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Technical Brief on Application of BAT for NOx and Particulates

Lynemouth Biomass Conversion Project

Lynemouth Power Ltd

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1. Executive Summary

The former coal-fired Lynemouth power station has been converted to biomass firing following the permanent cessation of coal-burn during December 2015. AECOM has prepared this Technical Brief in support of the derogation request being made by the plant operator, Lynemouth Power Ltd, from specific criteria listed in the revised Large Combustion Plant Best Available Techniques Reference (LCP BRef) document and associated BAT conclusions published in 2017. This report is supplemented by the cost benefit analysis and environmental justification also prepared to support the derogation request.

The Lynemouth installation is classed as an existing plant under the Industrial Emissions Directive (IED). This technical brief considers the characteristics of the installation and how they impact on which techniques represent BAT for this installation for the control of NOx and particulates emissions. It seeks to demonstrate why additional secondary abatement, some of which is considered to be generally applicable to new large combustion plant by the LCP BRef, is not appropriate to be retrofitted on the Lynemouth installation based on its site specific design configuration, design operating life and operating conditions. Additionally, it considers the construction timescales and impacts for the retrofit of any additional secondary abatement at the plant, particularly the additional capital investment required and the impact on the revenue loss due to outages required to carry out the construction works.

The biomass-conversion project manufacturer guaranteed NOx emission limit from each unit of the plant is 200 mg/Nm^3 compared with the annual average upper Best Available Techniques Associated Emission Level (BAT-AEL) of 160 mg/Nm^3 for an existing plant. For dust, the corresponding guaranteed emission limit is 20 mg/Nm^3 against the annual average upper BAT-AEL of 10 mg/Nm^3. While it is possible that the combustion units will achieve lower emissions on some of the biomass fuel feedstocks sourced for the installation, the combustion optimisation process has not yet been completed, and so the emissions performance of the units across a wide range of potential feedstocks is still unknown.

The biomass conversion was designed based on Annex V of the Industrial Emissions Directive (IED), as the existing LCP BRef (published in 2006) was under consultation for revision at the time of design development, with no certainty available regarding revised emission limit values (ELVs). As part of the biomass conversion project, several upgrades were made at the installation, and primary combustion measures to optimise biomass combustion and minimise emissions from the installation were installed.

The ELVs stated in Annex V of the IED aligned with the draft proposed daily BAT-AEL of 200mg/m^3 for this class of plant, and was therefore considered appropriate as design ELVs. In addition, the feedback from the UK LCP BRef Technical Working Group ("UK Split View - BAT AELS for NOx from biomass fired plant") considered the revised BAT-AELs for biomass fired combustion plants having an input of >300MWth to be inappropriate, mainly since most of the plants in the category comprise former coal fired plants retrofitted to fire using biomass, such as the Lynemouth power station, which are therefore limited by the technical characteristics of existing facility.

For the purpose of this analysis, AECOM assumes that to achieve the revised BAT-AELs specified in the LCP BRef, an improvement in the guaranteed performance of 40 mg/Nm^3 for NOx and 10 mg/Nm^3 for dust would be required. This raises the question of whether additional secondary control measures need to be applied and what type of measures could be employed. In the case of NOx, the addition of selective non-catalytic reduction (SNCR) or selective catalytic reduction (SCR) processes are the two potential technologies to achieve this level of reduction. For particulate or dust, further electrostatic precipitator (ESP) enhancements present the only viable solution for a biomass fired plant, although the use of fabric (bag) filters is also considered in this report. The design and construction of the current installation and the potential retrofit of these additional processes are discussed in this report.

For NOx abatement, analysis of SNCR performance has determined that its effectiveness for this application is limited to a removal efficiency of only circa 10%, which is not considered sufficient to meet the BAT-AL. This concurs with the feedback from the UK LCP BRef Technical Working Group (TWG) ("UK Split View - BAT AELS for NOx from biomass fired plant"), which considered that SNCR systems may not be appropriate for retrofitting to certain boilers. A number of SCR options have also been considered, including a conventional high-dust application, a high-dust in-duct installation, and a low-dust SCR located downstream of the air heater and ESP. Each of the potential SCR solutions would require an extended outage to implement, and would require high capital and operating costs. It should be noted that the UK LCP BRef TWG ("UK Split View - SCR on Biomass fired plant") considers installation of SCR systems on retrofitted biomass fired combustion plants as inappropriate. This is due to the likelihood of currently commercially available biomass fuels causing catalyst poisoning in SCR systems therefore requiring frequent catalyst replacement resulting in high operational costs; and the fact that retrofitted combustion plants are usually restricted by spatial constraints for installing a significant piece of equipment like a SCR system. There is also a concern that the unreacted ammonia from either SNCR or SCR could be absorbed by the ash, and thereby eliminate the ability to dispose of it onsite or beneficially recycle off-site without further treatment.

For dust abatement, both fabric filters and ESPs are considered to be generally applicable to combustion plants fired using solid fuels. However, according to the LCP BRef, large pulverised biomass combustion plants, like Lynemouth power station, more typically use ESPs.

Fabric filter materials used in bag filter systems are typically sensitive to the temperature of the ash and flue-gases, so unburnt carbon and hot fly ash agglomerations, like that observed in combustion plants fired using currently commercially available biomass, have significant potential to damage the filter material. The LCP BRef further notes that in applications where the ash has a high amount of unburnt matter, there is a risk of sparks or glowing particles reaching the bag filter due to higher combustion temperatures, as is expected from the proposed fuel at Lynemouth power station. This increases the risk of hopper fires as well as bag damage.. Therefore, fabric filters were considered to not be feasible for the Lynemouth power station due to the risk of high levels of unburned carbon in the biomass ash, and the associated risk of fire; this is a conclusion reached on many other biomass conversion projects worldwide.

In addition to technical limitations for installing bag filter system at the Lynemouth power station, there is the considerable additional capital investment required; especially since at this installation the existing ESPs would first need to be demolished to create space for connecting ductwork and other associated infrastructure, resulting in substantial outages and associated losses in revenue. The LCP BRef also notes that although initial investment required for the installation of bag filter systems in new facilities are relatively lower than ESPs, the operational costs are considerably higher, in particular due to the requirement to regularly replace bag filters, estimated to be required at a frequency of between 2 and 5 years and costing up to 10% of the capital investment.

The existing ESPs at the Lynemouth power station were upgraded as part of the biomass conversion project to make them more suitable for operating with biomass instead of coal; and the resulting lower dust loadings due to relatively lower ash in fuel (compared to coal) but different resistivity, in addition to upgrades to their electrical systems to improve their dust removal efficiency to meet the ELVs stated in Annex V of the IED. However, no modifications were made to the size and number of the collection plates, or to the number of fields.

A number of options for upgrading the ESPs were reviewed, including the installation of additional collection plates in the maintenance access spaces, raising the height of the ESP to create a large collection area within the existing footprint, and increasing the number of fields. Neither of the first two options provided certainty that they could meet the BAT-AEL of 10 mg/Nm^3. The limited amount of available space between the ESPs and the stack is also such that there is no room to add another field to Unit 2. Based on AECOM's experience with similar projects and the specific operational conditions at Lynemouth power station, it is expected that up to 6 – 7m of additional linear space would be required for each additional field for the ESP.

On this basis it is considered that, while for two of the units at Lynemouth power station may have sufficient room to add one (or possibly two) fields, that would require replacement of the ID fans and a complete reconfiguration of the ducting from the ESP outlet to the fan, and from the fan to the stack. As the existing ID fans at the installation were only installed recently as part of the biomass conversion project, any proposal for replacing these would need to consider both the lost investment already made for installing existing fans in addition to the additional investment for new fans.

It is anticipated that the extensive upgrade of the ESPs required to theoretically achieve additional dust abatement would be comprehensive, expected to be in the range of £5-£10 million for the installation.

Based upon the information received and reviewed, and the site specific configuration, the following conclusions are given.

