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54.17

NLS2010062
July 23, 2010

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
Washington, D.C. 20555-0001

Subject: Revisions and Supplements to Responses to Requests for Additional Information Related to the License Renewal of Cooper Nuclear Station
Cooper Nuclear Station, Docket No. 50-298, DPR-46

Dear Sir or Madam:

The purpose of this letter is for the Nebraska Public Power District to revise and supplement the responses submitted previously to certain Requests for Additional Information (RAI) related to the Cooper Nuclear Station License Renewal Application (LRA), as requested by the Nuclear Regulatory Commission staff. The revised and supplemented RAI responses are provided in Attachments 1, 2, and 3. Associated revisions to the LRA are provided in Attachment 4.

The General Manager of Plant Operations is authorized to sign under oath or affirmation in the absence of the Chief Nuclear Officer in accordance with Regulatory Issue Summary 01-018. Should you have any questions regarding this submittal, please contact David Bremer, License Renewal Project Manager, at (402) 825-5673.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 7/23/2010
(Date)

Sincerely,

Demetrius L. Willis
General Manager of Plant Operations

/wv

A136
NRR

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Attachments

cc: Regional Administrator w/ attachments
USNRC - Region IV

Cooper Project Manager w/ attachments
USNRC - NRR Project Directorate IV-1

Senior Resident Inspector w/ attachments
USNRC - CNS

Nebraska Health and Human Services w/ attachments
Department of Regulation and Licensure

NPG Distribution w/ attachments

CNS Records w/ attachments

Attachment 1

Revisions and Supplements to Responses to Requests for Additional Information
Related to License Renewal Conference Call Summaries
Cooper Nuclear Station, Docket No. 50-298, DPR-46

Over the course of the Cooper Nuclear Station (CNS) license renewal review period, the CNS License Renewal Team has conducted a number of conference calls with the Nuclear Regulatory Commission (NRC) staff to discuss the submitted responses to various NRC requests for additional information (RAI). These discussions have been documented in the conference call meeting summaries issued by the NRC, and included both clarifying revisions and supplemental information to certain RAI responses. These conference calls were conducted on September 2, 2009 (ADAMS Accession Number ML092680569), and September 21, 2009 (ADAMS Accession Number ML093000440). The NRC has communicated to the Nebraska Public Power District (NPPD) that several of these RAI-related discussions needed to be documented on the CNS docket. The RAIs are shown in italics, and the NPPD responses are shown in block font, with revisions shown in underline/strikeout format.

<u>NRC Supplemental Request (September 2, 2009, Conference Call)</u>: *RAI 2.4-1*

In the applicant's RAI response (ML092400412), the base plate and anchors are in scope. Why is the rest of the crane not in scope?

<u>NPPD Supplemental Response</u>:

The jib crane and its associated trolley located in the reactor building are used to move control rod drives when maintenance is required during an outage. The crane does not lift loads over safety-related equipment. It is built of a pipe column seismically anchored to the operating floor. The crane cannot break loose and damage any safety-related equipment on any of the different levels below it during an earthquake. Thus, its failure could not prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(l) (i), (ii), or (iii) of 10 CFR 54.4.

<u>NRC Supplemental Request (September 21, 2009, Conference Call)</u>: *RAI 2.4-1*

In the applicant's RAI response (ML092400412), the base plate and anchors are in scope. The staff asked why is the rest of the crane not in scope?

The crane cannot break loose and damage any safety-related equipment on any of the different levels below it during an earthquake. The term "cannot break loose" is a qualitative statement and suggests that the jib crane is located in a way that could have interaction with safety-related SSCs. Please provide further clarification.

NPPD Supplemental Response:

The jib crane and its associated trolley located in the reactor building are used to move control rod drives when maintenance is required during an outage. The crane does not perform a safety function and it is not critical to plant operation, and it does not lift loads over safety-related equipment. The crane is located such that its failure will not damage safety-related structures, systems, or components (SSCs). It is built of a pipe column seismically anchored to the operating floor. The crane cannot break loose and damage any safety-related equipment on any of the different levels below it during an earthquake. Thus, its failure could not prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(l)(i), (ii), or (iii) of 10 CFR 54.4.

