Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
ANO 1	Entergy	Yes. At the beginning of the outage, the head was inspected using a remote video camera robot. 100% of the head and nozzles were inspected for boric acid residue and compared with the initial baseline inspection performed during 1R14 and the follow-up inspection performed 1R15. The head was cleaned in 1R14 and there was essentially no change of boron crystal concentration on the head from the 1R14 baseline and the 1R15 inspection. During 1R16 a flow path was discovered at the bottom of nozzle 56. Following repair of the failed nozzle, the outer surface of the head at nozzle 56 was cleaned removing all boric acid residue and the base metal inspected for material wastage. There was no visual detection of boric acid material degradation or related surface corrosion. As a follow-up activity, the complete head assembly was again cleaned and a new baseline inspection performed using the video robot where 100% of the head and nozzles were inspected. As a backup, 100% of the head and nozzles was also inspected using a boroscope camera. Recognizing that there are unique advantages between the two video inspection systems, both were utilized. All inspections, both pre-outage and post nozzle 56 repair, were recorded on videotape. No degradation to the vessel head was found. A copy of a VHS formatted presentation that shows the robotic inspection capability was provided to the NRC in Entergy letter dated August 23, 2001 (1CAN080103)	Yes, There are unique advantages between the video robot and the boroscope. There are a few areas around the center nine (9) nozzles that the video robot cannot access due to interference with the insulation structure. Even though 100% head was inspected not all of the nozzle to head annulus could be viewed by the video robot. However, the down hill side of the center nozzles were inspected. To supplement the robot inspection, the boroscope was utilized to view the uphill side of the aforementioned center nozzles. Following repair of nozzle #56, utilizing both inspection systems, approximately 90% of the nozzle to head annulus was inspected for each of the center nozzles. 100% of the down hillside of the head was inspected for every nozzle. There was no indication of RCS leakage or resulting material wastage at any nozzle. Nozzle #56 is one of the outer nozzles and 100% of the annulus and bare metal was able to be inspected.
ANO 2	Entergy	It is not practical to perform a 100% bare metal visual examination of the ANO Unit 2 head. Insulation is in contact with the head and covers a majority of the head surface. The insulation around the CEDM nozzles and instrument nozzles does not allow direct 100 % (360 degree) inspection of the nozzle to head interface. However, it is possible to examine portions of head / nozzle interface from above for each nozzle in sufficient detail to determine that no significant corrosion has occurred. Inspections are performed every cycle in accordance with Generic Letter 88-05 and no evidence of surface corrosion from boric acid has been seen. Additionally, system engineering looks for the standard white / red rust colors similar to what is seen on valves that have experienced boric acid corrosion around the nozzles and insulation openings. Particular attention is given to looking for possible boric acid build-up i any location on the head. The perimeter of the head is inspected for signs of boric acid coming from under the insulation. Also, the insulation is inspected to determine if it is deformed or relocated for any reason to confirm there is no boric acid crystal buildup under the insulation. Inservice Inspection personnel also routinely perform inspections of the accessible portions head including the head-to-head flange weld. In addition, an inspection of the CEDM welds and motor housings was performed by CE during 2R14 (spring 1999). ANO-2 has not seen any evidence of boric acid leakage that would indicate leakage on the head. In addition, there has been no significant spillage or leakage from the CEDM motors or upper pressure housings.	Per NUREG/CR-6245 , leakage over a significant amount of time (six to nine years) and significant amounts of boric acid (~12 cubic feet of crystals) would be required to corrode the RPV head to a point where it challenges the structural integrity of the head. Per CEN-607 , CEN-614 , and NUREG/CR-6245, it is highly unlikely that the evidence of this leakage would go undetected over a six to nine year period (i.e., approximately four to six GL 88-05 inspections). Twelve cubic feet of boric acid crystals is equivalent to 1000 pounds of boric acid. If corrosion is approximately proportional to leakage, then several tenths of a gpm over several years would be required to threaten the structural integrity of the head. Additionally, CEOG document CE NPSD-690-P has previously evaluated inspecting the small bore Inconel 600 nozzles that could leak do to leakage from PWSCCs without removing the insulation. The document reports that if 10 pounds of boron crystals were to buildup due to PWSCC leakage, the boron would either extrude from the annulus region between the insulation and nozzle or from the insulation seams. Although this report was written for the small bore penetrations, it is considered valid for the Entergy's CE heads (ANO-2 and Waterford 3) and Westinghouse heads (Indian Point 2 and 3). Based on the GL 88-05 inspections along with other routine inspections of the ANO-2 head per question 1, Entergy has not identified any boric acid leakage that would indicate the conditions for head thinning on ANO-2. As noted below, ANO-2 will conduct an inspection of 100% of the RPV nozzles during the upcoming outage in approximately 5 weeks.
Beaver Valley 1	FirstEnergy Corp	September 2001 – A bare head examination was performed by Framatome ANP, assisted by FENOC Level III Visual personnel. The examination was performed by removing panels of mirror insulation at each of the three shroud openings to allow access to the penetrations using the Rovver 400 crawler supplemented with a video probe. Complete four-quadrant coverage of all the vessel head penetrations was achieved to detect any significant external corrosion or boric acid accumulation. The results of the visual examinations were also reviewed and video was observed by the NRC.	September 2001 – (Visual Inspection was 100%) Two of the head penetrations had boric acid crystals in the vicinity of the penetrations as well as adjacent penetrations due to previously documented # 1 and # 2 conoseal leakage (Conoseal # 1 – 1984, Conoseal #2 – 1989). Penetration #65 had a slight depression on the upper 180 degrees of circumference due to chronic conoseal leakage. This was characterized as corrosion wastage between 1/16" and 1/8" in depth and approximately ½" in width. Penetration #59 also had boric acid accumulations in the vicinity of the penetration. There was no wastage or appreciable corrosion in this area as evidenced by the machining tool marks still visible in the area.
Beaver Valley 2	FirstEnergy Corp	February 2002 - A bare head examination was performed by Framatome ANP, with follow-up review by FENOC Level II & III Visual personnel. The examination was performed by removing panels of mirror insulation at each of the three shroud openings to allow access to the penetrations using the Rovver 400 crawler supplemented with a video probe. Complete four-quadrant coverage of all the vessel head penetrations was achieved to detect any significant external corrosion or boric acid accumulation	February 2002 - (Visual Inspection was 100%) - The Unit 2 head was cleaner than Unit 1, with no evidence of any leakage from any of the penetrations and no significant boric acid leakage from other external sources.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
ANO 1	Entergy	No characterization was warranted since no degradation was found with the video inspection	ANO-1 will perform a qualified visual examination of the upper surface of the reactor vessel head during 1R17 (the nex refueling outage scheduled for the fall of 2002). The visual examination will determine if there is any significant corrosion to the vessel
ANO 2	Entergy	ANO-2 has not performed UT or another non-visual approach on the RPV head	For ANO-2, plans are to continue performing GL 88-05 inspections. Additionally preparations have been made to perform a volumetric examination of 100% of the RPV penetrations during the scheduled refueling outage 2R15 (April 2002). Entergy is discussing with Westinghouse potential alternate methods besides visual for investigating corrosion degradation of the low alloy steel area next to the nozzle. This would be needed for ANO-2 if an area of the head were suspected to be degraded since insulation removal is not feasible. Various techniques may include UT reflection from the nozzle ID, low frequency eddy current techniques, and/or use of an ultrasonic phased array probe from the ID of the head, which may be able to profile a corroded head surface
Beaver Valley 1	FirstEnergy Corp	N/A	No Spring 2002 outage.
Beaver Valley 2	FirstEnergy Corp	N/A	The Beaver Valley Unit 2 RFO was conducted during Feb 02. Examinations were completed with 100% coverage of the RV head penetration areas within the shroud periphery. With no evidence of leakage from any of the penetrations, and no evidence of any significant boric acid leakage on the head from other sources above the head, there is nothing to indicate the potential for boric acid corrosion of the reactor vessel head pressure boundary.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Braidwood 1	Exelon	At Braidwood Station there have not been any exams performed under the reactor vessel head insulation that would cover 100% of the reactor vessel head. During the fall 2001 refueling outage at Braidwood Unit 1 (A1R09), visual examinations were performed of the accessible areas of the head during Mode 3 prior to unit shutdown. These exams were performed using ASME Section XI VT-2 certified personnel and were intended to detect leakage or boric acid deposits per NRC Generic Letter 88-05 commitments. These exams were conducted on the reactor vessel head with the shroud assembly access doors opened and the vessel head insulation in-place. There were no signs of leakage or boric acid deposits. Also, during the Unit 1 refueling a VT-3 visual examination, using ASME Section XI certified personnel was performed on the underside of the reactor vessel head using a remote camera arrangement. This exam was conducted per the requirements of ASME Section XI, Category B-N-1, Item B13.10, and included a visual examination of the surface of the VHP to vessel head weld. There were no signs of cracking, linear indications, erosion, corrosion, or wear. Finally, during the restart of Unit 1 fro In general, Braidwood performs a visual exam of the CRDM housings and VHP housing areas above the vessel head insulation each refueling outage. This examination is performed in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR plants." The exam is performed by certified VT-2 examiners and is intended to identify any evidence of leakage including boric acid deposits. The exam is performed by direct VT-2 method through the open access doors in the cooling shroud assembly. The procedural requirements for this exam state: "QUANTIFY and RECORD all locations of Boric Acid residue, evidence of borated water and/or non-borated water. When examining Class 1 Components, pay special attention to the RX Vessel head canopy seal area, the RCP studs, steam generators and pressurizer." Since the start of Generic Letter 88-05 exams at Braidwood Station, there have been no recordable indications identified in the Generic Letter 88-05 exams conducted on the reactor vessel head. A DRPI (digital rod position indication) modification was performed at both Units 1 and 2 which provided an opportunity for additional inspections not typically experienced due to improved access and even more ability to identify boric acid, none was found. Everything contributing to boric acid leakage other than VHP cracking has been inspected and has not contributed to boric acid at either Braidwood unit. The VHPs at both Braidwood units is not currently considered a potential source of boric acid given both sites rankings (>129 EFPY)	Braidwood believes these examinations are sufficient to detect and monitor boric acid accumulation for several reasons. First, considering leakage from vessel head penetrations (VHP), Braidwood Units 1 and 2 are in the NRC category of plants which can be considered as having low susceptibility to VHP cracking. As reported in the Braidwood response to NRC Bulletin 2001-01, Braidwood Units 1 and 2 have been ranked for the potential for primary water stress corrosion cracking (PWSCC) of the reactor pressure vessel (RPV) top head nozzles using the time-at-temperature model and plant-specific input data reported in MRP-48. This evaluation indicates that it will take Braidwood Units 1 and 2 129.5 and 154.8 effective full power years (EFPY), respectively, of additional operation from March 1, 2001, to reach the same time at temperature that Oconee Nuclear Station Unit 3 had at the time that its leaking nozzles were discovered in February 2001. Because of this low susceptibility, leakage from the VHPs and subsequent accumulation of Boric Acid on the vessel head around the VHP is very unlikely. Leakage of borated reactor coolant from Control Rod Drive Mechanism Housings that might propagate down onto the vessel head surface is also considered unlikely. The Braidwood design has CRDM housings welded directly to the VHP. There are no bolted connections (Davis Besse has bolted connections in lieu of canopy seal welds) which might be susceptible to leakage and there has never been any RCS leakage through any of the three canopy seal welds (lower, intermediate, and upper) on the CRDM housings at Braidwood Station. Also, any leakage from the canopy seals, CRDM housings, or from a failed VHP-to-CRDM weld would be detected in the visual exams performed each outage described in the response to question 1. Braidwood Station has seven vessel head connections that could be considered bolted connections. There are two Reactor Vessel Level Indication System penetrations and five Core Exit Thermocouple Penetrations. All these penetrations are located around the periphery of the vessel head and are disconnected and reassembled each refuel outage. Again, leakage from these connections would be detected in the visual exams performed each outage described in the response to question 1. Also, leakage from these peripheral penetrations, as well as any other peripheral VHP, would show as dried boric acid trails on the bare metal of the vessel head since the area directly below these VHPs is un-insulated and directly observable when the vessel head is mounted on the stand during refueling.
