Doss Rebuttal Exhibit 1

Accounting Standard Codification 410-20

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General

Subsection revised 01-Oct-2012

Combine Subsections

00-1 The following table identifies the changes made to this Subtopic.

Paragraph	Action	Accounting Standards Update	Date
Fair Value (3rd def.)	Added	Accounting Standards Update No. 2012-04	10/01/2012
410-20-55-27	Amended	Accounting Standards Update No. 2012-04	10/01/2012
410-20-55-66	Amended	Accounting Standards Update No. 2012-04	10/01/2012

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General

Subsection revised 01-Jul-2009

Combine Subsections

05-1 This Subtopic establishes accounting standards for recognition and measurement of a liability for an asset retirement obligation and the associated asset retirement cost. This Subtopic also addresses the accounting for an environmental remediation liability that results from the normal operation of a long-lived asset.

05-2 Paragraph Not Used

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Entities

15-1 The guidance in this Subtopic applies to all entities, including rate-regulated entities that meet the criteria for application of Subtopic 980-10, as provided in paragraph 980-10-15-2. Paragraphs 980-340-25-1 and 980-405-25-1 provide specific conditions that must be met to recognize a regulatory asset and a regulatory liability, respectively. (See paragraphs 410-20-55-1 through 55-12 and 410-20-55-21 through 55-22 for implementation guidance)

> Transactions

15-2 The guidance in this Subtopic applies to the following transactions and activities:

a. Legal obligations associated with the retirementof a tangible long-lived asset that result from the acquisition, construction, or development and (or) the normal operation of a long-lived asset, including any legal obligations that require disposal of a replaced part that is a component of a tangible long-lived asset.

b. An environmental remediation liability that results from the normal operation of a long-lived asset and that is associated with the retirement of that asset. The fact that partial settlement of an obligation is required or performed before full retirement of an asset does not remove that obligation from the scope of this Subtopic. If environmental contamination is incurred in the normal operation of a long-lived asset and is associated with the retirement of that asset, then this Subtopic will apply (and Subtopic 410-30 will not apply) if the entity is legally obligated to treat the contamination.

c. A conditional obligation to perform a retirement activity. Uncertainty about the timing of settlement of the asset retirement obligation does not remove that obligation from the scope of this Subtopic but will affect the measurement of a liability for that obligation (see paragraph 410-20-25-10).

d. Obligations of a lessor in connection with leased property that meet the provisions in (a). Paragraph 840-10-25-16 requires that lease classification tests performed in accordance with the requirements of Subtopic 840-10 incorporate the requirements of this Subtopic to the extent applicable.

e. The costs associated with the retirement of a specified asset that qualifies as historical waste equipment as defined by EU Directive 2002/96/EC. (See paragraphs 410-20-55-23 through 55-30 and Example 4 [paragraph 410-20-55-63] for illustration of this guidance.) Paragraph 410-20-55-24 explains how the Directive distinguishes between new and historical waste and provides related implementation guidance.

15-3 The guidance in this Subtopic does not apply to the following transactions and activities:

a. Obligations that arise solely from a plan to sell or otherwise dispose of a long-lived asset covered by Subtopic 360-10.

b. An environmental remediation liability that results from the improper operation of a long-lived asset (see Subtopic 410-30). Obligations resulting from improper operations do not represent costs that are an integral part of the tangible long-lived asset and therefore should not be accounted for as part of the cost basis of the asset. For example, a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not. The obligation to clean up the spillage resulting from the normal operation of the fuel storage facility is within the scope of this Subtopic. The obligation to clean up after the catastrophic accident results from the improper use of the facility and is not within the scope of this Subtopic.

c. Activities necessary to prepare an asset for an alternative use as they are not associated with the retirement of the asset.

d. Historical waste held by private households. (The guidance in this paragraph does not pertain to an asset retirement obligation in the scope of this Subtopic.) For guidance on accounting for historical electronic equipment waste held by private households for obligations associated with Directive 2002/96/EC on Waste Electrical and Electronic Equipment adopted by the European Union, see Subtopic 720-40.

e. Obligations of a lessee in connection with leased property, whether imposed by a lease agreement or by a party other than the lessor, that meet the definition of either minimum lease payments or contingent rentals in paragraphs 840-10-25-4 through 25-7. Those obligations shall be accounted for by the lessee in accordance with the requirements of Subtopic 840-10. However, if obligations of a lessee in connection with leased property, whether imposed by a lease agreement or by a party other than the lessor, meet the provisions in paragraph 410-20-15-2 but do not meet the definition of either minimum lease payments or contingent rentals in paragraphs 840-10-25-4 through 25-7, those obligations shall be accounted for by the lessee in accordance with the requirements of this Subtopic.

f. An obligation for asbestos removal that results from the other-than-normal operation of an asset. Such an obligation may be subject to the provisions of Subtopic 410-30.

g. Costs associated with complying with funding or assurance provisions. Paragraph 410-20-35-9 otherwise addresses the measurement effects of funding and assurance provisions.

h. Obligations associated with maintenance, rather than retirement, of a long-lived asset.

i. The cost of a replacement part that is a component of a long-lived asset.

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Accretion Expense

An amount recognized as an expense classified as an operating item in the statement of income resulting from the increase in the carrying amount of the liability associated with the asset retirement obligation.

Asset Retirement Cost

The amount capitalized that increases the carrying amount of the long-lived asset when a liability for an asset retirement obligation is recognized.

Asset Retirement Obligation

An obligation associated with the retirement of a tangible long-lived asset.

Conditional Asset Retirement Obligation

A legal obligation to perform an asset retirement activity in which the timing and (or) method of settlement are conditional on a future event that may or may not be within the control of the entity.

Legal Obligation

An obligation that a party is required to settle as a result of an existing or enacted law, statute, ordinance, or written or oral contract or by legal construction of a contract under the doctrine of promissory estoppel.

Promissory Estoppel

"The principle that a promise made without consideration may nonetheless be enforced to prevent injustice if the promisor should have reasonably expected the promisee to rely on the promise and if the promisee did actually rely on the promise to his or her detriment." (See Black's Law Dictionary, seventh edition.)

Retirement

The other-than-temporary removal of a long-lived asset from service. That term encompasses sale, abandonment, recycling, or disposal in some other manner. However, it does not encompass the temporary idling of a long-lived asset. After an entity retires an asset, that asset is no longer under the control of that entity, no longer in existence, or no longer capable of being used in the manner for which the asset was originally acquired, constructed, or developed.

Closure

Related to the Resource Conservation and Recovery Act of 1976: the process in which the owner-operator of a hazardous waste management unit discontinues active operation of the unit by treating, removing from the site, or disposing of on site all hazardous wastes in accordance with an Environmental Protection Agency or state-approved plan. Included, for example, are the process of emptying, cleaning, and removing or filling underground storage tanks and the capping of a landfill. Closure entails specific financial guarantees and technical tasks that are included in a closure plan and must be implemented.

Disposal

Related to the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 and the Resource Conservation and Recovery Act of 1976: under the Resource Conservation and Recovery Act of 1976, the discharge, deposit, injection, dumping, spilling, leaking, or placing of any solid waste or hazardous waste into or on any land or water so that such solid waste or hazardous waste or any constituent thereof may enter the environment or be emitted into the air or discharged into any waters, including groundwaters. Similarly under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980 with regard to hazardous substances.

Hazardous Waste

Related to Resource Conservation and Recovery Act of 1976: a waste, or combination of wastes, that because of its quantity, concentration, toxicity, corrosiveness, mutagenicity or inflammability, or physical, chemical, or infectious characteristics may cause, or significantly contribute to, an increase in mortality or an increase in serious irreversible, or incapacitating reversible illness or pose a substantial present or potential hazard to human health or the environment when improperly treated, stored, transported, or disposed of, or otherwise managed. Technically, those wastes that are regulated under the Resource Conservation and Recovery Act of 1976 40 CFR Part 261 are considered to be hazardous wastes.

Natural Resources

Under the Comprehensive Environmental Response, Compensation, and Liability Act of 1980, natural resources are defined as land, fish, wildlife, biota, air, water, groundwater, drinking water supplies, and other such resources belonging to, managed or held in trust by, or otherwise controlled by the United States, state or local governments, foreign governments, or Indian tribes.

Discount Rate Adjustment Technique

A present value technique that uses a risk-adjusted discount rate and contractual, promised, or most likely cash flows.

Fair Value

The price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date.

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Background for Recognition

25-1 Paragraph 35 of FASB Concepts Statement No. 6, Elements of Financial Statements, defines a liability as follows {Note: The indented text below is reproduced from FASB Concepts Statement No. 6 and includes editorial changes for internal consistency within the Codification}.

> Liabilities are probable future sacrifices of economic benefits arising from present obligations of a particular entity to transfer assets or provide services to other entities in the future as a result of past transactions or events.

25-2 Probable is used with its usual general meaning, rather than in a specific accounting or technical sense (such as that in paragraph 450-20-25-1), and refers to that which can reasonably be expected or believed on the basis of available evidence or logic but is neither certain nor proved (Webster's New World Dictionary). Its inclusion in the definition is intended to acknowledge that business and other economic activities occur in an environment characterized by uncertainty in which few outcomes are certain (see paragraphs 44 through 48 of FASB Concepts Statement No. 6).

25-3 As stated in the preceding paragraph, the definition of a liability in Concepts Statement 6 uses the term *probable* in a different sense than it is used in paragraph 450-20-25-1. As used in Topic 450, probable requires a high degree of expectation. The term probable in the definition of a liability, however, is intended to acknowledge that business and other economic activities occur in an environment in which few outcomes are certain.

25-3A Paragraph 410-20-40-3 states that providing assurance that an entity will be able to satisfy its asset retirement obligation does not satisfy or extinguish the related liability.

> Fair Value Is Reasonably Estimated

25-4 An entity shall recognize the fair value of a liability for an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. If a reasonable estimate of fair value cannot be made in the period the asset retirement obligation is incurred, the liability shall be recognized when a reasonable estimate of fair value can be made. If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date.

25-5 Upon initial recognition of a liability for an asset retirement obligation, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related long-lived asset by the same amount as the liability. Paragraph 835-20-30-5 explains that capitalized asset retirement costs do not qualify as expenditures for purposes of applying Subtopic 835-20.

25-6 An entity shall identify all its asset retirement obligations. An entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation if any of the following conditions exist:

a. It is evident that the fair value of the obligation is embodied in the acquisition price of the asset.

b. An active market exists for the transfer of the obligation.

c. Sufficient information exists to apply an expected present value technique.

> Obligations with Uncertainty in Timing or Method of Settlement

25-7 The obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement. Thus, the timing and (or) method of settlement may be conditional on a future event. Accordingly, an entity shall recognize a liability for the fair value of a conditional asset retirement obligation if the fair value of the liability can be reasonably estimated. In some cases, sufficient information about the timing and (or) method of settlement may not be available to reasonably estimate fair value. An expected present value technique incorporates uncertainty about the timing and method of settlement into the fair value measurement. Uncertainty is factored into the measurement of the fair value of the liability through assignment of probabilities to cash flows.

25-8 An entity would have sufficient information to apply an expected present value technique and therefore an asset retirement obligation would be reasonably estimable if either of the following conditions exists:

a. The settlement date and method of settlement for the obligation have been specified by others. For example, the law, regulation, or contract that gives rise to the legal obligation specifies the settlement date and method of settlement. In this situation, the settlement date and method of settlement are known and therefore the only uncertainty is whether the obligation will be enforced (that is, whether performance will be required). In certain cases, determining the settlement date for the obligation that has been specified by others is a matter of judgment that depends on the relevant facts and circumstances. For example, a contract that provides the entity with an ability to extend its term through renewal should be evaluated to determine whether the settlement date should take into consideration renewal periods. Uncertainty about whether performance will be required does not defer the recognition of an asset retirement obligation because a legal obligation to stand ready to perform the retirement activities still exists, and it does not prevent the determination of a reasonable estimate of fair value because the only uncertainty is whether performance will be required.

b. The information is available to reasonably estimate all of the following:

1. The settlement date or the range of potential settlement dates

2. The method of settlement or potential methods of settlement (The term *potential methods of settlement* refers to methods of settling the obligation that are currently available to the entity. Therefore, uncertainty about future methods yet to be developed would not prevent the entity from estimating the fair value of the asset retirement obligation.)

3. The probabilities associated with the potential settlement dates and potential methods of settlement. (The entity should have a reasonable basis for assigning probabilities to the potential settlement dates and potential methods of settlement to reasonably estimate the fair value of the asset retirement obligation. If the entity does not have a reasonable basis of assigning probabilities, it is expected that the entity would still be able to reasonably estimate fair value when the range of time over which the entity may settle the obligation is so narrow and (or) the cash flows associated with each potential method of settlement are so similar that assigning probabilities without having a reasonable basis for doing so would not have a material impact on the fair value of the asset retirement obligation.)

25-9 In many cases, the determination as to whether the entity has the information to reasonably estimate the fair value of the asset retirement obligation is a matter of judgment that depends on the relevant facts and circumstances. It is expected that the narrower the range of time over which the entity may settle the obligation and the fewer potential methods of settlement the entity has available to it, the more likely it is that the entity will have the information to reasonably estimate the fair value of an asset retirement obligation. For an illustration of this guidance, see Example 3 (paragraph 410-20-55-47).

25-10 Instances may occur in which insufficient information to estimate the fair value of an asset retirement obligation is available. For example, if an asset has an indeterminate useful life, sufficient information to estimate a range of potential settlement dates for the obligation might not be available. In such cases, the liability would be initially recognized in the period in which sufficient information exists to estimate a range of potential settlement dates that is needed to employ a present value technique to estimate fair value.

25-11 Examples of information that is expected to provide a basis for estimating the potential settlement dates, potential methods of settlement, and the associated probabilities include, but are not limited to, information that is derived from the entity's past practice, industry practice, management's intent, or the asset's estimated economic life. The estimated economic life of the asset might indicate a potential settlement date for the asset retirement obligation. However, the original estimated economic life of the asset may not, in and of itself, establish that date because the entity may intend to make improvements to the asset that could extend the life of the asset or the entity could defer settlement of the obligation beyond the economic life of the asset. In those situations, the entity would look beyond the economic life of the asset in determining the settlement date or range of potential settlement dates to use when estimating the fair value of the asset retirement obligation.

25-12 An asset retirement obligation may result from the acquisition, construction, or development and (or) normal operation of a long-lived asset that has an indeterminate useful life and thereby an indeterminate settlement date for the asset retirement obligation.

25-13 If a current law, regulation, or contract requires an entity to perform an asset retirement activity when an asset is dismantled or demolished, there is an unambiguous requirement to perform the retirement activity even if that activity can be indefinitely deferred. At some time deferral will no longer be possible, because no tangible asset will last forever (except land). Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and (or) method of settlement.

> Uncertainty in Performance Obligations

25-14 This Subtopic requires recognition of a conditional asset retirement obligation before the event that either requires or waives performance occurs. Uncertainty surrounding conditional performance of the retirement obligation is factored into its measurement by assessing the likelihood that performance will be required. In situations in which the conditional aspect has only 2 outcomes and there is no information about which outcome is more probable, a 50 percent likelihood for each outcome shall be used until additional information is available.

25-15 An unambiguous requirement that gives rise to an asset retirement obligation coupled with a low likelihood of required performance still requires recognition of a liability. Uncertainty about the conditional outcome of the obligation is incorporated into the measurement of the fair value of that liability, not the recognition decision. Uncertainty about performance of conditional obligations shall not prevent the determination of a reasonable estimate of fair value. A past history of nonenforcement of an unambiguous obligation does not defer recognition of a liability, but its measurement is affected by the uncertainty over the requirement to perform retirement activities.

> Acquired Asset Retirement Obligations

25-16 If a tangible long-lived asset with an existing asset retirement obligation is acquired, a liability for that obligation shall be recognized at the asset's acquisition date as if that obligation were incurred on that date.

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Determination of a Reasonable Estimate of Fair Value

30-1 An expected present value technique will usually be the only appropriate technique with which to estimate the fair value of a liability for an asset retirement obligation. An entity, when using that technique, shall discount the expected cash flows using a credit-adjusted risk-free rate. Thus, the effect of an entity's credit standing is reflected in the discount rate rather than in the expected cash flows. Proper application of a discount rate adjustment technique entails analysis of at least two liabilities—the liability that exists in the marketplace and has an observable interest rate and the liability being measured. The appropriate rate of interest for the cash flows being measured shall be inferred from the observable rate of interest of some other liability, and to draw that inference the characteristics of the cash flows shall be similar to those of the liability being measured. Rarely, if ever, would there be an observable rate of interest for a liability that has cash flows similar to an asset retirement obligation being measured. In addition, an asset retirement obligation usually will have uncertainties in both timing and amount. In that circumstance, employing a discount rate adjustment technique, where uncertainty is incorporated into the rate, will be difficult, if not impossible. See paragraphs 410-20-55-13 through 55-17 and Example 2 (paragraph 410-20-55-35). For further information on present value techniques, see the guidance beginning in paragraph 820-10-55-4.

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Allocation of Asset Retirement Cost

35-1 A liability for an asset retirement obligation may be incurred over more than one reporting period if the events that create the obligation occur over more than one reporting period. Any incremental liability incurred in a subsequent reporting period shall be considered to be an additional layer of the original liability. Each layer shall be initially measured at fair value. For example, the liability for decommissioning a nuclear power plant is incurred as contamination occurs. Each period, as contamination increases, a separate layer shall be measured and recognized. Paragraph 410-20-30-1 provides guidance on using that technique.

35-2 An entity shall subsequently allocate that asset retirement cost to expense using a systematic and rational method over its useful life. Application of a systematic and rational allocation method does not preclude an entity from capitalizing an amount of asset retirement cost and allocating an equal amount to expense in the same accounting period. For example, assume an entity acquires a long-lived asset with an estimated life of 10 years. As that asset is operated, the entity incurs one-tenth of the liability for an asset retirement obligation each year. Application of a systematic and rational allocation method would not preclude that entity from capitalizing and then expensing one-tenth of the asset retirement costs each year.

35-3 In periods subsequent to initial measurement, an entity shall recognize period-to-period changes in the liability for an asset retirement obligation resulting from the following:

a. The passage of time
b. Revisions to either the timing or the amount of the original estimate of undiscounted cash flows.

35-4 An entity shall measure and incorporate changes due to the passage of time into the carrying amount of the liability before measuring changes resulting from a revision to either the timing or the amount of estimated cash flows.

35-5 An entity shall measure changes in the liability for an asset retirement obligation due to passage of time by applying an interest method of allocation to the amount of the liability at the beginning of the period. The interest rate used to measure that change shall be the credit-adjusted risk-free rate that existed when the liability, or portion thereof, was initially measured. That amount shall be recognized as an increase in the carrying amount of the liability and as an expense classified as accretion expense. Paragraph 835-20-15-7 states that accretion expense related to exit costs and asset retirement obligations shall not be considered to be interest cost for purposes of applying Subtopic 835-20.

35-6 The subsequent measurement provisions require an entity to identify undiscounted estimated cash flows associated with the initial measurement of a liability. Therefore, an entity that obtains an initial measurement of fair value from a market price or from a technique other than an expected present value technique must determine the undiscounted cash flows and estimated timing of those cash flows that are embodied in that fair value amount for purposes of applying the subsequent measurement provisions. Example 1 (see paragraph 410-20-55-31) provides an illustration of the subsequent measurement of a liability that is initially obtained from a market price. (See paragraph 410-20-25-14 for a discussion on conditional outcomes.)

35-7 Paragraph 410-20-25-14 explains how uncertainty surrounding conditional performance of a retirement obligation is factored into its measurement by assessing the likelihood that performance will be required. As the time for notification approaches, more information and a better perspective about the ultimate outcome will likely be obtained. Consequently, reassessment of the timing, amount, and probabilities associated with the expected cash flows may change the amount of the liability recognized. See paragraphs 410-20-55-18 through 55-19.

> Change in Estimate

35-8 Changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows shall be recognized as an increase or a decrease in the carrying amount of the liability for an asset retirement obligation and the related asset retirement cost capitalized as part of the carrying amount of the related long-lived asset. Upward revisions in the amount of undiscounted estimated cash flows shall be discounted using the current credit-adjusted risk-free rate. Downward revisions in the amount of undiscounted estimated cash flows shall be discounted using the credit-adjusted risk-free rate that existed when the original liability was recognized. If an entity cannot identify the prior period to which the downward revision relates, it may use a weighted-average credit-adjusted risk-free rate to discount the downward revision to estimated future cash flows. When asset retirement costs change as a result of a revision to estimated cash flows, an entity shall adjust the amount of asset retirement cost allocated to expense in the period of change if the change affects that period only or in the period of change and future periods if the change affects more than one period as required by paragraphs 250-10-45-17 through 45-20 for a change in estimate.

> Effects of Funding and Assurance Provisions

35-9 Methods of providing assurance include surety bonds, insurance policies, letters of credit, guarantees by other entities, and establishment of trust funds or identification of other assets dedicated to satisfy the asset retirement obligation. The existence of funding and assurance provisions may affect the determination of the credit-adjusted risk-free rate. For a previously recognized asset retirement obligation, changes in funding and assurance provisions have no effect on the initial measurement or accretion of that liability, but may affect the credit-adjusted risk-free rate used to discount upward revisions in undiscounted cash flows for that obligation.

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Settlement of an Asset Retirement Obligation

40-1 Typically, settlement of an asset retirement obligation is not required until the associated asset is retired. However, certain circumstances may exist in which partial settlement of an asset retirement obligation is required or performed before the asset is fully retired. The nature of asset retirement obligations in various industries is such that the obligations are not necessarily satisfied when the current operation or use of the asset ceases. These obligations can be settled during operation of the asset or after the operations cease. The timing of the ultimate settlement of a liability is unrelated to and should not affect its initial recognition in the financial statements provided the obligation is associated with the retirement of a tangible long-lived asset.

40-2 Paragraph 410-20-25-14 explains how uncertainty surrounding conditional performance of a retirement obligation is factored into its measurement by assessing the likelihood that performance will be required. If, as time progresses, it becomes apparent that retirement activities will not be required, the liability and the remaining unamortized asset retirement cost shall be reduced to zero.

40-3 Providing assurance that an entity will be able to satisfy its asset retirement obligation does not satisfy or extinguish the related liability. The effect of surety bonds, letters of credit, and guarantees is to provide assurance that third parties will provide amounts to satisfy the asset retirement obligations if the entity that has primary responsibility (the obligor) to do so cannot or does not fulfill its obligations. The possibility that a third party will satisfy the asset retirement obligations does not relieve the obligor from its primary responsibility for those obligations. If a third party is required to satisfy asset retirement obligations due to the failure or inability of the obligor to do so directly, the obligor would then have a liability to the third party.

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Classification of Accretion Expense

45-1 Accretion expense shall be classified as an operating item in the statement of income. An entity may use any descriptor for accretion expense so long as it conveys the underlying nature of the expense.

45-2 See paragraph 230-10-45-17 for additional information about the classification of cash payments for asset retirement obligations as operating items on the statement of cash flows.

> Statement of Cash Flows

45-3 Paragraph 230-10-45-17(e) states that a cash payment made to settle an asset retirement obligation is a cash outflow for operating activities.

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General

Subsection revised 01-Jul-2009

Combine Subsections

50-1 An entity shall disclose all of the following information about its asset retirement obligations:

a. A general description of the asset retirement obligations and the associated long-lived assets

b. The fair value of assets that are legally restricted for purposes of settling asset retirement obligations

c. A reconciliation of the beginning and ending aggregate carrying amount of asset retirement obligations showing separately the changes attributable to the following components, whenever there is a significant change in any of these components during the reporting period:

1. Liabilities incurred in the current period
2. Liabilities settled in the current period
3. Accretion expense
4. Revisions in estimated cash flows.

50-2 If the fair value of an asset retirement obligation cannot be reasonably estimated, that fact and the reasons therefor shall be disclosed.

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General

Subsection revised 01-Oct-2012

Combine Subsections

> Implementation Guidance

> > Determination of Whether a Legal Obligation Exists

55-1 This implementation guidance illustrates Section 410-20-15. In most cases involving an asset retirement obligation, the determination of whether a legal obligation exists should be unambiguous. However, in situations in which no law, statute, ordinance, or contract exists but an entity makes a promise to a third party (which may include the public at large) about its intention to perform retirement activities, facts and circumstances need to be considered carefully in determining whether that promise has imposed a legal obligation upon the promisor under the doctrine of promissory estoppel. A legal obligation may exist even though no party has taken any formal action. In assessing whether a legal obligation exists, an entity is not permitted to forecast changes in the law or changes in the interpretation of existing laws and regulations. Preparers and their legal advisors are required to evaluate current circumstances to determine whether a legal obligation exists.

55-2 For example, assume an entity operates a manufacturing facility and has plans to retire it within five years. Members of the local press have begun to publicize the fact that when the entity ceases operations at the plant, it plans to abandon the site without demolishing the building and restoring the underlying land. Due to the significant negative publicity and demands by the public that the entity commit to dismantling the plant upon retirement, the entity's chief executive officer holds a press conference at city hall to announce that the entity will demolish the building and restore the underlying land when the entity ceases operations at the plant. Although no law, statute, ordinance, or written contract exists requiring the entity to perform any demolition or restoration activities, the promise made by the entity's chief executive officer may have created a legal obligation under the doctrine of promissory estoppel. In that circumstance, the entity's management (and legal counsel, if necessary) would have to evaluate the particular facts and circumstances to determine whether a legal obligation exists.

55-3 Once an entity determines that a duty or responsibility exists, it will then need to assess whether an obligating event has occurred that leaves it little or no discretion to avoid the future transfer or use of assets. If such an obligating event has occurred, an asset retirement obligation meets the definition of a liability and qualifies for recognition in the financial statements. However, if an obligating event that leaves an entity little or no discretion to avoid the future transfer or use of assets has not occurred, an asset retirement obligation does not meet the definition of a liability and, therefore, should not be recognized in the financial statements.

55-4 Identifying the obligating event is often difficult, especially in situations that involve the occurrence of a series of transactions or other events or circumstances affecting the entity. For example, in the case of an asset retirement obligation, a law or an entity's promise may create a duty or responsibility, but that law or promise in and of itself may not be the obligating event that results in an entity's having little or no discretion to avoid a future transfer or use of assets. An entity must look to the nature of the duty or responsibility to assess whether the obligating event has occurred. For example, in the case of a nuclear power facility, an entity assumes responsibility for decontamination of that facility upon receipt of the license to operate it. However, no obligation to decontaminate exists until the facility is operated and contamination occurs. Therefore, the contamination, not the receipt of the license, constitutes the obligating event.

> > Expectation of Nonenforcement

55-5 This implementation guidance illustrates Section 410-20-15.Contracts between entities may contain an option or a provision that requires one party to the contract to perform retirement activities when an asset is retired. The other party may decide in the future not to exercise the option or to waive the provision to perform retirement activities, or that party may have a history of waiving similar provisions in other contracts. Even if there is an expectation of a waiver or nonenforcement, the contract still imposes a legal obligation. That obligation is included in the scope of this Subtopic. The likelihood of a waiver or nonenforcement will affect the measurement of the liability. For example, consider an entity that owns and operates a landfill. Regulations require that that entity perform capping, closure, and postclosure activities. Capping activities involve covering the land with topsoil and planting vegetation. Closure activities include drainage, engineering, and demolition and must be performed prior to commencing the postclosure activities. Postclosure activities, the final retirement activities, include maintaining the landfill once final certification of closure has been received and monitoring the ground and surface water, gas emissions, and air quality. Closure and postclosure activities are performed after the entire landfill ceases receiving waste (that is, after the landfill is retired). However, capping activities are performed as sections of the landfill become full and are effectively retired. The fact that some of the capping activities are performed while the landfill continues to accept waste does not remove the obligation to perform those intermediate capping activities from the scope of this Subtopic.

> > Acquisition, Construction, or Development of a Long-Lived Asset

55-6 This implementation guidance illustrates Section 410-20-15. Whether an obligation results from the acquisition, construction, or development of a long-lived asset should, in most circumstances, be clear. For example, if an entity acquires a landfill that is already in operation, an obligation to perform capping, closure, and postclosure activities results from the acquisition and assumption of obligations related to past normal operations of the landfill. Additional obligations will be incurred as a result of future operations of the landfill.

> > Normal Operations

55-7 This implementation guidance illustrates Section 410-20-15. Whether an obligation results from the normal operation of a long-lived asset may require judgment. Obligations that result from the normal operation of an asset should be predictable and likely of occurring. For example, consider an entity that owns and operates a nuclear power plant. That entity has a legal obligation to perform decontamination activities when the plant ceases operations. Contamination, which gives rise to the obligation, is predictable and likely of occurring and is unavoidable as a result of operating the plant. Therefore, the obligation to perform decontamination activities at that plant results from the normal operation of the plant.

55-8 For example, a certain amount of spillage may be inherent in the normal operations of a fuel storage facility, but a catastrophic accident caused by noncompliance with an entity's safety procedures is not. The obligation to clean up after the catastrophic accident does not result from the normal operation of the facility and is not within the scope of this Subtopic.

> > Components of a Larger System

55-9 An asset retirement obligation may exist for component parts of a larger system. In some circumstances, the retirement of the component parts may be required before the retirement of the larger system to which the component parts belong.

55-10 For example, consider an aluminum smelter that owns and operates several kilns lined with a special type of brick. The kilns have a long useful life, but the bricks wear out after approximately five years of use and are replaced on a periodic basis to maintain optimal efficiency of the kilns. Because the bricks become contaminated with hazardous chemicals while in the kiln, a state law requires that when the bricks are removed, they must be disposed of at a special hazardous waste site. The obligation to dispose of those bricks is within the scope of this Subtopic. The cost of the replacement bricks and their installation are not part of that obligation. This implementation guidance illustrates Section 410-20-15.

55-11 If assets with asset retirement obligations are components of a larger group of assets (for example, a number of oil wells that make up an entire oil field operation), aggregation techniques may be necessary to derive a collective asset retirement obligation. This Subtopic does not preclude the use of estimates and computational shortcuts that are consistent with the fair value measurement objective when computing an aggregate asset retirement obligation for assets that are components of a larger group of assets. This implementation guidance illustrates paragraph 410-20-30-1.

> > Obligations with Uncertainty About Government Enforcement

55-12 This implementation guidance illustrates Section 410-20-15. If, for example, a governmental unit retains the right (an option) to decide whether to require a retirement activity, there is some uncertainty about whether those retirement activities will be required or waived. Regardless of the uncertainty attributable to the option, a legal obligation to stand ready to perform retirement activities still exists, and the governmental unit might require them to be performed. Although the timing and method of settlement of the retirement obligation may depend on future events that may or may not be within the control of the entity, a legal obligation to stand ready to perform retirement activities still exists. The entity should consider the uncertainty about the timing and method of settlement in the measurement of the liability, consistent with a fair value measurement objective, regardless of whether the event that will trigger the settlement is partially or wholly under the control of the entity.

> > Expected Present Value Technique

55-13 This implementation guidance illustrates paragraph 410-20-30-1. In estimating the fair value of a liability for an asset retirement obligation using an expected present value technique, an entity shall begin by estimating the expected cash flows that reflect, to the extent possible, a marketplace assessment of the cost and timing of performing the required retirement activities. Considerations in estimating those expected cash flows include developing and incorporating explicit assumptions, to the extent possible, about all of the following:

a. The costs that a third party would incur in performing the tasks necessary to retire the asset

b. Other amounts that a third party would include in determining the price of the transfer, including, for example, inflation, overhead, equipment charges, profit margin, and advances in technology

c. The extent to which the amount of a third party's costs or the timing of its costs would vary under different future scenarios and the relative probabilities of those scenarios

d. The price that a third party would demand and could expect to receive for bearing the uncertainties and unforeseeable circumstances inherent in the obligation, sometimes referred to as a market-risk premium.

55-14 It is expected that uncertainties about the amount and timing of future cash flows can be accommodated by using the expected present value technique and therefore will not prevent the determination of a reasonable estimate of fair value.

> > Credit-Adjusted Risk-Free Rate

55-15 This implementation guidance illustrates paragraph 410-20-30-1. An entity shall discount expected cash flows using an interest rate that equates to a risk-free interest rate adjusted for the effect of its credit standing (a credit-adjusted risk-free rate). In determining the adjustment for the effect of its credit standing, an entity should consider the effects of all terms, collateral, and existing guarantees on the fair value of the liability.

55-16 Adjustments for default risk can be reflected in either the discount rate or the expected cash flows. In most situations, an entity will know the adjustment required to the risk-free interest rate to reflect its credit standing. Consequently, it would be easier and less complex to reflect that adjustment in the discount rate.

55-17 In addition, because of the requirements in paragraph 410-20-35-8 relating to upward and downward adjustments in expected cash flows, it is essential to the operationality of this Subtopic that the credit standing of the entity be reflected in the discount rate. For those reasons, the risk-free rate shall be adjusted for the credit standing of the entity to determine the discount rate.

> > Calculation of Accretion Expense

55-18 This implementation guidance illustrates paragraphs 410-20-35-1 through 35-6. In periods subsequent to initial measurement, an entity recognizes the effect of the passage of time on the amount of a liability for an asset retirement obligation. A period-to-period increase in the carrying amount of the liability shall be recognized as an operating item (accretion expense) in the statement of income. An equivalent amount is added to the carrying amount of the liability. To calculate accretion expense, an entity shall multiply the beginning of the period liability balance by the credit-adjusted risk-free rate that existed when the liability was initially measured. The liability shall be adjusted for accretion prior to adjusting for revisions in estimated cash flows.

> > Changes in Assumptions and Legal Requirements

55-19 This implementation guidance illustrates paragraph 410-20-35-8. Revisions to a previously recorded asset retirement obligation will result from changes in the assumptions used to estimate the expected cash flows required to settle the asset retirement obligation, including changes in estimated probabilities, amounts, and timing of the settlement of the asset retirement obligation, as well as changes in the legal requirements of an obligation. Any changes that result in upward revisions to the expected cash flows shall be treated as a new liability and discounted at the current rate. Any downward revisions to the expected cash flows will result in a reduction of the asset retirement obligation. For downward revisions, the amount of the liability to be removed from the existing accrual shall be discounted at the credit-adjusted risk-free rate that was used at the time the obligation to which the downward revision relates was originally recorded (or the historical weighted-average rate if the year[s] to which the downward revision applies cannot be determined).

55-20 Revisions to the asset retirement obligation result in adjustments of capitalized asset retirement costs and will affect subsequent depreciation of the related asset. Such adjustments are depreciated on a prospective basis.

> > Interim Property Retirements

55-21 This implementation guidance illustrates Section 410-20-15. There is no conceptual difference between interim property retirements and replacements and those retirements that occur in circumstances in which the retired asset is not replaced. Therefore, any asset retirement obligation associated with the retirement of or the retirement and replacement of a component part of a larger system qualifies for recognition provided that the obligation meets the definition of a liability. The cost of replacement components is excluded.

55-22 Examples of interim property retirements and replacements for component parts of larger systems are components of transmission and distribution systems (utility poles), railroad ties, a single oil well that is part of a larger oil field, and aircraft engines. The assets in those examples may or may not have associated retirement obligations.

> > Historical Waste on Electrical and Electronic Equipment Associated with EU Directive 2002/96/EC

55-23 EU Directive 2002/96/EC was adopted on February 13, 2003, and directs EU-member countries to adopt legislation to regulate the collection, treatment, recovery, and environmentally sound disposal of electrical and electronic waste equipment. The actual legislation adopted by individual EU-member countries can have different requirements. An entity should apply the guidance herein, adjusted as needed for the specific requirements of the applicable EU-member country.

55-24 The Directive distinguishes between new and historical waste. All products put on the market on or before August 13, 2005, are deemed to be historical waste equipment for the purposes of the Directive. Example 4 (see paragraph 410-20-55-63) does not address the accounting for new waste because there should be little diversity in practice in the accounting for such waste. Costs relating to waste of new equipment are to be borne solely by the producers of the new equipment. This implementation guidance illustrates Section 410-20-15.

55-25 Under the Directive, the waste management obligation remains with the commercial user until the historical waste equipment is replaced, at which time the waste management obligation for that equipment may be transferred to the producer of the replacement equipment depending on the law adopted by the applicable EU-member country. If the commercial user does not replace the equipment, the obligation remains with that user until it disposes of the equipment. The Directive provides each EU-member country with the option to obligate commercial users to pay part or all of the costs associated with the historical waste even if the equipment is replaced. In this situation, the obligation would remain (partly or wholly) with the commercial user until the user disposes of the equipment.

55-26 The accounting for the initial recognition and measurement of the liability and asset retirement cost should be consistent with paragraphs 410-20-25-1 through 25-4. The ability or intent of the commercial user to replace the asset and transfer the obligation does not relieve the user of its present duty or responsibility to settle the obligation. The replacement of the asset may, depending on EU-member country law, transfer the obligation to the replacement producer, and, if so, that transfer would affect the purchase price of the replacement asset. Upon initial recognition of a liability, an entity shall capitalize an asset retirement cost by increasing the carrying amount of the related asset by the same amount as the liability. The accounting subsequent to the initial recognition of the asset and liability should be consistent with the guidance in paragraphs 410-20-35-3 through 35-8.

55-27 If the asset is subsequently replaced, with the obligation being transferred to the producer of the replacement equipment, the commercial user should determine the portion of the total amount paid to the producer that relates to the replacement equipment (the new asset) and the portion that relates to the transfer of the asset retirement obligation. That determination should be based on the fair value of the asset retirement obligation, without the sale of the new asset. The price paid by the commercial user would not include any costs associated with the transfer of the obligation in situations in which the law in the EU-member country obligates commercial users to pay all of the costs associated with the historical waste even if the equipment is replaced. In those situations, the commercial user would not derecognize the liability from its balance sheet upon replacement, but rather when the obligation is ultimately settled.

55-28 The new asset should be measured as the residual amount (the excess of the price paid over the fair value of the asset retirement obligation transferred). That amount should be used in determining the new asset's cost basis. The commercial user should derecognize the liability from its balance sheet and recognize a gain or loss based on the difference between the carrying amount of the liability at the date of the sale and the portion of the sales price that relates to the obligation. The producer of the new asset should recognize revenue for the total amount received reduced by the fair value of the obligation upon the transfer of the obligation from the commercial user (that is, on a net basis). The requirements for the producer to measure the revenue from the sale of the new asset as the residual amount and recognize revenue only for the sale of the new asset are applicable for those producers for which the recycling of electronic waste equipment is not a revenue-generating business activity. In situations in which the recycling of equipment is a revenue-generating business activity for the producer, that producer should measure the revenue from the sale of the new asset and the assumption of the obligation in accordance with the provisions of Subtopic 605-25.

55-29 The producer of the new asset should derecognize that liability when the obligation is settled.

55-30 See Example 4 (paragraph 410-20-55-63), which describes accounting for obligations associated with Directive 2002/96/EC on Waste Electrical and Electronic Equipment adopted by the European Union. That Example refers to and paraphrases various provisions of the Directive. Nothing in that Example shall be considered a definitive interpretation of any provision of the Directive for any purpose.

> Illustrations

> > Example 1: Subsequent Measurement of a Liability Obtained from a Market Price

55-31 This Example illustrates the guidance in paragraphs 410-20-35-5 through 35-6. After initial measurement, an entity is required to recognize period-to-period changes in an asset retirement obligation liability resulting from the passage of time (accretion expense) and revisions in cash flow estimates. To apply the subsequent measurement provisions of this Subtopic, an entity must identify undiscounted cash flows related to an asset retirement obligation liability irrespective of how the liability was initially measured. Therefore, if an entity obtains the initial fair value from a market price, it must impute undiscounted cash flows from that price.

55-32 This Example illustrates the subsequent measurement of a liability in situations where the initial liability is based on a market price. Assume that the liability is initially recognized at the end of period 0 when the market price is $300,000 and the entity's credit-adjusted risk-free rate is 8 percent. As required by this Subtopic, revisions in the timing or the amount of estimated cash flows are assumed to occur at the end of the period after accretion on the beginning balance of the liability is calculated. At the end of each period, the following procedure is used to impute cash flows from the end-of-period market price, compute the change in that price attributable to revisions in estimated cash flows, and calculate accretion expense:

a. The market price and the credit-adjusted risk-free interest rate are used to impute the undiscounted cash flows embedded in the market price.

b. The undiscounted cash flows from (a) are discounted at the initial credit-adjusted risk-free rate of 8 percent to arrive at the ending balance of the asset retirement obligation liability per the provisions of this Subtopic.

c. The beginning balance of the asset retirement obligation liability is multiplied by the initial credit-adjusted risk-free rate of 8 percent to arrive at the amount of accretion expense per the provisions of this Subtopic.

d. The difference between the undiscounted cash flows at the beginning of the period and the undiscounted cash flows at the end of the period represents the revision in cash flow estimates that occurred during the period. If that change is an upward revision to the undiscounted estimated cash flows, it is discounted at the current credit-adjusted risk-free rate. If that change is a downward revision, it is discounted at the historical weighted-average rate because it is not practicable to separately identify the period to which the downward revision relates.

55-33 The following table illustrates the subsequent measurement of an asset retirement obligation liability obtained from a market price.

Subsequent Measurement of an Asset Retirement Obligation Liability Obtained from a Market Pric

	End of Period			
	0	1	2	
Market assumptions:				
Market price (includes market risk premium)	$ 300,000	$ 400,000	$ 350,000	$ 3
Current risk-free rate adjusted for entity's credit standing	8.00%	7.00%	7.50%	
Time period remaining	3	2	1	
Imputed undiscounted cash flows (market price discounted at market rate)	$ 377,914	$ 457,960	$ 376,250	$ 3
Change in undiscounted cash flows	377,914	80,046	(81,710)	
Discount rate:				
Current credit-adjusted risk-free rate (for upward revisions)	8.00%	7.00%		
Historical weighted-average credit-adjusted risk-free rate (for downward revisions)			7.83%	
Change in undiscounted cash flows discounted at credit-adjusted risk-free rate (current rate for upward revisions and historical rate for downward revisions)	$ 300,000	$ 69,916	$ (75,777)	$

55-34 The following table illustrates the measurement of liability under the provisions of the asset retirement obligation statement.

Measurement of Liability under Provisions of Asset Retirement Obligation Statement

Period	Beginning Balance	Accretion (8.0%)	Change in Cash Flows	Ending Balance
0			$ 300,000	$300,000
1	$ 300,000	$ 24,000		324,000
2	324,000	25,920		349,920
3	349,920	27,994		377,914

Period	Beginning Balance	Accretion (7.0%)	Change in Cash flows	Ending Balance
0				
1			$ 69,916	$ 69,916
2	$ 69,916	$ 4,894		74,810
3	74,810	5,236		80,046

Period	Beginning Balance	Accretion (7.83%)	Change in Cash Flows	Ending Balance
0				
1				
2			$ (75,777)	$ (75,777)
3	$ (75,777)	$ (5,933)		(81,710)

Period	Beginning Balance	Accretion	Change in Cash Flows	Ending Balance
0				
1				
2				
3			$ 3,750	$ 3,750

	Total			
Period	Beginning Balance	Accretion Expense	Change in Cash Flows	Ending Balance
0			$ 300,000	$300,000
1	$ 300,000	$ 24,000	69,916	393,916
2	393,916	30,814	(75,777)	348,953
3	348,953	27,297	3,750	380,000

> > Example 2: Recognition and Measurement

55-35 The following Cases illustrate the recognition and measurement provisions of this Subtopic:

a. Initial measurement of a liability for an asset retirement obligation using an expected present value technique, subsequent measurement assuming that there are no changes in expected cash flows, and settlement of the asset retirement obligation liability at the end of its term (Case A)

b. Subsequent measurement of an asset retirement obligation liability after a change in expected cash flows (Case B)

c. Recognition and measurement of an asset retirement obligation liability that is incurred over more than one reporting period (Case C)

d. Accounting for asset retirement obligations that are conditional and that have a low likelihood of enforcement (Case D).

55-36 Cases A, B, C, and D incorporate simplified assumptions to provide guidance in implementing this Subtopic. For instance, Cases A and B relate to the asset retirement obligation associated with an offshore production platform that also would likely have individual wells and production facilities that would have separate asset retirement obligations. Those Cases also assume straight-line depreciation, even though, in practice, depreciation would likely be applied using a units-of -production method. Other simplifying assumptions are used throughout the Cases.

> > > Case A: Initial Measurement Using a Present Value Technique, Subsequent Measurement with No Change in Expected Cash Flows

55-37 This Case depicts an entity that completes construction of and places into service an offshore oil platform on January 1, 2003. The entity is legally required to dismantle and remove the platform at the end of its useful life, which is estimated to be 10 years. Based on the requirements of this Subtopic, on January 1, 2003, the entity recognizes a liability for an asset retirement obligation and capitalizes an amount for an asset retirement cost. The entity estimates the initial fair value of the liability using an expected present value technique. The significant assumptions used in that estimate of fair value are as follows:

a. Labor costs are based on current marketplace wages required to hire contractors to dismantle and remove offshore oil platforms. The entity assigns probability assessments to a range of cash flow estimates as follows.

Cash Flow Estimate	Probability Assessment	Expected Cash Flows
$ 100,000	25%	$ 25,000
125,000	50	62,500
175,000	25	43,750
		$ 131,250

b. The entity estimates allocated overhead and equipment charges using the rate it applies to labor costs for transfer pricing (80 percent). The entity has no reason to believe that its overhead rate differs from those used by contractors in the industry.

c. A contractor typically adds a markup on labor and allocated internal costs to provide a profit margin on the job. The rate used (20 percent) represents the entity's understanding of the profit that contractors in the industry generally earn to dismantle and remove offshore oil platforms.

d. A contractor would typically demand and receive a premium (market risk premium) for bearing the uncertainty and unforeseeable circumstances inherent in locking in today's price for a project that will not occur for 10 years. The entity estimates the amount of that premium to be 5 percent of the expected cash flows adjusted for inflation.

e. The risk-free rate of interest on January 1, 2003, is 5 percent. The entity adjusts that rate by 3.5 percent to reflect the effect of its credit standing. Therefore, the credit-adjusted risk-free rate used to compute expected present value is 8.5 percent.

f. The entity assumes a rate of inflation of 4 percent over the 10-year period.

55-38 On December 31, 2012, the entity settles its asset retirement obligation by using its internal workforce at a cost of $351,000. Assuming no changes during the 10-year period in the expected cash flows used to estimate the obligation, the entity would recognize a gain of $89,619 on settlement of the obligation. The entity would account for the asset retirement obligation as follows.

Labor	$ 195,000
Allocated overhead and equipment charges (80% of labor)	156,000
Total costs incurred	351,000
Asset retirement obligation liability	440,619
Gain on settlement of obligation	$ 89,619

Initial Measurement of the Asset Retirement Obligation Liability at January 1, 2003

	Expected Cash Flows 1/1/03
Expected labor costs	$ 131,250
Allocated overhead and equipment charges (.80 × $131,250)	105,000
Contractor's markup [.20 × ($131,250 + $105,000)]	47,250
Expected cash flows before inflation adjustment	283,500
Inflation factor assuming 4 percent rate for 10 years	1.4802
Expected cash flows adjusted for inflation	419,637
Market-risk premium (.05 × $419,637)	20,982
Expected cash flows adjusted for market risk	$ 440,619
Expected present value using credit-adjusted risk-free rate of 8.5 percent for 10 years	$ 194,879

Interest Method of Allocation

Year	Liability Balance 1/1	Accretion	Liability Balance 12/31
2003	$ 194,879	$ 16,565	$ 211,444
2004	211,444	17,973	229,417
2005	229,417	19,500	248,917
2006	248,917	21,158	270,075
2007	270,075	22,956	293,031
2008	293,031	24,908	317,939
2009	317,939	27,025	344,964
2010	344,964	29,322	374,286
2011	374,286	31,814	406,100
2012	406,100	34,519	440,619

Schedule of Expenses

Year-End	Accretion Expense	Depreciation Expense	Total Expense
2003	$ 16,565	$ 19,488	$36,053
2004	17,973	19,488	37,461
2005	19,500	19,488	38,988
2006	21,158	19,488	40,646
2007	22,956	19,488	42,444
2008	24,908	19,488	44,396
2009	27,025	19,488	46,513
2010	29,322	19,488	48,810
2011	31,814	19,488	51,302
2012	34,519	19,488	54,007

Journal Entries

January 1, 2003:		
Long-lived asset (asset retirement cost)	$ 194,879	
Asset retirement obligation liability		$ 194,879
To record the initial fair value of the asset retirement obligation liability		
December 31, 2003–2012:		
Depreciation expense (asset retirement cost)	19,488	
Accumulated depreciation		19,488
To record straight-line depreciation on the asset retirement cost		
Accretion expense	Per schedule	
Asset retirement obligation liability		Per schedule
To record accretion expense on the asset retirement obligation liability		
December 31, 2012:		
Asset retirement obligation liability	440,619	
Wages payable		195,000
Allocated overhead and equipment charges (.80 x $195,000)		156,000
Gain on settlement of asset retirement obligation liability		89,619
To record settlement of the asset retirement obligation liability		

> > > Case B: Initial Measurement Using a Present Value Technique, Subsequent Measurement with Changes in Expected Cash Flows

55-39 This Case is the same as Case A with respect to initial measurement of the asset retirement obligation liability. In this Case, the entity's credit standing improves over time, causing the credit-adjusted risk-free rate to decrease by 0.5 percent to 8 percent at December 31, 2004.

55-40 On December 31, 2004, the entity revises its estimate of labor costs to reflect an increase of 10 percent in the marketplace. In addition, it revises the probability assessments related to those labor costs. The change in labor costs results in an upward revision to the expected cash flows; consequently, the incremental expected cash flows are discounted at the current credit-adjusted risk-free rate of 8 percent. All other assumptions remain unchanged. The revised estimate of expected cash flows for labor costs is as follows.

Cash Flow Estimate	Probability Assessment	Expected Cash Flows
$ 110,000	30%	$ 33,000
137,500	45	61,875
192,500	25	48,125
		$ 143,000

55-41 On December 31, 2012, the entity settles its asset retirement obligation by using an outside contractor. It incurs costs of $463,000, resulting in the recognition of a $14,091 gain on settlement of the obligation. The entity would account for the asset retirement obligation as follows.

Asset retirement obligation liability	$477,091
Outside contractor	463,000
Gain on settlement of obligation	$ 14,091

Initial Measurement of the Asset Retirement Obligation Liability at January 1, 2003

	Expected Cash Flows 1/1/03
Expected labor costs	$ 131,250
Allocated overhead and equipment charges (.80 × $131,250)	105,000
Contractor's markup [.20 × ($131,250 + $105,000)]	47,250
Expected cash flows before inflation adjustment	283,500
Inflation factor assuming 4 percent rate for 10 years	1.4802
Expected cash flows adjusted for inflation	419,637
Market-risk premium (.05 × $419,637)	20,982
Expected cash flows adjusted for market risk	$ 440,619
Present value using credit-adjusted risk-free rate of 8.5 percent for 10 years	$ 194,879

Subsequent Measurement of the Asset Retirement Obligation Liability Reflecting a Change in Labor Cost Estimate as of December 31, 2004

	Incremental Expected Cash Flows 12/31/04
Incremental expected labor costs ($143,000 – $131,250)	$ 11,750
Allocated overhead and equipment charges (.80 × $11,750)	9,400
Contractor's markup [.20 × ($11,750 + $9,400)]	4,230
Expected cash flows before inflation adjustment	25,380
Inflation factor assuming 4 percent rate for 8 years	1.3686
Expected cash flows adjusted for inflation	34,735
Market-risk premium (.05 × $34,735)	1,737
Expected cash flows adjusted for market risk	$ 36,472
Expected present value of incremental liability using credit-adjusted risk-free rate of 8 percent for 8 years	$ 19,704

Interest Method of Allocation

Year	Liability Balance 1/1	Accretion	Change in Cash Flow Estimate	Liability Balance 12/31
2003	$ 194,879	$ 16,565		$ 211,444
2004	211,444	17,973	$ 19,704	249,121 (a)
2005	249,121	21,078		270,199
2006	270,199	22,862		293,061
2007	293,061	24,796		317,857
2008	317,857	26,894		344,751
2009	344,751	29,170		373,921
2010	373,921	31,638		405,559
2011	405,559	34,315		439,874
2012	439,874	37,217		477,091

Schedule of Expenses

Year-End	Accretion Expense	Depreciation Expense	Total Expense
2003	$ 16,565	$ 19,488	$ 36,053
2004	17,973	19,488	37,461
2005	21,078	21,951	43,029
2006	22,862	21,951	44,813
2007	24,796	21,951	46,747
2008	26,894	21,951	48,845
2009	29,170	21,951	51,121
2010	31,638	21,951	53,589
2011	34,315	21,951	56,266
2012	37,217	21,951	59,168

(a) The remainder of this table is an aggregation of two layers: the original liability, which is accreted at a rate of 8.5%, and the new incremental liability, which is accreted at a rate of 8.0%.