NRC Supplemental Request (September 2, 2009, Conference Call): *RAI 2.4-3*

In the applicant's RAI response, the intake structure crane is addressed in LRA Section 2.4.2, "Water Control Structures." It is nonsafety-related, and located away from safety-related systems and components when not in use." Could its failure affect any safety system when in use?

NPPD Supplemental Response:

The intake structure crane, when in use, generally travels over nonsafety-related SSCs. However, if needed, it can also travel over safety-related components (i.e., service water pumps) using a safe load path established through engineering evaluation. The intake structure crane lifts the service water pump and motor parts out of individual hatches above the service water pump room when maintenance is required. Removal through the hatches follows a safe load path which prevents one pump being lifted above another. Procedural controls prevent lifting service water pump or motor parts where a load drop could result in damage to the other service water pumps or other safety-related equipment. Safety-related service water pumps are housed in a seismic Class I structure within the intake structure. As a Class I structure, the structure is designed to withstand impact of the crane in case of potential failure of the crane. Thus, its failure could not prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(l) (i), (ii), or (iii) of 10 CFR 54.4.

NRC Supplemental Request (September 2, 2009, Conference Call): *RAI 2.4-4*

Why are the trash racks are not in scope. Wouldn't their failure affect the function of the in scope traveling screens and have cascading effect on function of the safety-related system and components (i.e., service water system)? Your response does not say that. Please explain.

NPPD Supplemental Response:

The trash racks, nonsafety-related components, are installed about 10 feet in front of traveling screens toward the Missouri River. They protect the traveling screens from debris larger than three inches. Traveling screens are in scope due to their potential for structural interaction and not for system function. Although, catastrophic failure of the trash racks is not anticipated, their failure would not have a cascading effect on providing adequate water supply to the service water pumps. Thus, in the remote chance of total failure of the trash racks, their failure could not prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(l) (i), (ii), or (iii) of 10 CFR 54.4.

<u>NRC Supplemental Request (September 21, 2009, Conference Call)</u>: *RAI 2.4-10*

The applicant stated that:

> *Built-up roofing systems were used in the structures listed in Section 2.4.3 of the LRA. However, the roofing systems, including roofing membranes, are not within the scope of license renewal. They are nonsafety-related and provide protection from external environment to roof decking and roof slabs. Shielding and protection are provided by roof decking and roof slabs. The builtup roofing system does not perform any of the license renewal intended functions defined in 10 CFR 54.4(a)(l), (2) or (3).*

It is not clear if this is implying that there are no safety-related SSCs below the roof areas (in various buildings) where the waterproofing membrane is used. The staff requested more specific clarifications. The staff understands that 54.4(a)(2) will be addressed either by stating that there are no safety-related SSC's that could be affected by a leaking roof (degradation of the roof waterproofing membrane) or the roof waterproofing membrane will be included in the scope and subject to AMR.

<u>NPPD Supplemental Response</u>:

Roofing materials provide protection of equipment from the elements to protect the utility investment in equipment contained within plant structures. During the operating experience review for the CNS license renewal project, several occurrences of leaking roof membrane were identified, none of which affected the operability of equipment relied on to accomplish any of the functions identified in paragraphs (a)(l) (i), (ii), or (iii) of 10 CFR 54.4. This operating experience provides additional confirmation that a leaking roof will not prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(l) (i), (ii), or (iii) of 10 CFR 54.4. Nevertheless, the roofing membrane (elastomer) has been included in the scope of license renewal and subjected to aging management review. License Renewal Application (LRA) Tables 2.4-4 (Bulk Commodities Components Subject to Aging Management Review) and 3.5.2-4 (Bulk Commodities) were previously revised in NLS2009100 (ADAMS Accession Number ML100050070).

<u>NRC Supplemental Request (September 2, 2009, Conference Call)</u>: *RAI 2.4-11*

In the applicant's RAI response, "other subcomponents, specifically hoists and associated hardware, are supported by the structural components included under crane rails and girders. These subcomponents do not support a license renewal intended function identified in 10 CFR

54.4(a)(l), (a)(2), or (a)(3)." However, Table 2.2-3 shows hoists as in scope within line item "cranes, Trolleys, Monorails and Hoists." Please explain.