- The installation is currently undergoing combustion optimisation and performance guarantee testing following conversion to biomass-firing. Predicted performance by the manufacturer was used for this analysis because the emissions may still change as part of the optimisation task.
- The use of fabric filters for dust collection on a biomass-fired unit is discouraged due to the high levels of carbon in the ash, and the significant risk of fire from sparks or glowing particles reaching the filter. This

understanding is supported by the LCP BRef which recognises these risks for combustion plants fired on biomass. Moreover, in AECOM's experience with installations similar to the Lynemouth power station, this position is applied worldwide on biomass plants.

- The additional secondary abatement techniques which could potentially be retrofitted to reduce NOx and dust emissions would require extensive modifications to the flue gas system and require the plant units to be out of service for extended periods of time. Based on plant operations, it is expected that outages ranging from several weeks to a year (depending on the abatement measure) would be required for each unit at Lynemouth power station; thereby significantly reducing the output of the plant. It is expected that up to 12 months of outage per unit can be expected for the installation of SCR, ESP upgrades and bag filters.
- The exception to this is the SNCR which can be installed with minimum unit downtime. However, the NOx reductions that can be expected are minimal and would not meet the BAT-AELs. This position is acknowledged by the UK LCP BRef TWG split view, which recognises that SNCR may not be suitable for some retrofitted boilers.
- Both SNCR and SCR utilise reagents that will result in the presence of unreacted ammonia in the flue gas. Some of the ammonia will be absorbed by the ash that is being collected, which could impact the ability of the plant to dispose of it in the landfill that is located at the site or to send it for off-site recovery or recycling without further treatment, leading to substantial additional costs.

Therefore, based upon the technical evaluation of the plant options, it is considered that the Lynemouth Power station's existing NOx and dust control systems represent BAT for this installation and that the retrofit of further abatement measures is not technically feasible given the technical characteristics of the Lynemouth power station (shown in Appendix A).

2. Introduction

2.1 Background

The Lynemouth power station consists of three boiler / steam turbine / generator units each capable of having a generator output of 140 MWe, for a total gross output of 420 MWe. The boilers were originally designed and operated to fire locally mined coal and primarily provide power to a nearby aluminium smelter. With the closure of the smelter and the changes in coal fired plant economics, it has been converted to fire biomass. This conversion required substantial changes to the original fuel handling and combustion systems; however building infrastructure, and plant major systems and components such as cooling water systems, boilers, turbines etc. have not been substantially modified from the existing plant, and as such, the plant is classed as an existing plant under the Industrial Emissions Directive. The plant is presently in the combustion optimisation and performance guarantee testing phase of its conversion to biomass firing.

The project economics and viability are based upon its Contract for Difference (CfD) which is valid until March 2027. According to current plant programme, a major planned outage is scheduled for 2020/21; with 8 weeks of outage scheduled for each unit. As such, any lengthy additional planned outages to install additional emission controls and forced outages that occur as a result of the operation of those controls would have a significant negative impact on the financial performance of the plant over the duration of the CfD contract.

2.2 Purpose

AECOM has prepared this Technical Brief in support of the Best Available Techniques (BAT) assessment of the emissions control measures proposed to be implemented at the retrofitted installation compared to the measures considered to generally be applicable to new large combustion plants according to the Large Combustion Plant Best Available Techniques Reference (LCP BRef) document, to demonstrate that the proposed measures represent BAT for this installation; based on its site specific design configuration, design operating life and operating conditions. The operator is seeking derogation from the revised BAT Associated Emission Levels (BAT-AELs) published in the LCP BRef. A cost benefit analysis and environmental justification for the proposed measures has also been prepared to supplement this Technical Brief.

This brief seeks to demonstrate why secondary abatement is not appropriate for retrofitting to the Lynemouth power station based on the technical characteristics of the installation, and site specific operating conditions. Additionally, this report considers the construction timescales and impacts for the retrofit of any additional secondary abatement at the plant, with respect to the reduction in emissions achieved against the expected plant outages of up to a year (not considering planned outages of 8 weeks per unit).

AECOM has undertaken more than 100 BAT assessments for Environmental Permit activities in the combustion, oil and gas, petrochemicals, chemicals and manufacturing industries. It is recognised that the options defined as indicative BAT as set out in the BAT Reference Documents or the regulatory Sector Guidance Notes do not necessarily represent the best available technique for an existing plant given the plant's technical and site specific conditions and when the environmental cost benefit is considered, and hence an alternative 'derogation' approach may be more appropriate, depending on individual site conditions, in which case robust justification for such an approach would need to be provided to the Regulator.

This brief has therefore been prepared on the basis of AECOM's previous experience with BAT assessments as well as consideration of the potential abatement measures outlined in the LCP BRef document from an engineering perspective. The assessment reviews technical and operational issues likely to be faced by the Lynemouth power station for installing the additional measures and the effectiveness of these measures, if installed. The technical review of the abatement measures considered to be generally applicable to large combustion plant, and in particular to retrofitted biomass fired plant, has been undertaken on the basis of relevant experience for similar projects in USA and Europe. AECOM experts have extensive industry experience, specifically of the application of various abatement measures for control of emissions, having worked for more than 10 years supporting clients across all industrial sectors.

3. NOx and Particulate Emissions

3.1 Guaranteed Emissions

The biomass conversion project combustion sub-project contractually guaranteed emissions for NOx and stack particulate (dust) emissions are as follows:

- NOx ≤ 200 mg/Nm^3 @6% O_2 vol, dry basis
- Dust ≤ 20 mg/Nm^3 @ 6% O_2 vol, dry basis

3.2 BAT-Associated Emission Levels (BAT-AEL)

The revised LCP BRef document and associated BAT conclusions, originally issued in July 2006, were adopted on 31 July 2017 and published on 17 August 2017 by the European Commission pursuant to Article 13(6) of the Directive 2010/75/EU on Industrial Emissions. .

At the time of design and construction of the conversion of Lynemouth Power station to biomass, the July 2006 BRef was in effect; however BRef review was already in progress although there was a lack of certainty on the outcome and no revised BAT-AELs had been published at that time. Therefore, the emission limit values (ELVs) specified by the Industrial Emissions Directive (IED) (Annex V) were the basis of consideration during the design and construction stages of the project. The performance guarantee limits were therefore also based on the ELVs provided by the IED.

3.2.1 NOx BAT

The generally applicable primary control measures for the control of NOx, N_2O, and CO are contained in BAT conclusion 24 in the LCP BRef. These include the following.

- Combustion optimisation
- Low NOx Burners (LNB)
- Air staging
- Fuel Staging
- Flue gas recirculation

Of these measures, as key components of the biomass conversion project, Lynemouth has installed bespoke biomass LNB's with air staging in the form of a new boosted overfire air (BOFA system). These techniques are considered to be BAT for biomass fired plants by the LCP BRef. The LCP BRef states that the combustion characteristics of biomass in fully converted boilers are yet to be fully described. Combustion optimisation is currently being carried out in advance of performance guarantee testing.

Fuel staging within the burners is based on the principle of reduction of the flame temperature or localised hot spots by creation of several combustion zones in the combustion chamber with different injection levels (or staged injection) of fuel and air, allowing the conversion of the NOx formed back to nitrogen. The LCP BRef states that although, in principle, the fuel staging technique can be implemented in all types of fossil-fuel-fired boilers and in combination with low-NOx combustion techniques (for the primary fuel), it is less appropriate for retrofitted boilers as it requires large chamber volumes if high amounts of unburnt carbon are to be avoided. This is deemed to be of particular consequence for retrofitted biomass plants due the tendency of currently commercially available biomass to have high levels of unburnt carbon in the ash. The spatial constraints at the Lynemouth power station are considered to be restrictive for the installation of fuel staging, which would be expected to require considerable increase in combustion chamber size at the installation. Furthermore, the LCP BRef notes that the operating costs for fuel staging are typically estimated to be around twice as high as the costs for LNBs with boosted over-fire air.

Fuel staging is therefore not considered suitable for the Lynemouth power station, considering the significant spatial restraints and considerable additional operating costs, with respect to the relatively small reduction in the NOx emissions compared to the existing controls.

