# Future Emissions Control Technology Cost Estimates for Neil Simpson 1, Osage 1-3 and Ben French 1

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## Introduction

As a result of the recently adopted Environmental Protection Agency (EPA) Maximum Achievable Control Technology (MACT) rules and future requirements for achieving reasonable further progress for regional haze, Black Hills Power (BHP) requested that CH2M HILL perform an analysis on several of its generating units. The analysis is to estimate the capital cost to add emission controls to these units to meet these existing and future air pollution control requirements. The units under consideration are Neil Simpson Unit 1, Osage Units 1, 2, & 3, and Ben French Unit 1.

The analyses included a review of the promulgated and the proposed EPA MACT rules and anticipated reasonable further progress rules, and the development of a preliminary determination of required $NO_x/SO_2/PM_{10}$ emissions control levels necessary to meet these future requirements. A scaled cost estimate was developed for those identified technologies, with a level of accuracy of ± 50%.

Due to schedule constraints, no site visits were made. BHP provided layout drawings, site photos, and emissions test reports for the five units under consideration. Potential construction issues, equipment layout constraints, and site information were discussed with BHP. Accordingly, only conceptual retrofit issues were considered at this preliminary stage of analysis.

## Regulatory Review

The regulatory requirements for the Black Hills control technology evaluation are described below.

### Requirements for Regional Haze Reasonable Further Progress

The rules for achieving the first round of Reasonable Further Progress requirements for Regional Haze reduction are in various stages of development by the states. Colorado recently submitted their Reasonable Progress plan to EPA, which as a result of EPA intervention, required the inclusion of small non-eligible BART plants, to include one of Black Hills' units. Therefore with knowledge of plan requirements in other Region 8 states, we assume the recent Best Available Retrofit Technology (BART) limits that have been applied to other larger coal-fired utility boilers in the West will now be applied to these smaller units for states to demonstrate reasonable further progress. The presumptive limits in the 2005 BART rule do not apply to any of these units since those limits are for units (boilers) greater than 200 MW located at plants having a total generation capacity greater than 750 MW. None of the candidate units are this large.

EPA Region 8 has been scrutinizing and rejecting state plans, specifically due to perceived insufficient reductions in $NO_x$ emissions. We fully expect, as occurred in Colorado and most recently in North Dakota, that EPA will intervene in some fashion, with the end result being the inclusion of a close examination of these Black Hills' units.



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Even though the BART presumptive limits do not specifically apply, we have used them as reference. From recently completed BART studies conducted for other western coal fired power plant units, BART emission rates were established and are assumed to be applicable to the Black Hills units under consideration. Those levels require fabric filters for particulate control and lime spray driers for $SO_2$. In these other BART studies we generally concluded that SCR for NOx control was not appropriate. However, EPA has recently been overruling this conclusion and is causing the states to require SCR regardless of BART analysis conclusions. As a result, this analysis includes SCR as a worst case level of NOx control that may or may not be justified on all of these units. However, the SCR cost estimates were developed to analyze the economic impact on each unit for these types of controls in case they would be required in the future to achieve reasonable further progress for regional haze.

### MACT Requirements

EPA's Final Area Source Industrial Boiler MACT rule impacts all five units. The area source industrial boiler MACT rules went into effect on March 21, 2011. The existing Black Hills boilers which are rated at less than or equal to 25 MW will be subject to Industrial Boiler Area Source mercury and CO standards. These requirements will apply to Ben French Unit 1, Neil Simpson Unit 1 and Osage Units 1-3, and are detailed below:

- Applicable to existing coal-fired boilers of heat input greater than 10 MMBtu/hr, and are rated at less than or equal to 25 MW.
- Mercury emissions limit of 0.0000048 lb/MMBtu (44% more restrictive than the limit in Black Hills' new Wygen 3 coal fired unit at the Neil Simpson Complex near Gillette, WY)
- Carbon Monoxide emissions limit of 400 ppm by volume on a dry basis

### BART Requirements Review

In evaluating the potential regulatory required emissions levels, Best Available Retrofit Technology (BART) presumptive emission limits for $NO_x$ and $SO_2$ were examined. The BART rules generally applied to units larger than the five Black Hills units under consideration within this analysis. However, the BART presumptive limits provide a reasonable basis for consideration when determining achievable levels of emissions:

- NOx: For dry bottom wall-fired boilers (Neil Simpson Unit 1) burning sub-bituminous coal, the presumptive limit is 0.23 lb/MMBtu. No presumptive limits were established for stoker-fired or cyclone boilers.
- $SO_2$: Removal of 95% or emission rate of 0.15 lb/MMBtu
- PM: No specific BART guideline, however CH2M Hill generally considers a filterable particulate emission rate of 0.015 lb/MMBtu to be a BART emission level.