NPPD Revised Response:

As indicated in LRA Table 2.2-3, cranes, trolleys, monorails and hoists are evaluated as structural components or commodities of the structure in which they are located. Accordingly, the turbine building crane and its subcomponents (including bridge, trolley, hoists, hardware, rails and girders), which are in scope of ~~the LRA and subject to AMR~~license renewal, are evaluated in Section 2.4.3, "Turbine Building, Process Facilities and Yard Structures.~~,~~" ~~and are included within the LRA Table 2.4-3 *Steel and Other Metals* line item "Crane rails and girders."~~ In accordance with 10 CFR 54.21 (a)(l)(i), hoists are not listed in LRA Table 2.4-3 Steel and Other Metals line item "Crane rails and girders" as subject to aging management review because they perform their function with moving parts. The associated bolting is evaluated as a bulk commodity in Section 2.4.4, "Bulk Commodities," and is included in LRA Table 2.4-4 *Bolted connections* line item "Structural bolting." ~~Other subcomponents, specifically hoists and associated hardware, are supported by the structural components included under crane rails and girders. These subcomponents do not support a license renewal intended function identified in 10 CFR 54.4(a)(1), (a)(2), or (a)(3).~~If associated structural crane rails, girders, and bolting perform their intended functions, the hoists will not be a hazard to nearby equipment.

NRC Supplemental Request (September 21, 2009, Conference Call): *RAI 2.4-16*

Please clarify whether the failure of OWCGG building onto adjacent building(s) is postulated in the CNS Current License Basis.

NPPD Supplemental Response:

As indicated in CNS Updated Safety Analysis Report Section Xll-2.1, the Class II structural design criteria apply to structures, equipment, and components which are important to reactor operation, but are not essential for preventing an accident which would endanger the public health and safety, and are not required for the mitigation of the consequences of these accidents. Accordingly, the optimum water chemistry gas generator (OWCGG) building is categorized as Class II. The impact of failure of the building is acceptable not because of its design features, but because of its location. It is near but not attached to the turbine building and is a separate structure with independent masonry block walls and concrete floor. An evaluation of the consequences of its failure has determined that its failure will have no impact on adjacent structures. Its failure would not prevent satisfactory accomplishment of any of the functions identified in paragraphs (a)(l) (i), (ii), or (iii) of 10 CFR 54.4.

Attachment 2

Revisions to Response to Request for Additional Information Related to the Advisory Committee for Reactor Safeguards Plant License Renewal Subcommittee Questions Cooper Nuclear Station, Docket No. 50-298, DPR-46

The Nebraska Public Power District (NPPD) provided supplementary information to follow-up questions regarding Request for Additional Information (RAI) B.1.15-7(d) in NLS2010019, submitted on March 25, 2010 (ADAMS Accession Number ML100920090). In response to questions by the Advisory Committee for Reactor Safeguards Plant License Renewal Subcommittee, NPPD is making certain changes to the previously submitted information. The RAI follow-up questions are shown in italics, and the NPPD revised responses are shown in block font, with revisions shown in underline/strikeout format.

RAI B.1.15-7(d) Follow-up

The staff requested a supplement to the response to RAI B.1.15-7 (NLS2009040, June 15, 2009) which: a) explained why there were more startups than shutdowns, and b) either to provide a validated histogram for cycles preceding 1996 (from initial plant start up), or as an alternative, provide a discussion of the cycles accrued for startup and shutdown prior to 1996 (from initial plant start up), in comparison with the 1996 – 2007 trend.

The applicant agreed to provide the requested supplement.

NPPD Revised Position:

a) Normal startups on the histogram include all plant startups. Many shutdowns are not normal shutdowns, but may result from transients or equipment malfunctions, which are not included in the shutdowns shown on the histogram. For example, a shutdown due to loss of feedwater is categorized as a loss of feedwater. Also including this transient in the shutdown category would amount to double counting the transient. For these reasons, there is not a one-to-one correlation between the number of shutdowns and startups in certain calendar years or over a longer period such as, the period of 1996 through 2007.

