10 CFR 50
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10 CFR 54

Dominion Energy Services, Inc.
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January 29, 2019

Dominion Energy®

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

Serial No.: 18-448
NRA/DEA: R2'
Docket Nos.: 50-280/281
License Nos.: DPR-32/37

VIRGINIA ELECTRIC AND POWER COMPANY
SURRY POWER STATION (SPS) UNITS 1 AND 2
SUPPLEMENT TO SUBSEQUENT LICENSE RENEWAL
OPERATING LICENSES APPLICATION FOR SUFFICIENCY REVIEW
CHANGE NOTICE 1

By letter dated October 15, 2018 (Agencywide Documents Access and Management System (ADAMS) Package Accession No. ML18291A842), Virginia Electric and Power Company (Dominion Energy Virginia) submitted an application for the subsequent license renewal of Renewed Facility Operating License Nos. DPR-32 and DPR-37 for the Surry Power Station.

In a December 3, 2018 letter, the Nuclear Regulatory Commission (NRC) issued, "Surry Power Station, Unit Nos. 1 and 2 - Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule and Opportunity for a Hearing Regarding the Virginia Electric and Power Company's Application for Subsequent License Renewal (EPID Nos. L-2018-RNW-0023 and L-2018-RNW-0024)," (ADAMS Accession No. ML18320A188). The letter indicated that a supplement to the Subsequent License Renewal Application (SLRA) would be required by January 2019 to support the sufficiency review. This letter, SPS SLRA Change Notice 1, provides the requested supplemental information.

Specifically, Enclosure 1 provides the analysis of the impacts of the proposed action on Atlantic sturgeon critical habitat, and essential fish habitat. Each Section or Table change in Enclosure 1 is indicated by change type (i.e., addition, replacement, etc.). Also provided in Enclosure 1 is the National Marine Fisheries Service response to Dominion Energy Virginia regarding special status species and habitats and the Virginia Department of Environmental Quality response letter to the Coastal Zone Management Program Certification. As requested, Enclosure 2 provides information needed to address aging management of steel components in the reactor pressure vessel support assembly, via a supplement to SLRA Section 3.5.2.2.2.6.

Additionally, seven other topics require the SLRA to be supplemented. Enclosure 3 provides a description of each topic and identifies the affected SLRA section.

Enclosure 4 includes mark-ups of affected SLRA sections being supplemented, as described in Enclosures 2 and 3. It should be noted that changes to three commitments (Items #11, #16 and #23) are reflected in Table A4.0-1 (within Enclosure 4).

To aid the staff in assessing changes, Enclosures 2 and 4 show new text as underlined and deleted text as lined through.

A035
NRR

Enclosure 5 includes an updated revision to an industry report which was previously submitted with the SPS SLRA on October 15, 2018.

If there are any questions regarding this submittal or if additional information is needed, please contact Mr. Paul Aitken at (804) 273-2818.

Sincerely,

Mark D. Sartain
Vice President - Nuclear Engineering and Fleet Support

COMMONWEALTH OF VIRGINIA)
)
COUNTY OF HENRICO)

The foregoing document was acknowledged before me, in and for the County and Commonwealth aforesaid, today by Mark D. Sartain, who is Vice President - Nuclear Engineering and Fleet Support of Virginia Electric and Power Company. He has affirmed before me that he is duly authorized to execute and file the foregoing document in behalf of that Company, and that the statements in the document are true to the best of his knowledge and belief.

Acknowledged before me this 29th day of January, 2019.

My Commission Expires: March 31, 2022

Diane E Aitken
Notary Public

DIANE E. AITKEN
NOTARY PUBLIC
REG. #7763114
COMMONWEALTH OF VIRGINIA
MY COMMISSION EXPIRES MARCH 31, 2022

Commitments made in this letter: None.

Enclosures:

1 – Appendix E - Environmental Report Supplement – January 2019

Attachment 1 – Analysis of Critical Habitat and Essential Fish Habitat

Attachment 2 – National Marine Fisheries Service response letter to Dominion Energy Virginia's Letter Regarding Special Status Species and Habitat

Attachment 3 – Virginia Department of Environmental Quality CZMA response letter

2 – Reactor Vessel Support Steel Aging Evaluation

3 – Other Topics That Require a SLRA Supplement

4 – SLRA Mark-ups - Change Notice 1

5 – PWROG-17011-NP, Revision 2

cc: (w/o Enclosures except *)

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Enclosure 1

APPENDIX E
ENVIRONMENTAL REPORT SUPPLEMENT
JANUARY 2019

Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2

Enclosure 1
Attachment 1

ANALYSIS OF CRITICAL HABITAT AND ESSENTIAL FISH HABITAT

Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2

Each numbered section or table heading of the Analysis of Critical Habitat and Essential Fish Habitat provided herein is annotated to indicate if it is 'additional', 'new', or 'deleted' text. Also, the text in Section E3.7.8.5 is delineated as 'replacement' since the entire section has been replaced with the text provided.

E3.7.8.1.7 Atlantic Sturgeon (additions)

In the James River, Atlantic sturgeon staged from April through August/September in Burwells Bay to Hog Island (river mile [RM] 30), which is located in the vicinity of Surry Power Station (SPS) (Balazik et al. 2012). Telemetry data indicated that Atlantic sturgeon were present in this area from April/May through November. Females remained in the area prior to spawning even when males moved upstream in the fall. Females traveled upstream to RM 75 in a 48-hour span and then returned to the staging area around RM 30 post-spawn. Adults then begin to disperse to sites down river throughout the rest of the fall, occupying only lower river sites by November (Hager 2011). Adults were undetected on the tracking array and are presumed to have exited the system by November/December.

The 2017 Atlantic sturgeon stock assessment was conducted by the Atlantic States Marine Fisheries Commission. The stock assessment evaluated the status of Atlantic sturgeon along the Atlantic coast utilizing a variety of vetted fisheries-dependent and -independent data sets. The review panel accepted the analyses as supporting "a stable to slowly increasing population of Atlantic sturgeon" following the 1998 fishing moratorium. "The paucity of data available to develop reliable indices of abundance and the inability to distribute historical catches to specific rivers or DPSs precluded the application of traditional stock assessment methods, except at a coastwide level." (ASMFC 2018)

On August 17, 2017, the NMFS issued a final rule designating critical habitat for Atlantic sturgeon (82 FR 39160). The rule covered all five distinct population segments (DPS) of Atlantic sturgeon. Critical habitat boundaries for the Chesapeake Bay DPS were defined in the final rule. For the James River, it was defined as occurring from Boshers Dam (head of tide) downstream to where the main stem river discharges at its mouth into the Chesapeake Bay at Hampton Roads. In the final rule, NMFS indicated that the designated critical habitat (DCH) was in effect the known range within each tidal-affected river.

In 2018, Age-0 Atlantic sturgeon were collected for the first time from the James River by Virginia Commonwealth University (VCU) and the James River Association. As of November 2018, 153 juvenile Atlantic sturgeon were collected from the James River during routine trawl surveys by VCU, with most collected between the Benjamin Harrison Bridge near Hopewell, VA, and Sturgeon Point (just west of Fort Pocahontas in Charles City County, VA). The James River Association collected five Age-0 Atlantic sturgeon during an education program at Presquile National Wildlife Refuge (upstream of Hopewell, VA). (Bay Journal 2018)

Previous observations of juvenile Atlantic sturgeon in the James River were of older and substantially larger individuals, and regarded as yearling or older fish. In comparison, the presumed Age-0 fish from 2018 were between 2 and 4 inches (6-11 cm) in length and were presumed to have hatched within the few weeks leading up to the collection of early stage juveniles in October 2018. Kynard et al. (2016) described the locations that one could expect to find juvenile Atlantic sturgeon. Age-0 Atlantic sturgeon would likely reside in deep water in the channel and migrate out to the margins at night to feed in the shallower reaches. Older juveniles are more mobile but mimic the feeding/foraging behavior of Age-0 fish.

E3.7.8.1.14 Shortnose Sturgeon (new section)

In March 2016, a single shortnose sturgeon (*Acipenser brevirostrum*) was collected from the James River at RM 30. This was the first verified occurrence of a shortnose sturgeon in the James River. The fish was collected as part of a VCU program monitoring Atlantic sturgeon under the National Oceanic and Atmospheric Administration (NOAA) endangered species permit No. 16547. Species identification was verified by genetic analysis by the United States Geological Survey Leetown, West Virginia, Science Center. (Balazik 2017) In February 2018, a second sturgeon (a confirmed gravid female) was captured near RM 30 (NOAA 2018a). This species is federally and state-listed as endangered. It has been designated as Tier I, critical conservation need, in the Virginia wildlife action plan (VDGIF 2018).

Shortnose sturgeon are similar in appearance to Atlantic sturgeon, but can be distinguished by their smaller size, larger mouth, smaller snout shape, and scutes. The two species have a close lineage, are bottom-oriented, are morphologically similar, exhibit similar feeding behaviors, make spawning migrations, and spawn in similar habitats. Shortnose and Atlantic sturgeon are also behaviorally similar. The greatest distinction between the two is Atlantic sturgeon make coastal migrations, whereas the shortnose sturgeon tends to remain restricted to its natal river.

The shortnose sturgeon can grow to approximately 4.5 feet long and weigh up to 60 pounds. They are yellowish-brown and generally have a black head, back, and sides. Their bellies are white to yellow. They have five major rows of scutes and a protruding snout with four barbels (fleshy, whisker-like projections). (NOAA 2018b)

Shortnose sturgeon are amphidromous fish. They live in their birth (natal) river, make short feeding or migratory trips into salt water, and then return to freshwater to feed and escape predation. When they do enter marine waters, they generally stay close to shore. In the spring, adults move far upstream and away from salt water to spawn. After spawning, the adults move rapidly back downstream to the estuaries, where they feed, rest, and spend most of their time. (NOAA 2018b)

The shortnose sturgeon's tendency to live near its home estuary coupled with their current range from the Canadian Maritimes to Georgia suggests that historically, all large rivers on the Atlantic Coast of the United States may have had natal shortnose sturgeon populations that coexisted with Atlantic sturgeon (Jenkins and Burkhead 1993). Because all sturgeons were lumped together and called "common sturgeon" in the commercial catch statistics, it is impossible to estimate historic abundance and distribution of shortnose sturgeon alone, as capture records combined Atlantic and shortnose sturgeon until the shortnose was listed in 1973.

Kynard et al. (2016) details the life stages found and adult abundance in rivers throughout its range. Absent from Kynard's discussion is the Chesapeake Bay drainage, which indicates that there is not a known reproducing population within Chesapeake Bay. Jenkins and Burkhead (1993) note that there is only one valid record of a shortnose sturgeon in the entire Chesapeake Bay pre-1900s. Commercial fishing records indicate most or all mid-Atlantic rivers historically had sturgeon populations. Despite sampling targeted for sturgeons in recent decades, there has been no documented spawning and few shortnose sturgeon captured or observed in any mid-Atlantic river.

Kynard et al. (2016) explains that spawning populations throughout the range have usually been identified either by the presence of a spawning run of mature adults or by the presence of young juveniles (<1 year, too young to be tolerant of high salinity and whose movements are therefore restricted to their natal river and estuary). The capture of early life history stages and young juveniles remains the most convincing evidence of a viable spawning population. Tracking the migration of pre-spawning adults alone, without capture of early life history stages, is insufficient evidence to indicate successful spawning occurs. Kynard et al. (2016) further explains that the abundance of adults has also been used as a strong indicator of spawning success, particularly for rivers with tens of thousands of adults like the Hudson River. Recent tracking and genetic analysis of shortnose sturgeon from basins throughout the range indicates more coastal movement by shortnose sturgeon than previously recognized. Thus, throughout the range, the presence of a few adults in a river does not mean a spawning population is present. Migrant adult shortnose sturgeon entering rivers without a natal shortnose sturgeon population represent potential colonizers. Native populations of shortnose sturgeon were extirpated or reduced to a remnant population in many rivers, but if river habitats are available to complete their life history, coastal shortnose sturgeon migrants may find and colonize these rivers.

Until the observation of a shortnose sturgeon in the James River by Balazik (2017), the historic distribution of shortnose sturgeon in Virginia had not changed substantially since the issuance of the 2010 biological assessment of shortnose sturgeon. Shortnose sturgeon as amphidromous are known to inhabit the lower salinity reaches of their natal estuary; however, they can make coastal movements between watersheds (Dadswell et al. 2013). While the current paradigm is that shortnose sturgeon stray less often than the congeneric Atlantic sturgeon, there is recent evidence of straying and recolonization from adjacent rivers (Balazik 2017; King et al. 2014). The shortnose sturgeon captured from the James River in 2016 is hypothesized to have been a colonizing or roaming fish from the Potomac River (about 120 km away), or the Delaware River (about 340 km away), that entered the system through the Chesapeake and Delaware Canal (Balazik 2017). Historically there have been observations within the Chesapeake Bay in the Potomac River, including telemetry tagged fish. There is little evidence for spawning shortnose sturgeon populations within the Chesapeake Bay (Kynard et al. 2016). Kynard et al. (2016), reviewing previous research concerning the capture of three late-stage females in the Potomac River including one tagged female which swam a one-step spawning migration to spawning habitat in Washington, D.C., indicated the potential for spawning and the possibility of a natal remnant population or ongoing colonization by Delaware River adults. Fewer than 10 have been observed in the lower Susquehanna River (Kynard et al. 2016). No early life stages or young shortnose sturgeon have been observed in Virginia (Kynard et al. 2016).

No critical habitat has been designated for the shortnose sturgeon (NOAA 2018c, NOAA 2018d).

Kynard et al. (2016) reviewed research and literature available on the shortnose sturgeon and describes habitat requirements, foraging habitat, and diet by life stage in detail. The following summarizes the habitat features and requirements as presented by Kynard et al. (2016), which drew on and cited several other researchers.

Shortnose sturgeon in the southern part of their range forage mostly at the freshwater-salt water interface or in salt water which is still considered to be an amphidromous life history characteristic. The total length of river/estuary used as their home range is highly variable based on latitude in the sense that southern populations of shortnose sturgeon must travel further considering the width of the coastal plain to find suitable rocky or rough, clay bits on the river bottom for spawning. Shortnose sturgeon in the Potomac River utilized a larger range of habitats in the spring and fall compared to winter and summer periods.

Early life stage Atlantic and shortnose sturgeon are restricted to freshwater habitats. With increasing age, Atlantic sturgeon move downstream to a more saline habitat, while the shortnose sturgeon larvae and juveniles remain in the freshwater-salt water interface for a longer duration. The current knowledge base for larvae and Age-0 shortnose sturgeon foraging habitat is relatively unknown, especially in the mid-Atlantic. It is well documented in other waters that juveniles (Age 1+) and adults forage over sand and sand-mud habitats. Riverine habitats utilized by juveniles and adults vary from sandy to hard-mud and water depth varies from channel to shoals.

Early life stages of shortnose sturgeon disperse at variable rates and timings that may be correlated with latitude. Shortnose sturgeon in the northeast disperse as larvae, southern populations begin dispersal as free embryos and continue as larvae while shortnose sturgeon in the Savannah River continued a slow dispersal for months. The highly variable nature of the dispersal of early life stages of shortnose sturgeon may be linked to distributions of forage material. Yearling movements are not very well understood given the lack of telemetered fish studied. The timing of adult spawning migration is highly flexible and likely depends on the fish's reproductive status, distance from the spawning site and age.

Shortnose sturgeon at all life stages appear to follow the channel during any upstream or downstream migrations. The most suitable spawning habitat is considered to be the most upstream river reach used by shortnose sturgeon. Shortnose sturgeon early life stages also are very intolerant to salinities of 5-10 ppt until they are about 300 days of age. Shortnose sturgeon are known to utilize refuge seasonally in a concentrated range within their natal river. In mid-Atlantic and southern rivers, the most severe conditions that pose threats to survival for shortnose sturgeon are the summer months where the fish will retreat to areas with more moderate temperatures and higher dissolved oxygen levels.

Table E3.7-4 Federally and State Listed Threatened and Endangered Species in Surry, James City, York, and Isle of Wright Counties (addition)

Common Name	Scientific Name	Federal Status	State Status
Fish			
Shortnose sturgeon	*Acipenser brevirostrum*	LE	None

(VDGIF 2018)

E3.7.8.5 Essential Fish Habitat (replacement)

The essential fish habitat (EFH) mapper provided by NOAA provides spatial and descriptive representation of EFH (https://www.fisheries.noaa.gov/resource/map/essential-fish-habitat-mapper). NOAA notes that the graphic representations are based on text descriptions, which are the most authoritative information available for identification of EFH. Therefore, it is important that the user verify any graphic representations from the EFH mapper with the descriptive text and literature. Table E3.7-5 presents the results of the EFH mapper and literature review. No habitat areas of particular concern (HAPCs) or EFH areas protected from fishing are located on or adjacent to the project site (NOAA. 2018e).

Table E3.7-5 Essential Fish Habitat in the James River near Surry Power Station (additions)

The "EFH Mapper" column represents the designation from the NOAA online mapping tool. The "Lit Review" column represents the designation supported by Dominion Energy Environmental Services' literature review (E = Eggs, L = Larvae, J = Juvenile, A = Adult).

Species	Latin Name	EFH Mapper	Lit Review
Atlantic butterfish	*Peprilus triacanthus*	J, A	J, A
Atlantic herring[(a)]	*Clupea harengus*	J, A	-
Black sea bass	*Centropristis striata*	J, A	-
Bluefish	*Pomatomus saltatrix*	J, A	J
Clearnose skate[(a)]	*Raja eglanteria*	J, A	-
Little skate[(a)]	*Leucoraja erinacea*	A	-
Red hake	*Urophycis chuss*	E, L, J, A	-
Sandbar shark[(b)]	*Carcharhinus plumbeus*	-	-
Scup	*Stenotomus chrysops*	-	-
Summer flounder	*Paralichthys dentatus*	L, J, A	L, J, A
Winter skate[(a)]	*Leucoraja ocellata*	A	-
Windowpane flounder	*Scophthalmus aquosus*	J	J, A

(NOAA 2018e; NOAA 2018f; NOAA 2018g)

a) EFH designation near SPS was removed for these species by the New England Fishery Management Council & National Marine Fisheries Service Omnibus Amendment 2 (NOAA 2018h). The Mid-Atlantic Council is working collaboratively with the New England Fishery Management Council (Mid-Atlantic Fishery Management Council 2019).

b) Noted as having adjacent EFH during EFH query conducted on November 16, 2016 (ER citation NOAA 2016c).

See E4.6.6.4.2 for details regarding species-specific EFH characteristics.

E4.6.1.4 Analysis (additions)

Species-specific impingement of organisms at SPS was determined on a monthly basis. Per implementation guidelines for the 316(b) 2014 Rule, baseline impingement was determined based on a travelling screen mesh with a maximum opening of 0.56 inches. Because the travelling screen mesh at SPS is actually finer (1/8" x 1/2") than the baseline opening, the number of organisms representing "converts," those organisms that would be entrained under a baseline mesh size but were impinged at SPS, were also calculated. Identification of converts was based on morphometric measurements obtained during sampling. Converts represent a reduction in entrainment, and therefore were excluded from estimates of impingement mortality. Overall, converts accounted for an over 70% reduction in entrainment mortality. Initial survival of organisms was also determined during impingement sampling, and applied to the baseline estimates minus converts to develop estimates of impingement mortality. Where sample sizes were low for a given taxa, representative information from the scientific literature was used to evaluate survival. Initial impingement survival was over 80% for most taxa.

Bay anchovy accounted for the bulk (75%) of organisms collected during impingement sampling; however, most bay anchovy were classified as converts and excluded from impingement mortality estimates. Overall, finfish taxa experiencing the highest impingement mortality included Atlantic menhaden (32% of total IM), Atlantic croaker (22%), white perch (14%) and gizzard shad (13%). These four taxa represented over 80% of total impingement mortality. Blue crab dominated shellfish impingement mortality, accounting for 88% of all shellfish mortality.

Species and life stage-specific entrainment of organisms at SPS were determined on a monthly basis. As with impingement, per implementation guidelines for the 316(b) 2014 Rule, baseline entrainment was determined based on a travelling screen mesh with a maximum opening of 0.56 inches. Because the travelling screen mesh at SPS is actually finer (1/8" x 1/2") than the baseline opening, the number of organisms representing "converts," those organisms that would be entrained under a baseline mesh size but were impinged at SPS, were also calculated and removed from the entrainment estimate. Identification of converts was based on morphometric measurements obtained during laboratory processing of samples. Non-viable eggs (i.e., those that would not hatch into fish) were excluded from all entrainment estimates.

Because the entrainment study spanned two years, data was analyzed by year to examine annual variability. In both sampling years, shellfish accounted for the bulk (75% and 85% in years 1 and 2, respectively) of the total number of organisms collected. Gobies (*Gobidae*) accounted for 60% and 71% of the finfish collected in years 1 and 2, respectively. Mud crab zoea (*Panopeidae*; 39%) and juvenile Tellin clams (35%) dominated shellfish collection in year 1. In year 2, fiddler crab zoea (39%) and mud crab zoea (*Panopeidae*; 33%) were dominant.

E4.6.6.4.2 Threatened, Endangered, and Protected Species and Essential Fish Habitat, Analysis, Operational Activities (additions)

As noted previously (E3.7.8.1.14), there have been only two verified occurrences of shortnose sturgeon captured from the James River. Balazik (2017) provides a discussion on the historical documentation of shortnose sturgeon within the Chesapeake Bay drainage. He notes that there is debate regarding the potential for shortnose sturgeon in the Chesapeake Bay to be part of a remnant population or individuals colonizing the Chesapeake from the Delaware River via the Chesapeake and Delaware Canal. Based on extensive sampling in the James River conducted by a variety of researchers, often working with commercial fishermen, and the lack of documentation of any shortnose sturgeon in the river until 2016, Balazik (2017) concluded that the single specimen collected in 2016 was a transient or colonizing individual. No shortnose sturgeon have been collected in the historical or most recent entrainment or impingement studies conducted at SPS (E4.6.1.4). Historical and recent information available regarding the shortnose sturgeon in the James River reports it is extremely rare.

Information on shortnose sturgeon habitat and foraging is presented in Section E3.7.8.1.14. There is limited information available regarding the behavior, movements, or habits of the fish that could be applied to a species-specific assessment of potential impacts from SPS operations. The shortnose sturgeon has many attributes very similar to those for Atlantic sturgeon. The two species have a close lineage, are bottom-oriented, are morphologically similar, exhibit similar feeding behaviors, make spawning migrations, and spawn in similar habitats. The probable greatest distinction between the two is Atlantic sturgeon make coastal migrations, whereas the shortnose sturgeon tends to remain restricted to its natal river.

No shortnose sturgeon have been collected in the historical or most recent entrainment or impingement studies conducted at SPS (E4.6.1.4). Based on the similarities between shortnose and Atlantic sturgeon, the susceptibility of shortnose sturgeon to entrainment and impingement would be expected to be very similar to that of Atlantic sturgeon. As detailed in NOAA's July 13, 2012, consultation response regarding potential effects of SPS operations on Atlantic sturgeon, spawning and the early life history stages of Atlantic sturgeon would be confined to freshwaters located upstream of SPS. Therefore, the probability of entrainment through the 1/8" x 1" travelling screens is not expected. While yearlings, subadult, and adult Atlantic sturgeon would be present in the vicinity of SPS, various regulatory and mitigation measures are in place to prevent or reduce the probability of interactions. Historical and recent studies have demonstrated that the station's Ristroph travelling screens and debris return act to safely return impinged fish to the river away from the intakes. NOAA's assessment of the potential for Atlantic sturgeon to be impinged made use of shortnose sturgeon swimming ability information, noting juvenile and adult shortnose sturgeon can avoid impingement and entrainment at velocities as high as 3.0 fps. As noted in Section E3.7.8.1.7, the approach velocity at SPS trash racks is 0.98 fps, with a through-rack velocity of 1.12 fps. NOAA concluded the impingement or entrainment of Atlantic sturgeon is extremely unlikely to occur, and it is logical to carry this conclusion forward for shortnose sturgeon.

Operations at SPS may also affect water quality, require dredging, cause sedimentation, or result in chemical spills, and so interact with shortnose sturgeon. NOAA addressed these potential impacts with regards to Atlantic sturgeon, and the conclusion reached should also apply to shortnose sturgeon due to the similarities between the species. Regarding water quality, the station's thermal plume has the potential to alter movements of shortnose sturgeon; however, mixing occurs rapidly in the near field around the outfall, and is largely contained to the surface. NOAA did not expect any significant impairment of normal behaviors due to the presence of the thermal plume. With regards to other pollutants, NOAA noted pollution limits are authorized by the station's VPDES permit, at levels at or below U.S. Environmental Protection Agency aquatic life criteria.

NOAA did not address the potential effects of dredging, sedimentation, or chemical spills and these are discussed below.

Dredging in the lower reaches of rivers that include the salt-freshwater transition zone likely has a great impact on reducing the recruitment of shortnose sturgeon, where present in abundance. This zone is a physical feature located at the heads of coastal plain estuaries that traps and retains sediment, detritus, zooplankton and early-life stages of fish, and is considered critical for anadromous fishes. The salt-freshwater transition zone is where Age-0 and juveniles rear throughout the species' range (Kynard et al. 2016). Dredging of the intake and discharge canals at SPS only occurs when necessary, every three to four years, and is conducted following consultation and permitting by the U.S. Army Corps of Engineers (USACE) 404 program.

Sedimentation is related to ground-disturbing activities, and no major activities are planned for SPS. SPS maintains and implements a stormwater pollution prevention plan (SWPPP) that identifies potential sources of pollution reasonably expected to affect the quality of stormwater, such as erosion, and identifies best management practices (BMPs) that will be used to prevent or reduce the pollutants in stormwater discharges. These practices, as they relate to erosion, include nonstructural preventative measures and source controls, as well as structural controls to prevent erosion or treat stormwater containing pollutants caused by erosion. In addition, any ground disturbance of 2,500 square feet or more requires a construction stormwater permit to be obtained from the Virginia Department of Environmental Quality (VDEQ). The construction stormwater permit specifies BMPs to reduce erosion caused by stormwater runoff, thereby minimizing the risk of pollution from soil erosion and sediment, and potentially from other pollutants that the stormwater may contact. Although no license renewal-related refurbishment or construction activities are planned, any such activities would continue to be managed in adherence to the SPS SWPPP.

The dietary reliance of shortnose sturgeon in some rivers on bivalve mollusks makes them potentially susceptible to bioaccumulation of toxins from toxic algae blooms or other pollutants in the mollusks. Industrial practices at SPS that involve the use of chemicals are those activities typically associated with painting, cleaning of parts/equipment, refueling of onsite vehicles/generators, fuel oil and gasoline storage, and the storage and use of water treatment additives. The use and storage of chemicals at SPS are controlled in accordance with Dominion's fleet chemical control procedure and site-specific spill prevention plans. In addition, as presented in Section E2.2.7, nonradioactive waste is managed in accordance with Dominion's waste management procedure, which contains preparedness and prevention control measures.

Dominion continuously monitors SPS's radiological effluents and maintains compliance with radiation protection standards. Dominion also monitors radioactivity levels annually by collecting samples of air, water, silt, shoreline sediment, milk, aquatic biota, and food products. The results for 2012-2015 did not detect radionuclides attributable to SPS. As in previous years, Dominion concluded that the operation of SPS has created no adverse environmental effects or health hazards.

Dominion's new and significant information review addressed other Category 1 issues of aquatic resources and surface water quality and use. No new information was identified that would significantly impact water quality and aquatic resources. These issues concern the use of surface water for once-through cooling, discharge of metals in cooling water, discharge of biocides and sanitary wastes, the potential for water quality impacts from non-cooling water discharges, the potential for spills and minor chemical spills, sedimentation of surface waters, and related concerns. The new and significant information review concluded that compliance with current and future VPDES regulatory requirements and permit conditions, and implementation of the SWPPP and BMPs, will ensure continued protection of aquatic resources.

Considering the above discussion on the potential for impacts to the shortnose sturgeon attributable to SPS operations and Dominion's adherence to permit conditions and regulatory requirements and commitment to comply with future permit conditions and regulatory requirements, the potential for SPS operations to adversely impact the shortnose sturgeon is minimized. Therefore, Dominion's conclusions that "the continued operation of the site would have no adverse effects to any federally protected or state-listed species . . .impacts from the proposed [subsequent license renewal] SLR on threatened, endangered, and protected species in the vicinity of SPS are not likely to affect federally protected or listed species and EFH," is also applicable to the shortnose sturgeon.

Impacts to Designated Critical Habitat

While Atlantic sturgeon from any of the DPSs could potentially occur in the James River, individuals from the Chesapeake Bay DPSs are most likely to be present (NMFS 2012). A key conservation objective for the Gulf of Maine, New York Bight, and Chesapeake Bay DPSs is increased abundance via successful reproduction and recruitment to the marine environment. NMFS indicated the following physical features are essential to the conservation of the species:

1. A hard bottom substrate (e.g., rock, cobble, gravel, limestone, boulder) in low salinity waters for spawning and development of early life stages;
2. Aquatic habitat with a gradual downstream salinity gradient and soft substrate (e.g., sand, mud) downstream of spawning sites for juvenile foraging and development;
3. Water of appropriate depth (i.e., > 1.2 m) and absent physical barriers to passage (e.g., locks, dams) to allow unimpeded movements and provide staging, resting and holding areas;
4. Water temperature and oxygen, especially in the bottom meter of the water column, that will support all life stages (13-26°C for spawning habitat, no more than 30°C for juvenile rearing habitat, and 6 mg/l dissolved oxygen for juvenile rearing habitat).

The James River between Richmond and the mouth of the river is subjected to tidal motion and hence supports a tidal estuary. SPS is located in the transition region between the freshwater tidal river and the saline waters of the estuary proper. Cobham Bay just upstream of the Gravel

Neck Peninsula where SPS is located represents the approximate limit of salt water incursion, effectively dividing the James River into a tidally influenced freshwater river upstream (to the fall line at Richmond) and an estuary downstream. The upstream and downstream sides of the SPS site will have varying concentrations of ocean-derived salts, depending on river discharge. As discussed in E3.6.1, the salinity at the downstream side of the site is about 1 ppt at a river discharge of about 10,000 cfs.

Salinity levels in the James River near SPS are not a physical feature essential for the eggs and early life stages of the Atlantic sturgeon (Item 1 above). Section E4.6.6.4.2 identifies the known spawning grounds and areas of the James River suitable for spawning and early life stages as being in the lower salinity portions of the river upstream from SPS. Known spawning grounds are approximately 52 miles upstream of the SPS low-level intake and a second area with seemingly suitable habitat is located approximately 25 miles upstream of the low-level intake. Dominion considered SPS's potential to alter salinity gradients in its new and significant information review. The salinity gradient is governed by tidal influence rather than plant operations. The water withdrawn from the James River for SPS operations and returned through the once-through cooling system represents about 3% of the tidal flow in the James River in the vicinity of SPS (Section E3.6.3.1). The continued operation of SPS's once-through cooling system during the proposed SLR operating period is not anticipated to influence the salinity gradients. Thus, SPS operations would not impact the salinity level component of physical features 1 and 2 above.

The features of hard bottom and soft bottom substrates mentioned in physical features 1 and 2 as well as the depth requirement of physical feature 3 could be affected by dredging and sedimentation. The 2018 Atlantic sturgeon benchmark stock assessment report (Section 7) identifies habitat loss and degradation, including that from dredging operations, as among the greatest threats to Atlantic sturgeon (ASMFC 2018). Section E3.7.3 describes the river bed in the vicinity of SPS as composed of soft mud, clay, sand, and pebbles, with no single bottom type predominating. Dredging takes place in the James River and the river is subject to sedimentation from anthropogenic operations along the length of the river as well as natural forces. SPS periodically dredges the intake channel. USACE historically has dredged the main channel of the lower James River so ocean-going vessels can proceed upriver as far as Hopewell, approximately 50 river miles northwest of the SPS site, but this USACE main channel dredging has no nexus with SPS operations.

SPS dredging of the intake canal is conducted under Clean Water Act (CWA) Section 404 permits issued by the USACE. USACE is required to ensure that protected species and their habitat are not adversely affected by their federal action of issuing a permit allowing dredging and other Section 404 governed activities. Compliance with the 404 permit ensures that dredging activities do not contribute to water quality degradation or impact threatened and endangered species.

Physical feature item 3 concerns barriers to passage. The 2017 Atlantic sturgeon benchmark stock assessment report identifies habitat loss and degradation, including that from dam construction, as among the greatest threats to Atlantic sturgeon (ASMFC 2018). There are no known or planned river control structures on the James River. In addition, as indicated in Section E4.6.6.4.1, the proposed action does not include license-related refurbishment activities and there would be no license renewal-related refurbishment impacts to threatened, endangered, and protected species or EFH.

Physical feature item 4 concerns temperature, salinity, and dissolved oxygen conditions. Regarding the impact of SPS's thermal discharge on James River's conditions, as discussed in Section E.4.12.5 the cumulative trend in water temperature in the James River does not show an increase in maximum temperature and SPS's studies show rapid mixing of its thermal discharge with a drop of 1 to 2°F per 1,000 feet with the temperature rarely being greater than 5°F greater than ambient at 3,000 feet from the discharge point. Moreover, the James River is approximately 2.5 miles wide in the vicinity of the SPS site. Any increased temperature near the SPS site could be avoided by fish.

As stated above, SPS operations do not influence salinity levels and gradients of the James River. As for dissolved oxygen conditions, Dominion considered this condition within its new and significant information review. Reductions in dissolved oxygen can be related to thermal discharges and eutrophication. SPS compliance history review for the past five years indicates no violations for concerns with thermal discharges. No plant operations or modifications that would alter the thermal discharge are planned for the proposed SLR operating period. The VDPES permit also includes limits and monitoring requirements for constituents implicated in eutrophication both for the sewage treatment plant outfall and the stormwater outfalls. Compliance with current and future VDPES regulatory requirements and permit conditions and implementation will minimize the potential for poor dissolved oxygen conditions resulting from SPS discharges.

The 2017 Atlantic sturgeon benchmark stock assessment report (ASMFC 2018) identifies fishery and research bycatch in U.S. and Canadian waters, ship strikes, and habitat loss and degradation, including from dredging operations, shoreline modification, water pollution, and dam construction as among the greatest threats to Atlantic sturgeon. Of these, SPS has the greatest potential to contribute to habitat loss and degradation. The potential for dredging operations, shoreline modification, and water pollution to have detrimental effects to habitat is controlled and mitigated by regulatory processes and permits. There is no plan to construct a dam or barrier to Atlantic sturgeon movements in association with SPS.

Beyond the physical features mentioned above that influence the quality of the Atlantic sturgeon's habitat, Dominion's new and significant information review addressed other Category 1 issues of aquatic resources and surface water quality and use. No new and significant information was identified that would impact water quality and aquatic resources or directly or indirectly impact the DCH. These issues concern the use of surface water for once-through cooling, discharge of metals in cooling water, discharge of biocides and sanitary wastes, the potential for water quality impacts from non-cooling water discharges, the potential for spills and minor chemical spills, sedimentation of surface waters, and related concerns.

SPS maintains and implements a SWPPP that identifies potential sources of pollution reasonably expected to affect the quality of stormwater, such as erosion, and identifies BMPs that will be used to prevent or reduce the pollutants in stormwater discharges (these practices, as they relate to erosion, include nonstructural preventative measures and source controls, as well as structural controls to prevent erosion or treat stormwater containing pollutants caused by erosion). In addition, any ground disturbance of 2,500 square feet or more requires a construction stormwater permit to be obtained from the VDEQ. The construction stormwater permit specifies BMPs to reduce erosion caused by stormwater runoff, thereby minimizing the risk of pollution from soil erosion and sediment, and potentially from other pollutants that the stormwater may contact. Although no license renewal-related refurbishment or construction activities are planned, any such activities would continue to be managed in adherence to the SPS SWPPP.

Industrial practices at SPS that involve the use of chemicals are those activities typically associated with painting, cleaning of parts/equipment, refueling of onsite vehicles/generators, fuel oil and gasoline storage, and the storage and use of water treatment additives. The use and storage of chemicals at SPS are controlled in accordance with Dominion's fleet chemical control procedure and site-specific spill prevention plans. In addition, as presented in Section E2.2.7, nonradioactive waste is managed in accordance with Dominion's waste management procedure, which contains preparedness and prevention control measures.

Dominion continuously monitors SPS's radiological effluents and maintains compliance with radiation protection standards. Dominion also monitors radioactivity levels annually by collecting samples of air, water, silt, shoreline sediment, milk, aquatic biota, and food products. The results for 2012-2015 did not detect radionuclides attributable to SPS. As in previous years, Dominion concluded that the operation of SPS has created no adverse environmental effects or health hazards.

The new and significant information review concluded that compliance with current and future VPDES regulatory requirements and permit conditions, and implementation of the SWPPP and BMPs, will ensure continued protection of aquatic resources. Sedimentation is related to earth disturbing activities, and no major activities are planned for SPS.