## Present Unit Conditions

### Neil Simpson Unit 1

Neil Simpson Unit 1 is a 21.7 MW coal fired unit located at the Wyodak facility near Gillette, WY. The unit has a wall fired boiler manufactured by Foster Wheeler, and an electrostatic precipitator for particulate emissions control. There are low NOx burners installed to reduce NOx emissions, and no $SO_2$ emissions reduction equipment is currently installed.

## Osage Units 1-3

The Osage Station near Newcastle, Wyoming consists of three identical coal fired units, each rated at 11.5 MW. Each unit has a spreader-stoker boiler, and the flue gas first passes through cyclone mechanical collectors to remove large particles. Then the flue gas travels through a single shared ESP for additional particulate removal prior to being exhausted to atmosphere. Utilization of "good combustion practices" is practiced for NOx emissions reduction, and no $SO_2$ emissions reduction equipment is installed.

All three Osage units are currently not operating. Following the notification to the state of the suspension of operations, the state followed up by letter of September 21, 2010, advising that according to state regulation, if the units are not re-started within 5 years (October 1, 2015), the right to the continued use of the air resource necessary to accommodate the emissions from Osage will be forfeited. A re-start after October 1, 2015 would constitute the operation of a new facility and would have to be permitted as such.

## Ben French Unit 1

Ben French Unit 1 is a 25 MW coal fired unit located in Rapid City, South Dakota, and utilizes a cyclone Babcock & Wilcox boiler. The Title V permit does not include a NOx emission permit limit, and the $SO_2$ and particulate limits are listed below in Table 1. Particulate emissions control is provided by a Research Cottrell electrostatic precipitator (ESP). Utilization of "good combustion practices" is practiced for NOx emissions reduction, and no $SO_2$ emissions reduction equipment is installed.

**TABLE 1**
Unit Background Information

| | Neil Simpson Unit 1 | Osage Units 1-3 | Ben French Unit 1 |
|---|---|---|---|
| Boiler Type | Wall-Fired | Spreader-Stoker | Cyclone |
| Coal[2] | Sub-bituminous | Sub-bituminous | Sub-bituminous |
| Flue Gas Flow (Nominal) | 125,000 acfm | 85,000 acfm Each | 160,000 acfm |
| Unit Rating | 21.7 MW | 11.5 MW Each | 25 MW |
| Design Heat Input | 293 MMBtu/hr | 160 MMBtu/hr Each | 263 MMBtu/hr |
| Current Permit $NO_x$ Emissions Rate | 0.75 lb/MMBtu | 0.75 lb/MMBtu | N/A |
| Current Permit $SO_2$ Emissions Rate | 1.2 lb/MMBtu | N/A | 3.0 lb/MMBtu |
| Current Permit Particulate Emissions Rate | 0.33 lb/MMBtu | 0.31 lb/MMBtu & 40% Opacity | 0.39 lb/MMBtu & 20% Opacity |
| Site Constructability[1] | C | A | A |

[1]Factor describing available site space and ease of construction (A-normal, B-moderately difficult, C-very difficult)
[2]All units burn coal from the Wyodak Resources mine near Gillette, WY

## Test Results

The following Table 2 summarizes available testing results for the units. The test results demonstrate compliance with current permit levels.