b) During the initial years of plant operation there were more shutdowns for equipment issues and operator errors. Also the plant was on a 12 month refueling cycle which necessitated a startup and shutdown every year. As the staff gained experience, the number of equipment issues and personnel errors diminished. From 1974 to 1984, the first ten years of operation, there were approximately ~~44~~ 43 normal shutdowns, ~~2~~12 loss of feedwater pump shutdowns, ~~3~~20 turbine trips, and 50 other scrams. From 1985 through 1994, there were approximately 10~~1~~ normal shutdowns, five loss of feedwater pump shutdowns, five~~four~~ turbine trips, and 13~~2~~ other scrams. From 1995 to 2004~~9~~, there were approximately 17~~11~~ normal shutdowns, one~~two~~ loss of feedwater pump shutdown~~s~~, one turbine trip, and 3~~10~~ other scrams. For the two years just prior to the 2007 license renewal application analysis freeze date, 2005 through 2006, there were two normal shutdowns, one loss of feedwater pump shutdown, and three other scrams. This clearly shows that the rate of occurrence of transient events ~~startups and shutdowns~~ from 1996 through 2007 is much less than the rate of occurrence prior to 1996. The more recent trend is expected to be representative of future plant performance. Nonetheless, the Fatigue Monitoring Program will continue to track the number of plant transients to ensure that fatigue analyses based on those numbers remain valid through the period of extended operation.

The above data is based on a recreation of the cycle counting data. In most cases, the temperatures and pressures during actual plant transients were significantly less than those assumed in applicable stress and fatigue analyses.

Reference: Conference call conducted on January 14, 2010, regarding the response to RAI B.1.15-7(d), with subsequent input from the NRC staff.

Attachment 3

Supplement to Response to Request for Additional Information
Related to Safety Evaluation Report Open Item 3.0.3.1.2
Cooper Nuclear Station, Docket No. 50-298, DPR-46

The Nebraska Public Power District (NPPD) provided a response to Request for Additional Information (RAI) B.1.3-3 in NLS2010050 on May 4, 2010 (ADAMS Accession Number ML101310605). This RAI is related to Open Item 3.0.3.1.2-1 in the "Safety Evaluation Report Related to the License Renewal of Cooper Nuclear Station" (ADAMS Accession Number ML100960511). Discussions were held between the Cooper Nuclear Station (CNS) license renewal team and the Nuclear Regulatory Commission (NRC) staff on June 24, 2010, and it was determined that supplementary information was needed to resolve this Open Item. The RAI follow-up questions are shown in italics, and the NPPD responses are shown in block font.

NRC Request: *RAI B.1.3-3 Follow-up*

Effective management (inspection knowledge) of the aging effect in buried piping and tank.

1. *What length of pipe will be exposed in each of the planned inspections?*

2. *Given the past condition of the cathodic protection system, what is the basis of the station that they have a reasonable assurance of buried piping integrity?*

NPPD Response:

1. Planned direct visual inspections of excavated piping are expected to cover essentially the entire circumference of at least eight feet of piping.

2. There is reasonable assurance of in-scope piping integrity with or without cathodic protection for the following reasons:

    a. CNS has non-aggressive soil
    b. Buried in-scope piping is coated
    c. Visual inspections of excavated fire protection piping, and diesel generator fuel oil piping and tanks indicate that piping and tanks and applicable coating are in very good condition after more than 30 years of service
    d. Broadband electromagnetic (eddy current) exams from the inside of service water piping indicated good material thickness
    e. Review of site operating experience indicated no age-related failures of in-scope buried piping at CNS

    Additional inspections will be performed prior to and during the period of extended operation (PEO). The above factors in conjunction with these inspections will provide reasonable assurance of the integrity of the buried piping and tanks.

Recognizing the importance of an effective cathodic protection system, NPPD will upgrade the site cathodic protection system prior to the PEO for in-scope buried piping and tanks. The Buried Piping and Tanks Inspection Program will be revised to ensure that during the PEO the cathodic protection system will be maintained and annually tested in accordance with NACE (National Association of Corrosion Engineers) standards RP0285-2002 and SP0169-2007 with a minimum system availability of 90%. If 90% availability is not maintained, the condition will be entered into the corrective action program to evaluate the impact and effect corrective actions. License Renewal Application (LRA) Sections A.1.1.3 and B.1.3 have been revised to incorporate this programmatic commitment (see Attachment 4, Changes 1 and 3).

<u>NRC Request</u>: *RAI B.1.3-3 Follow-up*

Incorporation of operating experience.