The LCP BRef recommends additional primary measures like flue gas recirculation for biomass fired plants to reduce NOx formation. The recirculation of flue-gas leads to the reduction of available oxygen in the combustion zone and, as it directly cools the flame, in the decrease of the flame temperature; therefore, reducing both fuel-bound nitrogen conversion and thermal NOx formation. The LCP BRef recognises that installation of flue gas recirculation equipment in retrofitted plants would require an upgrade to the existing fans to maintain the rated capacity of the units; this is considered to be a problem for the Lynemouth power station, due to the installation's technical characteristics. In case flue gas recirculation is installed without the significant upgrades required, it may force a reduction in the combustion capacity of the units. Any upgrades to the existing fans, which were installed as part of the biomass conversion project, would require considerable additional investment.

Flue gas recirculation has a tendency to lead to higher unburnt carbon-in-ash; which would be a considerable issue for Lynemouth power station, where the biomass fuel already has high unburnt carbon in ash, leading to further issues with dust emissions. Flue gas recirculation may also cause corrosion of inlet ducting and fans because the flue-gas is cooled when mixed with incoming air, resulting in higher maintenance outages and associated costs.

Therefore, installation of flue gas recirculation at the Lynemouth power station is not considered to be suitable.

Lynemouth Power Limited (LPL) therefore considers that they have implemented all of the viable primary control measures as part of its conversion.

Therefore, a review of potential secondary NOx control measures has been undertaken. Secondary NOx control measures for BAT include Selective Non-Catalytic Reduction (SNCR) and Selective Catalytic Reduction (SCR) processes. SNCR involves the injection of either ammonia or urea reagent into the duct at a location where the flue gas temperature will promote the reaction with NOx. SCR utilises similar reagents, but requires a catalyst so that the reaction will occur at lower flue gas temperatures.

The feedback from the UK LCP BRef Technical Working Group (TWG) states that the majority of UK plant having an input of >300MWth put into operation no later than 7th January 2014 (i.e. installations classified as existing large combustion plant) comprise units that have been converted from coal fired units to biomass fired units, and even when applying a range of the proposed techniques, the proposed BAT-AEL of 160mg/m^3 is considered to be challenging for existing biomass conversions under all conditions using only primary measures.

Moreover, the emission performance of converted coal plant is generally expected to be very site specific and, therefore, the prediction of emissions values where there is a lack of data represents a high commercial risk to installations without the basis of operating experience, and performance guarantees must be relied upon. It is further recognised that most retrofit projects designed during the drafting period of the revised LCP BRef have been designed on the basis of the draft BAT-AELs (having an upper limit of 180mg/m^3) which aligns with the ELVs provided by Annex V of the IED. Installing additional measures to achieve the revised BAT-AELs, considering the economic limitations in terms of CfD contract length, available fuel and technical characteristics such as spatial restrictions, will be challenging for these installations.

The UK TWG for LCP BRef does not support the installation of SCR as a viable secondary technique for biomass plants >300MWth due to the potential for higher maintenance and operational costs. Many of the biomass fuels available on the market have elevated levels of potassium which could poison the catalyst used in SCR, leading to a significantly shortened lifetime of the catalyst in these units; therefore requiring frequent maintenance cycles for replacing the catalyst. Also, the configuration of the converted plant may render the installation of SCR as technically infeasible, as many retrofitted plants lack the additional space required. As a result, the costs of retrofitting SCR on the units are disproportionately high. Both of these issues apply to the Lynemouth power station; thereby making the installation of SCR unfeasible.

3.2.2 Dust BAT

The control measures for dust are contained in BAT Conclusion 26. These include the use of one or a combination of the following:

- Electrostatic precipitator (ESP)
- Bag filters
- Flue Gas Desulphurisation (FGD) system

According to the LCP BRef, in pulverised biomass combustion plants, the bulk of the ash is carried with the flue-gas out of the combustion chamber, with only a small quantity collected as bottom ash. ESPs are recognised as being the most commonly used technique for dust abatement in large scale pulverised biomass combustion plants.

Of these measures, Lynemouth power station has an ESP system installed, and as part of the conversion, the existing system was upgraded by installing a high frequency power supply.

According to the LCP BRef, fabric filter material used in bag filter systems is usually sensitive to the temperature of the ash and flue-gases, so unburnt carbon and hot fly ash agglomerations, like that observed in biomass fired plants, have the potential to damage the filter material. Furthermore, the LCP BRef notes that in fuels where the ash has a high amount of unburnt matter, as would be expected at Lynemouth power station, there is a risk of sparks or glowing particles reaching the bag filter due to higher combustion temperatures resulting in a high risk of hopper fires and bag damage. Therefore, bag filters are considered to be unsafe for use on biomass-fired boilers at Lynemouth power station, without additional operational techniques being employed, due to the high levels of unburned carbon in the ash and the associated risk of fire.

FGD systems can remove particulates, but as a secondary benefit to the primary purpose of removing sulphur dioxide (SO_2). FGD systems are primarily used at plants which are fuelled with fuels such as coal, peat and oil that contain varying amounts of sulphur. Due to the relatively low sulphur content of biomass proposed for use at the Lynemouth installation compared to coal, FGD is not required to be installed at the installation. Due to significant capital investment required for FGD systems, they are not considered to be cost-effective on large power station boilers when applied solely for the purpose of dust control. FGD is therefore considered to be unsuitable for the Lynemouth power station.

Therefore, of the dust control measures that are presented in the BAT, the only viable additional option for Lynemouth is an upgrade to the existing ESP.

As discussed above, the design of the installation conversion was based on the ELVs stated in Annex V of the IED as the existing LCP BRef (2006) was under review at the time of design development. The comparison of the revised BAT-associated emission levels (BAT-AELs) implemented by the LCP BRef for > 300 MWth biomass fired plants to the ELVs implemented by Annex V of the IED is provided in Table 3-1.

Table 3-1 Regulatory Emission Limit Comparison

Constituent	IED Annex V	LCP BRef 2017	
	New/Existing Plant	New Plant	Existing Plant
NOx, mg/Nm^3			
Yearly average	200	40-140	40-160
Daily average	-	65-150	95-200
Dust, mg/Nm^3			
Yearly average	20	2-5	2-10
Daily average	-	2-10	2-16

3.3 BAT-AEL Compliance

For the Lynemouth installation, the two emissions that are not predicted to meet the BAT-AELs in the revised BRef are NOx and dust, based on the contractually guaranteed emission levels. The guaranteed ELVs did satisfy the IED Annex V ELVs that were aligned with the draft proposed BAT-AELs at the time of design development of the biomass conversion project. Due to the uncertainty in the outcome of the BRef review process at that time and in the achievable performance under biomass-fired operation using primary measures, LPL were not able to factor these into the project at the design and construction phases. This is considered to be the case of most similar retrofitted plants, as recognised by the UK LCP BRef TWG split views. As such, there is a lack of data for retrofitted biomass combustion plants, and as performance guarantees provided by manufacturers are typically tailored for site specific operation it is difficult to compare like-for-like.

For NOx, the guaranteed emissions are 200 mg/Nm^3 and the annual average upper BAT-AEL is 160 mg/Nm^3 for an existing plant. For dust, the corresponding guaranteed emissions are 20 mg/Nm^3 and the annual average upper BAT-AEL is 10 mg/Nm^3. To achieve the revised BAT-AEL, an improvement in the guaranteed performance of 40 mg/Nm^3 for NOx and 10 mg/Nm^3 for dust is therefore required.

As a result, consideration is required as to whether additional secondary control measures need to be applied at the Lynemouth installation and what type of measures should be employed. Therefore, secondary measures outlined in the LCP BRef for NOx and dust control are assessed and discussed below.

4. Plant Design

The overall layout of the plant is included as Appendix A. The legacy configuration of the plant has resulted in a congested area between the boilers and the stack. There is very little or no room for the addition of major new equipment. There are photographs of this area included in Appendix B to illustrate this.

4.1 Fuel

The retrofitted combustion plant at Lynemouth has been designed to use biomass fuel comprising wood pellets; the retrofit design is fuel specific and the plant is therefore only capable of combusting wood pellets, with no capability to handle alternative fuels. The specification for the biomass to be used as fuel includes parameters which are pertinent to this analysis including the limits for ash content (≤ 1.5%, dry by weight) and nitrogen content (≤ 0.25%, dry by weight).

