U. S. NUCLEAR REGULATORY COMMISSION

REGION V

Report No: 50-397/91-39

Docket No: 50-397

Licensee: Washington Public Power Supply System
P. O. Box 968
Richland, WA 99352

Facility Name: Washington Nuclear Project No. 2 (WNP-2)

Inspection at: WNP-2 site near Richland, Washington

Inspection Conducted: October 23 - December 8, 1991

Inspectors: R. C. Sorensen, Senior Resident Inspector

D. L. Proulx, Resident Inspector

Approved by: P H Johnson 1/3/91
P. H. Johnson, Chief — Date Signed
Reactor Projects Section 3

Summary:

Inspection on October 23 - December 8, 1991 (50-397/91-39)

Areas Inspected: Routine inspection by the resident inspectors of control room operations, verification and validation of operating procedures, licensee action on previous inspection findings, operational safety verification, surveillance program, maintenance program, licensee event reports, special inspection topics, procedure adherence, and review of periodic reports. During this inspection, Inspection Procedures 42700, 61726, 62703, 71707, 90712, 90713, 92700, 92701, 92702 and 93702 were utilized.

Safety Issues Management System (SIMS) Items: None.

Results:

General Conclusions and Specific Findings

Significant Safety Matters: None.

Summary of Violations and Deviations: No violations or deviations were identified.

Open Items Summary: Three followup items were closed. One new item was opened.

DETAILS

1. Persons Contacted

*L. Oxsen, Deputy Managing Director
*J. Irish, Bonneville Power Association
*J. Baker, Plant Manager
L. Harrold, Assistant Plant Manager
C. Edwards, Quality Control Manager
R. Graybeal, Health Physics and Chemistry Manager
*D. Pisarcik, Assistant Health Physics and Chemistry Manager
*R. Webring, Plant Technical Manager
J. Harmon, Maintenance Manager
*A. Hosler, Licensing Manager
*S. Davison, Quality Assurance Manager
R. Koenigs, Design Engineering Manager
S. McKay, Operations Manager
*J. Peters, Administrative Manager

The inspectors also interviewed various control room operators, shift supervisors and shift managers, and maintenance, engineering, quality assurance, and management personnel.

*Attended the Exit Meeting on December 6, 1991.

2. Plant Status

At the start of the inspection period, the plant was operating at 100% power with an unusually high equipment drain (EDR) flow rate. On October 26, power was reduced to approximately 10% to allow a drywell entry for locating the source of the high EDR flow. Two drain valves on the reactor water cleanup (RWCU) line from the "A" recirculation loop were found to be about 1/8 to 1/4 turn open. When these were closed, EDR flow dropped to its normal rate of about 2 GPM. Reactor power was returned to 100% by October 28. The reactor was again shut down on the night of October 31 due to a condenser tube leak. The leak was repaired and the reactor was restarted on the evening of November 3. During the 1000 psi walkdown of the drywell on the morning of November 4, a reactor coolant pressure boundary weld was found to be leaking (see paragraph 4). The plant was shut down again and the weld was repaired, as well as three others that were possible future candidates for vibration induced fatigue failure. The reactor was restarted on November 7 and 100% power was achieved on November 9. On the morning of November 19, the plant scrammed from 100% power due failure of the feed flow summer in the Feedwater Level Control System (see paragraph 5). An Unusual Event was declared when reactor vessel level subsequently decreased to the Level 2 setpoint. The plant was taken to cold shutdown on the morning of November 20. The plant was restarted on November 22, and 100% power was again achieved a few days thereafter. At the end of the inspection period, the plant was operating at 100% power.

3. Previously Identified NRC Inspection Items (92701, 92702)

The inspectors reviewed records, interviewed personnel, and inspected plant conditions relative to licensee actions on previously identified inspection findings, as follows:

a. (Closed) Violation (397/91-12-05): Failure to Follow Emergency Diesel Generator (EDG) Operating Procedure

The licensee had incorporated guidance into the EDG operating procedure for action to take in the event of an excessively low level in the generator bearing oil. It specified that emergency action be taken (when the EDG was operating in a non-emergency condition) to secure the unit in the event of low oil level. The action that had been intended by the Technical staff person who initiated the procedure change was an immediate tripping of the EDG. However, a low level condition was experienced by the operators and the EDG was not tripped. This was cited as a violation of the operating procedure, which was required by Technical Specifications.