Journal Entries

January 1, 2003:		
Long-lived asset (asset retirement cost)	$ 194,879	
Asset retirement obligation liability		$ 194,879
To record the initial fair value of the asset retirement obligation liabiity		
December 31, 2003:		
Depreciation expense (asset retirement cost)	19,488	
Accumulated depreciation		19,488
To record straight-line depreciation on the asset retirement cost		
Accretion expense	16,565	
Asset retirement obligation liability		16,565
To record accretion expense on the asset retirement obligation liability		
December 31, 2004:		
Depreciation expense (asset retirement cost)	19,488	
Accumulated depreciation		19,488
To record straight-line depreciation on the asset retirement cost		
Accretion expense	17,973	
Asset retirement obligation liability		17,973
To record accretion expense on the asset retirement obligation liability		
Long-lived asset (asset retirement cost)	19,704	
Asset retirement obligation liability		19,704
To record the change in estimated cash flows		
December 31, 2005–2012:		
Depreciation expense (asset retirement cost)	21,951	
Accumulated depreciation		21,951
To record straight-line depreciation on the asset retirement cost adjusted for the change in cash flow estimate		
Accretion expense	Per schedule	
Asset retirement obligation liability		Per schedule
To record accretion expense on the asset retirement obligation liability		
December 31, 2012:		
Asset retirement obligation liability	477,091	
Gain on settlement of asset retirement obligation liability		14,091
Accounts payable (outside contractor)		463,000
To record settlement of the asset retirement obligation liability		

> > > Case C: Recognition and Measurement Over More than One Reporting Period

55-42 This Case depicts an entity that places a nuclear utility plant into service on December 31, 2003. The entity is legally required to decommission the plant at the end of its useful life, which is estimated to be 20 years. Based on the requirements of this Subtopic, the entity recognizes a liability for an asset retirement obligation and capitalizes an amount for an asset retirement cost over the life of the plant as contamination occurs. The following schedule reflects the expected cash flows and respective credit-adjusted risk-free rates used to measure each portion of the liability through December 31, 2005, at which time the plant is 90 percent contaminated.

Date	Expected Cash Flows	Credit-Adjusted Risk-Free Rate
12/31/03	$ 23,000	9.0%
12/31/04	1,150	8.5
12/31/05	1,900	9.2

55-43 On December 31, 2005, the entity increases by 10 percent its estimate of expected cash flows that were used to measure those portions of the liability recognized on December 31, 2003, and December 31, 2004, which results in an upward revision to the expected cash flows. Accordingly, the incremental expected cash flows of $2,415 [$2,300 (10 percent of $23,000) plus $115 (10 percent of $1,150)] are discounted at the then-current credit-adjusted risk-free rate of 9.2 percent and recorded as a liability on December 31, 2005. The entity would account for the asset retirement obligation as follows.

	Date Incurred		
	12/31/03	12/31/04	12/31/05
Initial measurement of the asset retirement obligation liability:			
Expected cash flows adjusted for market risk	$ 23,000	$ 1,150	$ 1,900
Credit-adjusted risk-free rate	9.00%	8.50%	9.20%
Discount period in years	20	19	18
Expected present value	$ 4,104	$ 244	$ 390
Measurement of incremental expected cash flows occurring on December 31, 2005:			
Incremental expected cash flows (increase of 10 percent)			$ 2,415
Credit-adjusted risk-free rate at December 31, 2005			9.20%
Discount period remaining in years			18
Expected present value			$ 495

Carrying Amount of Liability Incurred in 2003

Year	Liability Balance 1/1	Accretion (9.0%)	New Liability	Liability Balance 12/31
2003			$ 4,104	$ 4,104
2004	$ 4,104	$ 369		4,473
2005	4,473	403		4,876

Carrying Amount of Liability Incurred in 2004

Year	Liability Balance 1/1	Accretion (8.5%)	New Liability	Liability Balance 12/31
2004			$ 244	$ 244
2005	$ 244	$ 21		265

Carrying Amount of Liability Incurred in 2005
Plus Effect of Change in Expected Cash Flows

Year	Liability Balance 1/1	Accretion (9.2%)	Change in Estimate	New Liability	Liability Balance 12/31
2005			$ 495	$ 390	$ 885

Carrying Amount of Total Liability

Year	Liability Balance 1/1	Accretion	Change in Estimate	New Liability	Total Carrying Amount 12/31
2003				$ 4,104	$ 4,104
2004	$ 4,104	$ 369		244	4,717
2005	4,717	424	$ 495	390	6,026

Journal Entries

December 31, 2003:		
Long-lived asset (asset retirement cost)	$4,104	
Asset retirement obligation liability		$4,104
To record the initial fair value of the asset retirement obligation liability incurred this period		
December 31, 2004:		
Depreciation expense ($4,104 ÷ 20)	205	
Accumulated depreciation		205
To record straight-line depreciation on the asset retirement cost		
Accretion expense	369	
Asset retirement obligation liability		369
To record accretion expense on the asset retirement obligation liability		
Long-lived asset (asset retirement cost)	244	
Asset retirement obligation liability		244
To record the initial fair value of the asset retirement obligation liability incurred this period		
December 31, 2005:		
Depreciation expense [($4,104 ÷ 20) + ($244 ÷ 19)]	218	
Accumulated depreciation		218
To record straight-line depreciation on the asset retirement cost		
Accretion expense	424	
Asset retirement obligation liability		424
To record accretion expense on the asset retirement obligation liability		
Long-lived asset (asset retirement cost)	495	
Asset retirement obligation liability		495
To record the change in liability resulting from a revision in expected cash flow		
Long-lived asset (asset retirement cost)	390	
Asset retirement obligation liability		390
To record the initial fair value of the asset retirement obligation liability incurred this period		

> > > Case D: Conditional with Low Likelihood of Enforcement

55-44 This Case illustrates a timber lease in which the lessor has an option to require the lessee to settle an asset retirement obligation. Assume an entity enters into a five-year lease agreement that grants it the right to harvest timber on a tract of land and that agreement grants the lessor an option to require that the lessee reforest the underlying land at the end of the lease term. Based on past history, the lessee believes that the likelihood that the lessor will exercise that option is low. Rather, at the end of the lease, the lessor will likely accept the land without requiring reforestation. The lessee estimates that there is only a 10 percent probability that the lessor will elect to enforce reforestation. Paragraph 840-10-15-15 explains that Topic 840 does not apply to lease agreements concerning the rights to explore for or to exploit natural resources such as timber.

55-45 At the end of the first year, 20 percent of the timber has been harvested. The lessee estimates that the possible cash flows associated with performing reforestation activities in 4 years for the portion of the land that has been harvested will be $300,000. When estimating the fair value of the asset retirement obligation liability to be recorded (using an expected present value technique), the lessee incorporates the probability that the restoration provisions will not be enforced.

Possible Cash Flows	Probability Assessment	Expected Cash Flows
$ 300,000	10%	$ 30,000
-	90	-
		$ 30,000
Expected present value using credit-adjusted risk-free rate of 8.5 percent for 4 years		$ 21,647

55-46 During the term of the lease, the lessee should reassess the likelihood that the lessor will require reforestation. For example, if the lessee subsequently determines that the likelihood of the lessor electing the reforestation option has increased, that change will result in a change in the expected cash flows and be accounted for as illustrated in Case B.

> > Example 3: Recognition of a Conditional Asset Retirement Obligation

55-47 This Example includes four Cases that illustrate when an entity would be required to recognize the fair value of an asset retirement obligation. The Cases do not provide specific guidance for determining when an entity has sufficient information to reasonably estimate the fair value of the asset retirement obligation. The determination as to when an entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation should be based on the guidance in paragraphs 410-20-25-8 through 25-11. The Cases illustrate the initial recognition of a conditional asset retirement obligation based on the facts presented. Any differences in facts from those presented in the Cases may result in different conclusions.

55-48 The following Cases illustrate the guidance in paragraphs 410-20-25-7 through 25-11 and 410-20-30-1:

a. An entity has sufficient information to reasonably estimate the fair value of an asset retirement obligation at the time the obligation is incurred (Cases A and B).

b. An entity does not have sufficient information to reasonably estimate the fair value of an asset retirement obligation at the time the obligation is incurred (Case C).

c. An entity initially does not have sufficient information and later has sufficient information to reasonably estimate the fair value of an asset retirement obligation (Case D).

> > > Case A: Recognition when Fair Value Can Be Reasonably Estimated

55-49 Assume a telecommunications entity owns and operates a communication network that uses wood poles that are treated with certain chemicals. There is no legal requirement to remove the poles from the ground. However, the owner may replace the poles periodically for a number of operational reasons. Once the poles are removed from the ground, they may be disposed of, sold, or reused as part of other activities. There is existing legislation that requires special disposal procedures for the poles in the particular state in which the entity operates.

55-50 At the date of purchase of the treated poles, the entity has the information to estimate a range of potential settlement dates, the potential methods of settlement, and the probabilities associated with the potential settlement dates and methods based on established industry practice. Therefore, at the date of purchase, the entity is able to estimate the fair value of the liability for the required disposal procedures using an expected present value technique.

55-51 Although the timing of the performance of the asset retirement activity is conditional on removing the poles from the ground and disposing of them, existing legislation creates a duty or responsibility for the entity to dispose of the poles in accordance with special procedures, and the obligating event occurs when the entity purchases the treated poles. Although the entity may decide not to remove the poles from the ground or may decide to reuse the poles and thereby defer settlement of the obligation, the ability to defer settlement does not relieve the entity of the obligation. The poles will eventually need to be disposed of using special procedures, because the poles will not last forever. Additionally, the ability of the entity to sell the poles prior to disposal does not relieve the entity of its present duty or responsibility to settle the obligation. The sale of the poles transfers the obligation to another entity. The assumption of the obligation by the buyer affects the exchange price. The bargaining of the exchange price reflects the buyer's and seller's individual estimates of the timing and (or) amount of the cost to extinguish the obligation.

55-52 The asset retirement obligation should be recognized when the entity purchases the poles because the entity has sufficient information to estimate the fair value of the asset retirement obligation. Because the legal requirement relates only to the disposal of the treated poles, the cost to remove the poles is not included in the asset retirement obligation. However, if there was a legal requirement to remove the treated poles, the cost of removal would be included.

> > > Case B: Recognition when Fair Value Can Be Reasonably Estimated

55-53 Assume an entity recently purchased several kilns lined with a special type of brick. As of the date of purchase, the kilns had not yet been used in any smelting processes. The kilns have a long useful life, but the bricks are replaced periodically. Because the bricks become contaminated with hazardous chemicals while the kiln is operated, a state law requires that when the bricks are removed, they must be disposed of at a special hazardous waste site. The entity has the information to estimate a range of potential settlement dates, the method of settlement, and the probabilities associated with the potential settlement dates based on its past practice of replacing the bricks to maintain the efficient operation of the kiln.

55-54 Therefore, at the date the bricks become contaminated because of the operation of the kiln, the entity is able to estimate the fair value of the liability for the required disposal procedures using an expected present value technique.

55-55 Although performance of the asset retirement activity is conditional on removing the bricks from the kiln, existing legislation creates a duty or responsibility for the entity to dispose of the bricks at a special hazardous waste site, and the obligating event occurs when the entity contaminates the bricks. As of the purchase date, the kilns have not yet been used in any smelting processes, and the bricks have not yet been contaminated. Therefore, at the date of purchase, no obligation exists because the bricks have not been contaminated and could be disposed of without performing any special disposal activities.

55-56 The fair value of the asset retirement obligation should be recognized once the kilns have been placed into operation and the bricks are contaminated. Although the entity may decide not to remove the bricks from the kiln and thereby defer settlement of the obligation, the ability to defer settlement does not relieve the entity of the obligation. The contaminated bricks will eventually need to be removed and disposed of at a special hazardous waste site, because a kiln will not last forever. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing of settlement. An asset retirement obligation should be recognized once the kilns have been placed into operation and the bricks are contaminated because the entity has sufficient information to estimate the fair value of the asset retirement obligation. The asset retirement obligation is the requirement to dispose of the contaminated bricks at a special hazardous waste site. The cost to remove the bricks is not part of the obligation and should be accounted for as a maintenance or replacement activity.

> > > Case C: Recognition when Entity Has Insufficient Information to Reasonably Estimate Present Value

55-57 Assume an entity acquires a factory that contains asbestos. After the acquisition date, regulations are put in place that require the entity to handle and dispose of this type of asbestos in a special manner if the factory undergoes major renovations or is demolished. Otherwise, the entity is not required to remove the asbestos from the factory. The entity has several options to retire the factory in the future including demolishing, selling, or abandoning it. The entity believes it does not have sufficient information to estimate the fair value of the asset retirement obligation because the settlement date or the range of potential settlement dates has not been specified by others and information is not available to apply an expected present value technique. For example, there are no plans or expectation of plans to undertake a major renovation that would require removal of the asbestos or demolition of the factory. The factory is expected to be maintained by repairs and maintenance activities that would not involve the removal of the asbestos. Also, the need for major renovations caused by technology changes, operational changes, or other factors has not been identified.

55-58 Although the timing of the performance of the asset retirement activity is conditional on the factory undergoing major renovations or being demolished, existing regulations create a duty or responsibility for the entity to remove and dispose of asbestos in a special manner, and the obligating event occurs when the regulations are put in place. Therefore, an asset retirement obligation should be recognized when regulations are put in place if the entity can reasonably estimate the fair value of the liability. In this Case, the entity believes that there is an indeterminate settlement date for the asset retirement obligation because the range of time over which the entity may settle the obligation is unknown or cannot be estimated. Therefore, the entity cannot reasonably estimate the fair value of the liability. Accordingly, the entity would not recognize a liability for the asset retirement obligation when regulations are put in place, but it should disclose a description of the obligation, the fact that a liability has not been recognized because the fair value cannot be reasonably estimated, and the reasons why fair value cannot be reasonably estimated. The entity would recognize a liability in the period in which sufficient information is available to reasonably estimate its fair value.

> > > Case D: Recognition when Entity Initially Has Insufficient Information, but Later Has Sufficient Information to Reasonably Estimate Present Value

55-59 Assume an entity acquires a factory that contains asbestos. At the acquisition date, regulations are in place that require the entity to handle and dispose of this type of asbestos in a special manner if the factory undergoes major renovations or is demolished. Otherwise, the entity is not required to remove the asbestos from the factory. The entity has several options to retire the factory in the future including demolishing, selling, or abandoning it. At the acquisition date, it is not evident that the fair value of the obligation is embodied in the acquisition price of the factory because both the seller and the buyer of the factory believed the obligation had an indeterminate settlement date, an active market does not exist for the transfer of the obligation, and sufficient information does not exist to apply an expected present value technique. Ten years after the acquisition date, the entity obtains additional information based on changes in demand for the products manufactured at that factory. At that time, the entity has the information to estimate a range of potential settlement dates, the potential methods of settlement, and the probabilities associated with the potential settlement dates and potential methods of settlement. Therefore, at that time the entity is able to estimate the fair value of the liability for the special handling of the asbestos using an expected present value technique.

55-60 Although timing of the performance of the asset retirement activity is conditional on the factory undergoing major renovations or being demolished, existing regulations create a duty or responsibility for the entity to remove and dispose of asbestos in a special manner, and the obligating event occurs when the entity acquires the factory. In this Case, regulations are in place at the date of acquisition that require the entity to handle and dispose of the asbestos in a special manner. Therefore, the obligating event is the acquisition of the factory. If regulations were enacted after the date of acquisition, the obligating event would be the enactment of the regulations (see Case C).

55-61 Although the entity may decide to abandon the factory and thereby defer settlement of the obligation for the foreseeable future, the ability to defer settlement does not relieve the entity of the obligation. The asbestos will eventually need to be removed and disposed of in a special manner, because no building will last forever. Additionally, the ability of the entity to sell the factory does not relieve the entity of its present duty or responsibility to settle the obligation. The sale of the asset would transfer the obligation to another entity and that transfer would affect the selling price. Therefore, the obligation to perform the asset retirement activity is unconditional even though uncertainty exists about the timing and method of settlement.

55-62 In this Case, an asset retirement obligation is not recognized when the entity acquires the factory because the entity does not have sufficient information to estimate the fair value of the obligation. The entity would disclose a description of the obligation, the fact that a liability has not been recognized because the fair value cannot be reasonably estimated, and the reasons why fair value cannot be reasonably estimated. An asset retirement obligation would be recognized by this entity 10 years after the acquisition date because that is when the entity has sufficient information to estimate the fair value of the asset retirement obligation.

> > Example 4: Historical Waste on Electrical and Electronic Equipment Associated with EU Directive 2002/96/EC

55-63 This Example illustrates the guidance in paragraphs 410-20-55-23 through 55-29.

55-64 Assume an entity (a commercial user) is currently using electronic equipment that must be disposed of in accordance with the requirements of EU Directive 2002/96/EC. The EU-member country has not yet adopted the legislation. The entity has the ability either to replace the equipment or to dispose of the equipment without replacing it. In the EU-member country in which the entity operates, the producer of the replacement equipment will be wholly responsible for disposal costs if and when the equipment is replaced. The recycling of electronic waste equipment is not a revenue-generating business activity of the producer.

55-65 Upon the adoption of the legislation, the entity should recognize a liability for the fair value of the asset retirement obligation. Upon initial recognition of a liability, the entity should capitalize an asset retirement cost by increasing the carrying amount of the related asset by the same amount as the liability. The accounting subsequent to the initial recognition of the asset and liability should be consistent with the guidance in paragraphs 410-20-35-3 through 35-6.

55-66 The waste management obligation remains with the commercial user until the historical waste equipment is replaced or is disposed of by the commercial user itself. Assuming the equipment is replaced, the entity should determine the portion of the purchase price that relates to the cost of the replacement asset and the portion that relates to the assumption of the obligation by the producer. That determination should be based on the fair value of the obligation, without the sale of the new asset. The entity should recognize a gain or loss based on the difference between the carrying amount of the liability at the date of the sale and the portion of the sales price that relates to the obligation. The producer should recognize revenue for the total amount received, reduced by the fair value of the obligation, and recognize a liability for the fair value of the obligation upon transfer of the obligation from the commercial user. Assuming the equipment is disposed of by the entity rather than replaced, the entity should recognize a gain or loss based on the difference between the carrying amount of the liability at the date of the disposal and the actual cost of disposal. See paragraphs 820-10-55-77 through 55-81 for an illustration of an entity required to estimate the fair value of an asset retirement obligation.

55-67 For the financing of historical waste, the Directive also distinguishes between historical waste from private households and historical waste from "users other than private households" (referred to as "commercial users").

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General

Subsection revised 01-Jul-2009

Combine Subsections

> Interest

60-1 For guidance related to capitalization of interest cost, see Subtopic 835-20.

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XBRL Links to Codification

Subsection revised 22-Nov-2013

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CERTIFICATE OF SERVICE

DOCKET NO. E-2, SUB 1219
DOCKET NO. E-2, SUB 1193

I hereby certify that a copy of the foregoing **CORRECTION TO THE REBUTTAL TESTIMONY OF DAVID L. DOSS, JR.,** was served electronically or by depositing a copy in United States Mail, first class postage prepaid, properly addressed to the parties of record.

This the 13th day of August, 2020.

/s/ Kiran H. Mehta
Kiran H. Mehta
Troutman Pepper Hamilton Sanders LLP
301 S. College Street, Suite 3400
Charlotte, North Carolina 28202
Telephone: 704.998.4072
Kiran.mehta@troutman.com

ATTORNEY FOR DUKE ENERGY PROGRESS, LLC

I/A

Senior Management Committee
January 13, 2014

Ash Basin Closure Update

Jason Allen, Environmental, Health & Safety
David Fountain, Enterprise Legal Support & Litigation

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[redacted] [redacted] [redacted]

[redacted]

Agenda

- Groundwater regulation overview and results
- Coal ash program examples
  - Asheville Station
  - Riverbend Station
  - Cayuga Station
- Receptor impacts / actions
- Ash pond closure status
- Coal ash dam overview
- Areas of focus and recommendations

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2 | [redacted]

[redacted]

Coal Ash Program Overview

- A detailed program review was conducted
- We have ash / groundwater interfaces at almost all coal sites
  - 24 sites
  - 61 ponds
  - 58 structural/landfills
- Large number of experts have dedicated years to managing program
- Coal ash is impacting the environment
- Duke is in compliance with State and Federal standards
- Duke has a strong coal ash program and has opportunity to proactively become the industry leader

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3 [redacted] ly

Reviewed groundwater and coal ash conditions at all Duke power plants

Respective SME's for each region provided background and data

Duke experts have been working on coal ash issue for years, are very knowledgeable, and have program well underway

- Environmental scientist familiar with each region, regulatory SME's, Strategic Engineering group, Power Generation

- After a deep dive review I am very comfortable with the current status of our program

Need to be very clear that our coal ash is impacting the groundwater at all locations

This is not an overnight event, ash has been managed in this fashion for decades and it will take decades to close the ponds

All this said, we are compliant with all regulations and in many locations do far more that regulations require through our voluntary programs

I see our coal ash program as a huge opportunity to launch a public education program, invest considerable capital in our plants, and be an environmental leader when it comes to coal ash

[redacted]

Groundwater Regulation Overview and Results

Retired station, decommissioning is underway, detailed ash pond characterization work will begin in the first quarter of 2014

Expect considerable attention from environmental groups when we submit closure plan

Also likely to have considerable media coverage due to proximity of City of Charlotte drinking water intakes about 5 miles downstream of site

[redacted]

[redacted]

Complexities of Groundwater Monitoring

- Requirements vary by State (See Appendix A for details)
  - Sampling frequency
  - Sampling parameters
  - Sampling locations
- Remedial actions vary by State
  - Minimal groundwater regulations in place currently
  - Federal EPA guidance (CCR, ELG) a minimum of 12 months away
- As a general rule, mitigation equates to removing the source and allowing natural attenuation to occur

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The question of compliance is a very difficult one

Groundwater standards are very different in each state we operate

- specific standards are different
- compliance location is different

Reporting and remediation requirements also vary drastically

In general we monitor for the federal 2L groundwater standards at all sites and then report to the regulatory agencies as required

[redacted]

Groundwater Monitoring Methodology

- Install monitoring wells
  - Upgradient (Background wells - 43)
  - Downgradient (Compliance Monitoring wells - 258)
- Sample and report results as required
- Remediate concern if results are verified
- Expand sample area as needed if results indicate potential impact on receptor
  - Primary standard indication at compliance well
  - Install additional monitoring well if possible
  - Receptor located downstream of compliance well indication
  - Perform additional testing at receptor location

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Regardless of state requirements Duke monitors groundwater around ash storage areas at all sites (all active ponds and ash storage started after 19??)

All sites have background wells upgradient of ash ponds to provide baseline information on groundwater conditions in the area

- this is very important because there are several locations where certain standards are above the 2L limit prior to being impacted by our coal ash

Downgradient compliance monitoring wells then monitor any impacts our coal ash is having on the GW flow and ensures we are not impacting any receptors

If a monitoring wells shows a GW exceedence and a receptor could be impacted based on expected GW flow we take action to remediate

- depending on site this could include installation of additional monitoring wells
- testing the receptor well
- moving receptor to an alternate water source

[redacted]

Based on best available knowledge we do not have any receptors at any of our sites that currently in danger of being impacted by GW above 2L standards

Generating Station Ash Pond Groundwater Sampling Overview

Plant	Antimony	Arsenic	Barium	Boron	Cadmium	Chloride	Chromium	Copper	Iron	Lead	Mn	Mercury	Nickel	Nitrate	Nitrite	Selenium	Silver	Sulfate	Thallium	Zinc	TDS	pH
	2L Groundwater Standards Exceeded																					
Asheville				X		X	X		X	X	X			X		X		X	X		X	X
Sutton	X	X		X	X				X	X	X					X		X	X		X	X
Cape Fear	X	X		X	X				X		X					X		X			X	X
Dan River Steam Station	X	X		X					X		X							X			X	X
Gibson		X		X		X			X		X							X			X	X
Lee Plant (NC)		X		X			X		X	X	X										X	X
Buck Steam Station				X			X		X		X							X			X	X
Gallagher		X		X					X		X							X			X	X
Marshall Steam Station				X					X		X							X			X	X
Mayo					X		X		X		X								X		X	X
Miami Fort		X				X			X		X							X			X	X
Beckjord									X		X					X		X			X	X
Cliffside Steam Station							X		X		X							X			X	X
Roxboro							X		X		X							X			X	X
Allen Steam Station				X					X		X		X									X
Belews Creek							X		X		X								X			X
East Bend						X			X		X							X			X	
Robinson		X					X											X			X	X
Cayuga				X												X		X			X	
Riverbend	X								X		X											X
Weatherspoon									X		X								X			X
WS Lee Steam Station				X					X		X											X
Wabash River									X		X										X	
Crystal River		X																				
Edwardsport																						
Edwardsport IGCC																						
Zimmer																						

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Table summarizes where we are exceeding the federal 2L GW standards at our plants

- At compliance boundary (500' in NC, or at state approved monitoring well location)
- may or may not have similar state guidelines
- many of the background wells show same exceededence (i.e. Fe and Mn) so likely naturally occurring issues

Primary standard violation are in downgradient wells that does not have a receptor between the well location and any drinking water receptors

All results are communicated as required to state agencies and no remedial actions are currently outstanding

[redacted]

Coal Ash Program Examples

Asheville
Riverbend
Cayuga

(See Appendix B for additional information)

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Retired station, decommissioning is underway, detailed ash pond characterization work will begin in the first quarter of 2014

Expect considerable attention from environmental groups when we submit closure plan

Also likely to have considerable media coverage due to proximity of City of Charlotte drinking water intakes about 5 miles downstream of site

[redacted]

[redacted]

Asheville Station

Would now like to review three of our plants that show several key aspects of our groundwater and coal ash programs

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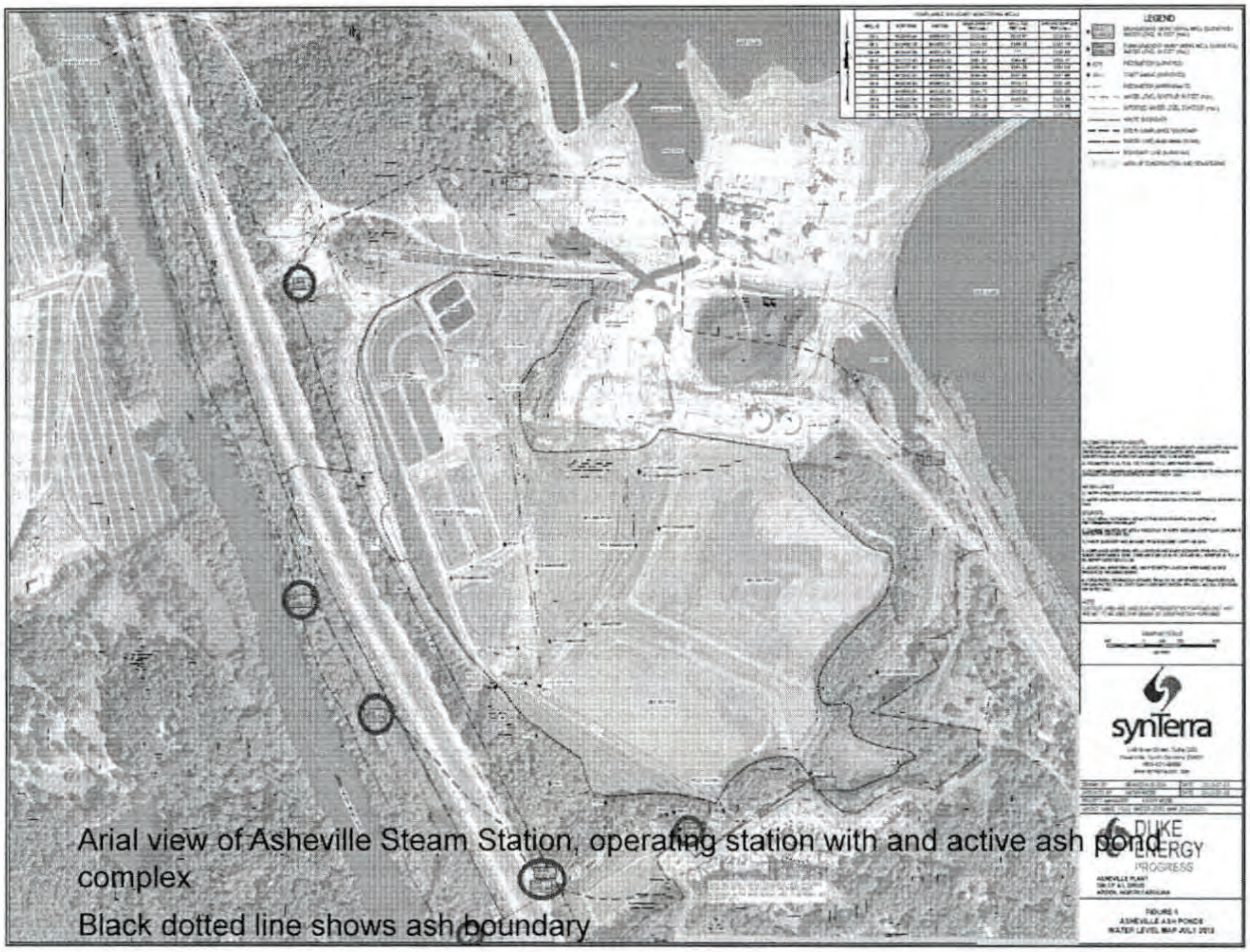
[redacted]



Arial view of Asheville Steam Station, operating station with and active ash pond complex

Black dotted line shows ash boundary

Red line is compliance boundary (500’ or property line whichever is closer)

Background (3 – yellow blocks) and compliance (8 – green blocks) well network is shown with groundwater flow contours (blue and green lines) (we will see in a couple slides how GW flow is determined)

Groundwater flow is toward the ash ponds and then toward the French Broad River

Boron and Thallium indication at Monitoring Well CB-3R (decreasing) (circled in red) side gradient of ash pond – near Bear Leah Trail receptors

Boron at monitoring well CB-4 CB-5 and CB-6 (decreasing) – no receptors between ahs pond and French Broad River

Boron and Selenium (decreasing) at Monitoring Well CB-7 and CB-8 down gradient of ash pond – no receptors between ahs pond and French Broad River

Levels of boron, selenium, and thallium have been decreasing since water level in pond decreased, dewatering key driver to improved results

Boron is not linked to health issues, but is an early indicator for other heavy metals such as arsenic, selenium, etc

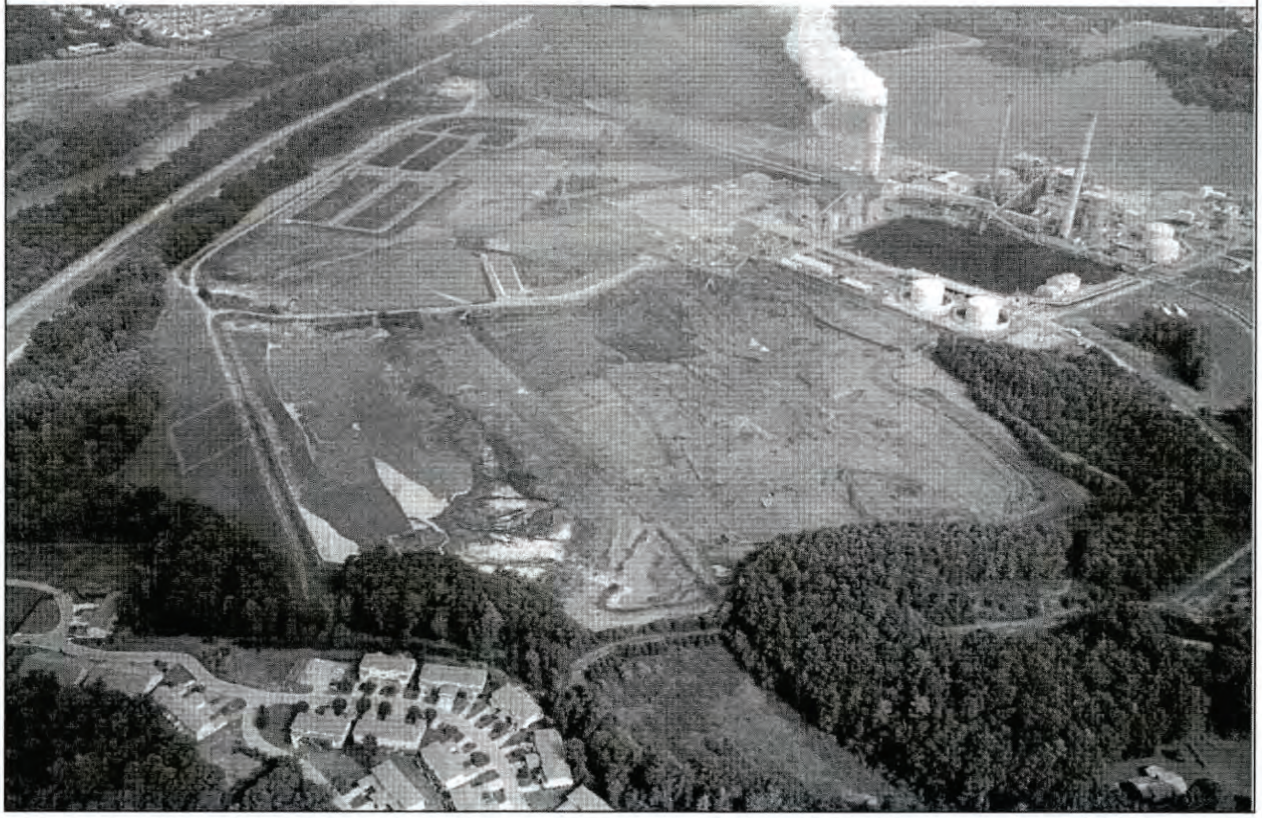
[redacted] [redacted]

All receptors (approx 2500) in pink box and further South and are all upgradient of ash ponds and are on municipal water, GW flow makes it very difficult for us to impact these locations

[redacted] [redacted] [redacted]

[redacted]

Asheville Ash Pond Excavation

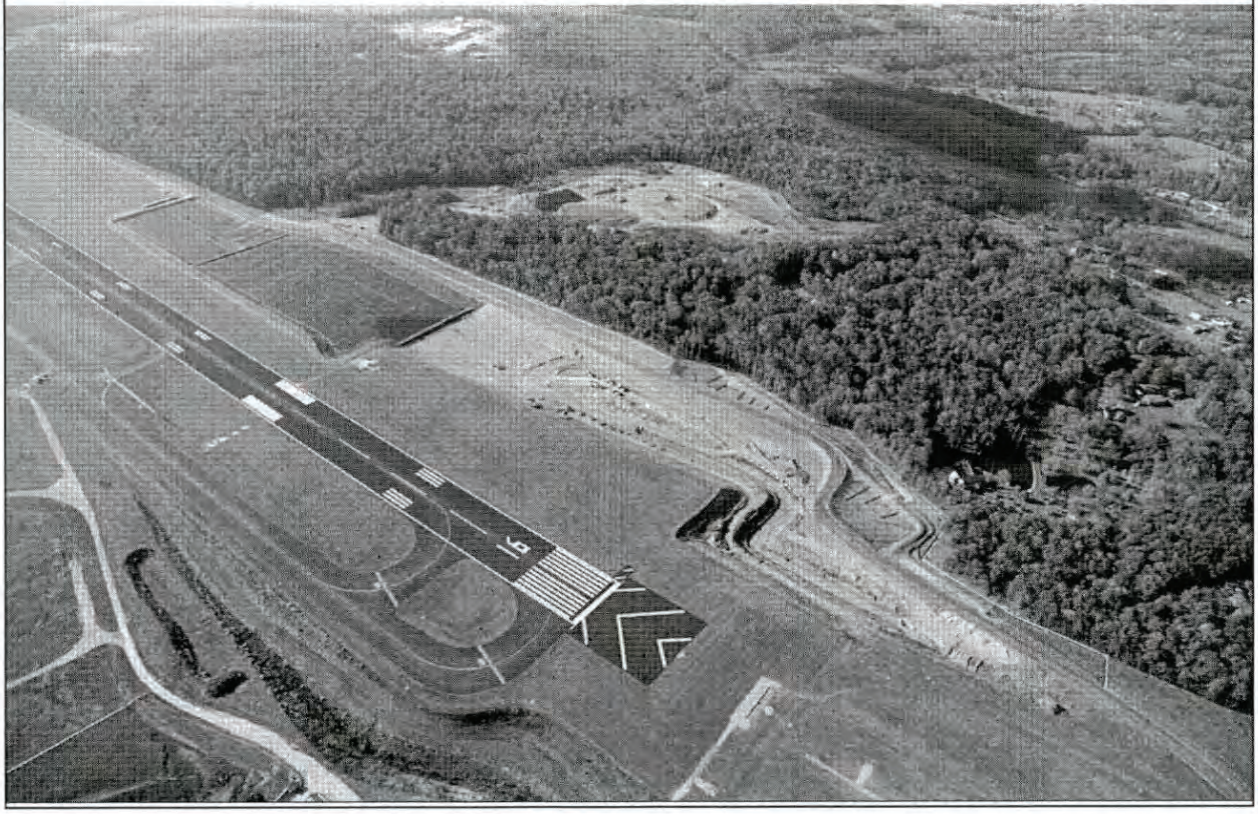


[redacted]

Asheville Ash Pond Excavation

[redacted] [redacted]

Asheville Airport Structural Fill



[redacted]

[redacted]

Asheville Airport Structural Fill

[redacted]

Riverbend Station

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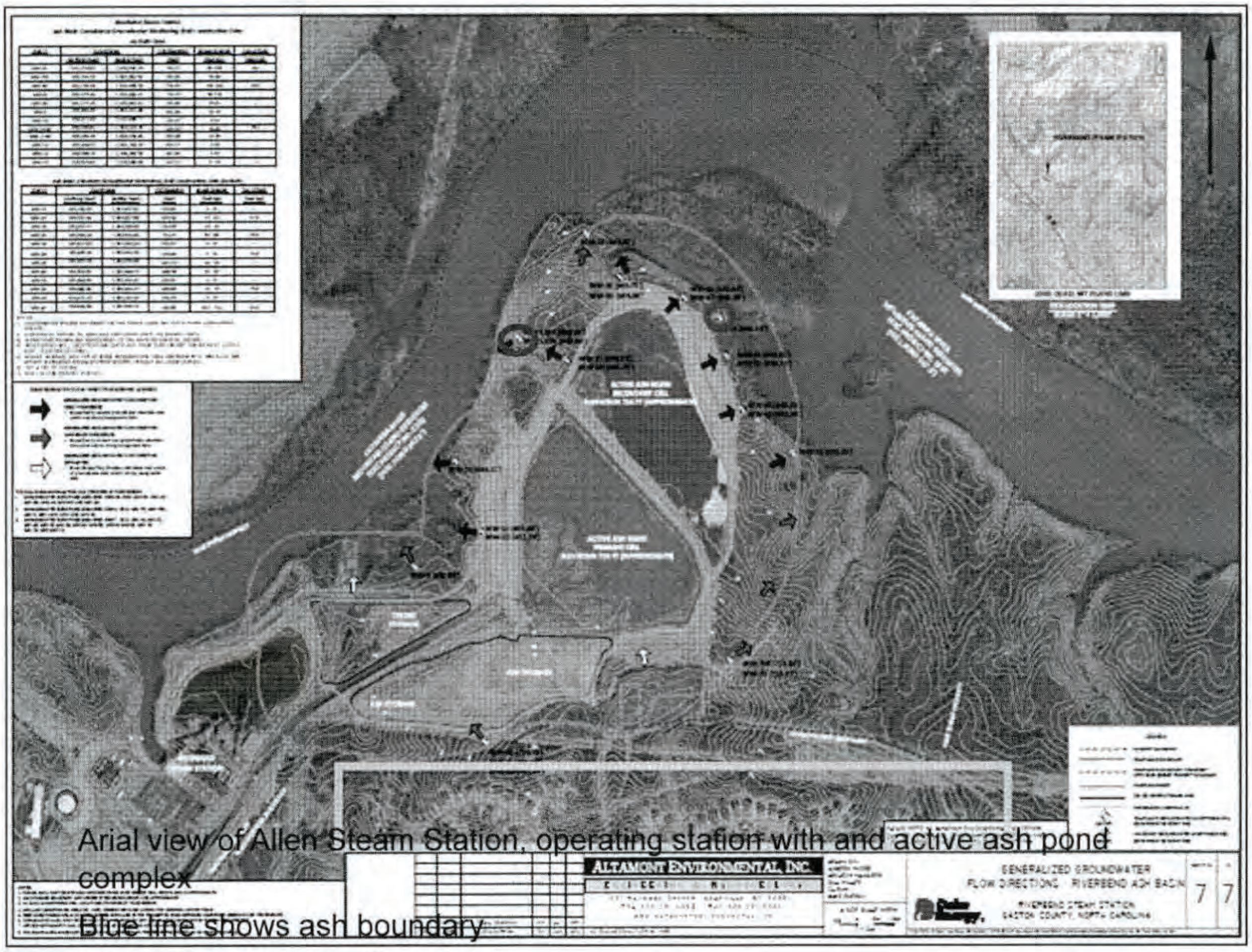
Retired station, decommissioning is underway, detailed ash pond characterization work will begin in the first quarter of 2014

Expect considerable attention from environmental groups when we submit closure plan

Also likely to have considerable media coverage due to proximity of City of Charlotte drinking water intakes about 5 miles downstream of site

[redacted]



Arial view of Allen Steam Station, operating station with and active ash pond complex

Blue line shows ash boundary

Red line is property boundary

Green line is compliance boundary (500' or property line whichever is closer)

Background (2) and compliance (12) well network is shown with groundwater flow indications (we will see in a couple slides how GW flow is determined)

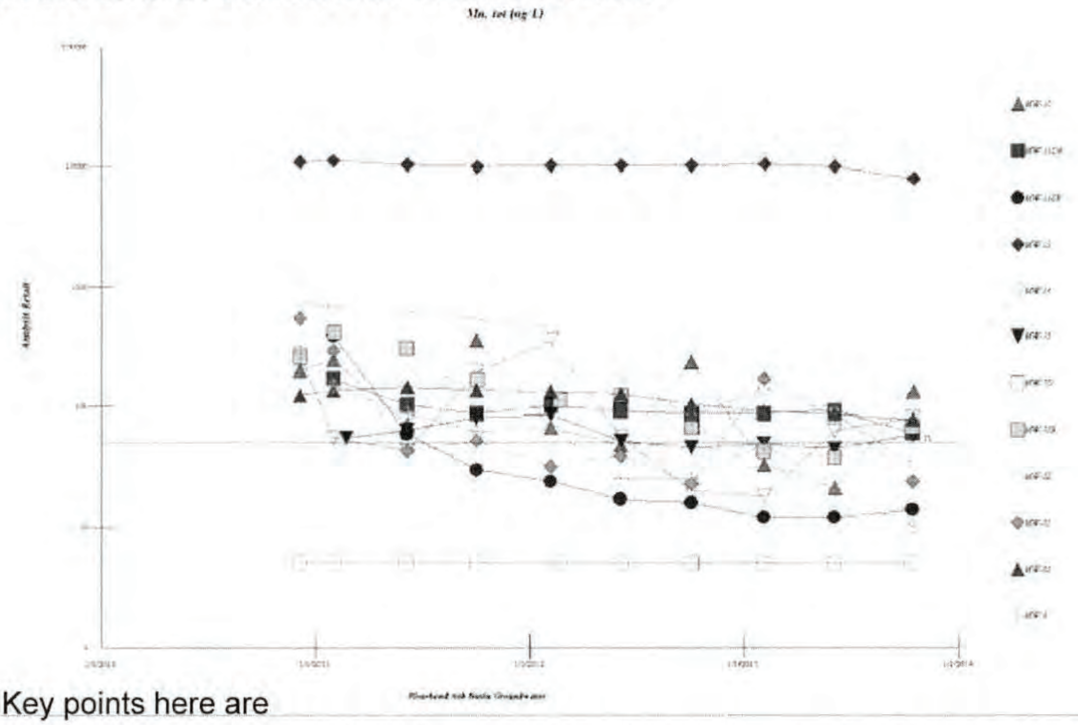
Groundwater flow is toward the Catawba River

Highest GW indications (Fe, Mn) are at well (MW- 13 - circled in red) Boron starting the show up in MW-11 downstream of ash pond just before GW enters Catawba River – no receptors

All receptors (approx 300) in pink box and are all upgradient of ash pond, GW flow makes it very difficult for us to impact these locations

[redacted]

Riverbend Groundwater Exceedences



Key points here are

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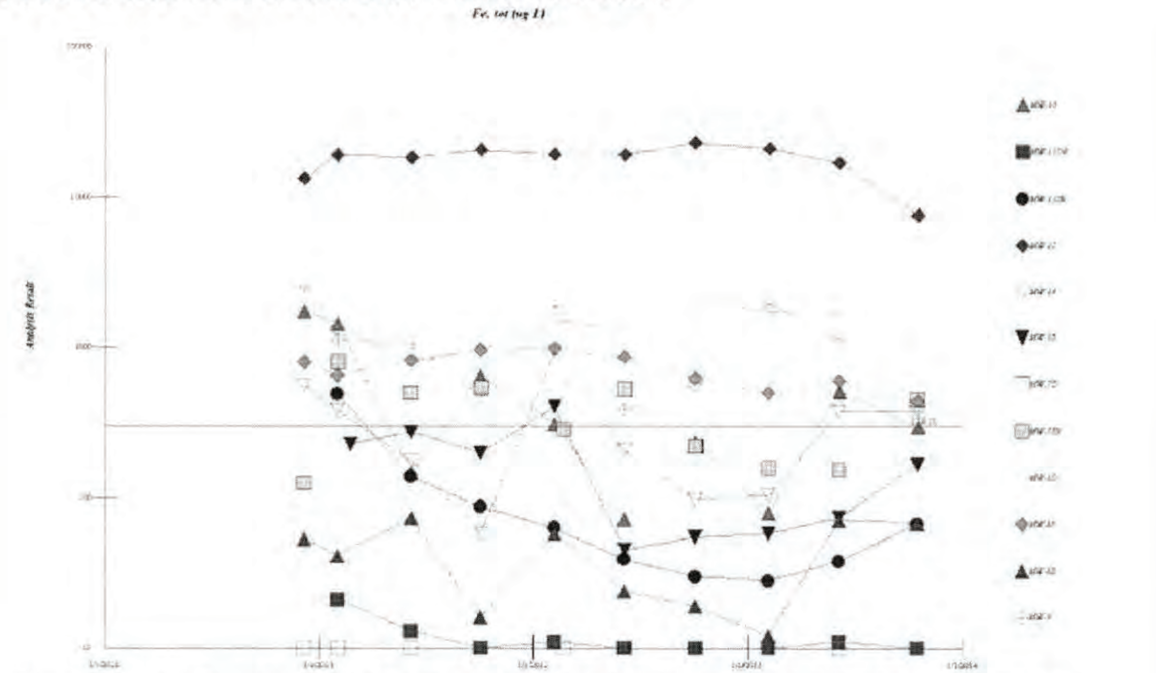
- most significantly impacted wells are downgradient of ash ponds
- no receptors
- Very early in the closure process, but with plant shut down flow from ash pond to GW is decreasing significantly, GW impacts are improving

[redacted]

Riverbend Groundwater Exceedences



With this said, to this point we have been focused on ensuring there were no receptors between the ash ponds and a large receiving body of water that acts as a GW sink

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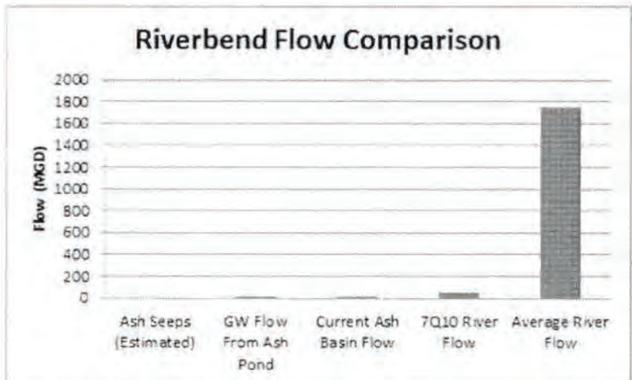
The primary concern raised at Riverbend Station is the impact on this body of water and the subsequent impact on municipal drinking water intakes

[redacted]

What is a Hydraulic Break?