Braidwood 2	Exelon	At Braidwood Station there have not been any exams performed under the reactor vessel head insulation that would cover 100% of the reactor vessel head. During the fall 2000 refuel outage at Braidwood Unit 2 (A2R08), visual examinations were performed of the accessible areas of the head during Mode 3 prior to unit shutdown. These exams were performed using ASME Section XI VT-2 certified personnel and were intended to detect leakage or boric acid deposits per NRC Generic Letter 88-05 commitments. These exams were conducted on the reactor vessel head with the shroud assembly access doors opened and the vessel head insulation in-place. There were no signs of leakage or boric acid deposits. In general, Braidwood performs a visual exam of the CRDM housings and VHP housing areas above the vessel head insulation each refueling outage. This examination is performed in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR plants." The exam is performed by certified VT-2 examiners and is intended to identify any evidence of leakage including boric acid deposits. The exam is performed by direct VT-2 method through the open access doors in the co A DRPI (digital rod position indication) modification was performed at both Units 1 and 2 which provided an opportunity for additional inspections not typically experienced due to improved access and even more ability to identify boric acid, none was found. Everything contributing to boric acid leakage other than VHP cracking has been inspected and has not contributed to boric acid at either Braidwood unit. The VHPs at both Braidwood units is not currently considered a potential source of boric acid given both sites rankings (>129 EFPY).	(see Braidwood 1 response)

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Braidwood 1	Exelon	N/A - Braidwood Station was not required by NRC Bulletin 2001-01 to perform any UT or non-visual examinations on VHPs or base material.	At this time, Braidwood Station does not plan on supplementing the examinations discussed in the response to Question 1. Also, because of the low susceptibility to VHP cracking discussed in the response to NRC Bulletin 2001-01, there ar no plans to perform a qualified, effective reactor vessel head bare metal visual exam on Braidwood Unit 2 during the Spring 2002 refuel outage. Braidwood Station believes that given the reliability of the VHPs, the absence of any past RCS leakage on the vessel head, the limited potential sources of boric acid leakage on the Reactor vessel, and the level of detail in current visual exams regarding detection and reporting of boric acid, it is very unlikely that there is significa boric acid corrosion.
Braidwood 2	Exelon	N/A - Braidwood Station was not required by NRC Bulletin 2001-01 to perform any UT or non-visual examinations on VHPs or base material.	At this time, Braidwood Station does not plan on supplementing the examinations discussed in the response to Question 1. Also, because of the low susceptibility to VHP cracking discussed in the response to NRC Bulletin 2001-01, there ar no plans to perform a qualified, effective reactor vessel head bare metal visual exam on Braidwood Unit 2 during the Spring 2002 refuel outage. Braidwood Station believes that given the reliability of the VHPs, the absence of any past RCS leakage on the vessel head, the limited potential sources of boric acid leakage on the Reactor vessel, and the level of detail in current visual exams regarding detection and reporting of boric acid, it is very unlikely that there is significa boric acid corrosion.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Byron 1	Exelon	At Byron Station there have not been any exams performed under the reactor vessel head insulation that would cover 100% of the reactor vessel head. During the Fall 2000 refueling outage at Byron Unit 1, visual examinations were performed of the accessible areas of the head during Mode 3 prior to unit shutdown. These exams were performed using ASME Section XI VT-2 certified personnel and were intended to detect leakage or boric acid deposits per NRC Generic Letter 88-05 commitments. These exams were conducted on the reactor vessel head with the shroud assembly access doors opened and the vessel head insulation in-place. There were no signs of leakag or boric acid deposits. During B1R11 (3/12/02) visual examinations (VT-2) were performed, using ASME Section XI certified personne There was no evidence of boric acid observed on any components above the insulation or on the insulation.	Byron believes these examinations are sufficient to detect and monitor boric acid accumulation for several reasons. First, considering leakage from vessel head penetrations (VHP), Byron Units 1 and 2 are in the NRC category of plants that can b considered as having low susceptibility to VHP cracking. As reported in the Byron response to NRC Bulletin 2001-01, Byron Units 1 and 2 have been ranked for the potential for primary water stress corrosion cracking (PWSCC) of the reactor pressure vessel (RPV) top head nozzles using the time-at-temperature model and plant-specific input data reported in MRP-48. This evaluation indicates that it will take Byron Units1 and 2 160.6 and 165.9 effective full power years (EFPY), respectively, of additional operation from March 1, 2001, to reach the same time at temperature that Oconee Nuclear Station Unit 3 had at the time that its leaking nozzles were discovered in February 2001. Because of this low susceptibility, leakage from the VHPs and subsequent accumulation of Boric Acid on the vessel head around the VHP is very unlikely.
		In general, Byron performs a visual exam of the CRDM housings and VHP housing areas above the vessel head insulation each refueling outage. This examination is performed in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR plants." The exam is performed by certified VT-2 examiners and is intended to identify any evidence of leakage including boric acid deposits. The exam is performed by direct VT-2 method through the access doors in the cooling shroud assembly. The corporate procedural requirements for this exam state: "Quantify, evaluate and document all leakage from pressure retaining components (including bolted connections and components exposed to boric acid residue, when applicable) discovered during a PT for corrective action in accordance with ASME Section XI IWA-5250 and applicable site procedures." Prior to B2R09, a site procedure was utilized which similarly required the following. Record all locations of Boric Acid residue, evidence of borated water. Pa special attention to the Reactor Vessel head, canopy seal, and the Reactor Coolant Pump studs."	Leakage of borated reactor coolant from Control Rod Drive Mechanism Housings that might propagate down onto the vessel head surface is also considered unlikely. The Byron design has CRDM housings welded directly to the VHP. There are no bolted connections that might be susceptible to leakage and there has never been any RCS leakage through any of the three canopy seal welds (lower, intermediate, and upper) on the CRDM housings at Byron Station, Unit 1. Byron Unit 2 has experienced leakage at a middle canopy seal weld location (October 1999) which was determined to be caused by TGSCC from contaminants trapped in the canopy seal area during fabrication. Also, any leakage from the canopy seals, CRDM housings, or from a failed VHP-to-CRDM weld would be detected in the visual exams performed each outage described in the response to question 1.
		Since the start of Generic Letter 88-05 exams at Byron Station, there have been instances where boric acid was identified in the Generic Letter 88-05 exams conducted on the reactor vessel head. In Septmber 1991, boron was detected on a on a Unit 1 head vent valve. The vent valve was cleaned and the CRDM areas were inspected with a robot rover. No evidence of degradation was found. In 1998, evidence of leakage was indicated from a conoseal swagelock fitting. The leakage was repaired and there was no indication boric acid had leaked to the insulation or below. This was in October 1999 where a pinhole leak was identified in a CRDM middle canopy seal weld. The middle canopy was repaired by replacement of the drive mechanism. The boric acid associated with the leak was removed.	Byron Station has seven vessel head connections that could be considered bolted connections. There are two Reactor Vessel Level Indication System penetrations and five Core Exit Thermocouple Penetrations. All these penetrations are located around the periphery of the vessel head and are disconnected and reassembled each refuel outage. Again, leakage from these connections would be detected in the visual exams performed each outage described in the response to question 1. Also, leakage from these peripheral penetrations, as well as any other peripheral VHP, would show as dried boric acid trails on the bare metal of the vessel head since the area directly below these VHPs is un-insulated and directly observable when the vessel head is mounted on the stand during refueling.
		A DRPI (digital rod position indication) modification was performed at both Units 1 and 2 which provided an opportunity for additional inspections not typically experienced due to improved access and even more ability to identify boric acid, none was found. Everything contributing to boric acid leakage other than VHP cracking has been inspected and has not contributed to boric acid at either Byron unit. The VHPs at both Byron units is not currently considered a potential source of boric acid given both sites rankings (>120 EFPY).	

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Byron 1	Exelon	N/A -- Byron Station was not required by NRC Bulletin 2001-01 to perform any UT or non-visual examinations on VHPs or base material.	At this time, Byron Station does not plan on supplementing the examinations discussed in the response to Question 1. Also, because of the low susceptibility to VHP cracking discussed in the response to NRC Bulletin 2001-01, there are n plans to perform a qualified, effective reactor vessel head bare metal visual exam on Byron Unit 1 during the Spring 2002 refuel outage. Byron Station believes that given the reliability of the VHPs, the limited amount of RCS leakage o the vessel head at the applicable unit (Byron Unit 1), the limited potential sources of boric acid leakage on the Reactor vessel, and the level of detail in current visual exams regarding detection and reporting of boric acid, it is very unlikely that there is significant boric acid corrosion

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Byron 2	Exelon	At Byron Station there have not been any exams performed under the reactor vessel head insulation that would cover 100% of the reactor vessel head. During the Spring 2001 refuel outage at Byron Unit 2, visual examinations were performed of the accessible areas of the head during Mode 3 prior to unit shutdown. These exams were performed using ASME Section XI VT-2 certified personnel and were intended to detect leakage or boric acid deposits per NRC Generic Letter 88-05 commitments. These exams were conducted on the reactor vessel head with the shroud assembly access doors opened and the vessel head insulation in-place. There were no signs of leakag or boric acid deposits. Also, during the Unit 2 refueling outage (B2R09), a VT-3 visual examination, using ASME Section XI certified personnel, was performe on the underside of the reactor vessel head using a remote camera arrangement. This exam was conducted per the requirements of ASME Section XI, Category B-N-1, Item B13.10, and included a visual examination of the surface of the VHP to vessel head weld. There were no signs of cracking, linear indications, erosion, corrosion, or wear. During the restart of Unit 2 from B2R09 refueling outage, a visual examination, at reactor coolant pressure and temperature, was performed using ASME Section XI certified personnel. The exam was conducted per the requirements of ASME Section XI, Category B-P, Item B15.10 and included the accessible areas of the reactor vessel head. There were no signs of leakage. In general, Byron performs a visual exam of the CRDM housings and VHP housing areas above the vessel head insulation each refueling outage. This examination is performed in response to Generic Letter 88-05, "Boric Acid Corrosion of Carbon Steel Reactor Pressure Boundary Components In PWR plants." The exam is performed by certified VT-2 examiners and is intended to identify any evidence of leakage including boric acid deposits. The exam is performed by direct VT-2 method through the access doors in the cooling shroud assembly. The corporate procedural requirements for this exam state: "Quantify, evaluate and document all leakage from pressure retaining components (including bolted connections and components exposed to boric acid residue, when applicable) discovered during a PT for corrective action in accordance with ASME Section XI IWA-5250 and applicable site procedures." Prior to B2R09, a site procedure was utilized which similarly required the following. Record all locations of Boric Acid residue, evidence of borated water. Pay special attention to the Reactor Vessel head, canopy seal, and the Reactor Coolant Pump studs." Since the start of Generic Letter 88-05 exams at Byron Station, there have been instances on Unit 2 where boric acid was identified in the Generic Letter 88-05 exams conducted on the reactor vessel head. In September 1990 a port column assembly articu-clamp was found leaking. The leak was repaired and the head area inspected with some associated insulation removed. No damage was identified. In April 1992 a leak was identified on the #5 conoseal thermocouple column. This leak was cleaned and repaired. The leak did not impact the insulation or area below. In October 1999 a pinhole leak was identified in a CRDM middle canopy seal weld. The middle canopy was repaired by replacement of the drive mechanism. The boric acid associated with the leak was removed. Portions of the RX head were de-insulated under the CRDM during the repairs. A DRPI (digital rod position indication) modification was performed at both Units 1 and 2 which provided an opportunity for additional inspections not typically experienced due to improved access and even more ability to identify boric acid, none was found. Everything contributing to boric acid leakage other than VHP cracking has been inspected and has not contributed to boric acid at either Byron unit. The VHPs at both Byron units is not currently considered a potential source of boric acid given both sites rankings (>120 EFPY).	(see Byron 1 response)
Callaway	AmerenUE	Most recent inspection (Refuel 11, 2001) was visual with head insulation in place	We have not performed a complete bare head examination of the entire head. We are comfortable with relying upon the EPRI/MRP susceptibility evaluations and with our current practice of removing insulation if indications of leakage are identified.
