UNITED STATES
ATOMIC ENERGY COMMISSION
DIRECTORATE OF REGULATORY OPERATIONS
REGION II - SUITE 818
230 PEACHTREE STREET, NORTHWEST
ATLANTA, GEORGIA 30303

TELEPHONE: 404 524-4503

January 26, 1973

J. G. Keppler, Chief, Reactor Test and Operations Branch, Directorate of Regulatory Operations, Headquarters

ADVANCE INSPECTION INFORMATION MEMORANDUM - DUKE POWER COMPANY (OCONEE 1)
REPORT NO. 50-269/73-1

The purpose of this memorandum is to provide advance inspection information on steam generator tube examination, loose control rod drive lead screw support tubes, and the inspection items remaining to be resolved and/or completed.

A. Steam Generator Tube Examinations

Over 90% of the tubes in both steam generators have been examined by B&W since completion of the hot functional testing. Prior to hot functional testing over 3000 tubes were examined. Four tubes have been removed from each steam generator for destructive testing.

The licensee has been advised that the results of the examinations must be available for review prior to licensing.

B. Control Rod Drive Lead Screw Support Tubes

On January 23, 1973, the Region was notified that approximately 20 control rod drive lead screw support tubes, which are 72 inches long and located directly under the reactor vessel head, were found to be loose following hot functional testing. Preliminary investigation indicates that some looseness in a cold condition is to be expected. Results of B&W's investigation will be available to Region II during the next inspection.

C. Outstanding Items

The following inspection items remain to be completed and/or resolved:

TRANSMITTED VIA MAG CARD
1/26/73 - 3:25 p.m. (cb)

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1. Reactor Coolant Pump Coastdown Test Procedure

The test procedure coastdown curve differs from the coastdown curve in the FSAR. This is being resolved by the licensee.

2. Administrative Policy Manual for Operational Quality Assurance

a. Definition of Major Change to Procedures

The licensee's definition of major change is based on whether or not the "intent" of the procedure was changed. The Region's position is that all but minor changes (typo's, etc.) require the same level of approval as the original procedure.

b. Review and Approval of Modifications

The licensee is considering changes to their modification review and approval requirements to assure compliance with Appendix B and 10 CFR 50.59.

c. Supplemental Information

The details of certain items peculiar to Oconee 1 and referenced in the manual will be provided by the licensee as supplemental information. The licensee has agreed to provide the supplemental information but is not certain that this can be accomplished prior to fuel loading.

3. Liquid Radwaste Flow Meter Calibration

The licensee will fill the tank with a known quantity of water and will verify the calibration of the 0-50 gpm flow meter on the liquid waste discharge line.

4. Completion of Work on Gaseous Effluent Monitors

The licensee has been advised that work must be complete and the monitors operating. The licensee has all but two monitors in service. Work is in progress.

5. Verification That Air Flows are From Clean to Containminated Areas

The licensee is in the process of verifying air flows.

6. Procedure for Transferring Spent Resin to Truck

The procedure has been drafted but has not been approved.

7. Verification of Process Monitor Operation

This work is in progress. The licensee was advised that the radwaste process monitors operation must be verified prior to loading fuel.

8. Completion of Decontamination Facilities

Work is in progress.

9. Verification That Hood Flows Meet Design Requirements

Modifications are in progress to assure correct air flows.

10. Completion of Air Filter Tests

The filters for the hydrogen purge system have been installed. Testing by factory representatives is scheduled prior to fuel loading.

11. Iodine Condensation Losses In An Outside Sample Line

The stack monitor sample line is routed outside the stack (∿ 90 ft.) but is not heated nor insulated. This arrangement could result in condensation of iodine and water. The line also has several 90° elbows. The licensee has agreed to remove the sharp bends and to insulate the line. The Region's position is that the line should also be heated.

12. Evaluation of Efficiency of Iodine Filters in Sample Lines

An in-place determination of the efficiency of the iodine filters in the unit vent and reactor building process monitors has not been made. The licensee intends to replace the filter cartridges monthly and to use the manufacturer's efficiency value. The Region's position is that the efficiency should be determined by testing.

13. Security Plan

The licensee has not identified the security plan applicable to Unit 1.

14. Hot Functional Tests

The licensee must reduce the test data to meaningful and understandable form, review and evaluate the results, approve the tests, and also conduct QA audits of test reviews. The licensee is planning to do this prior to fuel loading. Region II inspectors will complete their review of the test data and the licensee's evaluations.

15. Emergency Procedures

Region II has identified eight emergency procedures the licensee does not have which are needed prior to fuel loading.

a. Loss of Containment Integrity

b. Loss of Flux Indication

c. Inoperable Control Rods/Inability to Drive Rods

d. High Activity In RCS

e. Acts of Nature Other Than Earthquakes

f. Loss of S.G. Feed - (Plan to Write)

g. Abnormal Releases of Radioactivity

h. Irradiated Fuel Damage While Refueling - (Plan to Write)

16. Metallurgical Effects of Oil Fire on Reactor Coolant System Piping

The licensee has agreed to submit a report on the oil fire near one of the reactor coolant pumps addressing this concern. Region II will complete their review of this matter.

17. Steam Generator Tube Examination Results

The licensee has been advised that the results of the examinations must be available for review prior to licensing.

18. Baseline Inspection Data

A regional inspector is at the site reviewing the baseline inspection data. The licensee was advised that questions raised by the inspector (pertaining to the indications disclosed by the baseline inspection) must be resolved prior to licensing.

19. CRD Lead Screw Support Tubes

The licensee was advised that this matter must be resolved prior to licensing.

C. E. Murphy, Acting Chief
Facilities Test and Startup Branch

RO:II:RFW

DETAILS I

Prepared By: R F Warnick — March 8, 1973
R. F. Warnick, Reactor Inspector, Facilities Test and Startup Branch — Date

Dates of Inspection: December 30, 1972, January 17-19, 1973, and January 30 - February 1, 1973

Reviewed By: C E Murphy — March 9, 1973
C. E. Murphy, Acting Chief Facilities Test and Startup Branch — Date

1. Individuals Contacted

a. Duke Power Company (DPC)

W. O. Parker, Jr. - Manager, Steam Production Department
P. H. Barton - Manager, Technical and Nuclear Services
J. E. Smith - Plant Superintendent
J. W. Hampton - Assistant Plant Superintendent
D. G. Beam - Project Manager, Construction
D. L. Freeze - Principal Field Engineer
C. B. Aycock - Senior Field Engineer
J. W. Sigman - Maintenance Supervisor
L. R. Davison - Associate Field Engineer, NDT
A. R. Hollins - Associate Field Engineer, Welding
D. C. Holt - Assistant Nuclear Test Engineer
M. D. McIntosh - Operating Engineer
R. M. Koehler - Technical Support Engineer
L. E. Summerlin - Staff Engineer
C. L. Thames - Health Physics Supervisor
O. S. Bradham - Instrument and Control Engineer
L. A. Reed - Shift Supervisor

b. Babcock and Wilcox Company (B&W)

G. E. Kulynych - Project Manager
R. R. Beach - Manager, Field Operations
J. P. Rowe - Manager, Materials Laboratory
J. J. Williams - Manager, Contract Equipment II

c. B&W Construction Company

W. Faasse - Construction Site Manager
C. D. Thompson - Field Quality Control Supervisor

d. Diamond Power Specialty Corporation

B. D. Ziels - Manager, Engineering

2. Organizational Changes

J. W. Sigman has been promoted to Maintenance Supervisor replacing E. D. Brown who has been transferred to the Charlotte office and given increased responsibilities.

DPC has been informed by Licensing that 19 of their men have passed the licensing examinations. Twelve have been given Senior Operator Licenses and seven have been given Operator Licenses.

3. FSAR Training Commitment Versus Actual Training Received[1/]

The Oconee staff has prepared a revision to the FSAR description of the initial operating staff training program. The revision brings the FSAR into agreement with the training actually received.

This item is closed.

4. Security[2/]

Originally, Licensing indicated to DPC that the Oconee Nuclear Station security plan did not need to be implemented until Unit 2 was ready for operation. The lack of definition of a security plan for Unit 1 was referred by Region II to Headquarters for resolution. Since then, DPC has declared their intention of modifying their security plan and placing it into use with the licensing of Unit 1.

The Oconee Nuclear Station Security Plan, Rev. 1, dated December 26, 1972, has been revised to incorporate comments by Licensing. The proposed security plan, which will be submitted to Licensing the week of February 5, 1973, was reviewed by the inspector.

Portions of the plan cannot be implemented until certain equipment is installed. The inspector was informed that once the equipment is ordered, delivery lag time is estimated to be four months.

Procedures implementing applicable portions of the security plan are being written and will be reviewed by Region II. Additional security guards have been hired and are being trained. The increased security surveillance is apparent.

1/ See RO Inspection Report No. 50-269/72-11, Details I, paragraph 5.
2/ See RO Inspection Report No. 50-269/72-11, Details I, paragraph 6.

This previously reported unresolved item is considered to be satisfactorily resolved; however, additional inspection effort is anticipated within the near future.