The impingement and entrainment of organisms that comprise the Atlantic sturgeon's diet could also impact the quality of the DCH. The Atlantic sturgeon is primarily a benthic forager, feeding on worms, snails, shellfish, and bottom-dwelling fish (CBP 2018). As discussed in Section E3.7.8.5, impingement of fish and shellfish is mitigated at SPS by the existing modified travelling screens, which exclude organisms that cannot pass the 1/8" x 1/2" inch mesh. Organisms impinged on the screens are washed into a trough with flowing water and returned to the James

River. The 2015-2016 impingement study conducted at SPS documented impingement of shellfish and finfish on the station's travelling screens. Grass shrimp of the genus *Palaemonetes* were the most commonly impinged shellfish, followed by mud crabs of the family *Xanthoidea* and blue crabs. Together these three taxa accounted for 82% of the shellfish impinged during the study. All three taxa are abundant throughout the Chesapeake Bay and its tidal rivers (USFWS 1985; USFWS 1989), and potential food items for Atlantic sturgeon. The exoskeleton of hard-bodied shellfish enhances survival of shellfish impinged on travelling screens. Initial impingement survival was assessed as part of the 2015-2016 impingement study at SPS. Over 97% of grass shrimp and mud crabs were live and undamaged when removed from the screenwash return trough and examined, as were 67% of blue crab. Relatively few bottom-dwelling finfish were collected during the impingement study. Of the five finfish species comprising 95% of the total number of finfish impinged, only the Atlantic croaker (5% of the total) would be classified as a bottom-dwelling fish. Atlantic croaker is abundant throughout the Chesapeake Bay and its tidal rivers. In the 2015-2016 impingement study at SPS, 65% of impinged Atlantic croaker were classified as live and undamaged when examined. Given impinged shellfish and bottom dwelling finfish are returned to the James River in generally good condition following impingement at SPS, to the impact on Atlantic sturgeon food availability from impingement at SPS would be SMALL.

Organisms that can pass the travelling screen mesh and are entrained to the station condenser system are eventually returned to the James River via the station discharge canal. The survival rates of organisms entrained at SPS are not known, but studies at other power stations have indicated survival can be substantial, especially for hard-bodied invertebrates. The 2015-2017 entrainment study conducted at SPS documented entrainment of shellfish and finfish. Most shellfish were free swimming zoea or juveniles, and most finfish were post-yolk sac larvae. Mud crabs (*Panopeidae*), fiddler crabs, and Tellin clams together comprised over 82% of the total number of shellfish entrained, and are potential prey items for Atlantic sturgeon. Naked/seaboard gobies and bay anchovy comprised over 81% of the finfish entrained. While bay anchovy is a pelagic species that would be unlikely prey for Atlantic sturgeon, naked and seaboard gobies are bottom dwelling fishes that would be vulnerable as prey items. Due to their small size and fragile nature, entrainable organism survival was not assessed during the 2015-2017 entrainment study.

Dominion is currently processing impingement and entrainment data required by CWA §316(b) that were collected 2015-2017, will address impingement and entrainment mortality of finfish and shellfish, and determine if there is a need for additional protective measures. Dominion currently operates SPS under a VPDES permit that places limits on heat rejection, and is based on the results of a CWA §316(a) demonstration study that made use of physical and biological data collected 1970-1976. The station's thermal discharge (condenser cooling water) exits SPS through the discharge canal and increases water temperatures in a localized section of the James River in the immediate vicinity of the canal outlet. Dominion is in the initial stages of conducting studies to update the existing CWA §316(a) demonstration study. The current studies will include hydrothermal modeling of the station's thermal impact on the James River, and a biothermal assessment of temperature conditions resulting from operations on representative important species. Atlantic sturgeon will be one of the representative important species considered. Effects of thermal discharge on fish and shellfish will also be examined as part of the §316(b) agency review.

Considering SPS operations and Dominion's adherence to permit conditions and regulatory requirements and commitment to comply with future permit conditions and regulatory requirements, the potential for SPS operations to impact the physical features essential for Atlantic sturgeon habitat is minimized. Therefore, consistent with "the continued operation of the site would have no adverse effects to any federally protected or state-listed species . . .impacts from the proposed SLR on threatened, endangered, and protected species in the vicinity of SPS are not likely to affect federally protected or listed species and EFH," Dominion concludes that SPS operations under the proposed action are not likely to adversely modify the Atlantic sturgeon DCH.

Impacts to Essential Fish Habitat

The habitat conditions of the species listed in Table 3.7-5 are discussed below.

Atlantic Butterfish

Juveniles and adults form loose schools and are common in the mid-Atlantic during the summer. They occur in sheltered bays and estuaries all the way out to over 200 m depths. They are common in the salinity mixing zone of the James River, which would include near SPS (Cross et al. 1999). Juveniles are generally found over bottom depths between 10 and 280 meters where bottom temperatures are between 6.5 and 27°C and salinities are above 5. Adults are generally found over bottom depths between 10 and 250 meters where bottom temperatures are between 4.5 and 27.5°C and salinities are above 5 ppt (Mid-Atlantic Fishery Management Council 2011). Atlantic butterfish are considered to have EFH near SPS because that portion of the James River is a salinity mixing zone.

Atlantic Herring

Atlantic herring are unlikely to be found in the area surrounding SPS in any life stage. The EFH for this species is limited to high salinity areas (>25 ppt) of the Chesapeake Bay (New England Fishery Management Council and NMFS, 2016; Stevenson and Scott 2005). While some herring species are anadromous, traveling up coastal rivers to spawn, Atlantic herring are fully marine and migrate to coastal and offshore spawning grounds (Gulf of Maine Research Institute 2019). Atlantic herring are not considered to have EFH near SPS due to low salinity and the lack of marine habitat.

Black Sea Bass

Juveniles are found in the estuaries in the summer and spring, while adults are found through October. Juvenile and adult black sea bass are usually found in association with structured bottom habitats, both natural and man-made, preferring sand and shell substrate. Generally, juvenile and adult black sea bass are found in Virginia coastal areas when water temperatures rise to warmer than 6°C with salinities greater than 18 ppt (Mid-Atlantic Fishery Management Council 1998a; Steimle et al. 1999a). These conditions are rare near SPS (Bradshaw and Kuo 1987). Black sea bass are not considered to have EFH near SPS due to low salinity.

Bluefish

Juvenile bluefish occur in mid-Atlantic estuaries from May through October; adults from April through October. Adults are highly migratory and distribution varies seasonally according to the size of the individuals comprising the schools. Adults generally prefer salinity greater than 25 ppt (Mid-Atlantic Fishery Management Council 1998b), but juveniles can tolerate down to 3 ppt and can be abundant in the James River (Fahay et al. 1999). Bluefish are considered to have EFH in the vicinity of SPS due to the salinity mixing zone.

Clearnose Skate

Clearnose skates are unlikely to be found in the area surrounding SPS in any life stage. The EFH for this species is limited to only high salinity areas (>25 ppt of the Chesapeake Bay (New England Fishery Management Council and NMFS 2016; Packer et al. 2003). Clearnose skates are not considered to have EFH in the vicinity of SPS due to low salinity.

Little Skate

EFH for the little skate includes the Chesapeake Bay mainstem for the adult life stage for high (>25 ppt) and mixed salinity (0.5 to 25 ppt) (New England Fishery Management Council and NMFS, 2016, Table 28 and Appendix A). Little skates are not considered to have EFH near SPS due to low salinity, and they are unlikely to be found in the area surrounding SPS in any life stage.

Red Hake

Red hake are unlikely to be found in the area surrounding SPS in any life stage. The EFH for this species is limited to high salinity areas (>25 ppt) of the Chesapeake Bay (Steimle et al., 1999b). Red hake are not considered to have EFH near SPS due to low salinity.

Sandbar Shark

Sandbar sharks are an important commercial species in the southeastern U.S., with documented severe decline of catch per unit effort (CPUE) in the Chesapeake Bay area, likely due to heavy fishing pressure and the species' slow maturation. Shallow coastal waters of the lower Chesapeake Bay are primary summer nurseries and are designated as EFH and habitat areas of particular concern (NOAA 2006). However, recent research has shown more specific requirements of water temperatures of 17-28°C, salinity greater than 20.5 ppt, and depth greater than 5.5 m (Grubbs and Musick 2007). These conditions are rare near SPS (Bradshaw and Kuo 1987). Sandbar sharks are not considered to have EFH near SPS due to low salinity.

Scup

During the acceptance review of the application, NRC held conference calls with Dominion to obtain clarification on information associated with or supporting of the application. This species was identified by the NRC as occurring within the James River. Dominion searches of the NOAA EFH identified the EFH for the scup as extending into the Chesapeake Bay, but not into the James River. Scup are not considered to have EFH near SPS due to its range limit.

Summer Flounder

Summer flounder larvae are most abundant within 50 miles of shore at depths of 30 to 230 feet, most frequently from September to May. Juveniles use several estuarine habitats as nursery areas, including salt marsh creeks, seagrass beds, mudflats, and open bay areas in water temperatures greater than 2.5°C and salinities from 10 to 30 ppt. Adults are found in shallow coastal and estuarine waters during warmer months. Summer flounder are considered to have EFH in the vicinity of SPS due to the salinity mixing zone and appropriate bottom substrate.

Winter Skate

Winter skates are unlikely to be found in the area surrounding SPS in any life stage. The EFH for this species is limited to high salinity areas (>25 ppt) of the Chesapeake Bay (Omnibus EFH Amendment 2). Winter skates are not considered to have EFH in the vicinity of SPS due to low salinity.

Windowpane Flounder

Based on New England Fishery Management Council and NMFS (2016, Sections 2.1.1.10 and 2.2.1.10) reviews of EFH and finalized by NMFS (83 FR 15240, April 9, 2018), the windowpane flounder would also be potentially found in the SPS vicinity. SPS is adjacent to potential EFH for the juvenile and adult life stages of windowpane flounder. Habitat conditions for juveniles include intertidal and sub-tidal benthic habitats in estuarine, coastal marine, and continental shelf waters from the Gulf of Maine to northern Florida, including mixed and high salinity zones in bays and estuaries, including the Chesapeake Bay. EFH for juvenile windowpane flounder is found on mud and sand substrates and extends from the intertidal zone to a maximum depth of 60 meters. Young-of-the-year juveniles prefer sand over mud. Habitat conditions for adults include intertidal and sub-tidal benthic habitats in estuarine, coastal marine, and continental shelf waters from the Gulf of Maine to Cape Hatteras, including mixed and high salinity zones in bays and estuaries, including the Chesapeake Bay. EFH for adult windowpane flounder is found on mud and sand substrates and extends from the intertidal zone to a maximum depth of 70 meters. (New England Fishery Management Council and NMFS 2016, Sections 2.1.1.10 and

2.2.1.10). Windowpane flounder are considered to have EFH in the vicinity of SPS due to the presence of appropriate benthic habitats and marginally appropriate salinity.

The SPS vicinity does provide conditions important for Atlantic butterfish, bluefish, summer flounder, and windowpane flounder. Bluefish and summer flounder were collected in low numbers during the 2015 and 2016 impingement studies at SPS (IR-HDR 2018, Table 4.2). The entrainment sampling conducted in 2015, 2016, and 2017 did not document these species, with the exception of two juvenile summer flounders collected during the August 2015 to July 2016 sampling period.

The EFH for these species focus on salinity, temperature, and substrate composition. In some cases, EFH information is only available for one or two of these environmental factors. As discussed above for the DCH of Atlantic sturgeon, Dominion considered SPS's potential to alter salinity gradients, substrate, and temperature trends. The salinity gradient is governed by tidal influence rather than plant operations, and SPS operations would not impact the salinity level. The river bed in the vicinity of SPS is composed of soft mud, clay, sand, and pebbles, with no single bottom type predominating. SPS periodically dredges the intake channel under a USACE 404 permit which would require any special conditions to protect EFHs in the dredge area. SPS's thermal effluent is governed by its VPDES permit and the thermal plume disperses rapidly in the James River, with a temperature rarely above 5°F more than ambient temperature at 3,000 feet from the discharge point. The width of the James River near SPS also allows fish to avoid the plume.

The EFHs could also be impacted by sedimentation, chemical pollutants, and radiological effluents. As discussed for the DCH, SPS has programs and permits in place to address these water quality factors. SPS maintains and implements a SWPPP and a construction stormwater permit would be obtained from the VDEQ for any construction that would disturb more than 2,500 square feet. SPS also operates in accordance with the requirements contained in its spill prevention, control, and countermeasures (SPCC) plan to prevent and mitigate spills. SPS complies with radiological environmental standards, and annual sampling of environmental media indicates operation of SPS has created no adverse environmental effects or health hazards.

EFHs can also be impacted by the pressures of impingement and entrainment of the species or prey species. SPS operates under its current VPDES permit which considers the cooling water intake system as interim best technology available for reducing impingement and entrainment and requires Dominion conduct impingement and entrainment studies. The overall impingement and entrainment impacts of the SPS cooling water system are discussed in Section E4.6.1, concluding the impact of impingement and entrainment from continued operation of SPS's cooling water system to be SMALL. Four bluefish and seven summer flounder were collected during the 2015 and 2016 impingement studies at SPS out of the total finfish collection of approximately 286,000. Two juvenile summer flounders were collected during the August 2015 to July 2016 entrainment sampling period out of a total finfish collection of approximately 61,300 (IR-HDR 2018, draft, Table 4.5). Because of continued compliance with VDEQ requirements, and the absence or relative rarity of the EFH species of interest, Dominion concludes that impacts from impingement and entrainment of aquatic organisms during the proposed SLR operating term would be SMALL. Although additional mitigation measures may be implemented in the future as a result of the requirements in the final 316(b) Rule, these measures would minimize the already existing SMALL impacts.

SPS's adherence to its VDPES permit, USACE issued CWA Section 404 permits, as well as implementing BMPs and spill prevention measures will serve to prevent and minimize discharges to the James River that could significantly impact ambient conditions. No refurbishment activities are planned and any future modifications for CWA 316(b) compliance would consider impacts to aquatic communities and EFHs. SPS's compliance with current and future VPDES regulatory requirements and permit conditions, and implementation of the SWPPP and BMPs, will continue to minimize effects to the James River conditions, ensuring continued protection of aquatic resources and EFH. Therefore, consistent with discussions and analysis in the ER that conclude on page E4-44 "the continued operation of the site would have no adverse effects to any federally protected or state-listed species . . .impacts from the proposed SLR on threatened, endangered, and protected species in the vicinity of SPS are not likely to affect federally protected or listed species and EFH," Dominion concludes that SPS operations under the proposed action would have no adverse impact for the EFHs.

E4.12.5 Cumulative Impacts, Ecological Resources, Aquatic (addition)

The federally listed shortnose sturgeon would also not be adversely affected by SPS operations. SPS's ongoing programs to mitigate and control water quality (e.g., VPDES permit, CWA 404 permit, SWPPP, SPCC plan) would minimize the potential for impacts to both sturgeon species, including the designated critical habitat as well as EFHs adjacent to SPS.

Table E6.1-1 Environmental Impacts Related to Subsequent License Renewal at SPS (addition)

Resource Issue	ER Section	Environmental Impact
Special Status Species and Habitats		
Threatened, endangered, and protected species and essential fish habitat [10 CFR 51.53(c)(3)(ii)(E)]	E4.6.6	SMALL impact. No license renewal-related refurbishment or other license-renewal related construction activities have been identified. The continued operation of the site would have no adverse effects on any federally or state-listed species. SLR would have no effect on threatened, endangered, and protected species in the vicinity of SPS. **Add:** SPS operations under the proposed action are not likely to adversely modify the Atlantic sturgeon designated critical habitat. SPS operations under the proposed action would have no adverse impact on EFHs.

References (additions)

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Enclosure 1
Attachment 2

NATIONAL MARINE FISHERIES SERVICE RESPONSE LETTER TO DOMINION ENERGY VIRGINIA'S LETTER REGARDING SPECIAL STATUS SPECIES AND HABITAT

Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2

UNITED STATES DEPARTMENT OF COMMERCE
National Oceanic and Atmospheric Administration
NATIONAL MARINE FISHERIES SERVICE
GREATER ATLANTIC REGIONAL FISHERIES OFFICE
55 Great Republic Drive
Gloucester, MA 01930-2276

OCT - 4 2017

Jason E. Williams, Manager
Generation Environmental Services
Dominion Energy Services
5000 Dominion Boulevard
Glen Allen, VA 23060

Re: Virginia Electric and Power Company – Surry Power Station Units 1 and 2 Subsequent License Renewal

Dear Mr. Williams:

The National Oceanic and Atmospheric Administration's National Marine Fisheries Service (NMFS) has received your letter, dated August 3, 2017, seeking assistance in assessing the effects that extending the license term for Surry Power Station Units 1 and 2 (SPS) may have on resources under our jurisdiction within the immediate environments of facility. The applicant (Dominion Energy Virginia) proposes to maintain current operations over the license renewal period at SPS. The renewed license would use existing plant facilities and transmission lines. In addition to continued operation during this renewed license period, an approximate 85-acre management area for material from maintenance dredging in the James River at SPS' water intakes is presently being evaluated for permitted use. You also indicated that, if needed, the construction of a new concrete storage pad (pad #5) at the independent spent fuel storage installation (ISFSI) will be the only ground-disturbing activity anticipated at the SPS site during the extended license period. In 2012, we completed consultation with the Nuclear Regulatory Commission (NRC) pursuant to section 7 of the Endangered Species Act (ESA) of 1973, as amended, regarding effects of operations of the facility pursuant to the existing license. A copy of that consultation is included here your reference. Below, we provide updated information on trust resources.

Endangered Species Act

Several species listed by us occur in the James River where the intake for SPS is located. Individuals from any of the five listed distinct population segments (DPSs) of Atlantic sturgeon (*Acipenser oxyrinchus oxyrinchus*) occur in the James River and may be present in the action area. There are several references that post-date our 2012 letter that may help in assessing the impacts to Atlantic sturgeon in the James River (e.g., Balazik 2012; Balazik *et al.* 2012a, 2012b). Although listed sea turtle species occur seasonally in Chesapeake Bay and may be present near the confluence of the James River, none of these species occur in the James River near the SPS.

Since our informal consultation in 2012, new information confirms that shortnose sturgeon (*Acipenser brevirostrum*) are at least occasionally present in Virginia waters of the Chesapeake Bay. On March 13, 2016, a shortnose sturgeon was captured in the freshwater portion of the

James River at river kilometer 48 (within the 6-mile radius of the SPS site). Genetic analysis confirmed the fish was a shortnose sturgeon (see Balazik 2017). Since records of historical occurrence of shortnose sturgeon were begun in the late 1800s, shortnose sturgeon have seemed to be rare in the upper Chesapeake Bay and nonexistent in the lower Chesapeake Bay. At this time, we consider this fish to be a transient individual and there is no evidence of a James River population of shortnose sturgeon.

On August 17, 2017, we published the final rule (82 FR 39160) to designate critical habitat for the threatened Gulf of Maine DPS of Atlantic sturgeon, the endangered New York Bight DPS of Atlantic sturgeon, the endangered Chesapeake Bay DPS of Atlantic sturgeon, the endangered Carolina DPS of Atlantic sturgeon and the endangered South Atlantic DPS of Atlantic sturgeon pursuant to the ESA. We identified the James River from Boshers Dam downstream to where the main stem river discharges at its mouth into the Chesapeake Bay at Hampton Roads as part of the critical habitat for the Chesapeake Bay DPS of Atlantic sturgeon (Figure 1). The effective date of this final rule is September 18, 2017.

More information on shortnose and Atlantic sturgeon and recently designated critical habitat is available on our website (http://www.nero.noaa.gov/protected/section7/listing/index.html).

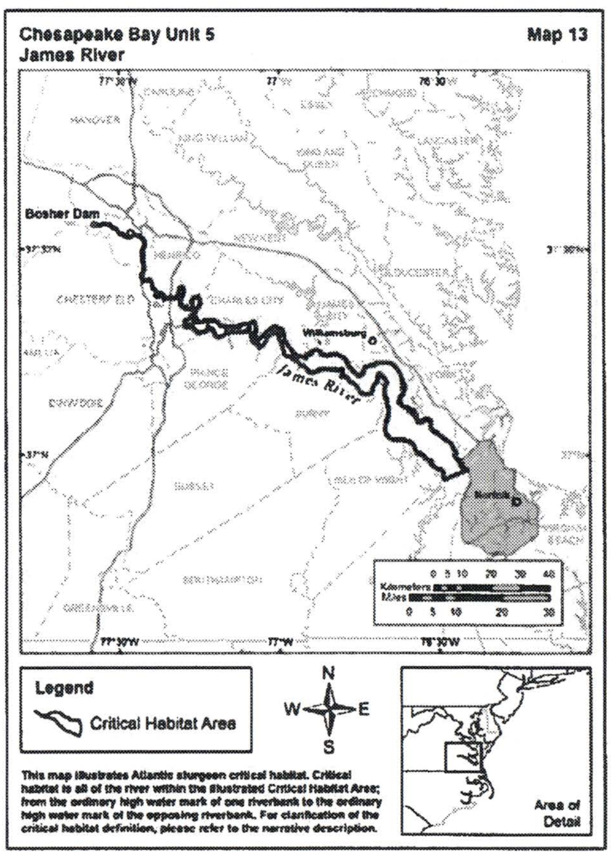

Figure 1: Atlantic Sturgeon Critical Habitat within the James River

Section 7 Consultation

Under Section 7(a)(2) of the ESA, each Federal agency is required to insure that any action they authorize, fund, or carry out is not likely to jeopardize the continued existence of any endangered species or threatened species and is not likely to destroy or adversely modify any designated critical habitat. The renewal of the operating license for the SPS facility by the NRC would be a federal action requiring section 7 consultation.

As noted in your letter, an approximate 85-acre management area for material from maintenance dredging in the James River at SPS' water intakes is presently being evaluated for permitted use. Your letter also describes the construction of a new concrete storage pad (pad #5) at the ISFSI during the extended license period, if needed. We recommend that the applicant undertake a complete analysis of the effects that dredging and construction-related ground disturbance will have on physical or biological features identified in the critical habitat designation. In addition, you should consider the effects to critical habitat from the stressors identified in the 2012 informal consultation (e.g., withdrawal of water, discharge of heated effluent, radiological impacts, non-routine and accidental events, etc.).

In addition to considering effects to critical habitat addressed above, the consultation will need to consider effects to shortnose and Atlantic sturgeon. SPS cannot operate without the intake and discharge of cooling water. Specific issues of concern related to the license renewal application review include the impingement and entrainment of endangered shortnose sturgeon and Atlantic sturgeon. Based on new information that confirms that shortnose sturgeon occur in the James River, an evaluation of impacts that extending the license term may have on both sturgeon species should be conducted. As noted in 2012, the best available information at that time supported a conclusion that no impingement or entrainment of shortnose or Atlantic sturgeon is expected at SPS. Any new monitoring, as well as consideration of any proposed changes in operating conditions, or other information should be considered to assess whether this conclusion remains valid.

In addition to impingement and entrainment, all other issues that were considered in the 2012 consultation will need to be re-evaluated based on the best available information for the license renewal. These include:

- Effects of entrainment and impingement on sturgeon and sturgeon prey
- A description of the thermal plume
- Effects of the thermal plume on sturgeon and sturgeon prey
- Impacts to water quality resulting from pollutants discharged from the facility
- Radiological impacts to sturgeon and sturgeon prey
- Impacts of climate change on sturgeon and sturgeon habitat in the action area
- Environmental risks associated with non-routine and accidental events at the facility

We look forward to working with NRC and the applicant throughout the relicensing process as environmental documentation is developed to identify and evaluate the potential impacts to species under NMFS' jurisdiction. Should you have any questions regarding these comments as they relate to ESA matters, please contact me at (978)282-8480 or Julie.Crocker@noaa.gov.

Sincerely,

Julia E. Crocker

Julia E. Crocker
ESA Fish Recovery Coordinator

File Code: Sec 7 Tech Assist NRC Surry Relicensing

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Enclosure 1
Attachment 3

VIRGINIA DEPARTMENT OF ENVIRONMENTAL QUALITY CZMA RESPONSE LETTER

Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
Street address: 1111 East Main Street, Suite 1400, Richmond, VA 23219
Mailing address: P.O. Box 1105, Richmond, Virginia 23218
www.deq.virginia.gov

Matthew J. Strickler
Secretary of Natural Resources

David K. Paylor
Director

(804) 698-4000
1-800-592-5482

February 2, 2018

Pamela F. Faggert
Chief Environmental Officer
Senior Vice President Sustainability
Dominion Energy Services, Inc.
5000 Dominion Boulevard
Glen Allen, VA 23060

RE: Federal Consistency Certification for the VEPCO Surry Power Station Units 1 and 2 Subsequent License Renewal, U.S. Nuclear Regulatory Commission, Surry County, DEQ 17-121F

Dear Ms. Faggert:

The Commonwealth of Virginia has completed its review of the above-mentioned Federal Consistency Certification (FCC). The Department of Environmental Quality is responsible for coordinating Virginia's review of FCCs and responding to appropriate officials on behalf of the Commonwealth. This letter is in response to the FCC dated August 3, 2017 and received on August 11, 2017, submitted by Dominion Energy Services, Inc. on behalf of the Virginia Electric and Power Company. The following agencies and planning district commission participated in this review:

Department of Environmental Quality (DEQ)
Department of Health (VDH)
Department of Conservation and Recreation (DCR)
Department of Historic Resources (DHR)
Department of Game and Inland Fisheries (DGIF)
Virginia Institute of Marine Science (VIMS)
Crater Planning District Commission (PDC)

In addition, the Marine Resources Commission, Surry County and the Hampton Roads Planning District Commission were invited to comment on the proposal.

PROJECT DESCRIPTION

The Virginia Electric and Power Company (applicant, Dominion, or VEPCO) is seeking approval from the U.S. Nuclear Regulatory Commission (NRC) to renew the operating licenses for Surry Power Station (SPS) Units 1 and 2 for an additional twenty years. SPS is located on the James River in Surry County, Virginia. Dominion expects to submit the renewal application to the NRC in the first quarter of 2019. For SPS Unit 1 the requested renewal would extend the license expiration date from May 25, 2032 to May 25, 2052. For SPS Unit 2 the requested renewal would extend the license expiration date from January 29, 2033 to January 29, 2053. The subsequent license renewal application also considers the impacts from the in-scope transmission lines which connect the generating units to the transmission grid and supply power to the plant during outages, located entirely on the SPS site. The license renewal process does not include modifications to structures or land disturbing activities. However, SPS may require additional space to store spent fuel during the period of extended operations. This involves the potential construction of an additional concrete pad at the existing Independent Spent Fuel Storage Installation (ISFSI). The ISFSI is a dry storage facility for spent fuel that is removed from SPS Unit 1 and 2. The ISFSI is separately licensed from the SPS by the NRC.

SPS is fueled by uranium dioxide in two nuclear reactors to produce steam to drive the turbines. Cooling water is withdrawn from the James River through an approximate 5,700-foot channel dredged in the riverbed between the main river channel and the eastern shore of Gravel Neck Peninsula. Dredging occurs every three to four years to maintain a depth of approximately 13 feet. A dredge materials management area (DMMA) is being constructed approximately four miles from the SPS site for use as a spoils area for future maintenance dredging of the intake. The applicant has submitted a Federal Consistency Certification that finds the proposed action consistent with the enforceable policies of the Virginia Coastal Zone Management Program.

FEDERAL CONSISTENCY PUBLIC PARTICIPATION

In accordance with 15 CFR §930.2, the public was invited to participate in the review of the proposal. Public notice of the proposed action was published in the OEIR Program Newsletter and on the DEQ website from August 17, 2017 to September 14, 2017. No public comments were received in response to the notice.

FEDERAL CONSISTENCY UNDER THE COASTAL ZONE MANAGEMENT ACT

Pursuant to the Coastal Zone Management Act of 1972 (CZMA), as amended, and the federal consistency regulations implementing the CZMA (15 CFR, Part 930, Subpart D, Section 930.50 *et seq.*), projects receiving federal permits, licenses or approvals, which can affect Virginia's coastal uses or resources, must be constructed and operated in a manner which is consistent with the Virginia Coastal Zone Management (CZM) Program. The Virginia CZM Program is comprised of a network of programs administered by several agencies. In order to be consistent with the Virginia CZM

Program, all the applicable permits and approvals listed under the enforceable policies of the Virginia CZM Program must be obtained prior to commencing the project.

FEDERAL CONSISTENCY CONDITIONAL CONCURRENCE

Based on our review of the consistency certification and the comments submitted by agencies administering the enforceable policies of the Virginia CZM Program, DEQ **conditionally concurs** that the proposal is consistent with the Virginia CZM Program provided all applicable permits and approvals are obtained and the conditions of the enforceable policies are adhered to as described below. DGIF has raised concerns related to the consistency of the project with the fisheries management enforceable policy of the Virginia CZM Program (refer to Item 5 of the Federal Consistency Analysis section, pages 8-10).

If, prior to construction, the project should change significantly and any of the enforceable policies of the Virginia CZM Program would be affected, pursuant to 15 CFR 930.66, the applicant must submit supplemental information to DEQ for review and approval. Other state approvals which may apply to this project are not included in this consistency concurrence. Therefore, the applicant must ensure that this project is constructed and operated in accordance with all applicable federal, state and local laws and regulations.

Conditions of Concurrence with the FCC
The conditions of the Commonwealth's concurrence include the following authorizations under the Virginia CZM Program:

- DGIF input and concurrence on the intake technology and conditions implemented to minimize impacts to fisheries resources and incidental take of endangered species in accordance with Virginia Code §29.1-100 to §29.1-570.

In accordance with the *Federal Consistency Regulations* 15 CFR Part 930, section 930.4, this conditional concurrence is based on the applicant obtaining the necessary authorizations prior to initiating project activities. If the requirements of section 930.4, sub-paragraphs (a)(1) through (a)(3) are not met, this conditional concurrence becomes an objection under 15 CFR Part 930, section 930.63.

FEDERAL CONSISTENCY ANALYSIS

According to information in the FCC, the proposed activity would have no effect on the following enforceable policies: dunes management and shoreline sanitation. With the exception of the fisheries management enforceable policy analysis, the resource agencies that are responsible for the administration of the enforceable policies of the Virginia CZM Program generally agree with findings of the FCC. The applicant must ensure that the proposed action is consistent with the aforementioned policies. The analysis which follows responds to the discussion of the enforceable policies of the

Virginia CZM Program that apply to this project and review comments submitted by agencies that administer the enforceable policies.

1. Nonpoint Source Pollution Control. According to the FCC (page 9), the proposed license renewal does not include land disturbing activities or modifications to structures. Should routine maintenance, renovation or infrastructure projects require ground disturbance, appropriate erosion and sediment control and stormwater best management practices (BMPs) will be in place. Dominion has submitted a notice of intent for a stormwater construction general permit for the construction and use of the DMMA during the current license term and all required permits will be obtained as necessary. The DMMA will also be in use during the proposed subsequent license renewal period.

1(a) Agency Jurisdiction. The DEQ Office of Stormwater Management within the Division of Water Permitting administers the nonpoint source pollution control enforceable policy through the Virginia Erosion and Sediment Control Law and Regulations (VESCL&R) (Virginia Code §62.1-44.15 *et seq.* and 9 VAC 25-840-30 *et seq.*) and the Virginia Stormwater Management Law and Regulations (VSWML&R) (Virginia Code §62.1-44.15 *et seq.* and 9 VAC 25-870-54 *et seq.*). In addition, DEQ is responsible for the issuance, denial, revocation, termination and enforcement of the Virginia Stormwater Management Program (VSMP) General Permit for Stormwater Discharges from Construction Activities related to municipal separate storm sewer systems (MS4s) and construction activities for the control of stormwater discharges from MS4s and land disturbing activities under the Virginia Stormwater Management Program.

1(b) Agency Recommendation. The applicant should consider the use of permeable paving for parking areas and walkways, where appropriate. Denuded areas should be promptly revegetated following construction work.

1(c) Requirements. Any future land disturbance on the site, including the construction of the DMMA, must adhere to the erosion and sediment control and stormwater management requirements.

1(c)(i) Erosion and Sediment Control. If future projects/maintenance on the site involve a land-disturbing activity of equal to or greater than 2,500 square feet in a Chesapeake Bay Preservation Area, the applicant is responsible for submitting a project-specific erosion and sediment control (ESC) plan to the locality for review and approval pursuant to the local ESC requirements. Depending on local requirements, the area of land disturbance requiring an ESC plan may be less. The ESC plan must be approved by the locality prior to any land-disturbing activity at the project site. All regulated land-disturbing activities associated with the project, including on and off site access roads, staging areas, borrow areas, stockpiles and soil intentionally transported from the project, must be covered by the project-specific ESC plan. Local ESC program requirements must be requested through the locality.

1(c)(ii) Stormwater Management Plan. Dependent on local requirements, a stormwater management (SWM) plan may be required. Local SWM program requirements must be requested through the locality.

1(c)(iii) General Virginia Pollutant Discharge Elimination System (VPDES) Permit for Discharges of Stormwater from Construction Activities (VAR10). The operator or owner of a construction activity involving land disturbance of equal to or greater than 1 acre is required to register for coverage under the General VPDES Permit for Discharges of Stormwater from Construction Activities and develop a project specific stormwater pollution prevention plan (SWPPP). The SWPPP must be prepared prior to submission of the registration statement for coverage under the general permit and the SWPPP must address water quality and quantity in accordance with the Virginia Stormwater Management Program (VSMP) Regulations. General information and registration forms for the General Permit are available at *www.deq.virginia.gov/Programs/Water/StormwaterManagement/VSMPPermits/ConstructionGeneralPermit.aspx*.

1(d) Conclusion. As designed, the project is consistent with the nonpoint source pollution control enforceable policy of the Virginia CZM Program as no land disturbance is proposed.

2. Air Pollution Control. According to the FCC (page 11), the SPS air emission sources are permitted under Title V of the Federal Clean Air Act by DEQ permit number PRO50336 which has been administratively continued beyond its expiration date of May 17, 2017. Air emissions from SPS result from intermittent use and testing of auxiliary boilers and diesel generators.

2(a) Agency Jurisdiction. The DEQ program implements the federal Clean Air Act to provide a legally enforceable State Implementation Plan for the attainment and maintenance of the National Ambient Air Quality Standards. This program is administered by the State Air Pollution Control Board at DEQ (Virginia Code §10-1.1300 through §10.1-1320).

2(b) Agency Finding. The DEQ Air Division states that the project site is located in an ozone (O_3) attainment area.

DEQ PRO confirmed that Dominion holds a Title V permit for this site (PRO50336). If there are any intended changes to the systems, a permit modification may be required.

2(c) Requirements. Dominion should be aware of the below air pollution control requirements that would apply to any future construction at the ISFSI or DMMA.

2(c)(i) Fugitive Dust. During construction, fugitive dust must be kept to a minimum by using control methods outlined in 9 VAC 5-50-60 *et seq.* of the *Regulations for the Control and Abatement of Air Pollution*. These precautions include, but are not limited to, the following:

- Use, where possible, of water or chemicals for dust control;
- Installation and use of hoods, fans, and fabric filters to enclose and vent the handling of dusty materials;
- Covering of open equipment for conveying materials; and
- Prompt removal of spilled or tracked dirt or other materials from paved streets and removal of dried sediments resulting from soil erosion.

2(c)(ii) Open Burning. If construction activities include open burning or the use of special incineration devices, this activity must meet the requirements under 9 VAC 5-130-10 through 9 VAC 130-60 and 9 VAC 5-130-100 of the *Regulations* for open burning. In addition, the *Regulations* provide for, but do not require, the local adoption of a model ordinance concerning open burning. The applicant should contact local fire officials to determine what local requirements, if any, exist.

2(d) Recommendation. PRO recommends that all actions should operate with air pollution control practices that minimize emissions. Fugitive dust should be kept to a minimum.

2(e) Conclusion. The project, as proposed, is consistent with the air pollution control enforceable policy of the Virginia CZM Program.

3. Coastal Lands Management. The FCC (page 12) states that Surry County implemented the Chesapeake Bay preservation-related regulation via Section 3.1400 of its zoning ordinance. The proposed license renewal does not include land-disturbing activities. However, SPS may require additional space to store spent fuel during the period of extended operations. This would involve the potential construction of an additional concrete pad at the existing ISFSI.

3(a) Agency Jurisdiction. The DEQ Office of Local Government Programs (OLGP) administers the coastal lands management enforceable policy of the Virginia CZM Program which is governed by the Chesapeake Bay Preservation Act (Bay Act) (Virginia Code §62.1-44.15 *et seq.*) and *Chesapeake Bay Preservation Area Designation and Management Regulations* (*Regulations*) (9 VAC 25-830-10 *et seq.*).

3(b) Agency Findings. DEQ-OLGP notes that in Surry County, the areas protected by the *Chesapeake Bay Preservation Act*, as locally implemented, require conformance with performance criteria. These areas include Resource Protection Areas (RPAs) and Resource Management Areas (RMAs) as designated by the local government. RPAs include tidal wetlands, certain non-tidal wetlands and tidal shores. RPAs also include a 100-foot vegetated buffer area located adjacent to and landward of these features and along both sides of any water body with perennial flow. RMAs, which require less stringent performance criteria than RPAs, consist of all remaining areas within Surry County that are located within the James River Watershed.

The proposed license renewal does not include additional construction outside of the SPS site. However, during the period of extended operations, space may be required for storage of spent fuel, which would entail construction of an additional concrete pad at the existing ISFSI. The ISFSI is co-located on the SPS site and is also operated by Dominion Energy Virginia under a general license pursuant to NRC regulations.

Although no RPA impacts are anticipated from the potential construction of an additional concrete pad, the ISFSI site is located within the County's designated Resource Management Area.

3(c) Requirements. The construction at the ISFSI site must be consistent with the general performance criteria provisions of 9VAC25-830-130 of the Regulations. This would include disturbing no more land than necessary to provide for the proposed use, minimizing impervious cover, and preserving indigenous vegetation to the maximum extent practicable consistent with the proposed use. In addition, all land disturbing activity exceeding 2,500 square feet must comply with the requirements of the *Virginia Erosion and Sediment Control Handbook*, Third Edition, 1992.