**Table 2 – Emission Test Results**

| Unit | Ben French 1 | | Neil Simpson 1 | | Osage 1-3 |
|---|---|---|---|---|---|
| Test Date Parameter | August 17, 1995 (with Bypass) | March 21, 2002 | September 21 & 23, 2010 | June 29, 2008 | September 28, 2009 |
| $NO_x$ (lb/MMBtu) | | 0.837 | 0.23 | | 0.4 |
| $NO_x$ (lb/hr) | | 299.5 | | | |
| $SO_2$ (lb/MMBtu) | | 0.724 | | 1.36 | |
| $SO_2$ (lb/hr) | | 258.9 | | | |
| Total PM (lb/MMBtu) | 2.77 | 0.036 | 0.02 | | 0.004 |
| Total PM (lb/hr) | | | | | |
| $PM_{10}$ (lb/MMBtu) | 2.0775 | | | | |
| $PM_{10}$ (lb/hr) | 0.0345 | | | | |
| $PM_{2.5}$ (lb/MMBtu) | 0.0184 | | | | |
| $PM_{2.5}$ (lb/hr) | 1.108 | | | | |
| Average Dry Standard Stack Flow Rate (dscfm) | | 89,915 | 67,282 | | |
| Average Actual Stack Flow (acfm) | | 164,927 | | | 251,100 |
| Calculated Actual Stack Flow (acfm) | | | 127,789 | | |

## Technology Review

After consideration of applicable regulatory requirements described above, an evaluation of site conditions and available emissions control technologies were completed for each unit. The selection of control technologies was not made through a detailed economic evaluation process, but rather through matching technology capabilities with emission level requirements.

The current regulatory environment is promulgating new MACT rules and achieving reasonable further progress for regional haze, which will require more stringent emission rates for both criteria and hazardous air pollutants (HAPS). These new regulations will require a significant upgrade to the existing emissions control equipment on all of the units under consideration. Therefore, a conservative approach was utilized in selection of the technologies for each unit, which is based on achieving a high probability of attaining emission rates which meet future regulatory requirements and expectations.

### *Neil Simpson Unit 1*

Neil Simpson Unit 1 has a wall-fired boiler, and therefore the relevant BART presumptive limit for NOx emissions for this type of boiler design is 0.23 lb/MMBtu. From the 2010 test information, Neil Simpson Unit 1 is meeting this NOx emission rate. However, to meet anticipated regulatory requirements an SCR is considered the technology most probable of being required for Neil Simpson Unit 1. While new low NOx burners and/or selective non-catalytic reduction (SNCR) may be able to achieve additional NOx reduction, the resultant emissions rate will not be as low as the projected NOx emission rate of 0.07 lb/MMBtu from an SCR system.

This unit is subject to the Industrial Boiler Area Source requirements which include a carbon monoxide emission limit. Reducing CO emissions through combustion controls typically increases NOx emissions and could potentially affect the ability of the unit to meet NOx emission limits without additional NOx controls.While Neil Simpson Unit 1 also currently meets the $SO_2$ and particulate permit limits of 1.2 lb/MMBtu and 0.33 lb/MMBtu respectively, these emission rates are higher than BART and anticipated acceptable regulatory emission levels. Therefore, a new SDA and fabric filter are recommended for Neil Simpson Unit 1 to achieve an $SO_2$ emissions rate of 0.15 lb/MMBtu and a filterable particulate emission rate of 0.015 lb/MMBtu.

Because of the congested site and equipment configuration, the Neil Simpson Unit 1 retrofit site complexity is considered "very difficult". There is very little site area and construction access available, which will significantly add to the overall equipment installation cost.

### *Osage Units 1-3*

The Osage Units 1-3 boilers are spreader-stoker design, and therefore do not have a BART identified NOx emissions presumptive limit. The operating permit NOx limit is 0.75 lb/MMBtu, and test results show that emissions are within this limit. There are no low NOx burner retrofits available for a spreader-stoker unit, and SNCR will provide limited NOx emissions reduction. Therefore, the installation of an SCR system is anticipated to meet regulatory expectations for Osage Units 1-3 to achieve a NOx emissions rate of 0.07 lb/MMBtu.

This unit is subject to the Industrial Boiler Area Source requirements which include a carbon monoxide emission limit. Reducing CO emissions through combustion controls typically increases NOx emissions and could potentially affect the ability of the unit to meet NOx emission limits without additional NOx controls.

Since there are no $SO_2$ permit limits for the Osage units, there is no $SO_2$ reduction equipment in place. The particulate emission permit limit is 0.31 lb/MMBtu, and particulate control is achieved by flue gas from each unit being combined and passed through a single ESP. Since the $SO_2$ emissions are uncontrolled, and the particulate emission rate is higher than BART a new SDA and fabric filter are recommended for Osage Units 1-3 to achieve an $SO_2$ emissions rate of 0.15 lb/MMBtu and a filterable particulate emission rate of 0.015 lb/MMBtu.