The licensee revised Plant Procedures Manual (PPM) 2.7.2, the EDG operating procedure, and PPM 7.4.8.1.1.2.1, the EDG monthly surveillance procedure, to provide specific guidance to trip the EDG when it is running in a non-emergency condition and a low bearing oil level condition has developed. This was also discussed in the Operations Department Night Order book, which was required reading for all of the Operations staff.

This item is closed.

b. (Closed) Violation (397/91-18-01): Second Verification Not Provided on Certain Clearance Orders as Required

The inspector had identified seven different clearance orders on safety-related components that did not have required independent verifications accomplished. The clearance order procedure was required by Technical Specifications.

The licensee revised clearance order procedures PPM 1.3.8A and PPM 1.3.8C. This revision included an addition to the Shift Manager's responsibilities to specify whether independent verification is required on any given clearance order, both when the clearance order is being hung and when it is being cleared.

This item is closed.

c. (Closed) Unresolved Item (397/91-35-05): Performing Traversing Incore Probe (TIP) Normalization after Local Power Range Monitor (LPRM) Calibration Instead of Prior to LPRM Calibration

The inspector had identified a potential problem with performance of the TIP normalization. It appeared that the normalization of the TIPs was being accomplished after the actual calibration of the

LPRMs, despite a Technical Specification (TS) requirement to perform the normalization prior to this calibration. Further review and discussions with reactor engineers revealed that the Powerplex system, installed in 1986, performs the normalization internal to the system prior to the calibration, after receiving all TIP data from all LPRM locations. Therefore the inspector determined that the licensee was in compliance with the Technical Specifications.

However, the inspector noted that the procedure that governs this process, PPM 9.3.3, "LPRM Calibration", had been in error from 1986 until 1989. Specifically, PPM 9.3.3 had directed that the five TIPs be run through the reference locations first, and that TIP normalization constants then be derived before running the TIPs through all the plumbed locations. This was in error, since Powerplex takes all the TIP data from all the plumbed locations as a batch, and does its own internal normalization prior to LPRM calibration, as described above. Since Powerplex functions in this way, and apparently has since it was first installed in 1986, it was apparent to the inspector that the reactor engineers had not been following PPM 9.3.3 until it was revised in 1989 to reflect how Powerplex really functions. Since PPM 9.3.3 is required by TS and Regulatory Guide 1.33, failure to follow this procedure is an apparent violation of TS requirements. However, since the criteria for a non-cited violation from the NRC Enforcement Policy were satisfied, this violation will not be cited (91-39-01, Closed).

This item is closed.

4. Leaking Socket Weld in Reactor Coolant Pressure Boundary

On October 31, the licensee shut down the reactor due to high reactor water conductivity resulting from an apparent condenser tube leak. The leak was repaired and the reactor was restarted on November 3. During the 1000 psia walkdown of the drywell on the morning of November 4, plant operators discovered a leaking socket weld in the reactor coolant pressure boundary. The weld was located on a 3/4-inch drain line connected to the 12-inch Train "A" shutdown cooling return piping to the recirculation loop. The licensee shut down the unit pursuant to Technical Specifications requirements.

Several similar socket weld failures have been experienced in the past at WNP-2. They have typically been the result of one or both drain valves being located downstream of an elbow in the drain piping, creating a large moment arm. This, coupled with high localized vibration, leads to fatigue cracking from the outside in. However, the licensee discovered upon further examination that the initiator of the November 4 failure was a construction defect in the weld (lack of fusion), causing it to crack from the inside out. Such defects are difficult, if not impossible, to detect in this type of weld. The ASME Code requires only dye penetrant testing (PT) and visual exams for this type of weld, which are effective only for detecting cracks in the outer surface of the weld. Ultrasonic testing or radiography, while effective for the interior of the weld, would be inconclusive in this application due to the geometry of the weld.

The licensee had previously classified all drain line socket welds in direct communication with the reactor coolant pressure boundary according to their susceptibility to a small break LOCA. Locations with a large moment arm and high vibration were considered highly susceptible. Locations with only one of these attributes were considered to be of medium susceptibility, and locations with neither of these attributes were considered to be of low susceptibility. Most of these welds had PT performed on them about a year ago when a similar problem had arisen. PT was again performed during the 1991 refueling outage. The particular weld that had failed on November 4 had shown no indications on both occasions. Most of the highly susceptible connections were upgraded to a stronger weld configuration during the 1991 refueling outage. This one, however, had been deferred to the 1992 refueling outage because of poor accessibility for repair.

