DUKE ENERGY.
CAROLINAS

Duke Energy
Allen Steam Station
253 Plant Allen Road
Belmont, NC 28012

June 12, 2017

Mr. William Willets, Permitting Section Chief
North Carolina Department of Environment Quality
Division of Air Quality
1641 Mail Service Center
Raleigh, North Carolina 27699-1641

Subject: **Mercury and Air Toxics Standard (MATS); 40 CFR 63, Subpart UUUUU**
Rescission Request to Use Halide Salts as a Mercury Control Strategy
502(b)(10) Change request Pursuant to 15A NCAC 2Q .0523
Duke Energy Carolinas, LLC Allen Steam Station
Facility ID No. 3600039; Permit No. 03757T
Belmont, North Carolina; Gaston County

Dear Mr. Willets:

Duke Energy Carolinas, LLC (Duke Energy) operates the G.G. Allen Steam Station which is a major source of hazardous air pollutants (HAP) as defined by the Clean Air Act. The electric generating units (EGUs) at this site are classified as existing sources under the National Emission Standards for Hazardous Air Pollutants From Coal and Oil-Fired Electric Utility Steam Generating Units (Mercury and Air Toxics Standards, or "MATS") rule presented at 40 CFR 63, Subpart UUUUU.

The MATS rule was promulgated on February 16, 2012 (77 Fed. Reg. 9304), and became effective April 16, 2012. With the publication of the MATS rule, sources had 3 years from the effective date, or until April 16, 2015, to comply with the MATS requirements. The MATS rule limits emissions of metallic compounds using filterable particulate as a surrogate, acid gas emissions by using sulfur dioxide (SO_2) or hydrogen chloride (HCl) as surrogates, and finally mercury emissions are measured directly.

Duke Energy has implemented a number of measures to reduce emissions to levels that will continuously comply with the MATS emissions limits Some control measures will be used at all times (i.e., flue gas desulfurization units), while other measures are considered "trim" technologies and would be used intermittently to ensure compliance.

One of the trim technologies that was identified was the use of a halide salt to minimize emissions of mercury. Permit applications requesting authorization to use this material at all of the coal-fired sites in the Carolinas were submitted to the North Carolina Division of Air Quality (NCDAQ). Since the submittal of these applications, Duke Energy has gained additional operational knowledge and data regarding our mercury emissions. At this time, the company does not have any plans to pursue application of the halide salt as a mitigation strategy.

Therefore via this correspondence, Duke Energy is respectfully requesting that in accordance with the provisions of 15A NCAC 2Q .0523, that the Allen permit be amended using the 502(b)(10) modification procedures. This proposed change will not cause any emission limit under the permit to be exceeded.

The site is required to provide written notification to the state at least seven days prior to making the change. Please accept this correspondence as our notification of the proposed change, effective as of the date of this letter. No changes in emissions are expected as a result of removing the permit language. The affected permit language may be found in the emission source descriptors for Units No. 1 through 5 along with Permit Condition 2.1.A.16. A copy of this letter will be attached to the permit and the modification will be formally included in the permit at the next opportunity.

We appreciate your consideration of this request. If you have additional questions or concerns, please do not hesitate to contact Ms. Ann Quillian at (919) 546-6610 or at Ann.Quillian@duke-energy.com.

Sincerely,

P. Brent Dueitt

P. Brent Dueitt,
General Manager II
Allen Steam Station

Enclosure

ec: Ann Quillian, NCRH15

502(b)(10) Notification Form

NCDENR v8/4/2014

Site Name: Duke Energy Carolinas, LLC. Allen Steam Station	Facility Contact: Randy Gantt, Lead EHS Professional
Site Address (911 Address): 253 Plant Allen Road	Contact Phone Number: 704-829-2587
City/County: Belmont/Gaston	Contact Email Address: Michael.Gantt@duke-energy.com
Facility ID No. 3600039	Regional Office Where Facility is Located: Mooresville