From review of the site information provided, there is adequate retrofit space available for installation of required equipment. Therefore, the retrofit difficulty is considered "normal".

### *Ben French Unit 1*

With a cyclone boiler, Ben French Unit 1 does not have a BART identified NOx emissions presumptive limit. Cyclone boilers generally emit high NOx emissions, and the unit information indicates a tested NOx emissions rate of 0.837 lb/MMBtu. There is no $SO_2$ emissions removal equipment installed on Ben French Unit 1, and the tested $SO_2$ emissions were 0.724 lb/MMBtu. Particulate test information shows a result of 0.036 lb/MMBtu.

Since all of the tested NOx, $SO_2$, and PM emission rates for Ben French Unit 1 are in excess of the anticipated regulatory requirements, emission reductions will likely be required for all three of the criteria pollutants listed. Based upon this premise, the likely technology requirements for NOx, $SO_2$, and PM reduction on Ben French are Selective Catalytic Reduction (SCR), Spray Dryer Absorber (SDA), and fabric filter respectively to achieve a NOx emission rate of 0.07 lb/MMBtu, an $SO_2$ emissions rate of 0.15 lb/MMBtu and a filterable particulate emission rate of 0.015 lb/MMBtu.

This unit is subject to the Industrial Boiler Area Source requirements which include a carbon monoxide emission limit. Reducing CO emissions through combustion controls typically increases NOx emissions and could potentially affect the ability of the unit to meet NOx emission limits without additional NOx controls.

From review of the site information provided, there is adequate retrofit space available for installation of required equipment. Therefore, the retrofit difficulty is considered "normal".

### Technology Selection

As evidenced by recent EPA Region 8 actions together with activities in other Region 8 states, it is a safe assumption that these units will become subject to future Reasonable Further Progress requirements for the reduction in regional haze. With this assumption, the recommended technologies and emission limits for all of the units under consideration are identical; namely installation of an SCR, SDA, and fabric filter as shown in Table 3.

**TABLE 3**
Recommended Technology and Emission Levels

| | Neil Simpson Unit 1 | Osage Units 1-3 | Ben French Unit 1 |
|---|---|---|---|
| Target $NO_x$ Emissions Level | 0.07 lb/MMBtu | 0.07 lb/MMBtu | 0.07 lb/MMBtu |
| $NO_x$ Technology | SCR | SCR | SCR |
| Target $SO_2$ Emissions Level | 0.15 lb/MMBtu | 0.15 lb/MMBtu | 0.15 lb/MMBtu |
| $SO_2$ Technology | SDA | SDA | SDA |
| Target Filterable Particulate Emissions Level | 0.015 lb/MMBtu | 0.015 lb/MMBtu | 0.015 lb/MMBtu |
| $PM_{10}$ Technology[1] | Fabric Filter | Fabric Filter | Fabric Filter |
| Mercury Technology | Sorbent Injection | Sorbent Injection | Sorbent Injection |

[1]—Pulse jet Fabric filter Air/Cloth ratio assumed to be 3.5 to 1.0 for normal design, and 5.0 to 1.0 for polishing unit.

Converting these units to burn natural gas was also considered, however, existing gas pipeline capacity at the sites is not sufficient to support burning natural gas in the units. Conversion to natural gas fuel would also require installation of new Low-NOx burners, potential replacement of the superheater, and exposure to future price volatility for natural gas fuel. In addition, Black Hills would need to consider life extension for the units with conversion to gas which could result in EPA New Source Review (NSR) requirements and a new permit for the unit.

While the recommended technologies listed above addressed only the criteria pollutants and mercury emissions, this analysis did not specifically analyze control technologies for other MACT related pollutants such as acid gases and organic/inorganic HAPs. However, the installation of the emissions control configuration of SCR/SDA/fabric filter technologies has demonstrated the capability for significant reduction of the other MACT pollutants. Mercury emissions compliance is assumed to be met through a combination of the installed SCR/SDA/fabric filter and utilization of sorbent injection, as has been done at the Black Hill's Neil Simpson Complex at Gillette, WY. The rule requires continuous compliance with the mercury limit and is demonstrated by the following;

- A carbon injection rate must be established during the compliance test and the facility must maintain a 12 hour average injection rate at or above that established during the test;
- The mercury concentration in the coal must be established during the compliance test and future shipments of coal cannot exceed that level. The Black Hills Wyodak Mine will be required to establish sampling protocols and procedures that comply with requirements and more significantly, establish a system to segregate coal supplies to individual plants to support the compliance requirements. Sampling and separation of coal supplies is expected to result in a significant cost to the Wyodak Mine.