Calvert Cliffs 1	CCNPP	Yes	N/A
Calvert Cliffs 2	CCNPP	No	CCNPP examined plant operating/maintenance records regarding previous boric acid leaks. Records indicated two leaks of boric acid onto the head (1993, 1995) both of which were immediately cleaned (and the sources of the leakage corrected). In addition, CCNPP did a bare metal inspection of approximately one third of the head during the most recent outage and there were no signs of boric acid deposits on the head. Looked for sources of leakage above the insulation on the remaining 2/3 of the head and determined there had been no leakage from above the insulation since 1995.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Byron 2	Exelon	N/A -- Byron Station was not required by NRC Bulletin 2001-01 to perform any UT or non-visual examinations on VHPs or base material.	(see above)
Callaway	AmerenUE	N/A	N/A
Calvert Cliffs 1	CCNPP	N/A	Completed detailed VT.
Calvert Cliffs 2	CCNPP	N/A	No Spring 2002 outage.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Catawba 1	Duke Power	100% bare metal visual examination of the reactor head was not conducted during the last unit outage EOC-12, October 2000	Examination of the head below the insulation was not conducted during the last unit outage. Records show that Unit #1 experienced a conoseal leak in 1992. The leak was discovered in Mode 5 and was very small. The boron was contained on the lower conoseal flange. This unit has experienced a 10 year ISI since 1992 where the shroud and the mirror insulation were removed and inspections were conducted. There were no significant findings. During each outage shortly after shutdown, Catawba personnel inspect the CRDM rod housing vent valves, part length vent valves, mirror insulation at Rx vessel flange, five conoseal flanges and thermocouple fittings, head vent line flanges, and RVLIS instrument tubing and isolation valve for any signs of leakage (wetness, leak tracks, or signs of boron). Results show no sign of leakage. With the Rx head on the storage stand an inspection of the CRDM canopy seal welds is performed each outage. These welds are located just above the insulation on the top of the reactor head. This requires looking into each of four openings in the upper shroud portion of the CRDM cooling shroud. Any leakage, either from the welds or external sources would be noted during this inspection. There are no signs of recent or past leakage. During startup with the NC system at temperature and pressure (Mode 3) an inspection of the reactor cavity area is performed jointly by QC and Rx Head Team personnel to specifically identify leakage. Other than the leaks mentioned above, no significant leakage has been observed.
Catawba 2	Duke Power	100% bare metal visual inspection of the reactor head was not conducted during the last unit outage EOC-11, September 2001	Examination of the head below the insulation was not conducted during the last unit outage. Records show that Unit #2 experienced a conoseal leak in 1990. The leak predominately sprayed away from the head. The shroud and mirror were not removed at the time of the leak however the area was cleaned with demineralized water. Record also show a leak from a CRDM vent plug which has subsequently been welded. This unit has experienced a 10 year ISI since 1990 where the shroud and the mirror insulation were removed and inspections were conducted. There were no significant findings. During each outage shortly after shutdown, Catawba personnel inspect the CRDM rod housing vent valves, part length vent valves, mirror insulation at Rx vessel flange, five conoseal flanges and thermocouple fittings, head vent line flanges, and RVLIS instrument tubing and isolation valve for any signs of leakage (wetness, leak tracks, or signs of boron). Results show no sign of leakage. With the Rx head on the storage stand an inspection of the CRDM canopy seal welds is performed each outage. These welds are located just above the insulation on the top of the reactor head. This requires looking into each of four openings in the upper shroud portion of the CRDM cooling shroud. Any leakage, either from the welds or external sources would be noted during this inspection. There are no signs of recent or past leakage. During startup with the NC system at temperature and pressure (Mode 3) an inspection of the reactor cavity area is performed jointly by QC and Rx Head Team personnel to specifically identify leakage. Other than the leaks mentioned above, no significant leakage as been observed
Comanche Peak 1	TUE	No	Yes. Since we have not had leakage above the head on either unit during recent operations.
Comanche Peak 2	TUE	No	Yes. Since we have not had leakage above the head on either unit during recent operations.
Cook 1	AEP	See Response to Question no. 4.	See Response to Question no. 4.
Cook 2	AEP	YES, a 100% visual examination of the R. V. Head external surfaces was performed in February 2002 as per the commitments made in response to the NRC Bulletin 2001-01. No boric acid corrosion or accumulation of boric acid was identified. The visual examination was performed using a remote-robot camera, with an insulation panel removed for easy access. The remote crawler (BTRIS) from Westinghouse/Brooks Associates was used.	A 100% visual inspection of the RV Head external surface was performed.
Crystal River 3	Progress Energy	Yes - A complete 100% visual inspection was performed of a bare head. Following the inspection, the head was also thoroughly cleaned No wastage was noted.	NA – 100% inspection was performed
Davis-Besse	Toledo Edison		

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Catawba 1	Duke Power	No ultrasonic examinations were conducted.	Catawba Unit #1 is expected to enter a refueling outage spring 2002. We will be conducting normal inspections of the reactor head including 88-05 Boron walkdown inspections and normal ISI pre-start pressure and temperature inspections as detailed in response to question 2 above. These inspections provide significant data regarding the potential of components to leak and the location of the leaking. Visual inspection of the insulation above the vessel hea ensure that components such as the conoseals, vent lines, etc are not and have not leaked. This inspection covers areas of the CRDM nozzle slightly above the vessel head. The area not covered by this inspections are those areas covered in the 2001 – 01 bulletin response which are subject to SCC cracking of the nozzle proper and the attachment welds. Catawba Nuclear Station is low in ranking and damage due to SCC of the nozzle or attachment weld isn't expected for many years.
Catawba 2	Duke Power	No ultrasonic examinations were conducted	No Spring 2002 outage.
Comanche Peak 1	TUE	N/A - No UT performed.	For fall outage on Unit 1, we are plan to do visual/ boroscope inspection of accessible head areas under insulation in support of Engineering eval that would address wastage issue resulting from boric acid corrosion.
Comanche Peak 2	TUE	N/A - No UT performed.	For the spring outage on Unit 2, plan to do visual/ boroscope inspection of accessible head areas under insulation in support of Engineering eval that would address wastage issue resulting from boric acid corrosion.
Cook 1	AEP	See Response to Question no. 4.	A 100% visual examination of the RV Head external surface is planned during the upcoming refueling outage in May 2002 using the methodology noted in item 1 for Unit 2.
Cook 2	AEP	a) YES, however, the change in back reflection would only be seen in the volume examined at the elevation of the J-groove weld. Erosion above the J-groove weld elevation would not be seen. For visual examination performed, see response to item 1 b) No	As noted in question no. 1, a 100% visual examination of Unit2 Reactor vessel head external surface was performed in February 2002.
Crystal River 3	Progress Energy	UT, capable of detecting changes in the back reflection (although not specifically the inspection purpose), was used on a total of nine nozzles. For the nine nozzles examined, a full length UT was performed to the top of the head.	NA – Crystal River Unit 3 completed Refuel XII in the fall of 2001. The next outage is scheduled for the fall of 2003
Davis-Besse	Toledo Edison		

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Diablo Canyon 1	PG&E	No - 100% reactor head visual inspection were NOT conducted at DCPP. During our most recent outages, DCPP unit 1 1R10 refueling (10-11/00), inspections for boric acid were conducted with the head insulation in place. No boric acid coming from under the insulation was detected. During DCPP 1R9 refueling outage (2-3/99) approximately 1/2 of the head insulation was removed to facilitate a canopy seal repair. No boric acid was observed on the reactor head. There was no specific head inspection, but incidental observations were that the head was very clean.	We have not performed a complete bare head examination of the entire head. We have reviewed all conditions that could have lead to leakage onto the reactor head. We have concluded that in all cases, the leakage did not reach the head or that the areas of the head which could have been affected were inspected and no wastage was found. To date, the mirror insulation has been effective in stopping minor boric acid leaks from above from being deposited on the reactor head. We conduct a thorough inspection on top of the mirror insulation each outage. The insulation has been very clean. Any minor leakage onto the insulation has been identified and corrected. In addition, we are confident with the methodology of the EPRI/MRP susceptibility evaluations and with our current practice of requiring additional inspections if indications of leakage are identified.
Diablo Canyon 2	PG&E	No - 100% reactor head visual inspection were NOT conducted at DCPP. During our most recent outages, DCPP unit 2 2R10 refueling (4-5/01), inspections for boric acid were conducted with the head insulation in place. No boric acid coming from under the insulation was detected.	We have not performed a complete bare head examination of the entire head. We have reviewed all conditions that could have lead to leakage onto the reactor head. We have concluded that in all cases, the leakage did not reach the head or that the areas of the head which could have been affected were inspected and no wastage was found. To date, the mirror insulation has been effective in stopping minor boric acid leaks from above from being deposited on the reactor head. We conduct a thorough inspection on top of the mirror insulation each outage. The insulation has been very clean. Any minor leakage onto the insulation has been identified and corrected. In addition, we are confident with the methodology of the EPRI/MRP susceptibility evaluations and with our current practice of requiring additional inspections if indications of leakage are identified.
Farley 1	Southern Nuclear	Yes, 100% visual performed under the insulation using remote crawler. No evidence of external surface corrosion was found. Some minor surface staining was observed consistent with locations that have been vented or disassembled in the past. No evidence of boric acid from active leakage was found.	Visual was 100%.
Farley 2	Southern Nuclear	Yes, all penetrations were visually inspected under the insulation using Welch Allyn video probe and guide tube. A few (less than 10) penetrations were inspected slightly less than 360 degrees around due to positioning of the camera. No evidence of external surface corrosion was found. Some minor surface staining was observed consistent with locations that have been vented or disassembled in the past. No evidence of boric acid from active leakage was found.	The visual inspection was sufficient to confidently conclude no external head corrosion.