5. Verification of Core Bypass Flow

The expected core bypass flows (leakage flows as defined in the FSAR Section 3, pages 3-43 and 3-43a) have been recalculated and updated to reflect current core and system pressure drop information and reported as-built dimensions. The three major leakage paths are through the core shroud, through the control rod guide tubes, and through interfaces separating the inlet and outlet regions. The calculations show that the core bypass flow will be 3.67% of the reactor coolant system flow. This flow is comprised of 1.64% through the core shroud, 1.67% through the control rod guide tubes and instrument guide tubes, and .36% between interfaces separating the inlet and outlet regions.

A Licensing representative stated that the previously required startup test to measure bypass flow will no longer be necessary.

This previously identified unresolved item is closed.

6. Loop Backflow

The reactor coolant system loop backflow was measured during hot functional testing and will be measured again prior to initial criticality but with the core in place. Measurements of the backflow is covered by TP-200/12, "Reactor Coolant Pump Flow Test."

With one pump operating, the backflow in the opposite loop was measured at eleven million pounds per hour. With two pumps in one loop operating, the backflow in the opposite loop was measured at fifteen million pounds per hour.

This previously reported unresolved item is now closed.

7. Administrative Policy Manual for Operational Quality Assurance of Nuclear Stations[1/]

The Region's comments on the manual have been resolved. The comments and the resolutions are as follows:

1/ See RO Inspection Report No. 50-269/72-11, Details I, paragraph 9.

a. Comment: The definitions of "abnormal occurrence" and "unusual event" as stated in the manual differ from definitions stated in the Technical Specifications (TS). To avoid confusion, the definitions should be in agreement (Manual paragraphs 1.2.2.1 and 1.2.2.35).

Resolution: The definitions in the TS are those requested by Licensing. The definitions in the manual are the same as in ANS 3.2.

b. Comment: The independence of the Steam Production Department Quality Assurance Engineer is not evident. Paragraph 1.4.2.3.3 (of the draft copy) states that he "is responsible to the Assistant Vice President, Steam Production, for matters pertaining to operational quality assurance." Figure 1.4-2 shows him under the Manager, Operation and Maintenance.

Resolution: Figure 1.4-2 has been revised to show the Steam Production Department Quality Assurance Engineer directly under the Manager, Operation and Maintenance, but with a dotted line connecting the QA Engineer with the Vice President, Steam Production Department. The language in paragraph 1.4.2.3.2 has also been revised to clearly state to whom the QA Engineer reports.

c. Comment: The manual does not discuss station QA personnel, their duties, nor their responsibilities.

Resolution: Station QA personnel duties and responsibilities have been added.

d. Comment: In paragraph 1.5.3, the allowed revisions do not include improvements in control of quality.

Resolution: This has been included in Rev. 1 to paragraph 1.5.3. The revision will be issued Friday, February 16, 1973.

e. Comment: In paragraph 2.1.5.5, reference is made to "periodically" verify that the various working files and index of the drawings are valid and accurate. The frequency needs to be specified.

Resolution: The master index will be checked for accuracy annually. The various working files will be compared with the master index semiannually.

f. Comment: Records need to be maintained of modifications (design changes) and also of all evaluations to determine if "unreviewed safety questions" exist (Manual Section 2.2).

Resolution: Paragraph 2.2.3.2 provides for this.

g. Comment: Each station needs a list of measuring and test equipment complete with calibration requirements, calibration frequencies, calibration procedure, storage requirements, and manufacturer's recommendation (Manual paragraphs 2.3.3.2 and 2.3.3.3 and 2.3.3.5).

Resolution: Control of measuring and test equipment will be implemented by June 1973.

h. Comment: Paragraphs 2.4.1 and 4.1.1 state that certain requirements shall be applicable to those materials, parts, and components for which quality assurance certification is required. DPC needs to identify those items for which quality assurance certification is required.

Resolution: This information is being compiled by DPC Engineering and will be available by December 1973.

i. Comment: The details of the training, retraining, and replacement training programs need to be available at the station (Manual paragraphs 2.5.4.1, 2.5.4.3, and 2.5.4.4).

Resolution: The retraining program will be available by March 1974. The training and replacement training programs are available now.

j. Comment: The frequency of audits to be conducted by the Steam Production Department Quality Assurance Engineer is not sufficient. The frequency in the draft copy was at least quarterly. This has been changed to semiannual (Manual paragraph 2.6.2.3).

Resolution: Audits will be made at least quarterly.

k. Comment: The word "should" denotes a recommendation while the word "shall" denotes a requirement according to DPC definitions. The paragraphs that key on the word "should" are not inspectable. In the draft copy of manual paragraphs 3.1.3, 3.1.4, 3.1.6, 3.2.1.5, 3.2.1.6, 3.2.2.6, 3.3.2.9, and 3.3.3.9, many "shoulds" are used where "shalls" need to be used.

Resolution: The "shoulds" in question have been changed to "shalls." (In certain instances, the requirement was reworded to clearly state what was intended.)

l. Comment: Paragraph 3.1.5 needs to make it clear that response procedures need to be prepared for all alarms. In addition to training, the book of alarm responses needs to be available in the control room for reference.

Resolution: Response procedures have been prepared for Unit 1 alarms and they are available in the control room.

m. Comment: Paragraph 3.4.1 states that the requirements of Section 3.4 shall be applicable to modifications of safety related structures, systems and components. These need to be identified for consistent application by DPC personnel.

Resolution: This information is being compiled by DPC Engineering and will be available by December 1973.

N. Comment: Do station modifications spoken of in Section 3.4 require engineering approval?

Resolution: This section has been rewritten.

Additional comment: The new Section 3.4 only requires approval by the Station Review Committee and the Plant Superintendent when the modification does not involve an unreviewed safety question or change the technical specifications. Changes to the design need to receive the same reviews and approvals as the original design.

Resolution: Section 3.4 has been rewritten and is now consistent with the requirements of Criterion III of Appendix B to 10 CFR 50.

o. Comment: In paragraph 4.3.2.2.6, a major change is defined as "a change to a test procedure which affects the intent of the applicable approved procedures. . . ." This definition is subject to interpretation because of the word "intent." Minor changes need to be limited to typographical, editorial, or obvious mistakes. All other changes should be major changes. As an alternate, a system to permit temporary changes as discussed in ANS 3.2, and which provides for formal reviews and approvals, may be used.

Resolution: DPC has agreed that minor changes are those "which correct errors in a procedure of a typographical or editorial nature." All other changes will considered major changes.

p. Comment: Test results need to be reduced to meaningful and understandable form. This is not covered in the document.

Resolution: This has been included in the manual.

q. Comment: Have the requirements of Criterion XVI, "Corrective Action," of Appendix B to 10 CFR 50 been covered in the manual?

Resolution: Yes, corrective actions and followup audits have been described in paragraph 2.6.2.3.2.

8. Modification to Permit Underwater Removal of the Gate from the Fuel Transfer Canal 30-Inch Valves

Reviewed Field Change Authorization No. 179 (May 1972) to modify the Oconee Unit 1 fuel transfer system 30-inch gate valves to permit underwater maintenance.

The change makes it possible to remove the valve bonnet bolts and then to pull the bonnet and the valve gate out of the water for maintenance.

The valve is on the spent fuel pool side (outside) of the containment building. A plate can be placed over the opening but is not secured by bolts.

The design and approvals were in order. The inspector has no further questions.

9. Reactor Coolant Pump Motor Oil Leak and Fire

A gasket failure occurred on a high pressure oil line flange in the oil lift pump circuit for the 1B2 reactor coolant pump motor. Oil leaked onto the pump casing and between the pump casing and inlet piping and the Mirror insulation installed at these points. The reactor coolant system was at an elevated temperature for hot functional testing and the leaking oil ignited upon contact with the hot pump casing and inlet piping. The fire was extinguished by operating personnel and the reactor coolant system was cooled down to permit investigation and cleanup.

Since Region II completed the advance inspection information memorandum, which is attached, DPC agreed that the fire was reportable under the requirements of 10 CFR 50, paragraph 50.55(e), and has submitted a report to the Region.

In addition, new flanges utilizing a recessed O-ring seal have been installed on all four oil lift pump systems for Unit 1. The oil overflow and leakage collection drain lines have been permanently rerouted so that the oil will now drain to new 150-gallon reservoirs which have been permanently mounted on the concrete floor below each reactor coolant pump. The four reservoirs have high level alarms.

Both A tanks and both B tanks have interconnecting overflow lines.

The metallurgical effects of the fire on the reactor coolant system piping are discussed in Details IV, paragraph 3, of this report.

No further inspection effort is planned.

10. Termination Check of Lifted Leads[1/]

DPC conducted an audit of cable terminations in engineered safeguards (ES) and reactor protective system (RPS) panels during the week of November 20, 1972. No lifted leads or incorrectly terminated ES or RPS leads were identified. The audit involved about 150 manhours of effort.

One item involving nonsafety related cable was identified which had been missed by both the field forces and the electrical QC. One eight-conductor cable was not terminated in a location which was shown on the latest drawing revision. (The electrical connections were correct but in the wrong location.) This has since been corrected.

There are no further questions and no additional inspection effort is planned.