Stormwater management criteria consistent with the water quality protection provisions of the *Virginia Stormwater Management Regulations*, 9VAC25-870-51 and 9 VAC25-870-103, shall be satisfied. These provisions require that localities subject to the Chesapeake Bay Preservation Act implement specified technical and administrative criteria from the VSMP regulations for Chesapeake Bay Preservation Act land-disturbing activities. Such activities include land disturbance equal to or greater than 2,500 square feet of land disturbance and less than one acre in designated Chesapeake Bay Preservation Areas.

3(d) Conclusion. Provided any construction at the ISFSI adheres to the above criteria, the proposed activity would be consistent with the Chesapeake Bay Preservation Area Designation and Management Regulations and the coastal lands management enforceable policy of the Virginia CZM Program.

4. Wetlands Management. According to the FCC (page 8), the proposed subsequent license renewal does not include land-disturbing activities or construction that will impact wetlands. The SPS holds a VMRC permit #2016-0710 for the maintenance dredging of the intake channel.

4(a) Agency Jurisdiction. The wetlands management enforceable policy is administered by the Virginia Marine Resources Commission (tidal wetlands) (Virginia Code 28.2-1301 through 28.2-1320) and the Department of Environmental Quality through the Virginia Water Protection Permit (VWP) program (tidal and non-tidal wetlands) (Virginia Code §62.1-44.15:20 and Water Quality Certification pursuant to Section 401 of the Clean Water Act).

4(b) Agency Findings. The DEQ Piedmont Regional Office (PRO) noted that if future development during the license term were to impact wetlands and streams, a DEQ VWP permit would be required.

The Virginia Marine Resources Commission (VMRC) did not comment on the proposal.

4(c) Agency Recommendation. DEQ PRO recommends that all construction activities avoid wetlands to the maximum extent possible.

4(d) Agency Requirement. If impacts to wetlands or surface waters will occur during the new license term, the applicant must submit a Joint Permit Application (JPA) to obtain a VWP permit as necessary.

4(e) Conclusion. Provided a JPA is submitted and a VWP Permit is obtained, as necessary, the project will be consistent with the wetlands management enforceable policy of the Virginia CZM Program.

5. Fisheries Management. According to the FCC (page 6), the permit for the process and stormwater discharge from the SPS facility (VA0004090) contains thermal limitations that are protective of indigenous shellfish, finfish, and wildlife in the James River. The Virginia Pollutant Discharge Elimination System (VPDES) program also addresses the Clean Water Act 316(b) regulations related to the impingement and entrainment impacts of cooling water intake structures. Environmental studies are currently underway to determine whether current operational methods to prevent entrainment are sufficient to meet the new 316(b) requirements. DEQ will make the compliance determination and modifications of the intake and/or cooling structures could be required in future. Dominion will continue to comply with the VPDES permit for the SPS during the proposed subsequent license renewal period.

5(a) Agency Jurisdiction. The fisheries management enforceable policy is administered by the Department of Game and Inland Fisheries (Virginia Code 29.1-100 to 29.1-570) and Virginia Marine Resources Commission (Virginia Code 28.2-200 to 28.2-713) which have management authority for the conservation and enhancement of finfish and shellfish resources in the Commonwealth.

5(b) Agency Findings.

5(b)(i) Virginia Department of Game and Inland Fisheries. The DGIF submitted significant comments on the proposal, which are summarized below. Refer to the attached email (Ewing/Howard, 10/6/17) for complete comments.

5(b)(i)(a) Atlantic Sturgeon. Since SPS was first licensed and began operation, the Atlantic Sturgeon has been federally-listed as an endangered species and the James River has been designated a Threatened and Endangered Species Water due to presence of Atlantic sturgeon. These fish are found in the river year-round, and are known to engage in both spring and fall migration and spawning in this reach of the river. These fish also are known to congregate in the James River from Hog Island downstream.

The consistency certification states that with relicensing and continued operation of SPS, "aquatic organisms would continue to be impinged and entrained at the intake structure, but these impacts were determined to be small." DGIF is concerned about impingement and entrainment of aquatic species, including the federally-listed endangered Atlantic sturgeon and other anadromous fishes. In addition, DGIF is concerned about potential impacts of the cooling water discharge upon Atlantic sturgeon and other anadromous fishes. Furthermore, DGIF understands that it is necessary for the applicant to periodically dredge the canal that diverts water from the James River to the cooling water intake, which may impact sturgeon.

DGIF notes that the NRC may consult with the U.S. Fish and Wildlife Service (FWS) to address potential impacts of this project on Atlantic sturgeon, and that FWS has expressed interest in DGIF's involvement in that process. DGIF anticipates mutual agreement among the agencies regarding any measures that may be appropriate. However, until such issues are resolved, DGIF cannot determine the likely impacts of relicensing and continued operations on these fishery resources.

5(b)(i)(b) Anadromous Fish. The affected reach of the James River, and Lawnes Creek, have been designated Anadromous Fish Use Areas due to the presence of alewife herring, blueback herring, American shad, striped bass, yellow perch, and hickory shad.

5(b)(ii) Virginia Marine Resources Commission. The VMRC did not comment on the proposal.

5(b)(iii) VDH Division of Shellfish Sanitation. VDH found that the project is located in or adjacent to approved shellfish growing waters. However, the activity, as described, will not require a change in classification.

5(b)(iv) Virginia Institute of Marine Science. VIMS had no comment on the FCC.

5(c) DGIF Recommendations. To protect resident aquatic species including federally Endangered Atlantic sturgeon and other anadromous fishes from impingement and entrainment, DGIF recommends that the applicant consider the redesign or retrofitting of the cooling water intake on the James River to take advantage of currently best technology available (BTA). Measures to protect the Atlantic sturgeon and other species could include intake screen mesh or design, intake velocity restrictions, or time-of-year restrictions on certain dredging or instream construction activities.

DGIF requests the opportunity to participate in discussions between the NRC, FWS, and Dominion regarding the potential impacts of this project on the Atlantic sturgeon, and believe such consultation may offer the best path toward determination of appropriate measures, if any, that are needed to ensure continued protection of Atlantic sturgeon and other resident aquatic species. DGIF also recommends that NOAA Fisheries Service be included in these discussions, as a cognizant federal agency.

5(d) Conclusion. At this time, DGIF cannot determine the likely impacts of relicensing and continued operations of the facility on fishery resources. Further coordination with and approval from DGIF on the methods in place to protect the Atlantic sturgeon and other species from impingement/entrainment at the intake structures is necessary in order for the project to be consistent with the fisheries management enforceable policy of the CZM Program (see **Federal Consistency Conditional Concurrence**, page 3).

6. Subaqueous Lands Management. According to the FCC (page 7), Dominion holds a permit from VMRC (#2016-0710) for encroachment in, on, or over state-owned subaqueous lands to allow for the dredging of the cooling water intake channel. The permit includes a limit of 150,000 cubic yards of sediment removal. The channel is dredged every three to four years. During the subsequent license renewal period, Dominion will continue to obtain the required subaqueous lands permit from VMRC.

6(a) Agency Jurisdiction. The management program for subaqueous lands establishes conditions for granting or denying permits to use state-owned bottomlands based on considerations of potential effects on marine and fisheries resources, tidal wetlands, adjacent or nearby properties, anticipated public and private benefits, and water quality standards established by the Department of Environmental Quality. The program is administered by the Virginia Marine Resources Commission (Virginia Code §28.2-1200 to §28.2-1213).

6(b) Agency Findings. The VMRC did not comment on the FCC documentation. However, a report (attached) was obtained from VMRC's Habitat Management Permits and Applications webpage that indicated that VMRC reviewed application #20160710 and issued a VMRC subaqueous permit for the maintenance dredging of the SPS intake channel effective until July 26, 2021.

6(c) Conclusion. As designed, the project is consistent with the subaqueous lands management enforceable policy of the Virginia CZM Program.

7. Point Source Pollution Control. According to the FCC (page 10), the facility holds a VPDES permit VA0004090 for its process water and industrial stormwater discharges. The permit administers compliance with the Clean Water Act 316(a) and (b) requirements which address water intake and thermal discharges. Dominion will obtain a General VPDES Permit for Discharges of Stormwater Associated with Industrial Activity (VAR05) permit for the DMMA.

7(a) Agency Jurisdiction. The point source program is administered by the State Water Control Board pursuant to Virginia Code §62.1-44.15. Point source pollution control is accomplished through the implementation of the National Pollutant Discharge Elimination System (NPDES) permit program established pursuant to §402 of the federal Clean Water Act and administered in Virginia as the VPDES permit program. The Water Quality

Certification requirements of §401 of the Clean Water Act of 1972 is administered under the Virginia Water Protection Permit program.

7(b) Agency Findings. PRO confirmed that Surry Power Station has two VPDES permits: a construction stormwater general permit number VAR106343 and the individual industrial VPDES permit number VA0004090.

7(c) Agency Requirement. Contact the VPDES Permit Manager (Emilee Adamson, 804-527-5072) to obtain a permit modification if changes to the outfalls are necessary.

7(d) Conclusion. As designed, the project is consistent with the point source pollution control enforceable policy of the Virginia CZM Program.

ADDITIONAL ENVIRONMENTAL CONSIDERATIONS

In addition to the enforceable policies of the Virginia CZM Program, comments were also provided with respect to other applicable requirements and recommendations. The applicant must ensure that this project is constructed and operated in accordance with all applicable federal, state, and local laws and regulations.

1. Solid and Hazardous Waste Management.

1(a) Agency Jurisdiction. On behalf of the Virginia Waste Management Board, the DEQ Division of Land Protection and Revitalization is responsible for carrying out the mandates of the Virginia Waste Management Act (Virginia Code §10.1-1400 *et seq.*), as well as meeting Virginia's federal obligations under the Resource Conservation and Recovery Act and the Comprehensive Environmental Response Compensation Liability Act (CERCLA), commonly known as Superfund. The DEQ Division of Land Protection and Revitalization also administers those laws and regulations on behalf of the State Water Control Board governing Petroleum Storage Tanks (Virginia Code §62.1-44.34:8 *et seq.*), including Aboveground Storage Tanks (9VAC25-91 *et seq.*) and Underground Storage Tanks (9VAC25-580 et seq. and 9VAC25-580-370 *et seq.*), also known as 'Virginia Tank Regulations', and § 62.1-44.34:14 *et seq.* which covers oil spills.

Virginia:

- Virginia Waste Management Act, Virginia Code § 10.1-1400 *et seq.*
- *Virginia Solid Waste Management Regulations*, 9 VAC 20-81
  - (9 VAC 20-81-620 applies to asbestos-containing materials)
- *Virginia Hazardous Waste Management Regulations*, 9 VAC 20-60
  - (9 VAC 20-60-261 applies to lead-based paints)
- *Virginia Regulations for the Transportation of Hazardous Materials*, 9 VAC 20-110.

Federal:

- Resource Conservation and Recovery Act (RCRA), 42 U.S. Code sections 6901 *et seq.*
- U.S. Department of Transportation *Rules for Transportation of Hazardous Materials,* 49 *Code of Federal Regulations,* Part 107
- Applicable rules contained in Title 40, *Code of Federal Regulations.*

1(b) Agency Findings. DEQ's Division of Land Protection and Revitalization (DLPR) conducted a 0.5-mile radius search of solid and hazardous waste databases for waste-related sites, including petroleum releases, in the project vicinity. Five sites were identified within the project area.

Hazardous Waste/RCRA Facility:
VAD000619502, Surry Power Station, 5570 Hog Island Rd, Surry, VA 23883, Small Quantity Generator (SQG)

Petroleum Releases:

- PC#20104125, Gravel Neck Turbine Station, 5208 Hog Island Road, Surry, VA 23883. Release Date: 09/15/2009. Status: Closed.

- PC#19943824, Surry Power Plant, 5570 Hog Island Road, Surry, VA 23883. Release Date: 05/16/1994. Status: Closed.

- PC#19931478, Surry Power Plant, 5570 Hog Island Road, Surry, VA 23883. Release Date: 02/03/1993. Status: Closed.

- PC#19891209, Surry Power Plant, 5570 Hog Island Road, Surry, VA 23883. Release Date: 03/31/1989. Status: Closed.

1(c) Recommendation. DEQ encourages the implementation of pollution prevention principles, including the reduction, reuse, and recycling of all solid wastes generated. All generation of hazardous wastes should be minimized and handled appropriately.

The project engineer or manager should contact the DEQ's Piedmont Regional Office Tanks Program (805-527-5020) for further information regarding the above identified petroleum release cases. Evaluate the location, nature, extent of the petroleum releases and the potential for the releases to have an impact on the project or any future land disturbing activities at the site.

1(d) Waste Management Requirements. Any soil or groundwater that is suspected of contamination or wastes that are generated during future construction-related activities must be tested and disposed of in accordance with applicable federal, state, and local laws and regulations. All construction waste, including excess soil, must be characterized in accordance with the *Virginia Hazardous Waste Management*

Regulations prior to disposal at an appropriate facility. It is the generator's responsibility to determine if a solid waste meets the criteria of a hazardous waste and ensure it is managed appropriately.

2. Natural Heritage Resources.

2(a) Agency Jurisdiction.

2(a)(i) Natural Heritage Resources. The Virginia Department of Conservation and Recreation's (DCR) Division of Natural Heritage (DNH): DNH's mission is conserving Virginia's biodiversity through inventory, protection and stewardship. The Virginia Natural Area Preserves Act (Virginia Code §10.1-209 through 217), authorized DCR to maintain a statewide database for conservation planning and project review, protect land for the conservation of biodiversity, and the protect and ecologically manage the natural heritage resources of Virginia (the habitats of rare, threatened and endangered species, significant natural communities, geologic sites, and other natural features).

2(a)(ii) Threatened and Endangered Plant and Insect Species. The Virginia Department of Agriculture and Consumer Services (VDACS): The Endangered Plant and Insect Species Act of 1979 (Virginia Code Chapter 39 §3.1-1020 through 1030) authorizes VDACS to conserve, protect and manage endangered and threatened species of plants and insects. Under a Memorandum of Agreement established between VDACS and the DCR, DCR represents VDACS in comments regarding potential impacts on state-listed threatened and endangered plant and insect species.

2(b) Agency Findings.

2(b)(i) Natural Heritage Resources. According to the information currently in DCR-DNH's Biotics Data System (Biotics), the Atlantic sturgeon (*Acipenser oxyrinchus,* G3/S2/LE/LE) has been documented adjacent to the project site in the James River. This species is currently classified as endangered by the National Oceanic and Atmospheric Administration National Marine Fisheries Service (NOAA Fisheries) and by the DGIF. Refer to the attached memorandum dated September 13, 2017 for more details about this species.

2(b)(ii) State-listed Plant and Insect Species. DCR finds that the current activity will not affect any documented state-listed plant and insect species.

2(b)(iii) State Natural Area Preserves. There are no State Natural Area Preserves under DCR's jurisdiction in the project vicinity.

2(c) Recommendations. Due to the legal status of the Atlantic sturgeon, DCR recommends coordination with NOAA Fisheries, to ensure compliance with the Virginia Endangered Species Act (VA ST §§ 29.1-563 – 570). DCR supports studies to determine if modifications to the intake/cooling structures are necessary to reduce entrainment and impingement impacts (as mentioned in the FCC).

Contact DCR-DNH to secure updated information on natural heritage resources if the scope of the project changes and/or six months has passed before it is utilized. New and updated information is continually added to the Biotics Data System.

3. Public Water Supply.

3(a) Agency Jurisdiction. The Virginia Department of Health (VDH), Office of Drinking Water (ODW) reviews projects for the potential to impact public drinking water sources (groundwater wells and surface water intakes). VDH administers both federal and state laws governing waterworks operation.

3(b) Agency Findings. VDH-ODW found the following public groundwater wells to be located within a 1,000-foot radius of the project site:

PWS ID Number	City/County	System Name	Facility Name
3181800	SURRY	SURRY POWER STATION	WELL B INSIDE GATE
3181800	SURRY	SURRY POWER STATION	WELL E WAREHOUSE ROAD W
3181800	SURRY	SURRY POWER STATION	WELL C HIGH LEVEL ROAD EAST
3181802	SURRY	VA POWER CONSTRUCTION SITE	WELL 1

The following surface water intakes are located within a 5-mile radius of the project site:

PWS ID Number	System Name	Facility Name
3700500	NEWPORT NEWS, CITY OF	SKIFFES CREEK

The project is not within the watershed of any public surface water intakes.

3(c) Requirement. Potential impacts to public water distribution systems or sanitary sewage collection systems must be verified by the local utility.

3(d) Agency Recommendations. Utilize Best Management Practices (BMPs) including erosion and sedimentation controls and spill prevention controls and countermeasures on the site. Properly manage materials while on the site and during transport to prevent impacts to nearby surface waters. Field-mark the wells within a 1,000-foot radius from the project site to protect them from accidental damage during any future construction activities.

4. Recreational Resources.

4(a) Agency Jurisdiction. The DCR Division of Planning and Recreational Resources provides policy and direction to the public and private sectors to improve the management of recreational resources (in addition to outdoor and open spaces), and addresses issues related to scenic rivers, highways and byways.

4(b) Agency Findings. The DCR Division of Planning and Recreational Resources found that the project is within a section of the James River that has scenic river designation.

Dominion may contact Lynn Crump at 804-786-5054 or via email at Lynn.Crump@dcr.virginia.gov with any questions about this designation.

5. Historic Structures and Architectural Resources.

5(a) Agency Jurisdiction. The Virginia Department of Historic Resources (DHR) conducts reviews of both federal and state projects to determine their effect on historic properties. Under the federal process, DHR is the State Historic Preservation Office, and ensures that federal undertakings – including licenses, permits, or funding – comply with Section 106 of the National Historic Preservation Act of 1966 (NHPA), as amended, and its implementing regulation at 36 CFR Part 800. Section 106 requires federal agencies to consider the effects of federal projects on properties that are listed or eligible for listing on the National Register of Historic Places. For state projects or activities on state lands, DHR is afforded an opportunity to review and comment on (1) the demolition of state property; (2) major state projects requiring an EIR; (3) archaeological investigations on state-controlled land; (4) projects that involve a landmark listed in the Virginia Landmarks Register; (5) the sale or lease of surplus state property; (6) exploration and recovery of underwater historic properties; and (7) excavation or removal of archaeological or historic features from caves. See DHR's website for more information about applicable state and federal laws and how to submit an application for review: http://www.dhr.virginia.gov/StateStewardship/Index.htm.

5(b) Agency Finding. DHR has been in direct consultation with the NRC regarding this project.

5(c) Requirement. The NRC should continue to coordinate directly with DHR, as necessary, pursuant to Section 106 of the National Historic Preservation Act (as amended) and its implementing regulations codified at 36 CFR Part 800 which require Federal agencies to consider the effects of their undertakings on historic properties.

6. Wildlife Resources and Protected Species.

6(a) Agency Jurisdiction. DGIF, as the Commonwealth's wildlife and freshwater fish management agency, exercises enforcement and regulatory jurisdiction over wildlife and freshwater fish, including state- or federally-listed endangered or threatened species, but excluding listed insects (*Virginia Code* Title 29.1). DGIF is a consulting agency under the U.S. Fish and Wildlife Coordination Act (16 U.S.C. sections 661 *et seq.*) and provides environmental analysis of projects or permit applications coordinated through DEQ and several other state and federal agencies. DGIF determines likely impacts upon fish and wildlife resources and habitat, and recommends appropriate measures to avoid, reduce or compensate for those impacts. For more information, see the DGIF website at www.dgif.virginia.gov.

6(b) Agency Findings. DGIF documents the state-listed endangered peregrine falcon from the project area. At this time the DGIF does not believe that the project is likely to result in adverse impacts upon peregrine falcons. DGIF documents bald eagle nests, roosts, and the James River Bald Eagle Concentration Zone from the project area. Significant habitat alteration, location of water-dependent facilities within concentration zones and/or near nests, or other recreational and commercial activities may result in adverse impacts upon eagles. Colonial waterbird colonies are documented from the project area.

6(c) Recommendations.

- Note that the peregrine falcon is a species that may be encountered on the SPS site and understand that future site development could impact this species.
- Ensure that this project is consistent with state and federal guidelines for the protection of bald eagles. Coordinate as appropriate with the U.S. Fish and Wildlife Service (FWS) regarding possible impacts upon bald eagles or the need for a federal bald eagle incidental take permit.
- To protect colonial waterbird colonies documented from the project area and associated with upland development at SPS, DGIF recommends that any colonies located on site be mapped and that an undisturbed, naturally vegetated buffer of 500-feet be maintained around each colony. Any significant construction activities within 0.25-mile of any colony should adhere to a time-of-year restriction from February 15 through June 15 of any year.

7. Local and Regional Participation. In accordance with CFR 930, Subpart A, § 930.6(b) of the *Federal Consistency Regulations*, DEQ, on behalf of the state, is responsible for securing necessary review and comment from other state agencies, the public, regional government agencies, and local government agencies, in determining the Commonwealth's concurrence or objection to a federal consistency certification.

7(a) Regional Comments. The Crater Planning District Commission reviewed the FCC and found it to be in accordance with the PDC's environmental policy directives.

8. Pesticides and Herbicides. Should construction or maintenance require the use of pesticides or herbicides for landscape maintenance, these chemicals should be in accordance with the principles of integrated pest management. The least toxic pesticides that are effective in controlling the target species should be used. Contact the Department of Agriculture and Consumer Services at (804) 786-3501 for more information.

9. Pollution Prevention. DEQ advocates that principles of pollution prevention and sustainability be used in all construction projects as well as in facility operations. Effective siting, planning, and on-site Best Management Practices (BMPs) will help to ensure that environmental impacts are minimized. However, pollution prevention and sustainability techniques also include decisions related to construction materials, design, and operational procedures that will facilitate the reduction of wastes at the source.

9(a) Recommendations. We have several pollution prevention recommendations that may be helpful in operating this facility:

- Consider development of an effective Environmental Management System (EMS). An effective EMS will ensure that the proposed facility is committed to complying with environmental regulations, reducing risk, minimizing environmental impacts, setting environmental goals, and achieving improvements in its environmental performance. DEQ offers EMS development assistance and recognizes facilities with effective Environmental Management Systems through its Virginia Environmental Excellence Program (VEEP). VEEP provides recognition, annual permit fee discounts, and the possibility for alternative compliance methods.
- Consider contractors' commitment to the environment when choosing contractors. Specifications regarding raw materials and construction practices can be included in contract documents and requests for proposals.

DEQ's Office of Pollution Prevention provides information and technical assistance relating to pollution prevention techniques and EMS. If interested, please contact Meghann Quinn, (804) 698-4021.

REGULATORY AND COORDINATION NEEDS

1. Nonpoint Source Pollution Control. Contact the DEQ Office of Stormwater Management (Hannah Zegler, 804-698-4206) with questions regarding nonpoint source pollution control as it relates to any future land disturbing activities on the site.

2. Air Pollution Control. For more information related to air pollution control requirements, contact DEQ PRO (804-527-5020). Contact the Air Permit Manager (James Kyle, 804-527-5047) to discuss a Title V permit modification, as necessary, to accommodate any future system changes.

3. Solid and Hazardous Wastes. All solid waste, hazardous waste, and hazardous materials must be managed in accordance with all applicable federal, state, and local environmental regulations. Contact DEQ PRO (804-527-5020) for information on the location and availability of suitable waste management facilities in the project area or if free product, discolored soils, or other evidence of contaminated soils are encountered during future land-disturbing activities on the site.

4. Natural Heritage Resources. Contact DCR-DNH, Rene Hypes at (804) 371-2708, to secure updated information on natural heritage resources if the scope of the project changes and/or six months passes before the project is implemented, since new and updated information is continually added to the Biotics Data System.

5. Potable and Sanitary Water Collection Systems. Potential impacts to public water distribution systems or sanitary sewage collection systems must be verified by the local utility. Contact the VDH- Office of Drinking Water with questions (804-864-7201).

6. Coastal Lands Management. Any future construction at the ISFSI site must be conducted in a manner that is consistent with the coastal lands management enforceable policy of the CZM Program as administered by DEQ pursuant to the Chesapeake Bay Preservation Act (Virginia Code 62.1-44.15 *et seq.*) and the Chesapeake Bay Preservation Area Designation and Management Regulations (9VAC25-830 *et. seq.*). For additional information contact Daniel Moore (804-698-4520).

7. Historic Resources. The NRC should continue to coordinate directly with DHR (Roger Kirchen, 804-482-6091) pursuant to Section 106 of the National Historic Preservation Act (as amended) and its implementing regulations codified at 36 CFR Part 800 which require Federal agencies to consider the effects of their undertakings on historic properties.

8. Fisheries Management. Coordinate with DGIF (Amy Ewing, 804-367-2211) regarding its recommendation to retrofit the James River cooling water intake with best technology available (BTA) in order to protect the federally-listed endangered Atlantic sturgeon and other aquatic organisms.

Include DGIF and NOAA Fisheries Service (804-684-7382) in discussions with the NRC and FWS regarding the potential impacts of this project on the Atlantic sturgeon. Continue to coordinate with DGIF until a determination on the likely impacts of relicensing and continued operations of the facility can be made.

9. Wildlife and Protected Species. Coordinate as appropriate with the U.S. FWS (Troy Andersen, troy_andersen@fws.gov) regarding possible impacts upon bald eagles or the need for a federal bald eagle incidental take permit. Contact DGIF, Amy Ewing at (804) 367-2211, with questions regarding its recommendations.

10. Point Source Pollution Control. Contact the VPDES Permit Manager (Emilee Adamson, 804-527-5072) if changes (additional outfalls) to the facility's existing VPDES permits become necessary.

Thank you for the opportunity to comment on the FCC submitted for the VEPCO Surry Power Station Units 1 and 2 Subsequent License Renewal project located in Surry County. Detailed comments of reviewing agencies are attached for your review. Please contact me at (804) 698-4204 or Janine Howard at (804) 698-4299 for clarification of these comments.

Sincerely,

Bettina Rayfield, Program Manager
Environmental Impact Review

Ec: Robbie Rhur, DCR
Amy Ewing, DGIF
Susan Douglas, VDH
Roger Kirchen, DHR
Emily Hein, VIMS
Tony Watkinson, VMRC
Ben McFarlane, HRPDC
Dennis Morris, Crater PDC
Tyrone Franklin, Surry County
Pamela Faggert, Dominion
Oula Shehab-Dandan, Dominion
Tony Banks, Dominion
Tam Tran, NRC

Howard, Janine (DEQ)

From: Ewing, Amy (DGIF)
Sent: Friday, October 06, 2017 4:59 PM
To: Howard, Janine (DEQ)
Cc: Fernald, Ray (DGIF); Oula K Shehab-Dandan; Greenlee, Bob (DGIF); Smith, Scott (DGIF)
Subject: ESSLog# 38468_14-121F_SurryPowerStationRelicensing_DGIF_AME20171006

Janine,

We have reviewed the consistency determination for the subject project, relicensing of Surry Power Station (SPS) Units 1 and 2, located at Surry Power Station in Surry County, adjacent to our Hog Island Wildlife Management Area. We note that the applicant, Dominion Energy, has reached out to us for information about wildlife resources under our jurisdiction that are known from the project area, and that we have therefore copied them on this response to you.

Since SPS was licensed and began operation, Atlantic sturgeon, in addition to other wildlife native to VA, have been federally listed as an Endangered Species. Therefore, the James River has been designated a Threatened and Endangered Species Water due to presence of Atlantic sturgeon. These fish are known from the river year-round, and to engage in both spring and fall migration and spawning in this reach of the river. These fish also are known to congregate in the James River from Hog Island downstream. In addition, this stretch of the James River, and Lawnes Creek, have been designated Anadromous Fish Use Areas because of the presence of alewife herring, blueback herring, American shad, striped bass, yellow perch, and hickory shad. The applicant states in their consistency determination that with relicensing and continued operation of SPS, "aquatic organisms would continue to be impinged and entrained at the intake structure, but these impacts were determined to be SMALL." To protect resident aquatic species including federally Endangered Atlantic sturgeon and other anadromous fishes from impingement and entrainment, we recommend that the applicant consider redesign/retrofitting of the cooling water intake on the James River to take advantage of currently best technology available (BTA). In addition, we are concerned about potential impacts of cooling water discharge upon Atlantic sturgeon. Furthermore, we understand that it is necessary for the applicant to periodically dredge the canal that diverts water from the James River to the cooling water intake, which activity also may impact sturgeon. We note that NRC may engage in consultation with the U.S. Fish and Wildlife Service to address potential impacts of this project on Atlantic sturgeon, and that USFWS has expressed interest in our input to that process. We gladly would participate in such discussions, and believe such consultation may offer the best path toward determination of appropriate measures, if any, that are needed to ensure continued protection of Atlantic sturgeon and other resident aquatic species. Such measures could include intake screen mesh or design, intake velocity restrictions, or time-of-year restrictions on certain dredging or instream construction activities. Though we would anticipate mutual agreement among the agencies regarding any measures that may be appropriate, until such issues are resolved, we cannot determine the likely impacts of relicensing and continued operations on these fishery resources, so we are unable to concur with the applicant's determination of consistency with the Fisheries Enforceable Policy of the CZMA. We also recommend that NOAA Fisheries Service be included in these discussions, as a cognizant federal agency.

Regarding other fish and wildlife resources under our jurisdiction, we offer the following additional comments:

(1) We recommend coordination with the USFWS regarding potential impacts upon federally Threatened northern long-eared bats associated with any tree removal associated with upland development on site.

(2) We document state Endangered peregrine falcons from the project area. Based on the information we currently have, we do not believe this project is likely to result in adverse impacts upon peregrine falcons. However, we recommend the applicant consider this species as one that may be encountered onsite, especially as they could be impacted by future site development.

(3) We document bald eagle nests, roosts, and the James River Bald Eagle Concentration Zone from the project area. Significant habitat alteration, location of water-dependent facilities within concentration zones and/or near nests, or other recreational and commercial activities may result in adverse impacts upon eagles. Therefore, we recommend that the applicant ensure that this project is consistent with state and federal guidelines for protection of bald eagles; and that they coordinate as appropriate with the U.S. Fish and Wildlife Service regarding possible impacts upon bald eagles or the need for a federal bald eagle incidental take permit.

(4) We document colonial waterbird colonies from the project area. To best protect these resource associated with upland development at SPS, we recommend that any colonies located on site be mapped and that an

undisturbed, naturally vegetated buffer of 500ft be maintained around each colony. We recommend that any significant construction activities within 0.25 mile of any colony adhere to a time-of-year restriction from February 15 through June 15 of any year.

(5) This project is located within 2 miles of a documented occurrence of a state or federal threatened or endangered plant or insect species and/or other Natural Heritage coordination species. Therefore, we recommend coordination with VDCR-DNH regarding the protection of these resources.

Thank you for this opportunity to review this project; we look forward to resolving these issues through consultation with the appropriate federal and state agencies, as is indicated in the applicant's request for our input, so that we can then concur with the determination of federal consistency.

Amy

Amy M. Ewing

Environmental Services Biologist/FWIS Program Manager

Chair, Team WILD (Work, Innovate, Lead and Develop)

804-367-2211 www.dgif.virginia.gov

"That land is a community is the basic concept of ecology, but that land is to be loved and respected is an extension of ethics" **Aldo Leopold, 1948**

DEPARTMENT OF
GAME & INLAND FISHERIES
CONSERVE. CONNECT. PROTECT.

DEPARTMENT OF ENVIRONMENTAL QUALITY
DIVISION OF AIR PROGRAM COORDINATION

ENVIRONMENTAL REVIEW COMMENTS APPLICABLE TO AIR QUALITY

TO: Janine L. Howard **DEQ - OEIA PROJECT NUMBER: DEQ #17-121F**

PROJECT TYPE: ☐ STATE EA / EIR **X FEDERAL EA / EIS** ☐ SCC

X CONSISTENCY CERTIFICATION

PROJECT TITLE: VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal

PROJECT SPONSOR: U.S. Nuclear Regulatory Commission

PROJECT LOCATION: X OZONE ATTAINMENT/ AREA

REGULATORY REQUIREMENTSMAY BE APPLICABLE TO: X LICENCE RENEWAL
☐ OPERATION

STATE AIR POLLUTION CONTROL BOARD REGULATIONS THAT MAY APPLY:

1. ☐ 9 VAC 5-40-5200 C & 9 VAC 5-40-5220 E – STAGE I
2. ☐ 9 VAC 5-45-760 et seq. – Asphalt Paving operations
3. ☐ 9 VAC 5-130 et seq. – Open Burning
4. ☐ 9 VAC 5-50-60 et seq. Fugitive Dust Emissions
5. ☐ 9 VAC 5-50-130 et seq. - Odorous Emissions; Applicable to________________
6. ☐ 9 VAC 5-60-300 et seq. – Standards of Performance for Toxic Pollutants
7. ☐ 9 VAC 5-50-400 Subpart_____, Standards of Performance for New Stationary Sources, designates standards of performance for the________________________
8. ☐ 9 VAC 5-80-1100 et seq. of the regulations – Permits for Stationary Sources
9. ☐ 9 VAC 5-80-1605 et seq. Of the regulations – Major or Modified Sources located in PSD areas. This rule may be applicable to the ________________________
10. ☐ 9 VAC 5-80-2000 et seq. of the regulations – New and modified sources located in non-attainment areas
11. ☐ 9 VAC 5-80-800 et seq. Of the regulations – State Operating Permits. This rule may be applicable to ______________________________________

COMMENTS SPECIFIC TO THE PROJECT: None.

K. S. Narasimhan

(Kotur S. Narasimhan)
Office of Air Data Analysis

DATE: September 20, 2017

COMMONWEALTH of VIRGINIA

DEPARTMENT OF ENVIRONMENTAL QUALITY
Street address: 629 East Main Street, Richmond, Virginia 23219
Mailing address: P.O. Box 1105, Richmond, Virginia 23218
Fax: 804-698-4019 - TDD (804) 698-4021
www.deq.virginia.gov

Molly Joseph Ward
Secretary of Natural Resources

David K. Paylor
Director

(804) 698-4020
1-800-592-5482

MEMORANDUM

TO: Janine Howard, DEQ Office of Environmental Impact Review

FROM: Heather Mackey, DEQ Principal Environmental Planner

DATE: September 11, 2017

SUBJECT: DEQ #17-121F: USNRC VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal – Surry County

We have reviewed the Federal Consistency Determination submittal for the proposed project and offer the following comments regarding consistency with the provisions of the *Chesapeake Bay Preservation Area Designation and Management Regulations* (Regulations):

In Surry County, the areas protected by the *Chesapeake Bay Preservation Act* (CBPA), as locally implemented, require conformance with performance criteria. These areas include Resource Protection Areas (RPAs) and Resource Management Areas (RMAs) as designated by the local government. RPAs include tidal wetlands, certain non-tidal wetlands and tidal shores. RPAs also include a 100-foot vegetated buffer area located adjacent to and landward of these features and along both sides of any water body with perennial flow. RMAs, which require less stringent performance criteria than RPAs, consist of all remaining areas within Surry County that are located within the James River Watershed.

The proposed project would extend the Nuclear Regulatory Commission (NRC) operating license expiration date for Surry Power Station (SPS) Unit 1 from May 25, 2032 to May 25, 2052, and for SPS Unit 2 from January 29, 2033 to January 29, 2053. The proposed license renewal does not include additional construction outside of the SPS site; however, during the period of extended operations space may be required for storage of spent fuel, which would entail construction of an additional concrete pad at the existing Independent Spent Fuel Storage Installation (ISFSI). The ISFSI is co-located on the SPS site and is also operated by Dominion Energy Virginia under a general license pursuant to NRC regulations. While the consistency determination is for an extension of the operations of the nuclear units only, the ISFSI is considered in the cumulative impacts of the Environmental Report supporting the SPS license renewal application.

Although no RPA impacts are anticipated from the potential construction of an additional concrete pad, the ISFSI site is located within the County's designated Resource Management Area. As such, the project must be consistent with the general performance criteria provisions of §9VAC25-830-130 of the Regulations. This would include disturbing no more land than necessary to provide for the proposed use, minimizing impervious cover, and preserving indigenous vegetation to the maximum extent practicable consistent with the proposed use. In addition, all land disturbing activity exceeding 2,500 square feet must comply with the requirements of the *Virginia Erosion and Sediment Control Handbook*, Third Edition, 1992. Finally, stormwater management criteria consistent with the water quality protection provisions of the *Virginia Stormwater Management Regulations*, §9VAC25-870-51 and 9 VAC25-870-103, shall be satisfied. These provisions require that localities subject to the Chesapeake Bay Preservation Act implement specified technical and administrative criteria from the VSMP regulations for Chesapeake Bay Preservation Act land-disturbing activities. Such activities include land disturbance equal to or greater than 2,500 square feet of land disturbance and less than one acre in designated Chesapeake Bay Preservation Areas.

Provided the above conditions are met, the proposed activity would be consistent with the Regulations and the *Chesapeake Bay Preservation Act.*

Howard, Janine (DEQ)

From: Zegler, Hannah (DEQ)
Sent: Wednesday, November 01, 2017 11:48 AM
To: Howard, Janine (DEQ)
Subject: RE: Dominion AS&S question

AS&S don't cover power plants so this would go to the locality... your comment below are appropriate.

From: Howard, Janine (DEQ)
Sent: Wednesday, November 1, 2017 11:43 AM
To: Zegler, Hannah (DEQ) <Hannah.Zegler@deq.virginia.gov>
Subject: RE: Dominion AS&S question

Hi Hannah,

This project isn't related to construction or rebuild of a utility line. It has to do with renewal of the Nuclear Regulatory Commission (NRC) operating license for the Surry Power Plant. So, modifications to structures at the Surry facility are not proposed, however there is a possibility that during the course of the renewed license term (which would be in effect until 2053) some land-disturbing activities on the power plant site itself may occur (for instance, an addition or renovation to a structure may become necessary). I'm wondering if the below language that requires ESC and SWM plans to be sent to the locality is correct for this scenario or whether the annual standards and specs language is more appropriate.