All of Black Hills units analyzed in this study are subject to the Industrial Boiler Area Source requirements. The carbon monoxide emission limits for the area source boilers is 400 ppmvd corrected to 3% $O_2$. CO is considered as a surrogate for organic HAPs so that the control of CO will also control emissions of the organic HAPs.

From review of available CO emissions information, and discussion with Black Hills, all of the units under consideration are capable, at least on a short term basis, of achieving the 400 ppmvd CO limit through implementation of good combustion practices. However, reducing CO emissions through combustion controls typically increases NOx emissions and could potentially affect the ability of the units to meet NOx emission limits.

The use of boiler combustion controls to consistently limit CO emissions to allowed levels will require higher excess air that contains oxygen flowing through each boiler. Continuous compliance with the CO limit is a requirement and compliance must be demonstrated through the use of an $O_2$ continuous emissions monitor, to be installed and maintained according to specific regulatory requirements. $O_2$ levels are established during the CO compliance test and the facility must maintain the 12 hour average $O_2$ content at or above that established during the compliance test. The capital and O&M costs of $O_2$ monitors, together with enforcement risk due to potential inability to balance CO and $NO_x$ emissions on these older units, is a significant consideration for Black Hills.

If additional CO reduction is required, a more detailed engineering evaluation would be required for each unit to determine the most applicable technology, expected CO emissions reduction, and potential increase in NOx emissions. New technologies are being developed to reduce CO emissions, such as adding oxidation catalysts to coal boilers. However, they are not yet being widely used so they were not evaluated further here.

## Emission Control Technology Cost Estimates

The cost estimates were prepared based on the following assumptions and approach:

- Estimates are based on overnight or current costs, with no escalation applied.
- No bottoms-up cost estimates were derived; rather estimating was completed by utilizing historical project costs and vendor information. This information was factored and adjusted to the individual unit information and site conditions.
- Estimates were developed by technology for each unit, and were estimated and presented on a stand-alone basis. If all of the technologies presented for each unit are implemented, some equipment, construction, and engineering cost savings may be realized. Installation of all $NO_x$, $SO_2$, and $PM_{10}$ technologies simultaneously has the potential of savings as compared to the sum of each individually presented technology estimates. However, installation of all of the technologies concurrently may also present construction challenges due to limited space around these units.
- Retrofit complexity factors were determined from review of the available site information, and discussions with BHP. No site visits were conducted on any of the units to visually determine retrofit difficulty.
- No economic evaluations were completed in developing the cost estimates, such as impacts to unit heat rate, alternative equipment layout, or optimization of integration of technologies.
- Due to the small size of all units reviewed in this analysis, project and cost inefficiencies are observed. Therefore, estimates are proportionally higher on a cost per kilowatt basis than would be the case if these controls were installed on larger sized units.
- Detailed balance of plant impacts were not analyzed; including boiler dynamic analysis, induced draft fan impacts, changes to ash handling systems, or degradation of heat rate.

The following table summarizes the estimated costs for the units considered:

**TABLE 4**
Black Hills Power MACT Emissions Control Technology Estimates

| Plant | Location | Technology | Unit Rating (MW) | Cost (2011 $) | Cost/kW (2011 $) |
|---|---|---|---|---|---|

| | | | | | |
|---|---|---|---|---|---|
| Neil Simpson Unit 1 | Gillette, WY | SCR | 21.70 | $14,122,000 | $651 |
| Neil Simpson Unit 1 | Gillette, WY | SDA | 21.70 | $5,341,000 | $246 |
| Neil Simpson Unit 1 | Gillette, WY | Fabric Filter | 21.70 | $4,675,000 | $215 |
| Osage Units 1-3 | Osage, WY | SCR | 34.50 | $22,795,000 | $661 |
| Osage Units 1-3 | Osage, WY | SDA | 34.50 | $9,720,000 | $282 |
| Osage Units 1-3 | Osage, WY | Fabric Filter | 34.50 | $10,211,000 | $296 |
| Ben French Unit 1 | Rapid City, SD | SCR | 25.00 | $14,527,000 | $581 |
| Ben French Unit 1 | Rapid City, SD | SDA | 25.00 | $6,170,000 | $247 |
| Ben French Unit 1 | Rapid City, SD | Fabric Filter | 25.00 | $5,236,000 | $209 |