11. Fuel Loading and Initial Criticality

The inspector identified the following items which need to be completed and reviewed or inspected before Region II will be through with their construction inspections and able to recommend the issuance of an operating license. The operating license is required before any fuel can be loaded into the reactor. (See attached advance inspection information memoranda dated January 26, 1973, and February 2, 1973.)

Preoperational Tests

Twenty-nine preoperational tests remain to be completed and/or reviewed, evaluated, and approved. Certain tests have deficiencies which must be resolved.

1/ See RO Inspection Report No. 50-269/72-10, Details I, paragraph 2.

Core Flood Restrictor Modifications

The installation of the core flood restrictors has not been completed.

Reactor Vessel and Internals

The reactor vessel and internals need to be cleaned after the core flood restrictors are installed.

Security Plan

The Unit 1 security plan must be approved by Licensing.

Administrative Procedures

Certain administrative instructions for use of emergency, alarm, maintenance, and operating procedures need to be written.

Liquid Waste Flow Monitor

DPC needs to complete the calibration of the 0-50 gpm flow meter for measuring the flow rate of liquid waste.

The inspector also identified items which need to be completed and reviewed or inspected prior to initial criticality. These are contained in the advance inspection information memorandum dated February 2, 1973, which is attached.

12. TP-600/10, Reactor Coolant System Hot Leakage

This test was unable to be conducted during hot functional tests because of excessive packing leaks on four valves at the top of the pressurizer and approximately ten other valves inside the reactor building. The test will be completed after the fuel is loaded into the reactor but before initial criticality.

During the hot functional tests, the leaking valves had asbestos-type braided compression packings which did not stand up under hot, borated water service. The leaking valves will be repacked using a graphite laminated packing which has proven successful at other nuclear power stations.

13. Training for Fuel Handlers

Twenty people have received training in preparation for loading the initial core. The training consisted of 16 hours of classroom instruction on mechanical equipment, procedures, health physics, and criticality; at least three hours of actual equipment operation;

and a one hour oral examination administered by the training director, a licensed SRO.

The inspector reviewed the course contents for adequacy, the oral examination checklist for completeness, and the record of training received by each individual.

There are no further questions.

DETAILS II

Prepared By: Francis Jape 3-7-73
F. Jape, Reactor Inspector
Facilities Test and Startup
Branch
Date

Dates of Inspection: January 17 - 19, 1973 and
January 29-30, 1973

Reviewed By: C E Murphy 3/9/73
C. E. Murphy, Acting Chief
Facilities Test and Startup
Branch
Date

1. Individuals Contacted

Duke Power Company (DPC)

J. E. Smith - Plant Superintendent
J. W. Hampton - Assistant Plant Superintendent
M. D. McIntosh - Operating Engineer
R. M. Koehler - Technical Support Engineer
L. E. Summerlin - Staff Engineer
B. C. Moore - Junior Engineer

2. Review of the Preoperational Testing Program

The inspector reviewed the status of the preoperational testing program. The results are as follows:

a. Test Results

The following test procedures and a periodic test were evaluated. Questions on three test procedures have been identified that require resolution prior to initial fuel loading and two that require resolution before initial criticality.

(1) TP 600/27, "Center CRD Venting"

Inspector's Comment

When performing this test, the temperature limit was exceeded. The test record indicates that DPC will either revise the temperature limit or replace the O-rings. This question needs to be resolved prior to initial fuel loading.

Licensee's Response

The O-rings are scheduled to be replaced.

(2) TP 200/36, "Loose Parts Monitoring System Functional Test"

Inspector's Comment

The test results have not been reduced to a concise acceptance statement.

Licensee's Response

The data are being reviewed and a statement will be available shortly.

(3) TP 200/34, "Reactor Vessel and Internal Flow Induced Vibration Test"

Inspector's Comment

The test results have not been reduced to a concise acceptance statement.

Licensee's Response

The test data are being reviewed and a statement will be available shortly.

(4) TP 600/10, "RC System Hot Leakage Test"

Inspector's Comment

This test appears to be incomplete.

Licensee's Response

The hot leakage test has been rescheduled for the heatup prior to initial criticality.

(5) TP 210/8, "Trace Heating Functional Test"

Inspector's Comment

The test results have not been reduced to a concise acceptance statement. In the present form, it is not possible to determine if the acceptance criteria have been met. Resolution of this test is required prior to initial fuel loading.

Licensee's Response

This test is currently under review and all deficiencies will be resolved prior to initial fuel loading.

(6) TP 600/18, "Reactor Protection System Functional Test"

There are no questions or comments on this test.

(7) TP 200/22, "Reactor Vessel Internals Inspection Following Hot Functional Tests"

There are no questions or comments on this test.

(8) TP 200/13, "RC Flow Coastdown Test"

There are no questions or comments on this test.

(9) TP 200/12, "RC Pump Flow Test"

Inspector's Comment

Backflow was verified but accuracy of flow measurement appears questionable. The flow test for A loop appears questionable.

Licensee's Response

This test is scheduled to be run again following initial core loading. Repairs to the flow metering devices are underway and more accurate data will be obtained when the test is rerun.

(10) TP 361/2, "Evacuation Alarm System Test"

Inspector's Comment

There are two deficiencies noted in the test record. The proposed resolution for room 505 is to post a sign at the entrance to this room. This solution does not appear to be within the acceptance criteria as stated in the test.

The second deficiency is to be corrected by installing an additional speaker in the Decon area. The inspector had no question on the resolution to this deficiency.

Both of these deficiencies should be resolved prior to initial fuel loading.

Licensee's Response

These deficiencies are under review and will be resolved prior to initial fuel loading.

(11) TP 330/1, "Integerated CRD System Test"

Inspector's Comment

Two deficiencies were noted in the test record. These deficiencies should be resolved before initial criticality.

Licensee's Response

Both of these deficiencies are under review and will be corrected prior to initial criticality.

(12) TP 161/3, "RB Purge System Functional and Operational Test"

There are no questions or comments on this test.

(13) TP 600/15, "CRD Operational Test"

There are no questions or comments on this test.

(14) TP 600/8, "Component Cooling Water Operational Test"

There are no questions or comments on this test.

(15) TP 800/22, "Thermal Measurements for 1B OTSG Fluids"

There are no questions or comments on this test.

(16) PT 204/7, "RB Spray Performance Test"

There are no questions or comments on this test.

b. Licensee's Review of Test Results

The index of all tests was reviewed to determine if the licensee has reviewed and accepted the results of all tests. Forty-seven tests have been identified as incomplete. These tests are listed below and have been identified as either requiring completion before initial fuel loading or before initial criticality.

(1) Tests to be Completed and Results Evaluated by DPC Before Initial Fuel Loading

Category 1

TP 120/5a	Main Bridge Position and Control Test
TP 210/8	Trace Heating Functional
TP 301/3k	Source Range Response Check with Source
TP 361/2	Evacuation Alarm Test
TP 230/1	Auxiliary Drains and Liquid Waste Functional

Category 2

TP 230/2C	Liquid Waste Disposal Hydro and Leak Test
TP 301/30	RPS DC Power Fan Failure Test

Category 3

200/2	Surveillance Specimen Holder Checkout
361/1A	RM Area Rod Monitoring Calibration and Functional Test

(2) Test Results to be Analyzed by DPC Before Initial Fuel Loading

Category 1

TP 120/5C	Spent Fuel Bridge Position and Control
TP 200/3	RC Hydro
TP 200/5C	RCP Initial Open Test
TP 200/34	Flow Induced Vibration
TP 600/4	CA Open Test
TP 600/5	RC Chem Test
TP 600/6	SG Chem Test
TP 600/18	RCP Functional Test
TP 600/21	H_2 Addition Test
TP 600/22	Degass Test

Category 2

TP 210/5	CA Functional
TP 253/3	H_2 System Calibration
TP 330/2D	CRD Patching Functional Test
TP 600/27	Center Rod Venting

Category 3

TP 220/4	SF Cooling Functional

(3) Test to be Completed and Results Evaluated by DPC Before Initial Criticality

Category 1

TP 115/1	Absolute Filter DOP Test
TP 115/5	HEPA Filter Inspection Test
TP 161/4	H_2 Purge Test
TP 161/4a	H_2 Purge Leak Test
TP 203/5	LP Injection Functional Test
TP 600/28	Piping System Vibration Test
TP 330/1	Integrated CRD System Test
TP 600/10	RC System Hot Leakage Test

Category 2

TP 110/2	Pent Room Flow Press Drop and Filter Test
TP 302/2	Incore Instrument Electrical Test
TP 360/1B	RM 1r 1A-44 Vent Iodine Monitoring Instrument Calibration

Category 3

TP 360/8	RM R1A-31 LPSW Monitoring Instrument Calibration
TP 360/10	RM R1A-35 LPSW Disc Instrument Calibration

Test Requested By Health Physics

1. Verification of in-plant flows.

2. Verification of hood flows.

(4) Test Results to be Analyzed by DPC Before Initial Criticality

Category 1

TP 161/3	RB Purge System Functional and Operational Test
TP 600/26	1500 psig HPI ES Test

Category 2

TP 230/8B	Coolant Treatment Evaporation Functional Test
TP 230/8C	Waste Evaporator Functional
TP 234/3	GWD Waste Gas Decay Flow Instrument Calibration

Category 3

TP 170/1	Auxiliary Building Vent Vans Valve Control Electrical Test
TP 230/9	Resin Slucing Equipment Functional
TP 230/10	Quench Tank Operational Test

3. Review of SRC and NSRC

The membership, meeting frequency and the activities of the Station Review Committee (SRC) and the Nuclear Safety Review Committee (NSRC) were reviewed to determine if these committees are performing as described in the FSAR.