- A large body of water
  - The relative low point for ground water flow
  - Significantly greater flow than groundwater contribution
  - Acts as a sink for all surrounding groundwater
  - Receptors located across a hydraulic break are unaffected, regardless of distance from ash pond



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The dilution factor when water reaches a large receiving body is generally overwhelming

	Belews Creek	
Riverbend		
Ash Seep flow estimate MGD	= 0.303409	0.001
GW Flow from ash ponds MGD	=0.9	0.5
Ash basin flow (NPDES Outfall) MGD	= 9	4.9
7Q10 river flow MGD	= 51.7	51.7
Current river flow MGD	= 371.0	1750

[redacted] [redacted]
[redacted]

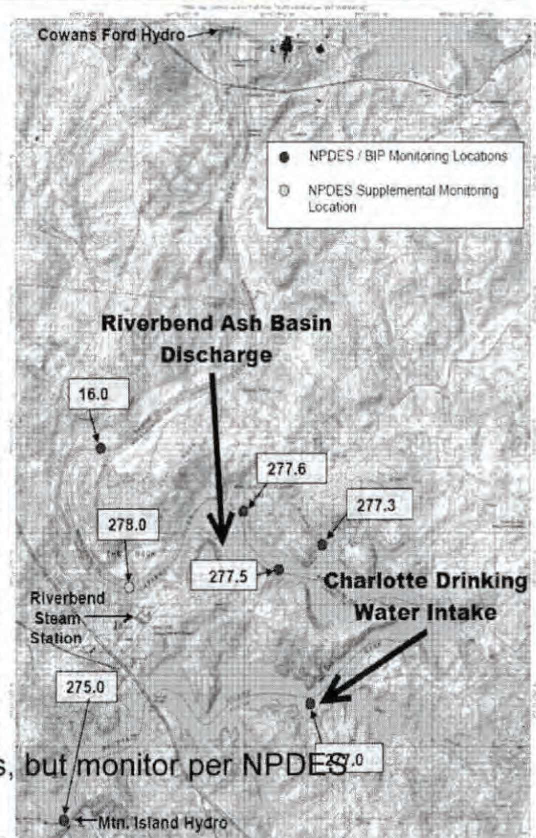
Additionally, GW standards are no longer in effect and surface water standards apply which are less strict for the majority of standards (NEED DETAILS HERE)

Riverbend ash basin flow is now at zero unless there is a significant rain event

[redacted]

Riverbend Station River Impact Monitoring

Upstream 278	As, (µg/L)	Cd, (µg/L)	Cr, (µg/L)	Cu, (µg/L)	Hg, USEPA (µg/L)	Pb, (µg/L)	Se, (µg/L)	TDS (mg/L)
Riverbend SS	< 1.00	NA	NA	NA	NA	NA	< 1.00	NA
Riverbend SS	< 1.00	< 1.00	< 1.00	1.02	< 0.05	< 1.00	< 1.00	51.00
Riverbend SS	< 1.00	< 1.00	< 1.00	< 1.00	< 0.05	< 1.00	< 1.00	52.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.22	< 0.05	< 1.00	< 1.00	42.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.25	< 0.05	< 1.00	< 1.00	51.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.66	< 0.05	< 1.00	< 1.00	< 25.00
Mean	1.00	1.00	1.00	1.23	0.05	1.00	1.00	44.20
Downstream 277.5								
Riverbend SS	< 1.00	< 1.00	< 1.00	1.38	< 0.05	< 1.00	< 1.00	47.00
Riverbend SS	1.12	< 1.00	< 1.00	1.42	< 0.05	< 1.00	< 1.00	54.00
Riverbend SS	< 1.00	< 1.00	< 1.00	< 1.00	< 0.05	< 1.00	< 1.00	49.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.30	< 0.05	< 1.00	< 1.00	42.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.11	< 0.05	< 1.00	< 1.00	51.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.67	< 0.05	< 1.00	< 1.00	31.00
Mean	1.02	1.00	1.00	1.31	0.05	1.00	1.00	45.67
CLT DW Intake 277								
Riverbend SS	< 1.00	< 1.00	< 1.00	1.58	< 0.05	< 1.00	< 1.00	52.00
Riverbend SS	< 1.00	< 1.00	< 1.00	3.22	< 0.05	< 1.00	< 1.00	55.00
Riverbend SS	< 1.00	< 1.00	< 1.00	< 1.00	< 0.05	< 1.00	< 1.00	53.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.83	< 0.05	< 1.00	< 1.00	47.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.21	< 0.05	< 1.00	< 1.00	56.00
Riverbend SS	< 1.00	< 1.00	< 1.00	1.65	< 0.05	< 1.00	< 1.00	< 25.00
Mean	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]



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Duke monitors rivers and lakes around plants, but monitor per NPDES requirements or surface water standards

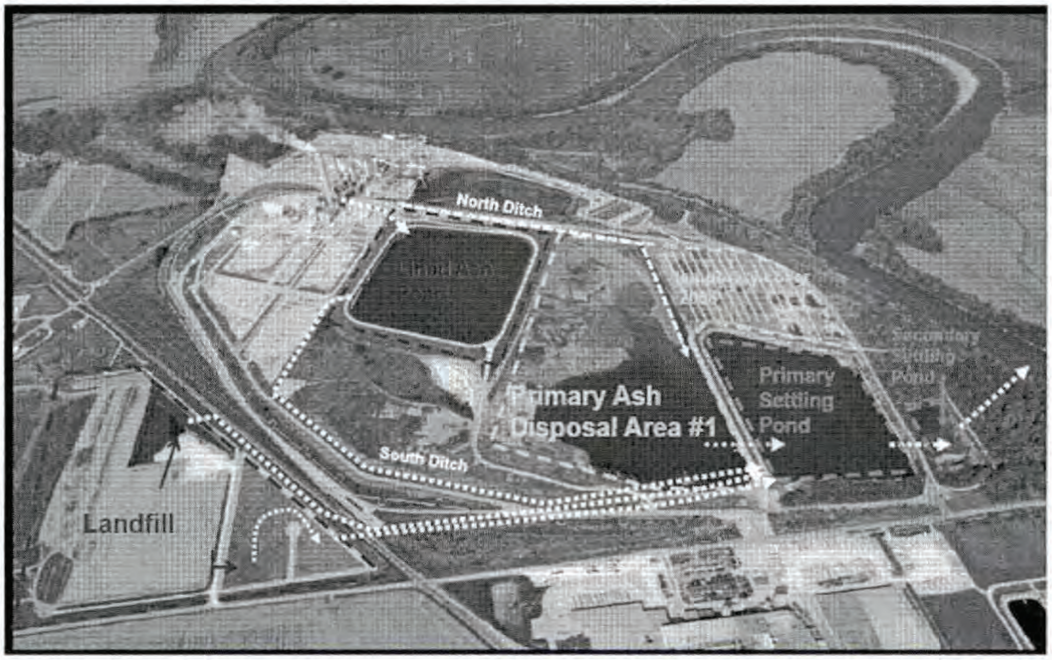
This often means we can't directly compare GW standards to surface water standards – we monitor different parameters

However, we do have comparable results for some stations

- Above the monitoring points around Riverbend are shown on the map on the right (upstream marker 278, Downstream of plant marker 277.5, at CLT drinking water intake marker 277)
- Results are essentially the same at all three locations over the past 3 years and all are below GW and surface water standards
- And impacts are reducing

[redacted]

Cayuga Station – Site Lay-out



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Finally, I would like to review the Cayuga site

We are going to flip through several slides quickly, but you will get a very good view of what impact remediation efforts are having and the benefits of a strong relationship with the state regulators

This site was selected based on the fact it is a very advanced coal ash remediation site that continues to operate as a coal plant and has significant impacts on GW

From this view you can see a new lined ash pond that is in service and was constructed in 2005. this is the only lined ash pond in the Duke fleet

The lined ash pond is built over an old existing ash pond and is acting as a synthetic cap for this pond

The primary ash disposal area #1 is in the process of being closed with the cap in place method

The Primary and secondary settling basins will remain in service

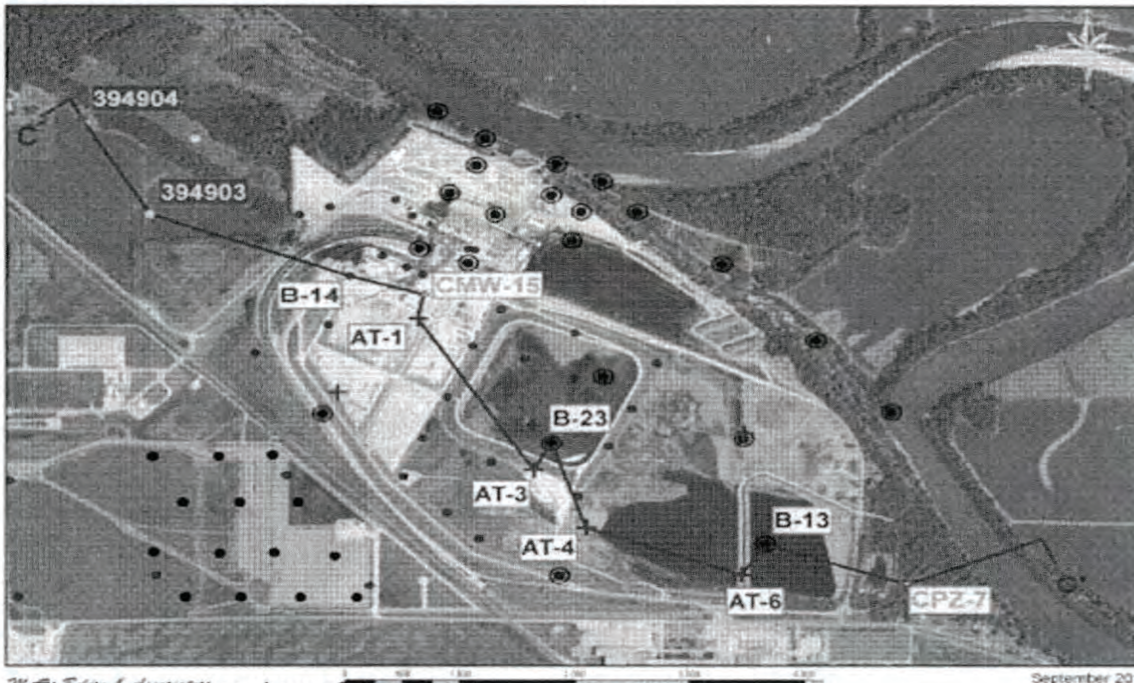
The site lined landfill is in the bottom left

[redacted] [redacted]
[redacted]

The Wabash river is in the top right and is the direction of GW flow

[redacted] [redacted]

Cayuga Station Cross Section – Areal View

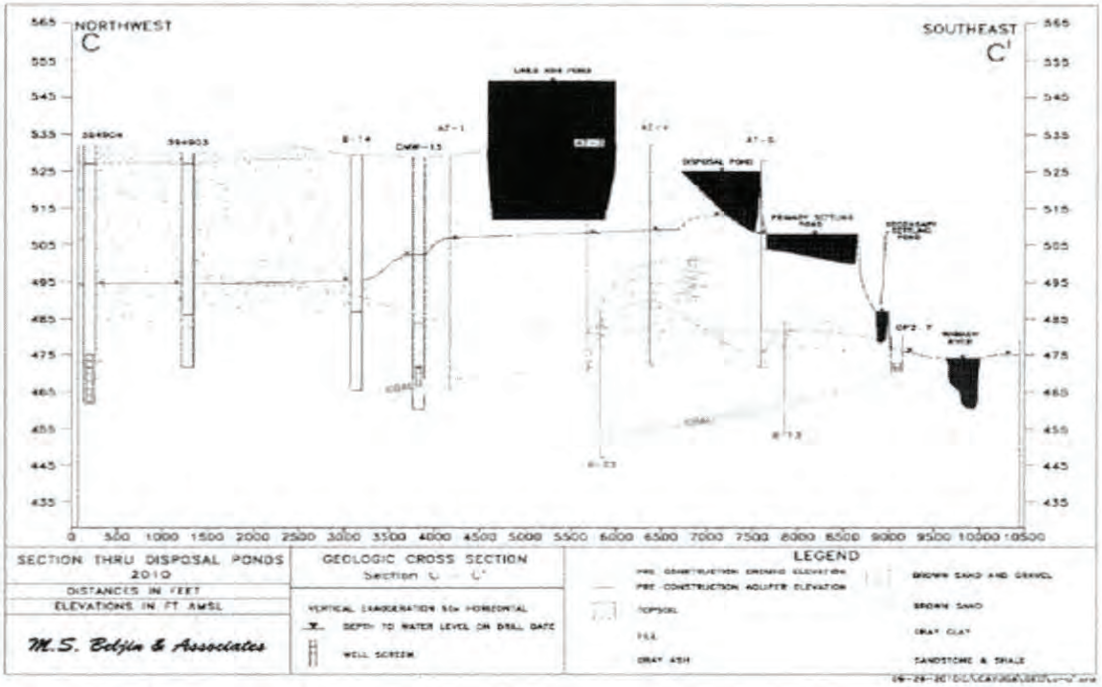


- The is a similar view of the site
- Pay special attention to the red line shown on the photo as these wells and piezometers were used to map the soil conditions and water levels to make the cut-away view on the next slide

[redacted]

[redacted]

Cayuga Station Groundwater Cross Section



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This cut-away view the Cayuga site shows very porous soil condition immediately below the plant that is made up of sand and gravel and the old existing ash pond

Another unique feature is the shale sandstone base the exits the ground right at river level

Like water above ground, groundwater flows downhill and travels from higher GW levels to lower lever

As you can see the Wabash River is the hydraulic break receiving body and is the low point, all GW flows to it

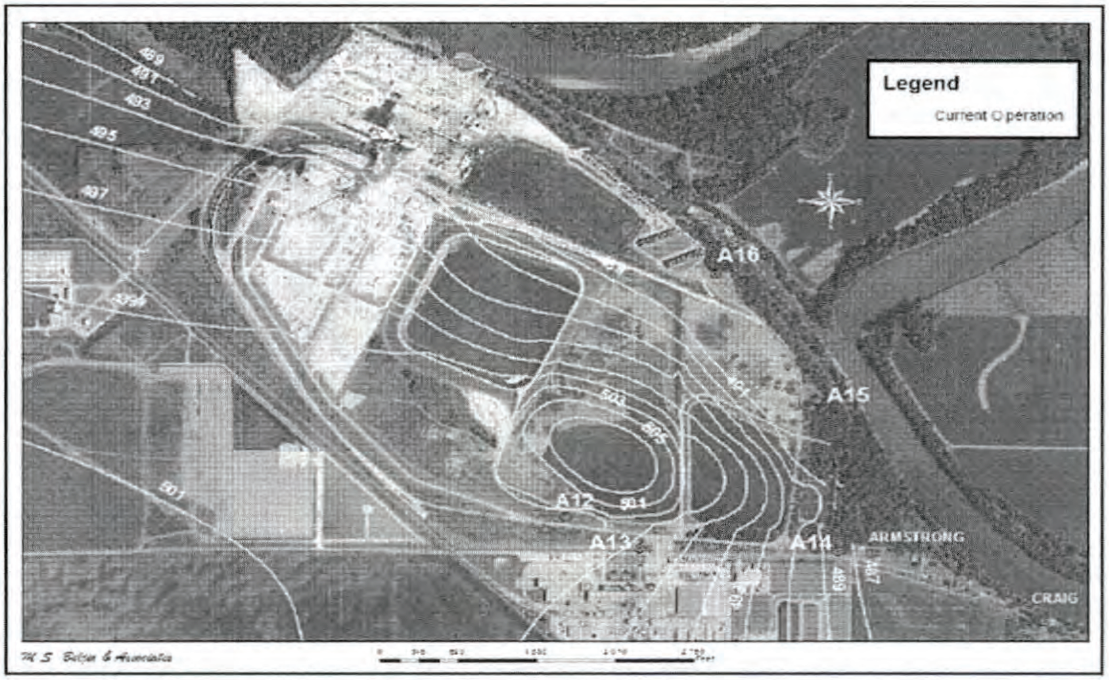
Our primary ash pond is the high point of ground water and influences the flow in the immediate area, with water flowing out in all directions

Due to the porous soil this site has some of the highest water loss of all sites (approx 6MGD into ash pond, 2MGD loss)

Seeps have been incorporated into the site NPDES permit during recent renewal process

[redacted]

Cayuga Station – Current Operations



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Here is a different view of the GW elevations

Generally the flow is toward the Wabash River as you saw on the cut away view

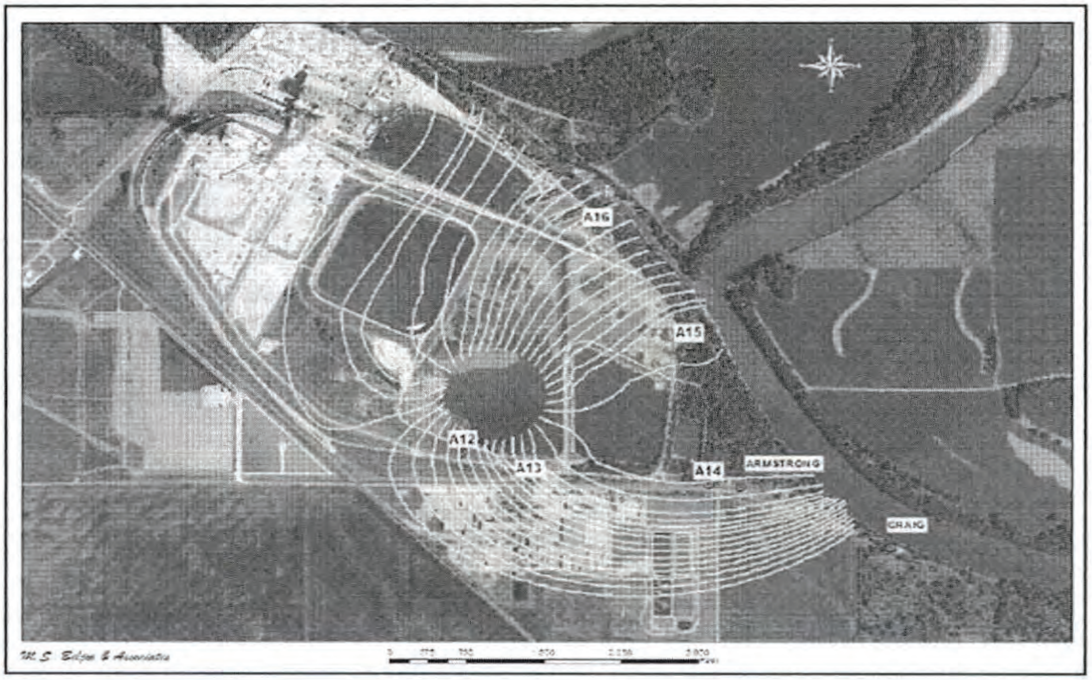
The primary ash pond influences this somewhat as water flows in all directions from this pond, but quickly turns back to the river

Note on the drawing that the lined ash pond has no impact on GW flow

[redacted]

[redacted]

Cayuga Station – Current Groundwater Flow



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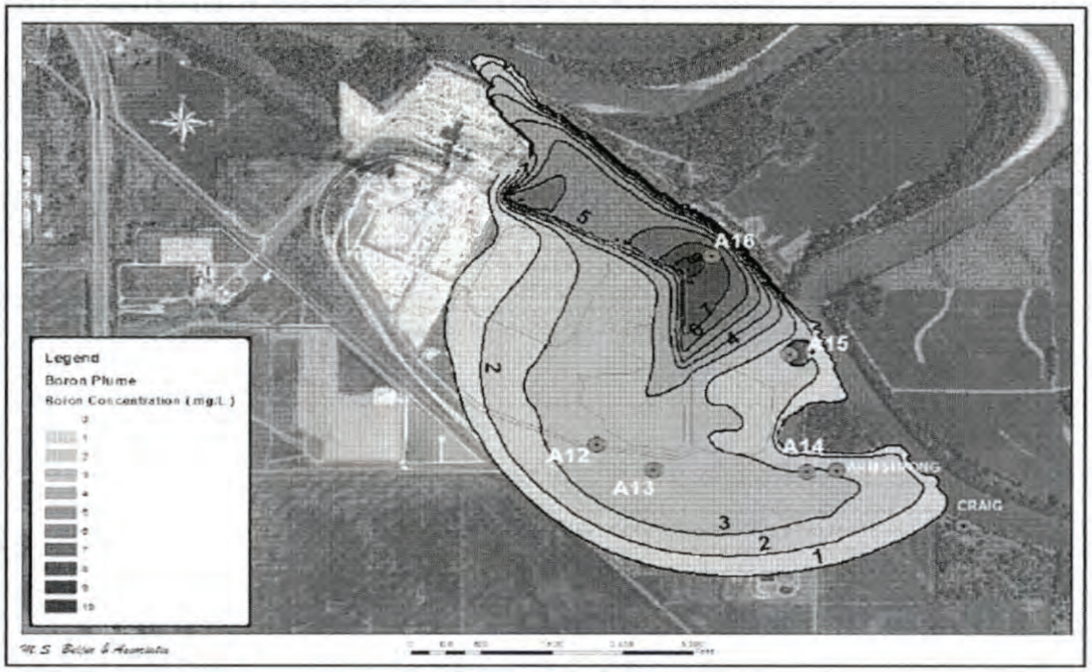
The drawing shows specific flow patterns from the primary ash pond to the Wabash River

[redacted]

Cayuga Station – Current Boron Plume



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A similar view showing the boron plume currently seen at the site

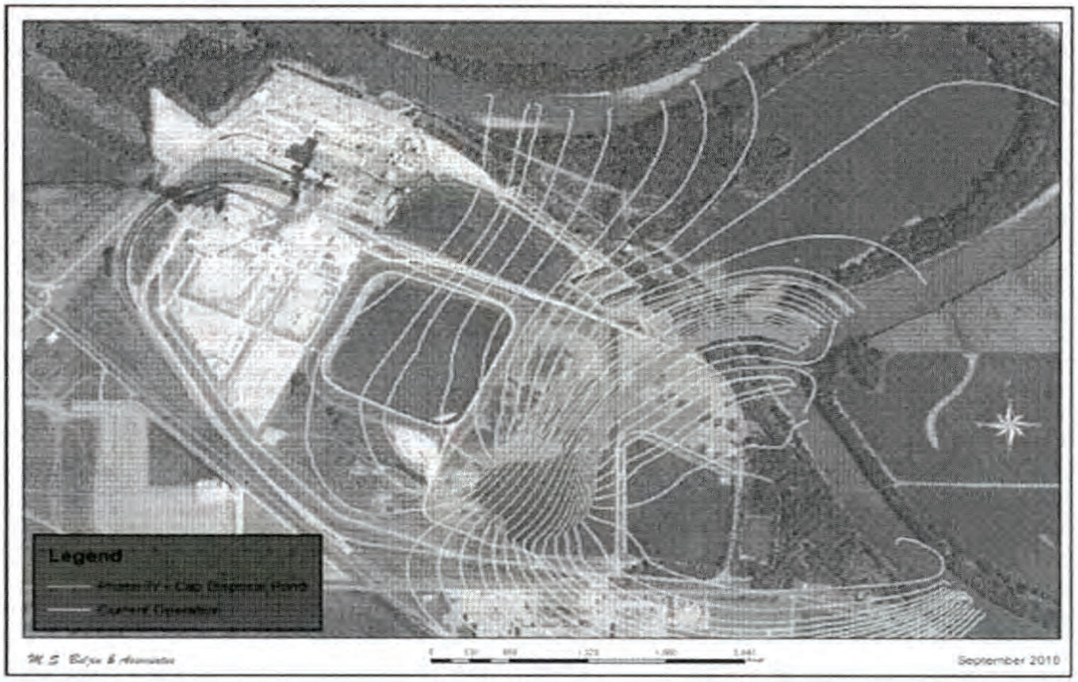
Remember that boron is only an early indicator of other elements and is not a health related standard

When this was first investigated there were 3 downgradient residences, one was purchased and demolished and two were moved to municipal water

Only 5 residences remain, all are upgradient away from the plume anfd on municipal water

[redacted] [redacted]

Cayuga Station – Groundwater Flow After Ash Pond Close



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The primary ash pond is in the process of being closed with the cap in place method

Voluntary ash pond closure underway and was coordinated with the State

They are using plant ash and gypsum as fill as it is produced to create 5% grade, plan for 2025 completion, end with clay or synthetic cap

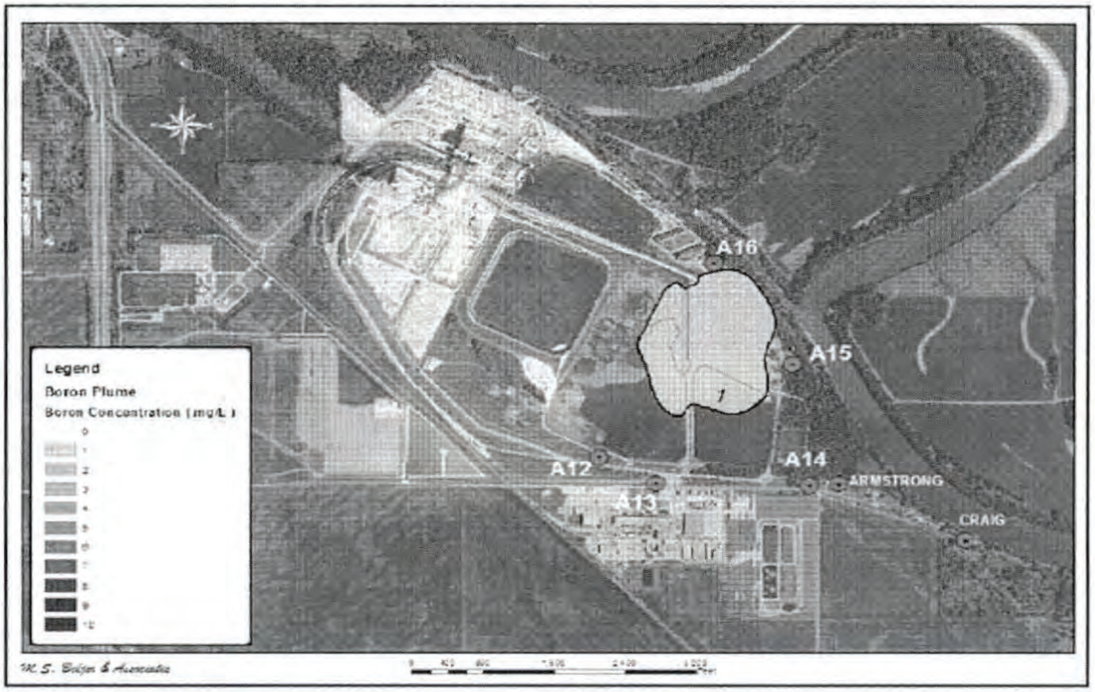
Could close faster if State did not allow us to use plant byproducts to close as they are produced

Minimal environmental impact and large cost savings

The blue lines show the new expected GW flow once the pond is capped

[redacted] [redacted]
[redacted]

Cayuga Station – Forecasted Boron Plume 2022



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This graphic shows the expected remaining Boron plume in 2022 once the pond is dewatered and capped

There will likely be a minimal impact on GW from the coal ash based on the fact that the very bottom of the old existing ash pond will remain in the GW table

The State is aware of this and approved the closure plan based on the minimal impact and the high dilution rate

Again, this shows the dramatic effect that ash basin dewatering can have. Groundwater impacts decrease quickly

Capping the pond then prevents future impacts from surface water leaching through the ash

[redacted] [redacted] [redacted] [redacted]
[redacted]

Receptor Impacts and Actions

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Retired station, decommissioning is underway, detailed ash pond characterization work will begin in the first quarter of 2014

Expect considerable attention from environmental groups when we submit closure plan

Also likely to have considerable media coverage due to proximity of City of Charlotte drinking water intakes about 5 miles downstream of site

[redacted]

Receptors – Who is at Risk?

- Receptors are those in the path of groundwater flow – i.e., downgradient
- Where groundwater flows into a water body, it is a barrier to distant receptors
- Receptors are residential/industrial groundwater drinking water wells in the path of migrating groundwater
- Most drinking water is provided by municipal systems
- Individuals up-gradient are not at risk

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As discussed earlier, receptors are locations that use groundwater (via wells) and could be impacted by our coal ash

Significant work has been done to date to ensure we are not impacting receptors

Over the next few years we will be completing detailed receptor surveys at all locations to verify GW flow expectation and what receptor water sources are

[redacted]

Receptor Summary

Plant	Background Wells	Compliance Wells	Groundwater Standard Exceedences	Secondary Standard Exceedences	Residences Within 1/2 Mile	Down Gradient Receptors	Side Gradient Receptors	Up Gradient Receptors
Crystal River	1	6	2	5	~ 0	0	0	0
Cayuga	2	10	2	2	~ 10	0	0	5
Edwardsport	0	0	0	0	~ 100	0	0	0
Edwardsport IGCC	0	0	0	0	~ 100	0	0	0
Gallagher	0	2/7	2	5	~ 50	0	1	0
Gibson	4	58	2	6	~ 15	0	5	0
Wabash River	0	5	0	3	~ 10	0	0	0
Beckjord	2	18	1	5	~ 10*	0	8*	2
East Bend	1	6	0	4	~ 5	0	0	0
Miami Fort	1	5	1	6	~ 0	0	0	0
Zimmer	2	8	0	0	~ 0	0	0	0
Allen Steam Station	2	11	2	3	~ 250	0	0	250
Asheville	3	8	4	8	~ 2500	0	3	3
Belews Creek	2	7	2	3	~ 50	0	1	40
Buck Steam Station	2	12	2	5	~ 150	0	0	150
Cape Fear	2	11	4	6	~ 100	0	0	20
Cliffside Steam Station	2	7	1	5	~ 25	0	5	10
Dan River Steam Station	1	6	3	5	~ 50	0	0	1
Lee Plant (NC)	3	10	3	5	~ 100	0	0	10
WS Lee Steam Station	2	13	1	3	~75	0	25	50
Marshall Steam Station	2	10	1	5	~ 100	0	0	3
Mayo	2	8	3	4	~ 20	0	5	10
Riverbend	2	12	1	3	~ 300	0	0	5
Robinson	1	2	2	3	~ 250	0	25	100
Roxboro	1	7	1	5	~ 20	0	0	20
Sutton	2	15	7	5	~ 200	0	0*	0
Weatherspoon	1	3	1	3	~ 100	0	80	0
Total	43	258	48	107	~ 4500	0	150	679

*Indicate larger populations could be affected due to proximity of municipal wells

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This table shows receptor information for all sites

- Residences located within ½ mile of ash storage areas (include all locations regardless if on wells, cisterns, municipal water)
- Downgradient recpetors – note that all downgradient recepetors have been eliminated
- Side gradient and upgradient receptors
- Monitoring wells are in place to ensure that side and up gradient receptors are not being impacted

[redacted]

Potentially Impacted Receptors: Action Taken to Date

Station	Constituent	Response
Asheville	Iron, manganese, thallium	Provided alternate water supply; more investigation
Sutton	Boron	Agreement to provide municipal connection to CFPUA
Allen	No impacts identified	NCDENR sampled neighbor's wells; results showed no 2L impacts
Cayuga	Boron	Provided municipal water connection; closing ash basin
Gibson	Boron	Provided municipal water connection; closing ash basin
Beckjord	Sulfate	Installed "interceptor" well

See Appendix C for detailed list of receptor work by station

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Preemptive actions taken to date are shown on this table

These issues have been monitored for years and when issues were identified action was taken

Could have been more proactive in the recent Sutton and Asheville cases, but both situations were being monitored

It is important that we continue to monitor GW samples and take actions proactively if any indications are seen

No current concerns at any sites where specific receptor testing should be done - **VERIFY**

Sutton and Asheville remediation work is currently in progress

[redacted]

Ash Pond Closure Status

Retired station, decommissioning is underway, detailed ash pond characterization work will begin in the first quarter of 2014

Expect considerable attention from environmental groups when we submit closure plan

Also likely to have considerable media coverage due to proximity of City of Charlotte drinking water intakes about 5 miles downstream of site

[redacted]

Ash Pond Closure Methodology (See Appendix D for Ash Pond Closure Details)

- Have begun site characterization and conceptual closure design at several retired sites
- Closure process for operating sites will be considered when regulatory risk of CCR and Effluent Limitations Guidelines (ELG) rules is manageable
- Detailed engineering reviews ensure we understand all factors
- Default strategy is cap-in-place/hybrid
- Excavation and removal reviewed further if default strategy does not ensure groundwater quality
- Throughout process, reuse options will be evaluated considering prudent cost, time to close and other factors
- The selected closure plan will be implemented when cost effective reuse options do not exist (including other factors)

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Our current hybrid strategy v. excavation and removal is:

Protective of groundwater – more so if one considers timeliness

Faster – benefits flow much sooner – decades in most cases

More cost effective

Reduced impact to customers, responsible cost management and recovery issues

[redacted]

Flexible - could excavate and remove if needed at a specific site

[redacted]

[redacted]

Ash Pond Closure Methodology Continued

- Decommissioned Site – Perform Site Characterization
  - Identify ash locations
  - Identify ash depth
  - Map expected groundwater flow and level
  - Locate potential receptors
  - Develop State approved closure plan
- Operating Site – Active Ash Pond(s)
  - Capital upgrades
    - Dry flyash and dry bottom ash, redundancy
    - Waste water pond(s)
    - Additional water treatment
  - Site Characterization – same as above

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Pond closure work has been underway for some time

Work is accelerating due to the current decommissioning work at several sites

However, work has either been completed or is underway at 13 ash ponds

Our plan for properly closing the ash ponds at the decommissioned sites is well defined

If we decide to proceed, the work to close the ponds at the active sites is very similar to the decommissioned sites, but capital investments at the plant must be completed first

This work is estimated to cost about $**XX** over **X** years

This work will involve system upgrades, additional redundancy, and new equipment to handle waste water processing

[redacted]

Ash Pond Current Closure Plans

Plant	Excavation Complete	Excavation In Progress	Excavation Planned	Hybrid Cap in Place Complete	Hybrid Cap in Place In Progress	Hybrid Cap in Place Planned	Eco-Evaporation Planned	Unknown	Active Unlined - In Service	Active Lined - In Service
Crystal River	1								1	
Cayuga					1					
Edwardsport	2									
Gallagher					1	1				
Gibson					2				1	
Wabash River						3		1		1
Beckjord			2			2		5	1	
East Bend									1	
Miami Fort						2			1	
Zimmer										
Allen Steam Station					1	3			1	
Asheville		1				1			1	
Belews Creek						2			1	
Buck Steam Station						3		1		
Cape Fear						2	3			
Cliffside Steam Station			1			1			1	
Dan River Steam Station			2			2				
Lee Plant (NC)						1	2			
WS Lee Steam Station						4		1	1	
Marshall Steam Station					1	1			1	
Mayo						1			1	
Riverbend						4		1		
Robinson						2				
Roxboro				1	1	2			1	
Sutton			1			2				
Weatherspoon				1		1				
Total	3	1	6	2	7	40	5	9	13	1

This table shows the wide variety of work being done or planned for our ash ponds

The general preference is to use the hybrid cap in place methodology to close the ponds since it is the lowest cost and when done properly can provide the same amount of environmental protection as excavation

Based on the site specific information we have currently, all forms of pond closure are expected to be used

As detailed characterizations are completed, closure plans will be modified to address new details identified

Regardless of the best information and engineering review there will always be the possibility of follow-up closure work

As an example, GW levels may not receded to the levels expected keeping the lower levels of ash in the GW table

In this case we may need to come back in at a later date an install additional hydraulic breaks

[redacted] [redacted] [redacted]
[redacted]

Coal Ash Dam Overview

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- Retired station, decommissioning is underway, detailed ash pond characterization work will begin in the first quarter of 2014
- Expect considerable attention from environmental groups when we submit closure plan
- Also likely to have considerable media coverage due to proximity of City of Charlotte drinking water intakes about 5 miles downstream of site

[redacted] [redacted] [redacted] [redacted]

[redacted]

Ash Dam Stability Review Process

- Initial dam construction based on detailed structural design plan
  - Soil conditions
  - Groundwater levels
  - Site conditions
  - Expected ash pond usage
- Routine inspection plan approved by State
- Perform routine inspects and report results as required
  - Vegetation management
  - Physical condition
  - Groundwater level
- Remediate all identified concerns

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All ash pond dams are inspected routinely based on plans approved by the state

This included vegetation management, physical condition, an GW levels

Any issues are noted, submitted to the state along with repair plans, review and completed once approved

[redacted]

Components of the Duke Energy Dam Management Program

Location	Dam Totals
DEC	29
DEP	29
Midwest	24*
DEF	0

- Dam Inspections (See Appendix E for detailed inspection results and recommendations)
  - Internal monthly visual inspections & annual document review
  - Inspected after unusual events (seismic activity or rain fall >2")
  - Regulatory or third-party engineering firm inspections every 2 – 5 years
- Operation and Maintenance Procedures
- Routine Engineering Studies
  - Slope Analysis, Hydraulic Analysis, Breach Analysis
- Emergency Action Plans

*Coal ash dams in Indiana are not regulated, 8 Midwest dams in Ohio and Kentucky are

Dam inspections are both time and event based

Internal and external engineering SME's are used

External engineering studies completed every 2 – 5 years based on regulatory requirements

EAPs include communication methods (primary and backup), perform inundation studies, inundation maps, share internal and external, conduct drills

[redacted]

[redacted]

Areas of Focus and Recommendations

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Retired station, decommissioning is underway, detailed ash pond characterization work will begin in the first quarter of 2014

Expect considerable attention from environmental groups when we submit closure plan

Also likely to have considerable media coverage due to proximity of City of Charlotte drinking water intakes about 5 miles downstream of site

[redacted]

Areas of Focus - Ash Basins and Dams

- General
  - Eco-evaporative closure method is going to be difficult to obtain approval
- Asheville
  - Need to provide alternate water supply to 3 residences on Bear Leah Drive
  - GW exceedences in downgradient monitoring wells improving with lower water levels
  - Very high profile ash remediation location, need to finalize long term plans for generation assets so that ash strategy can be finalized
  - This is first active ash pond that should be addressed
- Roxboro Ash Basin
  - Hyco Lake starting to trend up due to low turnover, likely need to move to ZLD like Mayo
  - Dry ash system needs additional redundancy before ash pond can be closed

Eco-evaporative closure method planned for 5 – 6 ponds currently, old ponds with significant cover growth

May cause more impact if we clear and install a synthetic cap

Geosyntech is the engineering firm performing the closure analysis and has used this method at other locations in the Northeast

Asheville

Working to mitigate GW impacts at three side gradient residences currently

Very high profile site

Need to finalize long term generation strategy before deciding on ash pond closure methodology

Roxboro

Hyco Lake has relatively low volume turnover, dry flayash system in place, still sluice bottom ash

May need to move to ZLD like Mayo due to scrubber waste water impact on lake

Would need more redundancy in dry ash system, currently sluicing to ash pond is emergency back-up system

[redacted] [redacted] [redacted] [redacted]
[redacted]

Areas of Focus - Ash Basins and Dams Continued

- Beckjord Ash Basins
  - Relatively steep slopes on C ash pond with history of shallow slope failure
  - Implemented a monitor and repair program to promptly address these shallow failures
  - Regulatory agency approved this program with the understanding the basin will be decommissioned in the near future
  - Several unstable old ash storage areas near landfill (~$50M to excavate)
  - We provided land North of A ash pond for municipal wells – avoid at all locations in future
  - Ash basins located over high yield aquifer (~$50 - $300M to remediate)
- Robinson Ash Basin
  - Ahs pond may contain low level radioactive material
  - It will be very difficult to move ash
  - Conceptual closure engineering to begin in 2014

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Beckjord Ash Basin C Pond

Relatively steep slopes and history of shallow slope failures.

Slope stability analyses indicates continued failure without improving the dams

If left unaddressed, shallow failures can be progressive and lead to a breach.

Geotechnical group has implemented a monitor and repair program to quickly address these shallow failures.

Regulatory agency has approved this plan despite the decommissioning of this pond in the near future.

The condition appears to be a medium risk.

All ash ponds are above high yield aquifer and no new ash storage project are approved in these locations even if lined

Robinson Ash Basin

Unit 1 and the associated ash basin are planned for decommissioning.

Experienced an event where ash may have been contaminated by materials from Unit 2. Due to incident where Unit 1 and Unit 2 shared a condensate storage tank

Tank drained and cleaned out into a waste water settling pond, this pond was

[redacted]

cleaned out and material put in ash pond

Will need to coordinate any closure plans with the nuclear group

At this time, unsure of the potential implications and unable to offer a degree of risk.

[redacted]

Areas of Focus - Ash Basins and Dams Continued

- Sutton Ash Basin
  - Small release of ash during Sept 2010 hurricane
  - Repairs were made, but additional ash placement has increased the pool height
  - The ash ponds are very full and some ash will need to be moved
  - Must complete municipal water connection to replace Cape Fear Municipal wells
  - Industrial wells are influencing GW flow and boron plume
  - Environmental groups focused on Sutton Lake which is not classified as waters of the State

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Sutton Ash Basin

Had a release of ash caused by overtopping due to hurricane conditions.

Repairs were made, but additional ash placement has increased the pool height, decreasing the freeboard (distance from pool level to dam crest).

Risk of additional overtopping during severe storm conditions.

Scheduled for decommission and it is expected this issue will be addressed through the decommissioning process.

Ash ponds very full, can't cap in place as is, need to move some ash. Interstate project needs a lot of fill, this would be great result if they use our ash (they are reluctant currently pending CCR ruling)

This condition appears to be a moderate risk.

[redacted]

Other Site Groundwater Concerns

- Future impacts are not completely solved by closing ash ponds
- Scrubber waste water next major issue, could be address as capital investments are made at operating sites to close ash ponds
- Groundwater conditions (level, spring) likely to change closure plans
- Gibson zero discharge pond
  - Water loss will continue after ash ponds closed
  - Impact to plant equipment as water cycles up
- Will face still opposition from environmental groups
- Zimmer has GW issues related to FGD runoff issues

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Expect vigorous SELC pushback when the plan is filed.

Scrutiny will only increase while reasonable efforts to close basins are not underway.

Concern over influence on judge in current consent decree and tie to recent Santee Cooper and SCANA decisions to excavate

Scrubber waste water is creating chloride, bromide, and TDs groundwater issues

[redacted]

Recommendations

- Internal
  - Aggressively pursue closure of ash ponds at all decommissioned sites
  - Ensure characterization work identifies all areas of concerns
  - Present all forms of closure methodologies to regulatory agencies to ensure there is alignment (hybrid, excavate, eco-evaporate)
  - Coordinate closure strategy with other utilities
  - Develop capital investment plan for coal plant upgrades – dry fly ash, dry bottom ash, redundancy, scrubber waste water (growth capital)
  - Close **all** active ash ponds (COR accounts)
- External
  - Launch a large scale stakeholder education program
  - Consider engaging environmental groups regarding closure plans

See Appendix F for capital and closure plan cost summaries

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Close ash ponds at decommissioned plants to establish a closure process with regulators and test acceptance of various closure methods

I would like to see Duke adopt the strategy if closing all ash ponds

Incorporate a capital investment program to allow for closure of active ponds and mitigate impacts of scrubber waste water

We should then launch a large media campaign to educate the public on the closure science and costs to gain support for this plan once vetted with regulatory agencies and other utilities

Is there a benefit to engaging environmental groups directly, they would likely want to be linked to a "close all ash ponds" announcement, but do we think it is possible for them to accept alternate closure methods to excavation?

Duke philosophy is to not create any new unprotected ash storage footprints

[redacted]

Appendix A - State groundwater regulation summary

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[redacted]

Groundwater Standards by State

Show Federal standards – then individual states, clarify summaries

	2L Groundwater Standards																						
North Carolina	Parameter	Antimony	Arsenic	Barium	Boron	Cadmium	Chloride	Chromium	Copper	Iron	Lead	Manganese	Mercury	Nickel	Nitrate	Nitrite	Selenium	Silver	Sulfate	Thallium	Zinc	TDS	pH
	Limit	1 µg/L	10 µg/L	700 µg/L	700 µg/L	2 µg/L	250 mg/l	10 µg/L	1 mg/l	300 µg/L	15 µg/L	50 µg/L	1 µg/L	100 µg/L	10 mg/l	1 mg/l	20 µg/L	20 µg/L	250 mg/l	0.2 µg/L	1 mg/l	500 mg/l	SU
			Primary			Primary		Primary	Secondary										Secondary		Secondary	Secondary	
South Carolina	Parameter	Antimony	Arsenic	Barium	Boron	Cadmium	Chloride	Chromium	Copper	Iron	Lead	Manganese	Mercury	Nickel	Nitrate	Nitrite	Selenium	Silver	Sulfate	Thallium	Zinc	TDS	pH
	Limit		10 µg/L			5 µg/L		100 µg/L	1 mg/l										300 mg/l		5 mg/l	500 mg/l	
	Do not report results to State under voluntary plan																						
Indiana	Parameter	Antimony	Arsenic	Barium	Boron	Cadmium	Chloride	Chromium	Copper	Iron	Lead	Manganese	Mercury	Nickel	Nitrate	Nitrite	Selenium	Silver	Sulfate	Thallium	Zinc	TDS	pH
	Limit																						
	2L Groundwater Standards - Voluntary																						
Ohio	Parameter	Antimony	Arsenic	Barium	Boron	Cadmium	Chloride	Chromium	Copper	Iron	Lead	Manganese	Mercury	Nickel	Nitrate	Nitrite	Selenium	Silver	Sulfate	Thallium	Zinc	TDS	pH
	Limit	1 µg/L	10 µg/L	700 µg/L	700 µg/L	2 µg/L	250 mg/l	10 µg/L	1 mg/l	300 µg/L	15 µg/L	50 µg/L	1 µg/L	100 µg/L	10 mg/l	1 mg/l	20 µg/L	20 µg/L	250 mg/l	0.2 µg/L	1 mg/l	500 mg/l	SU
	2L Groundwater Standards - Voluntary																						
Kentucky	Parameter	Antimony	Arsenic	Barium	Boron	Cadmium	Chloride	Chromium	Copper	Iron	Lead	Manganese	Mercury	Nickel	Nitrate	Nitrite	Selenium	Silver	Sulfate	Thallium	Zinc	TDS	pH
	Limit	1 µg/L	10 µg/L	700 µg/L	700 µg/L	2 µg/L	250 mg/l	10 µg/L	1 mg/l	300 µg/L	15 µg/L	50 µg/L	1 µg/L	100 µg/L	10 mg/l	1 mg/l	20 µg/L	20 µg/L	250 mg/l	0.2 µg/L	1 mg/l	500 mg/l	SU
	Federal 2L Groundwater Standards - Secondary Standards Guidance Only																						
Florida	Parameter	Antimony	Arsenic	Barium	Boron	Cadmium	Chloride	Chromium	Copper	Iron	Lead	Manganese	Mercury	Nickel	Nitrate	Nitrite	Selenium	Silver	Sulfate	Thallium	Zinc	TDS	pH
	Limit	1 µg/L	10 µg/L	700 µg/L	700 µg/L	2 µg/L	250 mg/l	10 µg/L	1 mg/l	300 µg/L	15 µg/L	50 µg/L	1 µg/L	100 µg/L	10 mg/l	1 mg/l	20 µg/L	20 µg/L	250 mg/l	0.2 µg/L	1 mg/l	500 mg/l	SU

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This chart shows the incredible variation state to state in groundwater monitoring standards

- Need to verify OH, KY, and FL standards

[redacted]

[redacted]

Appendix B - Additional GW monitoring examples

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[redacted] [redacted]

Allen Station

Would now like to review three of our plants that show several key aspects of our groundwater and coal ash programs

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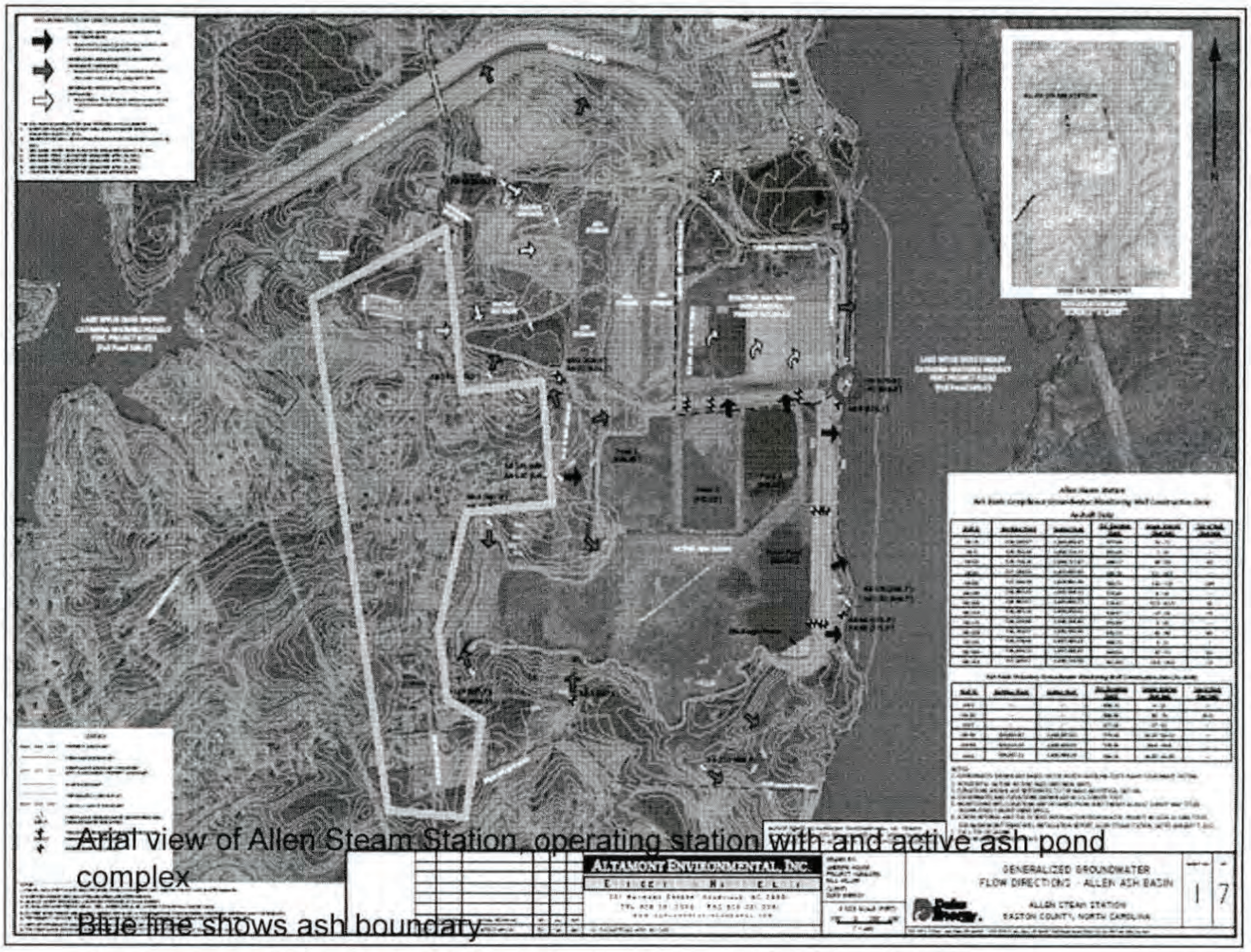
[redacted]



Arial view of Allen Steam Station, operating station with and active ash pond complex

Blue line shows ash boundary

Red line is property boundary

Green line is compliance boundary (500' or property line whichever is closer)

Background (2) and compliance (11) well network is shown with groundwater flow indications (we will see in a couple slides how GW flow is determined)

Groundwater flow is toward the ash ponds and then toward the Lake Wylie

Boron indication at Monitoring Well 4S (circled in red) downstream of ash pond just before GW enters Lake Wylie – no receptors

Boron is not linked to health issues, but is an early indicator for other heavy metals such as arsenic, selenium, etc

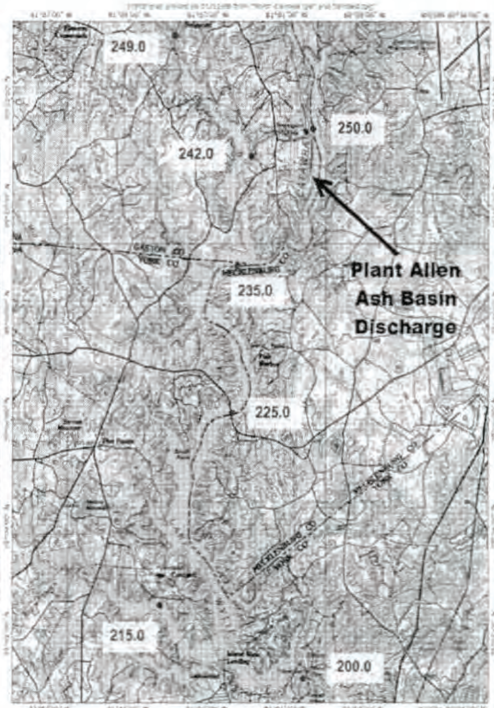
All receptors (approx 250) in pink box and are all upgradient of ash pond, GW flow makes it very difficult for us to impact these locations

State just sampled 4 wells in this area and the results showed no 2L standard exceedences

[redacted] [redacted] [redacted] [redacted]
[redacted]

Allen Steam Station River Impact Monitoring

Location	As (µg/	Cd (µg/	Cr (µg/	Cu (µg/	Hg (µg/	Pb (µg/	Se (µg/	Zn (µg/	TDS (mg/L)
250.0 (Upstream)	< 1.00	< 1.00	< 1.00	1.89	< 0.05	< 1.00	< 1.00	< 2.00	62
250.0 (Upstream)	< 1.00	< 1.00	< 1.00	2.57	< 0.05	< 1.00	< 1.00	2.10	56
250.0 (Upstream)	< 1.00	< 1.00	< 1.00	1.28	< 0.05	< 1.00	< 1.00	1.28	53
250.0 (Upstream)	< 1.00	< 1.00	< 1.00	2.23	< 0.05	< 1.00	< 1.00	< 1.00	51
250.0 (Upstream)	< 1.00	< 1.00	< 1.00	1.52	< 0.05	< 1.00	< 1.00	1.62	57
250.0 (Upstream)	< 1.00	< 1.00	< 1.00	1.92	< 0.05	< 1.00	< 1.00	1.28	29
Average- 100% RL	1.00	1.00	1.00	1.90	0.05	1.00	1.00	1.55	51
Average- 50% RL	0.50	0.50	0.50	1.90	0.03	0.50	0.50	1.30	51
235.0 (Downstream)	< 1.00	< 1.00	1.58	6.45	< 0.05	< 1.00	< 1.00	5.18	79
235.0 (Downstream)	< 1.00	< 1.00	< 1.00	6.62	< 0.05	< 1.00	< 1.00	2.53	71
235.0 (Downstream)	< 1.00	< 1.00	< 1.00	2.35	< 0.05	< 1.00	< 1.00	1.57	54
235.0 (Downstream)	< 1.00	< 1.00	< 1.00	6.03	< 0.05	< 1.00	< 1.00	1.82	54
235.0 (Downstream)	< 1.00	< 1.00	1.43	1.94	< 0.05	< 1.00	< 1.00	2.68	72
235.0 (Downstream)	< 1.00	< 1.00	< 1.00	6.37	< 0.05	< 1.00	< 1.00	1.92	44
Average- 100% RL	1.00	1.00	1.17	4.96	0.05	1.00	1.00	2.62	62
Average- 50% RL	0.50	0.50	0.84	4.96	0.03	0.50	0.50	2.62	62



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Duke monitors rivers and lakes around plants, but monitor per NPDES requirements or surface water standards

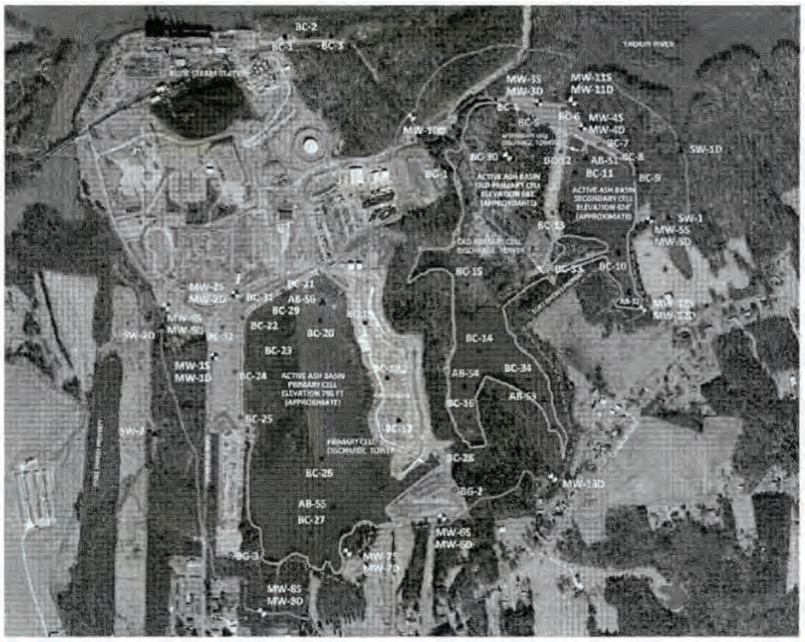
This often means we can't directly compare GW standards to surface water standards – we monitor different parameters