1(c)(i) Erosion and Sediment Control. If future maintenance activities on the site involve a land-disturbing activity of equal to or greater than 2,500 square feet in a Chesapeake Bay Preservation Area, the applicant is responsible for submitting a project-specific erosion and sediment control (ESC) plan to the locality for review and approval pursuant to the local ESC requirements. Depending on local requirements, the area of land disturbance requiring an ESC plan may be less. The ESC plan must be approved by the locality prior to any land-disturbing activity at the project site. All regulated land-disturbing activities associated with the project, including on and off site access roads, staging areas, borrow areas, stockpiles and soil intentionally transported from the project, must be covered by the project-specific ESC plan. Local ESC program requirements must be requested through the locality.

1(c)(ii) Stormwater Management Plan. Dependent on local requirements, a stormwater management (SWM) plan may be required. Local SWM program requirements must be requested through the locality.

Thanks!

From: Zegler, Hannah (DEQ)
Sent: Wednesday, November 01, 2017 10:38 AM
To: Howard, Janine (DEQ)
Subject: RE: Dominion AS&S question

Hey Janine,

Determining what is considered 'routine maintenance' on utility line projects has been an ongoing process for us... our definition is as follows:

7. Routine maintenance that is performed to maintain the original line and grade, hydraulic capacity, or original construction of the project. The paving of an existing road with a compacted or impervious surface and reestablishment of existing associated ditches and shoulders shall be deemed routine maintenance if

performed in accordance with this subsection;

Regardless, this exemption is only in the SWM regulations. Routine maintenance projects are not exempt from ESC requirements.

Hannah

From: Howard, Janine (DEQ)
Sent: Wednesday, November 1, 2017 10:25 AM
To: Zegler, Hannah (DEQ) <Hannah.Zegler@deq.virginia.gov>
Subject: Dominion AS&S question

Hi Hannah,

I'm working on project at the Surry Nuclear Power Station and want to make sure I get the ESC language correct. Would routine maintenance, renovation or infrastructure projects requiring ground disturbance at the site be covered by Dominion's AS&S?

Thanks,

Janine

Janine Howard
Environmental Impact Review Coordinator

Office of Environmental Impact Review
Division of Environmental Enhancement
Virginia Department of Environmental Quality
629 E. Main Street
Richmond, VA 23219

t: (804) 698-4299
f: (804) 698-4032

For program updates and public notices please subscribe to the OEIR News Feed

Howard, Janine (DEQ)

From: Emily A. Hein <eahein@vims.edu>
Sent: Monday, September 18, 2017 4:10 PM
To: Howard, Janine (DEQ)
Subject: RE: NEW PROJECT NRC SURRY POWER STATION 17-121F

Good afternoon,

VIMS has no comment on this project, thank you for double-checking.

Best,

Emily

Emily Hein
Assistant to the Associate Dean
Office of Research & Advisory Services
eahein@vims.edu, 804-684-7482
VIMS | William & Mary
Virginia Institute of Marine Science

From: Howard, Janine (DEQ) [mailto:Janine.Howard@deq.virginia.gov]
Sent: Monday, September 18, 2017 1:40 PM
To: Narasimhan, Kotur (DEQ) <Kotur.Narasimhan@deq.virginia.gov>; Emily A. Hein <eahein@vims.edu>; Watkinson, Tony (MRC) <Tony.Watkinson@mrc.virginia.gov>; Ben McFarlane <bmcfarlane@hrpdcva.gov>
Subject: RE: NEW PROJECT NRC SURRY POWER STATION 17-121F

Good Afternoon,

If you have comments on this project please submit them ASAP.

Thank you,

Janine Howard
Environmental Impact Review Coordinator

Office of Environmental Impact Review
Division of Environmental Enhancement
Virginia Department of Environmental Quality
629 E. Main Street
Richmond, VA 23219

t: (804) 698-4299
f: (804) 698-4032

For program updates and public notices please subscribe to the OEIR News Feed

From: Fulcher, Valerie (DEQ)
Sent: Wednesday, August 16, 2017 10:28 AM

Virginia Marine Resources Commission
Permit Application 20160710

Printed: Tuesday September 19, 2017 4:22 PM

Applicant: Virginia Power and Electric Company
5000 Dominion Boulevard
Glen Allen, VA 23060

Application Number:	20160710	**Engineer:**	Mark Eversole
Application Date:	May 3, 2016	**Locality:**	Surry
Permit Type:	VMRC Subaqueous	**Waterway:**	James River
Permit Status:	Issued	**Expiration Date:**	July 26, 2021
Wetlands Board Action:		**Public Hearing Date:**	

Project Description: Maintenance Dredge (Surry Power Station Intake Cha

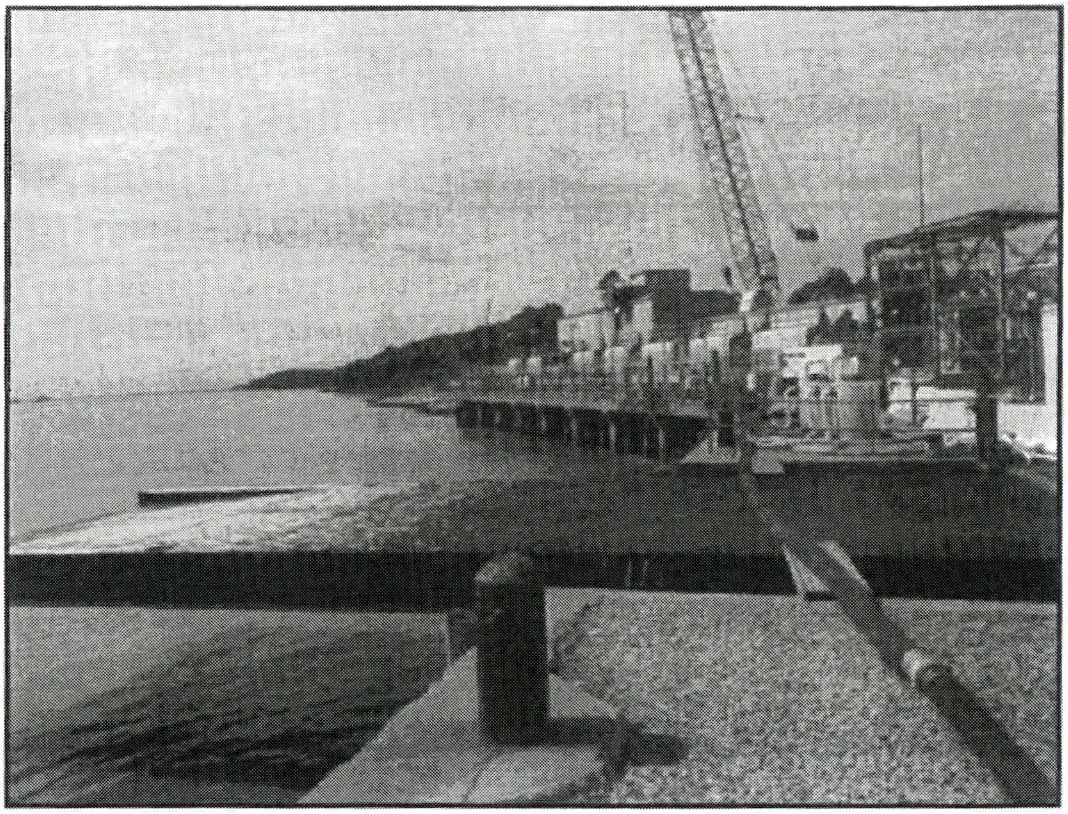
Project Dimensions:

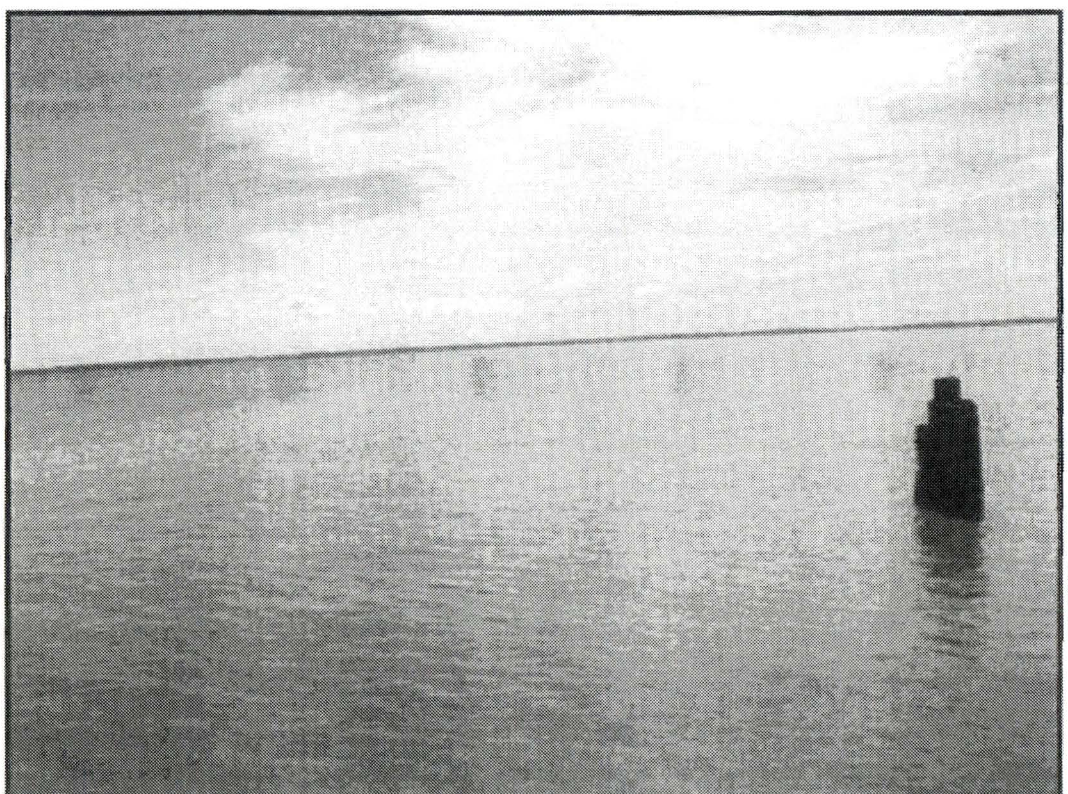
Dredging Maintenance: 150000 Cubic Yards

Virginia Marine Resources Commission

Photos for Permit Application 20160710

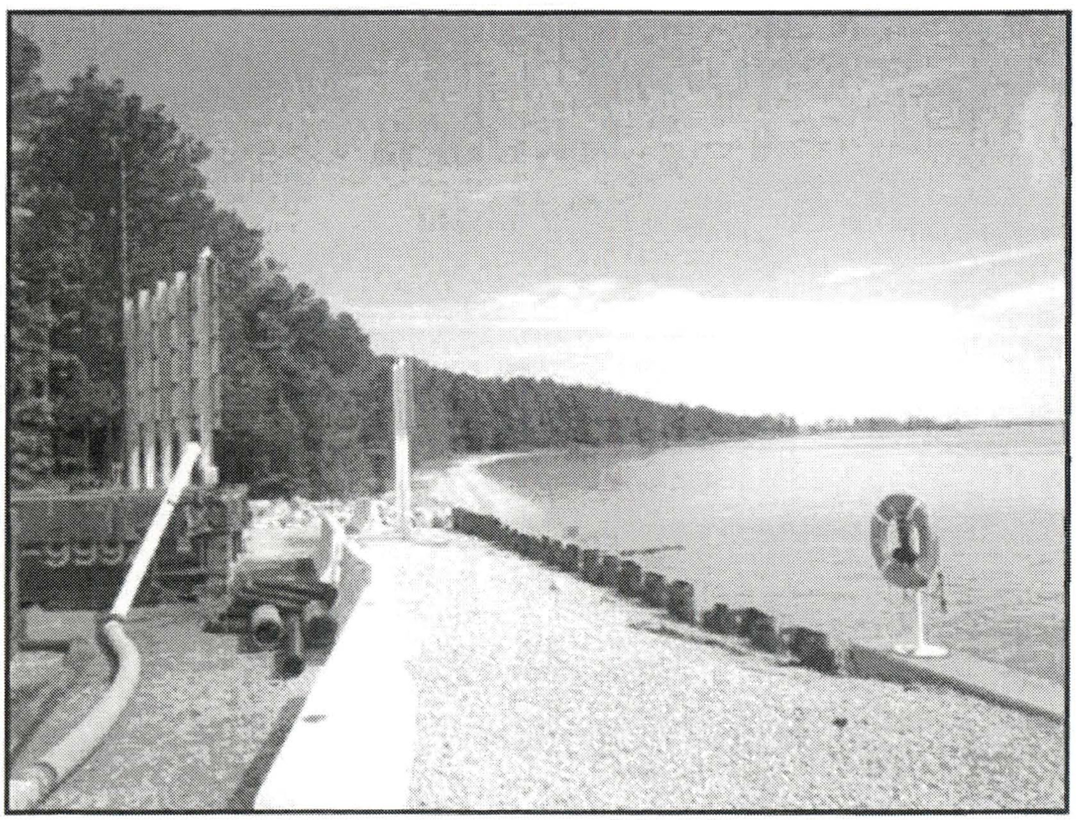
Printed: Tuesday September 19, 2017 4:22 PM





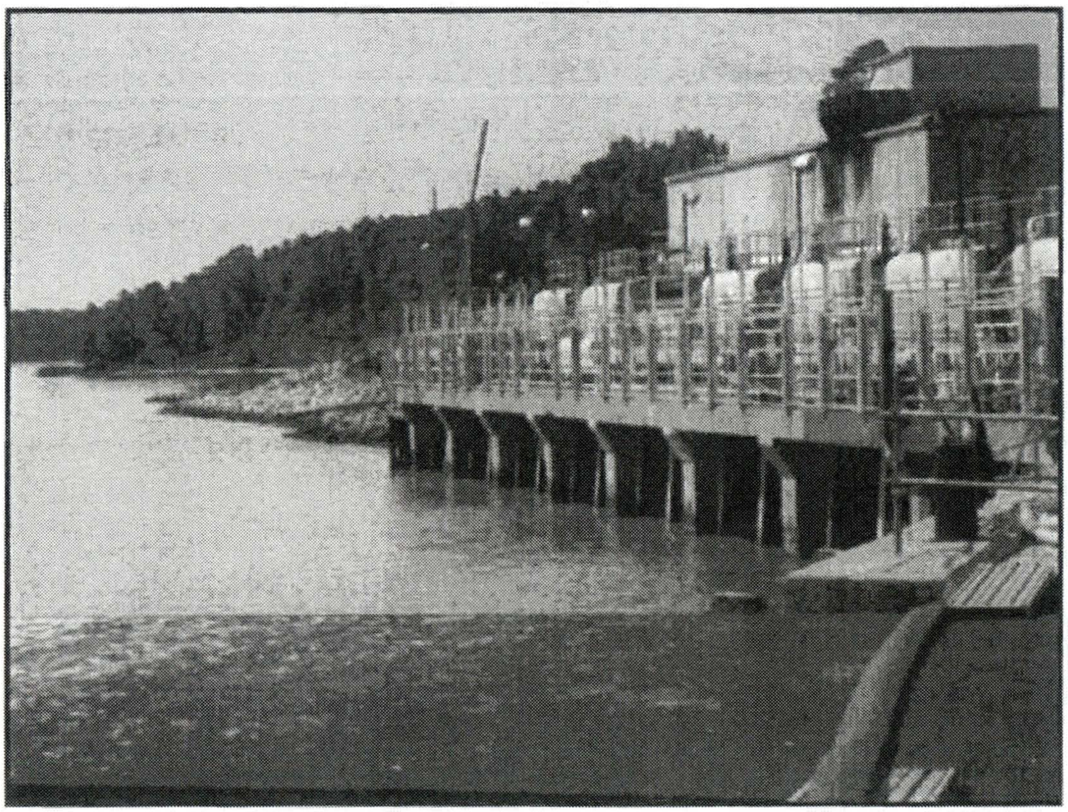
Virginia Marine Resources Commission
Photos for Permit Application 20160710

Printed: Tuesday September 19, 2017 4:22 PM



Virginia Marine Resources Commission
Photos for Permit Application 20160710

Printed: Tuesday September 19, 2017 4:22 PM



VIRGINIA DEPARTMENT OF
ENVIRONMENTAL QUALITY

MEMORANDUM

TO: Janine Howard, DEQ/EIR Environmental Program Planner

FROM: Katy Dacey, Division of Land Protection & Revitalization Review Coordinator

DATE: August 18, 2017

COPIES: Sanjay Thirunagari, Division of Land Protection & Revitalization Review Manager; file

SUBJECT: Environmental Impact Review: EIR Project No 17-121F VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal, Surry County VA

The Division of Land Protection & Revitalization (DLPR) has completed its review of the August 3, 2017 EIR for the VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal project located at 5570 Hog Island Road in Surry, Virginia 23883

Project Scope: renewal for operating licenses for Surry Power Station Unit 1 & 2 for additional 20 years

Solid and hazardous waste issues were not addressed in the submittal. The submittal did not indicate that a search of Federal or State environmental databases was conducted. DLPR staff conducted a search (0.5-mile radius) of solid and hazardous waste databases (including petroleum releases) to identify waste sites in close proximity to the project area. DLPR search did identify five sites that are the project area. Additionally, no waste sites of possible concern were located within the zip code of the project area, 23883. DLPR staff has reviewed the submittal and offers the following comments:

***Hazardous Waste/RCRA Facilities* - one is the project area**

VAD000619502, Surry Power Station, 5570 Hog Island Rd, Surry, VA 23883, Small Quantity Generator (SQG)

***CERCLA Sites* –none in the same zip code of the project area**

The above information related to hazardous wastes, RCRA/CERCLA sites can be accessed from EPA's websites at https://www3.epa.gov/enviro/, https://rcrainfopreprod.epa.gov/rcrainfoweb/action/main-menu/view and https://www.epa.gov/superfund

***Formerly Used Defense Sites (FUDS)* – none in close proximity to project area**

***Solid Waste* – none in close proximity to project area**

***Virginia Remediation Program (VRP)* – none in close proximity to project area**

***Petroleum Releases* - four are the project area**

PC#20104125, Gravel Neck Turbine Station, 5208 Hog Island Road, Surry, VA 23883. Release Date: 09/15/2009. Status: Closed.

PC#19943824, Surry Power Plant, 5570 Hog Island Road, Surry, VA 23883. Release Date: 05/16/1994. Status: Closed.

PC#19931478, Surry Power Plant, 5570 Hog Island Road, Surry, VA 23883. Release Date: 02/03/1993. Status: Closed.

PC#19891209, Surry Power Plant, 5570 Hog Island Road, Surry, VA 23883. Release Date: 03/31/1989. Status: Closed.

Please note that the DEQ's Pollution Complaint (PC) cases identified should be further evaluated by the project engineer or manager to establish the exact location, nature and extent of the petroleum release and the potential to impact the proposed project. Also, the project engineer or manager should contact the DEQ's Tidewater Regional Office at (757) 518-2175 (Tanks Program) for further information about the PC cases.

PROJECT SPECIFIC COMMENTS

None

GENERAL COMMENTS

Soil, Sediment, Groundwater, and Waste Management

Any soil, sediment or groundwater that is suspected of contamination or wastes that are generated must be tested and disposed of in accordance with applicable Federal, State, and local laws and regulations. Some of the applicable state laws and regulations are: Virginia Waste Management Act, Code of Virginia Section 10.1-1400 *et seq.*; Virginia Hazardous Waste Management Regulations (VHWMR) (9VAC 20-60); Virginia Solid Waste Management Regulations (VSWMR) (9VAC 20-81); Virginia Regulations for the Transportation of Hazardous Materials (9VAC 20-110). Some of the applicable Federal laws and regulations are: the Resource Conservation and Recovery Act (RCRA), 42 U.S.C. Section 6901 *et seq.*, and the applicable regulations contained in Title 40 of the Code of Federal Regulations; and the U.S. Department of Transportation Rules for Transportation of Hazardous Materials, 49 CFR Part 107.

Pollution Prevention – Reuse - Recycling

Please note that DEQ encourages all construction projects and facilities to implement pollution prevention principles, including the reduction, reuse, and recycling of all solid wastes generated. All generation of hazardous wastes should be minimized and handled appropriately.

If you have any questions or need further information, please contact Katy Dacey at (804) 698-4274.

MEMORANDUM
DEPARTMENT OF ENVIRONMENTAL QUALITY
Piedmont Regional Office

4949-A Cox Road **Glen Allen, VA 23060** **804/527-5020**

TO: Janine Howard
Environmental Program Planner

FROM: Kelley West
Environmental Planner

DATE: September 14, 2017

SUBJECT: VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal (17-121F).

I have reviewed the Federal Consistency Certification for the above referenced project by which Dominion Energy Virginia is applying to the NRC for the renewal of the operating licenses for the two nuclear generating units of Surry Power Station for an additional 20 years. Surry Power Station is located in Surry, Virginia. My comments are as follows:

Water- Erosion and Sediment Control and Storm Water Management: During the new license term DEQ has regulatory authority for the Virginia Pollutant Discharge Elimination System (VPDES) programs related to municipal separate storm sewer systems (MS4s) and construction activities. Erosion and sediment control measures are addressed in local ordinances and State regulations. Additional information is available at http://www.deq.virginia.gov/Programs/Water/StormwaterManagement.aspx. Non-point source pollution resulting from any projects should be minimized by using effective erosion and sediment control practices and structures. Consideration should also be given to using permeable paving for parking areas and walkways where appropriate and denuded areas should be promptly revegetated following construction work. If the total land disturbance exceeds 10,000 square feet, an erosion and sediment control plan will be required. Some localities also require an E&S plan for disturbances less than 10,000 square feet. A stormwater management plan may also be required. For any land disturbing activities equal to one acre or more, you are required to apply for coverage under the VPDES General Permit for Discharges of Storm Water from Construction Activities. The Virginia Stormwater Management Permit Authority may be DEQ or the locality. Specific questions regarding the Stormwater Management Program requirements should be directed to John McCutcheon at DEQ-PRO 804-527-5117.

Currently Surry Power Station has two VPDES permits through DEQ, the permit numbers are VAR106343(stormwater general permit) and VA0004090 (VPDES industrial individual permit). If there are any intended changes to the systems a permit modification may be required, please contact Emilee Adamson at (804) 527-5072.

Water-Wetlands: During the new license term if any impacts occur to streams or wetland features a Virginia Water Protection (VWP) permit may be needed. DEQ-PRO recommends that all construction activities avoid wetlands and streams to the maximum extent possible. For any questions or additional information concerning VWP Permit requirements, please contact Allison Dunaway at (804) 527-5086.

Air: Dominion Energy has a Title V permit (PRO50336) DEQ-PRO recommends all actions shall operate in a manner consistent with air pollution control practices for minimizing emissions, especially during periods of high ozone. Fugitive dust should be kept to a minimum, (9 VAC5-50-60). If there are any intended changes to the systems a permit modification may be required, please contact James Kyle at (804) 527-5047.

Waste: The generation or recovery of any hazardous waste materials should be tested and removed in accordance with the Virginia Hazardous Waste Management Regulations (9 VAC 20-60) and/or the Virginia Solid Waste Management Regulations (9 VAC 20-81). Please understand that it is the generator's responsibility to determine if a solid waste meets the criteria of a hazardous waste and as a result be managed as such. In addition, asbestos waste, lead waste, or contaminated residues generated must be handled and disposed of in accordance with the VSWMR or VHWMR as applicable. DEQ recommends that pollution prevention principles be implemented to reduce the amount of wastes at the source, such as the re-use and recycling of construction waste materials. If you have any questions concerning hazardous/solid waste management, please contact Jason Miller at (804)527-5028.

Molly Joseph Ward
Secretary of Natural Resources

Clyde E. Cristman
Director

COMMONWEALTH of VIRGINIA

DEPARTMENT OF CONSERVATION AND RECREATION

Rochelle Altholz
Deputy Director of Administration and Finance

David C. Dowling
Deputy Director of Soil and Water Conservation and Dam Safety

Thomas L. Smith
Deputy Director of Operations

MEMORANDUM

DATE: September 13, 2017

TO: Janine Howard, DEQ

FROM: Roberta Rhur, Environmental Impact Review Coordinator

SUBJECT: DEQ 17-121F, VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal

Division of Planning and Recreation Resources

The Department of Conservation and Recreation (DCR), Division of Planning and Recreation Resources (PRR), develops the *Virginia Outdoors Plan* and coordinates a broad range of recreational and environmental programs throughout Virginia. These include the Virginia Scenic Rivers program; Trails, Greenways, and Blueways; Virginia State Park Master Planning and State Park Design and Construction.

This project is within a section of the James River that has scenic river designation. If you have any questions about this designation, please contact Lynn Crump at 804-786-5054 or Lynn.Crump@dcr.virginia.gov.

Division of Natural Heritage

The Department of Conservation and Recreation's Division of Natural Heritage (DCR) has searched its Biotics Data System for occurrences of natural heritage resources from the area outlined on the submitted map. Natural heritage resources are defined as the habitat of rare, threatened, or endangered plant and animal species, unique or exemplary natural communities, and significant geologic formations.

According to the information currently in our files, the Atlantic sturgeon (*Acipenser oxyrinchus,* G3/S2/LE/LE) has been documented adjacent to the project site in the James River. The Atlantic sturgeon is a large fish that reaches a maximum length of about 4.3 meters and may live for several decades. The adults migrate between fresh water spawning areas and salt water non-spawning areas. They feed primarily on benthic invertebrates and small fishes as available.

Stocks on the Atlantic slope have been severely reduced by overfishing (mainly late 1800s and early 1900s), pollution, sedimentation, and blockage of access to spawning areas by dams (Gilbert 1989, Burkhead and Jenkins 1991, Marine and Coastal Species Information System 1996). In Chesapeake Bay and elsewhere in the range, hypoxic events have increased and may degrade nursery habitat for Atlantic sturgeon (Secor and Gunderson 1997). Habitat loss due to dam construction and water pollution are thought to be major factors impeding full recovery of populations (Smith 1985, cited by Johnson et al. 1997; Gilbert 1989). A late maturation age and use of estuaries, coastal bays, and upstream areas of rivers for spawning and juvenile development make stocks vulnerable to habitat alterations in many areas (NatureServe 2012). Please note that this species is currently classified as endangered by the National Oceanic and Atmospheric Administration National Marine Fisheries Service (NOAA Fisheries) and by the Virginia Department of Game and Inland Fisheries (VDGIF).

Due to the legal status of the Atlantic sturgeon, DCR recommends coordination with NOAA Fisheries and Virginia's regulatory authority for the management and protection of this species, the VDGIF, to ensure compliance with the Virginia Endangered Species Act (VA ST §§ 29.1-563 – 570). DCR supports studies to determine modifications designed to reduce entrainment and impingement impacts (pp. 2, 13).

There are no State Natural Area Preserves under DCR's jurisdiction in the project vicinity.

Under a Memorandum of Agreement established between the Virginia Department of Agriculture and Consumer Services (VDACS) and the DCR, DCR represents VDACS in comments regarding potential impacts on state-listed threatened and endangered plant and insect species. The current activity will not affect any documented state-listed plants or insects.

New and updated information is continually added to Biotics. Please re-submit project information and map for an update on this natural heritage information if the scope of the project changes and/or six months has passed before it is utilized.

The VDGIF maintains a database of wildlife locations, including threatened and endangered species, trout streams, and anadromous fish waters that may contain information not documented in this letter. Their database may be accessed from http://vafwis.org/fwis/ or contact Ernie Aschenbach at 804-367-2733 or Ernie.Aschenbach@dgif.virginia.gov. This project is located within 2 miles of a documented occurrence of a state listed animal. Therefore, DCR recommends coordination with the VDGIF, Virginia's regulatory authority for the management and protection of this species to ensure compliance with the Virginia Endangered Species Act (VA ST §§ 29.1-563 – 570).

The remaining DCR divisions have no comments regarding the scope of this project. Thank you for the opportunity to comment.

CC: Christine Vaccaro, NOAA Fisheries-Protected Species Division
Amy Ewing, VDGIF
Lynn Crump, DCR

Howard, Janine (DEQ)

From: Warren, Arlene (VDH)
Sent: Thursday, September 14, 2017 5:07 PM
To: Howard, Janine (DEQ)
Subject: RE: NEW PROJECT NRC SURRY POWER STATION 17-121F
Attachments: Shellfish Comments 17-121F_VEPCO_SurryPwrStnUnits1&2LicenseRenewal-VDH_DSS_ResponseLtr-20170912.pdf

Project Name: VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal
Project #: 17-121F
UPC #: N/A
Location: Surry County

VDH – Office of Drinking Water has reviewed the above project. Below are our comments as they relate to proximity to **public drinking water sources** (groundwater wells, springs and surface water intakes). Potential impacts to public water distribution systems or sanitary sewage collection systems **must be verified by the local utility.**

The following public groundwater wells are located within a 1-mile radius of the project site (wells within a 1,000-foot radius are formatted in **bold**):

PWS ID Number	City/County	System Name	Facility Name
3181800	**SURRY**	**SURRY POWER STATION**	**WELL B INSIDE GATE**
3181800	**SURRY**	**SURRY POWER STATION**	**WELL E WAREHOUSE ROAD W**
3181800	**SURRY**	**SURRY POWER STATION**	**WELL C HIGH LEVEL ROAD EAST**
3181802	**SURRY**	**VA POWER CONSTRUCTION SITE**	**WELL 1**

The following surface water intakes are located within a 5-mile radius of the project site:

PWS ID Number	System Name	Facility Name
3700500	NEWPORT NEWS, CITY OF	SKIFFES CREEK

The project is not within the watershed of any public surface water intakes.

- ***Radiological Health, Mr. Steven Harrison, Director, no comments received.***
- ***OEHS Onsite Sewage & Water Services, Mr. Dwayne Roadcap, no comments received.***
- ***Comments from OEHS Division of Shellfish Sanitation, Mr. Eric Aschenbach are attached.***

Best Management Practices should be employed, including Erosion & Sedimentation Controls and Spill Prevention Controls & Countermeasures on the project site.

Well(s) within a 1,000-foot radius from project site should be field marked and protected from accidental damage during construction.

Materials should be managed while on site and during transport to prevent impacts to nearby surface water.

Best Regards,

Arlene Fields Warren
GIS Program Support Technician

COMMONWEALTH of VIRGINIA

Department of Health

DIVISION OF SHELLFISH SANITATION

109 Governor Street, Room 614-B
Richmond, VA 23219

Ph: 804-864-7487
Fax: 804-864-7481

MEMORANDUM

DATE: 9/12/2017

TO: Janine Howard
Department of Environmental Quality

FROM: B. Keith Skiles, MPH, Director
Division of Shellfish Sanitation

SUBJECT: VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal

City / County: Surry

Waterbody: James River

Type: ☐ VPDES ☐ VMRC ☐ VPA ☐ VWP ☐ JPA ☑ Other: Federal Consistency Certification

Application / Permit Number: 17-121F

☐ The project will not affect shellfish growing waters.

☑ The project is located in or adjacent to approved shellfish growing waters, however, the activity as described will not require a change in classification.

☐ The project is located in or adjacent to condemned shellfish growing waters and the activity, as described, will not cause an increase in the size or type of the existing closure.

☐ The project will affect condemned shellfish waters and will not cause an increase in the size of the total condemnation. However, a prohibited area (an area from which shellfish relay to approved waters for self-purification is not allowed) will be required within a portion of the currently condemned area. See comments.

☐ A buffer zone (including a prohibited area) has been previously established in the vicinity of this discharge, however, the closure will have to be revised. Map attached.

☐ This project will affect approved shellfish waters. If this discharge is approved, a buffer zone (including a prohibited area) will be established in the vicinity of the discharge. Map attached.

☐ Other.

ADDITIONAL COMMENTS:

Area #: 60
eta

Howard, Janine (DEQ)

From: Kirchen, Roger (DHR)
Sent: Wednesday, August 16, 2017 11:07 AM
To: Howard, Janine (DEQ)
Subject: RE: NEW PROJECT NRC SURRY POWER STATION 17-121F

DHR has been in consultation with the NRC regarding this project. We request that the NRC continue to consult directly with DHR, as necessary, pursuant to Section 106 of the National Historic Preservation Act (as amended) and its implementing regulations codified at 36 CFR Part 800 which require Federal agencies to consider the effects of their undertakings on historic properties.

Roger

Roger W. Kirchen, Director
Review and Compliance Division
Department of Historic Resources
2801 Kensington Avenue
Richmond, VA 23221
phone: 804-482-6091
fax: 804-367-2391
roger.kirchen@dhr.virginia.gov

From: Fulcher, Valerie (DEQ)
Sent: Wednesday, August 16, 2017 10:28 AM
To: dgif-ESS Projects (DGIF); Rhur, Robbie (DCR); odwreview (VDH); Dacey, Katy (DEQ); Narasimhan, Kotur (DEQ); Gavan, Larry (DEQ); Moore, Daniel (DEQ); Sepety, Holly (DEQ); West, Kelley (DEQ); Kirchen, Roger (DHR); Emily A. Hein; Watkinson, Tony (MRC); dmorris@craterpdc.org; Ben McFarlane
Cc: Howard, Janine (DEQ)
Subject: NEW PROJECT NRC SURRY POWER STATION 17-121F

Good morning - this is a new OEIR review request/project:

Document Type: Federal Consistency Certification
Project Sponsor: U.S. Nuclear Regulatory Commission
Project Title: VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal
Location: Surry County
Project Number: DEQ #17-121F

The document is available at www.deq.virginia.gov/fileshare/oeir in the NRC folder. A hard copy has been mailed to Surry County.

The due date for comments is SEPTEMBER 14, 2017. You can send your comments either directly to JANINE HOWARD by email (Janine.Howard@deq.virginia.gov), or you can send your comments by regular interagency/U.S. mail to the Department of Environmental Quality, Office of Environmental Impact Review, 629 E. Main St., 6th Floor, Richmond, VA 23219.

Howard, Janine (DEQ)

From: Mark Bittner <mbittner@craterpdc.org>
Sent: Thursday, August 31, 2017 10:13 AM
To: Howard, Janine (DEQ)
Cc: 'Dennis Morris'
Subject: FW: NEW PROJECT NRC SURRY POWER STATION 17-121F

Dear Ms. Howard:

Thank you for submitting the SURRY POWER STATION 17-121F permit for review.

Based upon the Crater Commission's staff review, we find the proposal to be in full accord with the Crater Planning District Commission's environmental policy directives.

Please contact us if you have any questions.

Sincerely,

Mark Bittner

CPDC
Mark Bittner
Crater Planning District Commission
Director of Planning & Information Technology
(804) 861-1666 x237
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1964 Wakefield Street
Monument Professional Building
Petersburg, VA 23805
http://www.craterpdc.org

From: Fulcher, Valerie (DEQ) [mailto:Valerie.Fulcher@deq.virginia.gov]
Sent: Wednesday, August 16, 2017 10:28 AM
To: dgif-ESS Projects (DGIF); Rhur, Robbie (DCR); odwreview (VDH); Dacey, Katy (DEQ); Narasimhan, Kotur (DEQ); Gavan, Larry (DEQ); Moore, Daniel (DEQ); Sepety, Holly (DEQ); West, Kelley (DEQ); Kirchen, Roger (DHR); Emily A. Hein; Watkinson, Tony (MRC); dmorris@craterpdc.org; Ben McFarlane
Cc: Howard, Janine (DEQ)
Subject: NEW PROJECT NRC SURRY POWER STATION 17-121F

Good morning - this is a new OEIR review request/project:

Document Type: Federal Consistency Certification
Project Sponsor: U.S. Nuclear Regulatory Commission
Project Title: VEPCO Surry Power Station Units 1 & 2 Subsequent License Renewal
Location: Surry County
Project Number: DEQ #17-121F

The document is available at www.deq.virginia.gov/fileshare/oeir in the NRC folder. A hard copy has been mailed to Surry County.

Enclosure 2

REACTOR VESSEL SUPPORT STEEL AGING EVALUATION

**Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2**

Irradiation of the reactor vessel support steel assembly has been further evaluated. Section 3.5.2.2.2.6, Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation, pages 3-746 through 3-748, has been supplemented as shown in this enclosure (new text underlined and deleted text shown in strikethrough) to summarize the results of the further evaluation.

3.5.2.2.2.6 Reduction of Strength and Mechanical Properties of Concrete Due to Irradiation

Reduction of strength, loss of mechanical properties, and cracking due to irradiation could occur in PWR and BWR Group 4 concrete structures that are exposed to high levels of neutron and gamma radiation. These structures include the reactor (primary/biological) shield wall, the sacrificial shield wall, and the reactor vessel support/pedestal structure. Data related to the effects and significance of neutron and gamma radiation on concrete mechanical and physical properties is limited, especially for conditions (dose, temperature, etc.) representative of light water reactor (LWR) plants. However, based on literature review of existing research, radiation fluence limits of 1×10^{19} neutrons/cm^2 neutron radiation and 1×10^8 Gy (1×10^{10} rad) gamma dose are considered conservative radiation exposure levels beyond which concrete material properties may begin to degrade markedly (Ref. 17, 18, 19).