Fort Calhoun	OPPD	In the Spring of 1992 during a refueling outage, Fort Calhoun Station removed all the stepped, reflective insulation off the reactor head. A 100% visual examination of the head was then performed after cleaning off surface boric acid with demineralized water. No penetration leakage, local accumulation of boric acid or general corrosion was identified.	Technically, not applicable, because visual inspection was performed over 100% of the reactor head in 1992. However, since 1992, Fort Calhoun Station continues to be confident about the material condition of the external reactor head surface, which is demonstrated the following: a) A continually low RCS leakage with no adverse trends, and no excessive unidentified leakage b) No adverse ALARA trend with refueling outage reactor head work dosage c) No visual confirmation of boric acid deposits when reactor head stud detensioning was performed
Ginna	RG&E	RG&E head configuration is such that access to the upper head surface is restricted to existing CRDM Cooling shroud HVAC duct connection ports. There are three such ports equidistant around the circumference of the HVAC Shroud. The duct openings are nominally 16 inches at the connection to the HVAC duct work. Visual inspections performed by the refueling engineer through these HAVC ports during the 2000 refueling outage did not show any signs of large boric acid deposits on the external surface of the insulation. It is important to note that the insulation specification called for a waterproof emulsifier to be coated on the top of the tight fitting insulation. The insulation is specified as 2 layers of 1-1/2 inch thick block with joints sealed with a fibrous cement. Ginna Station has had only limited leakage above the head insulation. Three cases have been noted: 1) One case of a CRDM vent pin hole leak at the seismic restraint area. This area is located at the top of the control rod travel housing approximately 15 feet above the head and pictures show that the leakage was very localized. The area of stainless steel was cleaned at time of discovery.(1971) 2) One instance of inadvertent conoseal leakage during refueling on 3-16-85. Several gallons of primary water emitted due to three instru 3) Seepage at a lower instrument port conoseal. Refuel Engineer log entry notes the removal of the plate around the conoseal and notes t There have been no known instances of leakage from CRDM to CRDM adaptor seal welds at Ginna Station.	As noted in #1, Access to the Bare metal surface is prohibited by existing insulation. Per the information supplied in the Information Notice with regards to Davis-Besse, it appears that significant quantities of boric acid from previous leakage of flanged CRDM connections was allowed to remain in contact with the carbon steel of the RV Head. This boric acid was apparently re-wetted during cleaning activities with DI water during the 2000 refueling outage. Previous information contained in various Industry experience reports have noted the deleterious effects of wetted boric acid on carbon steel. As noted above, the design of the Ginna head insulation system provides some protection of the carbon steel head from leakage from above. Additionally very minor leakage has occurred at Ginna and that leakage has been cleaned up when discovered.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Diablo Canyon 1	PG&E	N/A. No non-visual NDE has been performed on the DCPP reactor heads and penetrations.	DCPP is committed to perform a bare head inspection of 100% of the reactor head penetrations. We are confident that this will ensure that any significant boric acid on the reactor head is detected.
Diablo Canyon 2	PG&E	N/A. No non-visual NDE has been performed on the DCPP reactor heads and penetrations.	DCPP is committed to perform a bare head inspection of 100% of the reactor head penetrations. We are confident that this will ensure that any significant boric acid on the reactor head is detected.
Farley 1	Southern Nuclear	N/A - No volumetric exams performed.	No Spring 2002 outage.
Farley 2	Southern Nuclear	N/A - No volumetric exams performed.	No Spring 2002 outage.
Fort Calhoun	OPPD	N/A	During the Spring 2002 refueling outage at Fort Calhoun Station, a 100% visual reactor head examination is planned mainly with a mechanized crawler and in a small percentage of areas by using a borescope. The crawler has been used a several other nuclear plants and has given high resolution visual data, which can be easily interpreted for both boric acid build-up around penetrations, and local boric acid accumulations. The visual data from the crawler would also be able t distinguish between a minor surface deposit of boric acid and a tarnished boric acid accumulation such as the one found at Davis-Besse. In conclusion, the Davis-Besse plant reactor head corrosion incident does not change the scope or method of performing the scheduled 100% reactor head visual inspection at Fort Calhoun Station.
Ginna	RG&E	RG&E performed a Eddy current inspection of all head penetrations during the 1999 refueling outage. This inspection would not have been capable of detecting corrosion of the low alloy carbon steel head material.	RG&E believes the best available way to show that no corrosion of the type described in Information Notice 2002-11 exists at Ginna is to demonstrate that no large deposits of Boric Acid were allowed to remain in contact with the carbon steel surface of the vessel. Best effort Visual inspection will be performed through the existing HVAC ducts, of the upper head region to ensure that no changes in insulation contour and appearance has occurred since our last inspection. Photographs of the entire head will be taken and compared to previous photographs of the head region inside the HVAC lower cooling shroud in order to identify any changes from the previous inspection. In addition, a video tape of the region will be made for future reference. The video will include the seal weld area of the CRDM assembly to the CRDM housing body adaptor to demonstrate that no boric acid has been deposited from above as in the Information Notice case.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Indian Point 2	Entergy	During the 2000 refueling outage, IP2 performed a VT-2 visual examination of the reactor vessel head and attachments during the RCS pressure test as required by the ASME, Section XI Code. No deficiencies were identified during this inspection, as documented in Test # PT-R75.	Yes. The recently discovered Davis Besse head corrosion was likely (root cause still in progress) a result of either (1) reactor coolant leakage through a crack in the Alloy 600 CRDM nozzle or (2) a result of above the head leakage which dripped on to the head outside surface. The probability that either one of these driving mechanisms is present at IP2, is considered to be extremely low for the following reasons: (1) The presence of through wall cracks in the CRDM nozzles at IP 2 is considered to be extremely unlikely. This conclusio is based on the fact that IP2 was ranked as one of the lowest plants in the moderate susceptibility category under the MRP ranking criteria which was used to respond to Bulletin 2001-01. In fact, IP2 has only accumulated 7.1 EFPY (normalized to 600 F) as of March 1, 2001. Since the accumulated EFPY to date is directly proportional to the susceptibility of the CRDM nozzles to PWSCC (i.e. rather than number of EFPY to reach the Oconee 3 condition), IP2 is considered to be the least susceptible plant in the moderate susceptibility category and it is also considered to be less susceptible than other plants which have been ranked as low susceptibility plants (i.e. other plants have accumulated more EFPY to date, even though they are ranked as low susceptibility plants). Based on this, IP2 is not expected to have any through wall cracks in the CRDM nozzles similar to those cracks detected in the Davis Besse nozzle which have likely contributed either in whole or i part to the wastage of the head base metal. (2) Although Indian Point 2 experienced CRDM leakage above the head during the late 1980's, the inspections performed a the time and the corrective actions implemented during the 1988 refueling outage have resulted in essentially a leakage free head surface since that time. The inspections performed during the late 1980's (i.e. at the time that leakage was detected) included removing a sample of the insulation to assess the condition of the head to ensure that no boric acid had reached the head surface and resulted in degradation of the head. These inspections verified that the head's protective aluminum silicone based paint/film remained intact. In addition to this protective film which has been demonstrated to be resistant to boric acid, the head also has permanently bonded insulation which acts as an additional protective barrier against potential leakage from above the head. The combination of both of these barriers is considered to have provided an effective protective barrier against the corrosive environment which would be necessary to promote structurally significant wastage of the head similar to that detected at Davis Besse
Indian Point 3	Entergy	A "best-effort" visual examination was performed in RO11 (5/01) with primary emphasis of detecting leakage of boric acid crystals at accessible nozzles to head interface on the exterior surface. Using a remote camera, approximately 60% of nozzles were inspected by a VT-2 equivalent examination from above the vessel head insulation. Inspection limitations included limited access to the balance of 40% nozzles, and a non-removable type of insulation. Insulation is 3 1/4" "Kaylo Block" filled with asbestos cement prior to application of two layers of asbestos tape. A final coating of 1/2" thick "One Cote" cement was applied over the tape. Insulation removal is not practical given ALARA concerns, asbestos issues, including contaminated airborne particles. The RO11 inspection was compared with an inspection videotaped during the previous refuel outage - RO10. There appear to be no changes in the condition of the vessel head under the cooling shroud with the exception of the Conoseal No. 4 penetration tube and canopy leakage discovered prior to the RO11 outage. Boron had precipitated from this leak and collected on the alloy steel canopy clamp Also, there is evidence that some traces did traverse down the tube and was entrained in the CRDM ventilation depositing on the exposed In summary, there was no evidence of leakage from penetration/vessel head joints at inspected locations.	The inspection in RO11 was compared with a similar inspection videotaped in RO10. There appeared to be no changes in the condition of the vessel head from above the contoured insulation.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Indian Point 2	Entergy	N/A. Indian Point 2 has not performed UT or another non-visual examination of the RPV head	IP2 is currently scheduled for a refueling outage during the Fall 2002. During this outage we will perform an Ultrasonic Inspection of the CRDM Alloy 600 nozzles in accordance with the Bulletin 2001-01 requirements. Although we currently have no plans to perform any additional inspections, we will be closely monitoring the developments of the Davis Besse vessel head and we will update our plans to include additional inspections if the root cause of the Davis Besse incident indicates that additional inspections are appropriate.
Indian Point 3	Entergy	N/A. Only a VT-2 was performed.	IP3 will perform a UT exam of all penetrations from below the vessel head, in Spring 2003. But same limitations (see 1) will exist preventing a visual exam of vessel top bear metal, for possible detection of external head corrosion from boric acid crystals. However, the NDE results in RO12 will determine any posible leakage on vessel head, from below. IP2 has same type of insulation as IP3 but has more head nozzles. IP2 has 97 head nozzles. IP3 has 79. IP2 is presently scheduled to perform UT of all nozzles from below the vessel head in Fall 2002. Removal of insulation is same issue as for IP3.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Kewaunee	NMC	An effective bare metal VT inspection was performed of 100% of the reactor vessel head external surface during the most recent refuelin outage performed at KNPP, from September through December 2001. The insulation was completely removed to conduct this examination. No evidence of corrosion was observed during the examination. No accumulation of boric acid was observed on the carbo steel head. Only minor amounts of boric acid were noted on some CRDM tubes in regions above the adaptor plug which where attribute to prior conoseal or vent plug leakage	N/A - A 100% VT examination was completed and no corrosion exists on the external surface of the head
McGuire 1	Duke Power	100% bare metal visual examination were not conducted during the last unit outage EOC-14, March 2001	During each outage shortly after shutdown, McGuire personnel inspect the CRDM rod housing vent valves, part length vent valves, mirror insulation at Rx vessel flange, five conoseal flanges and thermocouple fittings, head vent line flanges, and RVLIS instrument tubing and isolation valve for any signs of leakage (wetness, leak tracks, or signs of boron). Results show no sign of leakage. With the Rx head on the storage stand, an inspection of the CRDM canopy seal welds is performed each outage. These welds are located just above the insulation on the top of the reactor head. This requires looking into each of four openings in the upper shroud portion of the CRDM cooling shroud. Any leakage, either from the welds or external sources would be noted during this inspection. There are no signs of recent or past leakage. During startup with the NC system at temperature and pressure (Mode 3) an inspection of the reactor cavity area is performed jointly by QC and Rx Head Team personnel to specifically identify leakage. Recent records show one leaking conoseal found during one of these inspections. The conoseal was repaired and the area cleaned prior to continuing with startup. In addition records show one RVLIS leak that was discovered during a Mode 3 walkdown. Again, the leak was repaired and the area cleaned An examination of the outer row of CRDMs was conducted during the last outage in response to industry identified issues with the "J" groove weld and nozzle to vessel interface. This examination was conducted using video probes under the insulation. No signs of leakage were found. Partial bare metal visual inspections were completed in 1997 and the heads were free of any boric acid deposits. Since that time we have noted small signs of leakage from conoseals during start-up from RFO. Start-up activities were halted at that time to repair the leak and to clean the area of any small deposits. The deposits never got to the head.