Four locations left from the 1991 refueling outage were classified as highly susceptible to a small break LOCA. The licensee elected to provide temporary remedies for these locations during the early November outage, and provide a permanent solution during the 1992 refueling outage. In three of the four cases these temporary solutions involved removal of the valves from the drain line (i.e., replacing the drain line with a welded nipple), thus eliminating the large moment arm. In one location, another weld pass was completed on the socket weld. The medium susceptibility locations will also be worked during the 1992 refueling outage.

The licensee restarted the unit on the morning of November 7. While no violations or deviations were identified, the licensee was encouraged at the exit meeting to take steps to permanently rectify the recurring problem with socket weld failures.

5. <u>Feedwater Transient with Resultant Reactor Scram and Engineered Safety Feature (ESF) Actuations</u>

At about 7:45 a.m. on November 19, 1991, WNP-2 experienced a rapid reactor pressure vessel (RPV) level increase over a period of several seconds. The increase ended when RPV level reached the Level 8 setpoint of +54.5". This caused a trip of both feedwater pumps, and a turbine trip with a resultant reactor scram. RPV level subsequently decreased over about a 45-second period until it reached the Level 2 setpoint of about -50". A number of ESF actuations occurred at Level 2. The Division III emergency diesel generator (EDG) started, the high pressure core spray (HPCS) pump started, and non-essential loads were shed from the emergency buses. A number of nuclear steam supply shutoff system (NS^4) isolations also occurred, including a main steam isolation valve (MSIV) closure and an isolation of reactor closed cooling (RCC) water to the drywell. All of these actuations were according to design.

Reactor core isolation cooling (RCIC) was started manually by the operators when RPV level was decreasing through about -20". The MSIV isolation complicated the event, necessitating RPV pressure and level control using RCIC and safety relief valves (SRVs). An Unusual Event was declared when RPV level decreased to the Level 2 setpoint. The Emergency Operating Procedures (EOPs) were entered when RPV level decreased through

+13", as required. The operators responded well to the event, following their EOPs closely. Loss of RCC to the drywell caused drywell temperature to increase to about 139 degrees, constituting another EOP entry condition, and resulting in a drywell pressure increase. Another ESF actuation of HPCS occurred at a drywell pressure of about 1.34 psid. HPCS was quickly secured. RPV pressure and level were eventually stabilized and pressure was equalized around the MSIVs, allowing them to be opened. This allowed a condensate booster pump and bypass valves to be used for RPV pressure and level control. The Unusual Event and the EOPs were exited when plant conditions were stabilized in Mode 3 and RPV pressure and level were being controlled by a booster pump and the bypass valves. The decision was made to go to cold shutdown (Mode 4) later that day.

The feedwater transient was caused by the failure of a feedwater summer in the feedwater level control system (FLCS). The FLCS compares feedwater flow, steam flow, and actual RPV level, and adjusts feedwater flow accordingly by controlling feed pump speed. The feedwater summer adds the feedwater flow in both feedwater lines and inputs this value to the level controller. A one-amp fuse in the summer card blew, causing the summer output to go a value of less than zero. This was interpreted by the level controller as zero feedwater flow, and caused the feed flow/steam flow mismatch to go to maximum. The level controller rapidly ramped up the speed of both feedwater pumps, increasing feedwater flow to the maximum, and all the events depicted above ensued.

A similar event occurred in March 1987. The same fuse had blown at that time, although it was then a 1/4-amp fuse. The licensee decided following the 1987 event to upgrade the fuse size to one amp, since the 1/4-amp size was unduly conservative and increased the risk of a significant plant transient. The blown fuse in November 1991 was considered to have been valid, resulting from a failing capacitor in the summer card. The capacitor was replaced, and the card behaved normally. However, the licensee elected to replace the whole summer card in the FLCS.