Currently, the plant is undergoing combustion optimisation and performance guarantee testing. It is too early in this process to develop an ash mass balance to account for the distribution of ash following combustion, which consists of furnace bottom ash, ESP collected fly ash, and fly ash emissions.

The ash that is produced by combustion is made up of a combination of the fuel ash, and whatever carbon remains unburned. Biomass combustion typically produces higher levels of unburned carbon (UBC) in the fly ash than coal, and the amount of UBC in the Lynemouth ash is projected to be 30% (based on design performance).

4.2 Boiler

The existing boilers have been refurbished with bespoke biomass LNB and air staging for NOx control. The air staging has been accomplished by the installation of a boosted overfire air (BOFA) system. The BOFA uses two dedicated fans on each unit to supply high pressure air through a series of injection nozzles in the upper furnace. There are three nozzles located in the front wall, and three additional nozzles on each side of the furnace. The high pressure air from the BOFA system creates a high-energy air/fuel mixing zone in the upper furnace that allows for deeper air staging to reduce NOx formation, which enables complete combustion to help minimize carbon monoxide and unburned carbon from being emitted. The furnace is equipped with water wall lances to help keep the tubes clean.

The flue gas continues its upward flow as it exits the furnace, and passes through a set of platen tubes, followed in order by the final superheater, final reheater, primary superheater and primary reheater. After the gas exits the primary reheater, it makes a 180º turn and flows downward through the economiser. Additional soot blowers have been added to the convective section to prevent the build-up of ash and slagging on the convection tube surfaces.

After the flue gas leaves the economiser, the ducting contracts and then splits in two (an “A” and “B” side), before entering a pair of rotary air heaters. The air heaters transfer heat from the hot flue gas to the ambient combustion air, so that it is preheated and thus increases the overall unit efficiency.

4.3 ESP

There are two ESPs per unit (the “A” and “B” sides), each of which have two fields for capturing particulate. After the addition of the upgraded power supply, the refurbished ESP system has a design performance under biomass-firing of 20 mg/Nm^3 particulate.

4.4 Fans

A flue gas duct delivers the exhaust from the ESPs to the ID fans. There are two new upgraded Induced Draft (ID) fans on each unit. The “A-side” ESP feeds gas to the “A-side” ID fan, and it is the same for the “B-side” units. A bypass duct is located between the two sides, so that a single ID fan can be used to draw flue gas from either side ESP. The new ID fans were installed to accommodate the design changes to the boiler and the fuel gas system.

4.5 Stack

The ducts coming from the two ID fan outlets are then combined into a single plenum before entering the stack near its base. The stack is unchanged and consists of three separate stack liners (one for each unit) within the stack structure.

5. NOx Abatement Measures

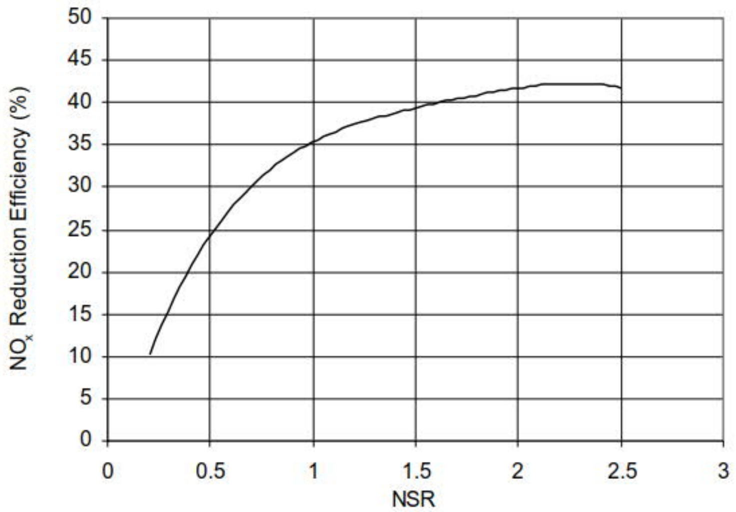
The project to convert Lynemouth Power station to burning biomass has a design performance NOx emission level of 200 mg/Nm^3, compliant with the ELVs specified in Annex V of the IED. The design was based on the ability to accommodate a variety of sources for the wood biomass pellets, each having unique fuel characteristics which will result in slightly different NOx emission rates. While it is possible that the unit will achieve lower NOx emissions on some fuels, the combustion optimisation process has not yet been completed and the full contracted range of fuels not utilised, and so the achievable emissions performance of the units is still unknown. Therefore, the analysis of additional NOx abatement measures will assume a baseline of 200 mg/Nm^3. As stated previously, the options for primary measures were fully utilised as part of the design, leaving post-combustion controls (SNCR and SCR) as the options to be evaluated for the potential to achieve compliance with the new BAT limit of 160 mg/Nm^3.

5.1 SNCR

SNCR utilises a reagent such as ammonia or urea, which is injected into the flue gas at a temperature that is suitable for promoting a reduction reaction with NOx.

Published literature[1] reviewing optimum operation of SNCR systems identifies the key factors affecting the NOx reduction efficiency of the system as temperature and Normalized Stoichiometric Ratio (NSR) (defined as the amount of reagent needed to achieve the targeted NOx reduction). Although higher temperature reactions support an increase in NOx reduction efficiency, there is higher reagent destruction at these temperatures; therefore an optimum reaction temperature must be maintained to achieve the desired NOx reduction with efficient use of reagent. In theory, NOx reduction is expected to be a linear function of reagent injection; however in practice, more than the theoretical amount of reagent is usually required to be injected into the boiler flue gas to obtain a specific level of NOx reduction, due to the complexity of the actual chemical reactions involving NOx and injected reagent, and mixing limitations between reagent and flue gas. The relation between rate of reagent injection and NOx reduction efficiency of SNCR is shown below in Figure 5-1.

Figure 5-1: Effect of NSR on NOx



Source: EPA/452/B-02-001: Section 4 - NO x Controls, U.S. Environmental Protection Agency, October 2000

As the NSR increases, the increment of NOx reduction decreases exponentially, demonstrably plateauing after a certain injection rate. Furthermore, the amount of NOx removed by additional reagent injection is generally much less than the amount of uncontrolled NOx generated by the reaction, which leaves a large portion of the injected reagent unreacted resulting in higher risks of ammonia slip from the combustion units.

The optimum temperature window in an SNCR system is generally about 950-1000ºC. If the reagent is injected at higher temperatures, some of it may be oxidized to form NOx. This can result in a lower overall reduction efficiency of the system, and can even produce an increase in NOx emissions. If the reagent is injected at a temperature that is too low, it may not react. This may cause high levels of ammonia slip in the flue gas emitted from the stack, and/or high concentrations of ammonia in the fly ash that is collected. The reagent that is injected is diluted with water to allow for easier handling and also to help penetrate into the unit to enhance mixing prior to vaporization. The water acts as a heat sink, and the implementation of SNCR typically results in a unit heat rate penalty of 0.25-0.5%.

The installation of SNCR is often complicated because at higher operating loads, the optimum temperature window usually occurs in the convective section of the boiler. This is especially challenging for the Lynemouth installation for a number of technical reasons, with key issues comprising:

- The vertical space inside the existing boilers is limited due to the tube banks that make up the superheat and reheat sections, and if the reagent impinges upon the boiler tubes, it may cause degradation of the metal that may increase risk of a forced outage;

[1] EPA/452/B-02-001: Section 4 - NO x Controls, U.S. Environmental Protection Agency, October 2000

- There is limited external access at the desired elevation at which to locate an injection system at the Lynemouth installation, either because of the structural supports for the boiler, or due to the presence of other equipment;
- The optimum injection location within the units at Lynemouth Power station will vary, since the temperature profile in the upper furnace will change with operating load, boiler cleanliness, and the fuel composition; and,
- The presence of additional heat recovery sections downstream of the injection point could potentially cause the flue gas temperature to decrease so that the residence time within the optimum temperature window is limited.