McGuire 2	Duke Power	100% bare metal visual examinations of the reactor head were not conducted during the last unit outage EOC-13, September 2000	During each outage shortly after shutdown, McGuire personnel inspect the CRDM rod housing vent valves, part length vent valves, mirror insulation at Rx vessel flange, five conoseal flanges and thermocouple fittings, head vent line flanges, and RVLIS instrument tubing and isolation valve for any signs of leakage (wetness, leak tracks, or signs of boron). Results show no sign of leakage. With the Rx head on the storage stand, an inspection of the CRDM canopy seal welds is performed each outage. These welds are located just above the insulation on the top of the reactor head. This requires looking into each of four openings in the upper shroud portion of the CRDM cooling shroud. Any leakage, either from the welds or external sources would be noted during this inspection. There are no signs of recent or past leakage. During startup with the NC system at temperature and pressure (Mode 3) an inspection of the reactor cavity area is performed jointly by QC and Rx Head Team personnel to specifically identify leakage. Inspection results to date show no significant signs of leakage. Partial bare metal visual inspections were completed in 1997 and the heads were free of any boric acid deposits. Since that time we have noted small signs of leakage from conoseals during start-up from RFO. Start-up activities were halted at that time to repair the leak and to clean the area of any small deposits. The deposits never got to the head.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Kewaunee	NMC	During this same refueling outage, UT of 1/3 of the circumference of the reactor vessel head to flange weld was performed using 0 degree, 45 degree, and 60 degree transducers. Thermal insulation is removed to provide access to the external surface of the reactor vessel head to conduct this UT examination. A magnetic particle examination of the external surface of 1/3 of the head to flange weld also was performed at this time. Thus, the UT examination was capable of detecting corrosion of the low alloy steel head materials. No changes in back reflection were noted and no evidence of corrosion or cracking was detected. The UT examinations did not reveal any recordable indications. A UT examination has not been performed of the full length of the RPV nozzles to the top of the head.	N/A. KNPP does not have a planned Spring 02 outage. The next refueling outage is scheduled for Spring 2003
McGuire 1	Duke Power	No ultrasonic examinations were conducted	McGuire Unit #1 is not scheduled for an outage during spring 2002. Duke has performed 88-05 inspections plus the other inspections denoted in the other responses (such as the start-up inspections performed of the head and insulation and surrounding areas looking for leakage).
McGuire 2	Duke Power	No ultrasonic examinations were conducted	McGuire Unit #2 is currently in a refueling outage. We are conducting normal inspections of the reactor head including 88-05 boron walkdown inspections and will conduct normal ISI pre-start pressure and temperature inspections as detailed in response to question 2. These inspections provide significant data regarding the potential of components to leak and the location of the leaking. Visual inspection of the insulation above the vessel head ensure that components such as the conoseals, vent lines, etc are not and have not leaked. This inspection covers areas of the CRDM nozzle slightly above the vessel head. The area not covered by this inspections are those areas covered in the 2001– 01 bulletin response which are subject to SCC cracking of the nozzle proper and the attachment welds. McGuire Nuclear Station is low in ranking and damage due to SCC of the nozzle or attachment weld isn't expected for many years. Duke has performed 88-05 inspections plus the other inspections denoted in the other responses (such as the start-up inspections performed of the head and insulation and surrounding areas looking for leakage).

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Millstone 2	Dominion Connecticut	During the current refueling outage, 2R14, the inspection at Millstone Unit 2 on the RVHP nozzles was done via UT from under the head. However the visual examinations discussed in the answer to question # 4 show that any accumulation of boric acid would have been detected.	See the answer to questions 1 and 4.
Millstone 3	Dominion Connecticut	No, at the last MP3 refueling outage in February-March, 2001, the normal inspections for system leakage and Generic Letter 88-05 boric acid were performed. No leakage or accumulations of boric acid on the head were noted. This inspection did not look under the insulation directly at the top of the reactor vessel head.	Millstone Unit 3 has had only two leaks above the head where boric acid would have run onto the head. The leaks were due to canopy seal weld problems and happened back in 1993. Both leaks were fixed with a clamp and the boric acid cleaned up on top of the insulation. Based upon this history and the fact that Millstone Unit 3 is a "cold head' plant which will significantly delay the onset of PWSCC, there is a reasonable expectation that no external corrosion on the reactor vessel head exists.
North Anna 1	Dominion Generation	The fall 2001 RV head inspections included 100% visual inspection of the RV head surface underneath the insulation. Inspections were conducted using robot mounted video cameras and hand manipulated boroscopes. While the primary concern of these inspections was th area immediately surrounding the CRDM penetration to head interface, there is a very high level of confidence that any significant corrosion of the head or accumulation of boric acid residue would have been detected by the inspections. For the North Anna Units, the heads were cleaned subsequent to the initial examination to provide a clean head for re-examination to establish a baseline for future examination.	N/A
North Anna 2	Dominion Generation	The fall 2001 RV head inspections included 100% visual inspection of the RV head surface underneath the insulation. Inspections were conducted using robot mounted video cameras and hand manipulated boroscopes. While the primary concern of these inspections was th area immediately surrounding the CRDM penetration to head interface, there is a very high level of confidence that any significant corrosion of the head or accumulation of boric acid residue would have been detected by the inspections. For the North Anna Units, the heads were cleaned subsequent to the initial examination to provide a clean head for re-examination to establish a baseline for future examination.	N/A
Oconee 1	Duke Power	100% bare metal visual inspection of the reactor head was conducted in November 2000 (last outage). The head was extensively cleaned such that erosion would have been detected. For all Oconee units the source of the boric acid leakage has been identified and repaired. That includes flange leakage events as well as CRDM penetration leakage events.	N/A
Oconee 2	Duke Power	100% bare metal visual inspection of the reactor head was conducted in April 2001 (last outage). The head was extensively cleaned such that erosion would have been detected. For all Oconee units the source of the boric acid leakage has been identified and repaired. That includes flange leakage events as well as CRDM penetration leakage events.	N/A
Oconee 3	Duke Power	100% bare metal visual inspection of the reactor head was conducted in November 2001 (last outage). The head was extensively cleaned such that erosion would have been detected. For all Oconee units the source of the boric acid leakage has been identified and repaired. That includes flange leakage events as well as CRDM penetration leakage events.	N/A
Palisades	NMC	A bare metal head examination was last performed during the 1995 refueling outage and there was not any evidence of corrosion or boric acid on the reactor head or any of the head penetrations. To support this examination, all of the stainless steel jacketing and Nukon blankets were completely removed and then replaced with new material. Total dose for this scope of work was 7.5 REM. On a continuing basis during each refueling outage, a VT-2 examination is performed with the insulation installed and there has been no evidence of boric acid extruding from any of the insulation penetrations. Additionally, when the reactor head is placed on the headstand, the reactor head insulation is removed from the lowest point of the reactor head hillside and the lower flange. No evidence of leakage has been identified in these areas.	The 1995 examination was the last 100% bare metal head examination. However, during the 2001 maintenance outage, all of the control rod drive upper housings were removed and all of the reactor head insulation was very accessible. To insure that the leakage from the leaking upper housing did not reach the reactor head, the stainless steel jacketing was removed in the area of the leak to verify that no boric acid reached the reactor head. No adverse conditions or evidence of boric acid below the stainless steel jacketing was identified during this outage. It should be noted that with the stainless steel jacketing tightly covering the insulation blankets there physically is not any voids that could hold any significant amounts of boric aci If a leak were to occur from below the insulation the boric acid would quickly extrude from metal jacketing and it would be identified.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Millstone 2	Dominion Connecticut	During the current refueling outage, 2R14, the UT examination performed at Millstone Unit 2 included examining the interference fit region. This examination is looking for evidence of a leak path. No evidence of any leakage was detected. Past experience with the inspection vendor, Framatech ANP, in examining the interference fit region has shown that corrosion is left by a leak path. Yes, the full length of the nozzle up to the top of the head was inspected.	During the current refueling outage, 2R14, Millstone Unit 2 has done/will do the following to show that there has been no significant boric acid corrosion: --Performed a UT inspection of 100% of the RVHP nozzles (ICIs, CEDMS and vent line) and found no cracking that could have lead to a through wall leak. See the answer to Question # 3 for more details. -- Will perform and document a visual inspection from the top of the reactor vessel head. This visual examination will cover the full length of the CEDMs, the insulation on top of the head and the vent line. This inspection will also look under the insulation to the maximum extent possible. All inspection personnel are ASME VT-2 qualified. These inspections will uncover any boric acid crystals that would have been left by leakage.
Millstone 3	Dominion Connecticut	Not applicable to Millstone Unit 3. As defined in Bulletin 2001-01, Millstone Unit 3 is a low susceptability plant that is not required to do an inspection of the RVHPs.	Millstone Unit 3's next outage is scheduled for Fall of 2002. Beyond the inspections discussed in Question 1 current plans do include an ISI inspection of canopy seal welds on selected CRDMs.
North Anna 1	Dominion Generation	N/A	No Spring 2002 outage.
North Anna 2	Dominion Generation	N/A	No Spring 2002 outage.
Oconee 1	Duke Power	Visual inspection is relied upon for detection of wastage of the head material	Oconee Unit #1 is scheduled for an outage April 2002. 100% bare metal visual examination of the reactor head will be conducted
Oconee 2	Duke Power	Visual inspection is relied upon for detection of wastage of the head material	Oconee Unit #2 is scheduled for an outage in the fall 2002. 100% visual bare metal head inspection will be conducted a this time
Oconee 3	Duke Power	Visual inspection is relied upon for detection of wastage of the head material	Oconee Unit #3 is not scheduled for an outage in the spring of 2002
Palisades	NMC	This question is not applicable to Palisades, since an UT examination of the RPV nozzles has not been performed. However, during the 1995 refueling outage the 8-incore instrument penetrations were examined by eddy current examination from the inside diameter and no cracking or loss of material was identified. The area examined for each of the incore instrument penetrations ranged from 33.5 to 22.0 inches below the upper flange. This allowed for an examination area ranging from the start of the taper below the J-weld to 2.0 inches above the J-weld. The entire examination area for each penetration was examined with no cracking observed.. Additional reactor head examinations recently performed include those required by ASME Section XI. Over the past two refueling outages the reactor head vessel to flange weld was completely examined by ultrasonic and magnetic particle examinations. The insulation was removed in these regions to provide access to conduct the NDE. This area covers the lowest portion of the reactor head hillside and the flange. No areas of degradation were identified during these examinations.	N/A. Palisades does not have a planned Spring 02 outage. The next refueling outage is scheduled for Spring 2003

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Palo Verde 1	Arizona Public Service (APS)	We have not performed a CEDM top of the head visual to-date other than Section XI visual examinations and GL 88-05 walkdowns. GL 88-05 walkdowns are based on the PV Boric Acid Corrosion Prevention program procedure guidance and include RV head components. APS inspects the top of CEDM's, RV flange area, and head vent isolation valve for evidence of boric acid leakage. There is no known active leakage onto the head. APS is reviewing past isolated spill events and evaluations as part of the anticipated Bulletin response.	We have had no evidence of CEDM head leakage to-date based on normal visual examinations.
Palo Verde 2	Arizona Public Service (APS)	We have not performed a CEDM top of the head visual to-date other than Section XI visual examinations and GL 88-05 walkdowns. GL 88-05 walkdowns are based on the PV Boric Acid Corrosion Prevention program procedure guidance and include RV head components. APS inspects the top of CEDM's, RV flange area, and head vent isolation valve for evidence of boric acid leakage. There is no known active leakage onto the head. APS is reviewing past isolated spill events and evaluations as part of the anticipated Bulletin response.	We have had no evidence of CEDM head leakage to-date based on normal visual examinations.