The 1987 event was also complicated by the shedding of electrical loads which occurs at Level 2 ($\geq$-50"). This included shedding of turbine service water (TSW) and RCC, and much of the normal plant lighting. The TSW system is the principal cooling water supply for many plant components, and must be restored promptly to avoid equipment damage. Loss of RCC results in heatup of the primary containment, requiring prompt operator action to avoid another isolation and ECCS actuation at less than 2 psig in the containment, after which RCC cannot be restored. This distraction of the operators and the need to move about the plant and perform various evolutions without normal lighting additionally complicates followup to an event. The LER which addressed the March 1987 event included a licensee commitment to assess the advisability of modifying the load shedding scheme to avoid unnecessary complications at Level 2 (a condition which is not unusual following some loss-of-feed events). During discussions following this event, plant management stated that TSW had been modified during the 1990 refueling outage to shed only if a loss of offsite power occurs, and that a design change addressing the RCC issue was budgeted for the 1994 refueling outage (subject to emergent work which might compete for budget resources).

The inspectors attended the debriefing of involved control room operators and the restart Plant Operations Committee (POC) meeting. The inspectors concluded that the licensee had thoroughly investigated the various aspects of the transient. The inspectors found the performance of the control room operators in response to the transient to be exemplary, and so informed the Plant Manager. The plant was restarted on November 22.

No violations or deviations were identified.

6. Operational Safety Verification (71707)

a. Plant Tours

The following plant areas were toured by the inspectors during the course of the inspection:

- Reactor Building
- Control Room
- Diesel Generator Building
- Radwaste Building
- Service Water Buildings
- Technical Support Center
- Turbine Generator Building
- Yard Area and Perimeter

b. The following items were observed during the tours:

(1) Operating Logs and Records. Records were reviewed against Technical Specification and administrative control procedure requirements.

(2) Monitoring Instrumentation. Process instruments were observed for correlation between channels and for conformance with Technical Specification requirements.

(3) Shift Manning. Control room and shift manning were observed for conformance with 10 CFR 50.54.(k), Technical Specifications, and administrative procedures. The attentiveness of the operators was observed in the execution of their duties and the control room was observed to be free of distractions such as non-work related radios and reading materials.

(4) Equipment Lineups. Valves and electrical breakers were verified to be in the position or condition required by Technical Specifications and administrative procedures for the applicable plant mode. This verification included routine control board indication reviews and conduct of partial system lineups. Technical Specification limiting conditions for operation were verified by direct observation.

(5) Equipment Tagging. Selected equipment, for which tagging requests had been initiated, was observed to verify that tags were in place and that the equipment was in the condition specified.

(6) General Plant Equipment Conditions. Plant equipment was observed for indications of system leakage, improper lubrication, or other conditions that could prevent the system from fulfilling its functional requirements. Annunciators were observed to ascertain their status and operability.

The inspector toured the reactor building with the Plant Manager on November 7 and pointed out to him components or equipment with substandard material condition. This included the following:

* A heating steam relief valve with a sizable body-to-bonnet leak at the 471' level. The leakage was directed into a collection funnel and drained away through a hose that extended to the 441' level, through the main corridor of the plant and into a floor drain in the turbine building.

* Notable leakage from a discharge check valve in Train "B" of the reactor closed cooling (RCC) water system. The shaft seal was leaking heavily and the leakage was directed via a hose to a floor drain. The inspector noted that this indicated that the RCC system may be further degrading. It was already lined up using certain of its pumps and heat exchangers to maximize cooling capacity, since it could not maintain low enough temperatures using all pump/heat exchanger combinations.

* Oil leakage from the "B" standby liquid control (SLC) pump motor. In addition, water leakage was observed from the "A" SLC pump stuffing box.

* Puddles of water standing around the "B" containment atmospheric control (CAC) skid. It appeared that there was a leak of standby service water somewhere on, or under, the CAC skid. Earlier in the week, the puddles had been large enough to form a pool around the CAC skid. A mop and bucket had been placed nearby with a sign indicating the existence of a personnel safety hazard.

Although none of the material deficiencies depicted above appeared to impact the operability of any safety related equipment, the inspector expressed his concern about the appearance and material condition of WNP-2 in general as evidenced by these specific examples. By the end of the inspection period, the licensee had taken steps to correct most of these deficiencies, and had identified for correction the rest of them.

(7) Fire Protection. Firefighting equipment and controls were observed for conformance with administrative procedures.

(8) Plant Chemistry. Chemical analyses and trend results were reviewed for conformance with Technical Specifications and administrative control procedures.