Further evaluation is recommended of a plant-specific program to manage aging effects of irradiation if the estimated (calculated) fluence levels or irradiation dose received by any portion of the concrete from neutron (fluence cutoff energy E > 0.1 MeV) or gamma radiation exceeds the respective threshold level during the subsequent period of extended operation or if plant specific OE of concrete irradiation degradation exists that may impact intended functions. Higher fluence or dose levels may be allowed in the concrete if tests and/or calculations are provided to evaluate the reduction in strength and/or loss of mechanical properties of concrete from those fluence levels, at or above the operating temperature experienced by the concrete, and the effects are applied to the design calculations. Supporting calculations/analyses, test data, and other technical basis are provided to estimate and evaluate fluence levels and the plant-specific program. The acceptance criteria are described in BTP RLSB-1 (Appendix A.1 of this SRP SLR).

[3.5.1-097] – Surry Power Station is a three-loop pressurized water reactor plant in which the reactor pressure vessel (RPV) is surrounded by a water-filled neutron shield tank. ~~The RPV is supported at each of the six nozzles by a support assembly. The bottom of each support assembly is supported by the top of the shield tank.~~ <u>The reactor vessel support steel assembly utilizes a neutron shield tank that supports sliding feet that support the hot leg and cold leg nozzles on the neutron shield tank (NST) top to allow the reactor vessel nozzles to move axially as the reactor vessel heats up and cools down during plant operations.</u> The neutron shield tank is constructed of two 1-1/2 inch thick steel shells separated by 34 inches of water. The weight of the RPV is carried by the neutron shield tank, and no vertical loads are transferred to the concrete biological shield (CBS) wall. The inner shell of the neutron shield tank extends continuously past the bottom of the reactor vessel to the basemat, where the vertical loads are transferred directly. Overturning moments and horizontal forces are resisted by the CBS wall through a layer of grout, which fills the 2 inch gap between the neutron shield tank and the CBS wall.

The maximum temperature on both the inside and outside surfaces of the CBS wall is 125°F. The maximum water temperature of the neutron shield tank is 125°F. The maximum fluence at the ID of the RPV is 7.71×10^{19} n/cm^2 (E > 1.0 MeV), determined by extrapolating surveillance program calculations to 80 years (72 EFPY). The actual EFPY value for SPS Units 1 and 2 is 68 however 72 EFPY was used in the EPRI study discussed below.

Irradiation Damage of the Concrete Biological Shield

EPRI Report 3002013051, "Irradiation Damage of the Concrete Biological Shield that Utilizes a Neutron Shield Tank: Basis for Concrete Biological Shield Wall for Aging Management," addresses the effects of irradiation exposure and environmental temperature on the structural capability of the CBS wall at nuclear power plants with a neutron shield tank between the RPV and CBS wall. The specific example plant utilized for development of this report was SPS, with the modeling parameters such as neutron shield tank design configuration, operating temperatures, and RPV fluence levels described above. Therefore, the plant-specific values determined and conclusions reached for the example plant in the report are directly applicable to SPS. Using an evaluation period of 72 EFPY (80 years of operation), those values and conclusions are:

- The maximum neutron fluence at the CBS wall surface of 1.18×10^{13} n/cm^2 (E > 1.0 MeV). This is substantially below the threshold value of 1.0×10^{19} n/cm^2 for E > 0.1 MeV.
- The estimated gamma surface dose at the CBS wall of 2.75×10^8 Rad is below the acceptability threshold of 1.0×10^{10} Rad.
- The maximum concrete temperature due to gamma heating is 125.1°F, which is approximately the same as the maximum ambient temperature of 125°F at the surface of the concrete and is below the acceptable long-term local temperature limit of 200°F for local areas.

In addition to the above conclusions, no plant-specific OE of concrete irradiation degradation has been identified. Therefore, no additional thermal and structural analyses are required to establish the structural capability of the CBS wall, and no plant-specific aging management program to manage the effects of irradiation is required.

Irradiation of the Reactor Vessel Support Steel Assembly

In 1986, DOE, EPRI, WOG, and Virginia Power contracted Stone and Webster to develop Project Topical Report (PTR): "Reactor Vessel Support for Unit No 1 Surry Power Station, Life Extension Evaluation of the Reactor Vessel Support, including Appendix 3, Resistance to Brittle Fracture of the Neutron Shield Tank Materials," to address the concern of irradiated reactor vessel (RV) supports. The PTR specifically addressed the resistance to brittle fracture of the Surry Unit 1 RV support steel materials in the NST as a result of loss of fracture toughness due to neutron irradiation embrittlement in support of plants considering initial license renewal.

The applied stresses for the area of the NST subject to high neutron fluence were developed in a separate calculation and compared to critical stresses derived from the fracture toughness evaluation to determine structural integrity of the Surry Unit 1 NST for 100 years of operation. A comparison of input parameters in the PTR including configuration, toughness, fluence, and EFPY was completed for SLR. The comparison and associated evaluation determined the following values and conclusions:

- The fluence to the NST shell at the RV sliding foot assembly is bounded by the fluence at the NST inner shell.
- The PTR was conservatively estimated for 100 years of plant operation (76.8 EFPY) that yields a fast neutron fluence (E>1Mev) of 9.5×10^{19} n/cm^2 at the inside surface of the RV and a fast neutron fluence (E>1Mev) of 5.0×10^{19} n/cm^2 at the outside surface of the RV.
- The fast neutron fluence (E>1Mev) on the ID of the NST for 100 years of plant operation is based upon 90% of the fluence on the outside diameter of the RV which is 4.5×10^{18} n/cm^2.
- The projected EFPY Value for SPS SLR is 68 EFPY which yields a fast neutron fluence (E>1Mev) of 3.42×10^{18} n/cm^2 at the inside surface of the NST.
- The maximum fracture toughness for 76.8 EFPY required to prevent propagation of a postulated surface flaw and postulated through wall crack was determined for the maximum design strength and design basis loading conditions.
- The peak stress values for the loads associated with the Surry Unit 1 NST were demonstrated to be below the critical stress for a through wall flaw and a surface flaw, thereby requiring no aging management.

An update was performed in support of subsequent license renewal using the PTR methodology. The updated evaluation validated the that Surry Unit 2 NST is similar and bounded in design and configuration by Surry Unit 1 NST, the applied stresses for both units are consistent and have not significantly changed since the previous evaluation and the 80 year projected fluence values at the inner surface of the NSTs also remain bounded by the values in the original PTR.

The subsequent license renewal evaluation concluded that brittle fracture will not occur based upon the fracture mechanics performed, which remains consistent with the previous conclusion documented in the PTR. Thus, aging due to loss of fracture toughness due to neutron irradiation embrittlement of the RV steel support assembly does not require aging management in the subsequent period of operation. In addition to the above conclusions, there is no plant-specific or industry operating experience of reactor vessel steel support assembly irradiation degradation that would impact a license renewal intended function.

Generic Safety Issue 15 (GSI-15) Considerations in NUREG-0933

The PTR fracture mechanics evaluation on the reactor vessel support steel assembly predated resolution of Generic Safety Issue 15 (GSI-15), "Radiation Effects on Reactor Pressure Vessel Supports," in 1996, as reported in NUREG-0933 which states in part:

> The preliminary conclusion indicated that the potential problem did not pose an immediate threat to public safety. The tentative results indicated that plant safety could be maintained despite reactor vessel support structures (RVSS) radiation damage. In order to encompass the uncertainties in the various analyses and provide an overall conservative assessment, several structural analyses conducted demonstrated the following:
>
> (1) Postulating that one of the four RPV supports was broken in a typical PWR, the remaining supports would carry the reactor vessel and the load even under safe-shutdown earthquake (SSE) seismic loads;
>
> (2) If all supports were assumed to be totally removed (i.e., broken), the short span of piping between the vessel and the shield wall would support the load of the vessel.

In summary, there is reasonable assurance that the Surry Units 1 and 2 reactor vessel support steel will perform the license renewal intended function during the subsequent period of operation.

Enclosure 3

OTHER TOPICS THAT REQUIRE A SLRA SUPPLEMENT

**Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2**

The following seven topics require the SLRA to be supplemented:

1. Hot Piping Containment Penetration Thermal Insulation
2. Cracking in Copper Alloy (>15% Zn)
3. Revision 2 of PWROG-17011-NP, "Update for Subsequent License Renewal: WCAP-14535-A, Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination and WCAP-15666-A, Extension of Reactor Coolant Pump Motor Flywheel Examination" - Issued
4. *Open Cycle Cooling Water System* program Enhancement 4 - Completed
5. *Fire Water System* program Enhancements: 1, 5 & 7 - Completed, 9 - Revised
6. Reactor Vessel Material Surveillance Program - USNRC Safety Evaluation Report Issued for Reactor Vessel Materials Surveillance Capsule Withdraw Schedules Change Request
7. *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* - Operating Experience Example 3 Updated

This enclosure includes a description of each of the above topics and identifies the associated SLRA section(s) supplemented.

1. Hot Piping Containment Penetration Thermal Insulation

The Surry Power Station (SPS) Subsequent License Renewal Application (SLRA) inadvertently omitted the insulation within hot piping containment penetrations that have normal operating temperatures greater than 150 °F. Dominion Energy has determined that this insulation is within the scope of license renewal with an intended function of thermal insulation for limiting heat transfer to the containment concrete at the hot piping containment penetrations. The following systems have thermally insulated hot piping containment penetrations whose temperature is normally greater than 150 °F:

- main steam
- feedwater
- blowdown
- chemical and volume control (reactor coolant letdown)

Based on the above, the following SLRA Sections / Tables have been supplemented, as shown in Enclosure 4, to address insulation within hot piping containment penetrations:

SLRA Section	SLRA Table
2.1.4.2	2.3.3-15
2.3.3.15	2.3.4-4
2.3.4.4	2.3.4-8
2.3.4.8	2.3.4-12
2.3.4.12	3.3.1
3.3.2.1.15	3.3.2-15
3.4.2.1.4	3.4.1
3.4.2.1.8	3.4.2-4
3.4.2.1.12	3.4.2-8
3.5.2.2.1.2	3.4.2-12

2. Cracking in Copper Alloy (>15% Zn)

Copper alloy (>15% Zn) components do not require aging management of cracking in an air-indoor uncontrolled environment. NUREG-2191, "Generic Aging Lessons Learned for Subsequent License Renewal (GALL-SLR) Report," incorporated and expanded upon the guidance provided in LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," which identified the potential for corrosion (and cracking) under insulation and specifically addressed the condensation environment and air-outdoor environment. NUREG-2221, "Technical Bases for Changes in the Subsequent License Renewal Guidance Documents NUREG–2191 and NUREG–2192," provides the basis for the potential for cracking of copper alloy (>15% Zn) components in air, and confirms that the presence of ammonia-based compounds and a wetted environment are needed to support the cracking aging effect. At Surry Power Station, copper alloy (>15% Zn) components in condensation environments (i.e., systems in which the temperature may be below ambient dewpoint), and in the air-outdoor environments, are identified as having the potential for cracking because the component surfaces in these environments may be wetted, and the potential for degradation of a wetted surface due to concentration of ammonia contaminants may exist.

The air-indoor uncontrolled environment is assigned to components that are uninsulated, or not exposed to condensation. Since these components are not expected to be wetted through condensation or potential leakage that is retained under insulation, no concentration of low-level contaminants (ammonia or ammonia compounds) is expected. Therefore, copper alloy (>15% Zn) components exposed to air-indoor uncontrolled environment are not wetted or exposed to ammonia contaminants and are not susceptible to cracking.

The internal surfaces of the service air system and instrument air system downstream of the air dryers is dry air with a dewpoint that is maintained and monitored to prevent a buildup of water in the system. Therefore, the internal surfaces of copper alloy (>15% Zn) components in the service air system and instrument air system in an air-dry environment are not susceptible to cracking. Copper alloy (>15% Zn) components in the instrument air and service air systems upstream of the air dryers with an internal condensation environment have been assigned cracking as an aging effect requiring management.

Based on the above, SLRA Table 3.2.1, Table 3.3.1, Table 3.4.1, Table 3.3.2-11, and Table 3.3.2-13 have been supplemented, as shown in Enclosure 4. SLRA Section A1.23, Table A4.0-1, Item 23 and Section B2.1.23 have been supplemented, as shown in Enclosure 4, to manage cracking of copper alloy (>15% Zn) and copper alloy (>8% Al) in a condensation environment or an air-outdoor environment with the *External*

Surfaces Monitoring of Mechanical Components program. SLRA Section A1.25, and Section B2.1.25 have been supplemented, as shown in Enclosure 4, to manage cracking of copper alloy (>15% Zn) in a condensation environment with the *Inspection of Internal Surfaces of Miscellaneous Piping and Ducting Components* program.

Additionally, Table 3.4.2-11 has been supplemented, as shown in Enclosure 4, to reflect a change to the environment of the single valve body made of copper alloy (>15% Zn) with a condensation environment. The environment for this component was reassigned from condensation to waste water for consistency with the surrounding components.

3. Revision 2 of PWROG-17011-NP, Update for Subsequent License Renewal: WCAP-14535-A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," and WCAP-15666-A, "Extension of Reactor Coolant Pump Motor Flywheel Examination" - Issued

Revision 2 of PWROG-17011-NP, Update for Subsequent License Renewal: WCAP-14535-A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," and WCAP-15666-A, "Extension of Reactor Coolant Pump Motor Flywheel Examination," has been issued in response to NRC comments. Changes incorporated in PWROG-17011-NP, Revision 2 do not change the content or disposition of the TLAA described in SLRA Section 4.7.2, Reactor Coolant Pump Flywheel Fatigue Crack Growth Analysis.

SLRA Section 4.8, reference 4.8-75 has been supplemented to identify PWROG-17011-NP, Revision 2 as indicated in Enclosure 4.

4. *Open-Cycle Cooling Water System* program Enhancement 4 - Completed

The *Open Cycle Cooling Water System* program (Section B2.1.11) implementing procedures have been revised to remove the reference to carbon steel piping that was replaced, and updated to reference the replacement piping material.

As a result of the above procedure revisions, Enhancement 4 in SLRA Table A4.0-1, Item #11 (*Open Cycle Cooling Water System* program) and SLRA Section B2.1.11 have been completed and deleted as shown in Enclosure 4.

5. *Fire Water System* program Enhancements: 1, 5 & 7 - Completed, 9 - Revised

The Fire Water System aging management program (XI.M27), Enhancement #9 is being revised to eliminate extraneous information. The statement, "Follow-up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval," is included in the SLRA Enhancement #9. The statement is being revised to align with GALL wording. The revised statement is, "Follow-up volumetric wall thickness examinations will be performed if internal visual inspections detect an unexpected level of degradation due to corrosion and corrosion product deposition."

In addition, the following enhancements in the *Fire Water System* program (Section B2.1.16) have been completed:

- Enhancement 1

  Procedure inspection guidance has been revised to be consistent with the 2011 edition of NFPA 25, Section 5.2.1.1. Sprinklers at the following locations have been added to the inspection scope: Radwaste Facility, Auxiliary Boiler, Maintenance Building, Condensate Polishing Building, Laundry Building, and Machine Shop Building.

- Enhancement 5

  Procedure flushing guidance for hydrants has been revised to be consistent with the 2011 edition of NFPA 25, Section 7.3.2. Hydrants outside the protected area that are within the scope of subsequent license renewal have been added to the flush scope.

- Enhancement 7

  Procedure flushing guidance for mainline strainers has been revised to be consistent with the 2011 edition of NFPA 25, Sections 10.2.1.7 and 10.2.7. The Radwaste facility mainline strainer will be inspected every five years.

Enhancement 1 is clarified to note deletion of the Maintenance Building from the enhancement implementation because the Maintenance Building is also known as the Machine Shop Building.

As a result of the above procedure revisions and the Enhancement 9 clarification, Enhancements 1, 5, and 7 in SLRA Table A4.0-1, Item #16 and SLRA Section B2.1.16 have been completed and deleted, and Enhancement 9 has been revised as shown in Enclosure 4.

6. *Reactor Vessel Material Surveillance Program - USNRC Safety Evaluation Report Issued for Reactor Vessel Materials Surveillance Capsule Withdraw Schedules Change Request*

By letter dated December 10, 2018, the NRC issued Safety Evaluation, "Surry Power Station, Unit Nos. 1 and 2 – Review of Reactor Vessel Material Surveillance Capsule Withdrawal Schedules" (ADAMS Accession No. ML18318A062), for the reactor vessel material surveillance capsule withdrawal schedules change request that was submitted on July 28, 2017. The December 10, 2018 letter approved a change to the withdraw schedule for Unit 1 Capsule Z from 2025 to 2027 and the withdraw schedule for Unit 2 Capsule U from 2027 to 2032. All other aspects of the reactor vessel material surveillance capsule withdrawal schedules change request submitted on July 28, 2017 will be reviewed during the SLRA review.

SLRA Section B2.1.19 has been revised to reflect the December 10, 2018, NRC Safety Evaluation and associated withdraw schedule change for Unit 1 Capsule Z and withdraw schedule change for Unit 2 Capsule U as shown in Enclosure 4.

7. *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* - Operating Experience Example 3 Updated

During the December 2015 AMP effectiveness review it was recommended that timely corrective action be taken to seal duct bank entrances for the underground 'C' RSST cables to prevent water and silt entry into a manhole to prevent exposing cables within the scope of license renewal to significant water. Corrective maintenance was scheduled and duct bank seals were installed to correct this condition during the 2018 Fall refueling outage.

The third example in the Operating Experience Summary Section of SLRA Section B2.1.39 has been updated to reflect the installation of duct bank seals as shown in Enclosure 4.

Enclosure 4

SLRA MARK-UPS
CHANGE NOTICE 1

**Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2**

SLRA MARK-UPS

Affected SLRA Section	SLRA Page(s)
Section 2.1.4.2	2-17 through 2-20
Section 2.3.3.15	2-101
Table 2.3.3-15	2-167
Section 2.3.4.4	2-214 and 2-215
Section 2.3.4.8	2-220 and 2-221
Section 2.3.4.12	2-226 and 2-227
Table 2.3.4-4	2-236
Table 2.3.4-8	2-241
Table 2.3.4-12	2-248
Table 3.2.1, Item 3.2.1-071	3-154
Section 3.3.2.1.15	3-220 and 3-221
Table 3.3.1, Items 3.3.1-132, and 182	3-309 and 3-316
Table 3.3.2-11	3-387, 3-391, and 3-392
Table 3.3.2-13	3-396 and 3-397
Table 3.3.2-15	3-420
Section 3.4.2.1.4	3-560 and 3-561
Section 3.4.2.1.8	3-566 and 3-567
Section 3.4.2.1.12	3-572 and 3-573
Table 3.4.1, Items 3.4.1-063, 064, and 106	3-600 and 3-608
Table 3.4.2-4	3-625
Table 3.4.2-8	3-647
Table 3.4.2-11	3-666
Table 3.4.2-12	3-669
Section 3.5.2.2.1.2	3-732 and 3-733
Section 4.8	4-137
Section A1.23	A-20
Section A1.25	A-21 and A-22
Table A4.0-1 item 11	A-67
Table A4.0-1 item 16	A-71 through A-73
Table A4.0-1 item 23	A-82 through A-83
Section B2.1.11	B-80 through B-90
Section B2.1.16	B-108 through B-119
Section B2.1.19	B-137 through B-144
Section B2.1.23	B-158 through B-165
Section B2.1.25	B-169 through B-177
Section B2.1.39	B-253 through B-259

Section 2.1.4.2

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Section 2.1.4.2, Nonsafety-Related Affecting Safety-Related, pages 2-17 through 2-20 in the "Functional Support for Safety-Related SSC 10 CFR 54.4(a)(1) Functions" subsection, has been supplemented as follows (new text underlined):

2.1.4.2 Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)

Functional Support for Safety-Related SSC 10 CFR 54.4(a)(1) Functions

This category addresses non-safety-related SSCs that are required to function in support of a safety-related SSC intended function. The functional requirement distinguishes this category from the other categories, where the nonsafety-related SSCs are required only to maintain adequate integrity to preclude structural failure or spatial interactions. The nonsafety-related SSCs that were included within the scope of subsequent license renewal to support a safety-related SSC in performing a 10 CFR 54.4(a)(1) intended function are identified on the subsequent license renewal boundary drawings in blue.

The SPS UFSAR, CLB and other design basis documents were reviewed to identify nonsafety-related systems or structures required to support satisfactory accomplishment of a safety-related function. Nonsafety-related systems or structures credited in CLB documents to support a safety-related function have been included with the scope of subsequent license renewal. SPS classifies systems that are required to perform or support a safety-related function as safety-related, with the following exceptions:

1. The circulating water system main condenser inlet and outlet valves are classified as safety-related because they are required to close for a number of design basis events to ensure adequate intake canal level. The portion of the circulating water system between the condenser inlet and outlet valves is nonsafety-related; however, it is required to maintain its pressure-retaining capability during those design basis events.

2. The turbine over-speed tripping devices, the stop valves, the throttle/governor valves, and the associated electro-hydraulic control system are relied on to prevent excessive turbine over-speed conditions that could lead to turbine rotor/disk failures, resulting in the generation of turbine missiles greater than those assumed in the UFSAR evaluations. However, the affected components fail to their safe condition, and the passive pressure boundary function of the valve bodies, the associated piping, and the EHC system are not needed to prevent turbine over-speed. Additionally, the valve internals and over-speed tripping devices are specifically excluded from an aging management review as active components.

3. The condensate system emergency condensate makeup tank, together with the feedwater booster pumps and associated flowpaths, provides a backup source of water to the suction of auxiliary feedwater pumps at either unit, so that the auxiliary feedwater pumps at either unit can supply auxiliary feedwater to both units (via a discharge cross-connect line).

4. The fuel pool cooling system removes heat from the spent fuel pool during normal operation.

5. The neutron shield tank cooling system provides shield tank cooling during normal operation.

6. The plumbing system turbine building sump pumps and discharge piping mitigate plant flooding.

7. The plumbing system removes water from the containment sub-surface drains to minimize hydrostatic pressure on the containment mat liner.

8. The plumbing system storm drains remove water from the yard area during maximum precipitation events to mitigate flooding.

9. The service water system expansion joints at the bearing cooling water heat exchangers have enclosures to mitigate the potential for flooding in the Turbine Building.

10. The ventilation system auxiliary building central exhaust fans and associated ducting provide ventilation for the charging pump cubicles.

11. Some nonsafety-related portions of systems are connected to safety-related (or (a)(2) functional) systems such that a portion of the nonsafety-related system must retain its pressure boundary integrity to support the integrity of the attached system. This function applies to the following systems:

    a. Steam generator blowdown
    b. Component cooling
    c. Condensate
    d. Instrument air
    e. Primary grade water
    f. Vacuum priming
    g. Boron recovery
    h. Reactor cavity purification
    i. Liquid waste

12. Cooling water from the component cooling system and piping insulation in hot containment piping penetrations (in the chemical and volume control, feedwater, main steam, and blowdown systems) limit heat transfer to the containment structure concrete.

The nonsafety-related systems, or nonsafety-related portions of safety-related systems and structures that support the above functions, were included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(2).

A supporting system review was performed as an additional confirmation of scoping to meet 10 CFR 54.4(a)(2) criteria. The scoping process was performed on a system and structure basis. For systems included within the scope of subsequent license renewal in accordance with the requirements of 10 CFR 54.4(a)(1), the scoping evaluation included the identification of any additional systems, including nonsafety-related systems, that are required to support the safety-related system intended functions. It was then confirmed that these identified systems were also included in scope. Except as identified above, the SPS systems required to support 10 CFR 54.4(a)(1) were classified safety-related, and as such included within the scope of subsequent license renewal in accordance with 10 CFR 54.4(a)(1). The identification of support systems was not required for structures since structural intended functions do not rely on supporting systems.

The next two 10 CFR 54.4(a)(2) scoping categories are the subject of NEI 95-10, Appendix F (as referenced in NEI 17-01). The guidance requires that, when demonstrating failures of nonsafety-related systems would not adversely impact the ability to maintain intended functions, a distinction must be made between nonsafety-related systems that are directly connected to safety-related systems and those that are not directly connected to safety-related systems. For a nonsafety-related piping system that is directly connected to and provides structural support for a safety-related piping system, the nonsafety-related piping and supports shall be included within the scope of subsequent license renewal up to (1) the analytical boundary defined in the CLB seismic analysis for the safety-related piping or, (2) if the seismic boundary is not clearly defined in the CLB information, up to and including the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions. The location of the point beyond which the failure of the nonsafety-related piping will not render the safety-related portion of the piping system unable to perform its intended function under CLB design conditions is identified using the guidance presented in NEI 95-10, Appendix F, Section 4 (as referenced in NEI 17-01).

Section 2.3.3.15

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal requiring an update to the system evaluation boundary and system intended functions for the chemical and volume system.

Section 2.3.3.15, Chemical and Volume Control, page 2-101, has been supplemented as follows (new text underlined and deleted text shown in strikethrough):

2.3.3.15 Chemical and Volume Control

System Evaluation Boundary

The evaluation boundary for the chemical and volume control system components subject to aging management review includes the letdown flowpath from the reactor coolant system through the regenerative and nonregenerative heat exchangers and letdown demineralizers to the volume control tank, the flowpaths from the volume control tank or refueling water storage tank through the charging pumps, to the reactor coolant system, the boric acid tanks, pumps and flowpaths to the charging pump suction flowpath, the reactor coolant pump seal injection flowpath and leakoff flowpath through the seal water heat exchanger, the charging pump seal coolers and oil pumps, heat exchangers and flowpaths, and nonsafety-related components that retain water or steam in buildings containing safety-related components. Additionally subject to aging management review are local air valves and air supply piping for select letdown isolation valves that are credited for post-fire operation using a portable air bottle and thermal insulation on letdown lines within containment penetrations.

System Intended Functions

Portions of the chemical and volume control system perform the following safety related functions: The system provides a pressure boundary for the reactor coolant system, controls reactor coolant system inventory and pressure; controls core reactivity, provides high-head safety injection flow, provides reactor coolant pump seal injection, provides safety-related instrumentation, and provides containment isolation. Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Insulation on hot piping containment penetrations limits heat transfer to the containment structure, and portions~~Portions~~ of the chemical and volume control system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for thermal insulation, spatial interaction and structural integrity.

Portions of the chemical and volume control system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), and Station Blackout (10 CFR 50.63). Therefore, the chemical and volume control system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

Table 2.3.3-15

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal requiring the addition of an "Insulation (containment penetration)" line to the table.

Table 2.3.3-15, Chemical and Volume Control, page 2-167, has been supplemented as follows (new text underlined):

Table 2.3.3-15 Chemical and Volume Control

Component Type	Intended Function(s)
Insulation (containment penetration)	Thermal Insulation

Section 2.3.4.4

Thermal insulation on hot piping within containment penetrations is added to the scope of subsequent license renewal requiring an update to the system evaluation boundary and system intended functions for the main steam system.

Section 2.3.4.4, Main Steam, pages 2-214 and 2-215, has been supplemented as follows (new text underlined and deleted text shown in strikethrough).

2.3.4.4 Main Steam

System Evaluation Boundary

The evaluation boundary for the main steam system components subject to aging management review includes the safety-related steam lines from the steam generators to the main steam isolation and non-return valves, main steam safety and pressure relief valves, and to the auxiliary feedwater pump turbine; the nonsafety-related steam lines from the non-return valves to the main turbine stop valves, condenser steam dump valves and moisture-separator reheater flow control valves (and attached piping to the first isolation valve), which are credited with providing isolation during fire and station blackout events if the main steam isolation valves fail to close; sensing lines for the turbine first stage pressure transmitters which feed the ATWS Mitigation System Actuation Circuitry; and the nonsafety-related steam dump, gland steam and associated attached piping components that provide support to directly connected safety-related components, or that retain water, steam or oil in buildings containing safety-related components. <u>Additionally, thermal insulation on hot piping within containment penetrations is subject to aging management review.</u>

System Intended Functions

Portions of the main steam system perform the following safety-related functions: The system removes heat from the reactor coolant system, provides overpressure protection for the reactor coolant and main steam systems, prevents uncontrolled blowdown of more than one steam generator, provides steam to the turbine driven auxiliary feedwater pump, provides containment isolation and provides safety-related indication. Therefore, the main steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

<u>Insulation on hot piping within containment penetrations limits heat transfer to the containment structure, and portions</u>~~Portions~~ of the main steam system contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the main steam system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for <u>thermal insulation,</u> spatial interaction and structural integrity.

Portions of the main steam system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the main steam system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

Section 2.3.4.8

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal requiring an update to the system evaluation boundary and system intended functions for the feedwater system.

Section 2.3.4.8, Feedwater, pages 2-220 and 2-221, has been supplemented as follows (new text underlined and deleted text shown in strikethrough):

2.3.4.8 Feedwater

System Evaluation Boundary

The evaluation boundary for the feedwater system components subject to aging management review includes the safety-related feedwater piping from outside Containment through the containment penetrations to the steam generators, the safety-related auxiliary feedwater pumps and associated suction and discharge piping components, and the nonsafety-related feedwater booster pumps and associated piping components from the emergency condensate makeup tanks (which are in the condensate system) to the auxiliary feedwater pump suctions, and the nonsafety-related main feedwater pumps, first-point feedwater heaters and piping components in buildings containing safety-related components. Thermal insulation on hot piping within containment penetrations is also subject to aging management review. Additionally, nonsafety-related instrument air piping and valves provide structural support for the safety-related air accumulators and associated air supply piping components that provide closing air for the bypass feedwater regulating valves and are subject to aging management review. The main feedwater regulating valves have a similar safety-related air-to-close configuration, but the components that support that function have instrument air mark numbers and are evaluated within the instrument air system.

System Intended Functions

Portions of the feedwater system perform the following safety-related functions: The system provides water to the steam generators during and following design basis events, provides containment isolation, provides safety-related indication, and limits feedwater flow to a faulted steam generator. Therefore, the feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

Insulation on hot piping within containment penetrations limits heat transfer to the containment structure, and portions of the feedwater system contain nonsafety-related components that provide a backup source of water to the suction of the auxiliary feedwater pumps, and portions contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the feedwater system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for thermal insulation, auxiliary feedwater delivery and for spatial interaction and structural integrity.

Portions of the feedwater system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the feedwater system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

<u>**Section 2.3.4.12**</u>

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal requiring an update to the system evaluation boundary and system intended functions for the blowdown system.

Section 2.3.4.12, Blowdown, page 2-227, has been supplemented as follows (new text underlined and deleted text shown in strikethrough):

2.3.4.12 Blowdown

System Evaluation Boundary

The evaluation boundary for the blowdown system components subject to aging management review includes the safety-related steam generator blowdown piping beginning within the steam generators, connecting to piping components in Containment, through containment penetrations to the outside containment isolation valves in the Auxiliary Building, as well as downstream nonsafety-related piping components that provide piping integrity for the circulating water system, or that provide support to directly connected safety-related components, or that retain water, including the blowdown heat exchangers and associated piping components in the Auxiliary Building and Turbine Building. <u>Additionally, thermal insulation on hot piping within containment penetrations is subject to aging management review.</u>

System Intended Functions

Portions of the blowdown system perform the following safety-related functions: The system isolates blowdown flow to mitigate design basis events, provides containment isolation, and provides safety-related instrumentation. Therefore, the blowdown system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(1).

<u>Insulation on hot piping within containment penetrations limits heat transfer to the containment structure, and portions</u>~~Portions~~ of the blowdown system contain nonsafety-related components that provide circulating water system integrity, and contain nonsafety-related components whose failure could prevent satisfactory accomplishment of a safety-related function. Therefore, the blowdown system is within the scope of license renewal in accordance with the criterion of 10 CFR 54.4(a)(2) for <u>thermal insulation,</u> pressure boundary integrity, and for spatial interaction and structural integrity.

Portions of the blowdown system are relied upon for compliance with regulations for Fire Protection (10 CFR 50.48), Environmental Qualification (10 CFR 50.49), Anticipated Transients Without Scram (10 CFR 50.62), and Station Blackout (10 CFR 50.63). Therefore, the blowdown system is within the scope of license renewal in accordance with the criteria of 10 CFR 54.4(a)(3).

Table 2.3.4-4

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal requiring the addition of an "Insulation (containment penetration)" line to the table.

Table 2.3.4-4, Main Steam, page 2-236, has been supplemented as follows (new text underlined):

Table 2.3.4-4 Chemical and Volume Control

Component Type	Intended Function(s)
Insulation (containment penetration)	Thermal Insulation

Table 2.3.4-8

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal requiring the addition of an "Insulation (containment penetration)" line to the table.

Table 2.3.4-8, Feedwater, page 2-241, has been supplemented as follows (new text underlined):

Table 2.3.4-8 Feedwater

Component Type	Intended Function(s)
<u>Insulation (containment penetration)</u>	<u>Thermal Insulation</u>

Table 2.3.4-12

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal requiring the addition of an "Insulation (containment penetration)" line to the table.

Table 2.3.4-12, Blowdown, page 2-248, has been supplemented as follows (new text underlined):

Table 2.3.4-12 Blowdown

Component Type	Intended Function(s)
Insulation (containment penetration)	Thermal Insulation

<u>Table 3.2.1</u>

Cracking of copper alloy >15% Zn in air clarification.

Table 3.2.1, Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report, Item 3.2.1-071 on page 3-154, has been supplemented as follows (new text underlined):

Table 3.2.1 Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.2.1-071	Insulated copper alloy (>15% Zn or >8% Al) piping, piping components, tanks exposed to air, condensation	Cracking due to SCC	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	Not applicable. SPS has no in-scope insulated copper alloy (>15% Zn or >8% Al) piping, piping components or tanks exposed to air or condensation in the Engineered Safety Features systems. <u>Aging of uninsulated copper alloy (>15% Zn) components exposed to air-indoor uncontrolled in the Engineered Safety Features is aligned to item 3.2.1-057. Cracking of copper alloy >15% Zn in air is not expected in the absence of wetting and ammonia contaminants, which are not present in the air-indoor uncontrolled environment.</u> The associated NUREG-2191 aging items are not used.

Section 3.3.2.1.15

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Section 3.3.2.1.15, Chemical and Volume Control, pages 3-220 and 3-221 in the "Materials List" and "Aging Effects Require Management" sub-sections, have been supplemented as follows (new text underlined):

3.3.2.1.15 Chemical and Volume Control

Materials

The materials of construction for the chemical and volume control system component types are:

- Calcium silicate
- Copper Alloy
- Copper Alloy with internal coating
- Glass
- Gray cast iron
- Stainless steel
- Steel

Aging Effects Requiring Management

The following aging effects, associated with the chemical and volume control system, require management:

- Cracking
- Cumulative fatigue damage
- Loss of coating or lining integrity
- Loss of material
- Loss of preload
- Reduction of heat transfer
- Reduction of thermal insulation resistance

Table 3.3.1

Thermal insulation on hot piping containment penetrations have been added to the scope of subsequent license renewal and cracking of copper alloy >15% Zn in air clarification.

Table 3.3.1, Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report, Items 3.3.1-132 and 3.3.1-182 on pages 3-309 and 3-316, respectively, have been supplemented as follows (new text underlined and deleted text shown in strikethrough):

Table 3.3.1 Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.3.1-132	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, External Surfaces Monitoring of Mechanical Components or AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191 with a different program assigned for some components. Loss of material of ~~insulated~~ steel and copper alloy (>15% Zn or >8% Al) components and cracking of ~~insulated~~ copper alloy (>15% Zn or >8% Al) components exposed to air-outdoor or external condensation is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. Cracking of copper alloy (>15% Zn) exposed to an internal condensation environment is managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. Aging of uninsulated copper alloy (>15% Zn) components exposed to air-indoor uncontrolled in the Auxiliary Systems is aligned to items 3.3.1-114, 3.3.1-130 and 3.3.1-131. Cracking of copper alloy (>15% Zn) in air is not expected in the absence of wetting and ammonia contaminants, which are not present in the air-indoor uncontrolled environment.
3.3.1-182	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	~~Not applicable. SPS has no in-scope non-metallic thermal insulation exposed to air or condensation in the Auxiliary Systems. The associated NUREG-2191 aging items are not used.~~ Consistent with NUREG-2191

Table 3.3.2-11

Cracking of copper alloy >15% Zn in air clarification.

Table 3.3.2-11, Auxiliary Systems - Instrument Air - Aging Management Evaluation, pages 3-387, 3-391, and 3-392, have been supplemented as follows (new text underlined and deleted text shown in strikethrough):

Table 3.3.2-11 Auxiliary Systems - Instrument Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Heat exchanger (air compressor seal water shell)	PB	Copper alloy (>15% Zn)	(I) Condensation	~~None~~ Cracking	~~None~~ Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~ VII.I.A-405a	~~3.3.1-114~~ 3.3.1-132	~~C~~ E;3
Heat exchanger (air compressor seal water tubesheet)	PB	Copper alloy (>15% Zn)	(E) Condensation	~~None~~ Cracking	~~None~~ Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~ VII.I.A-405a	~~3.3.1-114~~ 3.3.1-132	~~C~~ E;3
Valve body	LB;PB;SI	Copper alloy (>15% Zn)	(I) Condensation	~~None~~ Cracking	~~None~~ Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~ VII.I.A-405a	~~3.3.1-114~~ 3.3.1-132	~~C~~ E;3

Table 3.3.2-13 Plant-Specific Notes:

3. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage cracking of internal surfaces copper alloy (>15% Zn) components in a condensation environment.

Table 3.3.2-13

Cracking of copper alloy >15% Zn in air clarification.

Table 3.3.2-13, Auxiliary Systems - Service Air - Aging Management Evaluation, pages 3-396 and 3-397, have been supplemented as follows (new text underlined and deleted text shown in strikethrough):

Table 3.3.2-13 Auxiliary Systems - Service Air - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Trap body	LB	Copper alloy (>15% Zn)	(I) Condensation	~~None~~ Cracking	~~None~~ Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	~~VII.J.AP-144~~ VII.I.A-405a	~~3.3.1-114~~ 3.3.1-132	~~A~~ E;1

Table 3.3.2-13 Plant-Specific Notes:

1. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25) program will manage cracking of internal surfaces copper alloy (>15% Zn) components in a condensation environment.