Palo Verde 3	Arizona Public Service (APS)	We have not performed a CEDM top of the head visual to-date other than Section XI visual examinations and GL 88-05 walkdowns. GL 88-05 walkdowns are based on the PV Boric Acid Corrosion Prevention program procedure guidance and include RV head components. APS inspects the top of CEDM's, RV flange area, and head vent isolation valve for evidence of boric acid leakage. There is no known active leakage onto the head. APS is reviewing past isolated spill events and evaluations as part of the anticipated Bulletin response.	We have had no evidence of CEDM head leakage to-date based on normal visual examinations.
Point Beach 1	NMC	PBNP, Unit 1 conducts visual examinations of the reactor vessel head each refueling outage for the detection of RCS leakage and boric acid accumulation in response to Generic Letter 88-05, Inservice Inspection Section XI Program requirements, and in-house practices. The most recent examinations were completed May 2001 and did not reveal any reactor coolant system leakage on/above the reactor vessel head vessel or BA accumulation on the reactor vessel head. The insulation was not removed for these visual examinations	Although the bare metal external surface of the reactor vessel head has not been visually inspected, its integrity is known fo the following reasons: 1. The insulation was installed using three inch contoured blocks with a ¼ inch of Fiberfrax cement. The top of the insulations was then sealed with a waterproof coating. The insulation does not employ a metal covering of any type. Examinations performed to date indicate that the insulation is in good shape. No staining, discoloration, or other readily identifiable damage to the insulation has been noted to date, which would be an indication of leakage from damage such as degradation at a j-groove weld. 2. Instances of leakage at conoseals joints have occurred, however, the boric acid has been removed from the upper portion of the reactor vessel head and the mechanical joints were promptly repaired. The insulation configuration precludes boric acid from coming in contact with the reactor vessel head since it is covered with ¼ inch of cement and a waterproof coating 3. RCS leakage is trended and monitored to identify any unidentified RCS leakage above background levels. When increase
Point Beach 2	NMC	PBNP, Unit 2 conducts visual examinations of the reactor vessel head each refueling outage for the detection of RCS leakage and boric acid accumulation in response to Generic Letter 88-05, Inservice Inspection Section XI Program requirements, and in-house practices. The most recent examinations where completed May 2001 and did not reveal any reactor coolant system leakage on/above the reactor vessel head vessel or BA accumulation on the reactor vessel head. The insulation was not removed for these visual examinations.	Although the bare metal external surface of the reactor vessel head has not been visually inspected its integrity is know for the following reasons: 1. The insulation was installed using three inch contoured blocks with a ¼ inch of Fiberfrax cement. The top of the insulations was then sealed with a waterproof coating. The insulation does not employ a metal covering or any type. Thus, there is not a metal covering that could mask degradation of the insulation should leakage occur from some source. Examinations performed to date indicate that thermal the insulation is in good shape. No staining, discoloration, or other readily identifiable damage to the insulation has been noted to date, which would be an indication of leakage from damage such as degradation at a j-groove weld. 2. Instances of leakage at conoseals joints have occurred, however, the boric acid has been removed from the upper portion of the reactor vessel head and the mechanical joints where promptly repaired. The insulation configuration precludes boric acid from coming in contact with the reactor vessel head since it is covered with ¼ inch of cement and a waterproof coating 3. RCS leakage is trended and monitored to identify any unidentified RCS leakage above background levels. When increases in RCS leakage are detected the sources are identified. Methods used for assessing RCS leakage include monitoring of gases and air particulate, containment sump levels, and RCS inventory calculations. In response to this incident at Davis-Besse, a review of containment airborne radioactivity data was performed to determine if PBNP has had a "trending up" of airborne activity (which could indicate primary leakage). While the review is only of the last few years, there is no indicatio of any trend in increasing airborne radioactivity, nor of any "creeping up" of alert/alarm set point changes.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Palo Verde 1	Arizona Public Service (APS)	N/A	(N/A)
Palo Verde 2	Arizona Public Service (APS)	APS will be performing a under the head inspection this month in 2R10. Our inspection technology is qualified to detect cracking in the nozzle and j-weld. Current inspection methods will be evaluated based on Davis-Besse experience. APS is reviewing NDE capabilities for bore corrosion assessment.	If through-wall cracking is suspected or confirmed during 2R10 under the head inspections, APS will evaluate potential leakage effects at that time.
Palo Verde 3	Arizona Public Service (APS)	N/A	(N/A)
Point Beach 1	NMC	The primary approach to monitor RCS leakage and accumulation of BA on the reactor vessel head is through scheduled visual examinations discussed in response to question 1 above. In November 2000, PBNP performed an ultrasonic examination of one-third of the reactor vessel head to flange weld using 0 degree, 45 degree, and 60 degree transducers. At this time the thermal insulation was removed to provide access to the flange region of the external surface of the reactor vessel head. A magnetic particle examination was conducted at this time. Thus, th UT examination was capable of detecting corrosion of the low alloy steel head materials. No changes in back reflection where noted and no evidence of corrosion or cracking was detected. The UT examinations did not reveal any record able indications. A UT examination has not been performed of the full length of the RPV nozzles to the top of the head. However, an eddy current examination was performed on all 49 of the CRDM penetrations in 1994. No defects were identified during this eddy current examination.	N/A. PBNP Unit 1 does not have a planned Spring 02 outage. The next refueling outage is scheduled for Fall 2002
Point Beach 2	NMC	The primary approach to monitor RCS leakage and accumulation of BA on the reactor vessel head is through scheduled visual examinations discussed in response to question 1 above. In November 2000, PBNP performed an ultrasonic examination of essentially 100% of the reactor vessel head to flange weld using 0 degree, 45 degree, and 60 degree transducers. At this time the thermal insulation was removed to provide access to the flange region of the external surface of the reactor vessel head. A magnetic particle examination was conducted at this time. Thus, the UT examination was capable of detecting corrosion of the low alloy steel head materials. No changes in back reflection where noted and no evidence of corrosion or cracking was detected. The UT examinations did not reveal any record able indications. A UT examination has not been performed of the full length of the RPV nozzles to the top of the head.	The next refueling outage for PBNP Unit 2 is scheduled for Spring 2002. During this scheduled outage, the existing thermal insulation on the reactor vessel head will be removed and replaced with insulation of the metal reflective type. The bare metal of the external surface of the reactor vessel head will be visually examined during the insulation remova process or prior to installation of the new insulation. This bare metal visual examination will verify that the reactor vessel head is free of significant boric acid corrosion.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Prairie Island 1	NMC	A bare metal visual examination was last performed on the Unit 1 reactor vessel head during the August 2001 forced outage. The visual examination was performed to satisfy the requirements of NRC BL2001-01. This unaided visual inspection was performed with access under the thermal insulation via four peripheral view-ports. The visual inspection through the view-ports in the insulation is estimated to have covered >90% of the total combined circumference of all of the penetration to head interfaces and >98% of the total head surface area. No boric acid accumulation was noted during this examination. It is the practice at PINGP Unit 1 and 2 to perform a visual examination of the external surface of the reactor vessel head region including the CRDM penetrations through the view-ports in the insulation each scheduled refueling outage	The visual inspections had the limitation that they were performed through view-ports in the insulation. For that reason, it is possible that peripheral tubes might have masked the line of site to some small portions of the uphill sides of some of the interior penetrations. The visual inspections were performed to be as thorough as possible, and attempts were made to view each tube from at least two view-ports in order to provide coverage of both the uphill and downhill sides. For Unit 1, despite the limitations due to access, it is estimated that at least 98% of the total head surface area was accessible and subject to visual examination. Only a very small amount of boric acid accumulation located at the tube-to-head interface, in just the right position could have gone undetected. The probability of any undetected boric acid in these locations is felt to be extremely low as essentially no reactor coolant system leakage or accumulation of boric acid was detected in regions that where visible. Such a small amount of potential undetected boric acid accumulation cannot result in significant wastage of reactor vessel head material without a source of moisture. For reasons described above, there is a high degree of confidence that there is no significant external corrosion of either Uni
Prairie Island 2	NMC	A bare metal head examination was last performed during the February 2002 refueling outage for Unit 2 to satisfy the requirements of NRC BL2001-01. This unaided visual inspection was performed with access under the thermal insulation via four peripheral view-ports. The visual inspection through the view-ports in the insulation is estimated to have covered >90% of the total combined circumference of all of the penetration to head interfaces and >98% of the total head surface area. Additionally, a remote video inspection of the Unit 2 head was performed during the same refueling outage to provide reproducible photographic quality documentation. It is felt that between the video inspection and the visual inspection, 100% of the penetration interface circumferences and 100% of the head surface area was inspected, with no boric acid accumulation noted. It is the practice at PINGP Unit 1 and 2 to perform a visual examination of the external surface of the reactor vessel head region including the CRDM penetrations through the view-ports in the insulation each scheduled refueling outage	The visual inspections had the limitation that they were performed through view-ports in the insulation. For that reason, it is possible that peripheral tubes might have masked the line of site to some small portions of the uphill sides of some of the interior penetrations. The visual inspections were performed to be as thorough as possible, and attempts were made to view each tube from at least two view-ports in order to provide coverage of both the uphill and downhill sides. As noted above in response to question 1, for Unit 2, the areas restricted by access were further interrogated by performing a remote video inspection in order to provide 100% coverage. For reasons described above, there is a high degree of confidence that there is no significant external corrosion of either Uni 1 or Unit 2 Reactor Pressure Vessel Closure Head.
Robinson 2	Progress Energy	Yes – A complete 100% visual inspection was performed of a bare head. No wastage was noted	NA – 100% inspection was performed
Salem 1	PSEG	Yes, we can assure that there was no evidence of boric acid corrosion for Salem Unit 1 as Salem Unit 1 was inspected during 1R14 (Apri 2001). A bare head "effective" visual examination of 100% of the head was performed and there was no evidence of boric acid crystals.	The visual inspection at Salem 1 was 100% and was not hampered. There was no evidence of boric acid crystals on the head.
