualified personnel. Where appropriate, limiting conditions for operation were examined to ensure that while equipment was removed from service, the Technical Specification requirements were satisfied. Also, work activities, procedures, and work requests were reviewed to ensure adequate fire, cleanliness and radiation protection precautions were observed, and that equipment was tested and properly returned to service.

Outstanding work requests that were initiated by the Operations group for Unit 1 were reviewed to determine that the licensee is giving priority to safety-related maintenance and not allowing a backlog of work items to permit a degradation of system performance.

Of the areas inspected no violation was identified.

9. Surveillance Testing

The surveillance tests detailed below were analyzed and/or witnessed by the inspector to ascertain procedural and performance adequacy.

The completed test procedures examined were analyzed for embodiment of the necessary test prerequisites, preparations, instructions, acceptance criteria and sufficiency of technical content.

The selected tests witnessed were examined to ascertain that current, written approved procedures were available and in use, that test equipment in use was calibrated, that test prerequisites were met, system restoration was completed and test results were adequate.

The selected procedures perused attested conformance with applicable Technical Specifications, in that they appeared to have received the required administrative review and they apparently were performed within the surveillance frequency prescribed.

PROCEDURE	TITLE	DATE OF REVIEW
PT 1.11	Core Performance Parameter Check	6/29/82

PT 1.9	LPRM Calibration	6/23/82
PT 80.0	Reactor Pressure Vessel Operational Leak Check	6/30/82
PT 80.1	Reactor Pressure Vessel Hydrostatic Test	6/30/82

The inspector employed one or more of the following acceptance criteria for evaluating the above items: 10 CFR; ANSI 18.7.

During the surveillance inspection the following items were identified:

On June 29, 1982, Unit 2 vessel had been pressurized to conduct a leak test and an inservice inspection hydrostatic test per PT 80.0. A problem with a recirculation pump caused the test to be discontinued. An inspector review of PT 80.0 revealed that numerous changes had been made under a temporary change dated June 28, 1982. Because of the numerous changes the licensee decided to rewrite PT 80.0 and issue a new PT 80.1. before re-pressurizing the vessel again. Inspector review of the existing PT 80.0, the proposed revision to PT 80.0 and new PT 80.1, which had been partially completed on June 29 and 30, revealed that a test gauge was specified to be installed on drain connection for B21-PS-N002. However no steps were included in the procedures to valve the gauge into service. Inspection of the installed gauge on June 30, 1982 showed that it was not valved into service. Discussion with operation and instrument and control (I and C) personnel indicated that it had probably not been valved into service during the first pressurization on June 29 when data was taken from the gauge and entered on the partially completed PT 80.0. The gauge was to be used to verify that the reactor pressure vessel (RPS) flange O-rings did not leak.

PT 80.0 and PT 80.1 make reference to align per operating procedure OP-1, Nuclear Boiler System Rev. 16. The valve lineup checklist for OP-1 does not include B21-F008, the root valve for pressure sensor B21-PS-N002. This is another example of the violation cited in paragraph 5 of failure to implement and maintain procedures.

Licensee personnel were informed that performance of PT 80.1 as run on June 30, 1982 may not provide assurance that the pressure boundary as defined in ASME code section XI is fully tested. Specifically the piping between the inboard isolation check valves and the outboard isolation valves on core spray, feedwater, HPCI, RWCU and RCIC systems may not be tested. This is an unresolved item pending further testing or submission of acceptable code exemptions by the Licensee (324/82-25-01).

10. Operational Safety Verification

The inspector verified conformance with regulatory requirements throughout the reporting period by direct observations of activities, tours of facilities, discussions with personnel, reviewing of records and independent verification of safety system status. The following determinations were made:

Technical Specifications: Through log review and direct observation during tours, the inspector verified compliance with selected Technical Specification Limiting Conditions for Operation.

By observation during the inspection period, the inspector verified the control room manning requirements of 10 CFR 50.54(k) and the Technical Specifications were being met. In addition, the inspector observed shift turnovers to verify that continuity of system status was maintained. The inspector periodically questioned shift personnel relative to their awareness of plant conditions.

Control room annunciators: Selected lit annunciators were discussed with control room operators to verify that the reasons for them were understood and corrective action, if required, was being taken.

Monitoring instrumentation: The inspector verified that selected instruments were functional and demonstrated parameters within Technical Specification limits.

Safeguard system maintenance and surveillance: The inspector verified by direct observation and review of records that selected maintenance and surveillance activities on Safeguard systems were conducted by qualified personnel with approved procedures, acceptance criteria were met and redundant components were available for service as required by Technical Specifications.

Major components: The inspector verified through visual inspection of selected major components that no general condition exists which might prevent fulfillment of their functional requirements.

Valve and breaker positions: The inspector verified that selected valve and breakers were in the position or condition required by Technical Specifications for the applicable plant mode. This verification included control board indication and field observation (Safeguard Systems).

Fluid leaks: No fluid leaks were observed which had not been identified by station personnel and for which corrective action had not been initiated, as necessary.

Pla[illegible]usekeeping conditions: Observations relative to plant housek[illegible] identified no unsatisfactory conditions.

[illegible]ctive releases: The inspector verified that selected liquid and [illegible] releases were made in conformance with 10 CFR 20 Appendix B and [illegible]al Specification requirements.

Radiation Controls: The inspector verified by observation that control point procedures and posting requirements were being followed. The inspector identified no failure to properly post radiation and high radiation areas.

Security: During the course of these inspections, observations relative to protected and vital area security were made, including access controls, boundary integrity, search, escort, and badging.

During the performance of these observations the following item was identified.

During routine inspection of the Unit 2 drywell, it was observed by the inspector that the 1¼" bypass lines containing bypass valves E21-V17 and V18 around core spray testable check valves E21-F006A and B were apparently not adequately supported. Analysis by a licensee subcontractor indicates that the lines do not meet current seismic criteria. The licensee has decided to remove these valves and cap the lines prior to restart of Unit 2. Inspection of similar lines around other testable check valves on Unit 1 and 2 has been conducted. No other lines needed modification.

The Unit 2 core spray bypass lines were field modified during construction. Records of what seismic review was done are not available at this time.

Check of operating procedure OP-18, core spray system, revision 12 revealed that valves E21-V17 and V18 are not addressed in the valve lineup. This is another example of the violation described in paragraph 5 as a failure to implement and maintain procedures.