Table 3.3.2-15

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Table 3.3.2-15, Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation, page 3-420, has been supplemented as follows (new text underlined):

Table 3.3.2-15 Auxiliary Systems - Chemical and Volume Control - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation (containment penetration)	TI	Calcium silicate	(E) Air – indoor uncontrolled	Reduction of thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VII.I.A-704	3.3.1-182	A

Section 3.4.2.1.4

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Section 3.4.2.1.4, Main Steam System, pages 3-560 and 3-561 in the "Materials List" and "Aging Effects Require Management" sub-sections, have been supplemented as follows (new text underlined):

3.4.2.1.4 Main Steam System

Materials

The materials of construction for the main steam system component types are:

- Calcium silicate
- Copper alloy
- Stainless steel
- Steel

Aging Effects Requiring Management

The following aging effects, associated with the main steam system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- Reduction of thermal insulation resistance
- Wall thinning

Section 3.4.2.1.8

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Section 3.4.2.1.8, Feedwater System, pages 3-566 and 3-567 in the "Materials List" and "Aging Effects Require Management" sub-sections, have been supplemented as follows (new text underlined):

3.4.2.1.8 Feedwater System

Materials

The materials of construction for the feedwater system component types are:

- <u>Calcium silicate</u>
- Copper alloy
- Copper alloy (>15 percent Zn)
- Ductile iron
- Elastomer
- Glass
- Gray cast iron
- Polymer
- Stainless steel
- Steel

Aging Effects Requiring Management

The following aging effects, associated with the feedwater system, require management:

- Cracking
- Cracking or blistering
- Cumulative fatigue damage
- Hardening or loss of strength
- Long-term loss of material
- Loss of material
- Loss of preload
- <u>Reduction of thermal insulation resistance</u>
- Wall thinning

Section 3.4.2.1.12

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Section 3.4.2.1.12, Blowdown System, pages 3-572 and 3-573 in the "Materials List" and "Aging Effects Require Management" sub-sections, have been supplemented as follows (new text underlined):

3.4.2.1.12 Blowdown System

Materials

The materials of construction for the blowdown system component types are:

- <u>Calcium silicate</u>
- Nickel alloy
- Stainless steel
- Steel

Aging Effects Requiring Management

The following aging effects, associated with the blowdown system, require management:

- Cracking
- Cumulative fatigue damage
- Long-term loss of material
- Loss of material
- Loss of preload
- <u>Reduction of thermal insulation resistance</u>
- Wall thinning

Table 3.4.1

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal and cracking of copper alloy >15% Zn in air clarification.

Table 3.4.1, Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of the GALL-SLR Report, Items 3.4.1-063, 3.4.1-064 and 3.4.1-106 on pages 3-600 and 3-608, have been supplemented as follows (new text underlined and deleted text shown in strikethrough):

Table 3.4.1 Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of the GALL-SLR Report

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-063	Insulated steel, copper alloy (>15% Zn or >8% Al), piping, piping components, tanks, tanks (within the scope of AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks) exposed to air, condensation	Loss of material due to general, pitting, crevice corrosion (steel only); cracking due to SCC (copper alloy (>15% Zn or >8% Al) only)	AMP XI.M36, External Surfaces Monitoring of Mechanical Components or AMP XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks	No	Consistent with NUREG-2191. Loss of material of insulated steel components exposed to air-outdoor is managed by the External Surfaces Monitoring of Mechanical Components (B2.1.23) program. SPS has no in-scope insulated copper alloy (>15% Zn or >8% Al), piping, piping components, or tanks exposed to air-outdoor or condensation in the Steam and Power Conversion System. The temperatures of components with an air-indoor uncontrolled environment are above the ambient dewpoint; therefore, a condensation environment is not applicable. ~~The associated NUREG-2191 aging items are not used.~~ <u>Aging of copper alloy (>15% Zn) components in air-indoor uncontrolled environment in the Steam and Power Conversion systems is aligned to item 3.4.1-054. Cracking of copper alloy >15% Zn in air is not expected in the absence of wetting and ammonia contaminants, which are not present in an air-indoor uncontrolled environment.</u>

Item Number	Component	Aging Effect/Mechanism	Aging Management Program	Further Evaluation Recommended	Discussion
3.4.1-064	Non-metallic thermal insulation exposed to air, condensation	Reduced thermal insulation resistance due to moisture intrusion	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	~~Not applicable. SPS has no in-scope non-metallic thermal insulation exposed to air or condensation in the Steam and Power Conversion Systems. The associated NUREG-2191 aging items are not used.~~ Consistent with NUREG-2191.
3.4.1-106	Copper alloy (>15% Zn or >8% Al) piping, piping components exposed to air, condensation	Cracking due to SCC	AMP XI.M36, External Surfaces Monitoring of Mechanical Components	No	~~Not applicable. SPS has no in-scope copper alloy (>15% Zn or >8% Al) components exposed to outdoor air or external condensation in the Steam and Power Conversion systems. The contaminants necessary to promote cracking of copper alloy (>15% Zn) components are not expected in an indoor air or internal condensation environment. Aging of copper alloy (>15% Zn) components in indoor air or internal condensation environments in the Steam and Power Conversion systems are aligned to item 3.4.1-054. The associated NUREG-2191 aging items are not used.~~ Not applicable. SPS has no in-scope copper alloy (>15% Zn or >8% Al) components exposed to outdoor air or condensation in the Steam and Power Conversion systems. Aging of copper alloy (>15% Zn) components in an air-indoor uncontrolled environment in the Steam and Power Conversion System is aligned to item 3.4.1-054. Cracking of copper alloy >15% Zn in air is not expected in the absence of wetting and ammonia contaminants, which are not present in an air-indoor uncontrolled environment. The associated NUREG-2191 aging items are not used.

Table 3.4.2-4

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Table 3.4.2-4, Steam and Power Conversion System – Main Steam – Aging Management Evaluation, page 3-625, has been supplemented as follows (new text underlined):

Table 3.4.2-4 Steam and Power Conversion System – Main Steam - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation (containment penetration)	TI	Calcium silicate	(E) Air – indoor uncontrolled	Reduction of thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A

Table 3.4.2-8

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Table 3.4.2-8, Steam and Power Conversion System – Feedwater – Aging Management Evaluation, page 3-647, has been supplemented as follows (new text underlined).

Table 3.4.2-8 Steam and Power Conversion System - Feedwater - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation (containment penetration)	TI	Calcium silicate	(E) Air – indoor uncontrolled	Reduction of thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A

Table 3.4.2-11

During preparation of the cracking of copper alloy >15% Zn in air clarification, the following correction was also identified.

Table 3.4.2-11, Steam and Power Conversion System – Steam Drains – Aging Management Evaluation, page 3-666, has been supplemented as follows (deleted text shown in strikethrough):

Table 3.4.2-11 Steam and Power Conversion System - Steam Drains - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Valve body	LB;PB	Copper alloy	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Condensation	None	None	VIII.I.SP-6	3.4.1-054	A
			(I) Waste water	Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1
		Copper alloy (>15% Zn)	(E) Air – indoor uncontrolled	None	None	VIII.I.SP-6	3.4.1-054	A
			~~(I) Condensation~~	~~None~~	~~None~~	~~VIII.I.SP-6~~	~~3.4.1-054~~	~~A~~
			(I) Waste water	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.A-473c	3.3.1-160	A
				Loss of material	Selective Leaching (B2.1.21)	VII.E5.A-547	3.3.1-072	A
				Loss of material; flow blockage	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B2.1.25)	VII.E5.AP-272	3.3.1-095	A, 1

Table 3.4.2-12

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Table 3.4.2-12, Steam and Power Conversion System – Blowdown – Aging Management Evaluation, page 3-669, has been supplemented as follows (new text underlined):

Table 3.4.2-12 Steam and Power Conversion System - Blowdown - Aging Management Evaluation

Component Type	Intended Function(s)	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-2191 Item	Table 1 Item	Notes
Insulation (containment penetration)	TI	Calcium silicate	(E) Air – indoor uncontrolled	Reduction of thermal insulation resistance	External Surfaces Monitoring of Mechanical Components (B2.1.23)	VIII.H.S-403	3.4.1-064	A

Section 3.5.2.2.1.2

Thermal insulation on hot piping containment penetrations is added to the scope of subsequent license renewal.

Section 3.5.2.2.1.2, Reduction of Strength and Modulus Due to Elevated Temperature, pages 3-732 and 3-733, has been supplemented as follows (new text underlined and deleted text shown in strikethrough):

3.5.2.2.1.2 Reduction of Strength and Modulus Due to Elevated Temperature

Reduction of strength and modulus of concrete due to elevated temperatures could occur in PWR and BWR concrete and steel containments. The implementation of 10 CFR 50.55a and ASME Code Section XI, Subsection IWL would not be able to identify the reduction of strength and modulus of concrete due to elevated temperature. Subsection CC-3440 of ASME Code Section III, Division 2, specifies the concrete temperature limits for normal operation or any other long-term period. Further evaluation is recommended of a plant-specific AMP if any portion of the concrete containment components exceeds specified temperature limits [{i.e., general area temperature greater than 66°C (Celsius) [150°F (Fahrenheit)] and local area temperature greater than 93°C (200°F)}. Higher temperatures may be allowed if tests and/or calculations are provided to evaluate the reduction in strength and modulus of elasticity and these reductions are applied to the design calculations. Acceptance criteria are described in Branch Technical Position (BTP) RLSB-1 (Appendix A.1 of this SRP SLR).

~~[3.5.1-003] — UFSAR Section 15.5.1.8 discusses high temperature pipe penetrations. Containment structure piping penetrations for all thermally hot (over 150°F) piping systems are sleeved penetrations. The main steam and feedwater penetrations are provided with adequate space between the piping and the sleeve for the necessary pipe insulation, and for a pipe coil outside the insulation through which component cooling water is circulated. This cooling coil reduces the temperature of the sleeve and prevents any excessive heating (over 150°F) of the concrete in contact with the sleeve. UFSAR Section 15.6.2.2.1 discusses the reactor vessel support, which consists of six sliding foot assemblies mounted on the neutron shield tank. The neutron shield tank is a double-walled cylindrical structure that transfers the loadings to the heavy reinforced concrete mat of the Containment structure. The tank also serves to minimize gamma and neutron heating of the primary concrete shield. UFSAR Section 5.3.1.2 discusses the design basis for the Containment ventilation systems. The ventilation systems were originally designed to~~
~~limit the Containment bulk air temperature to below 105°F. Operating experience has demonstrated that the heat load in Containment exceeds the original design estimates but that the ventilation systems are adequate to maintain the Containment bulk air temperatures less than~~

~~125°F. The penetration cooling coils are managed for aging in the component cooling system (Section 2.3.3.8). The containment ventilation system is subject to Technical Specification limitations on containment bulk air temperature. Therefore, the aging effects due to elevated temperatures are not applicable for SPS, and a plant specific aging management program is not required.~~

[3.5.1-003] – UFSAR Section 15.5.1.8 discusses high temperature pipe penetrations. Containment structure piping penetrations for all thermally hot (over 150°F) piping systems are sleeved penetrations. The hot piping containment penetrations are provided with adequate space between the piping and the sleeve for the necessary pipe insulation, and for a pipe coil outside the insulation through which component cooling water is circulated. This cooling coil and insulation reduce the temperature of the sleeve and prevent any heating of the concrete in contact with the sleeve from exceeding the ACI Code limit of 200°F for local areas.

UFSAR Section 15.6.2.2.1 discusses the reactor vessel support, which consists of six sliding foot assemblies mounted on the neutron shield tank. The neutron shield tank is a double-walled cylindrical structure that transfers the loadings to the heavy reinforced-concrete mat of the Containment structure. The tank also serves to minimize gamma and neutron heating of the primary concrete shield.

UFSAR Section 5.3.1.2 discusses the design basis for the Containment ventilation systems. The ventilation systems were originally designed to limit the Containment bulk air temperature to below 105°F. Operating experience has demonstrated that the heat load in Containment exceeds the original design estimates but that the ventilation systems are adequate to maintain the Containment bulk air temperatures less than 125°F. The containment ventilation system is subject to Technical Specification limitations on containment bulk air temperature.

The penetration cooling coils are managed for aging in the component cooling system (Section 2.3.3.8). The insulation for the containment penetrations is managed for aging in the main steam system (Section 2.3.4.4), the feedwater system (Section 2.3.4.8), the blowdown system (Section 2.3.4.12), and the reactor coolant system letdown, which is managed as part of the chemical and volume control system (Section 2.3.3.15). The aging effects due to elevated temperatures are not applicable for SPS, and a plant-specific aging management program is not required.

4.8-60 NUREG/CR-5704, "Effects of LWR Coolant Environments on Fatigue Design Curves of Austenitic Stainless Steels," April 1999. (ML031480394)

4.8-61 WCAP-16990-P (Proprietary), Revision 0, "Surry Units 1 and 2 Measurement Uncertainty Recapture Power Uprate Project Engineering Report," May 2010.

4.8-62 Inspection and Enforcement Bulletin (IEB) 79-01B, "Environmental Qualification of Class 1E Equipment." (ML080310648)

4.8-63 IEEE Standard 323-1974, "IEEE Standard for Qualifying Class 1E Equipment for Nuclear Power Generating Stations." (ML032200206)

4.8-64 11448-EA-62, Revision 0, Add. 00C, "Reactor Containment Liner Fatigue Evaluation for 80-Year Plant Life."

4.8-65 Crane Manufacturers Association of America Specification 70, 1975.

4.8-66 NUREG-0612, "Control of Heavy Loads at Nuclear power Plants," July 1980. (ML070250180)

4.8-67 ANSI Standard B30.11-1973, "Monorail Systems and Underhung Cranes."

4.8-68 ANSI Standard B30.16-1973, "Overhead Hoists."

4.8-69 ASME Standard HST-4, "Performance Standard for Overhead Electric Wire Rope Hoists."

4.8-70 Electric Overhead Crane Institute (EOCI) Specification 61 for Electric Overhead Traveling Cranes.

4.8-71 NRC Generic Letter 81-07, "Control of Heavy Loads."

4.8-72 WCAP-14535A, "Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination," November 1996.

4.8-73 NRC Letter, "Surry Power Station, Units 1 and 2 - Issuance of Amendments to Extend the Inspection Interval for Reactor Coolant Pump Flywheels (TAC Nos. MC4215 and MC4216)," June 21, 2005. (ML051640591)

4.8-74 WCAP-15666-A, Revision 1, "Extension of Reactor Coolant Pump Motor Flywheel Examination," October 2003.

4.8-75 PWROG-17011-NP, Revision ~~1~~2, "Update for Subsequent License Renewal: WCAP-14535A, 'Topical Report on Reactor Coolant Pump Flywheel Inspection Elimination' and WCAP-15666-A, 'Extension of Reactor Coolant Pump Motor Flywheel Examination,'" ~~May 2018.~~ January, 2019.

A1.23 EXTERNAL SURFACES MONITORING OF MECHANICAL COMPONENTS

The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that manages loss of material, cracking, and reduction of heat transfer of metallic components; hardening or loss of strength, loss of material, and cracking or blistering of polymeric components; loss of preload of HVAC closure bolting; and reduced thermal insulation resistance. Periodic visual inspections, not to exceed a refueling outage interval, of metallic, polymeric, and insulation jacketing (insulation when not jacketed) are conducted. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual inspections conducted under this program.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel, aluminum and copper alloy (>15% Zn or >8% Al) components.

A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), are periodically inspected every ten years during the subsequent period of extended operation. Following insulation removal, surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect loss of material and cracking of the component surfaces.

Non-ASME Code inspection procedures include inspection parameters such as lighting, distance, offset, and surface conditions.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. Qualitative acceptance criteria are clear enough to reasonably assure a singular decision is derived based on observed conditions.

The external surfaces of components that are buried or in underground environments are inspected by the *Buried And Underground Piping And Tanks* program (A1.27). The external surfaces of outdoor tanks and indoor large volume metallic storage tanks (capacity >100,000 gallons) are inspected by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (A1.17). Loss of material due to boric acid corrosion is managed by the *Boric Acid Corrosion* program (A1.4).

A1.24 FLUX THIMBLE TUBE INSPECTION

The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that manages loss of material due to wear by inspecting for the thinning of flux thimble tube walls. Flux thimble tubes provide a path for the in-core neutron flux monitoring system detectors and forms part of the reactor coolant system pressure boundary. Flux thimble tubes are subject to loss of material at certain locations in the reactor vessel (RV) where flow-induced fretting causes wear at discontinuities in the path from the RV instrument nozzle to the fuel assembly instrument guide tube. The thimble tube design is a double-walled, asymmetrical configuration to accommodate thermocouple leads located in the annulus between the inner and outer flux thimble tubes. The outer tube is the component that is most susceptible to wear due to its contact with the discontinuities. The inner tube through which the incore detector travels is the reactor coolant system pressure boundary. The double wall design significantly reduces the potential for wear of the inner tube pressure boundary. Periodic eddy current examinations are performed to confirm the integrity of the inner flux thimble tube, and are consistent with the recommendations of NRC Bulletin 88-09, "Thimble Tube Thinning in Westinghouse Reactors."

A1.25 INSPECTION OF INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also manages hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components. This program consists of visual inspections of all accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to air, condensation, diesel exhaust, fuel oil, lubricating oil, and any water environment. Aging effects associated with items (except for elastomers) within the scope of the *Open-Cycle Cooling Water System* program (A1.11), *Closed Treated Water Systems* program (A1.12), and *Fire Water System* program (A1.16) are not managed by this program. For certain materials, such as flexible polymers, physical manipulation or pressurization to detect hardening or loss of strength is used to augment the visual examinations conducted under this program.

Surface examinations or ASME Code, Section XI, visual examinations (VT-1) are conducted to detect cracking of stainless steel, aluminum and, copper alloy (>15% Zn) components.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
11	*Open-Cycle Cooling Water* program	The *Open-Cycle Cooling Water* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that will be enhanced as follows: 1. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program. 2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation. 3. The internal lining of 24 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation. ~~4. Procedures will be revised to remove reference to the carbon steel piping that was replaced and will include the replacement material.~~(Completed SLRA Change Notice 1) 5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement. 6. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the Structures Monitoring program (B2.1.34) that are consistent with the requirements of ACI 349.3R. 7. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering. 8. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results. 9. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses. 10. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions. 11. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing "hoop" bands or rust staining from such reinforcing elements. 12. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation.	B2.1.11	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	The *Fire Water System* program is an existing condition monitoring program that will be enhanced as follows: ~~1. Procedures inspection guidance will be revised to require replacement of any sprinkler that shows any of the following: leakage, corrosion, physical damage, loading, painting unless painted by the sprinkler manufacturer, or incorrect orientation. Sprinklers at the following locations will be added to the test scope: The Radwaste Facility, Auxiliary Boiler, Maintenance Building, Condensate Polishing Building, Laundry Building, and Machine Shop Building.~~ (Completed Change Notice 1) 2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner. For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed. 3. Procedures will be revised to specify: a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow. b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action. c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination. d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures. 4. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests. ~~5. Procedures for hydrant flushing will be revised to require fully opening the hydrant and fully flowing the hydrant for no less than one minute and until foreign material has cleared. In addition, procedures will be revised to observe draining of the hydrant barrel and also require the barrel be pumped dry should it not drain within 60 minutes. Hydrants outside the protected area that are within the scope of subsequent license renewal will be added to the flush scope.~~ (Completed Change Notice 1)	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	6. The Fire Water System program will be revised to periodically inspect the insulated exterior surfaces of the fire water tanks on a 10-year frequency during the subsequent period of operation. Insulation is removed to provide a minimum inspection population of 25 one-square foot samples. The samples will be distributed in such a way that inspections occur on the tank dome, near the tank bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect. In addition, inspection locations will be based on the likelihood of corrosion under insulation occurring. 7. ~~Procedures for mainline strainer flushing will be revised to require flushing until clear water is observed after each operation or flow test. In addition to flushing after operation, the Radwaste Facility mainline strainer will require an inspection every five years for damaged and corroded parts.~~ (Completed Change Notice 1) 8. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. 9. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect age-related degradation in excess of what would be expected accounting for design, previous inspection experience, and inspection interval. If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following: a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected. b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. 10. Procedure will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
16	*Fire Water System* program	11. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer '1A' deluge sprinkler piping will be reconfigured to allow drainage. 12. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe w	B2.1.16	Program will be implemented and inspections or tests begin 5 years before the subsequent period of extended operation. Inspections or tests that are to be completed prior to the subsequent period of extended operation are completed 6 months prior to the subsequent period of extended operation or no later than the last refueling outage prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
23	*External Surfaces Monitoring of Mechanical Components* program	The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that will be enhanced as follows: 1. The Engineering walkdown procedure will be revised to include an item in the walkdown checklist to inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture. 2. The Engineering walkdown procedure will be revised to add the following requirements: a. Metallic Components • No surface imperfections, loss of wall thickness, flaking, or oxide coated surfaces • No blistering of protective coating • No evidence of leakage (for detection of cracks) on the surfaces of stainless steel, ~~and~~ aluminum, and copper alloy (>15% Zn or >8% Al) components (Revised Change Notice 1) • No accumulation of debris on air-side heat exchanger surfaces b. Elastomers and Flexible Polymers • No exposure of reinforcing fibers, mesh or underlying metal (for elastomers or flexible polymers with internal reinforcement) • No blistering, loss of thickness, dimensional change, or scuffing • No hardening of elastomeric elements as evidenced by a loss of suppleness during tactile inspection c. Insulation Metallic Jacketing • Inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture. d. HVAC Closure Bolting • Check that a sample of closure bolting that is in reach is not loose 3. The Engineering walkdown procedure will be revised to specify that walkdowns will be performed at a frequency not to exceed one refueling cycle. Since some surfaces are not readily visible during both plant operations and refueling outages, the enhancement will also specify that such surfaces will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained. 4. The Engineering walkdown procedure will be revised to provide non-ASME Code inspection guidance related to lighting, distance and offset for walkdown inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. 5. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. A minimum of 25 inspections for cracking will be performed from each of the stainless steel, ~~and~~ aluminum, and copper alloy (>15% Zn or >8% Al) component populations assigned to the program every ten years. For insulated components exposed to condensation, a minimum of 25 one foot axial length sections and components for each material and environment combination will be inspected for loss of material and cracking after the insulation is removed. The new procedure will specify that the inspections focus on the components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin. (Revised Change Notice 1)	B2.1.23	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

Table A4.0-1 Subsequent License Renewal Commitments

#	Program	Commitment	AMP	Implementation
23	*External Surfaces Monitoring of Mechanical Components* program	6. The Engineering walkdown procedure will be revised to specify that visual inspection of elastomers and flexible polymers will be supplemented by tactile inspection to detect hardening. Visual inspections will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area. 7. A new procedure will be developed to evaluate and project the rate of any degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection. 8. A new procedure will be developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions. 9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections to detect cracking in aluminum, ~~and~~ stainless steel, and copper alloy (>15% Zn or >8% Al) components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., 10-year inspection interval) in which the original inspection was conducted. (Revised Change Notice 1)	B2.1.23	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.
24	*Flux Thimble Tube Inspection* program	The *Flux Thimble Tube Inspection* program is an existing condition monitoring program that will be enhanced as follows: 1. An inspection procedure will be developed specifically for flux thimble tube eddy-current inspections, rather than continuing to use a generic procedure for tubing inspection. The procedure will include the acceptance criterion, with the basis, for loss of material for the inner flux thimble tube, and identify remediating actions to be implemented if the acceptance criterion is exceeded.	B2.1.24	Program enhancements for SLR will be implemented 6 months prior to the subsequent period of extended operation.

B2.1.11 Open-Cycle Cooling Water System

Program Description

The *Open-Cycle Cooling Water System* program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages loss of material, reduction of heat transfer, flow blockage, and cracking of the piping, piping components, and heat exchangers identified by the Virginia Electric and Power Company responses to NRC GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment." The program is comprised of the aging management aspects of the Virginia Electric and Power Company response to GL 89-13 and includes: (a) surveillance and control to reduce the incidence of flow blockage problems as a result of biofouling, (b) tests to verify heat transfer of safety-related heat exchangers, (c) routine inspection and maintenance so that loss of material, corrosion, erosion, cracking, fouling, and biofouling cannot degrade the performance of systems serviced by the open-cycle cooling water system. Additionally, recurring internal corrosion (RIC) is addressed in the Corrective Action Program through design modifications that have replaced materials more susceptible to degradation in raw water with materials that are less susceptible to degradation in raw water. This program includes enhancements to the guidance in GL 89-13 that address operating experience such that aging effects are adequately managed.

The open-cycle cooling water system includes those systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13.

The guidelines of GL 89-13 are utilized for the surveillance and control of biofouling for the open-cycle cooling water system. Procedures provide instructions and controls for chemical and biocide injection. Periodic sampling procedures monitor free available oxidant at heat exchangers. In addition, periodic flushing, cleanings and/or inspections are performed for the presence of biofouling.

Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the site commitments to GL 89-13 to verify heat transfer capabilities. Additionally, safety-related piping segments are examined (i.e. ultrasonic testing) periodically to ensure that there is no significant loss of material, which could cause a loss of intended function.

Routine inspections and maintenance ensure that corrosion, erosion, sediment deposition (silting), and biofouling do not degrade the performance of safety-related systems serviced by open-cycle cooling water. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) manages the aging effects of the internal surface coatings.

Aging effects associated with elastomers and flexible polymeric components in the open-cycle cooling water system are managed by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25).

The *Buried and Underground Piping and Tanks* program (B2.1.27) manages the aging effects of external surfaces of buried and underground piping and components. The external surface of the aboveground raw water piping and heat exchangers is managed by the *External Surfaces Monitoring of Mechanical Components* program (B2.1.23). The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging effects of internal surface coatings including those of metallic surfaces coated with Carbon Fiber Reinforced Polymer that is used as a pressure boundary.

NUREG-2191 Consistency

The *Open-Cycle Cooling Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI.M20, Open-Cycle Cooling Water System.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4)

1. Section XI.M20 of NUREG-2191, Open-Cycle Cooling Water, indicates that testing intervals can be adjusted to provide assurance that equipment will perform the intended function between test intervals, but should not exceed five years. The *Open-Cycle Cooling Water System* program takes exception to the NUREG-2191 requirement to perform testing of the recirculation spray heat exchangers (RSHXs) at an interval not to exceed five years.

<u>Justification for Exception</u>:

As described in the plant responses to GL-89-13, heat transfer performance testing of the RSHXs is not performed due to system configuration that would require significant design modifications to support such testing. Alternatively, the RSHXs are visually inspected to confirm the absence of indications of degradation. To further reduce the potential for degradation, the internal environment of the RSHXs and the portion of the connected piping that cannot be isolated from the RSHXs is maintained in dry layup (i.e., maintained in an air environment) and the internals of the portion of the inlet piping that is not in dry layup is maintained in wet layup (i.e., a treated water environment that has been chemically treated to maintain a basic pH) to minimize corrosion. The open-cycle cooling water side of the RSHXs are periodically flow tested and visually inspected.

The plant GL 89-13 responses stated that the RSHXs would be flow tested and visually inspected every fourth refueling outage (i.e., every six years) and that the testing and inspection intervals may be modified based on the results of further testing. Based on the results of further testing, the RSHXs are currently flow tested and visually inspected at an interval of eight refueling outages (i.e., every twelve years).

The change in frequency to once every eight refueling outages for RSHXs flow testing and visual inspection was evaluated by Engineering. The evaluation included a review of prior operating experience (flow testing and visual inspection results). Prior flow test results documented between 1997 and 2010 were reviewed. The test results identified little or no blockage, with the exception of a test performed in 2003. The 2003 results revealed 5% blockage, which was still less than the 10% blockage acceptance criteria. RSHXs service water inlet and outlet piping cleaning and inspection are performed on a frequency consistent with RSHXs flow testing. A review of prior piping inspection results between 1996 and 2014 showed the piping to be in satisfactory condition. Although coating defects and areas of corrosion were identified during the piping inspections, the RSHXs were capable of performing their intended function. Required coating and weld repairs were entered in the Corrective Action Program.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Selected fiberglass reinforced plastic (FRP) piping in the service water system will be replaced with a more degradation resistant material such as copper-nickel (Cu-Ni) prior to entering the subsequent period of extended operation. FRP piping associated with the Units 1 and 2 charging pump cooling water subsystems, service water rotating strainers, and the control room chillers may be replaced as part of a time-phased program.
2. Modifications necessary to provide new chemical injection site upstream of the service water rotating strainers will be completed prior to entering the subsequent period of extended operation.
3. The internal lining of 24 inch and larger service water inlet piping with carbon fiber reinforced polymer, with the exception of the recirculation spray heat exchanger piping downstream of the inlet motor-operated valves, will be completed prior to entering the subsequent period of extended operation.

Parameters Monitored and Inspected (Element 3)

4. ~~Procedures will be revised to remove reference to the carbon steel piping that was replaced and will include the replacement material.~~

5. Procedures will be revised to provide additional guidance for identifying and evaluating applicable concrete aging effects such as loss of material due to delamination, exfoliation, spalling, popout, scaling, or cavitation; and cracking due to chemical reaction, or corrosion of reinforcement.

Detection of Aging Effects (Element 4)

6. Procedures will be revised to require personnel who perform inspections and evaluation of concrete components to be qualified consistent with the qualifications identified in the *Structures Monitoring* program (B2.1.34) that are consistent with the requirements of ACI 349.3R.

Monitoring and Trending (Element 5)

7. Procedures will be revised to require trending of charging pump lube oil cooler and emergency service water pump engine heat exchanger inspection results by Engineering.

8. Procedures will be revised to require trending of wall thickness measurements. The frequency and number of wall thickness measurements will be based on trending results.

Acceptance Criteria (Element 6)

9. Procedures will be revised to include verification that predicted wall thicknesses at the next scheduled inspection will be greater than the minimum wall thicknesses.

10. Procedures will be revised to include criteria for the extent and rate of on-going degradation that will prompt additional corrective actions.

11. Procedures will be revised to identify acceptance criteria for visual inspection of concrete piping and components such as the absence of cracking and loss of material, provided that minor cracking and loss of material in concrete may be acceptable where there is no evidence of leakage, exposed rebar or reinforcing "hoop" bands or rust staining from such reinforcing elements.

Corrective Actions (Element 7)

12. Procedures will be revised to ensure that for ongoing degradation mechanisms (e.g., MIC), the frequency and extent of wall thickness inspections at susceptible locations are increased commensurate with the significance of the degradation.

13. Procedures will be revised to ensure that when measured parameters do not meet the acceptance criteria, additional inspections are performed, when the cause of the aging effect is not corrected by repair or replacement for components with the same material and environment combination. The number of inspections will be determined by the Corrective Action Program, but no fewer than five additional inspections will be performed for each inspection that did not meet the acceptance criteria, or 20% of the applicable material, environment, and aging effect combination inspected, whichever is less. The additional inspections will include inspections at both Unit 1 and Unit 2 with the same material, environment, and aging effect combination.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In September 2001, a through wall leak was identified in an eight inch carbon steel control room chiller service water supply line. A through wall leak in similar piping occurred again in September 2005. In May 2006, volumetric inspections measurements identified a location in an eight inch carbon steel control room chiller service water supply line that was less than the minimum allowable wall thickness. A design change was implemented, which replaced the eight inch carbon steel piping with copper-nickel piping.
2. Between August 2007 and July 2009, biofouling of the control room chillers Y-strainers and rotating strainers occurred on multiple occasions. The initial cause was thought to be insufficient backwash flow to the rotating strainers during periods of elevated service water temperatures with one control room chiller operating. Procedure changes were implemented to start an additional pump and backwash the rotating strainers when differential pressure reaches one psid. Further clogging of the Y-strainers resulted in compensatory actions being established. These measures included increased monitoring of control room chiller and service water operating parameters when service water temperature was greater than 80°F, weekly flushing of control room chiller service water lines, and securing the chiller and cleaning the chiller suction strainers when pump suction pressure approached the minimum required net positive suction head.

In July 2009, repeated clogging of the control chiller suction Y-strainers occurred. Additional compensatory measures included more frequent flushing of the control room chiller service water piping, and running a minimum of two control room chillers to minimize system transients, which was determined to exacerbate biofouling of the strainers. In the fall of 2009, a modification was completed that provided additional chemical (biocide) injection into the service water system downstream of the rotating strainers and upstream of the Y-strainers to control biofouling. Chemical injection has proven effective in reducing biofouling of the Y-strainers and associated piping.

3. In October 2009, following sampling of the service water side of the component cooling heat exchangers, chemistry personnel determined the free available oxidant (FAO) readings were below minimum acceptable values, which could jeopardize control of biofouling in the system. The chemical injection pump settings were adjusted to restore the pump discharge pressure. Samples taken following adjustments revealed that the FAO levels were acceptable.

4. In February 2010, augmented volumetric inspections of the component cooling heat exchanger service water supply and discharge piping identified piping wall thicknesses that were less than minimum allowed. A weld repair was performed and the calculation of record was updated to reflect the results of the wall thickness readings. Pipe stresses were determined to be within code allowable. Subsequent wall thickness measurements taken following repairs were acceptable.

5. In January 2012, during the performance of a license renewal inspection of a component cooling heat exchanger, pitting, defective coatings, barnacles, and river debris were identified in the heat exchanger. Corrective actions included replacement of a manway, removal of debris from the heat exchanger, coating repairs, and performance of a weld repair. Inspections performed in April 2013 and February 2016 also identified needed weld repairs to the heat exchanger end bell. A surface examination and system pressure test were performed satisfactorily following weld repairs.

6. In October 2013, during surface preparation and weld inspections, a through wall leak was observed in the 42 inch service water piping adjacent to the motor-operated valve supplying service water to the component cooling water heat exchangers from the '1B' condenser water box tunnel. The cause of pipe wall thinning was determined to be non-application of the pipe internal coating. Historically, the motor-operated valve exhibited seat leakage since original installation. In an effort to control leakage, a blank and a hose were used to divert the leakage. As a result, the piping at the blank was unable to be properly coated. Over time, the lack of coating resulted in significant wall loss. Corrective actions included replacement of the valve with a design which would minimize valve leakage, weld repairs to the piping, and internal coating of the piping. A post-weld surface examination and system pressure test were performed satisfactorily.

7. In November 2013, three through wall leaks were identified in the 42 inch piping upstream of the motor-operated valve supplying service water to the component cooling water heat exchangers from the '1D' condenser water box tunnel. The leaks were identified following sand blasting of the piping in preparation for application of internal coating. Weld repairs were performed to correct the deficiencies. A surface examination and system pressure test were performed satisfactorily subsequent to the repairs.

8. Between September 2015 and September 2016, five leaks occurred in the service water system due to cracking of fiberglass piping. The leaks were either repaired or new piping segments installed in accordance with the work order process. The fiberglass piping in the service water system may be replaced with corrosion resistant material such as copper-nickel as part of a time-phased program.

9. In December 2015, an effectiveness review of the Service Water System Inspections Activity (UFSAR Section 18.2.17) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. No gaps were identified by the effectiveness review.

10. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMA was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.

11. In September 2017, as part of oversight activities, of the Service Water Inspections Activity (UFSAR Section 18.2.17) it was noted that commitments for the low level intake screenwell (LLIS) and emergency service water pump suction end bell cleaning/inspections were not being performed and documented consistent with the original License Renewal commitment. The License Renewal commitments for the LLIS cleaning and pump inspections were originally incorporated into the procedure that dewatered the LLIS. The recent license renewal cleaning/inspections were performed by divers using a recurring work activity without dewatering the LLIS. A corrective action was initiated for engineering and outage planning to resolve the inconsistency. It was determined that the cleaning and inspection commitments were satisfactorily completed without dewatering the LLIS. Update of the maintenance strategy and associated documents to allow performance of the license renewal commitments with or without dewatering the LLIS is in progress.

12. In January 2018, an aging management program effectiveness review was performed for the Service Water System Inspections Activity (UFSAR Section 18.2.17). Information from the summary of that effectiveness review is provided below:

    The Service Water System Inspections Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed include the selection of components to be inspected, the inspection of components, the evaluation of inspection results, repairs/replacements, and AMA document updates. Engineering reports from 2004 to 2016 of inspections results were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of open-cycle cooling water system components within the scope of license renewal.

    The key aspects of the *Open-Cycle Cooling Water System* program involve controlling biofouling, testing critical heat exchangers, inspecting and cleaning the system, and designing with robust materials. The program is implemented using an active Service Water System Inspection and Maintenance Program and has a well-established Generic Letter 89-13 Program. These programs govern the approach to compliance with the Nuclear Regulatory Commission (NRC) Generic Letter 89-13, Service Water Problems Affecting Safety-Related Equipment. The Program is inspected every three years by the NRC using Inspection Procedure 71111.07, Heat Sink Performance. The most recent inspection did not identify any findings. Additionally, station effectiveness is assessed by implementing INPO SOER 07-2, Intake Cooling Water Blockage every three years. The assessment reviews operating experience, condition reports, and equipment performance for the three year period. The most recent assessment, completed in September 2016, concluded that open-cycle cooling water equipment has been performing satisfactorily.