The SRC met 74 times in 1972 with a quorum or more members. The committee activity consisted primarily of reviewing and commenting on test and operating procedures as described in the FSAR.

The NSRC (formerly called GORC) met six times in 1972 with more than a quorum of members. The agenda of these meetings was as described in the FSAR.

The inspector had no questions on the meetings of either of these committees.

4. Reactor Coolant Pump Flow and Coastdown Tests

During an earlier inspection, 1/ the inspector commented that the flow coastdown acceptance curve was not in agreement with the curve presented in the FSAR. The licensee has reviewed these curves and has included a revised coastdown curve for the acceptance criteria. The inspector reviewed the new curve and found it to be in agreement with the curve contained in the FSAR.

The inspector also reviewed the test results and found the data to be in agreement with the acceptance criteria.

5. Review of Operating and Maintenance Procedures

The licensee has responded to RO's comments and questions 2/ on operating and maintenance procedures by preparing a draft of the following Administrative Procedures:

1/ See RO Inspection Report No. 50-261/72-11, Details II, paragraph 6.
2/ See RO Inspection Report No. 50-269/72-11, Details II, paragraph 3 and 4.

Administrative Procedure No. 1 - "Drawing Distribution and Control"
Administrative Procedure No. 2 - "Tagging, Delineation, and Safety"
Administrative Procedure No. 3 - "Actions to be Taken in the case of Exceeding of Limits"
Administrative Procedure No. 4 - "Duties of the Control Operator of the Control Board"
Administrative Procedure No. 5 - "Activities Affecting Station Operation or Operating Indications"
Administrative Procedure No. 6 - "Control of Radiation Exposure"
Administrative Procedure No. 7 - "Reasons for Notifying the Operating Engineer or Superintendent"
Administrative Procedure No. 8 - "Procedures"
Administrative Procedure No. 9 - "Testing after Maintenance"

6. Fuel Inspection

An audit of the fuel inspection records was conducted by the inspector. The records examined indicated either no damage or only minor surface scratches. The fuel was inspected by DPC and B&W personnel. The licensee has documented inspection records for all fuel assemblies.

DETAILS III

Prepared by: M. S. Kidd 2/28/73
M. S. Kidd Date
Reactor Inspector
Facilities Test and
Startup Branch

Dates of Inspection: January 17-19 and
January 30 -
February 1, 1973

Reviewed by: C. E. Murphy 2/28/73
C. E. Murphy Date
Acting Chief
Facilities Test and
Startup Branch

1. Individuals Contacted

Duke Power Company (DPC)

J. E. Smith - Plant Superintendent
M. D. McIntosh - Operating Engineer
R. M. Koehler - Technical Support Engineer
L. E. Summerlin - Staff Engineer
N. A. Rutherford - Junior Staff Engineer
G. W. Cage - Assistant Operating Engineer
O. S. Bradham - Instrument and Control Engineer

2. Emergency Operating Procedures

a. Lack of Procedures

DPC's listing of emergency procedures was compared with those in AEC Safety Guide 33, "Quality Assurance Program Requirements (Operation)," and ANS 3.2, "Standard For Administrative Controls for Nuclear Power Plants." This comparison revealed that there are eight emergency conditions for which no procedure exists or which is not sufficiently covered. These are:

(1) Loss of containment integrity,
(2) Loss of flux indication,
(3) Inoperable control rods or inability to drive rods,
(4) High activity in reactor coolant system,
(5) Acts of nature (other than earthquake),
(6) Loss of feedwater,

(7) Abnormal releases of radioactivity, and
(8) Irradiated fuel damage.

After discussing the need for these procedures, licensee personnel stated that the first seven conditions listed above would be covered prior to initial criticality either by writing a separate emergency procedure or by expanding related alarm procedures or the Oconee emergency plan. Also, a procedure for handling irradiated fuel damage will be written within three months (by May 1, 1973).

b. Comments on Procedures

The inspector reviewed all Unit 1 emergency procedures which had been written and approved (14) and had the following comments:

(1) Certain of the procedures do not require the operator to perform actions manually which should have occurred automatically, but where the automatic actions have failed. Examples include EP 1800/4, "Loss of Reactor Coolant," and EP 1800/8, "Steam Supply System Rupture."

The inspector was informed that this problem would be corrected by implementing administrative instructions to all operating personnel requiring that any automatic action described in an emergency or alarm procedure which has not taken place be performed manually. These instructions are to be implemented prior to core loading.

In addition, the individual procedures will be rewritten within three months to incorporate similar instructions in them.

(2) Certain emergency procedures do not provide information to aid the operator in determining plant status. For example, EP 1800/12, "Loss of Control Room," directs the operator to maintain the steam generators at startup level and the pressurizer level within the normal operating range but does not state what these values are. EP 1800/2, "Turbine Trip," also lacks this type of information.

The inspector was informed that these procedures would be revised within three months to provide this type of information and that other procedures would be similarly revised, if necessary.

(3) Certain procedures direct action to be taken which is performed under another emergency procedure or an operating procedure without referencing the other procedure by title or number. Examples include EP 1800/5, "Boron Dilution,"

EP 1800/8, "Steam Supply System Rupture," EP 1800/11, "Loss of Low Pressure Injection System (Decay Heat Removal)," and EP 1800/12, "Loss of Control Room."

Licensee personnel stated that these procedures would also be rewritten within three months to include the references.

These subjects were discussed during the management interview at which time licensee management reaffirmed their plans to complete the efforts described in this section.

3. Alarm Procedures

a. Description of Procedures

Alarm and emergency procedures for Oconee are written in a format quite similar to that outlined in ANS 3.2. Each procedure consists of a descriptive title, alarm sources (alarm procedures only), symptoms, automatic actions, immediate manual actions, and subsequent manual actions.

A procedure will be written for each alarm plate in the control room and those at the various control stations throughout the plant. They are numbered sequentially with a 1700 series number. They are grouped by number with a set for each alarm panel (group 1701/x for panel 1SA1, 1702/x for panel 1SA2, etc.). The individual number corresponds to the location of the alarm on a panel counting from left to right and top to bottom.

b. Approval of Procedures

The inspector reviewed several alarm procedures and discussed his comments on them with station personnel. He was informed that all the alarm procedures had been rewritten and were being reviewed for approval by the Station Review Committee. After discussions concerning the status of them, licensee personnel stated that those procedures which are associated with safety related procedures will be approved prior to initial criticality. These plans were reiterated during the management interview.

c. Comments on Procedures

The inspector reviewed approximately sixty alarm procedures for Unit 1 and had comments on four of them.

(1) AP 1709/13, "CRD Return Low Flow"

The subsequent action of this procedure instructs the

operator to deenergize the control rod drives if stator temperatures exceed 160°F. Since this action will trip the reactor, the inspector commented that the procedure should contain a note of caution to this effect and reference the procedure or mode of shutdown to be followed.

Licensee personnel stated that the procedure would be revised to include the information commented on.

(2) AP 1702/11, "ICS Runback"

The manual action section of this procedure instructs the operator to refer to the emergency procedures for the conditions listed under the alarm sources sections. The inspector commented that this should be clarified in that only half of the conditions listed were covered by emergency procedures.

Licensee personnel stated that this would be corrected.

(3) AP 1702/35, "ICS Limited"

This procedure does not require the operator to perform any automatic action which has failed.

Licensee personnel stated that this would be remedied by use of the administrative instructions discussed in paragraph 2.b.(1).

(4) AP 1707/05, "ES Analog Channel A on Test"

This procedure contains no instructions for the operator in the manual actions section. The inspector stated that there should be some action taken such as verifying that a test was being run on the channel.

Licensee personnel replied that personnel would not perform maintenance or tests which might cause alarms without first notifying the control room operator. When the inspector asked if this philosophy were part of the administrative instructions for Oconee, licensee personnel stated that such instructions would be written and implemented. They stated that the instructions would require all personnel performing work which might cause an alarm to notify control room personnel before starting. They would also require the operator to investigate the cause of all alarms and notify his supervisor.

This subject was discussed during the management interview at which time licensee management stated that the administrative

instructions would be written and implemented prior to initial core loading.

The inspector was also informed that this procedure and others of an "information only" nature would be rewritten within three months to provide instructions for the operator.

4. Periodic Test and Instrument Procedures

The inspector reviewed approximately thirty periodic test and instrument procedures for Unit 1. A majority of these procedures are rewritten preoperational test procedures. The inspector was informed that weaknesses in the procedures discovered in the testing phase have been corrected in the rewritten procedures. The procedures reviewed are of a format consistent with guidelines of ANS 3.2 and other standards. They are quite detailed and provide for obtaining required documentation of data observed. The inspector's review resulted in comments on the following four procedures:

a. IP 201/01A, "Core Flood Tank Level Instruments Calibration"

This procedure does not require a check of the calibration status of test equipment.