1. *Is the applicant aware of Salem's false assurance from torsional guided wave data? What actions has the station taken to ensure screening by torsional guided wave will not give a false assurance of buried pipe integrity?*

<u>NPPD Response</u>:

Inspection methods for buried piping and tanks include direct visual inspections of excavated components, remote visual inspections of piping following vacuum excavation that exposes only a small section of piping, and non-visual methods such as torsional guided wave ultrasonic techniques and traditional ultrasonic thickness measurements. NPPD is aware of operating experience that has demonstrated limitations of certain non-visual examination methods, such as the torsional guided wave method. NPPD will assure that those limitations are considered during application of non-visual examination methods such that those methods are assured of providing valid assessment results for specific applications.

<u>NRC Request</u>: *RAI B.1.3-3 Follow-up*

Inspection effectiveness (frequency/extend).

1. *Beyond general statements, the applicant did not address inspections during the PEO, what are their specific plans for visual inspections of buried piping segments during the PEO?*

2. *Given some ambiguity in the language, I want to be clear on the planned inspections prior to the period of extended operation. My interpretation of the Cooper RAI response is that they will inspect at least one piping segment in each of the following systems, is this correct?*

    - *SRW*
    - *DGFO*

- *HPCI*
- *SBGT*
- *FP*
- *Condensate makeup*

Are there any plans to inspect buried plant drains, in scope LRA 3.3.2-12, or is this part of the planned inspections for SBGT? Similarly what are the plans to inspect the buried nitrogen tank?

NPPD Response:

1. Commitment NLS2010050-04 (ADAMS Accession Number ML101310605) is revised as follows to describe in greater detail the buried piping inspections that will be performed during the PEO (see Attachment 4, LRA Changes 1 and 3):

   As described in LRA Section B.1.3, ~~NPPD will enhance~~ the Buried Piping and Tanks Inspection Program ~~described in LRA Section B.1.3 to~~ will include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. The piping segments and tanks will be classified as having a high, medium or low impact of leakage based on items such as the safety class, the hazard posed by fluid contained in the piping, and the impact of leakage on plant operation. The corrosion risk will be determined through consideration of items such as piping or tank material, soil resistivity, drainage, the presence of cathodic protection, and the type of coating. ~~The inspection priority and frequency for periodic inspections of the in-scope piping and tanks will be established based on the results of the risk assessment. Inspections will be performed using inspection techniques with demonstrated effectiveness.~~ During the period of extended operation (PEO), examinations of in-scope buried piping and tanks will be performed at a frequency of at least once every 10 years. Examinations of buried piping and tanks during the PEO will consist of visual inspections as well as non-destructive examination (e.g. ultrasonic and guided wave) to perform an overall assessment of the condition of buried piping and tanks. The examinations will include visual inspection of at least eight feet of excavated piping on at least three high-risk in-scope systems, and will examine a minimum of 2% of the total linear feet of high-risk in-scope buried piping during each 10-year period.

2. As discussed in the response to RAI B.1.3-3, prior to the PEO, NPPD plans to perform opportunistic inspections during cathodic protection system upgrades. In addition, NPPD committed to inspect all high-risk buried tanks and at least one high-risk buried piping segment in each system within the scope of license renewal that contains high-risk buried piping.

   During the cathodic protection system upgrade, NPPD plans to perform remote visual inspections and ultrasonic wall thickness measurements at two locations on each system for the service water, fire protection and condensate makeup systems. These inspections are planned to entail visual inspection of the coating followed by coating removal and wall thickness measurement. Inspecting two locations near opposite ends of the associated piping segments provides a good indication of the overall condition of the coating and buried piping of each system.