    Over the summers of 2007 through 2009, a series of events involving an influx of biological growth from the James River prompted the creation of the Service Water Excellence Plan. The plan has resulted in numerous improvements designed to greatly reduce the adverse effects of biofouling and aging. For example, a biocide injection system has been installed to reduce biological growth, key pieces of safety-related piping have been converted to corrosion and fouling resistant materials, and new monitoring and flushing procedures have been instituted. More recently, since entering the first period of extended operation, the interior of the large diameter open-cycle cooling water piping has begun to be lined with carbon fiber reinforced polymer (CFRP). Surry Power Station is first in the industry to employ this technology. It is predicted that the CFRP will add 50 years of effective service life to the asset. The biocide injection point on the safety-related service water piping will also be relocated to maximize effectiveness.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and internal fouling of components, has occurred on several occasions. Corrective actions have been taken previously, and additional actions are scheduled to minimize the likelihood of piping and component degradation due to flow blockage and loss of material in the open-cycle cooling water system. The physical modifications completed or scheduled, and enhancements to operating practices and system design to improve OCCW system resistance to recurrence of internal corrosion are noted below:

The Open-Cycle Cooling Water (OCCW) System program will manage aspects of RIC in the service water system and the circulating water system that are within the scope of the program. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage loss of material on the internal surfaces of service water system and circulating water system piping that has been lined or coated. The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25) will manage loss of material on the internal surfaces of service water system and circulating water system piping not covered by NRC Generic Letter 89-13.

Flow Blockage:

Flow blockage in OCCW system piping and components is managed by periodically monitoring control room chiller Y-strainer differential pressure and periodically flushing affected piping flow paths. During times when service water temperatures are elevated, above 80°F, the operations surveillance frequency of monitoring service water suction pressure and rotating strainer differential pressures are increased to intervals as short once every 4 hours and piping flush frequency increased to once daily. As a preventive measure, biocide injection points have been added downstream of the rotating suction strainers and the biocide injection has significantly reduced hydroid attachment and growth. A plant modification is in progress to add additional injection points to the upstream portion of the service water rotating strainers.

Loss of Material in Uncoated Steel Piping:

Loss of material has resulted in recurrent wall thinning and through wall leakage in service water piping in uncoated steel service water piping associated with main control room chillers. Replacement of uncoated steel piping with corrosion resistant copper-nickel piping reduced the susceptibility of the OCCW systems to recurring internal corrosion. There has been no documented recurring internal corrosion on the control room chillers copper-nickel piping or other copper-nickel service water system piping within the scope of subsequent license renewal.

Loss of Material in Copper-Nickel Alloy Heat Exchanger Tubing:

Recurring internal corrosion (loss of material) was experienced in the copper-nickel alloy heat exchanger tubing at and beyond the tube sheet for the main control room chiller condensers, including a condenser that had been recently replaced. The affected heat exchanger components have been cleaned and coated with a protective epoxy coating with the coating extending six inches into the heat exchange tubes. The Corrective Action Program apparent cause evaluation identified that the heat exchanger management program did not require flow to be maintained for an extended period in new 90-10 copper-nickel alloy heat exchangers to permit a protective oxide film to form on the tubes prior to the placement of the heat exchangers into a stagnant wet lay-up condition. Implementing documents have been modified to incorporate this lesson-learned. After epoxy coating and modification of wet layup practices, there has been no documented recurring internal corrosion in the control room chiller condenser copper-nickel alloy tubing at and beyond the tube sheet.

Loss of Material in Coated Steel Piping and Heat Exchanger Channel Heads:

Corrosion-resistant Carbon Fiber Reinforced Polymer (CFRP) liner will be installed in the 96-inch circulating water inlet piping, and 24-, 30-, 36-, 42-, and 48-inch service water supply from the circulating water system to the recirculation spray and supply to the component cooling water heat exchangers. The CFRP system is designed to take the place of the existing carbon steel pipe and will form a repaired pipe within the existing piping that is capable of meeting the design requirements of the station piping. The appropriate relief has been granted for this repair by the NRC. The *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging of CFRP in the OCCW systems. For epoxy coated piping sections and heat exchanger channel heads that do not yet have the CFRP lining installed, the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28) will manage the aging of the existing epoxy-coated steel piping.

The above examples of operating experience provide objective evidence that the *Open-Cycle Cooling Water System* program includes activities to perform surveillance and control, heat exchanger testing, and routine inspection and maintenance to identify loss of material, reduction of heat transfer, flow blockage, and cracking of the piping, piping components, and heat exchangers within the scope of subsequent license renewal, as identified by the Virginia Electric and Power Company responses to NRC GL 89-13, and to initiate corrective actions. Occurrences identified under the *Open-Cycle Cooling Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Open-Cycle Cooling Water System* program, following enhancement, will effectively manage aging prior to loss of intended function.

Conclusion

The continued implementation of the *Open-Cycle Cooling Water System* program, following enhancement, provides reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis for the subsequent period of extended operation.

B2.1.16 Fire Water System

Program Description

The *Fire Water System* program is an existing condition monitoring program that manages loss of material, flow blockage, and loss of coating integrity for in-scope water-based fire protection systems. This program manages aging effects by conducting periodic visual inspections, flow testing, and flushes. Testing and inspections are conducted on a refueling outage interval as allowed by NUREG-2191, Section XI.M27, Table XI.M27-1, "Fire Water System Inspection and Testing Recommendations". There are no nozzle strainers, glass bulb sprinklers, fire pump suction strainers, or foam water sprinkler systems within the scope of subsequent license renewal.

The *Fire Water System* program will include testing a representative sample of the sprinklers prior to fifty years in service with additional representative samples tested at 10-year intervals. Sprinkler testing will be performed consistent with the 2011 Edition of NFPA 25, "Standard For The Inspection, Testing and Maintenance of Water-Based Fire Protection Systems," Section 5.3.1. The fifty year in-service date for sprinklers is October 26, 2021.

Portions of water-based fire protection system components that have been wetted, but are normally dry, such as dry-pipe or preaction sprinkler system piping and valves, were designed and installed with a configuration and pitch to allow draining. With the exception of two locations, Engineering walkdowns confirmed the as-built configuration that allows draining and does not allow water to collect. Corrective actions have been initiated for the two locations to verify a flow blockage condition does not exist and to restore the two locations to original configuration requirements that allow draining and do not allow water to collect. After corrective actions, portions of the water-based fire protection system that have been wetted, but are normally dry, will not be subjected to augmented testing and inspections beyond those required by NUREG-2191, AMP XI.M27, Table XI.M27-1.

The water-based fire protection system is normally maintained at required operating pressure and is monitored such that loss of system pressure is detected and corrective actions initiated. A low pressure condition is alarmed in the Main Control Room by the auto start of the electric motor driven fire pump, followed by the start of the diesel-driven fire pump if the low pressure condition continues to exist. The status of the fire pumps is indicated in the Main Control Room and at the fire pump control panels in the pump house. Both fire pumps may be manually started from the control room.

Piping wall thickness measurements are conducted when visual inspections detect surface irregularities indicative of unexpected levels of degradation. When the presence of organic or inorganic material sufficient to obstruct piping or sprinklers is detected, the material is removed and the source is detected and corrected.

Inspections and tests are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Non-code inspections and tests follow procedures that include inspection parameters for items such as lighting, distance, offset, presence of protective coatings, and cleaning processes that ensure an adequate examination.

If a flow test (i.e., NFPA 25, 2011 Edition, Section 6.3.1) or a main drain test (i.e., NFPA 25, 2011 Edition, Section 13.2.5) does not meet the acceptance criteria due to current or projected degradation, additional tests are conducted. The number of increased tests is determined in accordance with the site's corrective action process; however, there are no fewer than two additional tests for each test that did not meet the acceptance criteria. The additional inspections are completed within the interval (i.e., five years or annual/refueling) in which the original test was conducted. If subsequent tests do not meet the acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests required. The additional tests will include at least one test at the other unit on site with the same material, environment, and aging effect combination.

In addition to piping replacement, actions will be taken to address instances of recurring corrosion due to microbiological induced corrosion. Low Frequency Electromagnetic Technique (LFET) or similar scanning technique will be used for screening 100 feet of accessible piping during each refueling cycle to detect changes in the wall thickness of the pipe. Thinned areas found during the LFET scan are followed up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

Aging of the external surfaces of buried and underground fire main piping is managed by the *Buried and Underground Piping and Tanks* program (B2.1.27). Loss of material and cracking of the internal surfaces of cement lined buried and underground fire main piping are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

Aging of the fire water storage tank bottom surfaces exposed to oil soil are managed by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17).

Acceptance criteria, corrective action recommendations, and training/qualification of individuals involved in fire water storage tank internal coating inspections are implemented by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28).

NUREG-2191 Consistency

The *Fire Water System* program is an existing program that, following enhancement, will be consistent, with exception, to NUREG-2191, Section XI M27, Fire Water System.

Exception Summary

The following program element(s) are affected:

Detection of Aging Effects (Element 4)

1. The fire water storage tanks are insulated carbon steel tanks located in an outdoor environment. NUREG-2191, AMP XI.M27, Table XI.M27-1 and note 10 recommends the insulated external surfaces of fire water storage tanks be inspected for signs of degradation on a refueling outage interval for signs of degradation. This would require insulation removal each refueling cycle. Therefore, inspections of the external carbon steel surfaces of the fire water storage tanks will be performed on a 10-year frequency during the subsequent period of operation.

Justification for Exception:

The line item in NUREG-2191, Section XI.M27, Table XI.M27-1, for water storage tank external surfaces recommends the inspection guidance of NFPA, 2011 Edition, Section 9.2.5.5, which requires inspection of insulated tank surfaces. NFPA, 2011 Edition, Section 9.2.5.5, does not provide specific inspection guidance for corrosion of metallic surfaces under insulation in an outdoor air environment. NUREG-2191, Section XI.M29, Outdoor and Large Atmospheric Metallic Storage Tanks, element 4, provides inspection guidance for corrosion under insulation for insulated carbon steel tanks located in an outdoor environment. NUREG-2191, Section XI.M29, Table XI.M29-1, recommends a 10-year frequency for corrosion under insulation during the subsequent period of operation.

2. NUREG-2191, Table XI.M27-1, note 10 recommends main drain tests at each water-based system riser to determine if there is a change in the condition of the water piping and control valves on an annual or refueling outage interval. Surry Power Station will perform the main drain tests on twenty percent of the standpipes and risers every refueling cycle.

Justification for Exception

As indicated by NUREG-2191 Table XI.M27-1, note 10, access for some inspections is feasible only during refueling outages which are scheduled every eighteen months. Main drain tests on twenty percent of the standpipes and risers every eighteen months provide adequate information to determine the condition of the fire water piping is maintained consistent with the design basis.

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), Acceptance Criteria (Element 6), and Corrective Actions (Element 7)

1. ~~Procedures inspection guidance will be revised to require replacement of any sprinkler that shows any of the following: leakage, corrosion, physical damage, loading, painting unless painted by the sprinkler manufacturer, or incorrect orientation. Sprinklers at the following locations will be added to the test scope: The Radwaste Facility, Auxiliary Boiler, Maintenance Building, Condensate Polishing Building, Laundry Building, and Machine Shop Building.~~
2. Prior to 50 years in service, sprinkler heads will be submitted for field-service testing by a recognized testing laboratory consistent with NFPA 25, 2011 Edition, Section 5.3.1. Additional representative samples will be field-service tested every 10 years thereafter to ensure signs of aging are detected in a timely manner. For wet pipe sprinkler systems, a one-time test of sprinklers that have been exposed to water including the sample size, sample selection criteria, and minimum time in service of tested sprinklers will be performed.
3. Procedures will be revised to specify:
   a. Standpipe and system flow tests for hose stations at the hydraulically most limiting locations for each zone of the system on a five year interval to demonstrate the capability to provide the design pressure at required flow.
   b. Acceptance criteria for wet pipe main drain tests. Flowing pressures from test to test will be monitored to determine if there is a 10% reduction in full flow pressure when compared to previously performed tests. The Corrective Action Program will determine the cause and necessary corrective action.
   c. If a flow test or a main drain test does not meet acceptance criteria due to current or projected degradation additional tests are conducted. The number of increased tests is determined in accordance with the corrective action process; however, there are no fewer than two additional tests for each test that did not meet acceptance criteria. The additional inspections are completed within the interval in which the original test was conducted. If subsequent tests do not meet acceptance criteria, an extent of condition and extent of cause analysis is conducted to determine the further extent of tests. The additional tests include at least one test at the other unit with the same material, environment, and aging effect combination.
   d. Main drains for the standpipes associated with hose stations within the scope of subsequent license renewal will also be added to main drain testing procedures.

Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)

4. Procedures will be revised to perform system flow testing at flows representative of those expected during a fire. A flow resistance factor (C-factor) will be calculated to compare and trend the friction loss characteristics to the results from previous flow tests.

Parameters Monitored or Inspected (Element 3) and Detection of Aging Effects (Element 4)

~~5. Procedures for hydrant flushing will be revised to require fully opening the hydrant and fully flowing the hydrant for no less than one minute and until foreign material has cleared. In addition, procedures will be revised to observe draining of the hydrant barrel and also require the barrel be pumped dry should it not drain within 60 minutes. Hydrants outside the protected area that are within the scope of subsequent license renewal will be added to the flush scope.~~

6. The *Fire Water System* program will be revised to periodically inspect the insulated exterior surfaces of the fire water tanks on a 10-year frequency during the subsequent period of operation. Insulation is removed to provide a minimum inspection population of 25 one-square foot samples. The samples will be distributed in such a way that inspections occur on the tank dome, near the tank bottom, at points where structural supports, pipe, or instrument nozzles penetrate the insulation and where water could collect. In addition, inspection locations will be based on the likelihood of corrosion under insulation occurring.

~~7. Procedures for mainline strainer flushing will be revised to require flushing until clear water is observed after each operation or flow test. In addition to flushing after operation, the Radwaste Facility mainline strainer will require an inspection every five years for damaged and corroded parts.~~

8. A procedure will be created to provide a Turbine Building oil deluge systems spray nozzle air flow test to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected.

9. Procedures will be revised to perform internal visual inspections of sprinkler and deluge system piping to identify internal corrosion, foreign material, and obstructions to flow. Follow-up volumetric examinations will be performed if internal visual inspections detect <u>an unexpected level of degradation due to corrosion product deposition.</u> If organic or foreign material, or internal flow blockage that could result in failure of system function is identified, then an obstruction investigation will be performed within the Corrective Action Program that includes removal of the material, an extent of condition determination, review for increased inspections, extent of follow-up examinations, and a flush in accordance with NFPA 25, 2011 Edition, Annex D.5, Flushing Procedures. The internal visual inspections will consist of the following:
    a. Wet pipe sprinkler systems - 50% of the wet pipe sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote sprinkler, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2. During the next five-year inspection period, the alternate systems previously not inspected shall be inspected.
    b. Pre-action sprinkler systems - pre-action sprinkler systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.
    c. Deluge systems - deluge systems in scope for subsequent license renewal will have visual internal inspections of piping by removing a hydraulically remote nozzle, performed every five years, consistent with NFPA 25, 2011 Edition, Section 14.2.

Detection of Aging Effects (Element4)

10. Procedure will be revised to provide inspection guidance related to lighting, distance and offset for non-ASME Code inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.
11. The Unit 1 hydrogen seal oil system deluge sprinkler pipe and Unit 1 station main transformer '1A' deluge sprinkler piping will be reconfigured to allow drainage.

Detection of Aging Effects (Element4) and Acceptance Criteria (Element 6)

12. Procedures will be revised to address recurring internal corrosion with the use of Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. The procedure will specify thinned areas found during the LFET screening be followed up with pipe wall thickness examinations to ensure aging effects are managed and wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, the performance of opportunistic visual inspections of the fire protection system will be required whenever the fire water system is opened for maintenance.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Fire Water System* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2012, an Engineering walkdown of the fire protection piping header along the north wall of the Unit 2 Turbine Building revealed a potential leak location on the supply line to a hose rack. The flanged connection and straight pipe were removed and replaced.

2. In January 2012, a section of 2-inch fire protection "drop" piping in the Turbine Building developed a leak. The investigation for extent of condition and determination for the extent of fire protection piping to be inspected and replaced, as necessary, involved inspections of three locations in the Turbine Building and three locations in the Auxiliary Building. Microbiologically induced corrosion (MIC) was evident in many locations, but the extent of corrosion was not as severe in the Auxiliary Building as it was in the Turbine Building. Despite the less severe corrosion in the Auxiliary Building, the three segments of piping that were inspected were replaced. Similarly, one of the three segments of piping in the Turbine Building was replaced.

   A capital project was proposed for a multi-year process of replacing segments of 2-inch, 4-inch, and 10-inch piping in the Turbine Building. The initial phase that was completed included replacing 200 feet of ten inch piping in the Turbine Building. Additional phases were proposed, and described in the Fire Protection Strategic Plan. See April 2013 and November 2015 operating experience.

3. In June 2012, during inspection of Auxiliary Building fire protection piping minor sediment was discovered in the supply header to the Unit 1 cable tunnel sprinklers. Debris and MIC nodules were discovered inside a spool piece and accessible four inch piping. The sediment and debris were removed, the visual inspection was performed, and the blind flanges and spool pieces were replaced. The necessary pipe replacement is included in the Fire Protection Strategic Plan.

4. In March 2013, NRC Information Notice 13-06, "Corrosion in Fire Protection Piping Due to Air and Water Interaction", identified industry operating experience involving the loss of function of fire protection water systems due to the potential for adverse air and water interactions in pre-action and dry-pipe systems. Engineering evaluated the potential for similar adverse conditions and associated degradation in deluge systems at Surry Power Station that are periodically flow tested. Subsequently, in January 2018, a walkdown was performed to confirm that plant design specifications on drainage features for piping downstream of all in-scope pre-action and deluge valves in the fire protection system continued to be in effect. Two locations, one relating to main transformer 1A and one relating to Unit 1 generator hydrogen seal oil system, were identified as having a potential for adverse air and water interactions and entered into the corrective action program.

5. In April 2013, a section of two 10-inch fire protection system piping in the Turbine Building developed a leak. A walkdown of six locations was performed to determine extent of condition in the Turbine Building and the Auxiliary Building. MIC was evident in four locations, but the extent of corrosion in the Auxiliary Building was not as severe. Replacement of 4-inch and 10-inch fire protection header is a like-for-like replacement. The replacement of the Turbine Fire Protection Header was split into four different phases. One phase was to be accomplished each year. The second phase is planned to replace approximately 400 feet of ten-inch header pipe and 200 feet of two-inch hose station pipe. The necessary pipe replacement is included in the Fire Protection Strategic Plan.

6. In February 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1A to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. The result of the visual inspection was that coating degradation was continuing, and that some bare metal was evident. Similarly, volumetric examinations found additional thinning for the tank floor. An engineering evaluation projected that the tank floor plate would reach minimum acceptable thickness prior to the expiration of the Unit 2 renewed operating license. Monitoring of the tank floor will continue until the tank floor is repaired or replaced. The necessary tank repair or replacement is included in the Fire Protection Strategic Plan.

7. In August 2014, visual and volumetric inspections were performed for Fire Protection/domestic water storage tank 1B to determine the extent of additional degradation that had occurred since similar inspections were completed in December 2008. The most significant degradation was noted on the tank floor. The result of the visual inspection was that coating degradation was continuing, and that some bare metal was evident. Volumetric examinations found some thinning of the tank floor. An engineering evaluation projected that the tank floor plate would reach minimum acceptable thickness prior to the expiration of the Unit 2 renewed operating license. Monitoring of the tank floor will continue until the tank floor is repaired or replaced.

8. In September 2014, a materials analysis was performed on buried cement lined grey cast iron fire main piping that was fractured during flow testing of hose station valves. The fracture was attributed to a latent material defect in the cast iron. The piping was removed and replaced with an equivalent spool piece. Based on the oxidation along the top segment of the crack, the pipe was cracked for a long period of time. High levels of calcium deposits on the fracture (from the cement lining) indicate that the pipe was partially cracked at the top segment before factory installation of the cement liner (manufacturing process). Material analysis of the pipe determined that the microstructure consisted of graphite flakes that were approximately 75% ferrite and 25% pearlite. This resulted in a reduction in the supplied material hardness. Failure of pipe was not preventable through maintenance. The failure was caused by ground settling. During the pipe replacement it was observed that there was vertical misalignment between the replacement pipe and the existing buried pipe, which indicated that the buried side piping was exerting a large bending load at the anchor/foundation. This bending load along with the pre-existing crack and lower hardness value caused the pipe fracture. The balance of the failed pipe was found in good condition with no significant loss of cement lining material, corrosion, cracking, fouling, or reduction of pipe interior diameter.

9. In November 2015, an effectiveness review of the Fire Protection Program aging management activity (AMA) (UFSAR Section 18.2.7) was performed. The AMA was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. A comprehensive fire water system assessment recommended a large scale piping replacement of turbine building and auxiliary building piping. The large scale piping replacement project to be performed over multiple refueling outages was identified as a measure to address degradation in carbon steel system piping and to ensure that system intended functions were maintained. Completed and closed phases of this effort have included replacement of approximately 400 feet of 4 inch piping and 200 feet of 2 inch piping in 2014 and approximately 567 feet of 4 inch piping and 303 feet of 2 inch piping in 2015. An additional phase replacing approximately 175 feet of 4 inch piping and 100 feet of 2 inch piping has been completed and is awaiting final testing. Work documents for additional phases are planned and issued for work extending into 2019.

10. In April 2016, results from fire protection system flow tests with the motor driven fire pump in April 2016, July 2013, and April 2010 consistently showed that the system pressure is higher than the required value for the corresponding flow rate. In 2016, the result indicated that the measured pressure exceeded the required pressure by fourteen psi. In 2013, the measured pressure was thirteen psi higher than required. The result in 2010 measured a pressure that was 19 psi higher than required. The trend from these results does not indicate significant degradation over the six-year interval, particularly considering the two most recent measurements. There is confidence that continued implementation of flow monitoring for the fire protection system using the three year interval required by the Technical Requirements Manual will effectively manage aging prior to a loss of intended function.

11. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
    - Procedures credited for license renewal were identified
    - Procedures were consistent with the licensing basis and bases documents
    - Procedures contained a reference to conduct an aging management review prior to revising
    - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

    Procedure changes were completed as necessary to ensure the above items were satisfied.
12. In November 2017, as part of oversight reviews of the Fire Protection Program AMA (UFSAR Section 18.2.7), an inconsistency was identified in the performance interval for system integrity demonstration by main drain testing. The test interval had been extended from quarterly to each 18 months but the extended interval had not been incorporated into program documents. An Engineering Assignment to review operating experience to trended performance data to 2011 has been completed with no significant degrading trends observed. The new interval is consistent with the test interval of NFPA 25 (2011 Edition) Table 13.1.1.2 modified by NUREG-2191, Section XI.M27, Table XI.M27-1, Note 10.
13. In January 2018 an aging management program effectiveness review was performed for the Fire Protection Program AMA (UFSAR Section 18.2.7). Information from the summary of that effectiveness review is provided below:

    The Fire Protection Program AMA is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Fire Protection Program AMA that were reviewed include the inspection of components, the evaluation of inspection results, repairs/replacements, corrective actions, and AMA document updates. Engineering reports from 2006 to 2017 of inspections results were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 for age related degradation of fire protection components within the scope of license renewal.

    In the past, multiple fire water piping leaks had been identified in the Unit 1 and Unit 2 Turbine Buildings. As a result, a five phase large scale fire protection piping replacement project has been underway since 2015 to replace Turbine Building header piping and hose station piping as well as the Unit 1 and Unit 2 Auxiliary Building Hose station piping. Two of the Turbine Building phases are complete and two are waiting on testing. Phase five includes the remaining scope in the turbine building and the entire scope in the Auxiliary Building and is planned to start in 2018. Once complete, a large majority of the above ground fire protection piping in the plant will have been replaced, including areas where reoccurring leaks were previously identified.

The fire water/domestic water storage tanks are managed by the Tank Inspection Activities AMA (UFSAR Section 18.1.3); but, are also discussed here for overall fire protection performance considerations. The fire water/domestic water storage tanks were found to have failing internal coatings and loss of material on the tank floors. Estimates for projected useable tank lifetime and evaluations for additional monitoring were performed. Recommendations are being prepared for repair or replacement project considerations.

Multiple operating issues, and obsolescence of the diesel driven fire pump resulted in a design change that replaced the diesel driven fire pump and associated control panel. The new diesel driven fire pump has exhibited substantially improved performance compared to the original fire pump.

Activities to implement NFPA 25, 1998 Edition, Section 2-3.1.1 (1998 edition), testing of sprinklers that have been in service for fifty years have been initiated to prove continued functionality. The Unit 1 and Unit 2 turbine building sprinklers have been sampled and will be tested by 2021, when fifty years of service is reached.

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to microbiological induced corrosion, has occurred on several occasions. Periodic fire protection system piping flushes, flow testing and piping thickness measurements will be performed to identify pipe degradation prior to loss of system intended function. Periodic visual inspections and tank bottom thickness measurements are performed on the fire water storage tanks. In addition to recent piping replacements in the Turbine Building and the Auxiliary Building to address instances of RIC due to microbiologically-influenced corrosion, Low Frequency Electromagnetic Technique (LFET) or a similar technique on 100 feet of piping during each refueling cycle to detect changes in the pipe wall thickness. LFET screening or a similar technique will also be performed on accessible interior fire water storage tank bottoms during periodic inspections. Thinned areas found during the LFET scan are followed-up with pipe wall thickness examinations to ensure aging effects are managed and that wall thickness is within acceptable limits. In addition to the pipe wall thickness examination, opportunistic visual inspections of the fire protection system will be performed whenever the fire water system is opened for maintenance.

The above examples of operating experience provides objective evidence that the *Fire Water System* program includes activities to perform periodic fire main and hydrant inspections and flushing, sprinkler inspections, functional test, and flow tests to identify loss of material, flow blockage, and loss of coating integrity for in-scope water-based fire protection systems within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Fire Water System* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Appropriate guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Fire Water System* program, following enhancement, will effectively identify aging, and initiate corrective actions, prior to a loss of intended function.

Conclusion

The continued implementation of the *Fire Water System* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.19 Reactor Vessel Material Surveillance

Program Description

The *Reactor Vessel Material Surveillance* program is an existing condition monitoring program that manages reduction of fracture toughness of the ferritic reactor vessel beltline materials, in accordance with the version of ASTM E-185 available and used during fabrication of the reactor vessels. The program provides sufficient material to monitor reduction of fracture toughness due to neutron irradiation embrittlement until the end of the subsequent period of extended operation, and determine the need for operating restrictions on the irradiation temperature (i.e., cold leg operating temperature), neutron spectrum, and neutron fluence.

The *Reactor Vessel Material Surveillance* program was developed by Westinghouse Electric Company prior to 10CFR50 Appendix H. The *Reactor Vessel Material Surveillance* program consists of two elements. The first element is related to the number of capsules, location of capsules, and content of specimens. The second element is related to the test methods and schedule for testing. For the first element, related to the design of the program, WCAP-7723, "Virginia Electric and Power Co. Surry Unit No. 1 Reactor Vessel Radiation Surveillance Program" and WCAP-8085, "Virginia Electric and Power Co. Surry Unit No. 2 Reactor Vessel Radiation Surveillance Program" for Units 1 and 2, documented the program. The *Reactor Vessel Material Surveillance* program for Unit 1 meets either ASTM E 185-66 or ASTM E 185-70. WCAP-8085 states that the Unit 2 *Reactor Vessel Material Surveillance* program meets ASTM E-185-70. Initially, the requirements relating to the testing method was not mandated by the NRC through a particular version of ASTM E185. Therefore, when a capsule was removed from the reactor vessel, it was customary at the time to document which version of ASTM E185 was used for testing. Overtime, the NRC began the process of approving various editions of ASTM E185 for testing. To date, for testing and schedule considerations, the NRC has approved three editions of ASTM E185-73, -79, and -82. Currently, the *Reactor Vessel Material Surveillance* program complies with ASTM E-185-82 for testing and scheduling.

Since the withdrawal schedule in Table 1 of ASTM E 185-82 is based on plant operation during the original 40-year initial license term, standby capsules have been incorporated to ensure appropriate monitoring during the subsequent period of extended operation. The *Reactor Vessel Material Surveillance* program includes removal and testing of at least one capsule, with a neutron fluence of the capsule between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation. If a capsule meeting this criteria has not been tested previously, then at least one capsule will be removed and tested during the subsequent period of extended operation (or earlier) to meet this criterion.

Data from the *Reactor Vessel Material Surveillance* program is used to monitor neutron irradiation embrittlement of the reactor vessel, and is provided as input to the neutron embrittlement time-limited aging analyses (TLAAs) described in Section 4.2.

In accordance with 10 CFR Part 50, Appendix H, all surveillance capsules, including those previously removed from the reactor vessel, must meet the test procedures and reporting requirements of ASTM E 185-82, to the extent practicable, for the configuration of the specimens in the capsule. Any changes to the capsule withdrawal schedule, including the conversion of standby capsules in the *Reactor Vessel Material Surveillance* program or extension of the program for the subsequent period of extended operation, are required to be submitted to the Nuclear Regulatory Commission (NRC) for approval prior to implementation, in accordance with 10 CFR Part 50, Appendix H, Paragraph III.B.3. Standby capsules placed in storage (e.g., removed from the reactor vessel) are maintained for possible future re-insertion. If one or more capsules will not be maintained in such a way as to permit future insertion, then the NRC will be notified of the change.

Originally there were eight reactor vessel (RV) capsules installed in each RV prior to plant start-up. Eight capsules is more than the minimum recommended by either ASTM E 185-66 or ASTM E 185-70 for Unit 1 and ASTM E185-70 for Unit 2. Capsule W1 was installed into Unit 2 in 1991 as part of the Master Integrated Reactor Vessel Material Surveillance program. Capsule W1 contained specimens for both Units 1 and 2. Capsule W1 was removed and tested in 1997. The capsules contain representative RV material specimens, neutron dosimeters, and thermal monitors. Withdrawn capsules from each RV have been tested; one of the remaining untested capsules in each RV will be tested during the initial period of extended operation, one of the remaining untested capsules in each RV will be tested during the subsequent period of extended operation, and the remaining untested capsules (including standby capsules) in each RV are available to satisfy potential fluence monitoring requirements during the 20-year subsequent period of extended operation.

Surveillance Capsule Withdraw Schedule for Unit 1

Four Unit 1 capsules have been withdrawn from the RV (T, W, V and X). Three capsules have been tested (T, V and X). Only dosimetry was measured for Capsule W. For the initial period of extended operation, Unit 1 has one untested capsule (Capsule Z), which at its scheduled withdrawal date will be irradiated ~~close to~~ <u>greater than</u> the projected peak neutron fluence of 6.35 x 10^{19} n/cm^2 (E>1.0 MeV), based upon 68 EFPY at the end of the 80-year subsequent period of extended operation. Capsule Z is ~~currently~~ scheduled to be pulled in the 60-year initial period of extended operation during the ~~2025~~ <u>2027</u> Unit 1 refueling outage. As ~~currently~~ scheduled, Capsule Z is estimated to be irradiated to ~~6.31~~ <u>6.41</u> x 10^{19} n/cm^2 (E>1.0 MeV), which would ~~not exceed one times the projected peak neutron fluence at the end of the 80-year subsequent period of extended operation. A capsule withdrawal schedule change has been submitted to the NRC to move withdrawal of Capsule Z further out into the initial period of extended~~

~~operation. Moving withdrawal will ensure that Capsule Z will have been exposed to a fluence~~ be between one and two times the projected peak vessel neutron fluence at the end of the 80-year subsequent period of extended operation. ~~The schedule change, if approved, will move the capsule pull to 2027 when the capsule neutron fluence is projected to be 6.41 x 1019 n/cm2 (E>1.0 MeV), which is greater than the projected peak RV neutron fluence for 80 years.~~ Testing of Capsule Z in 2027 will satisfy the initial license renewal schedule for Unit 1.

Untested capsules (including standby capsules) remaining in the Unit 1 RV will be available to satisfy potential fluence monitoring requirements during the 80-year subsequent period of extended operation. Unit 1 will have three untested capsules (Capsules S, U, and Y) irradiated in excess of the 80-year projected peak neutron fluence of 6.35×10^{19} n/cm^2 (E>1.0 MeV) during the subsequent period of extended operation.

The following irradiation values are estimated at the end of the initial period of extended operation (48 EFPY):

- Capsule S is estimated to be irradiated to 5.42×10^{19} n/cm^2 (E>1.0 MeV)
- Capsule U is estimated to be irradiated to 4.59×10^{19} n/cm^2 (E>1.0 MeV)
- Capsule Y is estimated to be irradiated to 6.24×10^{19} n/cm^2 (E>1.0 MeV)

An 80-year projected peak neutron fluence irradiation of 6.35×10^{19} n/cm^2(E>1.0 MeV) is estimated to be attained by standby Capsules S, U, and Y in 2040, 2047, and 2032, respectively, during the subsequent period of extended operation. Withdrawal and testing of Capsule Y from Unit 1 will satisfy the expectation to test one capsule during the subsequent period of extended operation.

Two standby capsules will remain in the reactor, one of which will satisfy the requirement for fluence monitoring specified in ASTM E-185 and required by 10 CFR 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements."

Surveillance Capsule Withdraw Schedule for Unit 2

Six of the Unit 2 capsules have been withdrawn from the Unit 2 RV (X, W, W-1, S, V and Y). Four capsules have been tested (X, W-1, V and Y). Only dosimetry was measured for Capsule W and Capsule S. For the initial period of extended operation, Unit 2 has one untested capsule (Capsule U) which will be irradiated ~~in excess of~~ greater than the projected peak neutron fluence of 7.26×10^{19} n/cm^2 (E>1.0 MeV) that is based upon 68 EFPY at the end of the subsequent period of extended operation. Capsule U is scheduled to be pulled in the 60-year initial license renewal period ~~in 2027~~ during the 2032 Unit 2 refueling outage. As ~~currently~~ scheduled, Capsule U is estimated to be irradiated to ~~6.95~~ 7.31 $\times 10^{19}$ n/cm^2 (E>1.0 MeV) ~~by 2027~~, which would ~~not exceed one times the projected peak neutron fluence at the end of the 80 year subsequent period of extended operation. A capsule withdrawal schedule change has been submitted to move the~~

~~Capsule U withdrawal further out into the initial period of extended operation, to ensure that it will have been exposed to a fluence~~ be between one and two times the projected peak vessel neutron fluence at the end of the 80-year subsequent period of extended operation. ~~The schedule change, if approved, will move the capsule pull to 2032 when the capsule projected neutron fluence will be 7.31 x 1019 n/cm2 (E>1.0 MeV) which is greater than the projected peak RV neutron fluence for 80 years.~~ Testing of Capsule U in 2032 will satisfy the initial license renewal schedule for Unit 2.

Untested capsules (including standby capsules) remaining in the Unit 2 RV will be available to satisfy potential fluence monitoring requirements during the 80-year subsequent period of extended operation. Unit 2 will have two untested capsules Capsules (T and Z) that will be irradiated in excess of the 80-year projected peak neutron fluence of 7.26 x 10^{19} n/cm^2 (E>1.0 MeV) during the subsequent period of extended operation.

The following irradiation values are estimated at the end of the initial license renewal period (48 EFPY):

- Capsule T is estimated to be irradiated to 6.65 x 10^{19} n/cm^2 (E>1.0 MeV)
- Capsule Z is estimated to be irradiated to 5.39 x 10^{19} n/cm^2 (E>1.0 MeV),

An 80-year projected peak neutron fluence irradiation of 7.26 x 10^{19} n/cm^2(E>1.0 MeV) is estimated to be attained by standby ~~specimen~~ Capsules T and Z in 2036 and 2046, respectively, during the subsequent period of extended operation. Withdrawal and testing of Capsule T from Unit 2 will satisfy the expectation to test one capsule during the subsequent period of extended ~~period of~~ operation.

One standby capsule will remain in the reactor to satisfy the requirement for fluence monitoring specified in ASTM E-185 and required by 10 CFR 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements."

Request for NRC Approval of Changes to the Surveillance Capsule Withdraw Schedule

10 CFR 50, Appendix H, requires that prior to withdrawal of Capsule S or U from Unit 1 RV or Capsule Z from Unit 2 RV, a proposed withdrawal schedule with a technical justification will be submitted to the NRC for approval. By way of this SLR application, Dominion is requesting that NRC review and approve the changes to the proposed withdrawal schedule shown in the following:

- Table B2.1.19-1, Surveillance Capsule Withdraw Schedule For Surry Unit 1, and
- Table B2.1.19-2, Surveillance Capsule Withdraw Schedule For Surry Unit 2.

As part of Operating Experience, consistent with statements in Regulatory Guide 1.99, Revision 2, Dominion considers the use of surveillance data from other sources when they become available. As such, information from surveillance capsules withdrawn from sister plant vessels is used to supplement information from the *Reactor Vessel Material Surveillance* program subject to the credibility limitations stated in Regulatory Position 2.1 and 2.2 of Regulatory Guide 1.99, Revision 2.

The *Reactor Vessel Material Surveillance* program is also used in conjunction with the *Neutron Fluence Monitoring* program (B3.2) which monitors neutron fluence for reactor vessel components and reactor vessel internal components.

NUREG-2191 Consistency

The Reactor Vessel Material Surveillance program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M31, Reactor Vessel Material Surveillance..

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancements will be implemented in the following program element(s):

Scope of the Program (Element 1), Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4), and Monitoring and Trending (Element 5)

1. The RV Material Surveillance program for Unit 1 will be amended for Capsule Y to be pulled during the subsequent period of extended operation. Capsule Y will be pulled during the first refueling outage after the capsule reaches fluence greater than 100-year vessel irradiation which is between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.