(9) Radiation Protection Controls. The inspectors periodically observed radiological protection practices to determine whether the licensee's program was being implemented in conformance with facility policies and procedures and in compliance with regulatory requirements. The inspectors also observed compliance with radiation work permits, proper wearing of protective equipment and personnel monitoring devices, and personnel frisking practices. Radiation monitoring equipment was frequently monitored to verify operability and adherence to calibration frequency.

(10) Plant Housekeeping. Plant conditions and material/equipment storage were observed to determine the general state of cleanliness and housekeeping. Housekeeping in the radiologically controlled area was evaluated with respect to controlling the spread of surface and airborne contamination.

The inspectors noted on several occasions during the inspection period that plant housekeeping was poor. The inspectors found loose paper trash, unattended radwaste, standing water, ladders and loose hand carts resting against piping, and oil leaks throughout the reactor building. These deficiencies were brought to the attention of licensee management and were corrected. The Plant Manager stated that housekeeping conditions were not up to his expectations and that the sensitivity of equipment operators and floor coordinators would be increased.

(11) Security. The inspectors periodically observed security practices to ascertain that the licensee's implementation of the security plan was in accordance with site procedures, that the search equipment at the access control points was operational, that vital area portals were kept locked and alarmed, and that personnel allowed access to the protected area were badged and monitored and the monitoring equipment was functional.

c. Engineered Safety Feature Walkdown

Selected engineered safety features (and systems important to safety) were walked down by the inspectors to confirm that the systems were aligned in accordance with plant procedures. During walkdown of the systems, items such as hangers, supports, electrical power supplies, cabinets, and cables were inspected to determine that they were operable and in a condition to perform their required functions. Proper lubrication and cooling of major components were observed for adequacy. The inspectors also verified that certain system valves were in the required position.

Accessible portions of the following systems were walked down on the indicated dates.

System	Dates
Diesel Generator Systems, Divisions 1, 2, and 3	October 23, 30, November 4, 8

Hydrogen Recombiners	October 24, November 30
Low Pressure Coolant Injection (LPCI) Trains "A", "B", and "C"	October 23, 30, November 4, 8
Low Pressure Core Spray (LPCS)	October 24, 30, November 8
High Pressure Core Spray (HPCS)	October 23, November 7
Reactor Core Isolation Cooling (RCIC)	October 24, November 4
Residual Heat Removal (RHR), Trains "A" and "B"	October 23, November 8
Scram Discharge Volume	October 24, November 4
Standby Gas Treatment (SGT)	November 4
Standby Liquid Control (SLC)	November 4
Standby Service Water	October 24, 30 November 8
125V DC Electrical Distribution, Divisions 1 and 2	October 23, November 8
250V DC Electrical Distribution	October 23, November 8

No violations or deviations were identified.

7. Surveillance Testing (61726)

Surveillance tests required by the Technical Specifications (TS) were reviewed on a sampling basis to verify that: (1) a technically adequate procedure existed for performance of the surveillance tests; (2) the surveillance tests had been performed at the frequency specified in the TS and in accordance with the TS surveillance requirements; and (3) test results satisfied acceptance criteria or were properly dispositioned.

Portions of the following surveillance tests were observed by the inspectors on the dates shown:

Procedure	Description	Dates Performed
7.4.3.7.6.2	SRM Channel Functional Test	November 1
7.4.3.1.1.56	Main Steam Line High Rad Channel Functional Test	November 14

7.0.0	Shift and Daily Instrument Checks	December 1
7.4.3.1.1.49	APRM and Core Thermal Power Channel Calibration Checks	December 2

No violations or deviations were identified.

8. Plant Maintenance (62703)

During the inspection period, the inspector observed and reviewed documentation associated with maintenance and problem investigation activities to verify compliance with regulatory requirements and with administrative and maintenance procedures, required QA/QC involvement, proper use of clearance tags, proper equipment alignment and use of jumpers, personnel qualifications, and proper retesting. The inspector verified that reportability for these activities was correct.