However, we do have comparable results for some stations

- Above the monitoring points around Riverbend are shown on the map on the right (upstream marker 278, Downstream of plant marker 277.5, at CLT drinking water intake marker 277)
- Results are essentially the same at all three locations over the past 3 years and all are below GW and surface water standards
- And impacts are reducing

[redacted]

Example Investigation Plan – Buck Station



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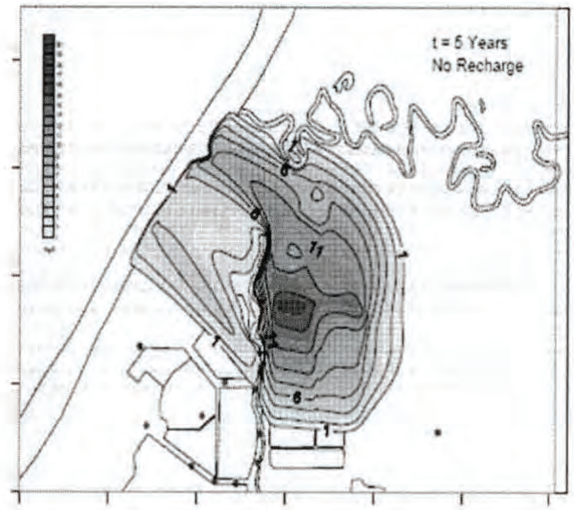
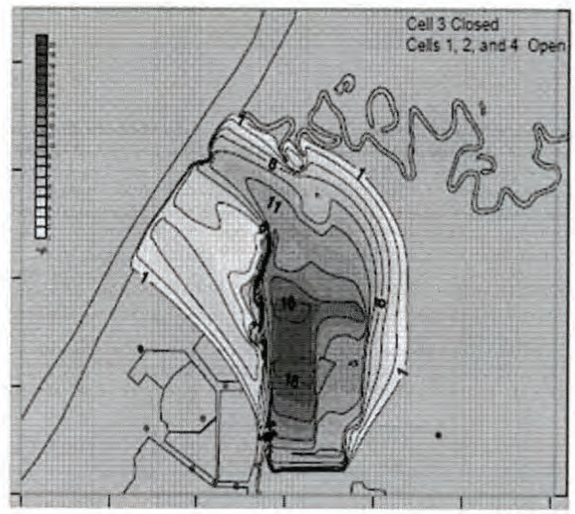
Gibson Station Boron Plume - 2012



Complete Shutdown



Phased Shutdown

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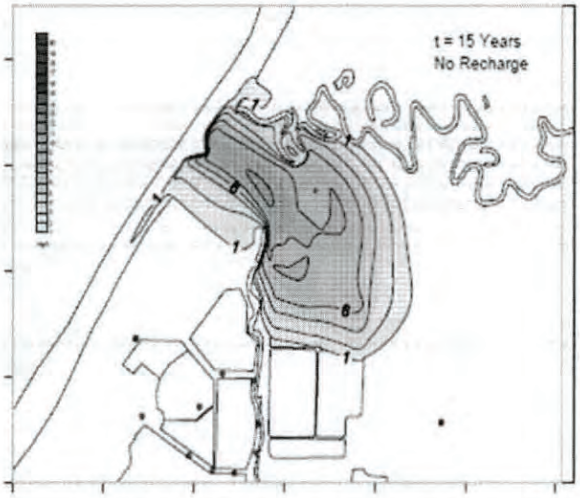
[redacted]

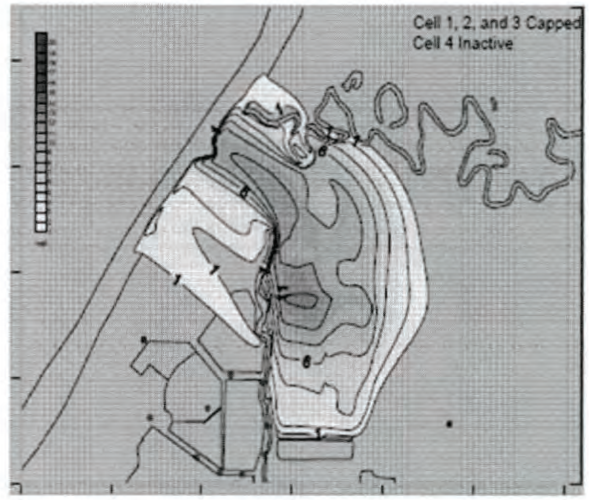
WP 1-3-1

WP 1-3-2

Gibson Station Boron Plume - 2027



Complete Shutdown



Phased Shutdown

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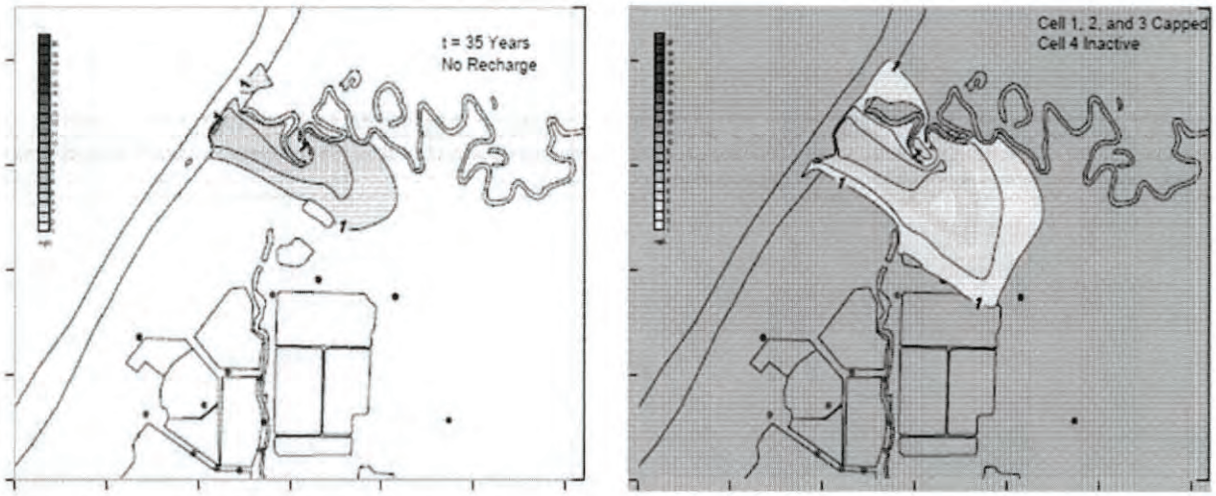
[redacted]

[redacted]

WP 1-3-1

WP 1-3-2

Gibson Station Boron Plume - 2047



Complete Shutdown **Phased Shutdown**

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[redacted] [redacted]

Appendix C – Receptor work summary

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[redacted] [redacted]

Potentially Impacted Receptors: Detailed Summary

Plant	Corrective Actions	Existing Concerns
Cayuga	One residence demolished, two residences moved to municipal water supply, industrial facility does not use for drinking water	None
Edwardsport	Legacy ash ponds cleaned out as part of IGCC conversion, linear installed and now used as water treatment pond for IGCC	None
Edwardsport IGCC	Likely need to fufill IDEM ash pond closure requirements for water treatment pond if IGCC stops using pond as water treatment location	None
Gallagher		None
Gibson	Residential receptors with elevated boron in wells were connected to municipal water supplies	None
Wabash River		None
Beckjord	Interceptor well installed North of A ash pond in the 80's to mitigate the sulfate indication that was found in neighboring public drinking water wells. All test post installation of the interceptor well have been below the sulfate limit	None
East Bend	One well has shown an upward trend for Chloride and sulfate, there are no potential receptors, but work is underway to address the trend	None
Miami Fort	The As indication in one well has been linked to a site condition and not the ash pond	None
Allen Steam Station	Potential receptors exist to the West of the ash ponds, but are upgradient and it is not believed they will see any impacts from the ash ponds. The State recently sampled several wells in this area, results are pending	None
Asheville	Five private wells are side-gradiant to the ash pond, two of these wells were put on bottled drinking water per the States request due Fe and Mn results. A groundwater receptor survey within 1/2 mile of the ash pond compliance boundary and a groundwater site conceptual model have been completed and results submitted to NCDENR. Long term mitigation efforts are	Yes
Belews Creek		None
Buck Steam Station	Potential receptors exist to the southeast of the ash ponds, but are upgradient and it is not believed they will see any impacts from the ash ponds.	None
Cape Fear		None
Cliffside Steam Station		None
Dan River Steam Station		None
Lee	One well (CMW-6) consistently have high As readings, additional land was purchased to allow Duke to have a full 500' compliance boundary in this area. Another well was installed in this area further from the ash basis. As readings are lower, but still above the GW limits	None
WS Lee Steam Station		None
Marshall Steam Station		None
Mayo		None
Riverbend	There has only been one sample event where Antimony was detected. The reading was 1.04µg/L and the lab detection limit is 1.00 µg/L	None
Robinson	Chromium exceedence has only been observed in a background well	None
Roxboro		None
Sutton	Two Cape Fear Public Utility Auhority drinking water wells will be removed from service with future service coming from the Wilmington, NC drinking water system. Other industrial receptors utilize non-potable wells	Yes
Weatherspoon	Only Thallium exceedence was in a background well	None

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Appendix D - Ash pond closure cost and timeline summary

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[redacted]

[redacted]

Ash Basin Closure Plan Submittal

- Can take years to complete so beginning the process is important
  - Subject to state approval and likely litigation
- State requirements exist now and there is reasonable expectation that the federal rule will be based on Subtitle D
- Hastens natural attenuation to reduce constituents in groundwater
- Demonstrates effectiveness for other locations
- Weatherspoon Plan Ready for Submittal to NCDENR; Discussing Further

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Expect vigorous SELC pushback when the plan is filed.

Scrutiny will only increase while reasonable efforts to close basins are not underway.

Concern over influence on judge in current consent decree and tie to recent Santee Cooper and SCANA decisions to excavate

[redacted]

Ash Basin Closure Conceptual Design

Current Characterization & Design Work		
Station	**Contractor**	**Complete**
Weatherspoon	S&ME	Completed
Dan River	AMEC	1/17/2014
Buck	HDR	2/28/2014
Lee (NC)	Geosyntec	1/1/2014
Cape Fear	Geosyntec	1/1/2014

Scheduled for 2014		
Station	**Start**	**Complete**
Riverbend	Feb.	Aug.
Sutton	Feb.	Aug.
Robinson	April	Oct.
Wabash River	April	Oct.
Beckjord (Budget)	May	Nov.

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Accelerate the timing of closure – very limited ability; Already falling behind original retired plant schedule and dependent on state agency approval

Hybrid Closure might be considered in order to minimize the surface area of an engineered cover system or to minimize the amount of borrow material from other sources.

[redacted]

Duke Energy Inventory of Unclosed Ash Ponds and Fills

	Ash Ponds (acres)	Total Fill (acres)	Total Acres	Ash Ponds (MM tons)	Total Fill (MM tons)	Total MM Tons
DEP	804	515	1,319	28.1	19.2	47.3
DEC	1,428	453	1,881	59.9	13.3	73.2
DEF	28	154	182	0.1	4.7	4.8
DEI	372	468	840	7.8	22.9	30.7
DEO & DEK	350	396	746	7.4	36.9	44.3
		Total Acres:	**4,969**		**Total Tons:**	**200,411,361**

- Total coal ash sites/structures- 24 sites/ 61 ponds; 58 structural/landfills
- Ash currently added to ponds- less than 1 million tons/year and decreasing
- Ponds serve multiple purposes (e.g., stormwater retention)

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Total Fill= Landfill is disposal while structural fill has a beneficial use (e.g., plant staging area, parking lot, warehouse, etc.)
New ash added to ponds is about 50/50 fly and bottom ash; most dry fly ash is being reused or disposed in lined landfills.

For example, MSS burns more than a unit train per day – a unit train is 120 cars, 10% ash

= 18,792 tons of coal/day and 1880 tons of ash/day

MSS 1-4 summer rating is 2087 MW (less than Belews Creek 1&2, Roxboro 1-4 and Crystal River 1, 2, 4, 5)

2014 estimate is about 4.5 MM tons produced with about 1 MM to ponds, 2.4 MM to landfills and 1.2 MM sold (rest is intra-station activity e.g., EBS and WHZ)

Ponds serve other functions – stormwater control, boiler chemical cleaning waste; other waste streams are treated and diluted in the ponds; ponds continue to operate after station is retired.

[redacted] [redacted] [redacted]
[redacted]

Ash Ponds and Fills Closure Costs

	Non-Hazardous Cap In Place	Non-Hazardous Excavation	Hazardous Excavation	Comments
Tons Excavated	27.4M	146.5M	189.5M	Additional 40M tons already lined and/or capped would require excavation under hazardous classification (e.g., 20M tons in Gibson East Ash Pond)
Rate to Excavate, Load, Haul & Place	$5.66 to $7.05/ton	$8.44/ton	$60 to $104/ton	Hazardous handling estimates derived from EPRI study. Increased cost for certified drivers/operators, double-lined trucks, hazmat suits, cleaning, spill management, etc. Hazardous reclassification requires all off-site landfills for certain stations.
Acres of Additional Landfill	0	1,174	1,516	
Acres Capped (ponds & landfills)	3,327	1,591	1,945	
10-year Capital	$1.5B	$3.3B	$11.5B	
Capital to Completion	$1.5B	$7.1B	$23.0B	Excavation options extend beyond 10 years. Excavating 750,000 tons/year/station assumed.

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Cap-in-place cost would not be lost if had to excavate & remove some (all) later since characterization studies, ash consolidation and other measures have value even for excavate and remove.

Typically look 10 years ahead for presentations. In previous presentation only the 10-year figure was provided. Total costs are over a 36-year period.

Assumptions & Risks:

Ash tonnages calculated using limited information. Due to age of the facilities, ash basin documentation is incomplete or does not exist, resulting in engineering estimates that are based upon some assumptions. Conceptual engineering studies will refine the ash tonnages.

Landfills were sited for each station and in many cases were offsite; selected by looking for open greenfields as close to the station as possible. No environmental, cultural, or public impacts were investigated; property values are unknown. If assumed locations are not available, costs will increase as the landfill location has to move outward, lengthening the haul distance.

Availability of qualified engineering firms to design, permit, and provide support during construction across the entire fleet during the same timeframe would be difficult and will increase costs. This is not factored into the estimates.

Availability and/or lack of qualified earthwork contractors and equipment to perform

[redacted]

construction activities across the entire fleet during the same timeframe would be difficult and will increase costs. This is not factored into the estimates.

Closure costs recovery for going beyond what is legally acceptable may be difficult.

[redacted] [redacted] [redacted]

[redacted]

Duke Energy Ash Pond Closure Cost Estimates			
Region	Non-Hazardous Hybrid Cap (-10%,+20%)	Non-Hazardous Excavating (-10%,+40%)	Hazardous Excavating (-10%,+50%)
Duke Energy Carolinas	$ 610,545,479	$ 4,211,468,450	$ 6,869,441,014
Duke Energy Progress	$ 433,356,243	$ 1,721,410,726	$ 4,321,673,898
Duke Energy Florida	$ 33,186,482	$ 194,503,065	$ 343,961,931
Duke Energy Indiana	$ 283,024,953	$ 550,820,447	$ 10,270,442,047
Duke Energy Ohio	$ 51,273,242	$ 347,085,229	$ 761,260,518
Duke Energy Kentucky	$ 20,692,161	$ 47,588,086	$ 147,840,162

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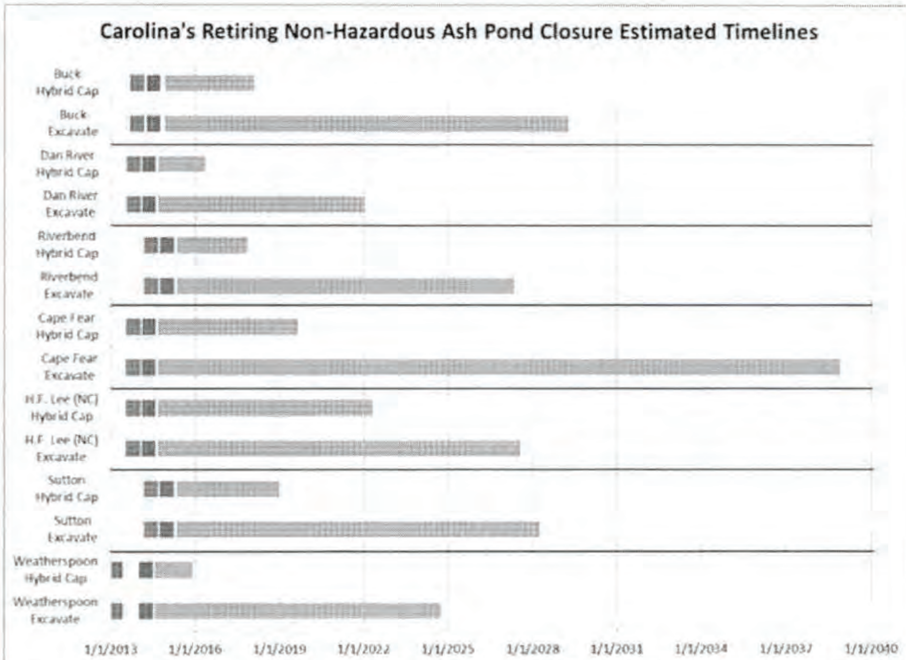

Legend
Conceptual Design Final Design Construction

Under current plans we anticipate closing all ponds at retiring units using cap-in-place or hybrid by 2022 to 2023 (HF Lee; Beckjord)

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Litigation regarding the landfill permitting and construction could delay this schedule even longer.

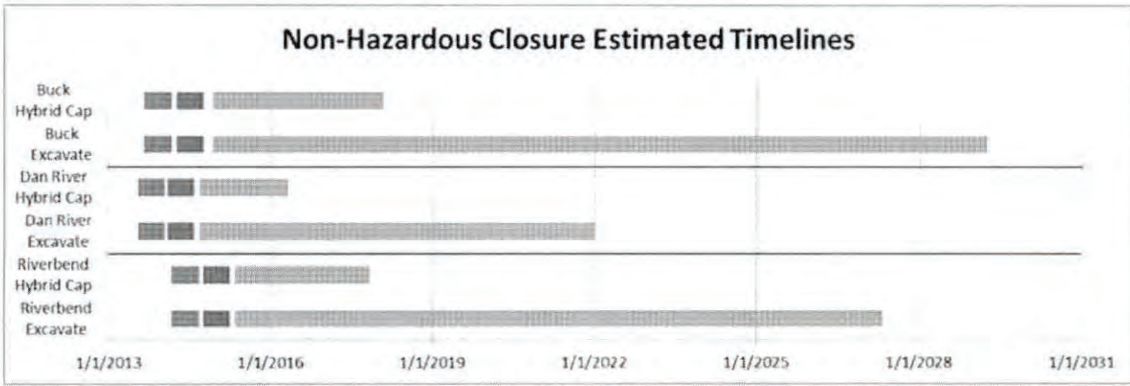
Explain why Riverbend and Sutton not first in order and get date we plan to start study- 1st quarter next year – expectation is March. We will need to get out a RFQ in January so that the contractor could begin work around that time.

Landfill construction 5 to 7 years (additional 1 to 3 years if litigated)

[redacted]

Duke Energy Carolinas Retired Ash Ponds			
Station	Non-Hazardous Hybrid Cap (-10%,+20%)	Non-Hazardous Excavating (-10%,+40%)	Hazardous Excavating (-10%,+50%)
Buck	$ 41,160,030	$ 222,153,709	$ 520,247,681
Dan River	$ 21,680,223	$ 49,245,450	$ 74,136,450
Riverbend	$ 34,764,370	$ 180,110,921	$ 537,037,838

Legend
Conceptual Design
Final Design
Construction



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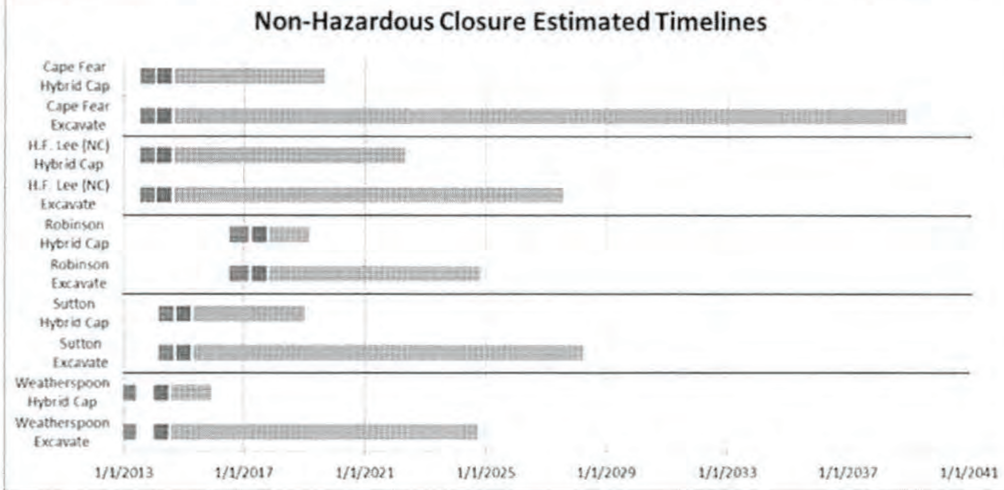
Duke Energy Progress Retired Ash Ponds			
Station	Non-Hazardous Hybrid Cap (-10%,+20%)	Non-Hazardous Excavating (-10%,+40%)	Hazardous Excavating (-10%,+50%)
Cape Fear	$ 79,301,092	$ 557,413,424	$ 1,242,461,739
H.F. Lee (NC)	$ 64,791,241	$ 201,479,526	$ 475,915,193
Robinson	$ 30,062,445	$ 32,477,571	$ 55,332,632
Sutton	$ 59,452,176	$ 185,641,409	$ 476,781,193
Weatherspoon	$ 31,166,512	$ 111,809,658	$ 263,368,159

Legend
- Conceptual Design
- Final Design
- Construction



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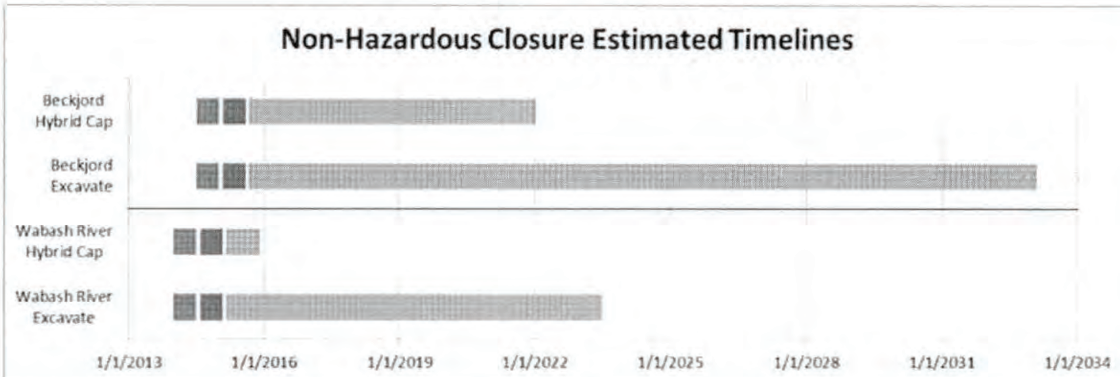
Duke Energy Ohio & Indiana Retired Ash Ponds			
Station	Non-Hazardous Hybrid Cap (-10%,+20%)	Non-Hazardous Excavating (-10%,+40%)	Hazardous Excavating (-10%,+50%)
Beckjord	$ 41,873,319	$ 317,288,305	$ 596,845,396
Wabash River	$ 48,004,780	$ 61,805,344	$ 440,338,625

Legend
Conceptual Design
Final Design
Construction



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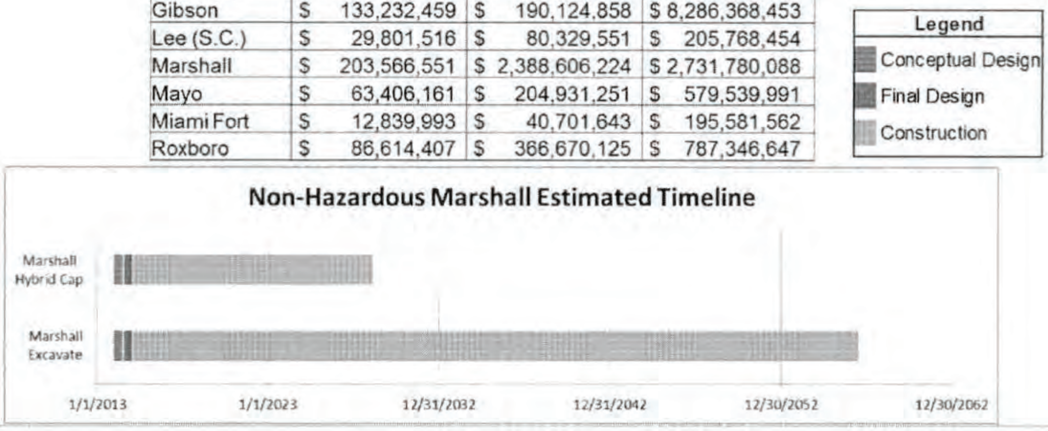
Duke Energy Operating Ash Ponds			
Station	Non-Hazardous Hybrid Cap (-10%,+20%)	Non-Hazardous Excavating (-10%,+40%)	Hazardous Excavating (-10%,+50%)
Allen	$ 95,446,399	$ 497,485,022	$ 899,414,442
Asheville	$ 18,562,209	$ 60,987,762	$ 440,928,344
Belews Creek	$ 125,423,443	$ 564,761,515	$ 1,323,903,631
Cayuga	$ 52,444,779	$ 133,673,275	$ 648,318,307
Cliffside	$ 58,702,947	$ 228,776,058	$ 577,152,430
Crystal River	$ 33,186,482	$ 194,503,065	$ 343,961,931
East Bend	$ 17,252,091	$ 36,683,367	$ 116,673,722
Gallagher	$ 49,342,935	$ 165,216,969	$ 895,416,662
Gibson	$ 133,232,459	$ 190,124,858	$ 8,286,368,453
Lee (S.C.)	$ 29,801,516	$ 80,329,551	$ 205,768,454
Marshall	$ 203,566,551	$ 2,388,606,224	$ 2,731,780,088
Mayo	$ 63,406,161	$ 204,931,251	$ 579,539,991
Miami Fort	$ 12,839,993	$ 40,701,643	$ 195,581,562
Roxboro	$ 86,614,407	$ 366,670,125	$ 787,346,647



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Appendix E - Coal ash dam summary and inspection results

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List of CCR Impoundments in the Dam Safety Program

	Station	Dam Name	Current Status	Hazard Classification	Last Regulatory Inspection	Hydraulic Height (ft)	Slope (#/1)	Impoundment Capacity (acre-ft)
DUKE ENERGY CAROLINAS	Allen	Retired Ash Basin Dam	DRAINED	High	Dec-12	70	2	5,915
		Active Ash Basin Dam	ACTIVE	High	Dec-12	50	2	1,870
	Belew's Creek	Ash Pond	ACTIVE	High	Apr-13	115	2.5	190,000
	Buck	Main Dam	ACTIVE	High	Jan-13	80	3	12,564
		New (Additional Primary) Dam	ACTIVE	High	Jan-13	70	2.5	2,844
		Basin 1 to Basin 2 Dam	ACTIVE	High	Jan-13	80	2.5	N/A
		Basin 2 to Basin 3 Dam	ACTIVE	High	Jan-13	80	2.5	801
		Intermediate Dam	ACTIVE	High	Jan-13	14	2.5	N/A
	Cliffside	Inactive Ash Basin #5 Main Dam	ACTIVE	High	Feb-13	97	2.5	685
		Inactive Ash Basin 1-4 Main Dam	ACTIVE	High	Feb-13	38	2.5	266
		Active Ash Basin Dam	ACTIVE	High	Feb-13	120	2.5	5,025
	Dan River	Active Primary Ash Basin	ACTIVE	High	Jan-13	37	2	477
		Active Secondary Ash Basin	ACTIVE	High	Jan-13	27	2	187
	Lee	Primary Ash Basin	ACTIVE	High	Jun-10	75	2	779
		Secondary Ash Basin	ACTIVE	High	Jun-10	75	2	391
	Marshall	Active Ash Basin Dam	ACTIVE	High	Jan-13	90	2	6,885
	Riverbend	Active Ash Basin Dam 1 (Primary)	ACTIVE	High	Dec-12	80	2.5	1,640
		Ash Basin Dam 2 (Secondary)	ACTIVE	High	Dec-12	70	2.5	987
		Ash Basin Intermediate Dam	ACTIVE	High	Dec-12	8	3	N/A

- Hazard Classification – Classification given by the state based on the possible effects of a dam failure
- Slope – (#) Horizontal : (1) Vertical

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List of CCR Impoundments in the Dam Safety Program

	Station	Dam Name	Current Status	Hazard Classification	Last Regulatory Inspection	Hydraulic Height (ft)	Slope (#/1)	Impoundment Capacity (acre-ft)
DUKE ENERGY PROGRESS & DUKE ENERGY FLORIDA	Asheville	1982 Ash Pond Dam	ACTIVE	High	Apr-13	95	2	1,400
		1964 Ash Pond Dam	ACTIVE	High	Apr-13	90	2.5	N/A
	Cape Fear	1956 Ash Pond Dam (Inactive)	DRAINED	High	Mar-10	20	1.1 - 1.5	N/A
		1963 Ash Pond Dam (Inactive)	DRAINED	High	Mar-10	22	1.5	N/A
		1970 Ash Pond Dam (Inactive)	DRAINED	High	Mar-10	27	2	N/A
		1978 Ash Pond Dam	ACTIVE	High	Mar-10	27	2	N/A
		1985 Ash Pond Dam	ACTIVE	High	Mar-10	28	2.0 - 4.0	1,764
	HF Lee	Active Ash Pond	ACTIVE	High	Jan-12	20	3.3	1,980
		Ash Pond 1 (Inactive)	EXEMPT	Low	Feb-10	7	2	231
		Ash Pond 2 (Inactive)	EXEMPT	Low	Feb-10	15	3	795
		Ash Pond 3 (Inactive)	EXEMPT	Low	Feb-10	10	2	850
	Mayo	Ash Pond Dam	ACTIVE	High	Mar-13	90	2.5	4,100
		FGD Settling Pond	ACTIVE	Low	Mar-13	20	3	103
		FGD Flush Pond	ACTIVE	Low	Mar-13	20	3	7
	Robinson	Ash Pond	ACTIVE	Low	Feb-11	20	2.5	410
	Roxboro	West Ash Pond Dam	ACTIVE	High	Mar-13	70	2	4,800
		West Ash Pond South Rock Filter	ACTIVE	Intermediate	Mar-13	51	1.3	4,800
		West FGD Settling Pond	DRAINED	High	Mar-13	36	2.75	442
		East FGD Settling Pond	ACTIVE	High	Mar-13	36	2.75	132
		FGD Forward Flush Pond	ACTIVE	High	Mar-13	36	2.75	51
		East Ash Pond	ACTIVE	Low	Mar-13	38	3	N/A
	Sutton	1972 Cooling Pond	ACTIVE	Low	Feb-12	12	2	6,900
		1971 Ash Pond	ACTIVE	Low	Feb-12	24	3	248
		1984 Ash Pond	ACTIVE	Low	Feb-13	32	2.5	1,364
	Weatherspoon	1979 Ash Pond	ACTIVE	Intermediate	Nov-12	28	1.5	425
	Crystal River	FGD Settling Pond 6	ACTIVE	No Ranking for Florida	Internal Jan-13	22	3	66
		FGD Settling Pond 7	ACTIVE		Internal Jan-13	16	3	16

Exempt - This dam is not under the jurisdictional authority of the regulatory agency due to size and/or hazard classification

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List of CCR Impoundments in the Dam Safety Program

	Station	Dam Name	Current Status	Hazard Classification	Last Regulatory Inspection	Dam Height (ft)	Slope (#/1)	Impoundment Capacity (acre-ft)
DUKE ENERGY INDIANA, KENTUCK & OHIO	Zimmer	Active Wastewater Pond	ACTIVE	Low	Exempt - No Dam	N/A	N/A	N/A
		Active Clearwater Pond	ACTIVE	Low	Exempt - No Dam			N/A
		Active Settling Basin D	ACTIVE	Low	Exempt - No Dam			N/A
	Beckjord	Inactive Ash Pond A	RETIRED	Significant	Mar-12	20	2	N/A
		Active Ash Pond B	ACTIVE	Significant	Mar-12	20	3	280
		Active Ash Pond C	ACTIVE	Significant	Mar-12	50	1.5	1,400
		Active Ash Pond C Extension	ACTIVE	Significant	Mar-12	40	3	1,300
	Edwardsport	Primary	CONVERTED to	Significant	Mar-12	15	2	N/A
		Secondary	wastewater ponds	Significant	Mar-12	15	2	N/A
	Gallagher	Ash Pond A	ACTIVE	Significant	Mar-12	29	2	936
		Secondary Pond	ACTIVE	Low	Mar-12	19	2	63
	East Bend	Active Wastewater Pond	ACTIVE	Significant	Mar-12	60	2	1,844
	Gibson	Inactive East Ash Pond 1	Closure underway	Low	Mar-12	20	3	1,733
		Inactive East Ash Pond 2	Closure underway	Low	Mar-12	20	3	1,733
		Inactive East Ash Pond 3	Closure underway	Low	Mar-12	20	3	3,325
		Active East Ash Pond Settling Basin	ACTIVE	Low	Mar-12	20	3	743
		Active North Ash Pond	ACTIVE	Low	Mar-12	20	3	350
		Active North Ash Pond Settling Basin	ACTIVE	Low	Mar-12	20	2	150
	Wabash River	Active Primary Pond A	ACTIVE	Significant	Mar-12	19	2	1,350
		Active Primary Pond B	ACTIVE	Significant	Mar-12	19	2	538
		Active Secondary Pond A	ACTIVE	Significant	Mar-12	20	2	73
		Active Secondary Pond B	ACTIVE	Significant	Mar-12	20	2	N/A
		Active South Pond	ACTIVE	Significant	Mar-12	22	2	1,450
	Miami Fort	Active Ash Pond A	ACTIVE	Significant	Mar-12	40	2	803
		Active Ash Pond B	ACTIVE	Significant	Mar-12	40	3	515
	Cayuga	Active Lined Disposal Cell 1	ACTIVE	Significant	Mar-12	32	3	1,400
		Active Ash Disposal Area 1	ACTIVE	Significant	Mar-12	42	2	260
		Active Primary Settling Pond	ACTIVE	Significant	Mar-12	55	2	225
		Active Secondary Settling Pond	ACTIVE	Low	Mar-12	24	2	36
		Retired Ash Pond	RETIRED	Significant	Mar-12	40	2	N/A

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Appendix F – Capital investment and pond closure cost summary

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Cost Recovery Issues

$s in millions

	Total Cost of Removal Reserve (as of 6/30/13)	Steam Cost of Removal Reserve (as of 6/30/13)	Non-Hazardous Cap In Place	Non-Hazardous Excavation & Disposal	Hazardous Excavation & Disposal
DEC	$1,600	$224	$610	$1,300	$4,200
DEP	1,100	138	430	1,000	2,800
DEI	731	367	280	500	3,000
DEO	231	-	100	250	820
DEK	61	12	20	35	140
DEF	488	71	30	190	340
Total 10 year	$4,211	$812	~$1,500	~3,300	~11,500

- Total cost to completion for nonhazardous excavation is $7.1B and for hazardous excavation is $23.0B
- The company could potentially reallocate portions of the "total" COR to cover the cap-in-place ash pond costs
  - Regulatory approval likely to be required to do this

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This table shows the various 10 year scenarios and the COR reserve balances. The second column shows the portion reserved for the steam assets. Just because the "steam" reserve is lower than the planned costs does not mean we could not use some of the other "total" COR reserve to cover the ash pond costs.

There are different points of view as to what type of approval would be required to access the COR funds not specifically allocated to steam currently. One point of view is that no approval is needed and the other is that we would have to notify regulators of the usage. As mentioned earlier, the next depreciation study would likely show that you would need to replenish these reserves at the next rate case; especially anything beyond the steam COR.

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Remaining Dry Ash Conversion Capital Project Cost Estimates (Non-Hazardous)

Project	Facility	Sum of 2013	Sum of 2014	Sum of 2015	Sum of 2016	Sum of 2017	Sum of 2018	Sum of 2019	TOTAL COSTS
Dry Flyash Collection	Asheville	$0	$0	$53,045	$79,568	$5,941,040	$9,335,920	$0	$15,409,573
	Cayuga	$11,386,085	$25,890,333	$6,973,736	$0	$0	$0	$0	$44,250,154
	Cliffside	$0	$0	$0	$2,377,075	$8,569,354	$13,365,744	$519,499	$24,831,672
	Killen	$0	$0	$0	$1,321,134	$4,762,687	$7,428,431	$288,728	$13,800,980
	Mayo	$335,346	$129,415	$307,010	$4,657,710	$0	$0	$0	$5,429,481
	Roxboro	$3,005,204	$16,298,109	$28,073,660	$1,465,458	$2,500,000	$0	$0	$51,342,431
	Stuart	$0	$0	$559,875	$3,171,692	$7,602,835	$8,259,174	$4,537,039	$24,130,615
	TOTAL	**$14,726,635**	**$42,317,857**	**$35,967,326**	**$13,072,638**	**$29,375,916**	**$38,389,269**	**$5,345,265**	**$179,194,906**
Dry Bottom Ash Collection	Allen	$0	$0	$0	$2,837,134	$11,688,995	$24,079,327	$21,701,495	$60,306,951
	Asheville	$0	$0	$625,912	$3,808,931	$9,747,014	$11,704,635	$268,849	$26,155,341
	Belews Creek	$0	$0	$0	$6,678,768	$25,223,481	$43,930,133	$18,001,907	$93,834,289
	Cayuga	$0	$0	$0	$3,277,056	$12,380,089	$21,575,892	$8,886,888	$46,119,925
	Cliffside	$0	$0	$0	$4,486,122	$16,172,471	$25,224,434	$980,421	$46,863,448
	Conesville	$0	$0	$0	$573,130	$2,361,294	$4,864,266	$4,383,920	$12,182,610
	East Bend	$0	$0	$0	$1,661,782	$6,846,540	$14,103,673	$12,711,116	$35,323,311
	Gallagher	$0	$0	$0	$1,036,588	$4,270,744	$8,797,730	$7,928,956	$22,034,018
	Gibson	$0	$0	$609,699	$10,128,637	$33,945,801	$54,793,619	$20,609,502	$120,087,258
	Killen	$0	$0	$0	$1,576,187	$5,682,155	$8,862,538	$344,469	$16,465,348
	Marshall	$0	$0	$0	$5,507,386	$21,171,342	$38,293,106	$20,208,672	$85,180,506
	Mayo	$6,706,400	$0	$0	$0	$0	$0	$0	$6,706,400
	Miami Fort	$0	$0	$1,230,463	$5,703,196	$11,487,503	$7,395,080	$276,979	$26,093,221
	Roxboro	$0	$0	$2,490,772	$12,717,206	$28,697,546	$28,331,717	$18,377,794	$90,615,034
	Stuart	$0	$0	$916,672	$5,192,949	$12,447,971	$13,522,581	$7,428,404	$39,506,578
	TOTAL	**$6,706,400**	**$0**	**$5,873,518**	**$65,185,071**	**$202,122,947**	**$305,478,932**	**$142,109,372**	**$727,476,239**
Dry Flyash Collection and Fixation	Gibson	$2,511,230	$103,885	$0	$0	$0	$0	$0	$2,615,115
	TOTAL	**$2,511,230**	**$103,885**	**$0**	**$0**	**$0**	**$0**	**$0**	**$2,615,115**
	GRAND TOTAL	**$23,944,265**	**$42,421,742**	**$41,840,843**	**$78,257,708**	**$231,498,863**	**$343,868,201**	**$147,454,637**	**$909,286,260**

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Duke Energy Steam Facility Data (As of 9/30/13)

Structure	Operating state	Jurisdiction	Steam unit facility	Owned capacity – summer rating (MW)	Fuel type	Current cooling method	Air Emissions controls	Ash handling (flyash; bottom ash)	Ash ponds on site (3)
Regulated	In Operation	DE Carolinas	Allen	1,127	Coal	Once-Through	Scrubber	Dry; Wet Sluice	Active and Inactive
Regulated	In Operation	DE Carolinas	Belews Creek	2,220	Coal	Once-Through	Scrubber and SCR	Dry; Wet Sluice	Active and Inactive
Regulated	In Operation	DE Carolinas	Cliffside 5	556	Coal	Closed Cycle	Scrubber and SCR	Wet Sluice; Wet Sluice	Active and Inactive
Regulated	In Operation	DE Carolinas	Cliffside 6	825	Coal	Closed Cycle	Scrubber and SCR	Dry; Dry	
Regulated	In Operation (1)	DE Carolinas	Lee	370	Coal	Once-Through		Wet Sluice; Wet Sluice	Active and Inactive
Regulated	In Operation	DE Carolinas	Marshall	2,078	Coal	Once-Through	658MW with Scrubber and SCR; 1420MW with Scrubber	Dry; Wet Sluice	Active and Inactive
Regulated	In Operation	DE Carolinas	Buck CC	620	Gas	Closed Cycle	SCR		Inactive
Regulated	In Operation	DE Carolinas	Dan River CC	620	Gas	Closed Cycle	SCR		Inactive
Regulated	In Operation	DE Carolinas	Catawba	435	Nuclear	Closed Cycle			
Regulated	In Operation	DE Carolinas	McGuire	2,200	Nuclear	Once-Through			
Regulated	In Operation	DE Carolinas	Oconee	2,538	Nuclear	Once-Through			
Regulated	In Operation	DE Progress	Asheville	376	Coal	Once-Through	Scrubber and SCR	Wet Sluice; Wet Sluice	Active and Inactive
Regulated	In Operation	DE Progress	Mayo	609	Coal	Cooling Lake	Scrubber and SCR	Dry; Dry	Inactive
Regulated	In Operation	DE Progress	Roxboro 1-4	2,327	Coal	Once-Through (1-3), Closed Cycle (4)	Scrubber and SCR	Dry; Wet Sluice	Active and Inactive
Regulated	In Operation (1)	DE Progress	Sutton 1-3	575	Coal	Cooling Lake		Wet Sluice; Wet Sluice	Active and Inactive
Regulated	In Operation	DE Progress	Smith 4-5	1,122	Gas	Closed Cycle	SCR		
Regulated	In Operation	DE Progress	Wayne County CC	920	Gas	Closed Cycle	SCR		Inactive
Regulated	In Operation	DE Progress	Brunswick	1,517	Nuclear	Once-Through			
Regulated	In Operation	DE Progress	Harris	742	Nuclear	Cooling Lake			
Regulated	In Operation	DE Progress	Robinson	724	Nuclear	Once-Through			Inactive
Regulated	In Operation	DE Florida	Anclote	1,011	Gas	Once-Through			
Regulated	In Operation	DE Florida	Bartow CC	1,133	Gas	Once-Through	SCR		
Regulated	In Operation (2)	DE Florida	Crystal River 1-2	873	Coal	Once-Through		Dry; Dry	Active
Regulated	In Operation	DE Florida	Crystal River 4-5	1,422	Coal	Closed Cycle	Scrubber and SCR	Dry; Dry	
Regulated	In Operation	DE Florida	Hines CC	1,912	Gas	Cooling Lake	SCR		
Regulated	In Operation	DE Florida	Suwannee River	129	Gas/Oil	Once-Through			
Regulated	In Operation	DE Florida	Tiger Bay	205	Gas	Closed Cycle			

(1) Potential retirements include DEC Lee Units 1-2; Sutton Units 1-3; Wabash River Units 2-5; Miami Fort Unit 6; and Beckjord Units 4-6. Reflects already completed retirements of Edwardsport 6-8 (160 MW), Buck 3-6 (385 MW), Cliffside 1-4 (198 MW), Dan River 1-3 (276MW), Riverbend 4-7 (454MW), Gallagher 1,3 (280MW) per Consent Decree, Beckjord 1 (94MW), Weatherspoon 1-3 (177 MW), DEP Lee 1-3 (301 MW), Bartow 1-3 (440 MW), Robinson 1 (177 MW), Cape Fear 5-6 (316 MW), Crystal River 3 (788 MW), and Beckjord 2-3 (222MW) which retired 10/1/2013. Wabash River Unit 6 (320 MW) potential to be converted to gas or retired. DEC Lee Unit 3 (170MW) to be converted to gas

(2) Crystal River 1-2 (875 MW) potential to be retired; MATS compliance options are being reviewed

(3) "Inactive" means that the storage facility is not currently receiving ash

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Duke Energy Steam Facility Data, cont. (As of 9/30/13)

Structure	Operating state	Jurisdiction	Steam unit facility	Owned capacity – summer rating (MW)	Fuel type	Current cooling method	Air Emissions controls	Ash handling (flyash; bottom ash)	Ash ponds on site (3,4)
Regulated	In Operation	DE Indiana	Cayuga	1,005	Coal	Once-Through	Scrubber; SCR Under Construction	Wet Sluice (Dry Under Construction); Wet Sluice	Active and Inactive
Regulated	In Operation	DE Indiana	Gibson	2,822	Coal	Cooling Lake, No NPDES Permit	Scrubber and SCR	Dry; Wet Sluice	Active and Inactive
Regulated	In Operation (1)	DE Indiana	Wabash River	668	Coal	Once-Through		318MW Dry; Wet 350MW Wet; Wet	Active and Inactive
Regulated	In Operation	DE Indiana	Gallagher 2&4	280	Coal	Once-Through	Baghouse	Dry; Wet Sluice	Active and Inactive
Regulated	In Operation	DE Indiana	Edwardsport IGCC	618	Coal	Closed Cycle - No Intake	Selexol and SCR	Dry Slag Handling	
Regulated	In Operation	DE Indiana	Noblesville CC	310	Gas	Closed Cycle			
Regulated	In Operation	DE Kentucky	East Bend	414	Coal	Closed Cycle	Scrubber and SCR	Dry; Wet Sluice	Active
Regulated	In Operation (1)	DE Kentucky	Miami Fort 6	163	Coal	Once-Through		Wet Sluice; Wet Sluice	Active
Non-Regulated	In Operation	DE Ohio	Conesville 4	312	Coal	Closed Cycle	Scrubber and SCR	Dry; Wet Sluice	Active
Non-Regulated	In Operation	DE Ohio	Stuart 1-3	675	Coal	Once-Through	Scrubber and SCR	Wet Sluice; Wet Sluice	Active
Non-Regulated	In Operation	DE Ohio	Stuart 4	225	Coal	Closed Cycle	Scrubber and SCR	Wet Sluice; Wet Sluice	
Non-Regulated	In Operation	DE Ohio	Killen	198	Coal	Closed Cycle	Scrubber and SCR	Wet Sluice; Wet Sluice	Active
Non-Regulated	In Operation (1)	DE Ohio	Beckjord	543	Coal	Once-Through		150 MW Dry; Wet 393MW Wet; Wet	Active and Inactive
Non-Regulated	In Operation	DE Ohio	Miami Fort 7-8	640	Coal	Closed Cycle	Scrubber and SCR	Dry; Wet Sluice	Active
Non-Regulated	In Operation	DE Ohio	Zimmer	605	Coal	Closed Cycle	Scrubber and SCR	Dry; Dry	
Non-Regulated	In Operation	Duke Energy	Fayette CC	633	Gas	Closed Cycle	SCR		
Non-Regulated	In Operation	Duke Energy	Hanging Rock CC	1,262	Gas	Closed Cycle	SCR		
Non-Regulated	In Operation	Duke Energy	Washington CC	639	Gas	Closed Cycle	SCR		
Regulated	Under Construction	DE Progress	Sutton CC	625	Gas	Closed Cycle	SCR		

(1) Potential retirements include DEC Lee Units 1-2, Sutton Units 1-3, Wabash River Units 2-5; Miami Fort Unit 6; and Beckjord Units 4-6. Reflects already completed retirements of Edwardsport 6-8 (160 MW), Buck 3-6 (369 MW), Cliffside 1-4 (198 MW), Dan River 1-3 (276MW), Riverbend 4-7 (454MW), Gallagher 1,3 (280MW) per Consent Decree, Beckjord 1 (94MW); Weatherspoon 1-3 (177 MW); DEP Lee 1-3 (391 MW); Bartow 1-3 (440 MW), Robinson 1 (177 MW), Cape Fear 5-6 (316 MW); Crystal River 3 (789 MW) and Beckjord 2-3 (222MW) which retired 10/1/2013. Wabash River Unit 6 (320 MW) potential to be converted to gas or retired. DEC Lee Unit 3 (170MW) to be converted to gas.

(2) Crystal River 1-2 (875 MW) potential to be retired, MATS compliance options are being reviewed

(3) "Inactive" means that the storage facility is not currently receiving ash

(4) Other locations with inactive ash ponds include the retired Riverbend, Cape Fear, and Weatherspoon Stations

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Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 179

Docket No. E-2, Sub 1219

Date of Request:	**May 6, 2020**
Date of Response:	**May 11, 2020**

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The attached response to NC Public Staff Data Request No.179-1, was provided to me by the following individual(s): Melissa Brammer Abernathy, Manager, Accounting II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

1. Page 12, lines 26-27 of Spanos Rebuttal Testimony states: "The method of determining the estimated net salvage percent depends on the type of property" and goes on to discuss the differences between estimated net salvage for power plants and the estimated net salvage for mass property accounts.

a. Are the quotes from the Commission on page 10, lines 7-19 of Spanos Rebuttal Testimony regarding the method for estimating net salvage for power plants or the method for estimating net salvage for mass property accounts?

Response:

The quotes on page 10, lines 9-19 are from the Commission's order regarding terminal net salvage in the Sub 1146 Order. However, the principle discussed – that net salvage should be the future cost, not today's cost – applies to net salvage in general and would, therefore, logically apply to net salvage for both power plants and mass property. As further evidence that the Commission would not apply a different concept to mass property net salvage from that of power plant net salvage, in the same section of the Sub 1146 Order the Commission recognized that other states have rejected Ms. McCullar's approach to net salvage for mass property (this portion of the Sub 1146 Order is presented on page 12 of Mr. Spanos' rebuttal testimony).

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 179

Docket No. E-2, Sub 1219

Date of Request: **May 6, 2020**
Date of Response: **May 11, 2020**

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The attached response to NC Public Staff Data Request No.179-7, was provided to me by the following individual(s): Melissa Brammer Abernathy, Manager, Accounting II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

7. Page 33, line 10 of Spanos Rebuttal Testimony is discussing Accounts 391 and 397 and claims that Ms. McCullar "excluded millions of dollars of investment from her calculations of depreciation expense for these accounts."
a. Is Mr. Spanos claiming that Ms. McCullar did not use the same investment amounts shown in Mr. Spanos's calculations shown on pages 623 and 631 of Spanos Exhibit 1?
b. Please provide the workpapers that show the millions of dollars of investments excluded from Ms. McCullar's calculation of depreciation expense for Accounts 391 and 397.

Response:

a. No. Mr. Spanos' contention is that Ms. McCullar did not calculate depreciation for the correct balances based on her proposals and instead excluded significant portions of each account from her calculations. Specifically, as shown on page 20 of Exhibit RMM-1, Ms. McCullar excludes a portion of each account from her depreciation calculations. A rate of zero was applied to these portions of each account in Mr. Spanos' calculations because these assets would be retired using Mr. Spanos' recommended amortization periods. However, these would not be retired when using Ms. McCullar's recommended amortization periods and, therefore, she should have calculated depreciation accruals for these amounts.

b. The millions of dollars of investments excluded from Ms. McCullar's calculations are those identified as "Fully Accrued" on page 20 of Exhibit RMM-1.

**THE STATE CORPORATION COMMISSION
OF THE STATE OF KANSAS**

Before Commissioners:	Susan K. Duffy, Chair Shari Feist Albrecht Dwight D. Keen

In the Matter of the Application of Atmos Energy Corporation for Adjustment of its Natural Gas Rates in the State of Kansas.	)))	Docket No. 19-ATMG-525-RTS

ORDER ON ATMOS ENERGY CORPORATION'S APPLICATION FOR A RATE INCREASE

This matter comes before the State Corporation Commission of the State of Kansas (Commission). Having reviewed the pleadings and record, the Commission makes the following findings:

1. On June 28, 2019, Atmos Energy Corporation (Atmos) filed an Application seeking an overall net revenue increase of $7.2 million, resulting from increasing base rates by $9.6 million, proposing a rate case expense surcharge of $817,882, rebasing amounts currently collected through the Gas System Reliability Surcharge Rider (GSRS) of $3.3 million; and adjusting $1.4 million of its Ad Valorem Tax Surcharge Rider (AVTS) into base rates.[1]

2. Atmos claims their current rates do not produce sufficient revenues to cover the costs to render reasonably sufficient and efficient service and, therefore, are not just and reasonable.[2] Without the proposed rate increase, Atmos contends it will be unable to acquire necessary capital at reasonable rates, carry out new construction, provide adequate gas supplies of gas and render the quality of service the public requires.[3] Atmos's Application is accompanied by supporting testimony from eight witnesses.[4]

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[1] Application, June. 28, 2019, ¶ 4.
[2] *Id.*, ¶ 5.
[3] *Id.*
[4] *Id.*, ¶ 4.