Licensee personnel stated that this requirement would be added.

b. IP 202/01D, "Emergency H.P. Injection Flow Instrument Calibration"

The inspector noted that data sheets for individual modules had not been filled in when this procedure was run. He was informed that it was common practice to test a whole logic string first and then check the individual modules only if the string check was not satisfactory.

When the inspector asked how this method can be used when such procedures do not speak to it, but are written with the intent of testing each component and then the string, licensee personnel stated that the situation would be clarified by developing administrative controls which permit a test of only the logic string if that test is satisfactory.

c. IP 340/4, "Absolute Position Indicator Calibration"

Step 3 of page 3 makes reference to figure 8.1, which the procedure does not contain. Also, step 47 of page 5 instructs the user to repeat certain steps in a confusing manner.

Licensee personnel stated that these steps would be rewritten and

clarified.

d. PT 620/15, "Keowee Hydro Operational Test"

One of the acceptance criteria of this test is that the hydro units come up to "rated speed and voltage" within 25 seconds. The inspector commented that the procedure does not define "rated speed and voltage."

Licensee personnel stated that these would be assigned quantitative values in the procedure.

5. Surveillance Test Schedules

Operations personnel informed the inspector that they did not have a formal testing schedule for operations established, but were in the process of developing one. Plans are to have a schedule for all periodic tests for which the group is responsible recorded in a logbook with a schedule for each general frequency of testing. This schedule would include those tests required by Technical Specifications and other tests to be performed by the operations group.

Discussions with technical support personnel revealed that the instrument and control group had developed a schedule for performing tests for which it is responsible. This schedule was being typed during the inspection. The performance group had not finalized the schedule for its tests but tentative plans indicated that all testing required would be covered.

Licensee personnel stated that the schedules for the three groups discussed above would be combined into a master schedule. The inspector commented that this schedule should be developed as quickly as practicable since it must be in effect as soon as an operating license is issued. This matter was discussed during the management interview.

DETAILS IV

Prepared by: N. Economos 3-9-73
N. Economos Date
Reactor Inspector
Engineering Section
Facilities Construction
Branch

Dates of Inspection: January 17-19, 1973
January 23-24, 1973
February 5, 1973

Reviewed by: J. C. Bryant 3/12/73
J. C. Bryant Date
Senior Inspector
Engineering Section
Facilities Construction
Branch

1. Individuals Contacted

a. Duke Power Company (DPC)

J. E. Smith - Plant Superintendent
J. W. Hampton - Assistant Plant Superintendent
S. Nabow - QA Project Engineer
J. Barbour - QA Engineer

b. Contractor Organizations

Babcock and Wilcox Company (B&W)

F. J. Sattler - Manager, In-service Inspection
G. Walton - Manager, Ultrasonic Inspection
W. E. Lawrie - Supervisor, NDT Developement

2. Baseline Data Inspection

The baseline inspection of components subject to volumetric examination for Oconee 1 was conducted by B&W under contract with DPC. The inspection included all hardware supplied by B&W with the exception of those items stipulated in Appendix 4A, paragraph 3 of the PSAR. The inspection was performed in accordance with Section XI of the ASME Code, 1970 Edition. Results of the inspection were summarized in a report submitted to the licensee on October 1971. The report included the items inspected, the type of inspection, techniques, inspection standards and the test data accumulated for reference in future in-service inspections. A total of 18 calibration blocks were

fabricated by B&W in accordance with applicable specifications of the 1968 edition of the ASME Code, Section III. These blocks have been assigned to DPC, who is responsible for their storage for future reference.

Selection of inspection methods, writing of inspection specifications, inspection and interpretation of inspection results were performed by B&W personnel qualified in accordance with the SNT specification SNT-TC-1A. Baseline specifications were written by Level III personnel and were reviewed and approved by B&W quality assurance personnel from the Engineering and Technology section. Preliminary review of results was conducted by B&W Levels II or III personnel at the site.

Significant indications were listed under two categories: "recordable" and "reportable."

In the case of ultrasonic examination, recordable indications were those producing a response >75% of calibration reference level and, with respect to RT, PT, and MT examinations, recordable indications were those whose magnitude or number was >½ the amount allowed by Section III, Appendix IX of the ASME Code.

Indications regarded as "reportable" were discontinuities greater in size, amplitude or number, of the amount permitted by Section III of the ASME Code, or those which, in the operator's opinion, indicated a crack, lack of penetration or nonfussion. Indications that displayed these characteristics were subject to complimentary inspection methods, and disposition was to be made jointly by DPC and B&W.

The examination included angle and straight beam examination of the base metal to a distance of 1T beyond the line of fussion. Angle beam examinations were conducted using 45° and 60° crystals from both sides of the welds. Vessel weld seams were scanned from both sides of the vessel. Minimum scanning sensitivity was set at 2x reference level. Welds ≥4" were scanned with 45° and 60° crystals used simultaneously. This was made possible with the use of a switching device which permitted single scanning while viewing the responses from both transducers on the cathode ray tube simultaneously.

Personnel conducting the examination were qualified as operators and assistant operators. Operators were qualified as Level II in accordance with the SNT specification, SNT-TC-1A, and the assistants as Level I of the same specification.

Results of the ultrasonic examination of components and weld penetrations, subject to baseline inspection, revealed reportable indications as follows:

a. Reactor Vessel and Closure Head Full Weld Penetrations

A total of 25 reportable indications were detected with lengths varying from one to ten inches and reflectors exhibiting maximum signal amplitudes ranging from 110% to 300% of the DAC curve.

b. Pressurizer, Including Vessel Circle Seam MK2 to 3, Core Spray Nozzle Weld Seam MK9 to 5, and Pressurizer Relief Nozzles

Results disclosed a total of 15 reportable indications with lengths up to 12 inches and reflectors with maximum signal amplitudes ranging up to 150% of DAC.

c. Reactor Coolant Outlet Nozzle Welds and Knuckle Area MK65-7, Both "W" and "Y" Axes

Results disclosed a total of 17 reportable indications from 1 to 4 1/2 inches in length and reflectors with maximum signal amplitudes ranging up to 200% of DAC.

d. Transition Ring Between the Steam Generator Lower Head and the Support Skirt

Results disclosed extensive reportable indications throughout the entire weld seam of both generators 1A and 1B. In the case of generator 1A, these indications varied from 1 to 5-3/4 inches in length with reflectors having maximum signal amplitudes ranging up to 220% of DAC. Likewise, the corresponding weld seam in generator 1B exhibited indications which varied from 1 to 14-3/4 inches in length with reflectors having maximum signals up to 200% of DAC.

Inasmuch as this report did not identify the nature, actual size and location of these indications, it was impossible to make a fair assessment of the indications in question. Consequently, the inspector requested that reportable indications be evaluated and possibly reexamined for the purpose of defining the morphology, severity and relative position of reportable indications. Reexamination included welds in the closure head, reactor vessel, pressurizer core spray and pressure release nozzles. However, in many instances, reexamination from the initial location was precluded by auxiliary components added to these areas since the time of the initial examination. In those instances, the transducer was positioned on a different location and in some cases, on a different surface, e.g., from the O.D. to the I.D. surface on the vessel. This produced reflectors whose amplitude and lengths conflicted with those detected during the original examination.

In the case of the pressurizer and steam generators 1A and 1B, evaluation was based on review of the original UT results and shop radiographs.

In the revised report submitted on February 5, B&W personnel in charge of in-service inspection activities for Oconee 1 reported that all data generated from the entire examination had been evaluated and reviewed by qualified Level III QC personnel who found no areas that did not meet the fabrication requirements for code acceptable components.

In reference to the indications detected in the support skirt weld joint adjacent to the steam generator lower head, B&W reported that the problem was approached through fracture mechanics analysis and baseline UT data evaluation in order to resolve whether these defects impaired the structural adequacy of the vessel or whether the defects were insignificant and could be safely ignored.

B&W's evaluation of the UT data obtained from the baseline inspection was that the defects were slag inclusions which followed the weld bead circumferentially around the vessel. The conclusion reached by B&W as a result of the UT data obtained from the baseline inspection and the engineering evaluation was that these defects (slag inclusions) would not in any way jeopardize the vessel from performing as designated.

In support of this position, B&W noted that the vessel had been shop inspected in accordance with Section III of the ASME Code and had met the acceptance criteria of the code, thus providing the confidence level that the defects in question were insignificant.

Ultrasonic examination of circumferential and longitudinal pipe welds and branch pipe connections >4" diameter produced three reportable indications located in circle seam AH-16 of hot leg pipe weld MK15 to 22. B&W personnel reported that a review of the original radiographs showed them to be acceptable to original fabrication requirements but not definitive enough to permit evaluation of the indications detected ultrasonically. Additional radiographs taken using a more refined technique revealed that the aforementioned indications were discontinuous lines of slag judged to be within the acceptance standards of Section III paragraph N-624 of the ASME Code. Hence, additional investigation of this area was not warranted.