Salem 2	PSEG	Salem Unit 2 is scheduled for an "effective" visual examination of 100% of the head during 2R12 (April 2002) in accordance with Bullet 2001-01. There has been no evidence of RPV head leakage of any kind or other leakage e.g Canopy Seals, at Salem Unit 2 for many years. A variety of inspections of the meridional welds and dollar weld have been performed during 1990, 1991, 1994 and 1999 all on top of the head and visually there has been no indication of boric acid crystals.	Salem Unit 2 is scheduled for an "effective" visual examination of 100% of the head during 2R12 (April 2002) in accordanc with Bulletin 2001-01. There has been no evidence of RPV head leakage of any kind or other leakage e.g Canopy Seals, at Salem Unit 2 for many years. A variety of inspections of the meridional welds and dollar weld have been performed during 1990, 1991, 1994 and 1999 all on top of the head and visually there has been no indication of boric acid crystals.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Prairie Island 1	NMC	N/A - no UT. However, reactor vessel head examinations recently performed include those required by ASME Section XI. For PINGH Unit 1, a portion of the reactor vessel head to flange circumferential weld was inspected using both magnetic and ultrasonic techniques in 1998. For PINGH Unit 2, a portion of the reactor vessel head to flange weld was inspected using both magnetic particle and ultrasonic techniques during the Spring 2000 refueling outage. Thermal insulation was removed to provide access to perform these NDE examinations. No evidence of cracking or corrosion was noted during these examinations.	No Spring 2002 outage. The next refueling outage for Unit 1 is scheduled for Fall 2002. Plans for the Fall 2002 refueling outage include performing another unaided visual inspection of the bare metal external surface of the Unit 1 reactor vessel head via access under the insulation through the view-ports in accordance with the intent of NRC BL2001 01. As noted above in response to question 3, experience at PINGP has demonstrated that this approach and practice of performing unaided visual examinations of the bare metal surface through the view-ports provides ample examination coverage of the reactor vessel head, with very few limitations or impediments. This practice of performing visual examinations of the bare metal external surface of the reactor vessel head will continue to ensure that no significant wastage of the low alloy steel head material could go undetected
Prairie Island 2	NMC	N/A - no UT. However, reactor vessel head examinations recently performed include those required by ASME Section XI. For PINGH Unit 2, a portion of the reactor vessel head to flange weld was inspected using both magnetic particle and ultrasonic techniques during the Spring 2000 refueling outage. Thermal insulation was removed to provide access to perform these NDE examinations. No evidence of cracking or corrosion was noted during these examinations.	No Spring 2002 outage. The next refueling outage for Unit 1 is scheduled for Fall 2002.
Robinson 2	Progress Energy	N/A	NA – Last refuel outage was Spring of 2001. Next scheduled is Fall of 2002. A 100% non-visual examination is planned for this outage
Salem 1	PSEG	N/A. Neither UT nor another non-visual approach was used at Salem 1. Both Salem units are ranked as 5 to 30 EFPY plants, moderately susceptible to PWSCC and therefore in a category where UT or another non-visual approach is not required. Salem Unit 2 is scheduled for an “effective” visual examination of 100% of the head during 2R12 (April 2002) in accordance with Bulletin 2001-01. Therefore, question 3 is not applicable to the Salem units.	N/A. No Spring 2002 outage.
Salem 2	PSEG	N/A. Neither UT nor another non-visual approach was used at Salem 1. Both Salem units are ranked as 5 to 30 EFPY plants, moderately susceptible to PWSCC and therefore in a category where UT or another non-visual approach is not required. Salem Unit 2 is scheduled for an “effective” visual examination of 100% of the head during 2R12 (April 2002) in accordance with Bulletin 2001-01. Therefore, question 3 is not applicable to the Salem units.	Salem Unit 2 is scheduled for an “effective” visual examination of 100% of the head during 2R12 (April 2002) in accordance with Bulletin 2001-01.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
San Onofre 2	SCE	No. SONGS did not have the ability to perform a direct inspection over 100% of the external surface without destroying existing insulation in previous outages.	Yes. We are confident that the routine refueling inspections at SONGS are capable of detecting any significant boric acid leakage originating above the insulation which could lead to head surface corrosion. SONGS also performs an effective visual inspection of approximately 1/2 of the external head surface (below the insulation) each refueling. There has been no evidence of any external head corrosion or active boric acid leakage found during these inspections. Detection of corrosion due to boric acid leakage under the un-removed head insulation depends on the radial location and the integrated leakage. We are confident that small active leaks under insulated regions near the exposed portion of the head would be evident during the refueling inspections. Corrosion in areas near the center of the vessel head would require larger integrated leakage to be detected. Therefore, small areas of corrosion near the head center may not be detected by past inspections. We do expect that the existing inspections would readily detect an aggressive corrosive environment under insulating material because the volume between the insulation and head surface is limited with respect to expected boric acid accumulations. There has been no significant unexplained growth in nominal RCS leak rates since our last inspections. This adds to our confidence that there has been no significant change in head conditions since our last inspections, particularly with respect to leak rates which are sufficient to maintain a significant area of head surface in a wet acid condition.
San Onofre 3	SCE	No. SONGS did not have the ability to perform a direct inspection over 100% of the external surface without destroying existing insulation in previous outages.	Yes. We are confident that the routine refueling inspections at SONGS are capable of detecting any significant boric acid leakage originating above the insulation which could lead to head surface corrosion. SONGS also performs an effective visual inspection of approximately 1/2 of the external head surface (below the insulation) each refueling. There has been no evidence of any external head corrosion or active boric acid leakage found during these inspections. Detection of corrosion due to boric acid leakage under the un-removed head insulation depends on the radial location and the integrated leakage. We are confident that small active leaks under insulated regions near the exposed portion of the head would be evident during the refueling inspections. Corrosion in areas near the center of the vessel head would require larger integrated leakage to be detected. Therefore, small areas of corrosion near the head center may not be detected by past inspections. We do expect that the existing inspections would readily detect an aggressive corrosive environment under insulating material because the volume between the insulation and head surface is limited with respect to expected boric acid accumulations. There has been no significant unexplained growth in nominal RCS leak rates since our last inspections. This adds to our confidence that there has been no significant change in head conditions since our last inspections, particularly with respect to leak rates which are sufficient to maintain a significant area of head surface in a wet acid condition.
Seabrook	North Atlantic Energy	No. See response to question #2 for historical perspective.	Our previous inspections have involved visually inspecting the accessible head insulation through four (4) lower shroud openings for evidence of leakage and boric acid deposits. No evidence of leakage or boric acid deposits have been found. A simplified RPV head modification was installed in refueling outage OR06 in the Spring of 1999. During installation of the modification, essentially the entire top head insulation was visible. During the close-out cleanliness inspection of this area, some small debris was retrieved or evaluated, but no evidence of leakage or boric acid deposits were noticed. Based on this lack of evidence, Seabrook is confident that boric acid does not exist on the bare head below the insulation.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
San Onofre 2	SCE	No. Non-visual examinations capable of detecting low alloy steel corrosion have not been previously performed a SONGS.	SONGS-2 is scheduled for refueling in May 2002. As committed to by our response to NRC Bulletin 2001-01, we will perform either a volumetric or a wetted surface examination on all of the reactor vessel head penetrations. In addition t that commitment, we plan to perform a 100% head surface inspection in conjunction with a modification to our head insulation that will allow for routine surface examinations of our vessel head in the future.
San Onofre 3	SCE	No. Non-visual examinations capable of detecting low alloy steel corrosion have not been previously performed a SONGS.	SONGS-3 is scheduled for refueling in January 2003. As committed to by our response to NRC Bulletin 2001-01, we will perform either a volumetric or a wetted surface examination on all of the reactor vessel head penetrations. In addition to that commitment, we plan to perform a 100% head surface inspection in conjunction with a modification to our head insulation that will allow for routine surface examinations of our vessel head in the future.
Seabrook	North Atlantic Energy	No UT examinations have been performed.	Seabrook has no plans to perform a bare head visual inspection during the May 2002 refueling outage (consistent with NRC Bulletin 2001-01 for plants within our susceptibility grouping).

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Sequoyah 1	TVAN	Inspection of the Sequoyah Unit 1 Reactor Head Penetration area was last performed on October 27, 2001. The best effort visual examination was performed by a Senior Metallurgical Engineer with past experience associated with reactor head inspections at Sequoya Nuclear Plant. The shroud plate was raised approximately 2 inches providing 100% visual access to the first row outer periphery penetrations and partial access to the second row penetrations. Because of restrictions associated with lead shielding, line of sight on the second row penetrations did not allow direct visual examination of the CRDM/Reactor Head interface. During inspection of the Unit 1 reactor head penetrations, there were no changes in physical condition with relationship to past inspections that could indicate PWSCC pressure boundary leakage or the presence of wastage.	For SQN 1, small particles of boron were identified at the CRDM to head interface on E1 and D14 (first row). The particles were localized and less than 1/32 inch in diameter. These locations are in areas where previous CRDM canopy seal weld leakage has occurred (CRDM canopy seal weld repairs for A5 and E13). There was no evidence of significant boron buildu or obvious leakage staining at the penetrations that is indicative of PWSCC pressure boundary leakage. No evidence of wastage was observed at these locations. Minor boron residue was noted on the outer periphery of the head. These conditions are also the result of previous CRDM canopy seal weld or conoseal leakage incurred in previous outages and have been previously evaluated by metallurgical engineering. No evidence wastage of the head was observed in these locations during this inspection. Based on the results of these partial and/or limited inspections no evidence exists that woul suggest external corrosion is present on the heads of the SQN 1 RV.
Sequoyah 2	TVAN	No.	No visual inspections performed to date. Sequoyah Unit 2 has never had a canopy seal leak and inspections above the head covering of all credible sources show no evidence of leakage. Sequoyah Unit 2 has been performing the limited inspection of periphery penetrations with no evidence of leakage.
Shearon Harris	Progress Energy	Shearon Harris Unit 1 was not required by the NRC Bulletin 2001-01 to perform any examinations of the vessel head penetrations, due to the unit's relative time at temperature. However, during RFO10, which was completed on 01/03/02, CP&L performed a visual inspectior of the accessible portions of the reactor pressure vessel head and nozzles. The very top of the head in an approximately 3' diameter circle could not be examined. The inspection was performed by a qualified VT-2 inspector in accordance with approved plant procedures. Thi inspection would have detected external surface corrosion or accumulation of boric acid crystals.	There is a high confidence level of no external corrosion for several reasons. a)There was no evidence of vessel head penetration nozzle leakage (crystals, streaming, "mouse hole" deposits, etc.) from the inspection performed last outage (11/01) where a significant portion of the head was inspected specifically for indications of leakage. No wastage areas wer noted. b)Previous boron deposits from canopy seal weld leaks, conoseal leaks, etc., were cleaned up at the time of discovery, and the surrounding area examined for residual boron and wastage. No wastage has been seen, and no accumulated boron has been left on the head. None of these past leaks have been in the area that could not be inspected last outage. c)During start-up from RFO10, QC personnel performed an inspection of mechanical seals above the reactor vessel head at operating temperature and pressure to verify that no RCS leakage was present.
South Texas 1	STPNOC	No	Are confident in ability to detect leakage. (Info provided by fax indicates that visual exams from outside cooling shroud insulation (with stud insulation removed) at begninning of each RFO. One case of leakage was documented (spare CRDM housing weld leak). A CSCA clamp was installed on the housing.
South Texas 2	STPNOC	No	Are confident in ability to detect leakage. (Info provided by fax indicates that visual exams from outside cooling shroud insulation (with stud insulation removed) at begninning of each RFO. Two cases of leakage at Unit 2 were documented. Both were repaired.
St. Lucie 1	FPL	St. Lucie 1 visual inspection of the head under insulation is planned for Fall 2002	St. Lucie 1 visual inspection of the head under insulation is planned for Fall 2002. The last 88-05 inspections were performed in Spring, 2001 and no evidence of boric acid was seen. The inspection procedure calls for the specific locations to be examined: reactor vessel head area, control rod drive mechanisms,ICI flanges and the general area around reactor vessel. 100% visual inspections are planned for St. Lucie 1 in 2002.
St. Lucie 2	FPL	St. Lucie 2 inspection of 12/2001 100% visual under in+sulation - showed no indication of plant leakage	At St. Lucie 2 the visual was 100% and performed so as to detect any boric acid crystal buildup.
Summer	SCANA	VC Summer has performed boric acid inspections every refueling outage as a surveillance commitment to Generic Letter 88-05. The Reactor Head – CRDM area inside the shroud was inspected above the insulation and no signs of leakage found.	VC Summer has conoseal welds on the CRDM drives. All previous RFO inspections have detected no leaks at these locations nor any leak associated with the RV Head Vent. Additionally we have never experienced CRDM Penetration problems seen by other plants. VC Summer is a T Cold Head plant as it relates to susceptibility ranking for CRDM Penetration cracking.