3. The Commission has jurisdiction to supervise and control natural gas public utilities, as defined in K.S.A. 66-104, doing business in Kansas.[5] The Commission has the power to require all natural gas utilities governed by the Natural Gas Public Utilities Act to establish and maintain just and reasonable rates.[6]

4. Notice of the proposed rate increase, public hearing, and evidentiary hearing was provided by an insert with the monthly billing statement for each customer in Atmos's service territory as well as by publishing notice in the major newspapers in the region. The Commission received comments from the public at the September 17, 2019 public hearing in Overland Park, Kansas, where a record was made. The Commission also received 527 public comments through its Office of Public Affairs and Consumer Protection.[7] The Commission issues this Order with due consideration of those comments.

5. On July 25, 2019, the Citizens' Utility Ratepayer Board (CURB) was granted intervention.

6. On October 31, 2019, Commission Staff (Staff)[8] and CURB filed their direct testimony. In its direct testimony, Staff recommended a net revenue decrease of $593,764; CURB recommended a net revenue decrease of $3,157,324.[9]

7. On November 18, 2019, Atmos filed rebuttal testimony from eight witnesses. James F. Reda and John D. Quackenbush filed rebuttal testimony without having filed direct testimony. Reda's testimony focused on the reasonableness of total compensation levels for

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[5] K.S.A. 66-1,201.
[6] K.S.A. 66-1.202.
[7] The public comments were entered into the record by the Prehearing Officer filing Notice of Filing of Public Comments on Dec. 18, 2019.
[8] Staff served the Direct Testimony of Justin T. Grady and Adam H. Gatewood on all parties via email on October 31, 2019. Due to a clerical error neither Grady's nor Gatewood's testimony was filed by 5:00 p.m. on October 31, 2019. On November 14, 2019, the Commission granted Staff's Motion for Leave to File Testimony Out of Time.
[9] Post-Hearing Brief of Commission Staff (Staff Brief), Jan. 16, 2020, ¶¶ 5, 6.

executives and the appropriateness of Atmos's annual and long-term incentive compensation programs.[10] Quackenbush's rebuttal testimony discussed the alternative regulatory mechanisms he approved for natural gas companies while he chaired the Michigan Public Service Commission,[11] and opined on the importance of Regulatory Research Associates' (RRA) assessments of state regulatory climates.[12]

8. The Parties were unable to reach a settlement, so the Commission held an evidentiary hearing, beginning December 10, 2019, and concluding December 12, 2019. Atmos, Staff, and CURB appeared by counsel and each party submitted prefiled testimony. The Commission heard live testimony from a total of 20 witnesses, including nine on behalf of Atmos, seven on behalf of Staff, and four on behalf of CURB. At the December 3, 2019 prehearing conference, the parties agreed to waive cross-examination of several witnesses. The parties had the opportunity to cross-examine the remaining witnesses at the evidentiary hearing as well as the opportunity to redirect their own witnesses. Following the evidentiary hearing, all of the parties submitted post-hearing briefs.

9. The major issues in dispute are:

- Return on Equity (ROE) / Capital Structure
- System Integrity Plan (SIP)
- Incentive Compensation
- Depreciation
- Rate case expense
- Other rate base and income statement adjustments

[10] Rebuttal Testimony of James F. Reda, Nov. 18, 2019, p. 3.
[11] Rebuttal Testimony of John D. Quackenbush, CFA (Quackenbush Rebuttal), Nov. 18, 2019, p. 12.
[12] *Id.*, pp. 14-15.

10. In determining rates, the Commission first establishes a revenue requirement and then designs a rate structure.[13] The revenue requirement includes rate base, operating expenses, and rate of return.[14] The rate of return is simply an opportunity to earn that rate, not a guarantee. Rate design includes allocating costs among and within the customer classes.

11. In setting rates, the Commission's goal is to balance the interests of all concerned parties and develop a rate within the "zone of reasonableness."[15] The parties whose interests must be considered and balanced include: (1) the utility's investors vs. the ratepayers; (2) present vs. future ratepayers; and (3) the public interest.[16]

12. In allocating the revenue requirement among the customer classes, the Commission follows cost causation principles,[17] so "that one class of consumers shall not be burdened with costs created by another class."[18]

A. RETURN ON EQUITY

13. Atmos initially proposed an ROE of 10.25%, with an overall rate of return of 7.98%.[19] Its witness, Dylan D'Ascendis, reached his ROE recommendation after applying several cost of common equity models, including the Discounted Cash Flow (DCF) model, the Risk Premium Model (RPM), and the Capital Asset Pricing Model (CAPM), to a proxy group of six natural gas distribution utilities and a separate proxy group of sixteen domestic, non-price regulated companies of comparable risk to the six natural gas companies.[20] D'Ascendis's models produced an ROE of 9.8% before he adjusted it upward by 0.40% for the small size of Atmos

[13] *Kansas Gas & Elec. Co. v. Kansas Corp. Comm'n*, 239 Kan. 483, 500 (1986).
[14] *Id.* at pp. 500-01.
[15] *Id.* at pp. 488-89.
[16] *Id.* at pp. 488, 1070.
[17] *See* Order on Petitions for Reconsideration and Clarification, ¶¶ 14-15, Docket No. 05-WSEE-981-RTS (Feb. 13, 2006).
[18] *Jones v. Kansas Gas & Elec. Co.*, 222 Kan. 390, 401 (1977).
[19] Direct Testimony of Dylan W. D'Ascendis (D'Ascendis Direct), June 28, 2019, p. 2.
[20] *Id.*, p. 3.

Kansas's operations and another 0.04% for flotation costs to arrive at an ROE of 10.24%.[21] Inexplicably, D'Ascendis's rounded up to 10.25% to reach his initial recommendation.[22]

14. CURB's witness, Dr. J. Randall Woolridge, applied the DCF and CAPM to his own proxy group of gas distribution companies and concluded Atmos's ROE is in the range of 7.50% to 8.70%,[23] ultimately recommending an ROE of 8.7%.[24]

15. Staff recommends an ROE of 9.1%, with a range of 8.55% to 9.35%.[25] Staff witness Adam Gatewood's ROE of 9.1% results in an overall rate of return of 7.02%.[26] Gatewood performed DCF, Internal Rate of Return (IRR), and CAPM analyses using D'Ascendis's proxy group.[27] He relied on a DCF model using both short-term and long-term growth rate forecasts to arrive at a midpoint ROE of 8.15%.[28] Applying long-term growth rate forecasts to D'Ascendis's proxy group is one explanation for why Gatewood's recommended ROE is lower than D'Asendis's.

16. In his rebuttal testimony, D'Ascendis lowered his initial ROE recommendation from 10.25% to 9.9%,[29] based on an extraordinary decline in interest rates since he filed his direct testimony.[30] In his revised ROE recommendation, D'Ascendis starts with an ROE of 9.45% before applying a 0.40% upward size adjustment and a 0.03% flotation cost adjustment to arrive at his 9.9% ROE recommendation.[31]

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[21] *Id.*, p. 4.
[22] *Id.*
[23] Direct Testimony of J. Randall Woolridge, Ph.D. (Woolridge Direct), Oct. 31, 2019, p. 4.
[24] *Id.*, p. 58.
[25] Direct Testimony of Adam Gatewood (Gatewood Direct), Nov. 5, 2019, p. 2.
[26] *Id.*, p. 2. Gatewood's 7.02% overall rate of return is based on a 4.35% cost of debt. *See id.*, p. 3. Applying the 4.37% cost of debt the Commission adopts in paragraph 29 of this Order increases his overall rate of return to 7.03%.
[27] Staff Brief, ¶¶ 16-18.
[28] *Id.*, ¶ 17.
[29] Rebuttal Testimony of Dylan W. D'Ascendis (D'Ascendis Rebuttal), Nov. 18, 2019, p. 2.
[30] *Id.*, p. 5.
[31] *Id.*, p. 4.

17. In determining the appropriate ROE, the Commission is guided by *Federal Power Commission v. Hope Natural Gas Company*, 320 U.S. 591 (1944) and *Bluefield Waterworks & Improvement Company v. Public Service Commission of West Virginia*, 262 U.S. 679 (1923) which find returns granted to regulated public utilities should be: (1) commensurate with returns on investment of similar risk; (2) sufficient to ensure the utility's financial integrity under proper management; and (3) adjusted to reflect changes in the money market and business conditions.[32] *Hope* and *Bluefield* have been adopted by the Kansas Supreme Court[33] and recognized by the Commission in Docket No. 10-KCPE-415-RTS (10-415 Docket).[34] While the Commission has substantial discretion in setting a fair rate of return, it must not be so unreasonably high or low as to be unlawful.[35]

18. Even after amending its proposed ROE in recognition of an extraordinary decline in interest rates, Atmos's proposed 9.9% ROE represents an increase of 80 basis points from its currently approved ROE of 9.1%.[36] Both Gatewood and Woolridge testified that there has been a clear downward trend in authorized ROEs for gas and electric utilities from 2000 to 2018.[37] Even Atmos acknowledges an overall downward trend in interest rates since 2008.[38] Atmos is the only party advocating an increase to its 9.1% ROE. Atmos's proposed ROE runs counter to the trends in Kansas and nationwide towards lower ROEs in recognition of historically low costs of capital.

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[32] *Federal Power Comm'n v. Hope Natural Gas Co.*, 320 U.S. 591, 603, 64 S.Ct. 281, 288 (1944); *Bluefield Waterworks & Improvement Co. v. Public Service Comm'n of West Virginia*, 262 U.S. 679, 692-93, 43 S.Ct. 675, 679 (1923).
[33] *Kansas Gas*, 239 Kan. at pp. 489-90.
[34] Order: 1) Addressing Prudence; 2) Approving Application, In Part: and 3) Ruling on Pending Requests (10-415 Order), pp. 40-41, Docket No. 10-KCPE-415-RTS (Nov. 22, 2010).
[35] *Southwestern Bell Tel. Co. v. Kansas Corp. Comm'n*, 192 Kan. 39, 85-86 (1963).
[36] *See* Gatewood Direct, p. 30.
[37] Transcript of Evidentiary Hearing (Tr.), Dec. 10, 2019, Vol. 1, p. 48 (Woolridge); *id*, pp. 159-160 (Gatewood).
[38] D'Ascendis Rebuttal, pp. 5-6.

19. On cross-examination, D'Ascendis admits that the only model that produces a 9.9% ROE applies to companies that are not price/rate regulated with adjustments for company size and equity flotation.[39] Yet, D'Ascendis is unaware of any instance where the Commission has recognized a size adjustment in setting an ROE.[40] With an equity market capitalization of $11.4 billion, Atmos is hardly a small company.[41] Staff questioned the appropriateness for a size adjustment because an investor cannot purchase stock specific to Atmos's Kansas operations nor can anyone purchase debt specific to Atmos's Kansas operations.[42]

20. As Quackenbush testified, Atmos Kansas makes up only about 4% of Atmos's operations, so when investors contemplate investing in Atmos, they focus on states like Texas, Mississippi and Louisiana that make up the lion's share of Atmos's operations, and therefore, the regulatory risk that exists in those three states more significantly impacts Atmos's ability to attract capital.[43] Similarly, Quakenbush admits that Atmos is not currently experiencing any difficulty raising capital,[44] as evidenced by its ability to recently issue $800 million in 10-year and 30-years notes with a yield of 2.625 and 3.375 percent, respectively.[45] Based on these admissions, there is no justification for a size adjustment to ROE.

21. Atmos has not met its burden to demonstrate its existing 9.1% ROE is hindering its ability to raise capital, or insufficient to ensure the utility's financial integrity under proper management.

22. At the same time, CURB's recommended ROE range of 7.50% to 8.70% strikes the Commission as too low. Woolridge's recommended ROE is significantly below Atmos's current

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[39] Tr., Vol. 1, pp. 86-87.
[40] *Id.*, p. 93.
[41] Gatewood Direct, p. 24.
[42] *Id.*, p. 103.
[43] *Id.*, p. 217.
[44] *Id.*
[45] *Id.*, p. 218.

authorized ROE and is even further below the average rates of return being allowed to natural gas utilities. As D'Ascendis testified, since 2018, the average and median authorized ROEs for natural gas utilities are 9.63% and 9.7% respectively.[46]

23. An ROE of 9.1%, as recommended by Staff, is below that requested by Atmos, and above that recommended by CURB. The current Baa Corporate Bond yield of 4.5%[47] is actually lower than the 4.89% yield in place during the 14-ATMG-320-RTS Docket, (the last time the Commission set Atmos's ROE).[48] Since capital costs have declined since the Commission set the 9.1% ROE, the 80 basis points increase sought by Atmos is not justified. Having reviewed the evidence provided by D'Ascendis, Woolridge, and Gatewood, the Commission believes an ROE of 9.1% strikes the proper balance of allowing Atmos to access capital markets while acknowledging the economic impact of higher ROEs on ratepayers.

B. CAPITAL STRUCTURE

24. D'Ascendis recommends using Atmos's actual capital structure as of March 31, 2019 to develop the overall rate of return.[49] Therefore, he proposes a capital structure consisting of 39.88% long-term debt and 60.12% common equity.[50] D'Ascendis testified that since a 60.12% equity ratio is within the range of common equity ratios of other utility proxy group members, it would be inappropriate to substitute a hypothetical capital structure.[51]

25. Both Staff and CURB recommend a capital structure of 43.68% long-term debt and 56.32% common equity.[52] Woolridge testified that Atmos's proposed capital structure has more equity than the rest of the gas proxy members and should be adjusted to reflect the issuance of

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[46] D'Ascendis Rebuttal, p. 47.
[47] Gatewood Direct, p. 32.
[48] *Id.*, p. 30.
[49] D'Ascendis Direct, p. 10.
[50] *Id.*
[51] *Id.*, p.21.
[52] Gatewood Direct, p. 17; Woolridge Direct, p. 24.

$800 million in senior notes on October 2, 2019.[53] Gatewood agrees that Atmos's proposed capital structure should be adjusted to reflect Atmos's issuance of $800 million in unsecured debt.[54] As Gatewood explained, the new debt issuance increases the balance of Atmos's long-term debt by 22% and since the debt bears a lower interest rate than the interest rate from the test-year, a lower rate of return is appropriate.[55] Gatewood testified that since Atmos has already issued the debt, adjusting its capital structure to reflect the debt is known and measurable and presents a better estimate of Atmos's actual costs going forward.[56]

26. On rebuttal, D'Ascendis argued that if the Commission elects to update the capital structure for post-test year events, it should also adjust the capital structure for all known and measurable post-test year events, including Atmos's two planned equity issuances in 2020, which would result in a capital structure of 58.22% common equity and 41.78% long-term debt.[57] Both Staff and CURB oppose including Atmos's planned 2020 equity issuances in the capital structure. CURB explains that those issuances were not raised in the evidentiary hearing and are not known and measurable.[58] Staff notes the adjustment related to the 2020 issuances is over a year removed from the test year and is not known and measurable.[59]

27. Atmos's concerns that factoring in the 2019 issuances, but not the planned 2020 offerings, would violate the principles of synchronization are not compelling. As Staff points out, all of the other adjustments, including those to plant in service and payroll, are not updated beyond September 30, 2019.[60] Staff argues the Commission should not adopt capital structure that was

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[53] *Id.*, p. 23.
[54] Gatewood Direct, p. 17.
[55] *Id.*
[56] *Id.*
[57] D'Ascendis Rebuttal, p. 14; Post Hearing Brief of Atmos Energy Corporation (Atmos Brief), Jan. 3, 2020, ¶ 23.
[58] Post-Hearing Brief of the Citizens' Utility Ratepayer Board (CURB Brief), Jan. 15, 2020, ¶ 26.
[59] Staff Brief, ¶ 40.
[60] *Id.*, ¶ 42.

updated during the hearing, including projected equity issuances that will not be finalized until 2020, and would not be synchronized with all of the other major elements of Staff's revenue requirement.[61] The Commission agrees.

28. Based on Gatewood's testimony that Atmos used the 2019 new debt to refinance existing short-term debt, rather than replacing long-term debt already accounted for in its long-term debt balances in the test year,[62] the Commission concludes the new debt is not be used to finance new plant and equipment outside of staff's update cutoff.

29. Including the new debt incurred in October 2019 has a significant effect on the Atmos's annual Gas Safety & Reliability Surcharge (GSRS) calculations, which are dependent on the rate of return set in this Docket.[63] Accordingly, failure to include the new debt from 2019 would result in customers paying higher GSRS charges based on an inflated rate of return.[64] This would result in shareholders, rather than customers receiving the benefit of cost savings from the new debt incurred in 2019.[65] Staff's recommended capital structure is within the 50% to 60% equity ratio range targeted by Atmos management.[66] Staff's proposed capital structure is within the range approved in Atmos's other divisions.[67] Therefore, the Commission approves the capital structure of 43.68% long-term debt and 56.32% common equity recommended by Staff and CURB. The parties agree that a 4.37% embedded debt cost is appropriate in this proceeding.[68] Accordingly, the Commission adopts a 4.37% debt cost in this proceeding.

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[61] *See id.*
[62] Gatewood Direct, p. 18.
[63] Staff Brief, ¶ 36.
[64] *Id.*
[65] *Id.*
[66] *Id.*, ¶ 37.
[67] *Id.*, ¶ 38.
[68] Atmos Brief, p. 12, n. 27.

C. SYSTEM INTEGRITY PLAN (SIP)

30. Atmos proposes a five-year pilot, SIP tariff to allow it to accelerate its replacement of obsolete materials in its Kansas underground pipes.[69] In its Post Hearing Brief, Atmos characterizes its proposed SIP as "essentially the same SIP mechanism agreed to by Atmos Energy, Staff, and CURB in Atmos Energy's last general rate case proceeding in the [16-ATMG-079-RTS] docket with one exception; the stipulated SIP in the 079 docket provided for a semi-annual rather than quarterly rate adjustments"[70] That characterization is misleading.

31. On cross-examination, Gary W. Gregory, Atmos's President of its Colorado and Kansas Division, admitted that the current SIP proposal does not include a $75 million cap over five years that was part of the SIP mechanism proposed in the 16-ATMG-079-RTS Docket (16-079 Docket).[71] Similarly, Gregory acknowledged the current SIP proposal does not include the three-year rate moratorium that was a condition of the SIP mechanism from the 16-079 Docket.[72]

32. In 2008, Kansas enacted a monthly Gas System Reliability Surcharge (GSRS) charge to allow natural gas utilities to invest in system integrity and to assist in complying with federal and state safety standards.[73] In 2018, the Kansas Legislature amended the Gas Safety and Reliability Policy Act, doubling the maximum monthly Gas System Reliability Surcharge (GSRS) charge on residential customers from $0.40 to $0.80.[74]

33. Atmos contends that the GSRS process produces an 11-month capital investment lag and does not cover the entire cost of investment for system integrity.[75] Therefore, Atmos believes a SIP mechanism is necessary. Both Staff and CURB oppose the proposed SIP. As Staff

[69] Application, ¶ 8.
[70] Atmos Brief, ¶ 31.
[71] Tr., Vol. 2, p. 257.
[72] *Id.*, p. 264.
[73] Direct Testimony of Gary L. Smith (Smith Direct), June 28, 2019, p. 9.
[74] K.S.A. 66-2204(e)(1); *See also* Smith Direct, p. 9.
[75] Smith Direct, p. 9.

witness Justin Grady testified, Atmos is fully recovering its investments in safety and reliability infrastructure today through the newly expanded GSRS.[76]

34. Staff recommends modifications to Atmos's proposed SIP: (1) capping the recovery of costs of incremental capital improvement at $50 million over five years; (2) beginning on January 1, 2021, and expiring on December 31, 2025; (3) requiring Atmos to file detailed annual SIP Plan Filings to be ruled on by the Commission each November 1; (4) requiring Atmos to make an annual surcharge filing by January 15, each year, with the first being due January 15, 2022; (5) providing only a return on and a return of capital expenditures above the $22 million per year in base safety, reliability, and GSRS-eligible capital expenditures; (6) requiring Atmos to file to renew, amend, or end the program by December 31, 2024; and (7) be accompanied by a three-year rate moratorium.[77]

35. Similarly, CURB explained it would be more amenable to the SIP if it would be: (1) used only after its GSRS is exhausted; (2) used only after taking advantage of depreciation; (3) limited to replacing cast iron or base steel pipeline; (4) updated annually; (5) limited to the monthly surcharge on residential customers to $0.40 per month; and (6) accompanied by a three-year rate moratorium.[78] The major difference between Staff's and CURB's proposed modifications is the size of cap.[79] Staff proposes a $50 million cap over the five-year pilot program, where CURB's proposal to limit the monthly surcharges equates to roughly a $35 million cap over the five-year period.[80]

[76] Direct Testimony of Justin T. Grady, Nov. 4, 2019, p. 15.
[77] *Id.*, pp. 28-29.
[78] CURB Brief, ¶ 40.
[79] *Id.*, ¶ 41.
[80] *Id.*

36. In its Reply Brief, Atmos continues to misstate the character of its proposed SIP. Atmos makes the remarkable claim that, "[f]rom the Company's perspective, it proposed a SIP tariff that was virtually identical to the tariff agreed to between Atmos Energy, Staff, and CURB in the last Atmos Energy rate case and supported by the Staff and the Company in the 343 docket. The only difference is that Atmos Energy proposed a quarterly surcharge mechanism in this docket rather than a semi-annual surcharge mechanism."[81] Atmos then offers up a revised SIP that was not presented to the Commission until after the evidentiary hearing.

37. Under its revised SIP, Atmos proposes a semi-annual surcharge mechanism with a $35 million cap over five years.[82] Atmos's revised SIP appears to address the vast majority of both Staff's and CURB's concerns. The only matter remaining in dispute is the timing of the surcharge. By proposing a semi-annual mechanism, Atmos appears to abandon its initial request for a quarterly surcharge mechanism. At the very least Atmos's proposal proves it does not believe a quarterly surcharge is necessary. Atmos offers no evidence to support a semi-annual surcharge. Instead it simply states, "both Staff and Atmos Energy indicated they could live with a semi-annual surcharge mechanism which was the arrangement incorporated into the 079 settlement."[83] That statement does not provide sufficient justification for the Commission to adopt a semi-annual surcharge. Nor does it recognize the important elements of the 16-079 Docket settlement still missing from Atmos's proposal, notably a three year rate moratorium. Therefore, even though the 16-079 Docket settlement contained a semi-annual surcharge, that is not compelling evidence that a SIP should be collected on a semi-annual basis.

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[81] Reply Brief of Atmos Energy Corporation (Atmos Reply Brief), Jan. 24, 2020, ¶ 19.
[82] *Id.*, Attachment A, p. 1.
[83] Atmos Reply Brief, p. 18.

38. Both Staff and CURB have supported an annual surcharge. Staff's and CURB's recommendations are supported by testimony from Justin Grady and Josh Frantz respectively. Furthermore, an annual surcharge is consistent with how the GSRS is collected. An annual surcharge is also less burdensome for the Commission and its Staff to administer. Since there is no evidence to support Atmos's revised semi-annual surcharge, and based on Atmos's acknowledgment that if the SIP mechanism was denied, it would continue to use the existing rate recovery options, such as the GSRS or rate cases, and more importantly, it would continue to spend and invest in its system and address safety issues without any pause, the Commission denies Atmos's proposed, modified SIP.

39. Both Staff and Atmos favor increasing the pace for replacing obsolete infrastructure.[84] The real dispute between the Staff and Atmos is the method of cost recovery.[85] The Commission is not opposed to a SIP in principle, just the SIP as originally proposed by Atmos. The Commission recognizes the urgent need to replace obsolete pipes, primarily bare steel and cast iron. Therefore, the Commission would approve the amended SIP proposed by Atmos in its Reply Brief, provided it includes: (1) an annual surcharge as suggested by CURB and Staff for replacing obsolete pipes, primarily bare steel and cast iron, and (2) is available only after its GSRS is exhausted; and (3) Atmos accepts a three-year rate moratorium. If after exhausting its GSRS, Atmos wishes to pursue a SIP including a $35 million cap over five years, with an annual surcharge, and a three-year rate moratorium, the Commission urges Atmos to collaborate with CURB and Staff to make a compliance filing, in accord with these conditions through a SIP tariff.

[84] *Id.*, p. 280.
[85] *Id.*, p. 281.

D. INCENTIVE COMPENSATION

40. Atmos claims its employee compensation plan supports and rewards high-performance by its employees, which benefits all stakeholders.[86] Staff recommends removing 100% of Atmos's short term Management Incentive Plan expenses, 50% of the time lapse portion of the Long Term Incentive Plan, and 100% of the expense associated with the Performance Based portion of the Long Term Incentive Plans allocated to Atmos's Kansas operations.[87] CURB recommends removing 100% of Atmos's compensation expenses beyond base salary.[88] Atmos contends that because its total compensation for employees (base pay plus incentive pay) is prudent and reasonable based upon those total salaries being below or at the total salaries paid in the market for similar positions, they should be recovered in rates.[89]

41. Atmos retained James F. Reda, who filed rebuttal testimony on the reasonableness of Atmos's total compensation levels, the competitiveness of Atmos's total compensation program, and the inclusion of incentive compensation in Atmos's cost of service.[90] In his prefiled rebuttal testimony, Reda states that Atmos's compensation levels compare favorably with the competitive market.[91] He reaches that conclusion because Atmos's compensation programs are at the 50th percentile of the marketplace and the incentive programs are tied to financial performance, which benefits all stakeholders.[92]

42. Despite Reda's concern that Atmos would not be able to retain qualified employees without its executive compensation program, on cross-examination, Reda admitted he did not conduct any studies on whether Atmos's ability to attract capital would be affected if the

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[86] Atmos Post Hearing Brief, ¶ 51.
[87] Staff Brief, ¶ 86.
[88] CURB Brief, ¶ 75.
[89] Atmos Brief, ¶ 43(c).
[90] Rebuttal Testimony of James F. Reda, Nov. 18, 2019, p. 3.
[91] *Id.*, p. 8.
[92] *Id.*, p. 28.

Commission disallowed the incentive compensation programs in rates.[93] Similarly, he failed to conduct any surveys of Atmos executives to measure potential turnover if the Commission disallowed the incentive compensation programs in rates.[94]

43. Furthermore, even if the Commission excludes Atmos's compensation plans from rates, the evidence suggests Atmos's shareholders will gladly finance those programs. In his prefiled rebuttal testimony, Reda notes that in 2018, 94% of Atmos's shareholders approved the Company's compensation structure.[95] He argues the shareholder approval demonstrates the executive compensation structure adds value to shareholders and customers.[96] But when asked during cross-examination whether he believes the shareholders vote was influenced by whether they expect ratepayers to bear those costs, Reda answered no.[97] Likewise, when asked if he thought shareholders were concerned with who might be paying for these plans, he again answered no.[98] This is despite the evidence in the record that most of Atmos's jurisdictions disallow some portion of incentive compensation.[99] Therefore, Atmos's own expert implicitly acknowledges that its shareholders are willing to bear the cost of the incentive programs. Accordingly, there is no reason to burden ratepayers with costs, as shareholders have shown are perfectly willing to fund the incentive programs. If shareholders pay for the incentive programs, the incentive programs will continue to allow Atmos to recruit and retain valued employees.

44. Staff does not claim Atmos's compensation levels are unreasonable or imprudent; instead Staff believes Atmos's compensation metrics are too heavily weighted towards its financial

[93] Tr., Vol. 3, p. 549.
[94] *Id.*, p. 550.
[95] Reda Rebuttal, p. 4.
[96] *Id.*
[97] Tr. Vol. 3, p. 551.
[98] *Id.*, p. 552.
[99] Tr., Vol. 3, p. 556.

goals.[100] Staff relies on the Commission's Order in the 10-415 Docket, where the Commission announced its intent to exclude programs that focus on the financial aspect, rather than operational aspects of the business,[101] to argue Atmos's programs should be disallowed. According to Staff, since the 10-415 Docket was issued, the Commission has repeatedly affirmed its decision, notably in the 12-KCPE-764-RTS Docket (12-764 Docket).[102] Therefore, Staff believes the policy to disallow incentive programs that focus on the financial benefits to the utility is settled law.[103] Atmos disagrees.

45. CURB recommends disallowing all incentive compensation expenses over and above base pay, including the financial portion of incentive compensation expenses for non-management employees.[104] In both the 10-415 and 12-764 Dockets, the Commission explicitly rejected CURB's more aggressive incentive compensation argument.[105]

46. The Commission concludes there is no reason to revisit its prior decisions on incentive compensation. Likewise, the Commission concludes there is no reason to revisit its decision announced in the 10-415 Docket to disallow incentive programs that focus on the financial aspect, rather than operational aspects. Accordingly, the Commission reaffirms its intent to disallow the costs of management incentive programs that focus on financial criteria. The Commission adopts Staff's recommendation to remove 100% of Atmos's short term Management Incentive Plan expenses, 50% of the time lapse portion of the Long Term Incentive Plan, and 100% of the expense associated with the Performance Based portion of the Long Term Incentive Plans

[100] Tr. Vol. 3, p. 655.
[101] Direct Testimony of Kristina A. Luke-Fry, Oct. 31, 2019, p. 19.
[102] *Id.*
[103] Staff Brief, ¶ 90.
[104] CURB Brief, ¶ 75.
[105] *See* Order on KCP&L's Application for Rate Change, Docket No. 12-KCPE-764-RTS, Dec. 13, 2012, ¶ 47.

allocated to Atmos's Kansas operations. Pursuant to K.S.A. 77-415(b), the Commission designates this paragraph as precedential.

E. DEPRECIATION

47. There are three primary issues related to the testimonies of each party - net salvage, service lives and depreciation calculation procedure.[106] Ned Allis prepared a depreciation study for Atmos.[107] The study is based on the Equal Life Group (ELG) procedure, which differs from the Average Life Group (ALG) procedure, currently used to calculate depreciation rates for Atmos.[108] Staff witness Roxie McCullar believes the ALG procedure should continue to be used to calculate depreciation rates for Atmos.[109] Additionally, McCullar recommends adjustments to several of Atmos's proposed net salvage rates.[110] McCullar's adjustments would reduce Atmos's proposed Depreciation Rate and Expenses by $2,622,802.[111]

48. CURB's witness, James Garren, proposes lower depreciation rates than Allis due to adjustments to the average service lives used to calculate depreciation rates for seven distribution accounts; and a proposed alternative method of estimating future net salvage, based on the most recent five-year history of the Company's net salvage experience.[112] Garren expresses concerns with Allis's methodology: (1) it produces unrealistically high future net salvage ratios; and (2) second, because net salvage and retirements are not causally related or mathematically correlated in any way, relying on this ratio yields unreliable and unsound results.[113] Therefore, Garren proposes a methodology which utilizes the most recent five-year average of net salvage to

[106] Rebuttal Testimony of Ned W. Allis (Allis Rebuttal), Nov. 18, 2019, p. 1.
[107] Direct Testimony of Ned W. Allis (Allis Direct), June 28, 2019, p. 1.
[108] *Id.*; Staff Brief, ¶ 106.
[109] Direct Testimony of Roxie McCullar (McCullar Direct), Oct. 31, 2019, p. 2.
[110] *Id.*, p. 11.
[111] *Id.*, p. 3.
[112] Direct Testimony of James S. Garren (Garren Direct), Oct. 31, 2019, p. 4.
[113] *Id.*

estimate future net salvage.[114] He estimates total future net salvage by multiplying the annual accrual requirement by the account remaining life.[115] Garren's adjustments would reduce Atmos's proposed Depreciation Rate and Expenses by $2,973,248.[116]

Net Salvage

49. Net salvage is gross salvage less cost of removal.[117] Net salvage is normally negative because cost of removal is typically greater than gross salvage for most accounts.[118] Depreciation rates are designed to recover future net salvage, not what has been recorded in the past.[119] Atmos, Staff, and CURB all propose different net salvage figures.

50. Allis proposes a methodology that calculates a ratio of annual net salvage over retirements, where he examines this ratio in five and ten year periods over the past fifteen years, and factors in the historical data, the age of the plant, managerial expectations, and the experience of other utilities in the industry, to arrive at a net salvage ratio for each account.[120]

51. On rebuttal, Allis claims Staff's and CURB's proposals rely almost entirely on historical data, compared to Atmos's forward looking proposals.[121] Allis accuses Staff and CURB of proposing alternatives that do not fully estimate future net salvage.[122] He argues that unlike Atmos, who has used the industry standard method of estimating future net salvage, Staff and CURB offer methodologies, which have no support from depreciation authorities and which at most have limited acceptance by regulatory commissions.[123] Allis contends that by failing to

[114] *Id.*, p. 34.
[115] *Id.*
[116] *Id.*, p. 36.
[117] Atmos Brief, ¶ 25.
[118] Allis Rebuttal, pp. 6-7, Garren Direct, p. 6.
[119] Allis Direct, pp. 13-14.
[120] Garren Direct, p. 27.
[121] Allis Rebuttal, pp. 1-2.
[122] *Id.*, p. 2.
[123] *Id.*

recover net salvage over the lives of the Company's assets, Staff's and CURB's proposals will produce intergenerational inequity, particularly as Atmos's accelerated pipe replacement program results in higher levels of net salvage.[124]

52. Atmos claims its uses the industry-standard method for analyzing net salvage is to express net salvage (and its components cost of removal and gross salvage) as a percentage or ratio of retirements,[125] whereas CURB's and Staff's methodologies consider the level of net salvage recorded in recent years, not as a percentage of retirements.[126]

53. As the Applicant, Atmos bears the burden of proof on all issues, including depreciation. The record contains several competing expert claims as to the correct methodology for determining the proper net salvage level, and Atmos is unable to prove that its methodology is the *only* methodology that will result in just and reasonable rates. While Atmos claims its methodology is superior to Staff's and CURB's, Atmos's net salvage estimates are not based purely on statistical analyses or historical net salvage amounts expressed as a percentage of retirements. As Allis states in his Direct Testimony, "the net salvage percentages in the Depreciation Study are based on a combination of statistical analyses and informed judgment."[127] Staff's depreciation witness McCullar testifies similarly, "[m]y proposed future net salvage accrual amounts are in current dollars that consider Atmos's historic practices, the impact of inflation, and builds a reserve for reasonable estimated future net removal costs associated with future retirements, based on the type of investments in the account, and my previous experience."[128]

[124] *Id.*
[125] Atmos Reply Brief, ¶ 28.
[126] *Id.*, ¶ 30.
[127] Allis Direct, p. 14.
[128] McCullar Direct, p. 12.

CURB's depreciation witness Garren, stands alone making a recommendation based strictly on the most recent five year average of net salvage.[129]

54. After examining the evidence on the issue of net salvage, the Commission is not convinced that it must adopt a particular methodology as the only "right" approach in this Docket. However, the Commission rejects CURB's methodology because it relies solely on recent historical net salvage experience. Although their methods of determining net salvage differ, Atmos, Staff, and CURB agree that the purpose of a net salvage analysis is to estimate the future level of net salvage that Atmos will incur as part of its depreciation expense. Both Staff and Atmos agree that a net salvage analysis should estimate appropriate levels of future net salvage, not solely rely strictly on historic expense levels. When deciding between Atmos and Staff's net salvage analyses, the Commission finds Staff's approach will best balance the interests of Atmos's current versus future ratepayers. Again, this finding is not based on adopting any particular methodology in this Docket, but that Staff's approach strikes the best balance between current and future ratepayers.

Service Lives

55. On the issue of the appropriate service life estimates for Atmos's assets, Staff and Atmos utilize the same service lives,[130] but CURB recommends longer service lives for seven accounts.[131] Allis claims CURB's proposals are not based on sound methodology and are not consistent with the recommendations of depreciation authorities.[132] Atmos also contends CURB's

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[129] Garren Direct, p 34.
[130] *Id.*, pp. 2-3.
[131] *Id.*, p. 3.
[132] *Id.*

service life proposals do not account for accelerated modernization of infrastructure.[133] Finally, Atmos asserts CURB's approach conflicts with NARUC's guidance on the issue.[134]

56. The Commission agrees with Atmos that Atmos's service life proposals are consistent with both the need to accelerate the modernization of infrastructure, and with the recommendations of depreciation authorities such as NARUC. Therefore, the Commission accepts Atmos's proposed service lives as agreed to by Staff.

ELG versus ALG

57. On the question of whether to use the ELG or ALG procedure, Allis dismisses CURB's position as lacking any support, and Staff's arguments as not standing up to scrutiny.[135] While both ALG and ELG procedures are calculated to recover 100% of the original cost over the life of the plant, the ELG procedure should be adjusted annually and is front-loaded.[136]

58. Atmos acknowledges that adopting Staff's and CURB's recommendations to increase the lives of existing assets and decrease depreciation expense certainly achieves any short-term policy or goal of maintaining lower customer rates, as depreciation expense is the largest revenue requirement adjustment in this rate case.[137]

59. In its Reply Brief, Atmos argues that just because ELG produces higher depreciation rates does not mean that it is unjust and unreasonable and that ALG results in too low of depreciation rates in the early years of the life of property.[138] In doing so, Atmos has not demonstrated the Commission should change from its current process of applying the ALG

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[133] Atmos Reply Brief, ¶ 42.
[134] *Id.*, 45.
[135] *Id.*
[136] McCullar Direct, p. 6.
[137] Atmos Brief, ¶ 42.
[138] Atmos Reply Brief, ¶ 52.

procedures to depreciation rates. Therefore, the Commission declines to deviate from the existing process. The Commission will apply ALG procedures to calculate Atmos's depreciation rates.

F. RATE CASE EXPENSE

60. The Parties agree that utilities are entitled to recover prudently incurred rate case expenses through rates.[139] Staff questions the costs associated with Reda's testimony regarding Atmos's incentive compensation plan and with Quackenbush's testimony regarding the proposed SIP.[140] CURB recommends allowing Atmos to collect its reasonable rate case expense through a three-year normalization.[141] CURB does not define what it considers reasonable rate case expense.

61. Atmos contends it would benefit the Commission to hear the perspective of someone from outside Atmos, who could provide a broader look at SIP-like mechanisms.[142] Therefore, Atmos believes the expenses of Quackenbush, a former regulator who had approved similar mechanisms, are justified for inclusion in rates.[143] The Commission disagrees.

62. As Quackenbush readily admits, he provides testimony on what other states have allowed for ROEs based on RRA reports.[144] He acknowledges that RRA's evaluation are from the perspective of investors.[145] Quackenbush's testimony is premised on his knowledge garnered as a former Michigan Commissioner. Expert testimony is proper if it will be of special help to the factfinder on technical subjects with which the factfinder is not familiar or if it would assist the factfinder in reaching a reasonable factual conclusion.[146] The Commission is capable of interpreting the RRA ratings without the aid of expert testimony. Furthermore, Quackenbush's

[139] Rebuttal Testimony of Jennifer K. Story, Nov. 18, 2019, p. 28; Direct Testimony of Ian D. Campbell, Oct. 31, 2019, p. 6.
[140] Staff Brief, ¶ 163.
[141] CURB Brief, ¶ 101.
[142] Atmos Brief, ¶ 72.
[143] *Id.*
[144] Tr., Vol. 1, p. 210-211.
[145] Quackenbush Rebuttal, p. 15.
[146] *Sterba v. Jay*, 249 Kan. 270, 282 (1991).

testimony substantially overlaps with that of Gary L. Smith and Gary W. Gregory. Under these circumstances, Quackenbush's testimony has little probative value, therefore, the Commission disallows his expenses from rate case expense.

63. Atmos believes Reda's testimony is necessary to show the reasonableness of total compensation paid to Atmos's employees based upon what similar employees are paid in the market.[147] In addition, since Staff did not question the reasonableness of similar testimony in the recent Kansas Gas Service rate case, Atmos assumed Reda's costs were prudently incurred.[148] Staff counters by explaining that Reda's compensation is significantly higher than his counterpart in the Kansas Gas Service rate case.[149] As Justin Grady testified, Kansas Gas Service spent $42,590 on an external consultant for incentive compensation; whereas Atmos spent $79,000, nearly double the amount incurred by Kansas Gas Service.[150] Subsequently, on February 14, 2020, Atmos updated its estimated rate case expense, upping Reda's expenses to $91,368.[151] Reda's expenses are higher than either of the outside attorneys that tried this case and higher than its ROE witness. ROE is a much larger financial piece of Atmos's rate case than incentive compensation.

64. Grady also questions the need for Reda's testimony because he believes Atmos could have used internal employees as it did in its last rate case to testify on incentive compensation.[152] Since Staff's treatment of incentive compensation expense has been consistent since the 10-415 case, Grady sees no need for Atmos to incur the cost of an outside expert on incentive compensation.[153] Grady notes that Gary Gregory is already a witness in this matter and

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[147] Atmos Brief, ¶ 71.
[148] *Id.*
[149] Staff Brief, ¶ 163.
[150] Tr., Vol. 2, p. 483.
[151] Estimated Rate Case Expense, Feb. 14, 2020, p. 1.
[152] Tr., Vol. 2, p. 482.
[153] *Id.*

that Barbara Myers, who is listed by Atmos on its rate case exhibit list as a manager of this filing, and has previously provided testimony on this topic, could have also testified in lieu of Reda.[154]

65. Reda did not prepare any studies for Atmos. Instead, he just reviewed two studies prepared by Pay Governance LLC for the Atmos Energy Board of Directors Human Resources Committee.[155] Both studies conclude that Atmos's total direct compensation levels were at or below the 50th percentile compared to its peer group and published survey data.[156] Since both studies were presented to Atmos back in October 2018,[157] the Commission questions the need to retain Reda to testify on these studies. Despite the Commission's concerns, since Atmos bears the burden of proof, it is entitled to pick a witness it believes will best present its case. Also, since the Commission did not disallow any rate case expense relating to incentive compensation in the recent Kansas Gas Service rate case,[158] it will not disallow all of Reda's expenses. While the Commission elects not to disallow all of Reda's expenses, it finds his expenses excessive and duplicative. Compared to the expenses incurred by Kansas Gas Service and also the expenses incurred by both Atmos's outside attorneys and Atmos's ROE witness, Reda's expenses are excessive. For these reasons, the Commission disallows half ($45,684) of Reda's expenses.

66. Atmos seeks to recover its rate case expense through a one-year surcharge on customer bills, but is willing to agree to a two-year recovery period.[159] CURB recommends allowing Atmos's rate case expenses to be recovered through a three-year normalization of those costs in base rates.[160] Staff opposes Atmos's proposed rate case expense surcharge because it

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[154] *Id.*
[155] Reda Rebuttal, p. 8.
[156] *Id.*, p. 9.
[157] *Id.*, p. 8
[158] *See* Tr., Vol. 2, p. 488.
[159] Atmos Brief, ¶ 73.
[160] CURB Brief, ¶ 101.

believes it will reduce Atmos's incentive to prudently manage its rate case expenses and because it would allow Atmos to recover its rate case expense too quickly.[161]

67. In Atmos's most recent rate case, the Commission ordered it to amortize its rate case expense over three years.[162] Atmos has not provided sufficient justification to change course. Therefore, the Commission finds Atmos should amortize its rate case expense over three years.

G. MONTHLY RESIDENTIAL CUSTOMER CHARGE

68. Currently, Atmos residential customers are charged a monthly fixed charge of $18.04 per month, in addition to paying for the volume of gas they use.[163] Atmos is seeking to increase the monthly fixed charge to $22.00.[164] Staff proposes a smaller increase to $18.89.[165] CURB recommends decreasing the monthly charge to $15.00.[166] CURB arrives at the $15.00 figure by performing a direct customer cost analysis,[167] which produces a residential direct customer cost in the range of roughly $9-$10.[168] Because the current fixed monthly charge is $18.04, CURB witness Watkins considers it excessive.[169] But Watkins stops short of recommending setting the fixed monthly charge at $10 because of gradualism and his assumption that the Commission will want to include some overhead expenses in the fixed charge.[170] Due to those two considerations, Watkins recommends a $15 customer charge.[171] On cross-examination,

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[161] Staff Brief, ¶ 159.
[162] *Id.*, ¶ 160.
[163] The Commission approved a residential fixed charge of $18.91 in Atmos's last rate case, Docket No. 16-ATMG-079-RTS. The $18.91 was reduced to $18.04 due to tax reform and further reduced to $17.72 for the period of April 2018-March 2019, due to the deferred revenue credit. Direct Testimony of Robert H. Glass, Ph.D. (Glass Direct), Oct. 31, 2019, p. 10, Table 4.
[164] Atmos Brief, ¶ 74.
[165] Staff Brief, ¶ 166.
[166] CURB Brief, ¶ 102.
[167] Tr. Vol. 3, p. 660.
[168] *Id.*, p. 661.
[169] *Id.*, p. 662.
[170] *Id.*
[171] *Id.*

Watkins acknowledges that shifting some costs from the fixed monthly charge to a volumetric charge could result in higher bills in cold weather.[172]

69. Atmos witness Paul H. Raab expresses his concern that Atmos faces a significant risk when it has to try to collect fixed costs through volumetric charges[173] because the costs remain fixed and Atmos may not collect enough revenues to meet its authorized rate of return.[174] Dr. Robert H. Glass, the Commission's Chief of Economics and Rates, testified that Atmos is best situated among gas utilities operating in Kansas because it is experiencing customer growth and has a weather normalization adjustment (WNA), which in addition to the weather normalization of the revenue requirement, protects Atmos from weather fluctuations,[175] and therefore, Atmos, should not require a higher customer charge.[176]

70. In Atmos's last rate case, Staff attempted to slow the trend of rising fixed monthly charges, where the fixed charges have increased at a greater rate than the commodity charge.[177] At the same time, Staff acknowledges that fixed costs should be recovered through fixed charges.[178] During the test year, 64% of the residential base rate revenue came from fixed charges.[179] CURB argues that by collecting roughly two-thirds of its residential base rate revenue through fixed charges, Atmos inhibits residential customer's ability to control their bills through conservation.[180]

71. The Commission concludes that an increase of the fixed monthly charge is not warranted based on Atmos's WNA and increasing customer base. At the same time, the

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[172] *Id.*, p. 666.
[173] *Id.*, p. 678.
[174] *Id.*, p. 679.
[175] *Id.*, p. 686.
[176] *Id.*
[177] Glass Direct, p. 21.
[178] *Id.*
[179] *Id.*, p. 22.
[180] Direct Testimony of Glenn A. Watkins, Oct. 31, 2019, p. 27.

Commission is concerned that CURB's recommended $15.00 fixed monthly charge is not supported by competent evidence. The Commission finds that Staff's proposed $18.89 strikes the proper balance between allowing Atmos to collect its fixed costs and providing customers with some ability to manage their gas usage to lower their monthly bills. An $18.89 monthly charge is consistent with Kansas Gas Service's $18.70 and Black Hills Energy's $17.25.[181] Accordingly, the Commission adopts $18.89 as the monthly residential customer charge.

72. On the issue of weather normalization, Atmos agrees to accept Staff's WNA proposal. In doing so, Atmos expresses its desire to work with Staff to develop updated WNA tariffs and future WNA annual filings to incorporate the new classes and weather sensitivity factors.[182] Accordingly, the Commission directs the parties to jointly develop the updated WNA tariffs and future WNA annual filings to incorporate the new classes and weather sensitivity factors. The parties shall file a status update by June 1, 2020 outlining the proposed implementation process for Commission consideration.

H. OTHER RATE BASE AND INCOME STATEMENT ADJUSTMENTS

73. The Commission accepts the following uncontested accounting adjustments:

- Donation Expense (Staff IS-9) ($74,772)
- Other Postretirement Benefits (Staff IS-14) ($68,917)
- Interest on Customer Deposits (Staff IS-7) ($1,102)
- Advertising Expense (Staff IS-8) ($9,605)
- Pension Expense (Staff IS-13) ($65,132)
- Pension Tracker 1 and OPEB Tracker 1 (Staff IS-15) $98,094

[181] Tr. Vol. 3, p. 687.
[182] Rebuttal Testimony of Gary L. Smith, Nov. 18, 2019, p. 24.

- Leases (Staff IS-16) $76,517
- Weather Normalization (Staff IS-17) ($466,047)
- Customer Annualization (Staff IS-18) $119,039
- KCC Annual Assessment Expense (Staff IS-10) ($8,070)
- Customer Deposits (Staff RB-5) $40,502
- Prepayments (Staff RB-6) $62,178
- Storage Gas (Staff RB-7) $527,781

Construction Work in Progress (CWIP)

74. Atmos believes it should be allowed to include the CWIP balance of $1,620,606, in rate base because it has verified the listed projects will be completed and in service by no later than February 2020, within one year from the end of the test year.[183] CURB witness Andrea C. Crane does not believe most of the claimed CWIP were incurred before the end of the test year, and thus should be excluded from rate base.[184] CURB recommends including $1,307,897 of CWIP in rate base.[185] Staff recommends excluding all CWIP not closed to Plant in Service by August 31, 2019 from rate base.[186] Staff's adjustment would remove $11,110,143 from Atmos's rate base.[187]

75. Staff's review of Atmos's workpapers reveals Atmos missed the projected in-service date of approximately 55% of the projects it projected to be placed into service by September 30, 2019.[188] The only evidence that Atmos offers to suggest that projects were expected to be completed by February 2020 is hearsay testimony from Jennifer Story that Bart Armstrong

[183] Atmos Brief, ¶ 52.
[184] Direct Testimony of Andrea C. Crane (Crane Direct), Oct. 31, 2019, p. 11.
[185] *Id.*, p. 12.
[186] Staff Brief, ¶ 124.
[187] Direct Testimony of Brad Hutton, Oct. 31, 2019, p. 5.
[188] Staff Brief, ¶ 128.

verified that the projects listed on a worksheet would be completed by February.[189] Her testimony is not enough to demonstrate the listed projects will be in service by February 2020. Therefore, the Commission approves Staff's adjustment to remove $11,110,143 from Atmos's rate base.

Miscellaneous Expenses

76. Staff recommends disallowing $46,123 of miscellaneous expenses because those dues paid to professional organizations do not directly benefit ratepayers.[190] Atmos counters that only $29,047 should be disallowed because the cost of those licensing fees and membership dues are reasonable, Staff used an incorrect allocation factor, and Staff eliminated some legal expenses that Atmos did not include in its Application.[191] Staff claims to have corrected these errors in its final adjustments, which Atmos did not dispute.[192] Atmos did not present any evidence to rebut Staff's claim that the license fees and membership dues directly benefit ratepayers. Accordingly, the Commission adopts Staff's adjustment and disallows $46,123 of miscellaneous expenses because those dues paid to professional organizations do not directly benefit ratepayers.

Plant, Accumulated Depreciation, Accumulated Deferred Income Tax (ADIT), and Excess Deferred Income Tax (EDIT) Accounts

77. Atmos seeks to update Plant in Service to September 30, 2019, which would increase its rate base by $9,402,791.[193] Staff opposes updating Atmos's balances for Plant in Service beyond August 31, 2019, because nearly every other update to the test year is through August 30, 2019.[194] Staff's adjustment would increase Atmos's rate base by $7,840,069.[195] The

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[189] Tr. Vol 2, p. 525.
[190] Staff Brief, ¶ 118.
[191] Atmos Brief, ¶ 64.
[192] Staff Brief, ¶ 119
[193] Atmos Brief, ¶ 55.
[194] Staff Brief, ¶ 131.
[195] *Id.*, ¶ 130.

Commission adopts Staff's adjustment as it more closely resembles Atmos's ongoing cost of doing business and is synchronized with the vast majority of other adjustments in this Docket.[196]

78. Staff advises that Plant in Service (and thus Depreciation Expense), ADIT, and Accumulated Depreciation need to be updated through the same date to avoid IRS Normalization Violations.[197] Therefore, the Commission finds that ADIT, Accumulated Depreciation, and Depreciation Expense should to be updated through August 31, 2019.

Accumulated Deferred Income Taxes (ADIT)

79. Staff proposed increasing ADIT by $1,081,792, which is an offset to Plant in Service, which decreases rate base.[198] Staff's adjustment is due to: (1) updating ADIT balances to update period of August 31, 2019; (2) remove ADIT associated with pension and FAS 106 costs; (3) remove ADIT associated with Regulatory Liability-Mid Tex; and (4) remove portions of ADIT corresponding to Staff's incentive compensation adjustment.[199] In acknowledging a difference in timing between the recovery of pension and post-retirement benefits in rates and the deduction for this amount on its tax return, Atmos claims that the timing difference is no different than any other timing difference for expense included in rates, and notes Staff has not made this adjustment in previous Atmos rate cases.[200] Atmos admits it mislabeled the Regulatory Liability-Mid Tex balance in its Application but argues that the balance should be included as an adjustment to rate base because it relates to pensions and post-retirement obligations.[201]

80. Staff claims its proposed adjustments to ADIT to remove the ADIT balances associated with pension expenses and FAS 106 costs are necessary to match up the removal of

[196] *See id.*, ¶ 132.
[197] Staff Brief, ¶ 141.
[198] *Id.*, ¶ 136.
[199] *Id.*
[200] Atmos Brief, ¶ 57.
[201] *Id.*, ¶ 58.

pension and FAS 106 costs from rate base.[202] Atmos has not effectively countered this rationale and Ms. Story admits that these balances are not in rate base.[203] Accordingly, the Commission accepts Staff's adjustments to ADIT for this issue. The remainder of Staff's adjustments to ADIT are consistent with its proposal to remove certain incentive compensation expenses from the revenue requirement.[204] Accordingly, since the Commission accepted Staff's proposal to remove certain incentive compensation expenses, it elects to adopt Staff's adjustments to ADIT.