LPL have evaluated SNCR as an option for the biomass retrofit project at Lynemouth. The system that was considered under the biomass conversion combustion and emissions sub-project consisted of:

- Common urea unloading storage and feeding station,
- Water boost station,
- Unitised metering and distribution modules, and
- Retractable Multi-Nozzle Lances (MNLs) injectors

In this system, the MNLs would be installed on each side of the unit at three different levels (see Drawing 10485-C0300-DGA-AR00-0015, Appendix A). The first would be located at the top of the radiant section below the platen tubes where the flue gas temperature is predicted to be about 950ºC. The second injection level would be between the screening tubes and the final superheater to obtain the ideal temperature window at intermediate loads. A third injection level would be installed between the final superheater and the final reheater for operation at full load, at which the flue gas temperature would be about 1000ºC. The potential issues with regards to the performance of the SNCR system at the Lynemouth installation are discussed in the sections below.

The design was based on the need to maintain the concentration of unreacted ammonia (ammonia slip) in the stack to less than 5 mg/Nm^3 (this is also the BAT-AEL that was established for ammonia in the LCP BRef). This was established in an effort to avoid having high levels of ammonia absorbed by the ash, which would affect its disposal classification, and also to reduce nitrogen deposition from ammonia discharged from the stack in the flue gas. Since biomass produces much less ash as a percentage of the mass of fuel being fired, it tends to absorb ammonia at a higher rate than a conventional coal-fired unit.

The ammonia content of the ash is a concern for Lynemouth. Although LPL are currently exploring opportunities for recycling ash generated from biomass combustion, these avenues have not yet been identified. Therefore, it is currently intended, until such routes are identified, to deposit the ash in the existing non-hazardous landfill at the site; the landfill was previously used for deposition of ash from coal combustion. The landfill is located adjacent to a residential development. The presence of significant levels of ammonia within the ash could lead to it being classified as a hazardous waste, or cause public complaints or nuisance due to the odour of ammonia; in this event LPL would not be able to deposit the ash generated at the installation without additional pre-treatment, resulting in much higher off-site ash treatment and disposal costs.

In the assessment of the SNCR concept for Lynemouth, assessment of the abatement efficiency estimated that it would reduce NOx emissions by only 12%, while maintaining the ammonia slip at less than 5 mg/Nm^3. However, the supplier determined that they could not guarantee this level of performance, and so the SNCR system proposed carried the same 200 mg/Nm^3 NOx guarantee as the conversion project base configuration utilising primary measures.

AECOM conducted an independent evaluation of the application of SNCR to the Lynemouth boilers using a slightly different concept. The AECOM approach would be to install wall-mounted nozzles to inject reagent from the back wall of the boiler using a high-pressure air blower to provide the motive force to penetrate into the space and achieve good mixing of the reagent with the flue gas. This approach would avoid the use of retractable lances, which have higher maintenance requirements, and would also make use of the relatively uncluttered space along the back wall. A photograph of the back wall is presented in Appendix B, in which the view ports are located in the gap below the final superheater, and the space above the buckstay is where the wall-mounted nozzles would be located for reagent injection at full load between the final superheat and reheat sections. The layout of the installation and the general arrangement of equipment at Lynemouth power station are presented in Appendix A.

AECOM's assessment of the potential performance of the system at Lynemouth power station is tempered by two concerns. The first is the relatively low baseline NOx concentration in the flue gas that is exiting the furnace. The effectiveness of the reduction reaction between NOx and the reagent is a function of the NOx concentration, and it becomes limited as it drops below 200 mg/Nm^3. As a result, it is much easier to obtain a given percentage reduction on a unit operating at 500 mg/Nm^3 than at 200 mg/Nm^3 because the chemical kinetics are less favourable. The second concern is the limited amount of space between the tube banks in the convective section at the Lynemouth Power station. There is only 1 metre of clearance in each of the gaps in which the reagent would be injected. Accounting for the flue gas velocity at that location, the available residence time in the space is less than 0.05 seconds. Once the flue gas enters the next heat recovery section its temperature decreases rapidly, and there is only an additional 0.05 seconds of reaction time before the flue gas cools below the minimum viable temperature. Based on previous AECOM experience with similar projects and published literature, optimum reaction time at the optimum temperature, would be expected to be about 0.2 seconds. The reaction time and combustion temperature achievable at the Lynemouth installation is therefore not considered to be sufficient to vaporize the chemical and for the reaction with the NOx to occur.

As such, AECOM believes it is unlikely that the system at the Lynemouth installation would be able to achieve more than about 10% NOx control due to the technical characteristics and constraints of the installation. Based on the current guaranteed NOx emission rate of 200 mg/Nm^3, the reductions predicted by both the biomass conversion project combustion and emissions contractor and AECOM would be in the range of 175-180 mg/Nm^3, which is above the BAT-AEL upper range of 160 mg/Nm^3 NOx. Even at this very modest level of NOx control, there would be a significant concern for impingement of liquid reagent on the final superheat and reheat sections because of their spacing. This is likely to cause thinning of the metal in the tube walls, and may eventually result in tube leaks that would force the unit into an outage to make repairs.

The LCP BRef states that the actual construction costs for SNCR depend on the boiler and its operating profile. Based on the specific conditions at the Lynemouth installation, LPL project engineers have estimated a total cost of £8.3 million for the purchase and installation of the SNCR system on the three combustion units.

In summary, the likelihood for lost generation due to tube failure and the risk that the ash would absorb an unacceptable amount of ammonia, in combination with the small reduction in NOx and the heat rate penalty resulting in a reduction in generating capacity by 0.25 – 0.5%, results in the conclusion that SNCR is not a technically viable option for the Lynemouth units. The technical considerations are further supported by the considerable capital investments, and lost revenues for the outages required for installing the SNCR system.

The issues identified regarding the installation of SNCR at the installation and the subsequent conclusion are supported by the UK BRef TWG split view document for the revised BAT-AEL, which recognises that SNCR may not be appropriate for retrofitting to certain boilers.

5.2 SCR

Similar to SNCR, SCR utilises the injection of a reagent such as ammonia or urea to react with the NOx that is present in the flue gas. However, SCR relies upon a reduction catalyst to promote the reaction at lower temperatures and to a greater degree of completeness. As such, it is capable of achieving much higher control efficiency than SNCR. SCR has been installed on solid-fuel fired power boilers in Germany, Japan and the U.S. for over 20 years, and have been demonstrated to reduce NOx emissions by 80%, or more. SCRs are most economical when they can be accounted for in the original design of a new boiler. However, retrofit of an existing boiler can be quite complex, resulting in high capital costs. As such, retrofits are best performed on units with high baseline NOx emission rates that require high control efficiencies.

An SCR installation requires a significant amount of space. On the basis of previous experience with similar projects, AECOM consider that to add an SCR module, the duct at the Lynemouth installation would need to be expanded to a cross-sectional area that is approximately three times that of the current duct. Allowing for transitions, the injection grid and two layers of catalyst, it is expected that the combustion units at the Lynemouth installation would require around 15m of linear duct run to incorporate an SCR. Another component of the system is a reagent injection grid which is located across the duct, and is usually followed by some form of mixing apparatus to help distribute the chemical evenly across the duct, prior to its reaching the reduction catalyst. Multiple layers of catalyst (usually three or four) are required to accomplish the full NOx reduction capability of the technology. The ideal temperature window for a conventional SCR is at temperatures ranging from just under 300ºC, up to almost 400ºC. On most units, this temperature range occurs in the ducting that connects the economiser to the air heater. These are known as “high-dust” SCRs because they are located upstream of the ESP. Each layer of catalyst must be protected from dust build-up by sootblowers. The general arrangement of the installation and the arrangement of the economiser to air heaters gas ducting at Lynemouth power station are presented in Appendix A, and demonstrate the spatial restrictions outlined here.

The flue gas velocity at this location is usually too high for the catalyst to operate properly and to avoid erosion from the dust that is present. As a result, the duct must be expanded to reduce the velocity to about 5m/sec. The modifications to the duct create additional pressure drop in the gas path (up to several inches of water column), and each catalyst layer produces about one inch of pressure drop. As a result, it is necessary to upgrade or install new Induced Draught (ID) fans to avoid a loss of generating capacity. It should be noted that new ID fans were installed at the Lynemouth installation as part of the biomass conversion project; therefore installation of new ID fans for the purpose of managing the pressure drop due to SCR operation would mean lost investment for the currently installed ID fans as well as additional costs for new fans, resulting in considerable additional costs for the operator.