Surry 1	Dominion Generation	The fall 2001 RV head inspections included 100% visual inspection of the RV head surface underneath the insulation. Inspections were conducted using robot mounted video cameras and hand manipulated boroscopes. While the primary concern of these inspections was th area immediately surrounding the CRDM penetration to head interface, there is a very high level of confidence that any significant corrosion of the head or accumulation of boric acid residue would have been detected by the inspections. For Surry Unit 1 the heads were cleaned subsequent to the initial examination to provide a clean head for re-examination to establish a baseline for future examination.	N/A
Surry 2	Dominion Generation	The fall 2001 RV head inspections included 100% visual inspection of the RV head surface underneath the insulation. Inspections were conducted using robot mounted video cameras and hand manipulated boroscopes. While the primary concern of these inspections was th area immediately surrounding the CRDM penetration to head interface, there is a very high level of confidence that any significant corrosion of the head or accumulation of boric acid residue would have been detected by the inspections. The Surry Unit 2 head was was determined to be clean and no subsequent cleaning of the head was required.	N/A

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Sequoyah 1	TVAN	N/A	No Spring 2002 outage.
Sequoyah 2	TVAN	N/A	Currently planning a similar "lift"type inspection as was performed on SQN 1, however, are considering enhancing this inspection by use of a remote device in order gain access to 100% of the head surface if possible.
Shearon Harris	Progress Energy	N/A - Shearon Harris Unit 1 was not required by the NRC Bulleting 2001-01 to perform any UT or non-visual examinations on the VHP's or base material.	N/A - Shearon Harris Unit 1 is not scheduled for an outage during the Spring of 2002.
South Texas 1	STPNOC	N/A	N/A - next outage is Fall 02
South Texas 2	STPNOC	N/A	N/A - next outage is Fall 02
St. Lucie 1	FPL	N/A	No Spring 2002 outage.
St. Lucie 2	FPL	N/A	No Spring 2002 outage.
Summer	SCANA	VC Summer has never performed UT or non-visual inspection on CRDM Penetrations.	VC Summer will again perform the GL 88-05 Boric Acid Inspection of the RV Head – CRDM area during RF 13 – Spring 2002. Any signs of boron either on top of or coming from under the head insulation will be investigated. Plans are in place to work with our RV Head Insulation manufacturer during the refueling outage to determine what it will take to perform an inspection. A bare metal under the insulation head inspection is being evaluated for RF 14 scheduled
Surry 1	Dominion Generation	N/A	No Spring 2002 outage.
Surry 2	Dominion Generation	N/A	Surry Unit 2 has a spring 2002 refueling outage. However, given the 100% visual examination perforemd only 5 month previous indicating a clean head, there are no plans to perform additional examinations at this time.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
TMI 1	Exelon	Yes. During the 1R14 Outage (October/November 2001), TMI Unit 1 performed a 100% qualified video inspection (with videotape) to determine the CRDM nozzle leakage status at the start of the outage. After the CRDM nozzle were repaired, the RV head surface was cleaned and another inspection/videotape completed to document the as left condition. No wastage was observed. Hot Shutdown checks inside the Reactor Building are performed at the start of each refueling outage. These checks are used to identify any leakage in the reactor building. Any source of leakage is repaired and "wastage" would be evaluated by a material non-conformance report (MNCR). NDE/ISI group has records of the specific reactor head inspections for 88-05. In the past, boron was observed on the TMI-1 reactor head and the source of leakage was determined to be from CRDM flange leaks. The two previous 88-05 inspections evaluated the boron to be old and not creating any new corrosion to the head. Therefore the boron on the reactor head was not cleaned until 1R14.	NA since 100% inspection performed.
Turkey Point 3	FPL	Turkey Point 3 inspection of 10/2001 - 100% qualified visual with insulation removed - showed no indication of past leakage	At Turkey Point 3 the visual was 100% and performed so as to detect any boric acid crystal buildup.
Turkey Point 4	FPL	Turkey Point 4- 100% qualified visual with insulation removed is planned for Spring 2002	The last 88-05 inspection was conducted in January 2001. The inspection procedure calls for specific locations to be inspected: Reactor Head, Head Vent Valves, RPI Stack, Instrumentation Ports,Reactor Vessel Closure Head Area Inside the (3) Removable Inspection Port Doors on the Shroud, Penetrations 51, 53, 55, and 57 thermocouple flanges,and the Reactor Head Flange.
Vogtle 1	Southern Nuclear	Refueling outage in progress. Plan to perform a visual inspection.	See response to 1. Vogtle 1 is ranked #50 (104.5 EFPY to Oconee 3) on the MRP PWSCC list so probability of penetration leakage is extremely low. Inspection above the insulation has been performed every outage and any leakage was repaired. No leakage has been observed since 1990.
Vogtle 2	Southern Nuclear		Vogtle 2 is ranked #52 (106 EFPY to Oconee 3) on the MRP PWSCC list so probability of penetration leakage is extremely low. Inspection above the insulation has been performed every outage and no leakage has been observed.
Waterford 3	Entergy	The most recent inspection of the RPV head was performed during RF10 (October 2000) as part of the Generic Letter 88-05 boric acid walkdown program. This inspection does not require the insulation be removed from the RPV head. The inspection, conducted by engineers, looks for any signs of leakage on the RPV head (e.g., dripping, rust stains on insulation, steam leaks, boric acid crystals, etc.) and is conducted while the RCS system is hot. Additionally, during RF10, ISI personnel inspected the circumferential head-to-head flange weld and saw no evidence of boric acid around the perimeter of the head. In April 1997 approximately 20 percent of the VHPs were examined around the perimeter of the reactor vessel head. No significant corrosion was identified during this partial bare metal inspection.	Per NUREG/CR-6245 , leakage over a significant amount of time (six to nine years) and significant amounts of boric acid (~12 cubic feet of crystals) would be required to corrode the RPV head to a point where it challenges the structural integrity of the head. Per CEN-607 , CEN-614 , and NUREG/CR-6245, it is highly unlikely that the evidence of this leakage would go undetected over a six to nine year period (i.e., approximately four to six GL 88-05 inspections). Twelve cubic feet of boric acid crystals is equivalent to ~1000 pounds of boric acid. If corrosion is approximately proportional to leakage, then several tenths of a gpm over several years would be required to threaten the structural integrity of the head. Additionally, CEOG document CE NPSD-690-P has previously evaluated inspecting the small bore Inconel 600 nozzles tha could leak due to leakage from PWSCCs without removing the insulation. The document reports that if 10 pounds of boron crystals were to buildup due to PWSCC leakage, the boron would either extrude from the annulus region between the insulation and nozzle or from the ends of the insulation. Although this report was written for the small bore penetrations, it is considered valid for the Entergy's CE heads (ANO-2 and Waterford 3) and Westinghouse heads (Indian Point 2 and 3). In 1989, leakage from the RPV head instrument flange was reported. The leak indirectly deposited boron on the RPV head (NW quadrant at periphery of head). During RF4, corrective actions were taken to eliminate the leak, inspect the areas exposed to the boron, and clean up the boric acid crystals from the surface of the insulation. Limited inspections were preformed under the insulation during RF4. No significant corrosion was identified during the RF4 inspection. During RF8 (April 1997) the insulation was removed around the perimeter of the reactor vessel head to facilitate inspection under the insulation where the boron deposits had been removed from the insulation during RF4 and to inspect approximately 20% of the VHP nozzles for signs of PWSCC. Small amounts of dry boric acid crystals were cleaned from the RPV head. No significant corrosion was identified during this partial bare metal inspection of the head nor were any signs of PWSCC identified. Additionally, over the years, minor versa-vent leakage (weepage) has been noted by indications of boric acid crystals on the coil stacks well above the head. This minor leakage has not reached the external surface of the insulation on the head at Waterford 3. Therefore, the area of the head affected by the leak in 1989 has been cleaned and inspected while other minor leakage above the head has been managed such that none has reached the outer surface of the head. Based on the GL 88-05 inspections along with other routine inspections of the Waterford 3 head per question 1 , Entergy has not identified any boric acid leakage that would indicate the conditions for head thinning at Waterford 3. As noted below, Waterford 3 will be conducting a bare metal visual inspection of the RPV head in less than one month in response to Bulletin 2001-01.

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
TMI 1	Exelon	N/A	N/A
Turkey Point 3	FPL	N/A	No Spring 2002 outage.
Turkey Point 4	FPL	N/A	100% visual inspections are planned for Turkey Point 4 in 2002
Vogtle 1	Southern Nuclear	N/A - No volumetric exams performed.	Visual inspection planned, including remote robotic crawler.
Vogtle 2	Southern Nuclear	N/A - No volumetric exams performed.	No Spring 2002 outage.
Waterford 3	Entergy	N/A. Waterford 3 has not performed UT or another non-visual approach on the RPV head	Waterford 3 will be performing an effective visual examination of 100% of the outer bare metal surface of the VHPs (essentially 360 degrees around each nozzle) for evidence of leakage during RF11 in accordance with Bulletin 2001-01. The insulation will be removed from the reactor vessel head to facilitate this inspection. Following the inspection (and any required repairs), a general head cleaning will be performed to remove any boron deposits that may be on the head. This visual inspection in combination with the cleaning of the head will reveal any indications of corrosion on the external surface of the head adjacent to the VHPs.

Unit Name	Utility	Response to Question 1: At your most recent inspection, did you do a sufficient visual examination over 100% of the head to have detected external surface corrosion or accumulation of boric acid crystals?	Response to Question 2: If the visual inspection was not 100% (or was in some way hampered), can you confidently say that you don't have external head corrosion?
Watts Bar 1	TVAN	An inspection similar to Sequoyah 1 was not performed on Watts Bar Unit 1 during the cycle 4 refueling outage based on its EPRI MRP susceptibility ranking and relatively short operating time. However, inspection of the canopy seal welds during this outage showed only trace amounts of residual boron from previous leaks which have been repaired. No new leaks or additional residue was noted.	Although similar periphery inspections were not performed at Watts Bar, results from the canopy seal weld inspection during the cycle 4 outage did not reveal any evidence of significant boron presence which could lead to wastage of the reactor vessel head. Only trace amounts of boron residue were noted from previous leaks which had been repaired. Based on the results of these partial and/or limited inspections no evidence exists that would suggest external corrosion is present on the heads of the SQN 1 or WBN 1 reactor pressure vessels.
Wolf Creek	WCNOC	Most recent inspection (Refuel 11, 2000) was visual with head insulation in place	We have not performed a complete bare head examination of the entire head. We are comfortable with relying upon the EPRI/MRP susceptibility evaluations and with our current practice of removing insulation if indications of leakage are identified

Unit Name	Utility	Response to Question 3: If UT or another non-visual approach was used at your most recent inspection, was the UT examination capable of detecting corrosion of the low alloy steel head material (changes in back reflection)? Did you perform a full length UT of the RPV nozzles to the top of the head?	Response to Question 4: For plants with Spring 2002 outages (all susceptible 'classes'), what plans can you make/how will you show that there is not significant boric acid corrosion?
Watts Bar 1	TVAN	N/A	No Spring 2002 outage.
Wolf Creek	WCNOC	N/A	Our current plan is to perform our Boric Acid Corrosion Inspection in accordance with our established site procedures. If active leakage is identified, insulation in the area affected will be removed to determine impact.