Excess Deferred Income Tax (EDIT)

81. Staff recommends: (1) updating the level of EDIT amortization and Atmos's EDIT regulatory liability to reflect Atmos's most recent revisions to EDIT amounts; (2) removing portions of EDIT that correspond to equity compensation and incentive compensation amounts removed by Staff; and (3) amortizing the before-tax-gross-up EDIT balance to deferred tax expense, as in every single regulated utility rate case filed in Kansas since the implementation of the Tax Cuts and Jobs Act.[205] Staff recommends including $19,346,609 of EDIT regulatory liability and an EDIT amortization amount of ($711,062).[206] Atmos's only dispute with Staff's adjustment is its removal of certain EDIT amounts related to its incentive compensation adjustment. As the Commission has accepted Staff's incentive compensation adjustment, so too does it accept Staff's EDIT adjustment related to incentive compensation. Accordingly, the Commission adopts Staff's adjustments to EDIT.

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[202] Staff Brief, ¶ 139.
[203] Tr. Vol 2, p. 526.
[204] Atmos Brief, ¶ 59.
[205] Staff Brief, ¶ 133.
[206] *Id.*, ¶ 134.

Accumulated Depreciation

82. Staff recommends decreasing Atmos's Rate Base by $2,161,428 to reflect the balance of Accumulated Depreciation through Staff's update period ending August 31, 2019. Staff's proposed adjustment would synchronize the balance of Plant In Service and its corresponding Accumulated Depreciation balances.[207] This adjustment to Accumulated Depreciation ensures ratepayers are given credit for the capital they have returned to Atmos, and therefore, no longer need to pay a return on.[208] Atmos's dispute with Staff appears to revolve around the timing to update the balance. The Commission adopts Staff's adjustment to synchronize Plant In Service and Accumulated Depreciation as of August 31, 2019.

Bad Debt Expense

83. Staff proposes to decrease operating expenses by $27,838 to account for bad debt expense. Staff used a three-year average net bad debt write-off percentage of 0.4004% through year-end August 31, 2019.[209] CURB favors a normalization adjustment that accounts for multiple years and would decrease operating expense by $46,869 to account for bad debt expense.[210] Atmos disputes CURB's and Staff's adjustments. Atmos argues CURB's adjustments are inconsistent with previous Atmos rate cases and will preclude the Company from recovering its actual costs.[211] Other than alleging Staff's methodology of using a three-year average is not consistent with past Commission practice in Atmos dockets, Atmos does not present a compelling reason to reject Staff's adjustment. Therefore, the Commission adopts Staff's adjustment to bad debt expense.

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[207] *Id.*, ¶ 135.
[208] *Id.*
[209] *Id.*, ¶ 146.
[210] CURB Brief, ¶ 93; Crane Direct, Schedule ACC-12.
[211] Atmos Brief, ¶ 63.

Depreciation Expense

84. Staff proposes decreasing annualized depreciation expense by $2,413,239, by increasing Atmos' pro-forma depreciation expense by $303,708 for updates to Atmos' Plant in Service and decreasing Atmos' depreciation expense by $2,716,947 to reflect Staff's recommended depreciation rates.[212] Any adjustment to depreciation expense needs to be synchronized with the updated Plant in Service date.[213] Having already adopted a Plant in Service date of August 31, 2019, the Commission adopts the same date for depreciation expense. Additionally, the Commission ruled above that Atmos' depreciation expense should be calculated using Staff's recommended depreciation rates. Accordingly, the Commission approves Staff's adjustment for depreciation expense.

Payroll Expense and Benefit Expenses

85. Atmos agrees with Staff's recommendation to update payroll and employee benefits expenses through August 31, 2019, but complains Staff's adjustment only included 11 months of the merit increases.[214] CURB recommends increasing payroll expense by $67,818.[215] Atmos also disagrees with CURB's payroll tax adjustment, claiming it mistakenly assumes that taxes are paid at the statutory rates.[216] Atmos seeks to add a 0.25% (one-twelfth of 3%) of the annualized merit increase to Staff's adjustment, which would increase payroll expense by $96,868 and increase employee benefit expense by $30,456.[217]

86. The Commission rejects Atmos' approach to calculating a full 12 months of merit increase because it multiplies the full year of payroll expense by 1.5%, when half of the months in

[212] Staff Brief, ¶ 150.
[213] *Id.*, ¶ 151.
[214] Atmos Brief, ¶ 60.
[215] CURB Brief, ¶ 92; Crane Direct, Schedule ACC-8.
[216] Atmos Brief, ¶ 60
[217] *Id.*

the test year already includes the potential 3.0% merit increase.[218] Additionally, Atmos's approach assumes that there are no hires, fires, or promotions since the test year. Staff's update, ending August 31, 2019, includes 12 months of actual known and measurable payroll expense that contains the changes to the test year payroll Atmos attempted to include in the cost of service. Accordingly, the Commission accepts Staff's adjustments.

87. Staff proposes decreasing operating expense by $202,065, by updating Atmos's benefits expense to account for actual expenses incurred by Atmos for the 12-months ending August 31, 2019.[219] CURB proposes a $26,847 increase in employee benefit expenses.[220] Atmos disputes CURB's adjustment to employee benefit expenses. The Commission rejects Atmos's adjustment because it is not based on actual known and measurable amounts, and is merely an estimate of how benefits expenses can change with changes to payroll expenses. Therefore, the Commission accepts Staff's adjustment which relies on known and measurable information, and more closely match Atmos's current cost of service.

Lobbying/Membership dues/Meals & Entertainment/SERP expenses

88. CURB asserts certain activities are not necessary for the provision of safe and adequate service and seeks to disallow up to 50% American Gas Association (AGA) dues expense not related to lobbying,[221] 50% of Atmos' request for meals and entertainment expenses not deducted from taxes,[222] and 100% of Atmos's supplemental executive retirement plan (SERP) expenses.[223] Staff does not contest Atmos's expenses in these areas. While K.S.A. 66-1,206(a) allows the Commission to disallow 50% of utility dues, donations and contributions to charitable,

[218] Staff Brief, ¶ 154.
[219] *Id.*, ¶ 157.
[220] Crane Direct, Schedule ACC-10.
[221] Atmos Brief, ¶ 65.
[222] CURB Brief, ¶ 100.
[223] Crane Direct, Schedule ACC-11.

civic and social organizations and entities, and not specific dues, donations and contributions which are found unreasonable or inappropriate, the Commission does not find that CURB has shown the challenged expenses are unreasonable or inappropriate. In addition, the Commission has already accepted Staff's adjustments to miscellaneous expenses, which removes various expenses that do not provide direct ratepayer benefits. Therefore, the Commission denies CURB's proposed adjustments for lobbying, membership dues, meals and entertainment, or SERP expenses.

Abbreviated Rate Case

89. Pursuant to K.A.R. 82-1-231(b)(3)(A), Atmos seeks to file an abbreviated rate case within 12 months of this Order.[224] The abbreviated rate case would be designed to update rates to reflect new non-growth revenue infrastructure investment that is not included in rates and is not eligible for recovery under Atmos's GSRS tariff or SIP tariff but will have been placed in service by the time the audit of the abbreviated filing is completed.[225] Staff argues because Atmos will fully recover its increase in safety, reliability, and GSRS-eligible Net Plant through the GSRS and SIP mechanism, an abbreviated rate case is unwarranted.[226] The Commission agrees. As discussed in paragraph 39, the Commission would approve a SIP with additional conditions, including a three-year rate moratorium. If Atmos elects to make a compliance filing with a SIP tariff, it will render its request for an abbreviated rate case moot. In the event that Atmos does not make a compliance filing, its request for an abbreviated rate case is denied.

90. Atmos requested a net revenue increase of $7,163,131. The Commission finds Atmos is entitled to a net revenue reduction of $223,953. Under Atmos's original request, the

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[224] Application, ¶ 9.
[225] *Id.*
[226] Staff Brief, ¶ 84.

average residential ratepayer's bill would have increased by $4.33 in winter months and $3.41 in summer months.[227] But under this Order, the average residential ratepayer's bill will only increase by $0.35 in winter months and $0.11 in summer months.[228] The slight increase in residential ratepayer's bills is designed to reduce the continued subsidization of the residential class, which represents about 72% of total base rate revenue collected,[229] by the commercial sales class, and bring the classes closer to parity.[230]

91. The Commission considered all of the evidence in the record and considered the positions and arguments of all the parties in making its findings and conclusions. The failure to specifically address a particular item, position, or argument offered into evidence does not indicate it was not considered by the Commission.

THEREFORE, THE COMMISSION ORDERS:

A. The Commission sets Atmos's overall revenue requirement based on an operating income of $14,780,974, a rate base of $242,313,526, a return on equity of 9.1%, and an overall rate of return of 7.03%. The Commission approves a base rate revenue requirement increase of $3,067,466. After accounting for the reduction of the GSRS charge by $3,291,419, the net impact on customers of this Order is a revenue requirement reduction of $223,953.[231]

B. Atmos's proposed SIP mechanism is rejected, but the Commission would approve a SIP tariff for a SIP with a $35 million cap over five years, and with an annual surcharge, three-year rate moratorium, and is available only after Atmos exhausts its GSRS, if sought by Atmos.

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[227] *See* Direct Testimony of Paul H. Raab (Raab Direct), June 28, 2018, p. 24.
[228] *See* Glass Direct, p. 26, Table 11.
[229] *Id.*, p. 19.
[230] *See id.*, p. 20; Raab Direct, p. 26.
[231] *See* Attachment A to the Order for an overview calculation of the revenue requirement increase.

C. Pursuant to K.S.A. 77-415(b), paragraph 46 of this Order is designated precedential. Accordingly, this Order will be included in the Commission's index of precedential orders, published on the Commission's website.

D. The corresponding rate increases shall be set in accordance with the Commission's Final Revenue Requirement Calculation, attached as Attachment A. The Commission's Final Revenue Requirement Calculation is based on Staff's filed schedules and revised in accordance with the Commission's decisions on the contested issues.

E. Any party may file and serve a petition for reconsideration pursuant to the requirements and time limits established by K.S.A. 77-529(a)(1).[232]

F. The Commission retains jurisdiction over the subject matter and parties to enter further orders as it deems necessary.

BY THE COMMISSION IT IS SO ORDERED.

Duffy, Chair; Albrecht, Commissioner; Keen, Commissioner

Dated: 02/24/2020

Lynn M. Retz

Lynn M. Retz
Executive Director

BGF

[232] K.S.A. 66-118b; K.S.A. 77-503(c); K.S.A. 77-531(b).

ATMOS ENERGY
COMMISSION ORDER
SUMMARY OF ADJUSTMENTS TO RATE BASE
FOR THE TEST YEAR ENDED MARCH 31, 2019

	DESCRIPTION	AMOUNT
RATE BASE PER APPLICANT		248,709,964
	ADJUSTMENTS TO RATE BASE ACCEPTED BY THE COMMISSION	
STAFF-1	Removal of Construction Work in Progress	(11,110,143)
STAFF-2	Update of Plant to August 31, 2019	7,840,069
STAFF-3	Update of Accumulated Depreciation to August 31, 2019	(2,161,428)
STAFF-4	Update of Accumulated Deferred Income Tax to August 31, 2019	(1,081,792)
STAFF-5	Update Customer Deposits to August 31, 2019	40,502
STAFF-6	Update Prepayments to a 13 month average ending to August 31, 2019	62,178
STAFF-7	Update Storage Gas balances to August 31, 2019	527,781
STAFF-8	Update certain tax items from the Company's estimated to actuals	(513,605)
TOTAL ADJUSTMENTS TO RATE BASE		(6,396,438)
COMMISSION ADOPTED RATE BASE		242,313,526

ATMOS ENERGY
COMMISSION ORDER
SUMMARY OF ADJUSTMENTS TO OPERATING INCOME
FOR THE TEST YEAR ENDED MARCH 31, 2019

DESCRIPTION		AMOUNT
OPERATING INCOME PER APPLICANT		12,798,524
ADJUSTMENTS TO OPERATING INCOME ACCEPTED BY THE COMMISSION		
STAFF-1	Payroll expense for 12 months ending August 31, 2019	(75,433)
STAFF-2	Payroll tax update (See Adj. No. 1)	49,345
STAFF-3	Benefit expense for 12 months ending August 31, 2019	202,065
STAFF-4	Equity Compensation Expense	559,029
STAFF-5	Depreciation Expense--Staff Depreciation Rates	2,413,239
STAFF-6	Bad Debt Expense	26,358
STAFF-7	Interest on Customer Deposits	1,102
STAFF-8	Advertising	9,605
STAFF-9	Donations	74,772
STAFF-10	Kansas Corporation Commission Assessment fees	8,070
STAFF-11	Miscellanous expenses	46,123
STAFF-12	Rate Case Expense	(323,667)
STAFF-13	Pension Expense Update through August 31, 2019	65,132
STAFF-14	OPEB Update through August 31, 2019	68,917
STAFF-15	Pension and Post Retirement tracker balances	(98,094)
STAFF-16	Lease Expense	(76,517)
STAFF-17	Weather Normalization	(466,047)
STAFF-18	Customer Annualization	119,039
STAFF-19	Income Tax Expense	(620,588)
TOTAL ADJUSTMENTS TO OPERATING INCOME		1,982,449
OPERATING INCOME ADOPTED BY THE COMMISSION		14,780,973

ATMOS ENERGY
COMMISSION ORDER
REVENUE REQUIREMENT CALCULATION
FOR THE TEST YEAR ENDED MARCH 31, 2019

LINE NO.	DESCRIPTION	AMOUNT
1	RATE BASE AS ADOPTED	242,313,526
2	RATE OF RETURN ON RATE BASE AS ADOPTED (1)	7.03%
3	NET OPERATING INCOME REQUIRED	17,034,641
4	PROFORMA OPERATING INCOME	14,780,973
5	DIFFERENCE	2,253,668
6	INCOME TAX FACTOR	0.734700
7	PROFORMA REVENUE INCREASE / (DECREASE)	3,067,466

(1) COMMISSION APPROVED CAPITAL STRUCTURE:

DESCRIPTION	CAPITALIZATION RATIO	COST OF CAPITAL	WEIGHTED COST OF CAPITAL
**********************	***********	******	*********
LONG TERM DEBT	43.68%	4.37%	1.91%
EQUITY	56.32%	9.10%	5.12%
TOTALS	100.00%		7.03%

I/A

CERTIFICATE OF SERVICE

19-ATMG-525-RTS

I, the undersigned, certify that a true copy of the attached Order has been served to the following by means of electronic service on 02/24/2020.

JAMES G. FLAHERTY, ATTORNEY
ANDERSON & BYRD, L.L.P.
216 S HICKORY
PO BOX 17
OTTAWA, KS 66067
Fax: 785-242-1279
jflaherty@andersonbyrd.com

SHELLY M BASS, SENIOR ATTORNEY
ATMOS ENERGY CORPORATION
5430 LBJ FREEWAY
1800 THREE LINCOLN CENTRE
DALLAS, TX 75240
shelly.bass@atmosenergy.com

JARED GEIGER, SR RATE ANALYST
ATMOS ENERGY CORPORATION
1555 BLAKE ST STE 400
DENVER, CO 80202
jared.geiger@atmosenergy.com

JOSEPH R. ASTRAB, ATTORNEY
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
j.astrab@curb.kansas.gov

TODD E. LOVE, ATTORNEY
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
t.love@curb.kansas.gov

DAVID W. NICKEL, CONSUMER COUNSEL
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
d.nickel@curb.kansas.gov

SHONDA RABB
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
s.rabb@curb.kansas.gov

DELLA SMITH
CITIZENS' UTILITY RATEPAYER BOARD
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3116
d.smith@curb.kansas.gov

PHOENIX ANSHUTZ, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3354
p.anshutz@kcc.ks.gov

COLE BAILEY, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3354
c.bailey@kcc.ks.gov

I/A

CERTIFICATE OF SERVICE

19-ATMG-525-RTS

BRIAN G. FEDOTIN, GENERAL COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3354
b.fedotin@kcc.ks.gov

ROBERT VINCENT, LITIGATION COUNSEL
KANSAS CORPORATION COMMISSION
1500 SW ARROWHEAD RD
TOPEKA, KS 66604
Fax: 785-271-3354
r.vincent@kcc.ks.gov

JAMES H JEFFRIES IV, PARTNER
MCGUIREWOODS LLP
201 NORTH TRYON STREET
SUITE 3000
CHARLOTTE, NC 28202-2146
jjeffries@mcguirewoods.com

/S/ DeeAnn Shupe
DeeAnn Shupe

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219
Outstanding Long-Term Debt
For the test year ended December 31, 2018
(Dollars in 000's)

E-1 Item 34A

PS DR 165-1 - Item 34a (Updated as of February 29, 2020 for the latest calendar year end (December 31, 2019))

Line No.	Type Obligation (Bonds, Debentures, Notes, etc.)	Issue Date	Maturity Date	Amount O/S (in thousands)	Coupon Rate	12/31/2019 Cost Rate to Maturity %	Net Proceeds to Duke Cost Rate* Cost Rate At Issue %	Bond Rating @ Issue Date Moody's	Bond Rating @ Issue Date S & P
1	First Mortgage Bond Taxable	10/02/91	09/15/21	$ 100,000	8.625%	8.625%	8.694%	A2	A
2	First Mortgage Bond Taxable	09/11/03	09/15/33	$ 200,000	6.125%	6.125%	6.306%	A3	BBB
3	First Mortgage Bond Taxable	03/22/05	04/01/35	$ 200,000	5.700%	5.700%	5.780%	A3	BBB
4	First Mortgage Bond Taxable	03/13/08	04/01/38	$ 325,000	6.300%	6.300%	6.379%	A2	A-
5	First Mortgage Bond Taxable	09/15/11	09/15/21	$ 500,000	3.000%	3.000%	3.096%	A1	A
6	First Mortgage Bond Taxable	05/18/12	05/15/22	$ 500,000	2.800%	2.800%	2.901%	A1	A
7	First Mortgage Bond Taxable	05/18/12	05/15/42	$ 500,000	4.100%	4.100%	4.181%	A1	A
8	First Mortgage Bond Taxable	03/12/13	03/15/43	$ 500,000	4.100%	4.100%	4.187%	A1	A
9	First Mortgage Bond Taxable	03/06/14	03/30/44	$ 400,000	4.375%	4.375%	4.421%	Aa2	A
10	First Mortgage Bond Taxable	11/20/14	12/01/44	$ 500,000	4.150%	4.150%	4.214%	Aa2	A
11	First Mortgage Bond Taxable	08/13/15	08/15/25	$ 500,000	3.250%	3.250%	3.339%	Aa2	A
12	First Mortgage Bond Taxable	08/13/15	08/15/45	$ 700,000	4.200%	4.200%	4.275%	Aa2	A
13	First Mortgage Bond Taxable	09/16/16	10/15/46	$ 450,000	3.700%	3.700%	3.756%	Aa3	A
14	First Mortgage Bond Taxable	09/08/17	09/08/20	$ 300,000	floating	2.065%	variable	Aa3	A
15	First Mortgage Bond Taxable	09/08/17	09/15/47	$ 500,000	3.600%	3.600%	3.649%	Aa3	A
16	First Mortgage Bond Taxable	08/09/18	09/01/23	$ 300,000	3.375%	3.375%	3.452%	Aa3	A
17	First Mortgage Bond Taxable	08/09/18	09/01/28	$ 500,000	3.700%	3.700%	3.756%	Aa3	A
18	First Mortgage Bond Taxable	03/07/19	03/15/29	$ 600,000	3.450%	3.450%	3.553%	Aa3	A
19	Pollution Control Bond backed by FMB	06/06/13	06/01/41	$ 48,485	4.000%	4.000%	4.024%	A1	A
20	Secured - Accounts Receivable Securitization	12/20/13	02/22/21	$ 195,000	floating	2.584%	variable	n/a	n/a
21	Secured - Accounts Receivable Securitization	12/20/13	02/22/21	$ 130,000	floating	2.551%	variable	n/a	n/a
22	Unsecured - Term Loan	12/14/18	12/31/20	$ 700,000	floating	2.510%	variable	n/a	n/a
23	Commercial Paper LTD		03/16/24	$ 150,000	market	1.779%	variable	n/a	n/a
24	LGIA - Friesian Holdings, LLC	06/06/19	12/29/23	$ 10,000	5.420%	5.420%	5.420%	n/a	n/a
25	Capital Lease - Harris E&E Center	04/01/01	04/01/51	$ 1,832	8.915%	8.915%	8.915%	n/a	n/a
26	Capital Lease - PEB Building	08/24/77	11/30/43	$ 10,233	8.500%	8.500%	8.500%	n/a	n/a
27	Capital Lease - PNG Transport Wayne Pipeline	06/01/12	05/31/32	$ 103,094	13.948%	13.948%	13.948%	n/a	n/a
28	Capital Lease - NCEMC	07/01/12	02/01/45	$ 18,135	8.443%	8.443%	8.443%	n/a	n/a
29	Finance Lease - Asheville CC Pipeline	03/04/19	03/03/39	$ 173,297	12.336%	12.336%	12.336%	n/a	n/a
30	Unamortized Debt Discount/Premium			$ (16,600)				n/a	n/a
31	Unamortized Debt Issuance Costs			$ (40,307)				n/a	n/a
32	Less: Current portion of LTD			$ (1,005,825)					
33	Long-Term Portion of Debt			$ 8,052,345					
34	Long-Term Debt (including current maturities)			$ 9,058,170					

Note: Totals may not foot due to rounding.

Reconciliation to Regulatory Cap Structure

Less	Capital Leases / LGIA Friesian	$ (316,591)
	Current Maturities	$ (1,000,000)
	Unamortized Debt Discount/Premium, Current	
	Unamortized Debt Issuance Costs	$ 40,307
	Debt for Regulatory Cap Structure	$ 7,781,885

Notes:
Capital leases are excluded from regulatory capital structure for DEP. Both interest & depreciation on the leases are included in O&M expense instead. Account 181 - Unamortized Debt Expense is included in rate base, and therefore, is excluded from regulatory capital structure.

Total First Mortage Bonds $7.575 Billion
Total Long Term Debt Excluding Leases $8.741
First Mortgage Bonds 86.7% (7.575 ÷ 8.741)

I/A

Doss Spanos Riley Rebuttal Public Staff Cross-Examination Exhibit 5

Public Staff 98

NCUC Form E-1
Item No. 23, 33d & 38
Page 1 of 1

Duke Energy Progress
Docket No. E-2, Sub 1219
For the test year ended December 31, 2018
Financial Forecast

Financial Data

Line			2019		2020		Projected ($ in Millions) 2021		2022		2023
	Capital Requirements										
	Construction Costs										
	Production Facilities	$	766	$	389	$	643	$	833	$	809
	Transmission Facilities	$	210	$	228	$	159	$	341	$	239
	Distribution Facilities	$	632	$	611	$	657	$	724	$	736
	General Facilities	$	146	$	103	$	100	$	101	$	26
1	Construction Costs (Note A)	$	1,755	$	1,332	$	1,558	$	1,999	$	1,810
2	Nuclear Fuel Costs (Note A)	$	126	$	189	$	162	$	169		133
3	Equity component of AFUDC	$	69	$	31	$	31	$	48	$	72
4	Long-Term Debt, Capital Stock Retired or Reacquired (Note B)	$	600	$	1,000	$	600	$	500	$	300
5	Changes in Working Capital	$	883	$	322	$	437	$	391	$	392
6	Other, Including Dividends		2		1		(0)		(0)		(0)
7	Total Capital Requirements	$	3,435	$	2,874	$	2,788	$	3,107	$	2,707
8	Provided by Internal Cash		71%		101%		89%		86%		105%
	Sources of Capital										
	Internal Cash										
9	Depreciation and Amortization	$	1,455	$	1,452	$	1,607	$	1,638	$	1,674
10	Other (Note D)	$	989	$	1,444	$	887	$	1,034	$	1,164
11	Total Internal Cash	$	2,444	$	2,896	$	2,494	$	2,672	$	2,837
12	Outside Financing	$	975	$	(22)	$	294	$	435	$	(130)
13	Total Sources of Capital	$	3,419	$	2,874	$	2,788	$	3,107	$	2,707
	Tentative Financing Program										
14	Long-Term Debt (Note B)	$	1,250	$	900	$	900	$	950	$	700
15	Preferred Stock		-		-		-		-		-
16	Common Stock		-		-		-		-		-
17	Infusion From/(To) Parent		-		(925)		(575)		(525)		(800)
18	Net Change in Short Term Debt		(275)		3		(31)		10		(30)
19	Total	$	975	$	(22)	$	294	$	435	$	(130)
	Capital Structure (Note C)										
20	Capitalization	$	18,235	$	18,040	$	18,669	$	19,613	$	20,395
	Ratios (Note C)										
21	Long-Term Debt		48%		48%		48%		48%		48%
22	Preferred Stock		0%		0%		0%		0%		0%
23	Common Stock		52%		52%		52%		52%		52%

A Only the debt component of AFUDC is included in these costs.

B Includes current maturities related to long-term debt.
Current maturities at year end are $1,000 in 2019, $600 in 2020, $500 in 2021 and $300 in 2022.

C "Capitalization" and "Ratios" exclude short-term debt.

D "Other" includes earnings, net deferred taxes and investment tax credits and other miscellaneous items.

Request:

4. Item 7 of Public Staff Data Request No. 156 contains a typo with respect to its current bond rating. As such, please provide an estimate of the basis point increase for its first mortgage bonds if Duke Energy Progress, LLC experiences a one-notch debt rating downgrade from a "A2" rating by Moody's Investors Services. For this answer, please assume what is considered to be a normal or typical period in the bond market.

Response:

In a relatively normal or typical period in the bond market, an A2 (issuer rating) / Aa3 (senior secured rating) utility similar to DE Progress would be expected to price up to 10 basis points wider as an A3 (issuer rating) / A1 (senior secured rating) utility. Please note that the pricing of bonds at different credit ratings can be impacted by a variety of factors including unique supply and demand factors the day of issuance. Additionally, greater differences can be expected during periods of dramatic market volatility where investors have more uncertainty on the credit quality and ability for issuers to potentially meet future commitments.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 166

Docket No. E-2, Sub 1219

Date of Request:	**March 12, 2020**
Date of Response:	**March 20, 2020**

[ ] **CONFIDENTIAL**

[X] **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No. 166-4, was provided to me by the following individual(s): Luke A. Governale, Treasury Director, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

I/A

DUKE ENERGY PROGRESS

Doss Spanos Riley Rebuttal Public Staff Cross-Examination Exhibit 7

Public Staff 100

Docket No. E-2, Sub 1219
North Carolina Retail Operations
ARO-RELATED COAL ASH REVENUE REQUIREMENTS
COMPANY VS. PUBLIC STAFF

SUMMARY FOR DEP
INCLUDES DIFFERENCES DUE TO IMPRUDENCE
DISALLOWANCES AND EQUITABLE SHARING

Prepared by Mike Maness
Director Public Staff
Accounting Division

Estimated Balance at **8/31/2020** **$ 293,101** **(000s Omitted)**

Year	Public Staff Recommended Revenue Requirement	Company Proposed Revenue Requirement (inc. Return on Rate Base)	Difference	Cumulative Difference
1	$ 10,896	$ 111,262	$ (100,367)	$ (100,367)
2	10,896	105,534	(94,638)	(195,005)
3	10,896	99,806	(88,910)	(283,915)
4	10,896	94,077	(83,182)	(367,096)
5	10,896	88,349	(77,453)	(444,550)
6	10,896	-	10,896	(433,654)
7	10,896	-	10,896	(422,758)
8	10,896	-	10,896	(411,862)
9	10,896	-	10,896	(400,966)
10	10,896	-	10,896	(390,071)
11	10,896	-	10,896	(379,175)
12	10,896	-	10,896	(368,279)
13	10,896	-	10,896	(357,383)
14	10,896	-	10,896	(346,487)
15	10,896	-	10,896	(335,592)
16	10,896	-	10,896	(324,696)
17	10,896	-	10,896	(313,800)
18	10,896	-	10,896	(302,904)
19	10,896	-	10,896	(292,008)
20	10,896	-	10,896	(281,113)
21	10,896	-	10,896	(270,217)
22	10,896	-	10,896	(259,321)
23	10,896	-	10,896	(248,425)
24	10,896	-	10,896	(237,529)
25	10,896	-	10,896	(226,634)
26	10,896	-	10,896	(215,738)
27	10,896	-	10,896	(204,842)
Total	$ 294,187	$ 499,029	$ (204,842)	

DUKE ENERGY PROGRESS

Docket No. E-2, Sub 1219
North Carolina Retail Operations
ARO-RELATED COAL ASH REVENUE REQUIREMENTS
COMPANY VS. PUBLIC STAFF

DEP PROPOSED REVENUE REQUIREMENT

Estimated Balance at 8/31/2020 $ 440,115 (000s Omitted)
Beginning-of-Year Amortization Assumption

Year	Beginning Balance	Amortization	Amortization Grossed Up	Unamortized Balance	ADIT Balance	Balance for Return	Revenue Requirement Level Return	Total Revenue Requirement
1	$ 440,115	$ 88,023	88,349	$ 352,092	$ (81,577)	$ 270,515	$ 22,913	$ 111,262
2	352,092	88,023	88,349	264,069	(61,183)	202,886	17,185	105,534
3	264,069	88,023	88,349	176,046	(40,788)	135,258	11,457	99,806
4	176,046	88,023	88,349	88,023	(20,394)	67,629	5,728	94,077
5	88,023	88,023	88,349	-	-	-	-	88,349

SETTLED ROR (PRE_TAX)

	Cap	Cost Rates	Weighted ROR	Gross-Up	Pre-Tax ROR
Debt	0.4800000	0.0404495	0.0194157	0.9963091	0.0194877
Equity	0.5200000	0.09600000	0.0499200	0.7654709	0.0652148
Total	1.0000000		0.0693357		0.0847025

Duke Energy Progress
Docket No. E-2, Sub 1219

North Carolina Retail Operations

ARO - RELATED COAL ASH REVENUE REQUIREMENTS DIFFERENCES
COMPARED TO INCREASED FINANCING COSTS

Year		(a) (Millions) Long Term Debt Issuances	(b) Basis Point Interest Rate Increase	(c) (Millions) Annual Interest Paid Increases
2020		Already Issued		
2021		$900 (1)	.10% (2)	$ .900 (3)
2022		$950 (1)	.10% (2)	$ .950 (3)
2023		$700 (1)	.10% (2)	$ .700 (3)
	Total	$2.550 Billion		$2.550

Year	(d) (Millions) Cumulative Interest Paid Increase	(e) (Millions) Public Staff Revenue Requirement Difference Annual	(f) (Millions) Cumulative Public Staff Revenue Requirement Difference
2021	$ .900	$100.357 (4)	$100.357
2022	$1.850	$94.638 (4)	$194.995
2023	$2.550	$88.910 (4)	$283.905

Reduction of Annual Revenue Requirement vs. Additional Interest

Year	(g) (Millions) Revenue Requirement Difference	(h) (Millions) Cumulative Interest Increase	(i) (Millions) Revenue Requirement Reduction
2021	$100.357	$ .900	$99.457 (5)
2022	$94.638	$1.850	$92.788 (5)
2023	$88.410	$2.550	$86.366 (5)
		Total	$278.611

Footnote

(1) DEP E-1 Item 38 Line 14 Long-Term Debt Issuances Filed October 30, 2019.

(2) DEP Response to Public Staff Data Request 166, Item 4, ten basis point financing increase if DEP downgraded First Mortgage Bond Moody's Credit Rating from Aa3 to A1.

(3) (a) times (b) equals (c)

(4) Public Staff Rebuttal Cross Examination Exhibit No. _____ titled ARO - RELATED COAL ASH REVENUE REQUIREMENTS COMPANY VS. PUBLIC STAFF

(5) (g) less (h) equals (i)

Doss DEP Supplemental Exhibit 1

I/A

Below is a listing of actvities considered for closure of Ash Basins

Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
Basin Closure Planning Activities:					
1	Engineering Analysis	Preliminary Engineering analysis to develop high level basin closure plans; this includes documentation requested/required by DEQ	ARO	§ 130A-309.212.(a)	
2	Detailed engineering plans	Detailed engineering plans, drawings and estimates to develop the basin closure plan	ARO	§ 130A-309.212.(a)	
3	Groundwater wells to determine water flow	Installation of groundwater wells, to determine the direction of the flow of ground water, used in the development of closure plans	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	
4	Permitting activities	Costs to produce and submit documentation to obtain required permits	ARO	§ 130A-309.203.	
5	Closure plans	Labor to produce closure plans for submission to regulatory bodies	ARO	§ 130A-309.212.(a)	
6	Public meetings	Labor cost to plan/attend public meetings as required to obtain permits and closure plan approvals	ARO		
7	Corporate Communication	Community outreach and education/corporate communication	O&M	NA	*These costs are not required to comply with law*
8	Groundwater wells monitoring	Installation of groundwater wells, monitoring of results and 30 year maintenance	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	*Excludes secondary source wells and other wells that are not installed for the purposes of monitoring ash basins (such as wells drilled to monitor coal piles and gypsum stacker pads)*
9	Letter(s) of credit (3rd party) as needed		N/A	N/A	*Cannot be charged to ARO; rather would be considered for inclusion in determining the credit-adjusted risk-free rate used for discounting*
10	Engineering studies	Detailed engineering studies to support ARO/Regulatory estimates (internal or external)	ARO		
10-a	EPRI - Coal ash recycling technology and market study	Detailed coal ash recycling/beneficial reuse study required by CAMA	ARO		
11	Ash disposal/placement - "Tipping" fees at landfills	Costs to place materials at off-site or 3rd party owned landfills	ARO	§ 130A-309.212.(a)(1)a.&b.	
12	Charah Termination Fee	Fees to be paid to Charah in the event Duke does not meet the minimum ash storage tonnages, as identified in the contracts	ARO		*Note: CCP Organization would have to demonstrate these were prudently incurred*
13	Donations to counties or municipalities	Donations, charitable or otherwise in conjuction with ash contractual arrangements, not specified as an ash placement fee.	Other		*These costs shall be charged to 426.1 Donations expense*
14	ABSAT Team/Overhead (Hamrick)	Burdened labor allocated to ash basin closure (including expenses)	ARO	§ 130A-309.212.(a)	
15	General EH&S Activities	Compliance and research	ARO	§ 130A-309.212.(a)	
16	Program of record	Development of written program of record	ARO	§ 130A-309.212.(a)	
17	Finance support	Major Projects Finance	ARO	§ 130A-309.212.(a)	
18	Insurance Claim (Support)	Additional finance resources for pulling together coal ash-related insurance claims- time allocated for insurance claim support cannot be charged to ARO, and should be charged to Cap/O&M as appropriate. Insurance proceeds will be netted against Cap/ O&M accounts initially charged for claim support labor, and any insurance proceeds exceeding time charged to Cap/O&M accounts will be credited back to ARO Reg Asset, reducing customer receivable	CAP/ O&M		
19	Supply Chain support	Procurement, contract administration	ARO	§ 130A-309.212.(a)	
20	Project controls oversight	Monitor, control, report, and communicate status of Project scope, schedule, and cost. The PCS works with the PM to provide financial, schedule, and / or risk analyses throughout the lifecycle of the Project.	ARO	§ 130A-309.212.(a)	

Doss DEP Supplemental Exhibit 1

I/A

Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
21	Contractor review of beneficial reuse	Contractor hired to review and make recommendation on the bid proposals we received on benefical reuse. CAMA required that Duke solicit bids to enhance our beneficial reuse of ash.	O&M		*This activity is similar to preliminary studies where we haven't yet selected the contract, but when the actual implementation of a contract for beneficial reuse is utilized for the removal of ash , then those costs can be recorded as an ARO.*
22	Landfill - Operating plant	Construction of landfill including permit, land acquisition, design - for disposal of production ash and future dry ash only	CAP	§ 130A-309.208.	*Please note - Subtitle D will have closure requirements of the landfill - once the landfill is constructed an ARO to close that landfill must be recorded.*
23	Landfill - Retired plant	Construction of landfill including permit, land acquisition, design - for disposal of existing ash	ARO	§ 130A-309.212.(a)(1)b.	
24	Landfill - Operating plant - combined use	Construction of landfill including permit, land acquisition, design - for disposal of existing wet and future dry ash combined	ARO	§ 130A-309.212.(a)(1)b.	*Includes Gallagher LF expansion engineering analysis/ infrastructure development*
25	Landfill cell closure	Applies to landfills that fall under CCR/ CAMA/ State-specific closure requirements	ARO	§ 130A-309.212.(a)(1)a.	
26	Movement of non-basin historical ash into landfill	Ash found on-site (non-production ash) and moved into on-site landfills, essentially used as fill material to close the landfill	ARO		
27	Post closure maintenance	Post closure maintenance of landfills as required by law	ARO	§ 130A-309.212.(a)(1)a.	Section 257.104(c) of CCR
28	Build Haul roads	Construction of haul roads to/from ash basin	ARO	§ 130A-309.212.(a)(1)a.&b.	
29	Duke labor costs	Duke labor, including burdens and expenses per Duke policy	ARO	§ 130A-309.212.(a)(1)a.&b.	
30	EPC Staff		ARO	§ 130A-309.212.(a)(1)a.&b.	
31	Engineering Procurement & Construction Management		ARO	§ 130A-309.212.(a)(1)a.&b.	
32	Safety Staff		ARO	§ 130A-309.212.(a)(1)a.&b.	
33	QA/QC Plan Development and Execution		ARO	§ 130A-309.212.(a)(1)a.&b.	
34	Field Construction staff		ARO	§ 130A-309.212.(a)(1)a.&b.	
35	Stabilization activities:	Dam stabilization to support timing/approach of basin closure (ex. Animal holes, large vegetation removal (e.g., trees))	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
36	Dam breaching	Activities to prevent dam from breaching	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
37	Dike butrous		ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
38	Erosion control	Ex. "rip rap" - which is a temporary structure that is removed after subsequent phases to stabilize and prevent erosion	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
39	Material relocation/ grading		ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure. This can be a dam stabilization activity and can also be associated with other CCP work.*
40	Seed/mulch area		ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure. This can be a dam stabilization activity and can also be associated with other CCP work.*
41	Sheet Piling	Structural stabilization of dam walls	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
42	Valves on settling ponds	These slide gate isolation valves provide the site with the ability to control flow into the weir boxes, which then discharges into the river or other body of water. During an emergency event, these slide gate isolation valves are used to stop the flow from the ash basin to the river, which helps to mitigate the risk of an unpermitted environmental discharge.	ARO	§ 130A-309.212.(a)(4)	*Supports operation/stabilization of basin or dam until timing of closure.*
43	Import fill/excavate fill or clay/dirt backfill		ARO	§ 130A-309.212.(a)(4)	*This can be a dam stabilization activity and can also be associated with other CCP work.*
44	Dewatering/Dewatering plan	Includes removal or grout of old stormwater pipes to the ash basin to stop water flow into basin	ARO	§ 130A-309.212.(a)(1)	*This includes the temporary System for ROB-121 which is a project to eliminate the discharge flow*
45	Dust Control		ARO	§ 130A-309.212.(a)	
46	Excavation of ash ponds/stacks/materials	*includes excavation on in scope ponds that are removed to build retention ponds*	ARO	§ 130A-309.212.(a)(1)b.	
47	Fill pond area and grade to drain		ARO	§ 130A-309.212.(a)(1)	
48	Grout fractured rock		ARO	§ 130A-309.212.(a)(4)	
49	Loading and hauling of ash materials		ARO	§ 130A-309.212.(a)(1)a.&b.	
50	Mobilization/demobilization	Mobilization and demobilization of work crews and projects on site (includes on site trailers)	ARO	§ 130A-309.212.(a)(1)a.&b.	

Doss DEP Supplemental Exhibit 1

I/A

Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
51	Rail Loading and unloading		ARO	§ 130A-309.212.(a)(1)a.&b.	
52	Rail heads and spur construction	Includes renovation, rail transportation and/or rail leases	ARO	§ 130A-309.212.(a)(1)a.&b.	*ARO accounting is precedent over lease accounting*
53	Remove wetlands		ARO	§ 130A-309.212.(a)(1)a.&b.	
54	Restore ash stack area and cinder pit area		ARO		
55	Site stormwater controls	including redirection of storm and waste water **as required to close basin**	ARO	§ 130A-309.208.(c)& (d)	
56	Redirection of water from CC/CT sites	Redirection of water that is currently running into ash ponds that need to be dewatered. Includes new piping and avoids continuing to flow water into basin	ARO	§ 130A-309.208.(c)& (d)	
57	Synthetic capping	"cap in place"	ARO	§ 130A-309.212.(a)(1)a.	*More detail may be needed on technologies*
58	Truck wash/rail wash stations		ARO	§ 130A-309.212.(a)(1)a.&b.	
59	Truck/weigh scales	Scales used for weighing ash, including scales located on and off Duke property	ARO	§ 130A-309.212.(a)(1)a.&b.	
60	Vacuum wells		ARO	§ 130A-309.212.(a)(1)a.&b.	
61	Extraction wells and groundwater monitoring	Installation of extraction wells to pump the groundwater to arrest the off-site migration. Includes treatment of the pumped groundwater as needed to meet standards and returned either to the ash basin or the discharge canal. Maintain operation of wells until cleared by DEQ.	ARO		*Required by DEQ*
62	Coal Combustion Products Organization - Overhead allocated to ash basin closure:				
63	CCP Staff - burdened labor including expenses	Burdened labor allocated to ash basin closure (including expenses)	ARO		
64	General EH&S Activities		ARO		
65	Supply Chain function - procurement, contract admin		ARO		
66	Finance support, Major Projects Finance	Direct cost support including contract support, project support, budget support and financial support	ARO		
67	Project controls oversight	Direct project controls support including contract support, project support, budget support and financial support	ARO		
68	Governance & Ops Support (Kerin)	Burdened labor allocated to ash basin closure (including expenses)			
69	Quality Compliance and Oversight	This organization performs quality assurance and control activities to support the CCP & ABSAT organizations for ash basin closure. Responsible for field verification and report closeout. This team supports both ash basins and cooling ponds and activities can be easily segregated.	ARO		
70	Regulatory Affairs Filing and Support	This organization ensures that CCP/CAMA regulatory requirements are implemented, tracked and documented. They are tasked with maintaining the operational record by facility and submittal of documents to the regulator as required.	ARO		
71	Governance & Ops Support	This organization develops and documents the System Owner and business processes, including emergency preparedness and response.	O&M		*Corporate based support*
72	Organization Effectiveness	This organization is the internal controls for operations - responsible for human performance, Corrective Action Program (CAP or "root cause"), performance reporting and self-assessments.	O&M		*Corporate based support*
73	Emergency Preparation Plan Development	Development of Emergency Action Plans (EAPs) across CCP fleet for CCR units classified as high or significant hazard potential, in accordance with CCR Rule.	O&M		
74	Engineering (related to as basins/in scope impoundments) (Renner):				
75	CCR Related engineering – post April 17th	Burdened labor allocated to ash basin closure (including expenses)	ARO		
76	CCR Activities prior to April 17th, including engineering studies specific only to CCR		O&M		

Doss DEP Supplemental Exhibit 1

I/A

Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
77	Project Engineering		ARO		
78	Outsourced engineering services		ARO		*Note: includes services of National Ash Management Advisory Board (NAMAB)*
79	Configuration Management		ARO		
80	Regional Engineering Services		ARO		
81	Geotechnical Engineering		ARO		
82	Project Management & Implementation (Emergent projects related to ash removal – Murray)				
83	Project initiation – Ash ponds and landfills		ARO		
84	Development of scope documents		ARO		
85	Project Controls	Scheduling and Estimating, Cost Management	ARO		
86	Project Managers, direct labor and expenses	Effective leadership and accountable for project outcomes	ARO		
87	Project Portfolio management		ARO		
88	Groundwater monitoring wells installation	- CAMA requirements	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	
89	Groundwater monitoring wells installation	- capturing results, analysis and required reporting – CAMA	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	
90	Groundwater wells	– 30 year post monitoring maintenance	ARO	§ 130A-309.209, § 130A-309.212.(a)(3)b.	
91	Groundwater Additional Source Wells (NC)	Wells to be drilled outside of basins (such as coal piles, gypsum storage areas and cooling ponds) in order to test for coal ash constituents. Data will be provided to NCDEQ in the Comprehensive Site Assessment.	ARO		*Wells are needed in order to provide sampling data to the NCDEQ- closure cannot be completed without these additional source wells*
92	Operations & Maintenance Activities (related to ash basins/in scope impoundments – Weisker):				
93	Plant demolition activities	Final dismantlement of generation plant	COR		
94	*By Products and Reagents Technical Support		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
95	*Vegetation management on ash basins and landfills		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
96	*QA field testing on CCR	This activity includes compaction of fill to meet standards	ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
97	Daily/Weekly/Monthly Inspections (vendor vs. "System Owners")		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
98	Visual observations of leak detection system		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
99	Camera inspection of leachate header and sumps		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
100	Inspect landfill features: leachate, sumps, conveyance system, E&SC structures, dust control and storm water control		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.* Please note that ARO cost treatment excludes GIB-156 project (leachate re-route that ties into plant FGD processes) in which installation should be charged as capital and maintenance of the system should be charged as O&M
101	Inspect for erosion, weeds, and other vegetation		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
102	Removal of trees greater than 2 inches in diameter		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
103	Mitigation of animal burrows	Basin stability for timing of closure	ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
104	Clean out of LCS Leachate header pipes and sumps		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
105	Annual topographic survey and capacity analysis		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
106	Annual Operational Report preparation and submittal		ARO	§ 130A-309.212.(a)(3)b.	* *Need to quantify non-incremental and incremental portion.*
107	Wet CCR Ash Basin Support	– daily logs, water levels discharge, water samples	O&M	NA	
108	Regulatory reqmnts and permit maint – solid waste		O&M	NA	
109	Purchase of mowers to comply with CAMA/CCR		ARO	§ 130A-309.212.(a)(3)b.	
110	Clarifying pond maintenance	This activity includes the annual maintenance, such as pond dredging, for ponds. These are not ash basin ponds	O&M	NA	
111	Operations and Maintenance Manuals (by station)	Detailed documentation of all of the Ash Basin facilities at each site of the inspection, operating and monitoring requirements	O&M	NA	
112	Repairs to landfill caps not subject or required by CCR	Repairs to existing assets, not intended for dam stabilization (ex. Pine Hall Road Landfill at Belews Creek)	O&M	NA	

Doss DEP Supplemental Exhibit 1

I/A

Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
113	Dam breaching for purpose of new plant construction	Dam breaching/ ash excavation and compaction of soil to required 90% density= ARO; incremental compaction over 90% requirement= Capital	CAP/ARO		** Need to quantify non-incremental and incremental portion.*
114	<u>Non-Ash Basin Management:</u>				
115	Vegetation management for cooling ponds and other non-ash areas		O&M		
116	Gypsum Stacker Pad Construction		CAP		
117	Calibration of truck scales (for gypsum)		O&M		
118	Preparation and submittal of annual reports		O&M		
119	Fly ash silo unloading, equipment maintenance, inspection and calibration		O&M		
120	Haul road monitoring and maintenance	Maintenance/Repairs of haul roads- O&M. Activities such as paving may qualify for Capital treatment (capital project is subject to normal capitalization rules- see Company's Capitalization Policy).	CAP/ O&M		
121	Cooling Pond maintenance (Phase 4/5 - no ash in pond)		O&M		
122	Air quality projects – permits		O&M		
123					
124	**Operating Plant conversion requirements:**				
125	Dry Fly Ash or Bottom Ash Handling Conversion	– modifications to plant equipment	CAP	§ 130A-309.208.(e)	
126	Dry bottom ash handling	– wet rim ditch alternate solution	CAP	§ 130A-309.208.(f)	*Required for continued operation of plant - avoid if closing plant*
127	Dry bottom ash handling	– submerged flight conveyor system	CAP	§ 130A-309.208.(f)	
128	Retention pond and related new piping	Constructed in order to support the on-going operations of an operating plant to be used to accumulate storm water and waste water streams that would not have sufficient CCR material to be considered a location subject to the CCR retirement closure requirements. Includes projects for repurposing the basin into a retention pond where the work being performed does not relate to ash excavation or closing the basin (for example- installation and removal of a sheet pile wall where the wall is not needed for basin closure but rather to support the repurposing project).	CAP		*Required for on-going operations at the plant site for storm and wastewater streams.*
129	Ash Pond Level Instrumentation	Instruments to provide remote monitoring to detect surface water levels in the ponds, which will be communicated to a central server system for monitoring.	CAP/ ARO		*Active Plant- Capital; Retired Plant- ARO*
130	Transmission lines/towers located in ash basins	Costs to construct new relocated line/tower = capital; cost to remove tower in order to close basin = ARO	CAP/ARO		*Capital project is subject to normal capitalization rules.*
131	Transmission and Distribution Related Activities	Costs relating to the contruction of new assets to support on-going T&D activites- Capital. Costs to remove T&D assets to support basin closure- ARO.	CAP/ARO		*Capital project is subject to normal capitalization rules.*
132	Contact Water Management	Costs related to contact water management and/ or loss of containment events that are not part of the basin closure projects	O&M		

Doss DEP Supplemental Exhibit 1

I/A

Ln#	Activity	Long Description	Charge Category	CAMA/CCR Rule reference (Note 1)	Comments
	Other:				
133	Groundwater remediation	Environmental remediation activity	Environ Res		*Note: This would apply to plants without a closure obligation*
134	Bottled water to residents	Providing bottled water to residents	ARO		*Required by HB630- temporary supply until residents are permanently connected to a municipal water line*
135	Beneficial reuse (not Asheville)	Projects promoting public health and environmental protection, offering equivalent success relative to other alternatives, and preserving natural resources	ARO	§ 130A-309.212.(a)(1)b.	
136	Beneficiation Facilities	Includes Engineering Analysis and Construction	ARO		*Required per HB 630- supports closure timing and risk ranking*
137	NC CAMA - Regulatory fee	*"shall only be used to pay the expenses of the Coal Ash Management Commission and the DEQ in providing oversight of coal combustion residuals." (Fee = 0.03% of NC revenues for DEP/DEC)*	Other	§ 62-302.1.	*Prohibits the NCUC/SCPSC from allowing utilities to recover this fee*
138	Land purchases for groundwater remediation	Duke will purchase property adjoining our plants with contaminated groundwater to remediate groundwater	ARO		
139	Land purchases due to fugitive landfill dust	Duke will purchase property adjoining our plants due to fugitive dust coating neighboring properties from the construction of a landfill (Cliffside)	Other		*Note: Until the land is re-purposed and is used and useful for plant operations, this shall be charged to FERC account 121 (Nonutility property)*
140	Permanent Connections to (Municipal) Water Supply	Costs of providing permanent, alternative water supplies to neighbors **within a half mile of ash basin compliance boundaries** by Oct 2018. ARO activities include the following: Costs incurred to connect households to the water lines or to install whole house filtration systems, reimbursements to homeowners for installation of water filtration system or connection to municipal water system after receiving Do Not Drink letters (prior to passage of HB630), Payments to periodic maintenance on whole house filter systems, Water Testing for residents within a half mile of the basins in order to determine if the appropriate water filter is in place	ARO		*Required per HB 630- supports risk rankings and closure method Note: costs chargeable to ARO for all residents of the Misty Waters community in Belmont, NC*
141	Permanent Connections to (Municipal) Water Supply for residents across a body of water	**Groundwater testing for all residents across the body of water is chargeable as ARO.** If testing/data shows that groundwater is flowing underneath the river and contamination is present, permanent water source connections are chargeable to ARO. If no contamination is present, connections to permanent water supply should be charged as O&M.	ARO/ O&M		*Pertains to Asheville residents located across the French Broad river*
142	Compensation Packages to Homeowners within a half mile of ash basins	Goodwill payment (currently estimated to be $5,000 per household), stipend for 25 years of water bills, Property Value Protection Plan (PVPP) program costs through 10/2019	O&M		
143	Data gap wells	Groundwater monitoring wells which would support both ash basin closure and a secondary source monitoring (data gap wells). In order to be ARO, basis needs to be supported by comprehensive site assessment and corrective action plan. If this information is not present, should be treated as O&M or capital.	ARO / O&M / Capital		

Note 1: Please note, as of current, this is not an all-inclusive list

Jessica L. Bednarcik
Stipulated Exhibits from DEC Evidentiary Hearing
(Rebuttal)

Duke Energy Progress, LLC
Docket No. E-2, Sub 1219

IN THE UNITED STATES DISTRICT COURT
FOR THE EASTERN DISTRICT OF NORTH CAROLINA

UNITED STATES OF AMERICA	)	
	)	**CASE NOS:**
	)	
V.	)	**5:15-CR-67-H-2**
	)	**5:15-CR-68-H-2**
	)	**5:15-CR-62, 67 & 68**
DUKE ENERGY CAROLINAS, LLC;	)	
DUKE ENERGY PROGRESS, LLC; AND	)	
DUKE ENERGY BUSINESS SERVICES, LLC	)	

SEMI-ANNUAL REPORT ON CLOSURE AND EXCAVATION ASHEVILLE, DAN RIVER, RIVERBEND, AND SUTTON

JULY 31, 2019

Semi-Annual Report on Closure and Excavation
Asheville, Dan River, Riverbend, Sutton
July 31, 2019

In compliance with the plea agreements for Duke Energy Carolinas, LLC ("DEC"), Duke Energy Progress, LLC ("DEP"), and Duke Energy Business Services, LLC ("DEBS"), this report provides the Court Appointed Monitor ("CAM") a detailed description of Duke Energy's efforts to facilitate the excavation of coal ash and the closure of all of the impoundments at the Asheville, Dan River, Riverbend, and Sutton sites. Duke Energy submitted an initial excavation plan to the North Carolina Department of Environmental Quality ("NCDEQ") on November 13, 2014, which detailed the first 12–18 months of projected ash basin excavation activities. Each year, Duke Energy provides an updated plan that highlights the completed milestones and provides the status of necessary permits. The most recent Excavation Plans were submitted to NCDEQ on December 11, 2018. This report serves as a progress report for those critical milestones set forth in the Excavation Plans and provides in-depth information on the processes implemented at each site.