2. The RV Material Surveillance program for Unit 2 will be amended for Capsule T to be pulled during the subsequent period of extended operation. Capsule T will be pulled during the first refueling outage after the capsule reaches fluence greater than 100-year vessel irradiation which is between one and two times the projected peak vessel neutron fluence at the end of the subsequent period of extended operation.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Reactor Vessel Material Surveillance* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. Dominion is a member of the Babcock and Wilcox Owner's Group Reactor Vessel Working Group (RVWG). While not required, SPS participates in the RVWG's Master Integrated Reactor Vessel Surveillance Program (MIRVSP). The MIRVSP integrates the plant specific reactor vessel surveillance programs of the participants, the existing supplemental B&W Owners Group irradiation capsules, and additional supplemental irradiation capsules to assure the availability of high fluence and thermal annealing data for the participants' reactor vessels. One objective of the MIRVSP is to maximize the effectiveness of data sharing among participants to assure that required data is available to the participants for current and extended plant operation.
2. In 1997, Unit 1 Capsule X Withdrawal and Test: Per BAW-2324, "Analysis of Capsule X, Virginia Power Surry Unit No. 1," the specimens in Unit 1 Capsule X were exposed to fluences equivalent to approximately 16.1 EFPY, 2.11×10^{19} n/cm^2 based on the calculated fluence, and satisfy the upper-shelf energy criterion and the pressurized thermal shock reference temperature screening criteria. The adjusted reference temperatures have been shown to be less than those used in the Unit 1 P-T limit curves, thereby demonstrating margin in the operating limits.
3. In 2002, Unit 2 Capsule Y Withdrawal and Test: Per WCAP-16001, "Analysis of Capsule Y from Dominion Surry Unit 2 Reactor Vessel Radiation Surveillance Program, the specimens in Unit 2 Capsule Y were exposed to fluences equivalent to approximately 20.3 EFPY, 2.72×10^{19} n/cm^2 based on the calculated fluence, and satisfy the upper-shelf energy criterion and the pressurized thermal shock reference temperature screening criteria. The adjusted reference temperatures have been shown to be less than those used in the Unit 2 P-T limit curves, thereby demonstrating margin in the operating limits.
4. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:
   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

Procedure changes were completed as necessary to ensure the above items were satisfied.

5. In November 2017, as part of oversight review activities, the Reactor Vessel Integrity Management Activity (UFSAR Section 18.2.14) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

6. In January 2018, an aging management program effectiveness review was performed of the Reactor Vessel Integrity Management Activity (UFSAR Section 18.2.14). Information from the summary of that effectiveness review is provided below:

   The Reactor Vessel Integrity Management Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the Reactor Vessel Integrity Management Activity that were reviewed included aging management activity procedures, documents, and incorporation of industry operating experience.

   The AMA procedure and associated documents were examined to evaluate the effectiveness of the Reactor Vessel Integrity Management Activity with respect to aging management. The procedure defines activities required to ensure adequate fracture toughness of the reactor vessel beltline plate and weld material consistent with the following parameters: heatup and cooldown limits, PTS reference temperature, a bounding fast fluence value, and upper shelf energy. These parameters are documented in the SPS UFSAR and Technical Specifications and as such changes to these parameters require NRC review.

   ~~As a result of the revised projected fluence calculations performed for the RV nozzles a revision to the reactor vessel material surveillance capsule withdraw schedule was submitted to the NRC for approval by Dominion Energy Virginia Letter 17-243 (July 2017) to reflect the latest projected fluence calculations in the estimated capsule fluence values. The proposed changes provide asset optimization and ensure the revised estimated standby capsule fluence values coincide with the nearest respective unit refueling outage for withdrawal.~~

   A review of industry operating experience resulted in a program procedure revision to include Westinghouse Technical Bulletin TB-16-5 that ensures proper installation and seating of surveillance capsules.

   The Reactor Vessel Integrity Management Activity ensures that the Dominion reactor vessels are consistent with the applicable regulations and industry standards with respect to reactor vessel embrittlement concerns.

The above examples of operating experience provides objective evidence that the *Reactor Vessel Material Surveillance* program includes activities to perform withdrawal and testing of reactor vessel capsule specimens to manage a reduction in fracture toughness due to irradiation of the ferritic reactor vessel beltline materials, and to initiate corrective actions. Occurrences identified under the *Reactor Vessel Material Surveillance* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements are provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Reactor Vessel Material Surveillance* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

1. The continued implementation of the *Reactor Vessel Material Surveillance* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.23 External Surfaces Monitoring of Mechanical Components

Program Description

The *External Surfaces Monitoring of Mechanical Components* program is an existing condition monitoring program that manages loss of material, cracking, and reduction of heat transfer of metallic components; hardening or loss of strength, loss of material, and cracking or blistering of polymeric components; loss of preload of HVAC closure bolting; and reduced thermal insulation resistance.

Visual inspections are performed during system inspections and walkdowns. The inspection parameters for metallic components include material condition, which consists of evidence of rust, general, pitting, and crevice corrosion; surface imperfections such as cracking and wastage; coating degradation such as cracking, flaking, or blistering; evidence of insulation damage or wetting; leakage; and accumulation of debris on heat exchanger surfaces. Coating degradation is used as an indicator of possible degradation on underlying surfaces of the component. Inspection parameters for elastomeric and polymeric components include blistering, hardening, discoloration, surface cracking, crazing, scuffing, loss of thickness, exposure of internal reinforcement, and dimensional changes. For certain materials, such as flexible polymers, physical manipulation to detect hardening or loss of strength will be used to augment the visual inspections conducted under this program.

Periodic visual inspections, not to exceed a refueling outage interval, of metallic and polymeric components and insulation jacketing (insulation when not jacketed) are conducted. This frequency accommodates inspections of components that may be in locations that are normally only accessible during refueling outages. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components intended functions are maintained. There are no cementitious components within the scope of this program.

ASME Code, Section XI visual examinations (VT-1) or surface examinations will be conducted to detect cracking of stainless steel, ~~and~~ aluminum and <u>copper alloy (>15% Zn or >8% Al)</u> components exposed to aqueous solutions or air environments containing halides. A minimum sample of 25 inspections will be performed from each of the aluminum and stainless steel component populations every ten years.

A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), will be periodically inspected every ten years during the subsequent period of extended operation. Following insulation removal, ASME Code, Section XI VT-1 examinations or surface examinations will be conducted to detect loss of material and cracking of the component surfaces.

A minimum of twenty-five one foot axial length piping sections and components for each material type will be inspected.

If any sampling-based inspections to detect cracking in stainless steel, ~~and~~ aluminum and copper alloy (>15% Zn or >8% Al) do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., 10 year inspection interval) in which the original inspection was conducted.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in-service, severity of operating conditions, and lowest design margin.

Inspections are performed by personnel qualified in accordance with site procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow site procedures consistent with the ASME Code. Non-ASME Code inspection procedures will include requirements for items such as lighting, distance, offset, surface coverage, and presence of protective coatings.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

The external surfaces of components that are buried or in underground environments are inspected by the *Buried and Underground Piping and Tanks* program (B2.1.27). The external surfaces of outdoor tanks and indoor large volume metallic storage tanks (capacity >100,000 gallons) are inspected by the *Outdoor and Large Atmospheric Metallic Storage Tanks* program (B2.1.17). Loss of material due to boric acid corrosion is managed by the *Boric Acid Corrosion* program (B2.1.4).

NUREG-2191 Consistency

The *External Surfaces Monitoring of Mechanical Components* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M36, External Surfaces Monitoring of Mechanical Components.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. The Engineering walkdown procedure will be revised to include an item in the walkdown checklist to inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture.

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

2. The Engineering walkdown procedure will be revised to add the following requirements:

   a. Metallic Components

   - No surface imperfections, loss of wall thickness, flaking, or oxide coated surfaces
   - No blistering of protective coating
   - No evidence of leakage (for detection of cracks) on the surfaces of stainless steel, ~~and~~ aluminum and copper alloy (>15% Zn or >8% Al) components
   - No accumulation of debris on air-side heat exchanger surfaces

   b. Elastomers and Flexible Polymers

   - No exposure of reinforcing fibers, mesh or underlying metal (for elastomers or flexible polymers with internal reinforcement)
   - No blistering, loss of thickness, dimensional change, or scuffing
   - No hardening of elastomeric elements as evidenced by a loss of suppleness during tactile inspection

   c. Insulation Metallic Jacketing

   - Inspect insulation metallic jacketing for any damage that would permit in-leakage of moisture.

d. HVAC Closure Bolting

- Check that a sample of closure bolting that is in reach is not loose

Detection of Aging Effects (Element 4)

3. The Engineering walkdown procedure will be revised to specify that walkdowns will be performed at a frequency not to exceed one refueling cycle. Since some surfaces are not readily visible during both plant operations and refueling outages, the enhancement will also specify that such surfaces will be inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

Detection of Aging Effects (Element 4)

4. The Engineering walkdown procedure will be revised to provide non-ASME Code inspection guidance related to lighting, distance and offset for walkdown inspections. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two to four feet (or less) will be appropriate. For distant surface inspections, viewing aids such as binoculars may be used. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used.

5. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed. A minimum of 25 inspections for cracking will be performed from each of the stainless steel, ~~and~~ aluminum and copper alloy (>15% Zn or >8% Al) component populations assigned to the program every ten years. For insulated components exposed to condensation, a minimum of 25 one foot axial length sections and components for each material and environment combination will be inspected for loss of material and cracking after the insulation is removed. The new procedure will specify that the inspections focus on the components most susceptible to aging because of time in service, severity of operating conditions, and lowest design margin.

6. The Engineering walkdown procedure will be revised to specify that visual inspection of elastomers and flexible polymers will be supplemented by tactile inspection to detect hardening. Visual inspections will cover 100% of accessible component surfaces. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area.

Monitoring and Trending (Element 5)

7. A new procedure will be developed to evaluate and project the rate of any degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

Acceptance Criteria (Element 6)

8. A new procedure will be developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

Corrective Actions (Element 7)

9. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections to detect cracking in stainless steel, ~~and~~ aluminum and copper alloy (>15% Zn or >8% Al) components do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., 10-year inspection interval) in which the original inspection was conducted.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *External Surfaces Monitoring of Mechanical Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In November 2009, Engineering noted a section of a condenser waterbox outlet rubber expansion joint was blistered and was soft to the touch. Photos were taken of the condition, and a condition report written. Engineering evaluated the condition against the criteria in a station inspection procedure. The evaluator noted that there was no liquid behind the soft areas, no cracking, and no delamination. The evaluator noted that the procedure indicated that soft spongy area on the internal circumference of a joint could be due to uncured arch material. Therefore, using the guidance in the procedure, the condition was determined to be acceptable.
2. In May 2013, during a system walkdown outdoors, vegetation was noted growing in the insulation of three lines associated with the fire protection system. The insulation was removed, and no damage to the piping from the vegetation was noted, however, some rusting was noted on the surface of the piping. The damaged insulation was repaired to prevent any further water intrusion.
3. In September 2013, corrosion was noted on the bottom of a section of Unit 1 emergency service water pump discharge piping. The external pipe coating was bulging, indicating corrosion beneath. Additionally, a piece of the coating was missing. Engineering performed non-destructive examination (NDE) on the area of localized coating degradation. The pipe wall thickness results were compared against the minimum wall thickness and found to be acceptable. Based on engineering evaluation, no further degradation was expected following recoating of the pipe.
4. In March 2014, an inspection of ductwork upstream of a cable spreading room air handler was performed. The inspection identified an area of corrosion in the top of a duct elbow and a condition report was submitted. A follow-on inspection with the insulation removed documented substantial rust damage on multiple sections of the ducting and another condition report was written. The unit was subsequently replaced as part of a design change to rectify persistent ventilation degradation and equipment obsolescence issues. The design change replaced the major mechanical components of the Unit 1 and Unit 2 cable spreading room ventilation systems and repaired associated ductwork. The design change also included replacement of the insulation and covering of the ductwork with an aluminum jacket for enhanced protection from water intrusion. Aluminum jacket is installed in a manner so as to shed water consistent with plant specifications.

5. In December 2015, an effectiveness review of the General Condition Monitoring Activities (UFSAR Section 18.2.9) was performed. This aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience program elements. System engineer walkdowns were identified as not being consistently maintained in the designated plant database and the walkdown attributes associated with license renewal activities were not being documented. The issues were documented in the Corrective Action Program. Corrective actions included:

   - Development and implementation of work group specific training for engineering roles and responsibilities related to walkdowns.
   - Implementation of changes to the walkdown procedure
   - Implementation of a process for ensuring system walkdown records are maintained
   - Development of a template in the walkdown tracking database to match the specific requirements in the walkdown procedure

   A follow-up review was performed in February 2016, when 22 of the 24 corrective actions had been completed. The review indicated that walkdowns were being performed and documented in accordance with license renewal requirements. The remaining corrective actions were completed subsequent to the follow-up review.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the General Condition Monitoring Activities (UFSAR Section 18.2.9) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was performed of the General Condition Monitoring Activities (UFSAR Section 18.2.9). Information from the summary of that effectiveness review is provided below:

   The General Condition Monitoring Activities are meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the General Condition Monitoring Activities that were reviewed include system engineer walkdowns to identify age-related degradation of plant equipment within the scope of license renewal. Walkdown records from 2006 through 2017 were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions were taken consistent with the observed aging degradation. The review also included pertinent issues found in the Corrective Action Program from 2006 through 2017 identified during walkdowns.

   In 2015, several issues with Engineering walkdowns were identified, including that the walkdowns were not being documented and maintained in the tracking database as required. This operating experience is discussed in item number five above.

The above examples of operating experience provide objective evidence that the *External Surfaces Monitoring of Mechanical Components* program includes activities to perform visual inspections to manage loss of material, cracking, and reduction of heat transfer of metallic components; hardening or loss of strength, loss of material, and cracking or blistering of polymeric components; loss of preload of HVAC closure bolting; and reduced thermal insulation resistance of components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *External Surfaces Monitoring of Mechanical Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *External Surfaces Monitoring of Mechanical Components* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *External Surfaces Monitoring of Mechanical Components* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing condition monitoring program that manages loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also manages hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components. This program consists of visual inspections of accessible internal surfaces of piping, piping components, ducting, heat exchanger components, polymeric and elastomeric components, and other components exposed to air, condensation, diesel exhaust, fuel oil, lubricating oil, and any water environment. Aging effects associated with items (except for elastomers) within the scope of the *Open-Cycle Cooling Water System* program (B2.1.11), *Closed Treated Water Systems* program (B2.1.12), and *Fire Water System* program (B2.1.16) are not managed by this program.

Inspections of metallic components monitor for visible evidence of loss of material. Indicators of aging effects for metallic components include corrosion and surface imperfections; loss of wall thickness; flaking or oxide-coated surfaces; debris accumulation on heat exchanger tube surfaces; and accumulation of particulate fouling, biofouling, or macro fouling.

ASME Code, Section XI visual (VT-1) examinations or surface examinations will be conducted to detect cracking of stainless steel, ~~and~~ aluminum and copper alloy (>15% Zn) components.

Inspections of polymeric and elastomeric components monitor for changes in material properties or loss of material. Indicators of loss of material and changes in material properties include surface cracking, crazing, scuffing, loss of sealing, dimensional change, loss of wall thickness, discoloration, exposure of internal reinforcement, hardening, and blistering. Physical manipulation or pressurization will be used to augment the visual examinations conducted under this program in order to detect hardening or loss of strength.

The internal inspections are performed during the periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. At a minimum, in each 10-year period during the subsequent period of extended operation, a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of nineteen components per population at each unit will be inspected.

Where the sample size is not based on the percentage of the population, it is acceptable to reduce the total number of inspections to nineteen components per population at each unit. The reduced total number of inspections is acceptable because the operating conditions and history at each unit are sufficiently similar (e.g., flowrate, chemistry, temperature, excursions) such that aging effects are not occurring differently between the units. Past power up-rates were implemented for both units at approximately the same time. Historically, water chemistry conditions between the two units have been very similar. The raw water source for both units is the James River. Emergency diesel generator runs are managed to equalize total run times among the diesels, so as to equalize wear and aging. Operating experience for each unit demonstrates no significant difference in aging effects of systems in the scope of this program between the two units.

If any inspections do not meet the acceptance criteria, additional inspections will be conducted, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (i.e., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval.

Where practical, the inspections will focus on the bounding or lead components most susceptible to aging because of time in-service, and severity of operating conditions. Opportunistic inspections will continue in each period even if the minimum number of inspections has been conducted.

Inspections are performed by personnel qualified in accordance with procedures and programs to perform the specified task. Inspections within the scope of the ASME Code will follow procedures consistent with the ASME Code. Non-ASME Code inspection procedures will include requirements for items such as lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes.

Acceptance criteria are such that the component will meet its intended function until the next inspection or the end of the subsequent period of extended operation. For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

NUREG-2191 Consistency

The *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Parameters Monitored/Inspected (Element 3) and Detection of Aging Effects (Element 4)

1. Procedures will be revised to require inspection of metallic components for flaking or oxide-coated surfaces.
2. Procedures will be revised to require inspection of elastomeric and flexible polymeric components for the following:
    a. Surface crazing, scuffing, loss of sealing, blistering, and dimensional change (e.g., "ballooning" and "necking")
    b. Loss of wall thickness
    c. Exposure of internal reinforcement (e.g., reinforcing fibers, mesh, or underlying metal) for reinforced elastomers
3. Procedures will be revised to specify that visual inspection of elastomeric and flexible polymeric components is supplemented by tactile inspection to detect hardening or loss of suppleness. The minimum surface area for tactile inspections will be at least 10% of the accessible surface area.

Detection of Aging Effects (Element 4)

4. Procedures will be revised to provide non-ASME Code inspection guidance related to lighting, distance, offset, surface coverage, presence of protective coatings, and cleaning processes. The procedure will specify adequate lighting be verified at the inspection location to detect degradation. Lighting may be permanently installed, temporary, or portable (e.g., flashlight), as appropriate. For accessible surface inspections, inspecting from a distance of two feet or less will be appropriate. For viewing angles which may prevent adequate inspection, a viewing aid such as an inspection mirror or boroscope should be used. For internal inspections, accessible surfaces will be inspected. If inspecting piping internal surfaces, a minimum of one linear foot will be inspected, if accessible. Cleaning will be performed, as necessary, to allow for a meaningful examination. If protective coatings are present, the procedure will require the condition of the coating to be documented.

5. A new procedure will be developed to specify that in each 10-year period during the subsequent period of extended operation, the minimum number of inspections is completed for the various sample populations (each material, environment, and aging effect combination). If opportunistic inspections will not fulfill the minimum number of inspections by the end of each 10-year period, the program owner will initiate work orders as necessary to request additional inspections. A representative sample of 20% of the population (defined as components having the same material, environment, and aging effect combination) or a maximum of nineteen components per population at each unit will be inspected. The new procedure will specify that the inspections focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions.

Monitoring and Trending (Element 5) and Acceptance Criteria (Element 6)

6. A new procedure will be developed to evaluate and project the rate of any degradation until the end of the subsequent period of extended operation or the next scheduled inspection, whichever is shorter. The inspection sampling bases (e.g., selection, size, frequency) will be adjusted as necessary based on the projection.

Acceptance Criteria (Element 6)

7. A new procedure will be developed to specify that, where practical, acceptance criteria are quantitative (e.g., minimum wall thickness). For quantitative analyses, the required minimum wall thickness to meet applicable design standards will be used. For qualitative evaluations, applicable parameters such as ductility, color, and other indicators will be addressed to ensure a decision is based on observed conditions.

Corrective Actions (Element 7)

8. A new procedure will be developed to specify that additional inspections will be performed if any sampling-based inspections do not meet the acceptance criteria, unless the cause of the aging effect for each applicable material and environment is corrected by repair or replacement. There will be no fewer than five additional inspections for each inspection that did not meet acceptance criteria, or 20% of each applicable material, environment, and aging effect combination are inspected, whichever is less. If any subsequent inspections do not meet acceptance criteria, an extent of condition and extent of cause analysis will be conducted to determine the further extent of inspections required. Additional samples will be inspected for any recurring degradation to ensure corrective actions appropriately address the associated causes. The additional inspections will include inspections of components with the same material, environment, and aging effect combination at both Unit 1 and Unit 2. The additional inspections will be completed within the interval (e.g., refueling outage interval, 10-year inspection interval) in which the original inspection was conducted or, if identified in the latter half of the current inspection interval, within the next refueling outage interval.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In January 2009, a leak was identified in a raw water vacuum priming elbow servicing a Unit 1 component cooling heat exchanger. The condition was determined to be pitting due to microbiologically induced corrosion (MIC). The pipe section was removed and replaced. A separate condition report written at the same time documented another leak at a different location in the same section of piping. Three separate through wall leaks were noted on this section of piping and documented on the two condition reports. To provide more information as to extent of condition, another section of vacuum priming pipe on a different component cooling heat exchanger was removed, and showed evidence of MIC, although not through wall. Engineering recommended creation of preventive maintenance items to replace the vacuum priming piping with similar configuration to the MIC-damaged sections on the four Unit 1 component cooling heat exchangers every ten years to prevent future through wall leaks. The new preventive maintenance items were approved in October 2010.
2. In March 2012, during performance of a preventive maintenance activity, it was identified that the housing for an air handling unit was degraded. The internal condition of the housing showed corrosion of the metal. The unit was subsequently replaced as part of a design change to rectify persistent ventilation degradation and equipment obsolescence issues. The design change replaced the major mechanical components of the Unit 1 and Unit 2 cable spreading room ventilation systems and repaired associated ductwork.
3. In May 2013, Engineering performed non-destructive examination on a length of Unit 2 recirculation spray heat exchanger service water vent piping. An elbow in the length of piping showed significant wall thinning. This piping is vented to atmosphere, but is temporarily fully wetted with service water when flow testing the recirculation spray heat exchangers. Quarterly ultrasonic testing of the piping was performed to monitor the progression of thinning until the piping was replaced in the next outage. Inspection during the replacement of the piping documented exfoliation due to corrosion. This is an example of recurring internal corrosion in the service water system.

4. In May 2015, discharge piping in the Unit 1 Turbine Building from plumbing system sump pumps was identified to have several leaks at a threaded fitting at a rate of four to five gallons per minute. The fitting material is cast iron exposed to waste water. The sump liquid pH was determined to be neutral, so the cause was attributed to corrosion from stagnant water over time. Other recent examples of leaks in plumbing system piping at fittings have also been noted. Soft patch repairs were made to the leaks, and work orders initiated to replace the piping. This is an example of recurring internal corrosion in the plumbing system.

5. In December 2015, an effectiveness review was performed of the Work Control Process Activity (UFSAR Section 18.2.19). The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the Detection of Aging Effects, Corrective Actions, and Operating Experience activity elements. A sample of completed as-found inspection forms was reviewed and identified that the documentation of as-found inspections was inconsistent and needed improvement.

   As a corrective action, training of mechanical maintenance personnel on expectations for properly documenting as-found conditions was conducted. An additional corrective action that recommended enhancement of the as-found inspection form was closed administratively. This operating experience is revisited in the January 2018 AMP effectiveness review. Due to the need for additional improvements noted during the January 2018 AMP effectiveness review, a condition report was entered into the Corrective Action Program.

6. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

7. In November 2017, as part of oversight review activities, the Work Control Process Activity (UFSAR Section 18.2.19) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

8. In January 2018, an aging management program effectiveness review was performed of the Work Control Process Activity (UFSAR Section 18.2.19). Information from the summary of that effectiveness review is provided below:

   The Work Control Process Activity plans and conducts testing and maintenance activities, both preventive and corrective. Visual inspections are conducted of the internal surfaces of plant components and adjacent piping that are in the scope of license renewal to monitor for aging effects such as cracking and loss of material. Potential age-related degradation conditions are recorded on "as-found" inspection forms and dispositioned as necessary in the Corrective Action Program. A review was performed of station operating experience identified via the Work Control Process Activity, including conditions identified in the Corrective Action Program from 2006 through 2017.

   While the automatic inclusion of the as-found inspection form in work packages ensures that inspections are performed on in-scope components, a review of a sampling of completed inspection forms throughout the period from 2006 to 2017 showed that inspection personnel are not consistent in the level of detail provided on the form when recording observed conditions. A self-assessment of the License Renewal program documented the issue of inconsistent level of detail on as-found inspection forms in 2015. This operating experience is discussed in item number five above. Corrective actions completed as a result of this Condition Report do not appear to have been effective.

   A sample of as-found inspection forms from March to June 2017 (after the corrective actions were completed) was reviewed and contained the following typical discrepancies:

   - Condition Report numbers not appropriately documented on the inspection sheets concerning discovered aging effects
   - Aging effects not described in detail and documented in the inspection sheet notes section
   - Aging effects table not filled out adequately
   - License Renewal inspection sheets inappropriately dispositioned

   To improve program effectiveness, the following will be addressed and documented during the next aging management program effectiveness review:

   - Investigation and evaluation of inspection results and corrective actions from a sample population of License Renewal equipment work orders
   - Clarification of procedural guidance on inspection parameters including documentation of aging effects
   - Re-training of inspection personnel (current staffing and maintenance of this population of inspectors)
   - Re-training of personnel reviewing inspection forms (current staffing and maintenance of this population of reviewers)

A condition report has been generated in the Corrective Action Program to document and track implementation of these corrective action

Recurring Internal Corrosion (RIC)

Recurring internal corrosion, including through-wall failures due to pitting and general corrosion, has been observed in the service water and plumbing systems. Occurrences in the service water system have been noted over a period from 2007 to 2013. Occurrences in the plumbing system have been noted over a period from 2011 to 2018. Corrective actions have been taken previously, and additional actions have been initiated as noted below to minimize the likelihood of piping and component degradation due to pitting and general corrosion in systems monitored by the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program (B2.1.25). Future occurrences of RIC will be documented in accordance with the Corrective Action Program.

Corrective actions include:

- Sections of service water piping not within the scope of GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," that have documented leaks in the past due to corrosion of carbon steel from a raw water environment have been replaced. Opportunistic inspections of susceptible piping and components will be performed when the system boundary is opened. Periodic system walkdowns in accordance with plant procedure will monitor for leakage. Additional corrective actions will be determined via the Corrective Action Program if significant loss of material is detected.
- Work orders have been created to replace affected portions of the plumbing system piping along an approximately 77 foot length in the Unit 1 Turbine Building basement that have documented leaks from corrosion due to stagnant water in the lines. Opportunistic inspections of susceptible piping and components in other portions of the system within the scope of subsequent license renewal will continue to be performed when the system boundary is opened.

Recurring internal corrosion has also been observed in various lined or coated components, such as the main condenser channel heads and the 96 inch circulating water discharge piping. The aging effects of internally coated/lined surfaces are managed by the *Internal Coatings/Linings For In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program (B2.1.28). Specific operating experience examples and corrective actions that discuss such aging effects are documented in the *Internal Coatings/Linings for In-Scope Piping, Piping Components, Heat Exchangers, and Tanks* program.

The above examples of operating experience provide objective evidence that the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program includes activities to perform opportunistic inspections to identify loss of material, cracking, reduction of heat transfer, and flow blockage of metallic components. The program also includes activities to perform opportunistic inspections to identify hardening or loss of strength, loss of material, cracking or blistering, and flow blockage of polymeric components within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

B2.1.39 Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Program Description

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing condition monitoring program that manages the aging effect of reduced electrical insulation resistance of inaccessible medium-voltage cables (operating voltages of 2kV to 35kV) exposed to significant moisture.

The program applies to inaccessible or underground non-EQ medium-voltage power cable installations (e.g., installed in buried conduits, duct banks, underground vaults, manholes, cable trenches or direct buried installations), within the scope of subsequent license renewal exposed to significant moisture. Significant moisture is defined as exposure to moisture that lasts more than three days (i.e., long term wetting or submergence over a continuous period), that if left unmanaged, could potentially lead to a loss of intended function. Power cable exposure to significant moisture may cause reduced electrical insulation resistance that can potentially lead to failure of the cable's insulation system.

Periodic actions are taken to prevent non-EQ inaccessible medium-voltage power cables from being exposed to significant moisture. Accessible cable conduit ends and manhole/vaults associated with cables included in this program are inspected for water collection and the water is drained, as necessary. Manholes associated with in-scope non-EQ inaccessible medium-voltage power cables are inspected to confirm that cables are not wetted or submerged in water, cables/vaults and cable support structures are intact and dewatering/drainage systems (i.e., sump pumps) and associated alarms operate properly. This inspection and water removal is performed based on actual plant experience over time with an inspection frequency being at least annually and after event driven occurrences (such as heavy rain, rapid thawing of ice and snow, or flooding). Dewatering devices and associated alarms are inspected and their operation verified periodically.

In-scope non-EQ inaccessible medium-voltage power cables routed through manholes, and duct banks are tested to detect reduced electrical insulation resistance of the cable's insulation system. Testing that is appropriate to the application at the time of the testing is performed. Cable testing includes one or more proven testing methods (such as dielectric loss [dissipation factor (Tan-Delta)/power factor], AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis). Cable testing acceptance criteria are defined prior to each test. Cables are tested at least once every six years. More frequent testing may occur based on test results and operating experience.

There are no submarine cables or other cables designed for continuous wetting or submergence currently in the scope of this program. Future installed cables of this design would be considered for inclusion in this program.

NUREG-2191 Consistency

The *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program is an existing program that, following enhancement, will be consistent with NUREG-2191, Section XI.E3A, Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Exception Summary

None

Enhancements

Prior to the subsequent period of extended operation, the following enhancement(s) will be implemented in the following program element(s):

Preventive Actions (Element 2)

1. Procedures will be revised to require inspection of in-scope manholes after event driven occurrences, such as heavy rain, rapid thawing of ice and snow, or flooding.
2. Procedures will be revised to add a step stating that automatic or passive drainage features of manholes are operating properly.

Parameters Monitored/Inspected (Element 3)

3. A procedure will be created for testing medium-voltage cable that includes a requirement for testing medium-voltage cables that are exposed to significant moisture to determine the condition of the electrical insulation.
4. Procedures will be revised to add a step to evaluate adjusting the inspection frequency of manholes based on plant-specific operating experience over time with water collection.

Detection of Aging Effects (Element 4)

5. A new recurring event and maintenance schedule will be created for testing the "A" RSST cables at least once every six years.
6. A new recurring event and maintenance schedule will be created for testing the "B" RSST cables at least once every six years.
7. A new recurring event and maintenance schedule will be created for testing the "C" RSST cables at least once every six years.

8. A new procedure will be created for testing medium-voltage cable that includes a requirement that the specific type of test performed will be a proven test, utilizing one or more tests such as dielectric loss (dissipation factor (Tan-Delta)/power factor), AC voltage withstand, partial discharge, step voltage, time domain reflectometry, insulation resistance and polarization index, or line resonance analysis, for detecting deterioration of the insulation system due to submergence (e.g., selected test is applicable to the specific cable construction: shielded and non-shielded, and the insulation material under test).

Monitoring and Trending (Element 5)

9. A new procedure will be created for testing medium-voltage cable that includes a requirement to review visual inspection and physical test results that are trendable and repeatable to provide additional information on the rate of cable or connection insulation degradation.

Acceptance Criteria (Element 6)

10. A new procedure will be created for testing medium-voltage cable that includes acceptance criteria for tests and inspections.

Operating Experience Summary

The following examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, has been, and will be effective in managing the aging effects for SSCs within the scope of the program so that their intended functions will be maintained consistent with the current licensing basis during the subsequent period of extended operation.

1. In May 2009, following rain, water was observed draining out of the AAC cabling lead box located outside the condensate polishing building. A walkdown of the installation and a review of drawings was performed. An inspection of the ductlines entering the lead box discovered water in the ductlines. The ductlines were dewatered. Additionally, the individual ductlines were sealed, and the 4kV cables from the AAC diesel generator were entered into the cable life cycle management plan for testing. No wetting/degradation has been observed in recent inspections.

2. In September 2012, during an NRC review of License Renewal (LR) commitments and activities, the NRC LR review team identified that the proposed method to perform an annual visual inspection for water accumulation in an in-scope manhole may not be effective.

   The 'C' RSST power cable was re-routed to this manhole in April 2009. This was the only medium-voltage cable within the scope of initial license renewal.

It was identified that the manhole was not being periodically inspected for water accumulation. As a result, the inspection procedure was revised to add the in-scope manhole. Additionally, it was noted that the procedure did not allow for manhole entry to attempt a visual inspection of this 42 foot deep manhole.

It was determined that the use of a boroscope would be effective to provide for the necessary inspection. The procedure was revised accordingly.

3. In December 2015, an effectiveness review of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) was performed. The aging management activity (AMA) was evaluated against the performance criteria identified in NEI 14-12 for the detection of Aging Effects, Corrective Actions, and Operating Experience program elements. The Non-Environmental Qualification (EQ) Cable Monitoring AMA includes elements of the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39).

   During this effectiveness review, timeliness of corrective action for sealing duct bank entrances for the underground 'C' RSST cables was identified. A Work Order that was created in 2011 to seal the duct bank entrances in order to prevent water and silt entry into a license renewal manhole had not been completed and there was no evaluation to allow delay of the work. Subsequently, an assessment was completed to evaluate whether any license renewal commitments were compromised by delay in implementing the work order. Annual visual inspections of the same license renewal manhole between 2013 and 2017 have found water level being controlled below the level of the cables such that the cables are not exposed to significant moisture, indicating that water in-leakage has not exceeded the capability of the sump pumps. No license renewal commitments were judged to be compromised. ~~and it was recommended that this work order be processed in accordance with station work management practices for implementation.~~Duct bank seals were installed to correct this condition during the 2018 Fall refueling outage.

   Results of the December 2015 effectiveness review for the other two associated aging management programs are provided in the SLRA sections indicated above.

4. In September 2016, the periodic surveillances of an in-scope manhole for water intrusion were reviewed. Since March 2012, when the inspection procedure was established, there has been no excessive water in the manhole, and no long term wetting of the medium-voltage cables in this manhole.

   The in-scope medium-voltage cables have been tested with the following results:

   - In 2011, the SBO AAC diesel cables were tan-delta tested with satisfactory results. These cables have been entered into the medium-voltage testing program.
   - In 2012, the RSST feeder cables were tan-delta tested with satisfactory results.
   - In 2015, the EDG #1 cables were meggered and PI tested (non-shielded cable) with satisfactory results. They again were tested satisfactorily in 2017.

5. In December 2016, as part of oversight review activities, a review of procedures credited by initial license renewal AMAs was conducted to confirm the following:

   - Procedures credited for license renewal were identified
   - Procedures were consistent with the licensing basis and bases documents
   - Procedures contained a reference to conduct an aging management review prior to revising
   - Procedures credited for license renewal were identified by an appropriate program indicator and contained a reference to a license renewal document

   Procedure changes were completed as necessary to ensure the above items were satisfied.

6. In November 2017, as part of oversight review activities, the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4) AMA owner confirmed that AMA inspections had been performed and the inspections addressed the required SSCs consistent with the aging management activity commitments. No gaps were identified by the review.

7. In January 2018, an aging management program effectiveness review was performed of the Non-Environmental Qualification (EQ) Cable Monitoring Activity (UFSAR Section 18.1.4). Information from the summary of that effectiveness review is provided below:

   The implementing procedure for this activity includes instructions for the *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.37), *Electrical Insulation for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits* program (B2.1.38) and *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39). This effectiveness review summary applies to the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program (B2.1.39).

The Non-Environmental Qualification (EQ) Cable Monitoring Activity is meeting or exceeding the requirements of selected NEI 14-12, "Aging Management Program Effectiveness," elements. Key activities of the AMA that were reviewed included the selection of components to be inspected or tested, the inspection and testing of the components, the evaluation of the inspection and testing results, repair/replacements of components as required, and AMA document updates. Engineering reports from the 2004/2006 and 2014/2016 inspection results of manholes containing in-scope medium-voltage cables were reviewed to confirm inspection frequencies were conducted at appropriate intervals and corrective actions taken consistent with the observed condition, such as raising cables from the bottom of the manhole when they were lying in water. The review also encompassed pertinent issues found in the Corrective Action Program from 2006 through 2017 for manhole water intrusion for those components within the scope of license renewal.

Due to the review of corrective actions to address wetted or submerged medium-voltage cables, the implementing procedure was enhanced to ensure manhole visual inspections are conducted at least annually and ensure the use of boroscopes to verify cables within the scope of license renewal were not exposed to submerged conditions when manholes cannot be entered.

The above examples of operating experience provide objective evidence that the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program includes activities to perform testing and visual inspections of manholes to identify the aging effect of reduced electrical insulation resistance for non-EQ inaccessible medium-voltage cables (operating voltage of 2kV to 35kV) exposed to significant moisture within the scope of subsequent license renewal, and to initiate corrective actions. Occurrences identified under the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program are evaluated to ensure there is no significant impact to the safe operation of the plant and corrective actions will be taken to prevent recurrence. Guidance or corrective actions for additional inspections, re-evaluation, repairs, or replacements is provided for locations where aging effects are found. The program is informed and enhanced when necessary through the systematic and ongoing review of both plant-specific and industry operating experience. There is reasonable assurance that the continued implementation of the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, will effectively manage aging prior to a loss of intended function.

Conclusion

The continued implementation of the *Electrical Insulation for Inaccessible Medium-Voltage Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements* program, following enhancement, will provide reasonable assurance that aging effects will be managed such that the components within the scope of this program will continue to perform their intended functions consistent with the current licensing basis during the subsequent period of extended operation.

Enclosure 5

**PWROG-17011-NP, REVISION 2
UPDATE FOR SUBSEQUENT LICENSE RENEWAL:
WCAP-14535A, "TOPICAL REPORT ON REACTOR COOLANT PUMP FLYWHEEL INSPECTION ELIMINATION" AND WCAP-15666-A, "EXTENSION OF REACTOR COOLANT PUMP MOTOR FLYWHEEL EXAMINATION"**

**Virginia Electric and Power Company
(Dominion Energy Virginia)
Surry Power Station Units 1 and 2**