502(b)(10) QUALIFICATION CHECKLIST

☑	This change does not violate any existing requirement in the current Title V air quality permit
☑	This change does not cause emissions allowed under the permit to be exceeded
☑	This change does not require a case-by-case determination (e.g. BACT)
☑	This change is not a modification under Title I of the federal Clean Air Act
☑	This change does not alter (modify or add to) any existing monitoring, reporting or recordkeeping provisions in my current permit
☑	This change does not require a change to an existing permit term that was taken to avoid an applicable requirement (e.g. PSD avoidance condition)
☑	This change does not require a permit under the NC Toxics program
☑	This change will not be made until at least seven (7) business days after the NC DAQ receives written notification
☑	A copy of this notification form and interim permit conditions will be attached to my permit until the permit is revised at the next significant modification or renewal

DESCRIPTION OF CHANGE

Provide a brief description of the change, the anticipated date on which the change will occur, and any permit term or condition no longer applicable as a result of the change. Attach a process flow diagram if relevant. At the next renewal or significant modification of the permit, NC DAQ will require that all applicable application forms (A1 to A4, D1, E1, E2 and E5 and any other applicable B/C/D/E form(s)) be submitted for each emission source associated with the requested 502(b)(10) change.

The facility will not be using halide salts for mercury control, therefore requesting removal of Permit Condition 2.1.A.16 as well as references in the emission source descriptors for U1 Boiler, U2 Boiler, U3 Boiler, U4 Boiler, and U5 Boiler.

ATTACH A COPY OF THE PROPOSED PERMIT CONDITIONS FOR EACH REQUIREMENT THAT APPLIES TO THE PERMIT MODIFICATION

New or Modified Source/Control Device	ID No.	Applicable Standard with Proposed Monitoring (e.g. 15A NCAC 2D .0515, .0521, .1111 MACT ZZZZ)	Emissions Change (tons/year)
U1 Boiler, U2 Boiler, U3 Boiler, U4 Boiler, U5 Boiler	ES-1, ES-2, ES-3, ES-4, ES-5	15A NCAC 02Q .0317, 15A NCAC 02D .0530	

SIGNATURE OF RESPONSIBLE OFFICIAL/AUTHORIZED CONTACT

I understand that it is my responsibility to ensure each proposed modification qualifies as a 502(b)(10) change under 15A NCAC 2Q .0523. My facility assumes all financial risks associated with construction and operation without a permit revision and will not proceed until after providing both the EPA and NC DAQ a seven business day advanced notice. This notification will be attached to the permit prior to making a change and remain until the permit is revised to include the change(s). The facility will follow the proposed monitoring and attached permit conditions during the interim period and address compliance in the annual compliance certification. Emissions resulting from the affected source(s) will be included in the annual emissions inventory. I am aware the permit shield in 15A NCAC 2Q .0512(a) does not extend to the change(s).

Name (typed): P. Brent Dueitt	Title: General Manager
X Signature: P. Brent Dueitt	Date: June 12, 2017

SECTION 1 - PERMITTED EMISSION SOURCE(S) AND ASSOCIATED AIR POLLUTION CONTROL DEVICE(S) AND APPURTENANCES

The following table contains a summary of all permitted emission sources and associated air pollution control devices and appurtenances:

Page No.	Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
8, 51, 53, 58	ES-1[1] (U1Boiler) **CAM** **MACT** UUUUU	Coal/No. 2 fuel oil[2]-fired electric utility boiler (1,980 million Btu per hour heat input capacity) equipped with a modified fuel burner system (low NOx concentric firing system), separated overfire air (SOFA), lowered fired (LOFIR) low NOx technologies, alkaline-based fuel additive**, ~~and halide salt mercury oxidation fuel additives~~ at a nominal rate not to exceed 15 gallons per hour see footnote *	CD-1b (U1-SNCR) CD-2 (U1ESP) CDU1/2/5 FGD	Selective non-catalytic reduction (SNCR) NOx control system, Cold-side electrostatic precipitator (280,477 square feet of plate area), and Flue Gas Desulfurization spray tower scrubber; 32 to 182 gallons per minute limestone slurry injection
8, 51, 54, 58	ES-2[1] (U2Boiler) **CAM** **MACT** **UUUUU**	Coal/No. 2 fuel oil[2]-fired electric utility boiler (1,980 million Btu per hour maximum heat input) equipped with a modified fuel burner system (low NOx concentric firing system), separated overfire air (SOFA) low-NOx control equipment, alkaline-based fuel additive**, ~~and halide salt mercury oxidation fuel additives~~ at a nominal rate not to exceed 15 gallons per hour see footnote *	CD-3b (U2SCNR) CD-4 (U2ESP) CDU1/2/5 FGD	Selective non-catalytic reduction (SNCR) NOx control system, Cold-side electrostatic precipitator (280,477 square feet of plate area, and Flue Gas Desulfurization spray tower scrubber; 32 to 182 gallons per minute limestone slurry injection
8, 51, 55, 58	ES-3[1] (U3Boiler) **CAM** **MACT** **UUUUU**	Coal/No. 2 fuel oil[2]-fired electric utility boiler (3,390 million Btu per hour heat input capacity) equipped with a modified fuel burner system (low NOx concentric firing system), separated overfire air (SOFA), lowered-fire (LOFIR) low-NOx equipment, alkaline-based fuel additive**, ~~and halide salt mercury oxidation fuel additives~~ at a nominal rate not to exceed 15 gallons per hour	CD-5b (U3SNCR) CD-6a (U3FGT) CD-6b (U3FGT) CD-7 (U3ESP) CDU3/4 FGD	Selective non-catalytic reduction (SNCR) NOx control system, **And flue gas conditioning systems:** - Ammonia injection ash conditioner (29 pounds per hour [20 parts per million maximum ammonia injection rate]) and - Sulfur trioxide injection ash conditioner (190 pounds per hour maximum injection rate), Cold-side electrostatic precipitator (336,960 square feet of plate area), and Flue Gas Desulfurization spray tower scrubber; 32 to 182 gallons per minute limestone slurry injection
		Note: The ammonia and sulfur trioxide ash conditioning and NOx systems may be operated independently of each other or in combination. Each system may be operated intermittently as necessary, based on the boiler system requirements, to maintain compliance with the applicable emission standards.		

Page No.	Emission Source ID No.	Emission Source Description	Control Device ID No.	Control Device Description
8, 51, 56, 58	ES-4[1] (U4Boiler) **CAM** **MACT** **UUUUU**	Coal/No. 2 fuel oil[2]-fired electric utility boiler (3,390 million Btu per hour heat input capacity) equipped with a modified fuel burner system (low NOx concentric firing system), separated overfire air (SOFA) low NOx equipment, alkaline-based fuel additive**, ~~and halide salt mercury oxidation fuel additives~~ at a nominal rate not to exceed 15 gallons per hour	CD-8b (U4SNCR) CD-9a (U4FGT) CD-9b (U4FGT) CD-U4/5ActC CD-9 (U4ESP) CDU3/4FGD	Selective non-catalytic reduction (SNCR) NOx control system, **And flue gas conditioning systems:** - Ammonia injection ash conditioner (29 pounds per hour [20 parts per million maximum ammonia injection rate]) and - Sulfur trioxide injection ash conditioner (190 pounds per hour maximum injection rate), System for injecting powdered activated carbon Cold-side electrostatic precipitator (336,960 square feet of plate area), and Flue Gas Desulfurization spray tower scrubber; 32 to 182 gallons per minute limestone slurry injection
		Note: The ammonia and sulfur trioxide ash conditioning and NOx systems may be operated independently of each other or in combination. Each system may be operated intermittently as necessary, based on the boiler system requirements, to maintain compliance with the applicable emission standards.		
8, 51, 57, 58	ES-5[1] (U5Boiler) **CAM** **MACT** **UUUUU**	Coal/No. 2 fuel oil[2]-fired electric utility boiler (3,390 million Btu per hour heat input capacity) equipped with a modified fuel burner system (low NOx concentric firing system), separated overfire air (SOFA), lowered fired (LOFIR) low-NOx equipment, alkaline-based fuel additive**, ~~and halide salt mercury oxidation fuel additives~~ at a nominal rate not to exceed 15 gallons per hour see footnote *	CD-10c (U5SNCR) CD-11a (U5FGT) CD-11b (U5FGT) CD-U4/5ActC CD-11 (U5ESP) CDU1/2/5 FGD	Selective non-catalytic reduction (SNCR) NOx control system, **And flue gas conditioning systems:** - Ammonia injection ash conditioner (29 pounds per hour [20 parts per million maximum ammonia injection rate]) and - Sulfur trioxide injection ash conditioner (190 pounds per hour maximum injection rate), System for injecting powdered activated carbon Cold-side electrostatic precipitator (336,960 square feet of plate area), and Flue Gas Desulfurization spray tower scrubber; 32 to 182 gallons per minute limestone slurry injection
		Note: The ammonia and sulfur trioxide ash conditioning and NOx systems may be operated independently of each other or in combination. Each system may be operated intermittently as necessary, based on the boiler system requirements, to maintain compliance with the applicable emission standards.		
		Limestone Receiving, Storage, Transfer, and Grinding		
33, 36, 48	ES-8-1 (RUL)	Railcar transfer to dual hopper	CDRULBF	Railcar unloading enclosure dust collection system with fabric filter; 48,000 acfm, collection area 9,600 to 12,000 square feet (to be determined) **NSPS OOO**
33, 48	ES-8-2A (LUBF1) **NSPS OOO**	Dual hopper transfer to hopper conveyor No.1		