The prior Semi-Annual Excavation Report was submitted to the CAM on January 31, 2019. This Excavation Report provides an update of the sites' activities up to June 30, 2019.

I. Asheville Steam Electric Generating Plant

The Asheville Steam Electric Generating Plant is located in Arden, NC, approximately eight miles south of Asheville, NC. The Plant's Unit 1 was constructed in 1964 with a second coal- burning unit (Unit 2) added in 1971. Current generation capacity of the Plant is 376 megawatts (MW) from the two coal-fired units. In 1999 and 2000, two natural gas and oil combustion turbines with an additional output of 324 MW were added.

The Plant had two ash basins. The first basin was created in 1964 when the Plant began operation and is currently being excavated (1964 Ash Basin). In 1982, a second basin (1982 Ash Basin) was constructed directly adjacent to the 1964 Ash Basin's south retention dam. The 1982 Ash Basin was excavated, verified clean, and turned over for construction of the natural gas combined-cycle plant in September 2016. Decommissioning of the 1982 Ash Basin Dam (BUNCO-89) was completed in January 2018.

Duke Energy's Coal Combustion Residuals Removal Verification Procedure (Removal Verification Procedure) was used to verify that primary source ash was removed from the 1982 Ash Basin. Subsequent to removal of the ash pursuant to the Removal Verification Procedure, Duke Energy implemented its Excavation Soil Sampling Plan ("ESSP"), which was developed for meeting the applicable performance standard. Although not required under the Coal Ash Management Act of 2014 ("CAMA"), in November 2016, NCDEQ sent Coal Combustion Residuals Surface Impoundment Closure Guidelines for Protection of Groundwater to Duke Energy instructing the Company to submit the ESSP to NCDEQ as part of the site's excavation plan.

The 1964 Ash Basin Dam (BUNCO-097) was constructed in 1964 to serve as a wastewater treatment facility for the treatment of ash sluice water. The surface area of the basin is approximately 45 acres. The basin does not retain a permanent pool with the exception of a three-acre unlined retention pond known as the "Duck Pond" and the lined Center Pond that is part of the rim ditch system described below.

Production ash is sluiced to a concrete rim ditch system that is located within the footprint of the 1964 Ash Basin. The rim ditch system also receives plant stormwater drainage and low volume wastewater from the Duck Pond. Coal Combustion Residuals ("CCR") are dredged from the rim ditch, dewatered, and transported off-site. Asheville ash is a non-hazardous material.

The wastewater is treated in the rim ditch system and then pumped through the Center Pond filters (constructed at the end of the rim ditch) to a settling pond outside of the 1964 Ash Basin. The settling pond serves as the monitoring point for Outfall 001 of the Plant's National Pollutant Discharge Elimination System ("NPDES") permit NC0000396.
Treated wastewater discharged from this settling pond is routed to the French Broad River in accordance with the terms and conditions of the NPDES permit.

During the period January 1, 2019 – June 30, 2019, approximately 396,598 tons of ash have been excavated and transported off-site. As of June 30, 2019, approximately 6,612,061 million tons of ash have been excavated from the Asheville site. Dewatering of the ash basins and the removal of ash from the site continues to be performed within project phases. The project has completed Phase I and has been planning and implementing Phase II.

The following items in Phase I have been completed:

1. Excavation and closure of the 1982 Ash Basin.
2. Design and construction of alternate treatment methods for FGD process water to replace engineered wetlands process.
3. Decommissioning, excavation, and transportation of the FGD engineered wetlands in the 1964 Ash Basin to an approved RCRA Subtitle D landfill.
4. 1982 Ash Basin dam decommissioning and grading material into former 1982 Ash Basin footprint to facilitate the construction of the natural gas-fired plant.
5. Initiation of the 1964 Ash Basin ash excavation and transportation.

Phase II Scope

1. Submit and obtain permits for Phase II activities.
2. Excavate and transport approximately 2 million tons of ash from the 1964 Ash Basin, including newly generated ash.
3. Evaluate, design, and construct the wastewater treatment system and water equalization basin for utilization after plant and rim ditch retirement.
4. Maintain lowered water state of the Duck Pond and implement 1964 Ash Basin dewatering plan.
5. Continue to validate production rates to meet project requirements and

increase efficiency.

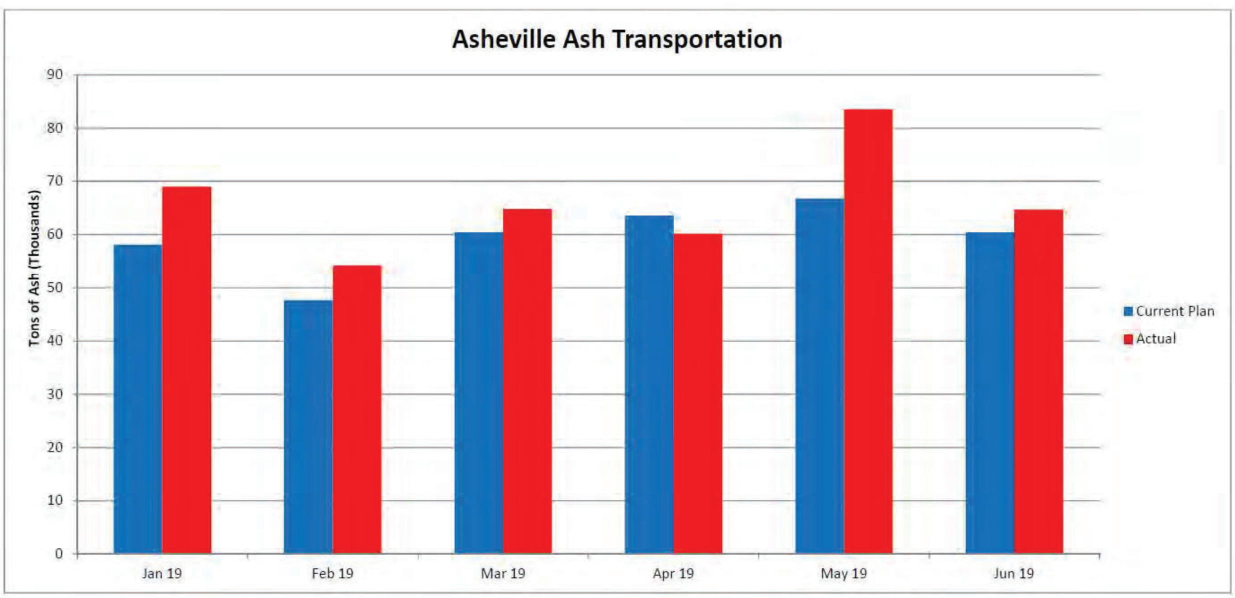
6. Gain knowledge and opportunities for program improvement that can be applied to the subsequent phase(s).
7. Plan activities for Phase III.

Phase III Scope

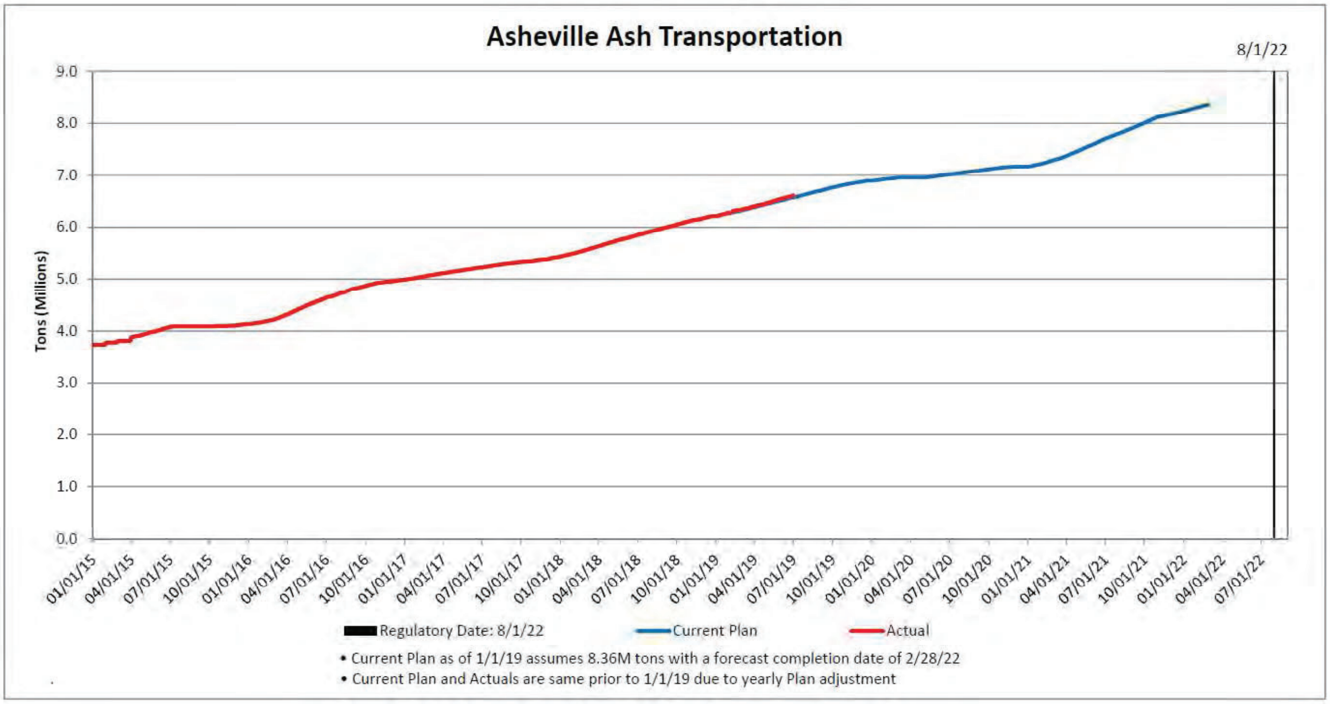
1. Prepare remaining required permit applications for subsequent phase(s) of ash removal activities (if applicable).
2. Decommission and remove the 1964 Ash Basin rim ditch.
3. Continue to manage wastewater with the on-site wastewater treatment system.
4. Excavate and transport the remaining ash from the 1964 Ash Basin to an approved landfill or structural fill location.
5. Initiate 1964 Ash Basin dam decommissioning to remove ash commingled material in the dam.
6. Complete closure activities for the 1964 Ash Basin.

The charts below track the tonnage of ash transported from January 1, 2019 to June 30, 2019 and from January 2015 to completion.

Ash Transported Off Site in Thousands of Tons | January 1, 2019 to June 30, 2019



Ash Transported Off Site in Millions of Tons | January 2015 to February 2022



Critical Milestones within the Plan are summarized in the table below.

MILESTONES	NO LATER THAN DATE	STATUS
Submit Excavation Plan to NCDEQ	November 15, 2014	Completed November 13, 2014
Complete Comprehensive Engineering Review	November 30, 2014	Completed November 30, 2014
Receive Dam Safety Permit to excavate 1982 Ash Basin dam face	December 12, 2014	Received approval June 25, 2015
Excavation Plan acknowledgment from NCDEQ	February 17, 2015	Received February 2, 2015
Receive updated Distribution of Residual Solids Permit	February 28, 2015	Received Final Permit September 2, 2015
Decommission engineered wetlands and commission alternate FGD wastewater treatment system	November 3, 2015	Completed FGD wastewater conveyance to sewer October 28, 2015
Submit Updated Excavation Plan to NCDEQ	November 15, 2015	Completed November 13, 2015
Dewater and remove engineered wetlands	March 2, 2016	Completed on May 13, 2016 with no impact on final completion schedule
Complete removal of ash from 1982 Ash Basin (except interim storage of production ash)	July 31, 2016	Completed September 30, 2016
Submit Updated Excavation Plan to NCDEQ	December 31, 2016	Completed December 21, 2016
Submit Updated Excavation Plan to NCDEQ	December 31, 2017	Completed December 1, 2017

Submit Updated Excavation Plan to NCDEQ	December 31, 2018	Completed December 11, 2018
Cease Operation of coal-fired units at the Asheville Plant	January 31, 2020*	On Track
Impoundments closed pursuant to Part II, Sections 3(b) and 3(c) of CAMA	August 1, 2022*	On Track
Submit Updated Excavation Plan to NCDEQ	December 31, Annually	On Track

* Pursuant to the North Carolina Mountain Energy Act of 2015

Erosion and Sediment Control Plan

Asheville Plant permits allow for the excavation and transportation of ash on existing paved roads and within the ash basins during excavation. Any new construction supporting ash basin closure will be in compliance with applicable erosion and sediment control permits.

Dewatering Plan

The 1964 Ash Basin is currently void of free-standing water, except for the Duck Pond and for the lined Center Pond (part of the rim ditch system). Stormwater and process water flows into the Duck Pond are captured and pumped to the head of the rim ditch wastewater treatment system within the footprint of the 1964 Ash Basin. The treated wastewater continues to flow to the permitted NPDES Outfall 001. In July 2018, the site commenced interstitial dewatering of the 1964 Ash Basin. At the time, the site was operating under an administratively extended NPDES Wastewater Permit and, at the direction of NCDEQ, was required to pretreat interstitial wastewater prior to discharging it into the rim ditch system. This additional pretreatment is not required under the new NPDES Wastewater Permit, which went into effect on December 1, 2018. After the coal plant and rim ditch retirement, a water equalization basin and a new wastewater treatment system will be required to complete dewatering of the 1964 Ash Basin.

Location(s) for Removed Ash

Ash removed from the site will be transported by the contractor to permitted facilities. The ash disposal location(s) will be managed and maintained to ensure environmental compliance with all applicable rules and regulations. Ash from the 1964 Ash Basin is currently being transported to a permitted ash monofill at the R&B Landfill in Homer, Georgia. Plans for ash disposal during Phase III are currently being evaluated and will be finalized in 2019. The on-site landfill at Duke Energy's Rogers Energy Complex remains an option. Discussion and evaluation of the construction of an on-site landfill at the Asheville Plant is ongoing with NCDEQ.

Transportation Plan

Ash is currently being transported from the site via highway trucks to the R&B Landfill in Homer, Georgia. Truck loading operations are conducted with a crew working typically 12 hours per day, five days per week. Transportation is conducted by approved transporters and meets Department of Transportation ("DOT") and other applicable federal, state, and local regulations.

Environmental and Dam Safety Permitting Plan

Excavation of ash creates potential for stormwater impacts. The site is operating under an NPDES Industrial Stormwater Permit ("ISW") issued on May 24, 2016. As required by the ISW, the site has an active Stormwater Pollution Prevention Plan ("SPPP") implemented November 2016 and updated August 2017. Throughout most of 2018, the facility operated under an administratively extended NPDES Wastewater Permit. The facility was issued a new NPDES Wastewater Permit in Q4 2018, which included modifications to facilitate the closure of the 1964 Ash Basin. The new NPDES Wastewater Permit went into effect on December 1, 2018.

If the Company constructs any treatment basins or conducts grading related to construction activities within the 1964 Ash Basin footprint, an approved Erosion and Sediment Control Plan and a Buncombe County Post-Construction Stormwater Permit may be required. There are no jurisdictional wetlands/streams associated with the removal of ash in the 1964 Ash Basin in Phase II.

All necessary Dam Safety approvals have been or will be obtained to cover activities on or around jurisdictional dikes. Any impacted monitoring wells or piezometers will be abandoned in accordance with NCDEQ requirements. Fugitive dust will be managed to mitigate impacts to neighboring areas. Additional site-specific or local requirements will be secured, as needed.

Permit Matrix

MEDIA	PERMIT	RECEIVED DATE (R) TARGET DATE (T)	COMMENTS
Water	NPDES Industrial Stormwater Permit	May 24, 2016 (R)	The site has two active SPPP.
	NPDES Wastewater Permit Renewal	Q4 2018 (R)	Became effective December 1, 2018.
	Jurisdictional Wetland and Stream Impacts / 404 Permitting and 401 WQC	N/A	No impacts to jurisdictional wetlands and streams have been identified at this time.
	Erosion and Sediment Control Plan	April 1, 2020 (T), if needed	Permit may be required for grading activities.
	Buncombe County Post-Construction Stormwater Permit	April 1, 2020 (T), if needed	Permit may be required for any basin construction or grading activities.

Dam Safety	Dam Decommissioning Request Approval	Complete June 25, 2015 (R) and July 1, 2016 (R) Q4 2019 (T) for 1964 Ash Basin dam decommissioning	Dam Safety Permits to excavate ash from the interior face of the 1982 Ash Basin dam and the 1964 Separator Dike were received on June 25, 2015 and July 1, 2016, respectively. A permit for decommissioning of the 1964 Ash Basin dam will be required and has been submitted to NCDEQ.
Other Requirements	Site-Specific Nuisance/Noise/ Odor/Other Requirements, including DOT	October 28, 2015 (R)	During Phase I, the Company received an Industrial User Permit on June 13, 2015 to discharge the FGD wastewater into the Metropolitan Sewerage District system. As noted above, this activity was completed on October 28, 2015.

Site Progression of the Excavation Process at the Asheville Steam Electric Generating Plant

1982 Basin in February 2015 When Project Began

Finalization of 1982 Basin Excavation in September 2016

Aerial View February 2015

Aerial View September 2016

Aerial View November 2018

Asheville – June 2019

II. Dan River Steam Station

The Dan River Steam Station is located in Rockingham County near Eden, NC. The Plant operated from 1949 until retirement of the coal-fired units in 2012. Upon retirement of the coal-fired units, a new 620 MW gas-fired unit began operation.

The Primary Ash Basin was constructed in 1956, with an embankment crest elevation of 523.5 feet mean sea level (msl). In 1968, the basin embankment crests were raised to elevation 530 feet msl and extended in length approximately 1,200 feet east along the Dan River. An intermediate dike was constructed in 1976, resulting in two basins, with the Primary Ash Basin dam crest being raised to elevation 540 feet msl. The east side of the basin was designated the Secondary Ash Basin. The Primary Ash Basin was periodically dredged and the material dry-stacked on higher terrain north of the basins (referred to as dry ash stacks). The dam numbers for the ash basins are (ROCKI-237) and (ROCKI-238). The dry ash stacks have been capped with soil.

Duke Energy's Coal Combustion Residuals Removal Verification Procedure (Removal Verification Procedure) was used to verify that primary source ash has been removed from the basin. Subsequent to removal of the ash pursuant to the Removal Verification Procedure, Duke Energy implemented its Excavation Soil Sampling Plan, which was developed for the purpose of meeting the applicable performance standard. Dan River ash is a non-hazardous material.

The Primary Ash Basin at Dan River consists of a composite dam made up of local borrow materials, including silty sands and sandy silts with some clay. Portions of the dam may have been built on, or contain, ash materials. The eastern face of the embankment is armored with rock up to elevation 512 feet msl. A rock fill berm was constructed alongside the river, up to elevation 503 feet msl. An intermediate bench was constructed at approximate elevation of 530 feet msl. The Primary Ash Basin has an approximate footprint of 39 acres with a surface water area of 18 acres. Previously, the Primary Ash Basin received sluiced ash from pipes in the southwest corner and outlets into the Secondary Ash Basin through a decant structure located near the northeast corner of the Primary Ash Basin. Initially, the Primary Ash Basin contained approximately 1,215,000 tons of CCR material. In September 2018, the CCR inventory of the Primary Basin was increased by 552,000 tons due to quantifying CCR material under vertical expansion embankment soil, incorporating revised bottom of ash floor grades, and including estimated soil waste.

The intermediate dike was constructed in 1976, bisecting the basin into Primary and Secondary Ash Basins. The dike was constructed on existing ash deposits, with an upper crest elevation of 540 feet msl adjacent to the Primary Ash Basin and a lower crest elevation of 530 feet msl adjacent to the Secondary Ash Basin. The dike had a surface road at the 540 feet msl level. It had a vegetated slope adjacent to the road, which extends to a 530 feet msl elevation shelf adjacent to the Secondary Ash Basin. A rock buttress was constructed below the elevation 530 feet msl crest. The width of the intermediate dike was approximately 100 feet.

The Secondary Ash Basin embankments, including the intermediate dike forming the southwest boundary, had a crest elevation of 530 feet msl and are constructed of the same local materials as the Primary Ash Basin. The eastern face of the embankment is armored with rock up to elevation 512 feet msl. A rock fill berm was constructed alongside the river, up to elevation 503 feet msl. The basin received decanted flow from the Primary Ash Basin in the northwestern corner, and flows exit the basin through a decant structure near the southeastern corner. Flow from the Secondary Ash Basin was regulated by NPDES Permit No. NC 0003468. The pool level was controlled by the decant riser using concrete stop-logs and conveys to the outlet through a 36-inch diameter reinforced concrete pipe constructed through the embankment dike. Initially, the Secondary Ash Basin contained approximately 390,000 tons of CCR material. The outfall was grouted and abandoned on September 6, 2018.

North Carolina state law requires that ash from the basins at the Dan River site be excavated and relocated to a lined facility, with the ash basins closed by August 1, 2019. This requirement was completed on May 20, 2019. Soil sampling data from the excavated basins is currently being compiled for submission to NCDEQ.

The dry ash stacks were located to the north of the Primary and Secondary Ash Basins. These ash stacks consisted of CCR material dredged from the Primary Ash Basin. Initially, Ash Stack 1 and Ash Stack 2 contained approximately 950,000 tons and 415,000 tons of CCR material, respectively. Stormwater run-off from the ash stacks flowed to a temporary water storage area. The excavation of all CCR from Ash Stack 1 was completed on July 27, 2017. Although not required by North Carolina state law, excavation of Ash Stack 2 is expected to be completed by December 31, 2019.

During the period January 1, 2019 – June 30, 2019, approximately 881,773 tons of ash have been excavated. Of this amount, approximately 20,805 tons were sent to the Roanoke Cement Company for beneficial use and the remainder to an on-site landfill. As of the CAMA excavation completion date of May 20, 2019, approximately 3,530,502 million tons of ash have been excavated from the Dan River site. Dewatering of the ash basins and the removal of ash from the site will be performed in project phases.

The project has completed Phase I and is now implementing Phase II. The following items in Phase I have been completed or initiated:

1. Developed and installed approved erosion and sediment control measures.
2. Obtained applicable permits for work in Phase I.
3. Developed and constructed the infrastructure to remove and transport the ash.
4. Completed rail load out spur for rail transportation.
5. Began bulk dewatering of the Secondary Ash Basin.
6. Initiated and completed the removal of the first 1 million tons of ash from

the Dan River site.

7. Obtained a Permit to Construct the new on-site landfill on October 27, 2016, following resolution of the environmental justice review.
8. Commenced construction of an on-site landfill.
9. Completed a plan to reroute and eliminate inflows to the ash basins.
10. Validated production rates to meet project requirements.
11. Planned activities for subsequent phase(s), including development of option(s) for beneficial use or proposed ash disposal location(s).

The Dan River NPDES wastewater permit was issued and became effective on December 1, 2016. The removal of bulk free water of the Secondary Basin was completed when the basin water level was lowered to elevation 515 feet msl in 2016. Interstitial dewatering commenced in 2018 to support excavation in the Primary and Secondary Basins and was completed May 20, 2019 with the completion of basin ash excavation. All leachate and contact stormwater wastewater treatment is performed by the City of Eden's Publicly Owned Treatment Works (POTW) in accordance with the Industrial User Pre-treatment Permit issued to Duke Energy by the City of Eden. To provide additional wastewater treatment capability, an on-site treatment system was installed, which sent treated water to the discharge point of Outfall 002. The Secondary Basin riser structure and the pipe leading to Outfall 002 were plugged with grout on September 6, 2018.

The excavation of Ash Stack 1 began on October 13, 2015, following acknowledgement of this Plan by NCDEQ and the receipt of final permits. Phase I was completed on March 23, 2017. Phase II includes completion of the on-site landfill and excavation of the basins to the on-site landfill. Construction of an on-site landfill began on October 31, 2016 and was completed on April 18, 2018.

In accordance with the project plan, during Phase I, the Company removed ash to an off-site location while simultaneously developing an on-site landfill, which was needed in order to meet the closure requirements mandated under CAMA. The Company received a Permit-to-Operate (PTO) for the first landfill cell on May 30, 2017, and promptly began transporting ash to the on- site landfill. The PTO for the second landfill cell was received on October 2, 2017, and the final remaining PTO for the third landfill cell was received on April 18, 2018.

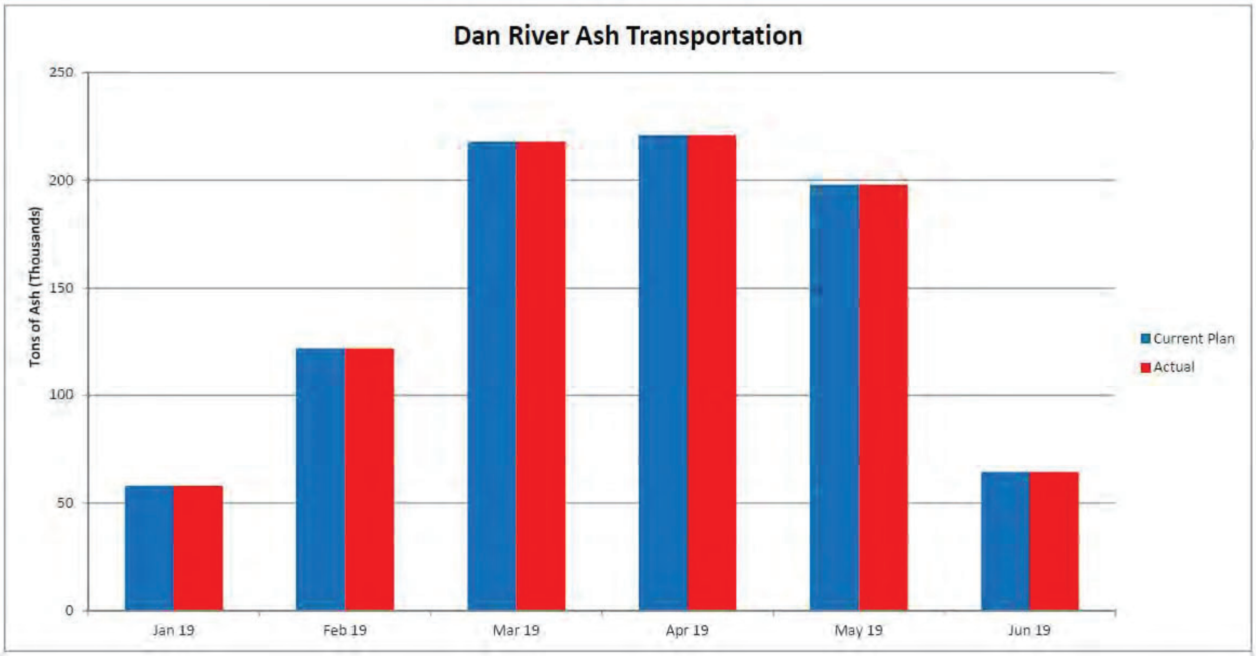
<u>Phase II Scope</u>

1. Submit and obtain applicable permits.
2. Complete construction of the on-site landfill. Cells 1, 2, and 3 are complete.
3. Receive PTOs for the on-site landfill cells. PTOs received for Cells 1, 2, and 3.
4. Excavate and transport the remaining ash from the Dan River Station to the on-site landfill or for off-site reuse options.
5. Continue dewatering of the Primary and Secondary Ash Basins.

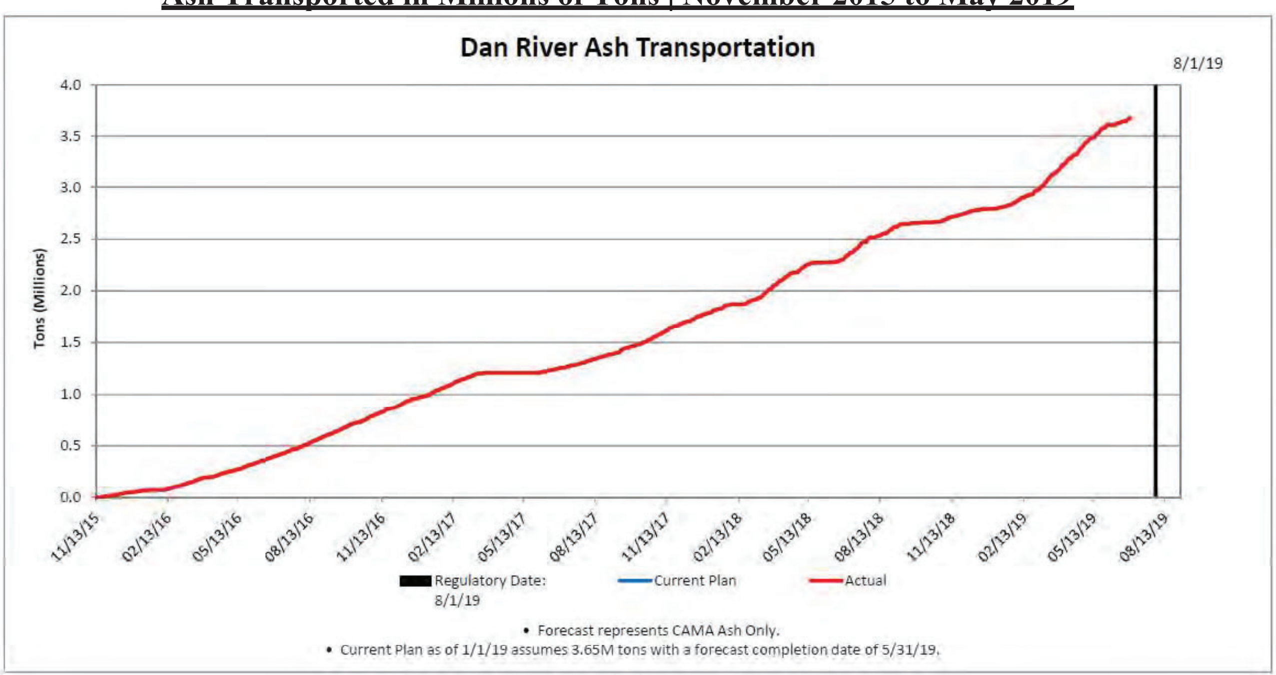
6. Complete closure activities.
7. Operate and close cells for the on-site landfill.

The charts below track the tonnage of ash transported from January 1, 2019 to June 30, 2019 and from November 2015 to completion.

Ash Transported in Thousands of Tons | January 1, 2019 to June 30, 2019



Ash Transported in Millions of Tons | November 2015 to May 2019



In October 2018, the CCP Project Team decided to change the ash excavation contractor at Dan River due to concerns with excavation performance. To ensure completion of basin ash excavation with sufficient margin to the August 1, 2019 deadline, the project implemented several recovery actions. Beginning in January 2019, the project utilized lime to moisture condition the CCR and CCR laden soil to achieve landfill specifications. From February 18 through May 10, 2019, the project worked 24 hours per day, seven days per week. These recovery actions enabled the project to complete ash excavation of the Primary and Secondary Ash Basins on May 20, 2019, as validated by third party sampling performed on May 23, 2019. Soil sampling data from the excavated basins is currently being compiled for submission to NCDEQ during Q3 2019. Although not required by North Carolina law, excavation of Ash Stack 2 is expected to be completed by December 31, 2019.

Critical Milestones within the Plan are summarized in the table below.

MILESTONES	NO LATER THAN DATE	STATUS
Submit Excavation Plan to NCDEQ	November 15, 2014	Completed November 13, 2014
Complete Comprehensive Engineering Review	November 30, 2014	Completed November 30, 2014
Excavation Plan acknowledgement from NCDEQ	February 17, 2015	Completed February 2, 2015
Receive Industrial Stormwater (ISW) Permit	March 18, 2015	Completed October 1, 2015
Commence Work – Ash Removal (including ash stack soil overburden)	Final permit approval + 60 days	Completed October 13, 2015
Submit Updated Excavation Plan to NCDEQ	November 15, 2015	Completed November 13, 2015
Receive Permit-to-Construct On-Site Landfill	March 31, 2016	Delayed due to NCDEQ environmental justice review; completed October 27, 2016
Submit Updated Excavation Plan to NCDEQ	December 31, 2016	Completed December 21, 2016
Submit Updated Excavation Plan to NCDEQ	December 31, 2017	Completed December 1, 2017
Eliminate stormwater discharge into impoundments	December 31, 2018	Completed June 26, 2018
Submit Final Excavation Plan to NCDEQ	December 31, 2018	Completed December 11, 2018
Impoundments closed pursuant to Part II, Sections 3(b) and 3(c) of CAMA	August 1, 2019	Completed May 20, 2019

Erosion and Sediment Control Plan

The Erosion and Sediment Control ("E&SC") Plan for the excavation of the Ash Stack and related site activities have been approved. The approval of this plan by NCDEQ meets the requirement outlined in the referenced NCDEQ letter. Modifications from E&SC plans for subsequent phase(s) will be approved by NCDEQ prior to installation and initiation of subsequent phase work. The approved contractor will install the E&SC measures indicated in the plan. All control measures will be maintained throughout the project in accordance with the E&SC plans. When possible, portions of the E&SC plan will be closed out at the approval of NCDEQ as areas become stabilized.

Dewatering Plan

The Dan River ash basins were dewatered to facilitate the removal of ash and to mitigate risk. Interstitial dewatering of the Primary Ash Basin commenced in March 2018. Interstitial dewatering of the Secondary Ash Basin commenced in June 2018. Interstitial dewatering was completed on May 20, 2019 with the completion of basin ash excavation. Leachate from the on-site landfill, interstitial waste water, and contact stormwater are being treated by the City of Eden's POTW in accordance with the Industrial User Pre-Treatment Permit issued to Duke Energy by the City of Eden. In addition, and to provide additional treatment capacity beyond what the City of Eden could accommodate, the facility installed an on-site wastewater treatment system in Q3 2018 to treat interstitial wastewater for discharge to Outfall 002 in compliance with the facility's NPDES Wastewater Permit.

Locations for Removed Ash

Ash removed from the site will be transported by the contractor to permitted facilities. The ash disposal location(s) will be managed and maintained to ensure environmental compliance with all applicable rules and regulations.

Maplewood Landfill

The Maplewood Landfill is located near Jetersville, Virginia and is where 1.2 million tons of ash where shipped by rail during Phase I. The final rail shipment of ash to the Maplewood Landfill from Dan River occurred on March 23, 2017.

Dan River On-Site Landfill

Transportation of ash to the on-site landfill began on May 31, 2017. The project team utilized lessons learned from Phase I in developing and constructing the on-site landfill, which provides the improvements below:

- Provide a reliable, long-term, cost-effective, solution for ash designated for removal
- Support development of a diverse supplier program to drive innovation and competition

- Establish performance baselines and a system to optimize excavation, transportation, and disposal of ash

Transportation Plan

Ash is currently being transported from the Ash Stack 2 via off-road articulated dump truck to the on- site landfill. Truck loading operations are conducted with a crew working typically 12 hours per day, five to six days per week. From February 18 through May 10, 2019 the project worked 24 hours per day, seven days per week. Ash transportation to Roanoke Cement Company for beneficiation was by on-road truck. The site completed shipping ash to Roanoke Cement for beneficial reuse on May 17, 2019. Transportation off-site was conducted by approved transporters and met DOT and other applicable federal, state, and local regulations.

Environmental and Dam Safety Permitting Plan

Excavation of ash creates potential for stormwater impacts. The facility holds an approved E&SC plan and associated Construction Stormwater Permit approval for ash stack removal and dam decommissioning. Also, NCDEQ indicated that an NPDES ISP is required to excavate ash. The Company has received the NPDES ISP to support ash removal at the site. Pursuant to the requirements of the NPDES ISP, a SPPP incorporating best management practices has been created and is currently being implemented. Future modifications to the permit/plan will be managed as necessary. On October 27, 2016, Duke Energy received a modified NPDES Wastewater Permit, which included provisions for dewatering activities.

The area between Ash Stack 1 and Ash Stack 2 was determined to be a jurisdictional wetland and an Individual Permit ("IP") was required to remediate this area and complete stormwater diversion prior to basin closure. Wetlands/stream impacts related to the rail improvements were managed through the United States Army Corps of Engineers ("ACOE") with particular attention paid to the difference between jurisdictional wetlands/streams under Section 404 and those arising from Section 401 waters. The Company received approvals from ACOE and NCDEQ for wetlands/stream impacts related to the rail. The Company received approvals from ACOE and NCDEQ for wetlands/stream impacts related to stormwater diversion in Q4 2017. The Company also received approvals from ACOE and NCDEQ for wetlands/stream impacts related to dam decommissioning in Q2 2019.

In order to facilitate on-site landfill construction and operation, NCDEQ's Solid Waste Section issued a Landfill Permit-to-Construct on October 27, 2016. Following construction of each cell of the on-site landfill, Construction Quality Assurance Reports were submitted to obtain the corresponding PTO. NCDEQ's Solid Waste Section issued a Landfill PTO for Cell 1 on May 30, 2017, a Landfill PTO for Cell 2 on October 2, 2017, and a Landfill PTO for Cell 3 on April 18, 2018.

Dam Decommissioning Plan Sequence 'A' was approved by NCDEQ Dam Safety on February 20, 2018. Dam Decommissions Plan Sequence 'B' was approved on July 16, 2018 and Decommissioning Plan Sequence 'C' was approved on May 10, 2019. Any impacted wells or piezometers will be properly abandoned in accordance with NCDEQ requirements. Fugitive dust will be managed to mitigate impacts to neighboring areas.

Other than the agreement with the City of Eden regarding development of the on-site landfill, there are no additional site-specific or local requirements identified.

Permit Matrix

MEDIA	PERMIT	RECEIVED DATE (R) TARGET DATE (T)	COMMENTS
Water	NPDES Industrial Stormwater Permit	October 1, 2015 (R)	SPPP implementation was completed March 31, 2016.
	NPDES Wastewater Permit – Major Modification	October 27, 2016 (R)	Effective December 1, 2016.
	City of Eden – Industrial User Permit	June 3, 2016 (R)	Revised permit issued March 1, 2019 with increased flow limit of 600,000 gpd.
	Jurisdictional Wetland and Stream Impacts / 404 Permitting and 401 WQC	September 14, 2015 (R)	Two stream crossings for rail upgrade.
	Jurisdictional Wetland and Stream Impacts / 404 Permitting and 401 WQC	401 Permit October 9, 2017 (R) 404 Permit October 24, 2017 (R)	Area between Ash Stack 1 and Ash Stack 2 Permits updated in Q2 2019 to include installation of four stormwater outfalls on Dan River for Dam Decommissioning.
Dam Safety	Dam Decommissioning Request Approval	Sequence 'A' February 20, 2018 (R) Sequence 'B' July 20, 2018 (R) Sequence 'C' March 31, 2019 (T)	Sequence 'A' approved February 20, 2018. Sequence 'B' approved July 16, 2018. Sequence 'C' approved May 10, 2019.

Waste	Site Suitability Report	August 28, 2015 (R)	None.
	Permit-to-Construct Landfill	October 27, 2016 (R)	Target Date was March 31, 2016. Delay was due to NCDEQ's environmental justice review.
	Permit-to-Operate Landfill	Cell 1 May 30, 2017 (R) Cell 2 October 2, 2017 (R) Cell 3 April 18, 2018 (R)	Cell 1: Target Date was March 31, 2017. Delay was due to NCDEQ's environmental justice review.
Other Requirements	Site-Specific Nuisance/Noise/ Odor/Other Requirements, including DOT	July 21, 2015 (R)	Eden City Council adopted zoning amendment on July 21, 2015, which allows construction of Dan River on-site landfill.

Site Progression of the Excavation Process at the Dan River Steam Station

April 2016 Aerial View Primary Basin

Cell 1 Lining & Initial Dirt Work on Cell 2

First CCR Train Leaves Dan River November 2016

Last CCR Train Loaded & Ready for Pickup March 2017

Aerial View September 2018

Dan River May 2019

III. Riverbend Steam Station

Riverbend is located off of Horseshoe Bend Beach Road near the town of Mount Holly in Gaston County, NC on the south bank of the Catawba River. The seven-unit Station began commercial operation in 1929 with two units and then expanded to seven by 1954. At its peak, the generating facility had a capacity of 454 megawatts. As of April 1, 2013, all of the coal-fired units were retired. Demolition was completed in June 2018.

Riverbend ash is a non-hazardous material. The discharge from the ash basin system was permitted through Outfall #002 to the Catawba River under NPDES Permit No. NC0004961. Riverbend has been decommissioned, and no active ash placement or sluicing is occurring within the ash basin system.

Duke Energy's Coal Combustion Residuals Removal Verification Procedure was used to verify that primary source ash has been removed from the basin. Subsequent to removal of the ash pursuant to the Removal Verification Procedure, Duke Energy implemented its Excavation Soil Sampling Plan, which was developed for the purpose of meeting the applicable performance standard. The ash basin system was an integral part of the Station's NPDES-permitted wastewater treatment system, which predominantly received inflows from the ash removal system, station yard drain sump, and stormwater flows. During Station operations, inflows to the ash basin were highly variable due to the cyclical nature of Station operations. The ash basin system consisted of a Primary Ash Basin and a Secondary Ash Basin, which were separated by an Intermediate Dam. The Primary Ash Basin and the Secondary Ash Basin are no longer separated since the decommissioning of the Intermediate Dam. For the purpose of stormwater management, the Ash Stack was also within the ash basin system.

The ash basin system was located approximately 2,400 feet to the northeast of the power plant, adjacent to the Catawba River. The Primary Ash Basin is impounded by an earthen embankment dam, referred to as Primary Dam (GASTO-97), located on the west side of the Primary Ash Basin. The Secondary Ash Basin is impounded by an earthen embankment dam, referred to as Secondary Dam (GASTO-98), located along the northeast side of the Secondary Ash Basin. Both the Primary and Secondary Dams are currently being decommissioned.

Originally, the ash basin at Riverbend consisted of a single basin commissioned in 1957. In 1979, the original single basin was divided by constructing a divider dam (Intermediate Dam (GASTO- 99)) to form two separate basins (Primary Ash Basin and Secondary Ash Basin). This modification improved the original basin's overall ability for suspended solids removal. The Primary Dam was raised, and the Intermediate Dam was built over sluiced ash to a crest of 730 feet mean sea level (msl). At the same time, the Secondary Dam crest elevation remained at 720 feet msl. As part of the Excavation Project, the Intermediate Dam was removed in February 2017. Prior to excavation, the Primary Ash Basin and the Secondary Ash Basin were estimated to contain a total of approximately 3.6 million tons of CCR.

The inflows from the ash removal system and the Station yard drain sump were directed through sluice lines into the Primary Ash Basin. The discharge from the Primary Ash Basin to the Secondary Ash Basin was through a concrete discharge tower located near the divider dam. The surface area of the combined Ash Basin is approximately 69 acres with an approximate maximum basin elevation of 714 feet msl. The full basin elevation of Mountain Island Lake is approximately 647 feet msl.

Prior to the Station being retired, stormwater and wastewater effluent from other non-ash related Station flows to the ash basin were discharged in compliance with the Station's NPDES permit to the Catawba River through a concrete discharge tower located in the Secondary Ash Basin. The concrete discharge tower drained through a 30-inch diameter corrugated metal pipe into a concrete-lined channel. The channel extended from the Secondary Ash Basin to NPDES Outfall #002, which discharged to the Catawba River. This discharge pipe has been grouted closed.

An ash fill deposit, known as the "Ash Stack," was constructed from ash removed from the Primary and Secondary Ash Basins during basin clean-out projects. The Ash Stack was utilized for periodic ash basin clean-outs to prolong the life of the ash basins. The Ash Stack is a 29-acre area located south of the Primary Ash Basin. The Ash Stack was constructed during two ash basin clean-outs; the last recorded ash basin clean-out project was in 2007. Prior to Phase I excavation, the Ash Stack had 1.5 to 2 feet of soil cover and vegetation that was maintained following the last deposit in this area. For the purpose of water management, the stormwater run-off from the Ash Stack area was routed to the ash basin system. As of March 16, 2019, CCR excavation was complete with approximately 1.55 million tons of CCR material removed from the Ash Stack, in total.

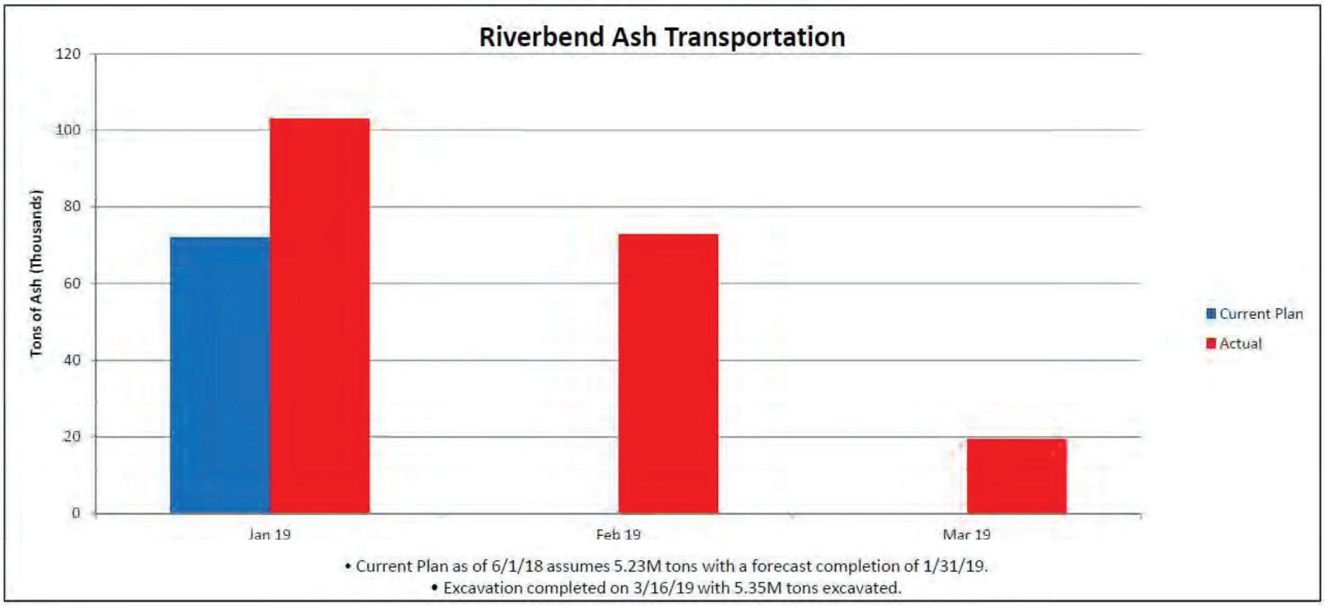
Prior to construction of the ash basin, bottom ash (cinders) was deposited in a primarily dry condition in the "Cinder Pit" and other areas near the cinder pit and coal pile. The Cinder Pit was approximately 13 acres and was located in a triangular area northeast of the coal pile and northwest of the rail spur. This area was utilized for storage of ash material at the Station prior to the installation of precipitators and a wet sluicing system. The Cinder Pit contained predominantly dry cinders. As of March 16, 2019, CCR excavation was complete with approximately 300 thousand tons of CCR material removed from the Cinder Pit area, in total.

During the period January 1, 2019 – March 16, 2019, approximately 195,530 tons of ash were excavated and transported off-site. As of March 16, 2019, CCR excavation was complete and approximately 5,351,309 million tons of ash have been excavated from the Riverbend site.

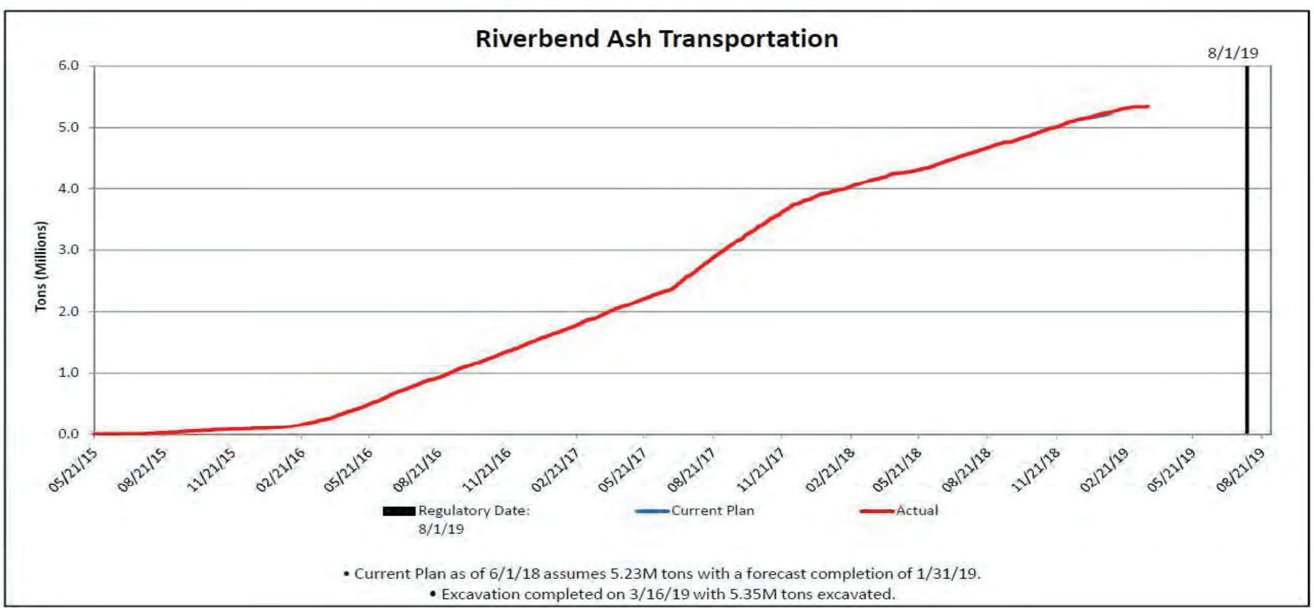
The Riverbend NPDES wastewater permit was issued and became effective on March 1, 2016. Decanting of bulk water began soon thereafter and continued until halted in June 2016. In July 2016, NCDEQ imposed a new requirement to install a physical-chemical treatment facility. Following installation of a water treatment facility, bulk dewatering commenced in the fall of 2016 and was completed on January 31, 2017. With CCR excavation complete, there is no contact water. Treatment and discharge of water through the NPDES Outfall #002 has stopped. As of June 1, 2019, NCDEQ deemed the wastewater outfall as decommissioned and changed the classification to “Physical Chemical Water Pollution Control Treatment System (PCNC – Not Classified).”

The charts below track the tonnage of ash transported from January 1, 2019 to March 16, 2019 and from May 2015 to completion.

<u>Ash Transported Off Site in Thousands of Tons | January 1, 2019 to March 16, 2019</u>



<u>Ash Transported Off Site in Millions of Tons | May 2015 to March 2019</u>



Critical Milestones within the Plan are summarized in the table below.