Due to space and constructability limitations that often accompany a conventional SCR retrofit, another option is to install a “low-dust” SCRs downstream of the ESP. These systems require significant modification to the ducting on the back end, necessitating some form of reheat to raise the flue gas temperature from around 140°C at this location in the installation up to about 220-230ºC, and require a greater amount of catalyst to achieve the desired NOx reduction efficiency due to the lower temperature.

A third option that is often considered, but rarely implemented, is an “in-duct” SCR. This is similar to a high-dust SCR design, but involves the installation of only a single layer of catalyst in the existing duct. These systems produce NOx reductions of approximately 30%. But, due to the high velocity in the duct (about three times the optimal velocity for SCR catalyst), they produce a much greater pressure drop (almost ten inches of water column), and it would be necessary to replace the existing ID fans to avoid a decrease in generating capacity. At this velocity, the catalyst would also be subject to unacceptably high erosion rates and would require frequent outages for replacement. As stated above, the existing ID fans were installed as part of the biomass conversion project; therefore replacing them with new ID fans for maintaining the generating capacity of the installation would mean sunk costs for the currently installed ID fans as well as additional costs for new fans, resulting in considerable additional costs for the operator.

Since SCR utilises the same reagent as SNCR, it is also subject to the potential for unreacted ammonia to either be absorbed by the ash and/or emitted from the stack. As discussed in section 5.1 above, an increased amount of ammonia in the ash that is collected could affect the plant’s ability to landfill the material onsite as a non-hazardous waste; although routes for recycling this ash are currently being investigated by LPL. Classification of the ash as hazardous waste due to the presence of ammonia could necessitate additional treatment of the ash prior to disposal in a suitable off-site facility, resulting in considerable additional costs for LPL.

Retrofitting SCR at Lynemouth would represent a significant investment, and any of the aforementioned configurations would require an extended outage to implement. There is not sufficient space between the economiser outlet and the air heater inlet (only 9 metres) to install a conventional high dust SCR, as is demonstrated by the site layout and general arrangement shown in Appendix A and supplementary photographic evidence in Appendix B. The only option would be to locate the SCR above the ESP. This would require a support structure to be built around the ESP that could support the elevated SCR housing. It would be necessary to open the rear wall of the boiler house, and to modify the duct to include a 90º turn that would carry it into the SCR. A return duct would then bring the flue gas back from the SCR and make another 90º turn downward and back into the air heater. This would be a significant construction effort that would likely require that the unit be down for over a year. The pressure drop associated with the duct modifications and the SCR catalyst would make it necessary to replace the ID fans to avoid a loss of generating capacity. The new, larger fans would consume a greater amount of electricity, and would further increase the plant’s operating costs. AECOM considers that the cost of this option would be prohibitive, especially in light of the minor amount of NOx reduction (20%) that is required to meet the upper end of the BAT NOx regulatory emission limit.

Implementation of an in-duct SCR would be subject to many of the same issues as the conventional high-dust version. The boiler-house wall would have to be removed to allow for access to the duct during the construction phase, and access panels would need to be installed to allow for periodic replacement of the catalyst. The size of the ID fans would have to be increased due to the high pressure drop across the catalyst at high velocity. It is also not a given that the 9m of available space is enough to inject the reagent, mix it thoroughly with the flue gas, and then pass through a catalyst layer. It would be necessary to perform a computational fluid dynamics analysis of the available space before it would be possible to assess whether the space is sufficient and to predict how much NOx would be removed. This option would also require an extended outage to complete the modifications, likely requiring over 12 months. Due to the high cost of the modifications, and the significant amount of lost generation due both to the initial installation and to the frequent catalyst replacement outages, AECOM does not consider in-duct SCR to be a viable option at Lynemouth. This position is concurred by the UK LCP BRef TWG split view on the installation of SCR for NOx abatement at retrofitted biomass plants due to the significant costs for frequent catalyst replacement due to catalyst poisoning from fuel, and technical infeasibility.

A low-dust, low-temperature SCR at Lynemouth would suffer from most of the same issues as for a conventional high-dust installation, with the added complication that a reheat system would need to be installed to raise the temperature of the flue gas leaving the ESP so that it would be hot enough to promote the reduction reaction across the catalyst. The most likely approach would be to install a bypass duct that would run take off some fraction of the flue gas downstream of the economiser, and mix it in with the remaining flue gas as it leaves the ESP. This would result in a significant heat rate penalty, resulting in substantial loss in generation capacity of the combustion units, with the output efficiency expected to be reduced by 0.25 - 0.5%. It would involve a large construction effort and an extended outage of the unit.

It is also not clear where there is space available for locating the SCR housings. One possibility would be in the area behind the stack; this would require modifications to the duct, so that the flue gas would exit the ESP and travel through the SCR, after which it would pass through a new ID fan, and then return to the stack. In this scenario, it would be necessary to wrap the ducting for Unit 2 around the stack to reach the back side. The additional ducting and the larger catalyst volume associated with low-temperature SCR would create significant additional pressure drop, so the ID fans would need to be replaced and the associated operating cost would increase. However, the area behind the stack is unlikely to provide sufficient space due to recent installation of new 11kV substations and cabling. Therefore, the most likely location for potential SCR housings is at the contractors' laydown area which is around 100m away from the combustion units. The primary issue with locating the SCR at this distance is the cost to fabricate and install the longer duct, and the pressure drop and heat loss associated with the longer run. As discussed previously, the replacement of the existing ID fans would mean lost capital investment in the existing fans which were installed as part of the biomass conversion project, in addition to additional investment for new fans.

According to the LCP BRef, the investment costs of an SCR unit depend on the volume of the catalyst, which is determined by the flue-gas volume, by the ammonia slip, and by the NOx conversion rate which should be attained. The LCP BRef estimates that the investment costs for an SCR unit for a coal-fired boiler is around €15million per 1,000,000m^3/hr of flue gas treated. On this basis, it is estimated that a capital investment of around £25million will be required to install a SCR system at the Lynemouth installation. AECOM experience and knowledge of the Lynemouth Power station layout, however, would suggest that the actual costs for installing a SCR unit at the Lynemouth Power station would be considerably higher than those estimated by the LCP BRef, especially considering the modifications that would have to be made to the duct and supporting structure.

Due to the extended outage that would be required to implement a low-dust SCR, the heat rate penalty that would be imposed by the need to reheat the flue gas, and the significant capital and operating costs for the system, AECOM does not recommend it for Lynemouth.

6. Particulate Abatement Measures

For the conversion of the Lynemouth units to biomass firing, LPL incorporated new high frequency switch integrated rectifier (SIR) technology including larger power supplies to increase the ESP particle collection efficiency and reduce particulate emissions to achieve the 20mg/Nm^3 guarantee level required under IED Annex V. The electrical upgrade uses the same ESP internals as already exist, but puts a higher charge into the ESP and manages it better with upgraded controls. The legacy SO_3 injection system, introduced to improve ESP efficiency when firing low sulphur coals, has been decommissioned as it would not provide any benefit under biomass combustion. The combustion modifications consisted of low NOx burners in a two-stage configuration as well as BOFA. This system meets the conversion requirements with a contract performance guarantee limit for carbon in ash figure of 30% across the fuel range.

Since the optimisation of the boilers is not yet completed, the analysis of additional dust abatement measures will assume a baseline of 20 mg/Nm^3. As stated previously, under coal-firing Lynemouth Power complied with the TNP limits and environmental quality standards for SO_2 through the selective use of lower-sulphur coals and no FGD was installed at the plant. While an existing FGD, listed as a BAT technique for the reduction of particulate emissions, could contribute to some degree of dust removal, it is not considered a "primary" technology such that a new FGD system would be applied solely for dust control. This leaves fabric filters and ESP upgrades as the only applicable BAT techniques for dust control to be addressed for the potential to achieve compliance with the new BAT limit of 10 mg/Nm^3.