SECTION 2 - SPECIFIC LIMITATIONS AND CONDITIONS

2.1 - Emission Source(s) and Control Devices(s) Specific Limitations and Conditions

The emission source(s) and associated air pollution control device(s) and appurtenances listed below are subject to the following specific terms, conditions, and limitations, including the testing, monitoring, recordkeeping, and reporting requirements as specified herein:

A. Five Coal/No. 2 Fuel Oil-fired Electric Utility Boilers:

Flue Gas Desulfurization spray tower scrubber (ID No. CDU1/2/5FGD) on:

Boiler (ID No. ES-1) with a low NOx concentric firing system, separated over-fire air, lowered-fire low NOx technologies, alkaline-based fuel additive, ~~and halide salt mercury oxidation fuel additive;~~ and associated selective non-catalytic NOx reduction system (ID No. CD 1b), and a cold-side electrostatic precipitator (ID No. CD-2); and

Boiler (ID No. ES-2) with low NOx concentric firing system, separated over-fire air, alkaline-based fuel additive, ~~and halide salt mercury oxidation fuel additive;~~ and associated selective non-catalytic NOx reduction system (ID No. CD 3b) and cold-side electrostatic precipitator (ID No. CD-4); and

Boiler (ID No. ES-5) with a low NOx concentric firing system, separated over-fire air, lowered-fire low NOx technologies, alkaline-based fuel additive, ~~and halide salt mercury oxidation fuel additive;~~ and associated selective non-catalytic NOx reduction system (ID No. CD 10c), cold-side electrostatic precipitator (ID No. CD-11), and flue gas conditioning systems consisting of an ammonia injection ash conditioner (ID No. CD-11a), a sulfur trioxide injection ash conditioner (ID No. CD-11b), and powdered activated carbon system (ID No. CD-U4/5ActC)[1].

Flue Gas Desulfurization spray tower scrubber (ID No. CDU3/4FGD) on:

Boiler (ID No. ES-3) with a low NOx concentric firing system, separated over-fire air, lowered-fire low NOx technologies, alkaline-based fuel additive, ~~and halide salt mercury oxidation fuel additive;~~ and associated selective non-catalytic NOx reduction system (CD-5b), cold-side electrostatic precipitator (ID No. CD-7 (U3ESP)), and flue gas conditioning systems consisting of an ammonia injection ash conditioner (ID No. CD-6a) and a sulfur trioxide injection ash conditioner (ID No. CD6b); and

Boiler (ID No. ES-4) with a low NOx concentric firing system, separated over-fire air, alkaline-based fuel additive, ~~and halide salt mercury oxidation fuel additive;~~ and associated selective non-catalytic NOx reduction system (CD-8b), cold-side electrostatic precipitator (ID No. CD-9), and flue gas conditioning systems consisting of an ammonia injection ash conditioner (ID No. CD-9a), a sulfur trioxide injection ash conditioner (ID No. CD-9b), and powdered activated carbon system (ID No. CD-U4/5ActC)[1].