MILESTONE	NO LATER THAN DATE	STATUS
Submit Excavation Plan to NCDEQ	November 15, 2014	Completed November 13, 2014
Complete Comprehensive Engineering review	November 30, 2014	Completed November 30, 2014
Excavation Plan Acknowledgement from NCDEQ	February 17, 2015	Completed February 2, 2015
Receive Industrial Stormwater (ISW) Permit	March 5, 2015	Completed May 15, 2015
Commence Work – Ash Removal	Final permit approval + 60 Days	Completed May 21, 2015 After Receipt of ISW Permit
Submit Updated Excavation Plan to NCDEQ	November 15, 2015	Completed November 13, 2015
Submit Updated Excavation Plan to NCDEQ	December 31, 2016	Completed December 21, 2016
Submit Updated Excavation Plan to NCDEQ	December 31, 2017	Completed December 1, 2017
Submit Final Excavation Plan to NCDEQ	December 31, 2018	Completed December 11, 2018
Eliminate Stormwater Discharge into Impoundments	December 31, 2018	Completed December 14, 2018
Impoundments Closed per Part II, Sections 3(b) and 3(c) of CAMA	August 1, 2019	Completed March 16, 2019

Erosion and Sediment Control Plan

The E&SC plans for the excavation of the Ash Stack, construction of the rail infrastructure, and haul roads were developed, submitted to NCDEQ, and approved. All control measures were maintained through the project in accordance with the E&SC plans. These E&SC plans have been closed out at the approval of NCDEQ.

Dewatering Plan

The Riverbend ash basins were dewatered to facilitate the removal of ash and to mitigate risk. An engineered dewatering plan for Riverbend was developed, and bulk dewatering was completed on January 31, 2017. Interstitial dewatering and stormwater removal continue through the required water treatment components noted in the previous phase of this Ash Plan.

During excavation, contact water was controlled and diverted through ditches and pumps into sumps located within the area of the Basin. As water was collected in the sump(s), it was pumped into one of the two lined holding ponds, which were constructed to store water prior to treatment. Water from the holding pond(s) was pumped to the wastewater treatment facility onsite, treated, and discharged to the Catawba River, in accordance with the NPDES permit. The holding ponds and the wastewater treatment facility will be decommissioned.

Location(s) for Removed Ash

A total of approximately 5.35 million tons of ash from the Ash Stack, ash basin system, and Cinder Pit have been excavated and removed from the Riverbend site. Ash removed from the site was transported by the contractor to permitted facilities.

A pilot program for ash removal began on May 21, 2015, to transport ash by truck to the R&B Landfill in Homer, Georgia. Ash transport to the landfills located at the Marshall Steam Station in Sherrills Ford, North Carolina began on July 27, 2015. Initial ash shipments by truck from Riverbend to the Brickhaven Structural Fill began on October 23, 2015. Ash transportation to the R&B Landfill was terminated in September 2015, and ash transportation to the Marshall Landfill was terminated in Q1 2016. Early in Q1 2016, rail transport of the remaining ash commenced to the Brickhaven Structural Fill.

R&B Landfill

A total of approximately 16,000 tons of ash were removed from the site and transported to the R&B landfill in Homer, Georgia, which is a permitted facility.

Marshall FGD and Industrial Landfills

The FGD and industrial landfills are located at the Duke Energy Marshall Steam Station facility in Sherrills Ford, North Carolina. Both are permitted facilities, and 88,745 tons of CCR material were relocated there.

Brickhaven Structural Fill

The Brickhaven Structural Fill is located at the Brickhaven Mine near the City of Moncure in Chatham County, North Carolina. It resides on approximately 299 acres. Ash transported there is beneficially used as structural fill material at the reclaimed mine. A total of approximately 5.23 million tons were relocated to the Brickhaven Structural Fill.

Transportation Plan

The majority of Ash was transported off-site via rail car. As previously noted above, a pilot program for ash removal began with the transportation of ash by truck to the R&B Landfill in Homer, Georgia, Marshall Steam Station landfills, and the Brickhaven Structural Fill. Truck transportation has ceased and was replaced by rail transportation.

Environmental and Dam Safety Permitting Plan

Excavation of ash creates potential for stormwater impacts. The facility holds approved E&SC plans and associated Construction Stormwater Permits for ash removal. Also, NCDEQ indicated that an NPDES ISP is required to transport ash. The Company received the ISP to support ash removal at the site. Pursuant to the requirements of the ISP, a stormwater pollution prevention plan SPPP incorporating best management practices was created and is currently being implemented. Future modifications to the permit/plan will be managed as necessary.

On February 12, 2016, NCDEQ issued NPDES Permit NC0004961 for operation of the wastewater treatment works at Riverbend and for discharging treated wastewater to the Catawba River (Mountain Island Lake) and associated tributaries and wetlands. Certain effluent limits (pH and total hardness) in the permit were subsequently modified under that certain Special Order by Consent ("SOC") (EMC SOC WQ S16-005) dated November 10, 2016.

There are no jurisdictional wetlands/streams associated with the removal of the Ash Stack or Primary or Secondary Ash basins in Phase I. Future wetland/stream impacts and jurisdictional determinations will be managed through the ACOE with attention paid to the difference between jurisdictional wetlands/streams under Section 404 and those arising from Section 401 waters.

All necessary Dam Safety approvals have been obtained to cover activities on or around jurisdictional dams. Dam decommissioning plans for the Primary and Secondary Dams have been submitted and approved by NCDEQ Dam Safety. Any impacted wells or piezometers will be abandoned in accordance with NCDEQ requirements. Fugitive dust will be managed to mitigate impacts to neighboring areas. Additional site-specific or local requirements will be secured, as needed.

Permit Matrix

MEDIA	PERMIT	RECEIVED DATE (R) TARGET DATE (T)	COMMENTS
	NPDES Industrial Stormwater (ISW) Permit	May 15, 2015 (R)	NCDEQ issued the ISW permit May 15, 2015. SPPP implementation date was November 15, 2015.
Water	NPDES Wastewater Permit – Major Modification	Q1 2016 (R) (Modified by SOC in Q4 2016)	Permit became effective December 1, 2016.
	Jurisdictional Wetland and Stream Impacts / 404 Permitting and 401 WQC	N/A	There are no identified jurisdictional wetland/stream impacts.
	Intermediate Dam Decommissioning Request Approval	June 16, 2016 (R)	Submitted May 31, 2016. Received approval June 16, 2016. Decommissioning completed March 13, 2017.

Dam Safety	Primary Dam Modification Request Approval	August 3, 2017 (R)	Submitted May 8, 2017. Received approval August 3, 2017. Modification completed March 3, 2018.
	Primary and Secondary Dam Decommissioning Request Approval	June 7, 2018 (R)	Resubmitted May 29, 2018. Received approval June 7, 2018.
Waste	Individual Structural Fill Permit	October 15, 2015 (R) (Permit to Operate)	Mine Reclamation Owner/Operator obtained an Individual Structural Fill Permit Pursuant to G.S. § 130A-309.219 of CAMA.
Duke Energy Lake Services	Water Conveyance Permit	August 2, 2016 (R)	Original permit received April 7, 2016. Amended permit for revised quantities received August 2, 2016.
Other Requirements	Site-Specific Nuisance/Noise/ Odor/Other Requirements, including DOT	N/A	None identified

Site Progression of the Excavation Process at the Riverbend Steam Station

2015 Dry Stack

2018 Dry Stack

Ash Basin 2015

Ash Basin 2017

Ash Basin 2019

Ash Basin March 2019

IV. L.V. Sutton Electric Plant

Sutton is located in New Hanover County near Wilmington, North Carolina, situated between the Cape Fear River to the west and the Northeast Cape Fear River to the east. Sutton was a three-unit, 575-megawatt (MW) coal-fired power plant. The Plant operated from 1954 until retirement of the coal-fired units in November 2013. Upon retirement of the coal-fired units, a new 625 MW gas-fired unit began operations.

There were two CCR basins—the 1971 and 1984 Basins—containing fly ash, bottom ash, boiler slag, stormwater, ash sluice water, coal pile runoff, and low volume wastewater. One other area that contains CCR material is the Lay of Land Area ("LOLA"). The LOLA consists mostly of bottom ash and soil. The Sutton facility also includes a cooling lake (also known as Sutton Lake), which is not part of the CCR management system. Sutton Lake is accessible to the general public and is used for recreational purposes. Sutton Lake was classified as Waters of the State on November 5, 2014.

Duke Energy's Coal Combustion Residuals Removal Verification Procedure (Removal Verification Procedure) will be used to verify that primary source ash has been removed from the basin. Subsequent to removal of the ash pursuant to the Removal Verification Procedure, Duke Energy will implement its Excavation Soil Sampling Plan (ESSP). For the Sutton site, two separate ESSPs were developed. The ESSP for the 1971 Ash Basin provides a standardized method for confirming ash removal, where ash extends underwater or below the water table and visual confirmation of the removal may not be possible. The ESSP for the 1984 Ash Basin and LOLA provides a standardized method for collecting soil samples at ash basins that are to be closed via excavation and following all visible ash removal. Although not required under CAMA, in November 2016, NCDEQ sent Coal Combustion Residuals Surface Impoundment Closure Guidelines for Protection of Groundwater to Duke Energy instructing the Company to submit the ESSP to NCDEQ as part of the site's excavation plan. Sutton ash is a non-hazardous material.

1971 Ash Basin

The 1971 Basin was operated from 1971 to 1985. It was opened again in 2011 for temporary use during repair work and ash removal activities. The 1971 Basin is unlined and was initially constructed with a crest elevation of 18 feet mean sea level (msl), which was raised in 1983 to 26 msl. The 1971 Basin initially contained approximately 3.8 million tons of CCR material. The southern basin dikes of the 1971 Basin contain ash and will be excavated as part of final closure.

1984 Ash Basin

The 1984 Basin was operated from 1984 to 2013. The 1984 Basin was constructed with a 12-inch thick clay liner at the basin bottom, which extends along the side slopes where it is protected by a 2-foot thick sand layer. The 1984 Basin crest elevation is 34 feet msl. In 2006, an Interior

Containment Area ("ICA") was constructed within the 1984 Basin with a crest elevation of 42 feet msl. The 1984 Ash Basin initially contained approximately 2.8 million tons of CCR material.

The LOLA is located between the discharge canal and the coal pile. It is believed that the presence of CCR in this area may have been due to plant operations between approximately 1954 and 1972. A small portion adjacent to the coal pile storage area was used to locate fuel oil storage tanks. This area contains approximately 686,000 tons of CCR and soil mixture at depths of 0 to 15 feet.

Sutton Variance

On November 16, 2018, Duke Energy submitted to the North Carolina Department of Environmental Quality an application for a variance to extend by six months (until February 1, 2020) the CAMA closure deadline applicable to the 1971 and 1984 Ash Basins at Sutton. Based on NCDEQ's analysis of the information submitted by Duke Energy, NCDEQ partially granted the variance extending the closure date for Sutton by four months to December 1, 2019.

However, the Sutton site has completed excavation required under CAMA without having to use the Variance extension. The excavation production quantities have been better than planned this reporting period. Good weather has been the major contributor for the results. The Wilmington area experienced below normal rainfall levels during the first six months of this year.

Current Operating Permit Details

The Cooling Basin, 1971 Basin, and 1984 Basin are operated under NPDES Permit No. NC0001422 to regulate effluent discharges to the Cape Fear River. Additionally, the dams of the Cooling Basin, 1971 Basin, and 1984 Basin are listed under the NCDEQ Dam Safety Program. The dam identification numbers for the Cooling Basin, 1971 Basin, and 1984 Basin are NEWHA-003, NEWHA-004, and NEWHA-005, respectively. The dam inventory lists the Cooling Basin and 1971 Dam as exempt. The 1984 Dam is listed as impounding, hence regulated. In 2014, these dams were re-rated as high hazard by NCDEQ. The 2006 ICA constructed within the 1984 Basin was permitted and used as a "basin within a basin," where an interior dam was constructed on top of the CCR within the basin; sluiced CCR was excavated from rim ditches, placed within the interior basin, and compacted to heights that are above the exterior basin dams. This operation was discontinued before reaching the permitted final grades when the Plant was shut down in November 2013.

During the period January 1, 2019 – June 30, 2019, approximately 1,924,428 tons of ash have been excavated. In total, 6,789,347 tons were excavated from the Sutton ash basins. Dewatering of the ash basins and the removal of ash from the site is being performed in project phases. The project has completed Phase I and is now implementing Phase II.

The following items in Phase I and Phase II have been completed:

1. Developed and installed approved erosion and sediment control measures.
2. Developed and constructed the infrastructure to remove and transport the ash from the basins.
3. Completed the installation of a wastewater treatment system to support dewatering of the ash basins.
4. Began on-site treatment of wastewater from the ash basins and landfill leachate using the on-site wastewater treatment facility.
5. Initiated and completed the removal of the first 2 million tons of ash from the Sutton site.
6. Completed the construction of 4600 feet of sheet pile wall to support future dike and berm removal.
7. Commenced the excavation of CCR and the removal of the 1971 Basin southern dike.
8. Received NCDEQ permits to decommission the 1971 and 1984 Basin dikes and outfall structure(s).
9. Designed, permitted, and constructed the on-site landfill.
10. Commenced operation of all on-site landfill cells. Cell 7 was placed in-service on January 10, 2019 and Cell 8 was place in-service on April 1, 2019.
11. Commenced final closure construction and capping for Cells 3 and 4 on April 3, 2019.
12. Continued the excavation and transport of Phase II ash to the on-site landfill.
13. Completed the installation of the on-site extraction well system and completed the relocation of several miles of outfall discharge piping to support operation of the extraction well system and future dike excavation.
14. Submitted and obtained all necessary permits for Phase II activities.
15. Completed dewatering of the 1984 and 1971 Basins.
16. Continued to excavate and transport material from the 1971 and 1984 Ash Basins to an approved on-site landfill.
17. Completed the excavation of CCR of the 1971 Basin southern dike.
18. Completed the excavation and dredging of material from the 1971 and 1984 Ash Basins on June 24, 2019.

The Sutton NPDES wastewater permit was issued to Duke Energy in December 2015 to allow for removal of bulk free water. The removal of the bulk free water was completed on January 28, 2016. After the required wastewater treatment facility was installed and operational, removal and treatment of the basin interstitial water commenced in June 2016. Based on revisions to the NPDES permit, the stormwater from the fossil plant has been rerouted and no longer discharges into the basins. Therefore, rainwater is the only inflow into the basins. Basin dewatering was then implemented on an as-needed basis to maintain the basins' clear water ponds as low as reasonably possible.

Under this Plan, the Company began removing ash to an off-site location while simultaneously developing an on-site landfill to meet the closure requirement mandated in CAMA. The Sutton on-site landfill construction permit was received on September 22, 2016. This date was significantly later than originally planned, resulting from delays with NCDEQ's environmental justice review.

The construction of the on-site landfill commenced early in Q4 2016. The first Permit-to-Operate for a completed landfill cell was obtained on July 6, 2017 from the NC Division of Waste Management. Phase I CCR excavation and transport off-site completed on June 27, 2017, and the Phase II CCR excavation and placement in the on-site landfill commenced on July 7, 2017. Landfill construction was completed March 26, 2018. Currently, all cells are in operation. The closure of two of the operating cells commenced in April 2019.

Phase II Scope

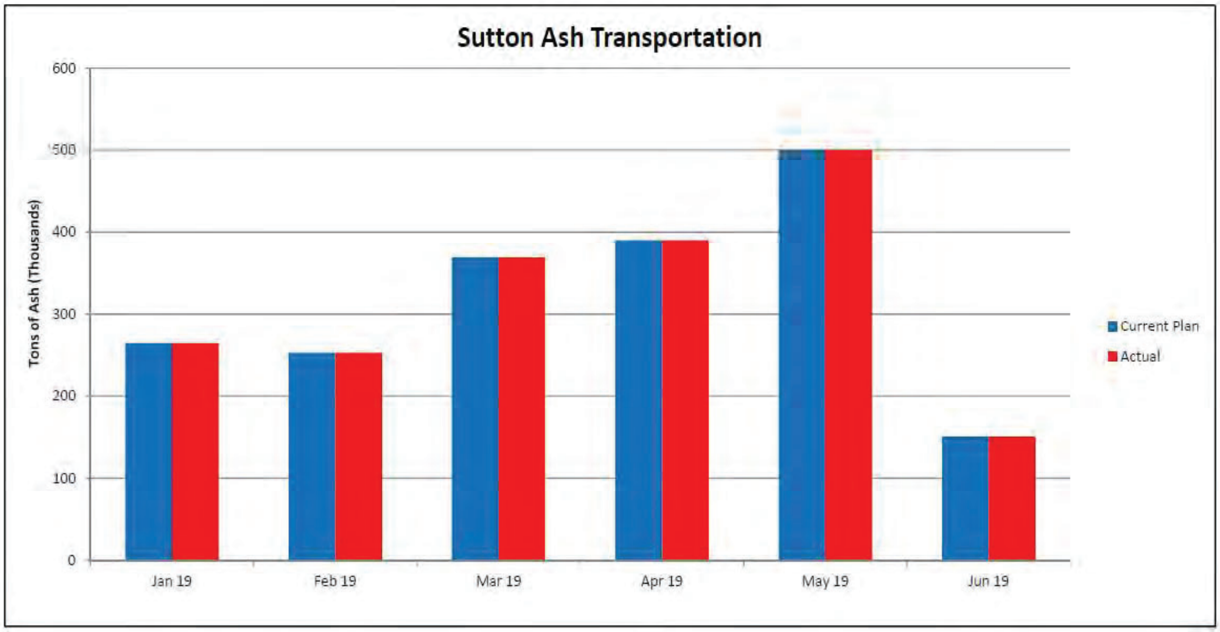
1. Construct, operate, and close cells for the on-site landfill. Cell 5 closure is scheduled to commence during Q3 2019.
2. Install and maintain required site haul roads.
3. Continue to treat landfill leachate water using the on-site wastewater treatment facility.
4. Continue infrastructure activities that are required to support the future excavation of the basins and the LOLA.
5. Complete closure activities for the 1971 and 1984 Ash Basins.

Inactive Ash Areas Scope

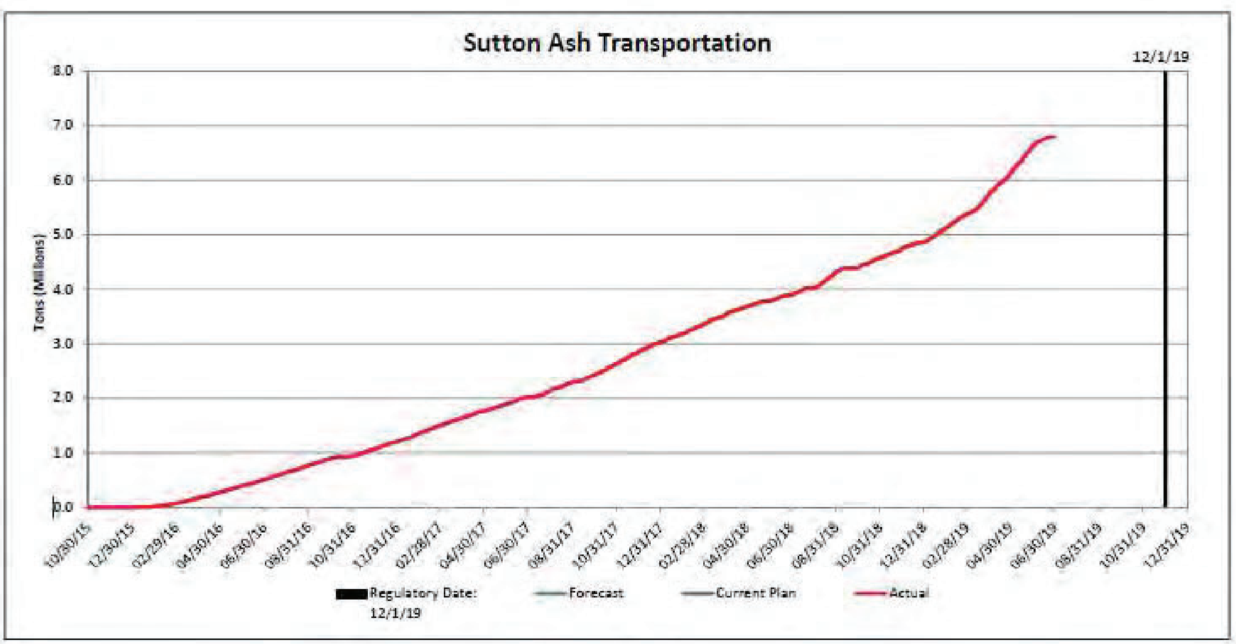
1. Submit and obtain any necessary permits for activities.
2. Excavate and transport approximately 684,600 tons of material from the LOLA to the on-site landfill.
3. Reinforce the LOLA western dike.
4. The LOLA will be closed as part of overall site closure, but is not subject to Part II, Sections 3(b) and 3(c) of CAMA.
5. Operate and close the remaining cells for the on-site landfill.

The charts below track the tonnage of ash transported from January 1, 2019 to June 30, 2019 and from October 2015 to completion.

Ash Transported Off Site in Thousands of Tons | January 1, 2019 to June 30, 2019



Ash Transported On-Site in Millions of Tons | October 2015 to June 2019



Critical milestones within the Plan are summarized in the table below.

MILESTONES	NO LATER THAN DATE	STATUS
Submit Excavation Plan to NCDEQ	November 15, 2014	Completed November 13, 2014
Complete Comprehensive Engineering Review	November 30, 2014	Completed November 30, 2014
Excavation Plan Acknowledgement from NCDEQ	February 17, 2015	Completed February 2, 2015
Submit Updated Excavation Plan to NCDEQ	November 15, 2015	Completed November 13, 2015
Commence Work – Ash Removal	Final Permit Approval + 14 days	Completed October 30, 2015
Receive NPDES Wastewater Permit	December 11, 2015	Completed December 2015
Receive Permit-to-Construct On-Site Landfill	February 29, 2016	Completed September 22, 2016
Submit Updated Excavation Plan to NCDEQ	December 31, 2016	Completed December 21, 2016
Receive Permit for Basin Dam Decommissioning	August 1, 2017	Completed December 7, 2017
Receive Permit-to-Operate On-Site Landfill, Cell 3	August 31, 2017	Completed July 6, 2017
Submit Updated Excavation Plan to NCDEQ	December 31, 2017	Completed December 1, 2018
Eliminate Stormwater Discharge into Impoundments	December 31, 2018	Completed July 2016
Submit Final Excavation Plan to NCDEQ	December 31, 2018	Completed December 11, 2018
1971 and 1984 Basins Closed Pursuant to Part II, Sections 3.(b) and 3.(c) of CAMA and Variance approved	December 1, 2019	Completed June 24, 2019
Excavate CCR from the Lay of the Land Area (LOLA)	June 20, 2020	On Track

Erosion and Sediment Control Plan

The project currently has one active E&SC plan: Site Wide Clearing Activities (NEWHA-2016-025). Additional applications are expected to be submitted during this phase as the project planning develops. Modifications from E&SC plans for subsequent phase(s) will be approved by NCDEQ prior to installation and initiation of subsequent phase work. The approved contractor will install the E&SC measures indicated in the plan. All control measures will be maintained throughout the project in accordance with the E&SC plans and permits. When possible, portions of the E&SC plan will be closed out at the approval of NCDEQ as areas become stabilized.

Dewatering Plan

The Sutton ash basins were dewatered to facilitate the removal of ash and to mitigate risk. Engineering analysis had shown that lowering the water below the level of ash within each basin did not improve the factor of safety against failure of the associated dam; therefore, removal of entrapped water was not required.

An engineered Dewatering Plan for Sutton was developed, and dewatering has been in progress since October 2015. Interstitial basin dewatering continued throughout the life of the project. Pumping was managed to control the water level as low as reasonably possible.

The plan called for the removal of ash from the 1971 Basin through different methods than from the 1984 Basin and the LOLA. Heavy equipment operation directly on top of the ash in the basin had been deemed impractical due to high groundwater recharge rates. Therefore, removal of the ash from the 1971 Basin incorporated hydraulic dredging and dewatering of the resulting dredged material. The water generated during ash removal was directed back to the 1971 Basin.

Interstitial dewatering and landfill leachate wastewater treatment will be performed by the on-site wastewater treatment facility in accordance with the NPDES permit.

Location(s) for Removed Ash

Ash removed from the site was transported by the contractor to permitted facilities. The ash storage location has been managed and maintained to ensure environmental compliance with applicable rules and regulations.

Brickhaven Structural Fill was the primary disposal location for the first two million tons of CCR material that was excavated at Sutton, and the on-site landfill located at Sutton is the primary disposal location for the remaining CCR material.

Brickhaven Structural Fill

The Brickhaven Structural Fill is located at the Brickhaven Mine near the City of Moncure in Chatham County, NC. It resides on approximately 299 acres. Ash was transported and beneficially used as fill material for a structural fill project at the reclaimed mine. The final rail shipment of ash to the Brickhaven Structural Fill from Sutton occurred on June 27, 2017.

Sutton On-Site Landfill

Ash excavated from the basins and LOLA will be disposed of in the on-site CCR landfill. The project includes the installation of a liner and leachate collection system for the landfill.

Transportation Plan

Ash was transported from the basins via off-road articulated dump truck to the on-site landfill. Ash from the LOLA via off road articulated truck to the on-site landfill is scheduled to commence in July 2019.

Environmental and Dam Safety Permitting Plan

Excavation of ash creates potential for stormwater impacts. Since Sutton has no point source discharges consisting solely of industrial stormwater, NCDEQ determined that an individual industrial stormwater permit is not necessary. Instead, NCDEQ has included internal stormwater outfalls and the requirement to develop a stormwater pollution prevention plan as a requirement of the NPDES wastewater permit.

NCDEQ has determined that removal of dry ash from the Sutton ash basins can be regulated via the Construction Stormwater General Permit. Ash removal activities were originally permitted when NC DEMLR approved erosion control plan NEWHA-2016-023. These activities are now encompassed in NEWHA-2016-025.

NCDEQ determined that dewatering activities, including free water removal, required an NPDES wastewater permit modification. Based on this requirement, the Company applied for a permit modification to specifically allow decanting of free water and dewatering of interstitial water. Application was made in January 2015. The Company received the modified NPDES permit in December 2015 for a term of one year. On October 1, 2017, the permit was re-issued and included the authorization to treat and discharge landfill leachate through the on-site wastewater treatment plant.

There are no jurisdictional wetlands/streams associated with the removal of ash from the 1984 and 1971 Ash Basins during Phase I and II. Wetlands stream impacts were permitted for the construction of the on-site landfill.

All necessary Dam Safety approvals will be or have been obtained to cover activities on or around jurisdictional dams. Breaching of the dams will require Dam Safety approval. Any impacted wells or piezometers will be properly abandoned in accordance with NCDEQ requirements. Fugitive dust will be managed to mitigate impacts to neighboring areas.

Permit Matrix

MEDIA	PERMIT	RECEIVED DATE (R) TARGET DATE (T)	COMMENTS
Water	NPDES Wastewater Permit – Major Modification	Major Modification to allow basin dewatering: December 2015 (R)	None
		Major Modification to allow the discharge of landfill leachate: October 1, 2017 (R)	An NPDES permit revision was required to authorize the treatment and discharge of landfill leachate. The target date was originally January 2017, but was affected by shifts in Agency priorities. The draft permit was posted for public comment in June 2017 and again in August 2017. The approved NPDES modification was received and went into effect on October 1, 2017.
	Jurisdictional Wetland and Stream Impacts/ 404 Permitting and 401 WQC	September 2016 (R)	Four cells in the new Sutton landfill have identified jurisdictional wetland/stream impacts in Phase I. Wetland permits have been received. No impacts to jurisdictional wetlands requiring additional permitting have been identified for Phase II.
Dam Safety	Dam Decommissioning Request Approval	February 7, 2018 (R)	Original target date was March 2017. Permit is required to support excavation plan.
Waste	Site Suitability Report	July 2, 2015 (R)	Site Suitability obtained for Sutton landfill. Previous date was March 31, 2015. Change was related to additional requirements to complete the report prior to submittal.
	Permit-to-Construct Landfill	September 2016 (R)	The original target date was February 23, 2016.
	Permit-to-Operate Landfill	Cell 3: July 6, 2017 (R) Cell 4: Aug. 25, 2017 (R) Cell 5: Dec. 7,2017 (R) Cell 6: Feb. 7, 2018 (R)	The original project target date for Cell 3 was November 23, 2016. Delay was due to NCDEQ's

		Cells 7 & 8: May 16, 2018 (R)	environmental justice review process.
Other Requirements	Site-Specific Nuisance/Noise/ Odor/Other Requirements, including DOT Requirements	N/A	None identified

Site Progression of the Excavation Process at the L.V. Sutton Electric Plant

Aerial View 2015

Aerial View June 2016

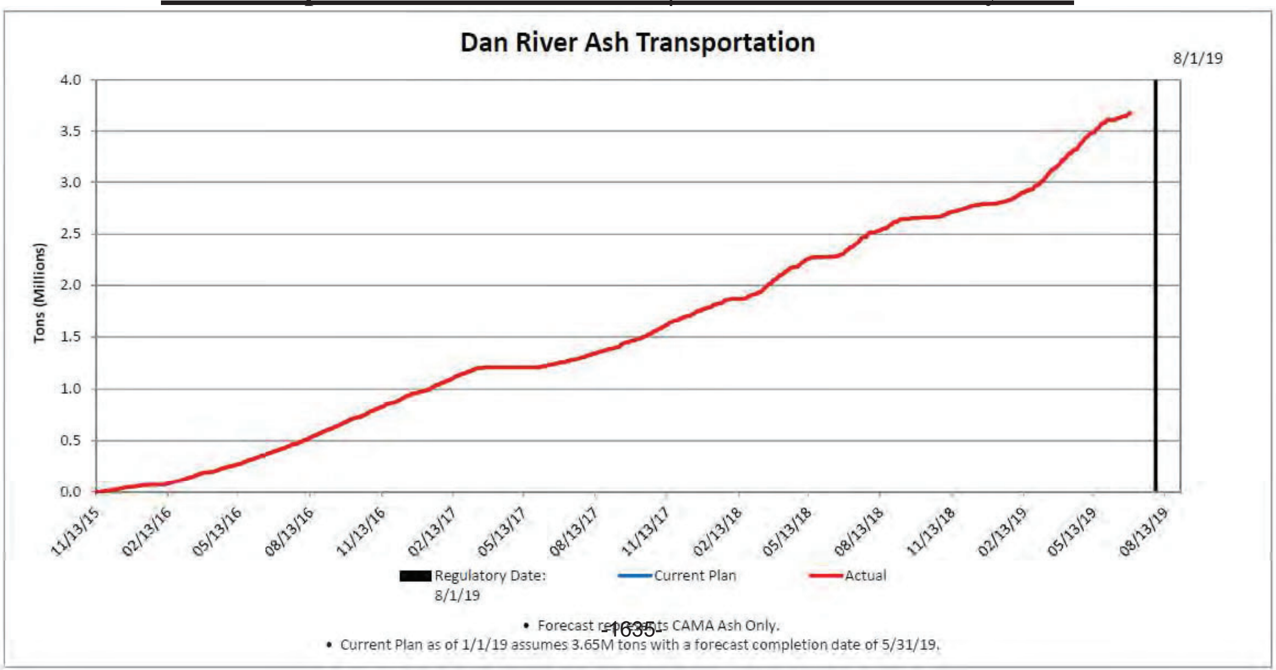
Aerial View June 2017

Aerial View August 2018

Aerial View January 2019

Aerial View June 2019

Ash Transported in Millions of Tons | November 2015 to May 2019



	Extrapolate Points From Graph Tons	Average between Points Tons		Date	Actual CY	Actual Tons	Planned Tons	Planned CY	8.1 Milestones CY
6/13/2017	1.20E+06	33,333		Jun-17	27,778	33,333	30,000	25,000	25,000
		33,333		Jul-17	55,556	66,667	63,600	53,000	28,000
	1.30E+06	33,333		Aug-17	83,333	100,000	97,200	81,000	28,000
		100,000		Sep-17	166,667	200,000	130,800	109,000	28,000
		100,000		Oct-17	250,000	300,000	164,400	137,000	28,000
	1.60E+06	100,000		Nov-17	333,333	400,000	198,000	165,000	28,000
		66,667		Dec-17	388,889	466,667	318,000	265,000	100,000
		66,667		Jan-18	444,444	533,333	438,000	365,000	100,000
	1.80E+06	66,667		Feb-18	500,000	600,000	558,000	465,000	100,000
		133,333		Mar-18	611,111	733,333	678,000	565,000	100,000
		133,333		Apr-18	722,222	866,667	798,000	665,000	100,000
	2.20E+06	133,333		May-18	833,333	1,000,000	996,000	830,000	165,000
		116,667		Jun-18	930,556	1,116,667	1,194,000	995,000	165,000
		116,667		Jul-18	1,027,778	1,233,333	1,392,000	1,160,000	165,000
	2.55E+06	116,667		Aug-18	$\boxed{1,125,000}$	1,350,000	1,590,000	$\boxed{1,325,000}$	165,000
	Average Tons	90,000							1,325,000
	Average CY	75,000		Behind as of Aug 31st	200,000	CY			
				ADD ASH Moved From Ash Stack 2	168,000				
					368,000				
				Amount in White paper	352,368				

Complete Sequence 1 & 2 September 2018

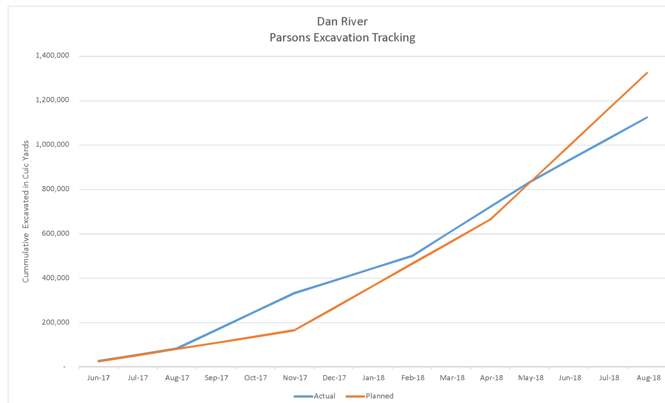


Exhibit C	Sequence 1	1,235,000
	Sequence 2	105,500
		1,340,500
	INCREASE	460,000 CY
		34%

Duke Energy Carolinas
Response to
North Carolina Public Staff Data Request
Data Request No. NCPS 231

Docket No. E-7, Sub 1214

Date of Request: **March 9, 2020**
Date of Response: **March 11, 2020**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to North Carolina Public Staff Data Request No. 231-8, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to North Carolina Public Staff under my supervision.

Camal O. Robinson
Associate General Counsel
Duke Energy Carolinas

North Carolina Public Staff
Data Request No. 231
DEC Docket No. E-7, Sub 1214
Item No. 231-8

Request:

8. On page 20, line 22 through page 21, line 2 of her rebuttal testimony, witness Bednarcik states, "Through this process and by implementing lessons learned from other excavation projects, including how to accurately assess bottom of ash floor grades and estimated soil waste, the Company's estimate increased by at least 552,000 tons over the course of the project."
a. Please provide the date that borings were first performed at the Dan River site to assess bottom of ash grades.
b. Please provide an explanation of how long Duke Energy anticipated it would take to excavate this additional ash.
c. Please provide a timeline of the increases in the total ash estimate netting an additional 552,000 tons, including each date the estimate changed and the estimate as of each date.

Response:

a. The first date of borings/wells for conceptual closure was 6/3/2013 as provided in the "Data Report – Ash Basin Closure – Conceptual Design" (amec, 9/20/2013). An excerpt from the data report summary tables is attached as back-up.

PS DR 231-8a First
Borings and Wells.p

b. As set forth in Purchase Order Number 5067043 Exhibit B Section 8.1 Key Milestones, the production rate for Sequences 1, 2 & 3 beginning in May 2018 was 165,000 CY (198,000 tons) per month. As such, the estimated time to excavate the additional 552,000 tons was 2.8 months. The Purchase Order was provided in the response to PS DR 2-9.

c. See attached spreadsheet 'PS DR 231-8c Dan River CCR quantity history.xlsx'

PS DR 231-8c Dan
River CCR quantity h

History of CCR Quantity Estimates at Duke Energy's Dan River Steam Station[1]

CCR Estimate Iteration	CCR Quantity[2]				Notes
	Primary and Secondary Ash Basin (tons)	Ash Fill 1[3] (tons)	Ash Fill 2[3] (tons)	Total	
1	1,802,887	not calculated	not calculated	N/A	1/22/2014, AMEC, conceptual closure design
2	1,603,366	954,487	414,588	2,972,441	7/14/2017, Amec Foster Wheeler, Dam Decommissioning Sequence A
3	2,152,614	1,342,460	580,006	4,075,080	9/7/2018, Wood, "Estimated Material Quantities for Closure of On-Site CCR Units - CCR Volume and Landfill Airspace"
4	2,152,614	1,342,460	580,006	4,075,080	10/10/2018, Wood, "Estimated Material Quantities for Closure of On-Site CCR Units - CCR Volume and Landfill Airspace - Revision 1"
5	2,176,626	1,342,460	580,006	4,099,092	1/14/2019, Wood, "Estimated Material Quantities for Closure of On-Site CCR Units - CCR Volume and Landfill Airspace - Revision 2"
6	2,116,120	1,339,204	634,224	4,089,547	1/31/2020, Wood, "Estimated Quantities of CCR Disposal at Duke Energy's Dan River Station"

unit weight	**1.2**	**tons/cy**

Notes:

1. This table summarizes quantity estimates available to the author at the time of summary and may not be an exhaustive list of calculations developed for this site.
2. Assumes CCR unit weight of 1.2 tons/cy.
3. Ash Fill 1 and 2 quantities may include cover soil and soil spoil piles that were placed within the ash fill footprints.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 181

Docket No. E-2, Sub 1219

Date of Request:	**May 6, 2020**
Date of Response:	**May 13, 2020**

☐ **CONFIDENTIAL**

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No.181-2, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

2. On page 11, lines 9-14 of her rebuttal testimony, witness Bednarcik states, "Charah incurred significant capital expenditures to acquire the Brickhaven and Sanford Clay Mines – which could accommodate 12 million tons of ash and 8 million tons of ash, respectively – and upfit them to safely accommodate ash disposal, including by installing railway to physically access the Brickhaven mine and preparing the sites to store the transported CCR."

Please provide the page and section numbers or excerpts from the Charah Master Contract that required Charah to completely develop the Brickhaven and Sanford Clay Mines for ash disposal.

Response:

The Master Contract does not state that Charah was to "completely develop the Brickhaven and Sanford Clay Mines for ash disposal" (emphasis added), but rather Section 7.3 of Exhibit B in the contract states: "Contractor agrees that Contractor will develop the Brickhaven and Sanford Clay Mines only as reasonably necessary to accommodate the phased volumes of Ash to be loaded, transported and placed at the Mines under the applicable Purchase Orders and as reasonably necessary to comply with the permits in effect at such Mines." This language was retained in Revision 1 to the Master Contract in Section 7.3(b). Pursuant to this language, Charah, in fact, developed each site as "reasonably necessary" to accommodate ash to be excavated under issued Purchase Orders. Some access improvements were implemented at Sanford, as shown in the response to PS DR 181-9. As shown in the response to DEC PS DR 112-20, the actual development costs identified by Charah were different between Brickhaven and Sanford sites, showing that they were developed to a different extent to meet the requirements of Section 7.3 of the Master Contract. And, as shown in "Bednarcik Rebuttal Exhibit 3", the "Development/Acquisition" actual costs for Brickhaven were $76,295,517 compared to $5,113,934 for Sanford – again, showing that they were developed to a different extent.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 181

Docket No. E-2, Sub 1219

Date of Request:	**May 6, 2020**
Date of Response:	**May 13, 2020**

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The attached response to NC Public Staff Data Request No.181-4, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

4. Please indicate whether witness Bednarcik is asserting on page 14, line 8 of her testimony that, at the time it entered into Contract 8323, Duke knew the pricing for some of the costs of development (synthetic and clay liners, temporary caps, anchor trenches, and temporary and final seeding), but the remaining cost (e.g., purchasing the properties, construction of the leachate management system, infrastructure construction, and rail construction, and obtain all permits) were unknown.

Response:

Known pricing for certain items are identified in Master Contract 8323, dated November 12,2014 and are contained in Exhibit E; Alternative pricing is contained in Exhibit F and Exhibit G. Unknown costs were not included in the Master Contract.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 181

Docket No. E-2, Sub 1219

Date of Request:	**May 6, 2020**
Date of Response:	**May 13, 2020**

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The attached response to NC Public Staff Data Request No.181-5, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

5. On page 14 of her rebuttal testimony, witness Bednarcik states, "The development costs that were included in the per ton price of the purchase orders were markedly different from the development costs intended to be captured by the fulfillment fee." Please explain how Charah would have been compensated for the "costs intended to be captured by the fulfillment fee" had Duke delivered 20 million tons of coal ash for disposal at the Brickhaven and Sanford mines.

Response:

There is initial development and ongoing development that make up development costs. The "**Prorated Cost**" is the contractual mechanism that determines termination costs and uses a "**Prorated Percentage**" to determine that value. The definition of "**Prorated Percentage**" is defined in Contract 8323, Exhibit B, Section 1 Definitions, Rules of Construction, Order of Precedence, Section 1.1 and is shown below:

"**Prorated Percentage**" means with respect to the Brickhaven and Sanford Clay Mines, as of any date of determination, the amount of such land acquisition, development, closure, post-closure monitoring, and leachate collection and disposal costs not recovered by Contractor through the payment by Duke Energy of the "Unloading/Development/Placement" portion of the applicable Per Ton Prices for the total tonnage of Ash transported to the Brickhaven and Sanford Clay Mines as of such date, which the parties agree shall be equal to one (1) less the percentage determined by dividing (a) the total tonnage of Ash transported to the Brickhaven and/or Sanford Clay Mines under the Agreement as of such date by (b) twenty million tons of Ash (20,000,000) less any Tons of Third Party Ash placed in the Brickhaven and/or Sanford Clay Mines as of such date. *(underline added for emphasis)*

The "**Prorated Percentage**" by contract definition is [1 **-** (7,342,409 tons / 20,000,000 tons)] and is approximately 63.288% and is nothing more than a percent calculation by Contract.

The definition of "**Prorated Cost**" is defined in Contract 8323, Amendment 1, dated January 7, 2015, 1., Amendment to Section 1.1 of Exhibit B and is shown below:

"**Prorated Cost**" means, with respect to the Brickhaven and Sanford Clay Mines, as of any date of determination, an amount equal to (a) the actual cost incurred by Contractor for land acquisition and development and expected to be incurred by Contractor for closure, post-closure monitoring, and leachate collection and disposal for and at the Brickhaven and Sanford Clay Mines as of such date multiplied by (b) the Prorated Percentage, as such amount may be modified or adjusted by the parties pursuant to the process described in Section 7.3. The parties agree that in no event following the Prorated Cost Triggering Event will the Prorated Costs exceed (i) at any time prior to Contractor commencing rail installation and cell preparation Services at the Brickhaven or Sanford Clay Mines, $25,000,000, (ii) at any time following the commencement by Contractor of rail installation and cell preparation Services at the Brickhaven or Sanford Clay Mines, but prior to the placement of any Ash at the Brickhaven or Sanford Clay Mines, $35,000,000 and (iii) at any time following the placement of Ash at the Brickhaven or Sanford Clay Mines, $90,000,000.

So, the "**Prorated Cost**" is simply what was spent by the Contractor at Brickhaven and Sanford Clay Mines multiplied by the "**Prorated Percentage**" (a percentage defined by Contract defintion) and the "**Prorated Cost**" is limited to $90,000,000 after placement of any Ash at the Brickhaven and Sanford Clay Mines.

If Duke Energy had delivered 20 million tons of coal ash to the Brickhaven and Sanford mines, the cost per ton for subsequent purchase orders would have been adjusted to account for all the costs incurred by Charah, including those that were included in the negotiated fulfillment fee. When looking at the price per ton actually recovered in the purchase orders that were issued for Riverbend and Sutton versus the overall costs that were identified in the "prorated costs" definition provided above, the price per ton collected for the ash actually sent to Brickhaven did not adequately cover all costs. And as no purchase orders were issued for Sanford, all costs incurred were included in the negotiated fulfillment fee.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 181

Docket No. E-2, Sub 1219

Date of Request:	**May 6, 2020**
Date of Response:	**May 13, 2020**

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The attached response to NC Public Staff Data Request No.181-8, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

8. On page 15, lines 8-11, of her rebuttal testimony, witness Bednarcik states, “Charah actually incurred development costs for the Sanford site to receive the planned-for ash, including, but not limited to, capital expenses to purchase the property, as well as anticipated Site Closure and Post Closure costs required for compliance with the Mine Reclamation Permit.”
a. Please provide the page and section numbers or excerpts from the Charah Master Contract that led Charah to believe it had to purchase the Sanford site.
b. Please explain if Charah incurred the anticipated Site Closure and Post Closure costs at the Sanford site in the amounts of $8,927,540 and $1,212,500 as shown on witness Bednarcik’s Confidential Rebuttal Exhibit 3.

Response:

a. As shown in the “CONFIDENTIAL Phase 1 Excavation Package Executive Summary 11112014” document provided in response to the DEP PS DR 5-8 in the 2017 DEP Case, at the time of award “Charah’s expected price is based on utilizing a clay reclamation mine that Charah has not permitted. There is a high probability Charah will be successful in purchasing and permitting the clay reclamation mine.” Charah also provided alternative pricing and locations if they were not able to obtain and/or permit the Brickhaven and Sanford mines. Since the Master Contract included the 20,000,000 ton number, as discussed throughout the Rebuttal Testimony, and the Brickhaven mine had a fill capacity of 12 million tons and the Sanford mine had a fill capacity of 8 million tons, the commitment was that Charah would be able to manage 20 million tons. This is further confirmed by the following provisions: - In Exhibit B of the Master Contract, o the definition of “fill site(s)” states “Fill site(s) means, if applicable, the site(s) owned by Contractor that is/are identified in the Purchase Order for the placement and beneficial reuse of the Ash as beneficial structural fill.” (Emphasis added)_. The word “owned” means that Charah purchases and owns the sites. (note, this definition was changed in revision 2 to include “any site(s) that are owned by Contractor’s third party customer.” o Section 7.3: “In connection with such determination, at Duke Energy’s request and in Duke Energy’s sole discretion, Contractor will transfer such Mines to Duke Energy…” – how could they transfer it to us if they did not own it? o Throughout the original contract, there are references to the fact that if the “Contractor [should] be unable to transport the Ash to the Brickhaven Clay Mine for any reason approved by Duke Energy or any restriction under and Environmental Law, Seller has identified the Sanford Mine… as its first alternative location.” There was another alternative location identified if Brickhaven and Sanford were not available – the Anson County Landfill in Polkton, NC (this was identified in Exhibit G of the Master Contract.) - In the Master, Amendment 1 o Section 1.1 (a) definition of “deemed terminated” includes a provision of termination when “Duke Energy does not make available Ash to be placed at either the Brickhaven or Sanford Clay Mines as the primary placement Site or Seller is prohibited from placing Ash at Brickhaven and Sanford Clay Mines due to a change in applicable Environmental Law following the occurrence of the Prorated Cost Triggering Event…” o Section 1.1 (b) definition of “prorated costs” has as a base the “actual cost incurred by Contractor for land acquisition and development and expected to be incurred by Contractor for closure, post-closure monitoring, and leachate collection and disposal for and at the Brickhaven and Sanford Clay Mines…" (emphasis added) Also, there a minimum of $25,000,000 payment – that was if there was NO development. Therefore, that shows the purchase of the property occurred just for Duke. b. The Company has not undertaken to confirm whether or not Charah has yet incurred the $8,927,540 and $1,212,500 costs for Site Closure and Post Closure, respectively, at the Sanford site. Regardless of whether such costs have already been incurred, however, they are costs that Charah will eventually occur and, therefore, were rolled into negotiations for the fulfillment fee.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 181

Docket No. E-2, Sub 1219

Date of Request: **May 6, 2020**
Date of Response: **May 13, 2020**

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Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No.181-9, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

Request:

9. On page 17, lines 14-17 of her rebuttal testimony, witness Bednarcik states, "In addition, Amendment 1, Section 7.3(c) provides that "[t]he parties acknowledge and agree that the actual Prorated Costs will depend to a significant degree upon the amount of Ash placed at the Site(s) and the status of the Site(s) at the time of termination." Please provide a detailed description of the Sites at the time of termination.

Response:

As stated in the response to PS DR 181-7 and shown in "Bednarcik CONFIDENTIAL Rebuttal Exhibit 4, question 4, no ash was placed at the Sanford Clay Mine Site. At the Brickhaven Mine Site, 7,342,409 tons of ash was placed. The definition of "Site(s)" is defined in Contract 8323, Exhibit B, Section 1 Definitions, Rules of Construction, Order of Precedence, Section 1.1 and is shown below:

"Site(s)" means, as applicable, the Fill Site or Permitted Landfill.

Further, the definition of "Fill Site" is defined in Contract 8323, Exhibit B, Section 1 Definitions, Rules of Construction, Order of Precedence, Section 1.1 and is shown below:

"Fill Site(s)" means, if applicable, the site(s) owned by Contractor that is/are identified in the Purchase Order for the placement and beneficial reuse of the Ash as beneficial structural fill.

To the best of the Company's recollection, at the time of termination:

- The Sanford Site had some access road improvements, and some land clearing activities had occurred. Surveying and geotechnical investigations had been conducted but no construction activities had occurred related to cell development.
- The Brickhaven Site had the following featured constructed on-site to support the receipt, unloading and placement of ash:

• A two mile rail spur from the main CSX line was constructed to support receipt of ash by train. The rail included one track approximately one mile in length off the main line and four tracks of sufficient length to accept two loaded trains of 85 cars, one track for storage of emptied cars and one run-around track for egress by CSX locomotives. The rail spur included construction of two bridges to allow crossing streams and wetlands. The rail unloading area was constructed to allow rail cars to be unloaded into haul trucks that transported the ash to the structural fill. Haul roads were constructed to support hauling ash from the unloading area to the active placement areas of the facility.

• The structural fill had been lined with a water proof barrier consisting of layers of clay, geo-composite material and HDPE liner. The clay had been mined from the Brickhaven site. A leachate collection system had been constructed to support collection of leachate which was being pumped to storage tanks and then into haul trucks for transport to offsite treatment facilities.

• The coal ash that was transported to the site had been placed in the structural fill and had been covered with temporary cover. The placement of the final cover system was in progress.

Duke Energy Progress
Response to
NC Public Staff Data Request
Data Request No. NCPS 181

Docket No. E-2, Sub 1219

Date of Request: **May 6, 2020**
Date of Response: **May 13, 2020**

☐ **CONFIDENTIAL**

☒ **NOT CONFIDENTIAL**

Confidential Responses are provided pursuant to Confidentiality Agreement

The attached response to NC Public Staff Data Request No.181-11, was provided to me by the following individual(s): Trudy H. Morris, Project Manager II, and was provided to NC Public Staff under my supervision.

Camal. O. Robinson
Associate General Counsel
Duke Energy Progress

North Carolina Public Staff
Data Request No. 181
DEP Docket No. E-2, Sub 1219
Item No. 181-11
Page 1 of 1

Request:

11. On page 23, line 20 through page 24, line 5, of her rebuttal testimony, witness Bednarcik states in part, "Mr. Garrett's contention that the Company did not incur any closure or post-closure costs at the Sanford Clay Mine is incorrect" and "These expenses are described in the Company's Responses. . . attached hereto as Bednarcik Rebuttal Exhibit 4." Regarding these statements, admit that Bednarcik Rebuttal Exhibit 4 describes estimated closure and post closure costs at the Sanford/Colon site and not actual costs incurred.

Response:

DEP admits that Bednarcik Rebuttal Exhibit 4 describes estimated closure and post closure costs at the Sanford/Colon site and not actual costs incurred.

Corrected Allen basin names 03/15/18

Ash Basin Information

Site	Basin	When constructed	Ash in Tons as of 8/7/17 (Millions)	When closed if applicable	CCR Applicable?
DEC					
Allen	Retired basin	1957	6.2	1973	Y
	Active Basin	1972	10.4	n/a	Y
Belews Creek	Active basin	1972	12.2	n/a	Y
Buck	Basin #1	1957	3.6	2013	Y
	Basin #2	1977	2	2013	Y
	Basin #3	1977	0.9	2013	Y
Cliffside	U1-4 inactive basin	1957	0	1977	Y
	U5 inactive basin	1970	2.4	1980	Y
	Active basin	1980	5	n/a	Y
Dan River	Primary basin	1956	1.2	2012	Y
	Secondary basin	1977	0.4	2012	Y
Marshall	Active basin	1965	16.7	n/a	Y
Riverbend	Primary basin	1957	1.1	2014	N
	Secondary basin	1957	1	2014	N
WS Lee	Primary basin	1974	2.2	2014	Y
	Secondary basin	1978	0.03	2014	Y
	1951/1959 inactive basin	1951	0.07	1974	N