3. Reactor Coolant Oil Fire

Visual examination of the pipe and core coolant pump housing exposed to the oil fire 1/ revealed the affected surfaces were covered with baked-on oil residue, and other combustion products in various concentrations.

The inspector also noted that oil residue was still evident in the "Mirror" insulation. Chemical analysis results of several patch tests taken from areas covered with this residue showed no significant concentrations of halogens within this region. Management indicated efforts were underway to remove the residue from the affected surfaces by mechanical means and by washing. The "Mirror" insulation was scheduled to be cleaned according to procedures generated for this purpose.

4. Inspection of Reactor Internals

Cleanliness of the internal components was being maintained in accordance with applicable cleanliness specifications generated by B&W for Oconee. The inspector conducted an onsite inspection of these components and found no evidence to warrant further consideration of this matter. Close visual examination of pressure vessel clad surfaces, internal components and steam generators 1A and 1B of Oconee 1 disclosed the physical integrity of all the main parts including those which had been modified, was not impaired by the hot functional test.

5. Core Flood Restrictors

Field construction activities are controlled by Field Change Package (FCP-001), generated by B&W for implementation of field operations. The document contains field changes, drawings, welding procedures and specifications taken from the QA manual formulated for the major repair performed on Oconee 1.

Engineering support and field supervision is provided by B&W under contract with DPC; the latter furnishing the necessary manpower and qualified personnel. Qualified welding procedures and performance qualifications of five weldors scheduled for work on the project were reviewed and found to meet the minimum requirements of Section IX of the ASME Code.

1/ Memo from C. E. Murphy to J. G. Keppler, dated January 3, 1973.

All field welding was to be performed using the manual, gas tungsten arc process with 308L SS filler rod material, with a preheat temperature of 70°F and a 350°F maximum indicated interpass temperature. The proposed method of attachment utilizes a backing ring, positioned at the end of the restrictor closest to the reactor, to be field fabricated by weld buildup and subsequently machined to approximately ¼" x ¼". The other end of the restrictor is supported by four buttons, fabricated in the same manner, equally spaced and positioned approximately ten inches into the nozzle. All areas effected by this activity will be dye penetrant tested.

6. Steam Generator Tubing Examination

Eddy current (EC) inspection of the tubes in both steam generators was 87% completed. The purpose of this inspection was to identify those tubes with possible defects at or near the upper surface of the lower tube sheet. The defects of most concern were circumferentially oriented cracks, believed to be the result of stress assisted intergranular corrosion.

The inspection was being implemented through a special procedure generated by B&W, Lynchburg, Virginia. Personnel performing this inspection were from the research and development facilities of B&W and had been specifically trained for the job requirements. All men on this project carried a Level II rating.

Tubes with questionable indications located within three inches on either side of the upper surface of the lower tube sheet were to be ultrasonically examined. At the time of this inspection, approximately 200 tubes had been designated for ultrasonic examination. A complete set of records describing pertinent procedure information and test results will be maintained by B&W for future reference. Preliminary results showed nothing that had not been previously identified. All indications were located near the top of the bottom tube sheet.

On a subsequent inspection during January 23-24, 1973, B&W supervisory personnel reported that a total of six tubes had been plugged in steam generator 1B, because of UT indications. A total of ten tubes had been plugged in steam generator 1A for similar reasons. Tubes with representative indications were to be forwarded to B&W, Alliance, for a metallurgical investigation.

The inspector expressed interest in the results of the quantitative analysis of the corrosion products found in the defective tubes and in the concentration levels of the trace elements found at the localized area of the grain boundaries adjacent to the fissures on these tubes, since this information may help to determine the possible cause of the condition under investigation.

DETAILS V

Prepared by: C. M. Campbell 2-20-73
C. M. Campbell Date
Radiation Specialist
Radiological and
Environmental Protection Branch

Dates of Inspection: January 30-31, 1973

Reviewed by: J. T. Sutherland 2-20-73
J. T. Sutherland Date
Acting Chief,
Radiological and
Environmental Protection Branch

1. Individuals Contacted (All Duke Power Company)

J. E. Smith - Plant Superintendent
R. M. Koehler - Technical Support Engineer
O. S. Bradham - Instrument and Controls Engineer
L. A. Reed - Shift Supervisor
C. L. Thames - Health Physics Supervisor
D. C. Smith - Junior Chemist

2. Organizational Changes

None

3. Completion of calibration of liquid flow meter on rad waste discharge line

Discussion with licensee representatives revealed that this has not yet been completed. After completion of installation the meter could not be calibrated to the desired accuracy apparently due to the low conductivities encountered in the liquids being metered. This has resulted in a different type of meter being installed and the need to fabricate an upstream filter. The fabrication is in process and as soon as it is completed the meter will be calibrated. Licensee management has committed to complete the calibration prior to fuel loading.

4. Completion of work on gaseous effluent monitors

During the last health physics inspection (December, 1972) three gaseous effluent monitors were not fully operational. Calibration of these monitors has been completed and all units are now fully operational.

5. Verification of in-plant air flows

Verification of in-plant air flows including laboratory hood flows, has not yet been completed. A licensee representative stated that it had been determined that additional air flow paths into the laboratories had been needed. These have been created but the actual testing and balancing of the system can not be performed until the filters and grills are in place. Due to a delay in obtaining these from the vendor the licensee is fabricating temporary grills and filters to simulate the same resistance to flow as will be experienced with the permanent assemblies. Once these temporary assemblies are installed the system will be tested and balanced. Then, the verification of in plant air flows will be performed. Upon completion of the installation of the permanent assemblies, the air flows will be again verified. Both verifications will be documented and the documentation reviewed during a subsequent inspection. Licensee management has committed to complete the flow verifications prior to initial criticality.

6. Installation of Solid Waste Compactor

The installation of the solid waste compactor has been completed. It was observed that the exhaust blower motor has been reinstalled. A licensee representative stated that the unit has been tested and is fully operational.

7. Spent Resin Transfer Procedure

The inspector reviewed two draft procedures (Misc. Test Procedure - Resin Transfer and Dewatering and Procedure for Shipment of Radioactive Material), discussed the licensee's health physics plans for resin transfer operations and inspected the physical transfer facilities. The licensee is planning to complete a detailed operating procedure after evaluation of the completed resin transfer system test. A licensee representative stated that the testing of this transfer system will be done using actual resin and the vendor supplied mobile cask system that will be utilized during subsequent resin transfers. The inspector asked what measures will be taken to prevent potential contamination of the storm drain located adjacent to and downgrade from where the truck mounted cask will be located. Licensee representatives stated that provisions will be made to protect the drain area but it is presently uncertain exactly how this will be done since this is still being evaluated. In response to the inspectors question a licensee representative stated that there is no control over any liquids after they have entered the storm drain. A licensee representative stated that the testing of the transfer system was planned for February 2 or February 5, 1973. The completed operating procedure will be reviewed during a subsequent inspection.

8. Calibration of Beckman Beta-Mate II

The calibration of the Beta-Mate II was completed on January 15, 1973. The unit is fully operational and was observed to be in use during the inspection.

9. Calibration of Process Monitors

At the time of the last health physics inspection four process monitors had not been completely calibrated. All of these units have now been calibrated and are fully operational.

10. Status of Decontamination Facilities

Work has been completed on the installation and hook-up of the hood. It was observed that the hood has been placed in its permanent location and the hook-up of the hood exhaust duct to the room ventilation ducting has been completed.

11. Verification of air flow in laboratory hoods

Verification of air flows in the hoods in the health physics and radiochemistry hoods has not yet been done. Modifications to the ventilation system, to get more flow paths into the laboratory areas to the hoods, are not completed. Upon completion of this the verification testing will be performed. Management has committed to completion of this item prior to initial criticality. (See Details V, paragraph 5).

12. Filter testing of hydrogen purge system

The evaluation of the results of this test had not been completed. Management committed to having this completed prior to achieving initial criticality.

13. Sample delivery line losses

Licensee is in process of having the remaining sharp angle turns removed in the sample delivery line from the reactor building to process monitors RIA 47, 48 and 49. Licensee has agreed to conduct tests to determine sampling line losses. Samples will be collected from the reactor building and by its process monitor for comparison. This evaluation will be performed at a subsequent time when there is adequate activity in the line to allow for valid measurements.

14. Verification of efficiency of halogen collection media

Licensee will perform a sampling program to verify the

performance of the halogen process monitors. Grab sampling will be done for laboratory analyses for comparison with the process monitor readout and the laboratory analyses of the halogen collection filter. The grab samples will be obtained from the existing sampling point adjacent to the process monitors.

15. Iodine condensation losses

The licensee has completed the insulation of the outside sample delivery line, from the unit vent (stack) to its process monitor, in order to reduce the possibility of condensation. A differential pressure monitor with control room readout and alarm is installed to indicate any blockage problems.

16. Representative sampling of liquid effluent dur liquid waste discharge

Licensee has made provisions to obtain representative liquid samples during rad waste discharge. Management has committed to do continuous liquid sampling during liquid discharge from the rad waste system. Discussions with licensee representatives indicated that the actual details of the continuous sampler are still being evaluated.