Commitment NLS2010050-05 (ADAMS Accession Number ML101310605) is revised as follows to describe in greater detail the buried pipe and tank inspections that will be performed prior to the PEO (see Attachment 4, LRA Changes 1 and 3):

> ~~Prior to the period of extended operation, NPPD will inspect all high-risk buried tanks and at least one high-risk buried piping segment in each system within the scope of license renewal that has high-risk buried piping. This includes, but is not limited to, safety-related systems, which are service water, diesel generator fuel oil, high pressure coolant injection, and standby gas treatment systems. In addition, irrespective of risk ranking, NPPD will inspect at least one segment of buried piping in each of three in-scope systems, service water, fire protection, and condensate makeup.~~ As described in LRA Section B.1.3, prior to the PEO, NPPD will inspect buried piping and tanks in six systems. These systems are diesel generator fuel oil (DGFO), standby gas treatment, high pressure coolant injection (HPCI), service water (SW), condensate makeup (CM), and plant drains. Direct or opportunistic visual inspections of excavated piping will be performed for DGFO, standby gas treatment, plant drains, SW, and CM systems. NPPD will use a non-visual examination method for the emergency condensate storage tank supply to HPCI piping due to its lack of ready access for excavation. In addition, non-visual examination methods may be employed for buried piping in other systems where the piping configuration allows for effective assessment via such methods. The total linear feet of piping inspected using all of the methods discussed above will be a minimum of 2% of all high-risk in-scope buried piping.

The nitrogen vaporization tank is not entirely buried, but the bottom of the tank is below ground level. The tank contains a potable water volume that acts as a heat source to evaporate nitrogen credited in response to regulated events. It is a nonsafety-related, nonseismic tank exposed to its design basis conditions during normal operation. NPPD expects the risk rank of the nitrogen vaporization tank will be low and therefore does not anticipate inspecting the tank prior to the PEO. Normal operation of the nitrogen system demonstrates the vaporization tank remains capable of performing its license renewal intended function under design basis conditions.

Attachment 4

Changes to the License Renewal Application
Cooper Nuclear Station, Docket No. 50-298, DPR-46

This attachment provides changes to the Cooper Nuclear Station (CNS) License Renewal Application (LRA) associated with Attachment 3 and certain other supplemental changes. The changes are presented in underline/strikeout format.[1]

1. LRA Section A.1.1.3, "Buried Piping and Tanks Inspection Program," is revised to read[2]:

"A.1.1.3 Buried Piping and Tanks Inspection Program

The Buried Piping and Tanks Inspection Program is a new program that will include (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, and gray cast iron components. Preventive measures will be in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components will be inspected on a periodic basis, as well as, when excavated during maintenance. If trending within the corrective action program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

~~Prior to entering the period of extended operation, plant operating experience will be reviewed to verify that an inspection occurred within the past ten years. If an inspection did not occur, a focused inspection will be performed prior to the period of extended operation. A focused inspection will be performed within the first ten years of the period of extended operation, unless an opportunistic inspection occurs within this ten-year period. A "focused inspection" is defined as an inspection performed in areas with a history of corrosion problems and in areas with the highest likelihood of corrosion problems.~~ Prior to the PEO, inspections will be performed for buried piping and tanks in six systems. These systems are diesel generator fuel oil (DGFO), standby gas treatment, high pressure coolant injection (HPCI), service water (SW), condensate makeup (CM), and plant drains. Planned or opportunistic direct visual inspections of excavated piping will be performed for DGFO, standby gas treatment, plant drains, SW, and CM systems. NPPD will use a non-visual examination method for the emergency condensate storage tank supply to HPCI piping due to its lack of ready access for excavation. In addition, non-visual examination methods may be employed for buried piping in other systems where the piping configuration allows for effective assessment via such methods. The

[1] The changes shown are made against the original LRA submitted on September 24, 2008, as revised by subsequent LRA changes. Where other previously made LRA changes affect the same text, a footnote is provided cross-referencing the letter where the previous change was made.

[2] This LRA section was previously revised in NLS2009040 (ADAMS Accession Number ML091690050) in response to RAI B.1.3-1.

total linear feet of piping inspected using all of the methods discussed above will be a minimum of 2% of all high-risk in-scope buried piping.

During the PEO, examinations of in-scope buried piping and tanks will be performed at a frequency of at least once every 10 years. Examinations will consist of visual inspections as well as non-destructive examination (e.g. ultrasonic and guided wave) to perform an overall assessment of the condition of buried piping and tanks. The examinations will include visual inspection of at least eight feet of excavated piping on at least three high-risk in-scope systems, and will examine a minimum of 2% of the total linear feet of high-risk in-scope buried piping during each 10-year period.