### *Mercury Emissions Control*

The mercury limit in the Industrial Boiler rule is 44% more restrictive than the mercury limit in Black Hills' new Wygen 3 coal fired plant at the Neil Simpson Complex near Gillette, WY. Mercury emissions control, which obviously will be required to meet the Industrial Boiler rule, is assumed to be provided through the use of a sorbent injection system, in conjunction with the addition of SCR/SDA/Fabric Filter systems, as has been done at the Black Hill's Neil Simpson Complex near Gillette, WY. Sorbent injection has been proven as a feasible supporting mercury control technology, and only one system will be required for each plant site. There will be one system each required for Neil Simpson Unit 1, Osage Units 1-3, and Ben French Unit 1. In addition to the costs in Table 3, an estimated capital cost for each sorbent injection system was determined to be $1 million ($29 to $46/kW for the three sites). Black Hills has been able to demonstrate at the Neil Simpson Complex, that this combination of emission controls enables continuous compliance with mercury emission limits.

## Life Extension Cost Estimates

If the five units were to continue operating with new emission controls to meet the Area Source Industrial Boiler MACT and Regional Haze further progress requirements, then life extension would also be required for the units. The life extension upgrades needed at each facility would add to the total upgrade cost if investments of these magnitudes were made to each unit. The estimated life extension costs for the five units are listed in Table 5 below.

**TABLE 5**
Life Extension Cost Estimates

| | Neil Simpson Unit 1 | Osage Units 1-3 | Ben French Unit 1 |
|---|---|---|---|
| Boiler | $2,500,000 | $5,000,000 | $1,500,000 |
| Turbine Generator | $1,000,000 | $2,500,000 | $4,000,000 |
| Condenser/Cooling System | $600,000 | $1,500,000 | $550,000 |
| DCS System | $1,500,000 | N/A | $1,000,000 |
| Coal Storage & Preparation | $750,000 | $400,000 | $475,000 |
| Ash Handling & Storage | $350,000 | $2,500,000 | $75,000 |
| Other Plant Systems | $1,400,000 | $1,900,000 | N/A |
| TOTAL | $8,100,000 | $13,800,000 | $7,600,000 |
| ($/kW) | $373 | $400 | $304 |

**TABLE 5**
Life Extension Cost Estimates

| | Neil Simpson Unit 1 | Osage Units 1-3 | Ben French Unit 1 |
|---|---|---|---|

[1]—Pulse jet Fabric filter Air/Cloth ratio assumed to be 3.5 to 1.0 for normal design, and 5.0 to 1.0 for polishing unit.

The Neil Simpson Unit 1, Osage Units 1-3 and Ben French Unit 1 were all originally designed to be baseloaded. Future operation of the units is expected to be for cycling service which would result in additional operating and maintenance costs. These units cannot be ramped up quickly and they have very high heat rates when used for spinning reserve (i.e. approx. 16,000 Btu/kW-Hr). In addition, the extensive life extension work to these old coal fired power plants, required to make these emission control cost investments feasible, will attract the attention of EPA and third parties. As has been demonstrated in the recent past, it is safe to assume that as a result of life extension work, the EPA will initiate New Source Review (NSR) investigations, which historically have lead to significant capital costs to meet Best Available Control Technology (BACT) requirements for emission control equipment and emission limits similar to those of new plants.

An additional consideration is that Neil Simpson Unit 1, Osage Units 1-3 and Ben French Unit 1 all sluice their bottom ash. This is a potential issue based on EPA's proposed new coal ash disposal regulations which are likely to require dry bottom ash disposal. To convert these units to dry ash disposal would require that the existing ash sluice lines be terminated at a dewatering tank where the ash would settle and the water removed. The dewatered ash would then be trucked to the place of final disposal.