17. Health physics training for fuel handlers

The inspector reviewed the health physics training program for fuel handlers. The program consists of formal, informal and practical training. The topics covered include review of basic health physics, limits, instrumentation, alarm and emergency response, contamination control, anticipated radioactivity levels, and other pertinent topics. Upon completion of training the trainees are observed by supervision performing required duties. Upon completion of training the fuel handlers are determined to be qualified and the training is documented in each individuals training file.

DETAILS VI

Prepared By: J. C. Bryant, Senior Inspector, Engineering Section, Facilities Construction Branch — 2/23/73 Date

Dates of Inspection: January 30-31, 1973

Reviewed By: R. F. Warnick, Reactor Inspector, Facilities Test and Startup Branch — 2/23/73 Date

1. Persons Contacted

a. Duke Power Company (DPC)

J. E. Smith - Plant Superintendent
J. W. Sigman - Maintenance Supervisor
G. M. Thrailkill - Staff Engineer
R. Miller - Principal Engineer, Mechanical Section (by telecon)
W. O. Parker - Manager, Steam Power Production

b. Contractor Organizations

Babcox and Wilcox Company (B&W)

G. E. Kulynych - Project Manager
R. R. Beach - Manager, Field Operations
J. P. Rowe - Manager, Materials Laboratory

2. Piping Systems Vibration Test

The partially completed test, No. TP/1/A/600/28, "Piping Systems Vibration Test," was reviewed. This test pertained to the following systems: Low pressure injection including core flood, decay heat removal and 1-1/2-inch supply to pressurizer; high pressure injection; spent fuel cooling; low pressure service water; component cooling; steam generator flush and drains; reactor coolant system, loop drains; reactor building spray; reactor coolant pressurizer and surge; and pressurizer relief valve vents.

The procedure required that these systems be visually and audibly inspected. It further required that, if unusual movement or vibration were detected, a Vibragraph or vibration analyzer be used to measure frequencies and amplitudes and a determination be made that limits were not exceeded. Graphs were provided for this determination.

A chronological log was kept by the engineers inspecting and the systems were signed off at completion of the visual and, where required, instrument inspections. All systems were signed off except for spent fuel cooling which had not been completed and was scheduled in the immediate future.

Data sheets provided calculations from instrument measurements where separate frequencies and amplitudes were added to assure compliance with specifications, and measurements were plotted on the graphs provided. Measurement points were marked on isometrics.

Irregularities, not necessarily related to the test, which were found during the inspection, were noted in the log. At the inspector's request, a punch list showing those items as entered and later corrected was presented.

The staff engineer stated that the main steam lines will be measured for vibration when power operation is underway.

No discrepancies were found during the inspection.

3. Pipe and Component Hanger Hot Deflection and Inspection Test

The completed test, No. TP/1/B/600/4, was reviewed. The stated purpose of the test was to verify the predicted load and travel on selected hangers and to adjust those not within the required margins. Also, measurements were taken at several points on one of the primary loops to determine lateral and vertical movement of the reactor coolant pumps, steam generator, and pressurizer, and vertical movement of the reactor.

Data was taken at 50°F increments from 150°F to 500°F. The data were reviewed and approved by DPC Engineering Department. The review stated that all data fell within calculated values.

Data were taken on deflection of some of the hangers, and the report and log stated that no travel exceeded the operating range. DPC Engineering stated that the official data were taken by Grinnell Corporation and that a full report would be prepared by DPC, probably in early 1973.

Site personnel stated that all lines in the primary system were walked at each temperature to verify freedom from seismic restraints, supports and other equipment. This inspection and results were noted in the test log.

Movement of primary equipment and connecting coolant loop lines was measured at 13 points on one loop. Acceptable movement was provided for ten of these points. Since lagging had been replaced, visual inspection showed little of how measurements were taken. At one SG reference point, a permanent reference point could be seen. DPC supervision stated that pointers were clamped to equipment, and measurements taken to these reference points by calipers and micrometers.

Data were reviewed for primary loop equipment movement. All data fell within the acceptance criteria except for horizontal deflection of A-2 coolant pump. Allowable movement was given in the X direction as 1-3/16 inches and in the Z direction as 9/16 inch (both horizontal movement).

It was noted on the test, log, and review that A-2 pump reached the design limit in Z direction at 350°F. Telecons were made to DPC Engineering and permission was given to increase temperature to the next plateau provided no physical interference was noted. At 450°F, DPC Engineering provided a new limit of 1-1/4 inches for the Z direction and this was not exceeded.

After completion of the test, the test summary stated that the design values for X and Z had been reversed on the reference drawing; therefore, Z had a limit of 1-3/16 inches which had not been exceeded. The Regulatory Operations inspector found that after this determination was made, the reviewers apparently did not check the X movement data against the new value of 9/16 inch. Data revealed that the maximum deflection in the X direction was 0.853 inch at 500°F. It had also exceeded the limit at 450°F with 0.649 inch.

The inspector questioned DPC Engineering and requested an Engineering evaluation concerning the excessive deflection. A letter was subsequently received which stated that evaluation revealed that the excessive movement had not resulted in exceeding allowable stress values.

The inspector had no further questions at this time.

4. Control Rod Drive Lead Screw Support Tubes

A presentation was made in which DPC and B&W personnel provided the following information.

Following hot functional testing, the licensee observed that all CRD lead screw support tubes exhibited minor degrees of "looseness." Tests by B&W proved that a support tube that is installed tightly will, because of differential expansion, be deformed about one mil by one thermal cycle. No further deformation results from repeated thermal cycles. The deformation causes the tube to appear to be "loose" under cold conditions. The looseness is not sufficient to permit the support tube to touch the lead screw. B&W reports the looseness disappears at 250°F.

No further inspection effort is planned at this time.

5. Steam Generator Tube Examination 1/

B&W personnel described the inspections performed and results obtained following discovery of a steam generator tube leak.

During the hydrostatic pressure test of the A steam generator, prior to hot functional testing, a tube leak was discovered. The section of tube containing the leak was removed for examination and analysis. The leak occurred in a circumferential crack located approximately 1/8 inch above the top side of the bottom tube sheet. The crack existed in an arc of approximately 120°.

The crack was intergranular and a deposit was found on the secondary side covering the crack. Analysis of the deposit revealed that it contained sulphur. A laboratory study on the effects of sulphur on Inconel 600 was instituted. The study revealed that polythionic acid could cause cracking in Inconel. The acid was not found, but it could have existed under conditions of temperature and moisture to which the generator had been exposed.

Following identification of the leak, 1000 tubes in each steam generator were examined by eddy current test over their entire length by a contractor. B&W developed an improved eddy current technique and examined another 1000 tubes. Some, which had questionable indications, were also examined by UT. Several tubes were removed for destructive examination.

Approximately 400 tubes in each SG gave some indication near the entrance to the top of the lower tube sheet. B&W said that this was to be expected due to the change in SG configuration at this point. After hot functional testing, all tubes in both SG's were eddy current tested over the lower 30 inches, which included 6 inches above the tube sheet. UT was also used to aid in identification of signals. Additional destructive examination was made. In all, approximately 19 tubes were removed and examined as an aid in defining the different classes of indications given by NDT.

In addition to the leaking tube, three others had cracks (up to 20 miles in depth but not penetrating). The four cracked tubes were adjacent to at least one other cracked tube. These four tubes gave a unique pattern on eddy current and ultrasonic tests. All four tubes, and no others examined, had a deposit on the secondary side over the crack area. No other pattern of signals revealed any damage to tubes when laboratory examined. The conclusion drawn was that contamination entered the A steam generator, localized at the four cracked tubes, and during layup attacked the tubes.

1/ See RO Report No. 50-269/72-10, Details I, paragraph 8.

DPC is studying layup procedures for possible modifications to prevent conditions that might facilitate corrosion.

An additional 15 tubes in SG's A and B were plugged (some removed) due to damage sustained by interference with auxiliary feedwater nozzles.

The inspector had no further questions.

6. Pressurizer Relief and Safety Valves

A visual inspection was made of pressurizer relief and safety valve discharge piping and DPC supervision was questioned concerning verification of adequacy of the restraints. DPC stated that the relief valve had been popped at operating temperature and pressure with no unfavorable reaction noted, and that safety valves had been reevaluated by DPC Engineering to verify adequacy.

No calculations were reviewed.

DETAILS VII

Prepared By: J. C. Bryant for 3/14/73
W. D. Kelley, Reactor Inspector
Engineering Section
Facilities Construction Branch
Date

Dates of Inspection: January 30 - February 2, 1973
and February 26, 1973

Reviewed By: J. C. Bryant 3/14/73
J. C. Bryant, Senior Inspector
Engineering Section
Facilities Construction Branch
Date

1. Individuals Contacted

a. Duke Power Company (DPC)

A. R. Hollins - Associate Field Engineer - Welding
L. R. Davidson - Associate Field Engineer - NDT
D. G. Beam - Construction Manager

b. Contractor Organizations

1. DPC Consultant

H. Thielsch - Professional Engineer

2. Babcock and Wilcox Company (B&W)

W. Faasse - Field Project Engineer
C. D. Thompson - QA Engineer
J. L. Troxell - Senior Welding Engineer

2. Welding Deficiencies Program

a. Radiographic Inspection

All radiographs have been reevaluated by independent Level II and Level III examiners and all reradiography has been completed and accepted by the consultant. The findings of the audit of this portion of the program are contained in RO:II Report No. 50-269/72-9.

b. Weld Data Records

The consultant required DPC to review and correct all errors or illegible information on the weld data cards. This required the review of other documentation where the identical information was recorded. All errors have been corrected.

c. Documentation - Weld Material

The weld material documentation has been broken into the following four categories:

(1) List of weld material heat numbers for which actual material certifications are available.