1 NOTIFICATION REQUIREMENT - This permit may be revoked unless the emission source(s) and associated air pollution control device(s) listed in Section 1 are constructed in accordance with the approved plans, specifications, and other supporting data. Within 15 days after start up of the new or modified facilities, the Permittee shall provide written notice of the start up to the Regional Supervisor, DAQ.

non-waste determination by EPA or the basis for concluding that the fuel is not a waste, and the total fuel usage amount with units of measure.

iii. Indicate whether the Permittee burned new types of fuel during the reporting period. If the Permittee did burn new types of fuel the Permittee must include the date of the performance test where that fuel was in use.

iv. Include the date of the most recent tune-up for each EGU. The date of the tune-up is the date the tune-up provisions specified in §63.10021(e)(6) and (7) were completed.

v. A certification.

vi. If there is a deviation from any emission limit, work practice standard, or operating limit, the Permittee must also submit a brief description of the deviation, the duration of the deviation, emissions point identification, and the cause of the deviation.

vii. For each excess emissions occurring at an affected source where the Permittee is using a CMS to comply with that emission limit or operating limit, the Permittee shall include the information required in §63.10(e)(3)(v) in the compliance report specified in §63.10031(c). [§63.10031(c) and §63.10031(d)]

uu. Each affected source that has obtained a Title V operating permit pursuant to 40 CFR Part 70 or Part 71 shall report all deviations as defined in this subpart in the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A). If an affected source submits a compliance report pursuant to Table 8 of Subpart UUUUU along with, or as part of, the semiannual monitoring report required by 40 CFR 70.6(a)(3)(iii)(A) or 40 CFR 71.6(a)(3)(iii)(A), and the compliance report includes all required information concerning deviations from any emission limit, operating limit, or work practice requirement in this subpart, submission of the compliance report satisfies any obligation to report the same deviations in the semiannual monitoring report. Submission of a compliance report does not otherwise affect any obligation the affected source may have to report deviations from permit requirements to the permit authority. [§63.10031(e)]

vv. On or after April 16, 2017, within 60 days after the date of completing each performance test, the Permittee shall submit the performance test reports required by the Subpart to EPA's WebFIRE database by using the Compliance and Emissions Data Reporting Interface (CEDRI) that is accessed through EPA's Central Data Exchange (CDX) (www.epa.gov/cdx). The Permittee shall comply with all applicable requirements in §63.10031(f). [§63.10031(f)]

ww. If the Permittee had a malfunction during the reporting period, the compliance report must include the number, duration, and a brief description for each type of malfunction which occurred during the reporting period and which caused or may have caused any applicable emission limitation to be exceeded. [§63.10031(g)]

~~16. 15A NCAC 02Q .0317: AVOIDANCE CONDITIONS for~~
~~15A NCAC 02D .0530: PREVENTION OF SIGNIFICANT DETERIORATION~~

~~a. In order to avoid applicability of 15A NCAC 02D .0530(g), the $PM_{2.5}$ emissions from these sources (ID Nos. ES-1 through ES-5) shall be less than 10 tons per consecutive 12-month period, attributable to applying halide salt mercury oxidation fuel additives (or other equivalent fuel additives) to the incoming coal. All particulate matter (PM) emissions are assumed to be $PM_{2.5}$.~~

~~**Testing** [15A NCAC 02Q .0508(f)]~~

~~b. If emissions testing is required, the Permittee shall perform such testing in accordance with General Condition JJ found in Section 3. If the results of this test are above the limit given in Section 2.1.A.16.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530.~~

~~**Monitoring/Recordkeeping** [15A NCAC 02Q .0508(f)]~~

~~c. Calculations of $PM_{2.5}$ emissions from applying halide salt mercury oxidation fuel additives to the incoming coal in these sources (ID Nos. ES-1 through ES-5) shall be made and recorded in a logbook (written or electronic format) at the end of each month when the additives have been used. The $PM_{2.5}$ emissions from applying halide salts shall be equivalent to the amount of halide salts applied to the coal. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0530 if the $PM_{2.5}$ emissions from applying halide salts are not monitored and recorded or if the $PM_{2.5}$ emissions exceed the limit in Section 2.1.A.16.a above.~~