The inspector witnessed portions of the following maintenance activities:

Description	Dates Performed
AR-6030, RPS MG Set Bearing Replacement and Testing	November 12
AR-5549, Repair of RHR-FCV-64B	December 5

During the testing portion of the work on the RPS MG set the inspector noted that, although the work was generally performed in a deliberate step-by-step manner with good participation from the maintenance engineer, minor deficiencies existed. AR-6030 stated that no fire impairment checklist or permit was necessary for the work. However, the fire door for the RPS MG set room was propped open to allow for the passage of cables for testing equipment. The fire impairment checklist was nevertheless obtained, despite the improper procedural guidance. This was brought to the attention of the maintenance engineer, and the procedure was revised to indicate that a fire impairment checklist was required.

The inspector also noted that AR-6030 directed the user to "periodically monitor bearing vibration and temperature levels" for the MG set. This was to preclude destruction of the MG set by operating it at excessive vibration and temperature for an extended period of time. The mechanic stated that he interpreted this statement to mean that the bearing vibration and temperature should be checked at hourly intervals when data required for the procedure were to be taken. The inspector discussed this observation with the maintenance engineer, who stated that the intent of this procedural direction was for the mechanic to take the periodic readings approximately every five minutes, and then directed the mechanic to begin taking these periodic readings. The first reading taken at this time showed excessive vibration of the MG set and indicated that it should be immediately secured. However, before the mechanic could take action, the MG set tripped automatically.

Although the reactor protection system (RPS) MG set is not safety related, the deficiencies noted above indicate the need to ensure that the expectations of management and engineering are properly communicated to maintenance personnel performing the work.

During the repair of RHR-FCV-64B, the inspector noted that the maintenance work request (MWR) directed the repair of the wrong lead within the torque switch compartment (lead BVID-9119 versus the correct wire, BRHR-9036). The error was found at the worksite, a procedure change was initiated, and the work was performed in accordance with the MWR. Although the work was performed correctly, this incident emphasized the need for attention to detail in the development of work procedures.

No violations or deviations were identified.

9. Review of Verification and Validation Program (42700)

The inspector reviewed the licensee's Verification and Validation (V&V) program to ascertain the contribution of the V&V program to the quality of Plant Operations procedures. The V&V program at WNP-2 consists of a twofold process. The verification process has thorough checklists to research the applicable requirements and as-built drawings. The validation process can consist of walkthrough in the plant, operation in the simulator, or a tabletop discussion. The inspector determined that decisions appeared to have been appropriate the type of validation to perform for specific procedures.

The inspector noted that a large percentage of the V&V effort was dedicated to surveillance procedures (Volume 7) and annunciator/abnormal operating procedures. There are a large number of these procedures and each was to be V&V'd and would be subject to a subsequent biennial V&V. Other procedures contained in different volumes of the PPMs were V&V'd when time permitted. The inspector expressed concern that Volume 2 (system operating) procedures required to be invoked when using the EOPs were not prioritized as being among the first procedures to be V&V'd. The inspector had noted previously, as discussed in NRC Inspection Report No. 91-28, that PPMs 2.3.3A/B had not been V&V'd despite being invoked by the EOPs. The inspector also noted several errors in those two PPMs which were documented in NRC Inspection Report No. 91-28. The inspector's subsequent review of the V&V program revealed that five other procedures (contained in Volumes 2 and 12 of the PPMs) called out by the EOPs apparently had not received a V&V. These procedures are listed as follows:

Procedure PPM Number	Description
2.4.2	Operation of the RHR System
2.3.1	Primary Containment Venting, Purging and Inerting
12.10.1	Operation of the Post Accident Sampling System

2.10.2	Operation of Turbine Building Heating, Ventilation, and Air Conditioning (HVAC) System
2.10.5	Operation of the Radwaste Building HVAC System

The licensee committed to reassess the prioritization process for performing Verification and Validation and make adjustments to the program, if necessary. The inspector will verify these actions during a future inspection (Followup Item 91-39-02).

No violations or deviations were identified.

10. Unresolved Items

Unresolved items are matters about which more information is required to determine whether they are acceptable items, violations or deviations. One unresolved item was closed during this inspection, as discussed in paragraph 3 of this report.

11. Exit Meeting

The inspectors met with licensee management representatives periodically during the report period to discuss inspection status, and an exit meeting was conducted with the indicated personnel (refer to paragraph 1) on December 6, 1991. The scope of the inspection and the inspectors' findings, as noted in this report, were discussed with and acknowledged by the licensee representatives.

The licensee did not identify as proprietary any of the information reviewed by or discussed with the inspector during the inspection.