The cathodic protection system will be maintained and annually tested in accordance with NACE standards RP0285-2002 and SP0169-2007 with a minimum system availability of 90%. If 90% availability is not maintained, the condition will be entered into the corrective action program to evaluate the impact and effect corrective actions.

This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M34, Buried Piping and Tanks Inspection, prior to the period of extended operation."

Reference: Attachment 3- Response to RAI B.1.3-3 Follow-up.

2. LRA Section A.1.1.33, "Reactor Vessel Surveillance Program," will be revised as follows[3]:

"The Reactor Vessel Surveillance ~~Maintenance~~ Program will be enhanced as follows.

- If the CNS license renewal capsule is removed from the reactor vessel without the intent to test it, the capsule will be stored in a manner which maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary.

- Ensure that the additional requirements specified in the final NRC safety evaluation for BWRVIP-116 will be addressed before the period of extended operation.

Th~~is~~ese enhancements will be implemented prior to the period of extended operation."

Reference: The LRA originally contained an enhancement similar to this for a "standby capsule." This was deleted in NLS2010061, after it was recognized that a standby capsule would not be applicable to CNS as part of the Boiling Water Reactor Vessel and Internals Project (BWRVIP) Integrated Surveillance Program (reference BWRVIP-86,

[3] This LRA section was previously revised in NLS2010061 (ADAMS Accession Number ML101800268).

Section 3.1.1). In subsequent discussions with the NRC staff, it was requested that the enhancement be restored, but with reference to the "license renewal capsule."

3. LRA Section B.1.3, "Buried Piping and Tanks Inspection Program," is revised to read[4]:

"B.1.3 Buried Piping and Tanks Inspection

Program Description

The Buried Piping and Tanks Inspection Program is a new program that will include (a) preventive measures to mitigate corrosion and (b) inspections to manage the effects of corrosion on the pressure-retaining capability of buried carbon steel, and gray cast iron components. Preventive measures will be in accordance with standard industry practice for maintaining external coatings and wrappings. Buried components will be inspected on a periodic basis, as well as, when excavated during maintenance. If trending within the Corrective Action Program identifies susceptible locations, the areas with a history of corrosion problems are evaluated for the need for additional inspection, alternate coating, or replacement.

~~Prior to entering the period of extended operation, plant operating experience will be reviewed to verify that an inspection occurred within the past ten years. If an inspection did not occur, a focused inspection will be performed prior to the period of extended operation. A focused inspection will be performed within the first ten years of the period of extended operation, unless an opportunistic inspection occurs within this ten-year period. A "focused inspection" is defined as an inspection performed in areas with a history of corrosion problems and in areas with the highest likelihood of corrosion problems.~~ Prior to the PEO, inspections will be performed for buried piping and tanks in six systems. These systems are diesel generator fuel oil (DGFO), standby gas treatment, high pressure coolant injection (HPCI), service water (SW), condensate makeup (CM), and plant drains. Planned or opportunistic direct visual inspections of excavated piping will be performed for DGFO, standby gas treatment, plant drains, SW, and CM systems. NPPD will use a non-visual examination method for the emergency condensate storage tank supply to HPCI piping due to its lack of ready access for excavation. In addition, non-visual examination methods may be employed for buried piping in other systems where the piping configuration allows for effective assessment via such methods. The total linear feet of piping inspected using all of the methods discussed above will be a minimum of 2% of all high-risk in-scope buried piping.

The CNS program will include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and the risk for corrosion. The program will classify pipe segments and tanks as having a high, medium or low impact of leakage based on items such as the safety class, the hazard posed by

[4] This LRA section was previously revised in NLS2009040 (ADAMS Accession Number ML091690050) in response to RAI B.1.3-1.

fluid contained in the piping, and the impact of leakage on plant operation. Corrosion risk will be determined through consideration of items such as piping or tank material, soil resistivity, drainage, the condition of cathodic protection, and the type of coating.

During the PEO, examinations of in-scope buried piping and tanks will be performed at a frequency of at least once every 10 years. Examinations will consist of visual inspections as well as non-destructive examination (e.g. ultrasonic and guided wave) to perform an overall assessment of the condition of buried piping and tanks. The examinations will include visual inspection of at least eight feet of excavated piping on at least three high-risk in-scope systems, and will examine a minimum of 2% of the total linear feet of high-risk in-scope buried piping during each 10-year period.