6.1 Fabric Filter

Fabric filters (bag filter system) provide a very high efficiency dust removal solution. Not unlike for low-dust SCR, a bag filter system installation would represent a large construction project, requiring significant duct modifications, upgraded ID fans, and a significant footprint. It would necessitate an extended unit outage, and the capital and operating costs would be prohibitive.

Selection of fabric for the construction of filters needs to take into account the composition of the gases, the nature and particle size of the dust, the method of cleaning to be employed, the required efficiency and economics. The gas temperature also needs to be considered, together with the method of gas cooling (if any) and the resultant water vapour and acid dew point. The filter material is typically sensitive to the temperature of the ash and flue-gases, therefore unburnt carbon and hot fly ash agglomerations may damage the filter material.

Furthermore, the LCP BRef notes that for fuels where the ash has a high amount of unburnt matter such as those at Lynemouth power station, there is a risk of sparks or glowing particles reaching the bag filter due to higher combustion temperatures leading to a high risk of hopper fires and bag damage. This concern is supported by LPL operational experience during the biomass conversion project commissioning phase.

Even with ideal operation, the maintenance costs for bag filters are substantial. Bag filter material life is limited, requiring regular replacement (up to every two to five years depending on the fuel, according to the LCP BRef), and creates another waste to dispose of. The LCP BRef suggests that the cost of replacing filters could be as high as 10% of the initial investment for the bag filter. Bag filters also have a higher parasitic load than ESP, primarily due to the operation of the ID fans, estimated to be up to double the amount needed when using an ESP.

According to the LCP BRef, UK indicative capital costs (1999 prices) are in the region of £10/kWe for bag filters. On this basis, it is estimated that with an output of 420MWe, a capital investment of around £4.2million will be required for the Lynemouth installation. However, this does not consider the cost to LPL for demolition of the existing ESP units and the additional infrastructure required to enable the new bag filter system to connect to the combustion units. It should be noted that, as stated by the LCP BRef, although capital costs of bag filters are quite low, maintenance costs are high, as the filter material has to be changed every two to five years. The minimum expense of the filter change is approximately 10 % of the investment cost. The total construction and operational costs for the installation of a new bag filter system, in conjunction with the lost revenue from the extensive outages for construction at the Lynemouth installation, is considered to be excessive.

Therefore, given the high level of carbon in ash that is generated by the woody pellet biomass at the installation could potentially damage the filter and pose a serious safety concern because of the fire hazard it presents, as well as the considerable capital and maintenance costs associated with the installation of a bag filter, AECOM does not recommend further consideration of fabric filters as a viable dust control technology solution for Lynemouth.

6.2 ESP Upgrades

The other option for reduction of dust emissions from the installation is an Electrostatic Precipitator (ESP). ESPs are used extensively in large combustion plants and are capable of operating over a wide range of temperatures, pressures and dust burden conditions. The LCP BRef acknowledges that although ESPs are generally been the preferred economic solution, especially for larger pulverised biomass fired plants, bag filters have also been installed in view of their relatively higher abatement efficiency. However, the considerable cost for replacing existing ESPs when retrofitting coal fired plants for biomass combustion with respect to the required extent of abatement must be taken into consideration.

The Lynemouth installation currently has three two-field ESPs (one for each combustion unit). ESPs operate on the basis of resistivity of the gas particles, such that particles are charged and separated under the influence of an electrical field. ESPs are capable of operating over a wide range of conditions. The abatement efficiency of ESPs depends on the number of fields, residence time (size), and upstream particle removal devices.

The performance of an ESP is based on the Deutsch equation, which relates efficiency to the total surface area of the collecting electrodes, the volumetric flow rate of the gases and the migration velocity of the particles. Therefore, for a given dust, removal performance of the ESP can, theoretically, be increased by maximising the surface area of the collecting electrodes. Another way of increasing the dust removal efficiency is to increase the electrode spacing. Therefore, for increasing the efficiency of the ESPs, additional space would be required for allowing for the supplementary equipment.

The existing two-field ESPs at the Lynemouth plant underwent upgrades as part of the biomass conversion project to manage the change in the fuel composition from coal to biomass. This resulted in lower dust loadings due to relatively lower ash in fuel (compared to coal) but different resistivity. In addition, upgrades were made to the electrical systems to improve their dust removal efficiency to meet the ELVs stated in Annex V of the IED, and therefore assist the installation in achieving the project performance guarantee requirements. No modifications were made to the size and number of the collection plates, or to the number of fields.

As such, there remain a number of options to further upgrade the existing ESPs at the Lynemouth plant to improve their dust removal efficiency. However, there are limitations to the effectiveness of expanding the size of an ESP. In the case of the Lynemouth units, the first two fields will have taken out the fraction of the dust that was most easily captured. That which remains presents a greater challenge, so that doubling the collection area of the ESP does not correlate to similar removal efficiency on top of what was originally achieved.

As seen in the photographs in Appendix B, there is a limited amount of space between the boiler house and the stack, where the existing ESPs sit. There is a short run of horizontal duct exiting the boiler house from each side (A and B) of each ESP. The duct undergoes a rapid expansion during the transition to the ESP inlet, and then passes through the two ESP fields. The flue gas exits the ESP through a short section of horizontal duct, which turns and flows downward into the suction side of the ID fan (such that the ID fans sit underneath the ESP outlet ducting).

6.2.1 Installation of Collection Plate in Maintenance Access Space

Most ESPs that were fabricated for the European market were designed with gaps between the fields that allow for ease of maintenance. This is different from the typical ESP in the USA, in which there are no gaps. One approach that could be used to increase the dust removal efficiency of an ESP without changing the footprint would be to add collection plates in these maintenance gaps. Another benefit of this option is that it would likely not increase the pressure drop to the extent that it would negatively impact the unit generating capacity. The retrofit would include provisions to creating a different means to access the unit internals to perform routine maintenance. A modification of this type would require a unit outage which would take several months to complete, resulting in lost generation revenue for the unit As the removal efficiency is related to the surface area of the collector plates, so in theory the more plates installed in these spaces, the more ash will be captured; however, this approach is limited at the Lynemouth installation by the available space. This approach, therefore, is typically used when only moderate additional reductions are needed, and so it would not be capable of lowering the outlet dust emissions by 50% at Lynemouth Power station, to meet the BAT limit of 10 mg/Nm^3. Therefore, AECOM does not recommend this approach for dust control at Lynemouth station.

6.2.2 Increase the Field Height

Another option for increasing the dust removal efficiency without altering the footprint of the existing ESP is to increase the height of the fields. For this option, it would be necessary to create a structure that would support the additional weight of the taller field. The transition ducting at the ESP outlet could be readily modified to accommodate the change in height, and it would not be necessary to change the inlet ducting to the ID fan. However, the transition ducting between the boiler house and the ESP inlet would present a major concern due to the rapid expansion of the duct in a short amount of space. In an effort to even out the vertical distribution of the gas, it would be necessary to install some internal guide vanes within the duct, along with a perforated plate at the ESP inlet. These modifications would produce a significant pressure drop that would require an ID fan upgrade to avoid a loss of generating capacity. This would be a major construction effort and would necessitate a unit outage that could take one year to complete, resulting in lost generation revenue for the unit. It must also be noted that the existing ID fans at the installation were installed as part of the biomass conversion project; therefore any costs for required for upgrading or replacing these would comprise a significant cost for the operator. Of greater concern is that it may not be physically possible to add enough height to the fields to accomplish the desired reduction of the dust down to the BAT limit of 10 mg/Nm^3. Therefore, AECOM does not recommend this approach for dust control at Lynemouth power station.