(2) List of weld material heat numbers for which typical material certifications are available.

(3) List of weld material heat numbers contain obvious transposition of mill heat numbers or misprints of numerials or letters. An explanation is given for each error and the correct heat number listed.

(4) List of weld material heat numbers for which no data is available nor an explanation of the deficiency.

The above was the subject of a separate report by the consultant. An engineering justification was made for the one heat number for which no mill test report was available.

d. Welding Procedure Qualifications

The consultant reviewed all welding procedures with their revisions and tabulated his findings. The review included the welding procedure qualification test coupons. If the test coupons did not meet the dimensions of ASME Code Section IX, the procedures were requalified. The consultant reported that all welding procedures are now qualified in accordance with ASME Code Section IX.

e. Weldor Qualification Tests

The weldor qualification test coupons were reviewed by the consultant and those weldors on site whose test coupons did not conform to the dimensions specified by ASME Code Section IX were requalified. The weldor qualification test coupons of weldors who are not presently employed by DPC were reviewed by the consultant. He evaluated them as being acceptable for qualification even though they did not meet the ASME Code Section IX dimensions.

The inspector took no exception to the evaluation.

f. Inspection Procedure and Personnel

The DPC nondestructive testing procedures were reviewed by the consultant and he required that they be qualified by a demonstration test. He reviewed the qualifications of the nondestructive test personnel and his evaluation is that they were qualified to perform the tests.

g. Final System Audit

The consultant has performed his final system audit.

He insisted that all systems piping be inspected and all isometric erection drawing be revised to the "as built" status by DPC before he performed his audit. All isometric drawings have been revised and the isometric revision sheets have been approved by DPC's mechanical engineer, associate engineer-welding, and associate engineer-NDT.

The consultant selected for audit, from the field weld joint checkoff list, over 100 buttwelds that had not been re-radiographed in the radiograph inspection program. At least one buttweld per isometric drawing was selected for audit.

After the weld was selected by the consultant for audit, all information stenciled on the pipe was recorded, photographs taken of the weld, and the weld width and ferrite content measured and recorded. The stenciled information recorded was the weldors identification symbol and pipe and/or fitting heat number. The nearest branch weld to the buttweld was also selected for audit and the above information recorded.

The isometric drawings were audited by the consultant for the piping size and material and the information recorded. The end point welds on the isometric drawings were checked to be sure they were documented. The piping material documentation was not audited because this item was considered closed by DPC by Region II's letter of April 20, 1972 (CO:II:CEM 50-269/71-7).

The weld data cards were reviewed by the consultant and the information pertaining to the weldors symbol, NDT technician identification, weld procedure, weld material heat number, and weld repair history was recorded. The weldor's symbol had to agree with the weldor's symbol stenciled on the pipe, and the weldor's qualification was verified against the time of the weldors employment.

The welding material heat numbers for the buttwelds recorded on the weld data cards were listed and audited to determine if they agreed with the specifications on the isometric drawing. The radiographs were then evaluated and audited for film overlap and compared with the weld photograph.

Two welds on System 51A Isometric drawing 16-III and 2-II were selected at random by the RO inspector and the results of the consultants audit were reviewed in detail with the consultant. The audit was in accordance with the final system audit and documentation was available and was checked for verification by the consultant.

h. Reactor Coolant Loop Piping - Post Weld Heat Treatment

During the audit of the reactor coolant loop piping documentation, it was found that in a number of instances post weld heat treatment temperature was recorded above the maximum specified temperature of 1150°F and went as high as 1270°F. Holding times as long as 8 hours were recorded while the maximum specified time was 3-1/2 hours.

Tests were conducted on both the base material and weld deposits and it was reported that the tensile properties were lowered slightly; the impact data didnot show any significant shift of the transition curve; and the analysis of the properties of the material used in the components and the data obtained indicate that all material should be acceptable for the intended service.

3. Thin Wall Valves

DPC has completed their program of measuring valve wall thickness and identified those valves important to nuclear safety that were below the minimum wall thickness specified by the standard or code referenced in their purchase order.

The entire valve body wall thickness of these valves was not verified. DPC elected to measure only the barrel of the body and the run extending out from the barrel for a distance "T" where "T" is the calculated minimum wall thickness. This criterion was not stated in their report, "Reactor Coolant System Pressure Boundary Valves."

The valve wall thickness measurements were made by technicians previously qualified as Level I - Ultransonics per SNT-TC-1A who were given an exercise in thickness measurement using specimens made from wrought pipe specimens.

A small test specimen was made from a forged valve body of ASTM A-182, F316 material and its acoustic properties were compared with a test specimen machined from ASTM A-296, T316 bar stock that covered the full range of thickness to be measured. There was no difference in measurements of the two specimens due to acoustic properties from 0.105 inches through 0.450 inches. A cast stainless steel bar of CF8M material was used as a calibration standard for measuring cast valve body wall thickness. DPC noted that there was a difference in the acoustic properties of the cast material for a given thickness and that an error existed between physical valve body wall thickness measurement.

These findings were not stated in their report nor was this error taken into consideration in reporting the measured wall thickness. The RO letter of February 16, 1973, states that if a measurement error of 2% cannot be met, the measured wall thickness must meet the required thickness by an amount at least equal to the maximum measurement error.

The thin areas of the valve body wall thickness were not mapped and available to the design engineer preparing the report nor the radiographs of the casting evaluated for casting defects that might require an engineering evaluation in order to use higher stress values.

The method of determining the wall thickness of valve number IRV-67 was changed by the vendor from B16.5 to the 1968 edition of ASME Section III, Nuclear Vessels, Article 1-2, paragraph 1-222(2). This edition of Section III is for nuclear vessels and the paragraph and section referenced are for cylindrical shells. They do not apply to valve bodies. It was not until the 1971 edition of Section III that subarticle NB 3500 was included for the design of Class I valves. At that time this section was broadened to include nuclear power plant components.

This does not meet the requirements of the RO letter of June 30, 1972, paragraph 4, which states that the wall thickness must meet the requirements of the codes and standards in effect on the date of purchase.

Thin walled valves will remain an unresolved item pending resolution of the following:

a. Justification for not measuring the entire valve body wall thickness.

b. Documentation of the measurement error using UT and its effect on the tabulated wall thickness in the report.

c. (1) Calculation of valve wall thickness of valve No. 1-RV-67 in accordance with the applicable codes.

(2) In valve No. 1-RV-67, determination that mating surfaces of the two parts are not perpendicular to the root of the assembly pressure containing weld as shown on the manufacturer's drawing.

4. Venturi Insert Assembly - Core Flood Nozzle

B&W field sketch RH-12273 has been revised (Rev. 1, Jan. 1-23-73), requiring eight 3/8" wide by 4-1/4" long slots on the inside of the venturi insert core flood nozzle assembly. The slots were machined into the assembly at the B&W shop. The sketch required the slots to be free of weld metal to the inside diameter of the positioning ring and a slot in the inside positioning ring at the bottom of the nozzle to allow drainage of the area between the two venturi assembly positioning rings. The sketch was revised on February 1, 1973, by the design engineer upon his arrival on site to show that the welding was controlled where the slots were not covered by weld deposit and to show the dimensions of the slots in the bottom of the positioning ring.

The positioning rings were made by weld buildup in accordance with B&W weld procedure WR-87. The rings were machined using the same pneumatic driven boring equipment used for machining the main coolant loop piping weld end preparation in the field. The venturi was welded in accordance with B&W welding procedure WR-88.

A review of weld data sheet No. WR-87 revealed that it was for welding in the flat-vertical and overhead positions, and it referenced B&W welding procedure qualification, PQ 1605. The welding procedure qualification, PQ-1605, was dated September 22, 1967, and stated that the qualification position was the horizontal fixed or 5G position. The welding of the retainer ring was in the 5G position. The B&W welding engineer concurred that weld data sheet WP88 was not applicable to the welding of the venturi and revised the weld data sheet to reference the correct welding procedure qualification.

The procedure required the welding wire to be of 308L composition and actual mill test certications were available from Arcos Corp. for the wire. The certifications met the specifications (Heat No. C2209T308L).

A B&W field construction procedure (O11) was written, which is a process sheet for the repair with the quality control check points identified. The repairs and inspection for both nozzles are being signed off on a single work copy kept in the reactor at the work location in the vessel. The construction procedure will be revised (Sequence No. 410) to reflect the design changes of B&W field sketch RH-12273.

DPC weldors performing the modification welding were qualified in accordance with the B&W weld procedures referenced on the weld data sheet. The qualifications were available for audit.

The inspection revealed no discrepancies.