The cathodic protection system will be maintained and annually tested in accordance with NACE standards RP0285-2002 and SP0169-2007 with a minimum system availability of 90%. If 90% availability is not maintained, the condition will be entered into the corrective action program to evaluate the impact and effect corrective actions.

This program will be implemented prior to the period of extended operation."

Reference: Attachment 3- Response to RAI B.1.3-3 Follow-up.

4. LRA Section B.1.33, "Reactor Vessel Surveillance," will be revised as follows[5]:

"The following enhancements will be implemented prior to the period of extended operation.

Elements Affected	**Enhancements**
5. Monitoring and Trending	If the CNS license renewal capsule is removed from the reactor vessel without the intent to test it, the capsule will be stored in a manner which maintains it in a condition which would permit its future use, including during the period of extended operation, if necessary."

Reference: The LRA originally contained an enhancement similar to this for a "standby capsule." This was deleted in NLS2010061, after it was recognized that a standby capsule would not be applicable to CNS as part of the BWRVIP Integrated Surveillance Program (reference BWRVIP-86, Section 3.1.1). In subsequent discussions with the NRC staff, it was requested that the enhancement be restored, but with reference to the "license renewal capsule."

[5] This LRA section was previously revised in NLS2010061 (ADAMS Accession Number ML101800268).

ATTACHMENT 3 LIST OF REGULATORY COMMITMENTS©[4]

Correspondence Number: NLS2010062

The following table identifies those actions committed to by Nebraska Public Power District (NPPD) in this document. Any other actions discussed in the submittal represent intended or planned actions by NPPD. They are described for information only and are not regulatory commitments. Please notify the Licensing Manager at Cooper Nuclear Station of any questions regarding this document or any associated regulatory commitments.

COMMITMENT	COMMITMENT NUMBER	COMMITTED DATE OR OUTAGE
NPPD will upgrade the site cathodic protection system prior to the period of extended operation for in-scope piping and buried tanks.	NLS2010062-01	January 18, 2014
The Buried Piping and Tanks Inspection Program will be revised to ensure that during the PEO the cathodic protection system will be maintained and annually tested in accordance with NACE standards RP0285-2002 and SP0169-2007 with a minimum system availability of 90%. If 90% availability is not maintained, the condition will be entered into the corrective action program to evaluate the impact and effect corrective actions.	NLS2010062-02	January 18, 2014
The Buried Piping and Tanks Inspection Program will include a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. The piping segments and tanks will be classified as having a high, medium or low impact of leakage based on items such as the safety class, the hazard posed by fluid contained in the piping, and the impact of leakage on plant operation. The corrosion risk will be determined through consideration of items such as piping or tank material, soil resistivity, drainage, the presence of cathodic protection, and the type of coating. During the period of extended operation (PEO), examinations of in-scope buried piping and tanks will be performed at a frequency of at least once every 10 years. Examinations of buried piping and tanks during the PEO will consist of visual inspections as well as non-destructive examination (e.g. ultrasonic and guided wave) to perform an overall assessment of the condition of	NLS2010050-04 Revision 1	January 18, 2014

COMMITMENT	COMMITMENT NUMBER	COMMITTED DATE OR OUTAGE
buried piping and tanks. The examinations will include visual inspection of at least eight feet of excavated piping on at least three high-risk in-scope systems, and will examine a minimum of 2% of the total linear feet of high-risk in-scope buried piping during each 10-year period.		
Prior to the PEO, NPPD will inspect buried piping and tanks in six systems. These systems are diesel generator fuel oil (DGFO), standby gas treatment, high pressure coolant injection (HPCI), service water (SW), condensate makeup (CM), and plant drains. Direct or opportunistic visual inspections of excavated piping will be performed for DGFO, standby gas treatment, plant drains, SW, and CM systems. NPPD will use a non-visual examination method for the emergency condensate storage tank supply to HPCI piping due to its lack of ready access for excavation. In addition, non-visual examination methods may be employed for buried piping in other systems where the piping configuration allows for effective assessment via such methods. The total linear feet of piping inspected using all of the methods discussed above will be a minimum of 2% of all high-risk in-scope buried piping.	NLS2010050-05 Revision 1	January 18, 2014