~~**Reporting** [15A NCAC 02Q .0508(f)]~~

~~d. The Permittee shall submit a semi-annual summary report, acceptable to the Regional Air Quality Supervisor, of monitoring and recordkeeping activities postmarked on or before January 30 of each calendar year for the preceding six-month period between July and December, and July 30 of each calendar year for the preceding six-month period between January and June. Semi-annual reports shall only be required when operating the halide salt injection system during any semi-annual period pursuant to General Condition LL. The report shall contain the following:~~

~~i. The monthly $PM_{2.5}$ emissions due to the injection of halide salts with the incoming coal in these sources, for the previous 17 months. The emissions must be calculated for each of the 12-month periods over the previous 17 months.~~

B. No. 2 fuel oil-fired auxiliary boiler (ID No. ES-6 (AuxB))

The following table provides a summary of limits and standards for the emission source(s) described above:

Regulated Pollutant	Limits/Standards	Applicable Regulation
Particulate Matter	0.09 pounds per million Btu heat input	15A NCAC 02D .0503
Sulfur Dioxide	0.5 weight percent sulfur content fuel oil	15A NCAC 02D .0524 (40 CFR Part 60 Subpart Dc)
Visible Emissions	20 percent opacity (except during startups, shutdowns, and malfunctions) when averaged over a six-minute period. However, six-minute averaging periods may exceed 20 percent opacity if (i) no six-minute period exceeds 87 percent opacity, (ii) no more than one six-minute period exceeds 20 percent opacity in any hour, and (iii) no more than four six-minute periods exceed 20 percent opacity in any 24-hour period.	15A NCAC 02D .0521
Nitrogen Oxides	Annual Boiler Tune-up requirement	15A NCAC 02D .1407
N/A	Recordkeeping only; monthly fuel records	15A NCAC 02D .0524 (40 CFR Part 60 Subpart Dc)
Hazardous Air Pollutants	Best Combustion Practices	15A NCAC 02D .1109

1. 15A NCAC 02D .0503: PARTICULATES FROM FUEL BURNING INDIRECT HEAT EXCHANGERS

a. Emissions of particulate matter from the combustion of fuel oil or propane that are discharged from this source into the atmosphere shall not exceed **0.09 pounds per million Btu heat input**. [15A NCAC 02D .0503 (a)]

Testing [15A NCAC 02Q .0508(f)]

b. If emissions testing is required, the testing shall be performed in accordance with General Condition JJ. If the results of this test are above the limits given in Section 2.1 B.1.a above, the Permittee shall be deemed in noncompliance with 15A NCAC 02D .0503.

Monitoring/Recordkeeping/Reporting [15A NCAC 02Q .0508(f)]

c. No monitoring/recordkeeping/reporting is required for visible emissions from these sources to assure compliance with this regulation.

2. 15A NCAC 02D .0524: NSPS 40 CFR PART 60 SUBPART Dc

a. The Permittee shall comply with all applicable provisions, including the notification, testing, recordkeeping, and monitoring requirements contained in Environmental Management Commission Standard 15A NCAC 02D .0524 "New Source Performance Standards (NSPS) as promulgated in 40 CFR Part 60 Subpart Dc, including Subpart A "General Provisions." [15A NCAC 02D .0524]

b. The maximum sulfur content of any fuel oil received and burned in the auxiliary boiler (ID No. ES-6, AuxB) shall not exceed 0.5 percent by weight. [15A NCAC 02D .0524]

Monitoring/ Recordkeeping [15A NCAC 02Q .0508(f)]

c. In addition to any other recordkeeping required by 40 CFR § 60.48c or recordkeeping requirements of the EPA, the Permittee shall record and maintain monthly records of the amounts of each fuel fired during each month. Records must be maintained for a minimum of two years. The Permittee shall be deemed in noncompliance with 15A NCAC 02D .0524 if these records are not maintained.

Reporting [15A NCAC 02Q .0508(f)]