6.2.3 Add Additional Field(s)

The most effective way to upgrade an ESP to achieve a desired outlet emission rate is to increase the number of fields, and modern installations often have six or seven fields to achieve high removal efficiencies. The problem with this approach at Lynemouth is that the space to expand the ESPs is severely limited. While there may be room behind the outermost units (1 and 3) to add one, and possibly two more fields, there is no room for any expansion behind Unit 2. The additional field(s) to Units 1 and 3 would be a complicated and expensive retrofit which would require a complete reconfiguration of the outlet ducting, ID fans, and a corresponding reconfiguration of the ducting from the ID fans to the stack. There would be a significant increase in pressure drop that would require an ID fan upgrade to avoid a loss of generating capacity. In addition, this would be a major construction effort and would necessitate a unit outage that could take more than one year to complete, resulting in lost generation revenue for the unit. While it would be possible to meet the BAT limit of 10 mg/Nm^3 on Units 1 and 3, there would be no decrease in the dust emissions from Unit 2. As a result of the lost generation due to the extended outage, the lack of improvement to the Unit 2 dust emissions, and the high cost to construct and operate the expanded ESP, AECOM does not recommend this approach for dust control at Lynemouth Power Station.

6.2.4 Additional Investment Costs

According to the LCP BRef, the UK has established indicative capital costs for ESPs of £25/kWe; therefore estimating that a new ESP would require an investment of around £10million. As the Lynemouth installation already has ESP units, which could potentially be upgraded, instead of requiring a new ESP, it is considered that the required investment would be less than that required for a new system. Based on previous LPL and AECOM experience the additional upgrades are considered to require between £5million and £10million, especially considering the modifications that would need to be made on the back end to rearrange the ducting and replace the ID fans. These additional costs, in combination with lost revenue during the considerable outages required to install the upgrades, make the upgrades cost prohibitive to the operator.

7. Conclusions and Recommendation

Based upon the information received and reviewed and the site visit conducted, the following conclusions are given.

- During the course of the recent conversion of Lynemouth Power Station from coal to biomass-firing, significant upgrades to the combustion and emissions system have been introduced which achieve significant reduction in emissions and will enable the installation to achieve the Annex V ELVs for NOx and dust.
- The conversion project has included the implementation of a number of BAT techniques including combustion optimisation, bespoke biomass low-NOx burners and air staging (BOFA) to reduce primary emissions of NO_x and upgrades to the ESPs to improve capture efficiency for biomass ash dust emissions.
- Additionally, significant investments has been made in upgrading of the draught air system including new primary air (PA) and induced draft (ID) fans, fuel distribution systems and upgraded forced draft (FD) fan controls. To install additional abatement equipment, LPL would have to scrap a proportion of the existing equipment, for which it is still paying;
- The biomass conversion project was specified to achieve the IED Annex V ELVs and the plant is currently undergoing combustion optimisation and performance guarantee testing. Predicted performance by the manufacturer was used for this analysis because the emissions may still change as part of the optimisation task.
- The use of fabric filters for dust collection on a biomass-fired unit is not recommended due to the high levels of carbon in the ash, and the significant risk of fire due to the risk of sparks or glowing particles reaching the bag filter. In AECOM's experience, this position is applied worldwide on biomass plants; this is also supported by the LCP BRef which acknowledges the issues with using fabric filters for biomass fired plant, therefore requiring considerable additional equipment such as a pre-collector upstream of the bag filter to reduce the risk of hopper fires and bag damage. Due to the spatial constraints at the Lynemouth installation, it is considered that the additional space for installing supplementary equipment is limited.
- The additional secondary abatement techniques which could potentially be retrofitted to reduce NOx and dust emissions would require extensive modifications to the flue gas system and require the plant units to be out of service for long periods of time.

The exception to this is the SNCR which can be installed with minimum unit downtime. However, the NOx reductions that can be expected are minimal and would not meet the BAT limits. The issues with installation of SNCR on retrofitted biomass units is recognised by the UK BRef TWG split view.

The installation of SCR at retrofitted combustion plant is not supported by the UK BRef TWG split view on the subject due to the technical difficulty due to the limited space available at existing plant as well as the likelihood, of considerable operational costs for frequent catalyst replacement because of catalyst poisoning from most commercially available biomass.

Moreover, both SNCR and SCR would lead to a considerable loss in generation capacity due to their parasitic load on the installation, therefore leading to a reduced efficiency of the installation. They would also require replacement of the existing ID fans, which were installed as part of the biomass conversion project, therefore leading to sunk costs for the existing fans in addition to additional costs for new fans.

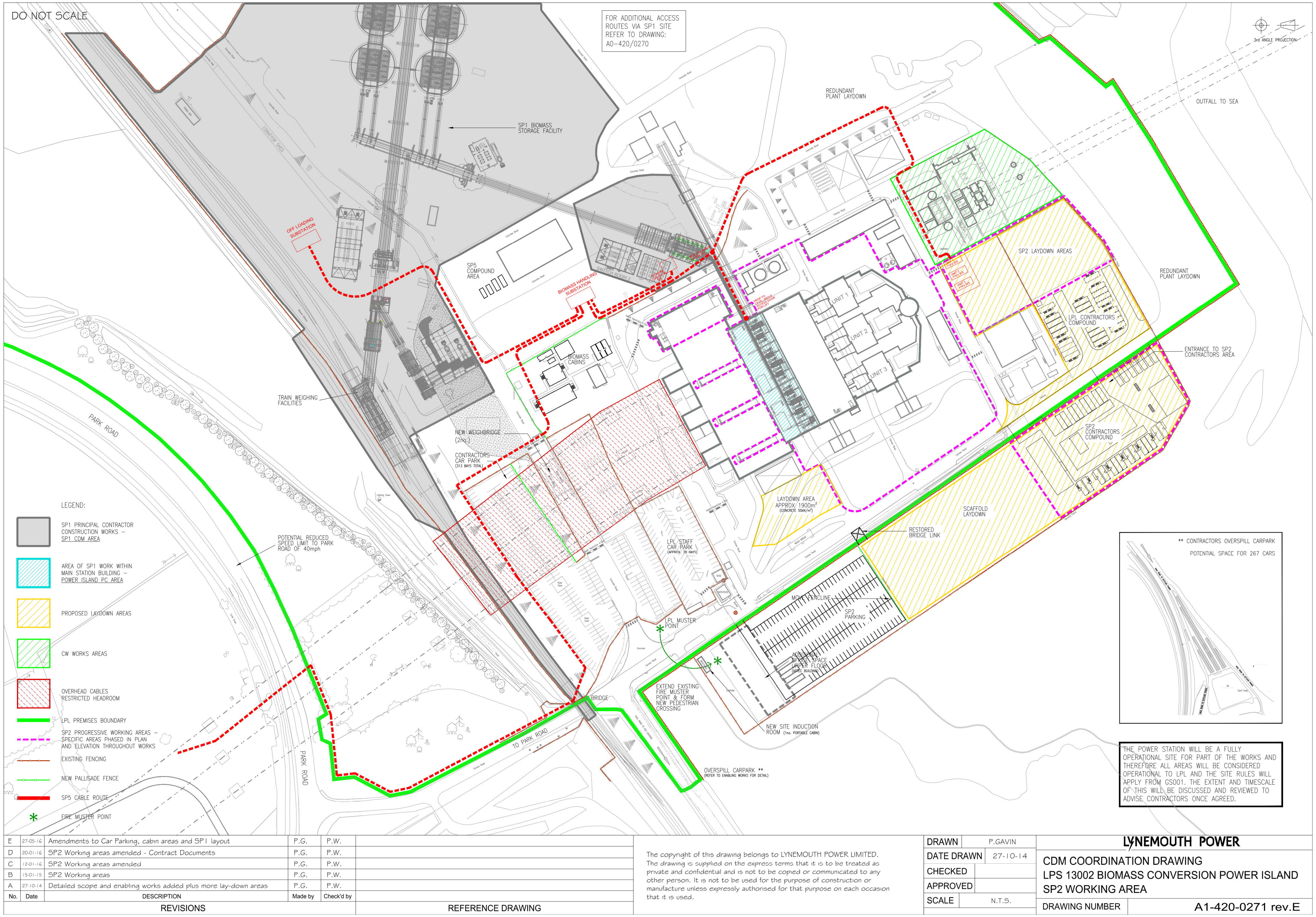
Both SNCR and SCR utilise reagents that will result in the presence of unreacted ammonia in the flue gas. Some of the ammonia will be absorbed by the ash that is being collected, which could impact the ability of the plant to recycle or dispose of it onsite by the classification of the ash as hazardous due to presence of ammonia.

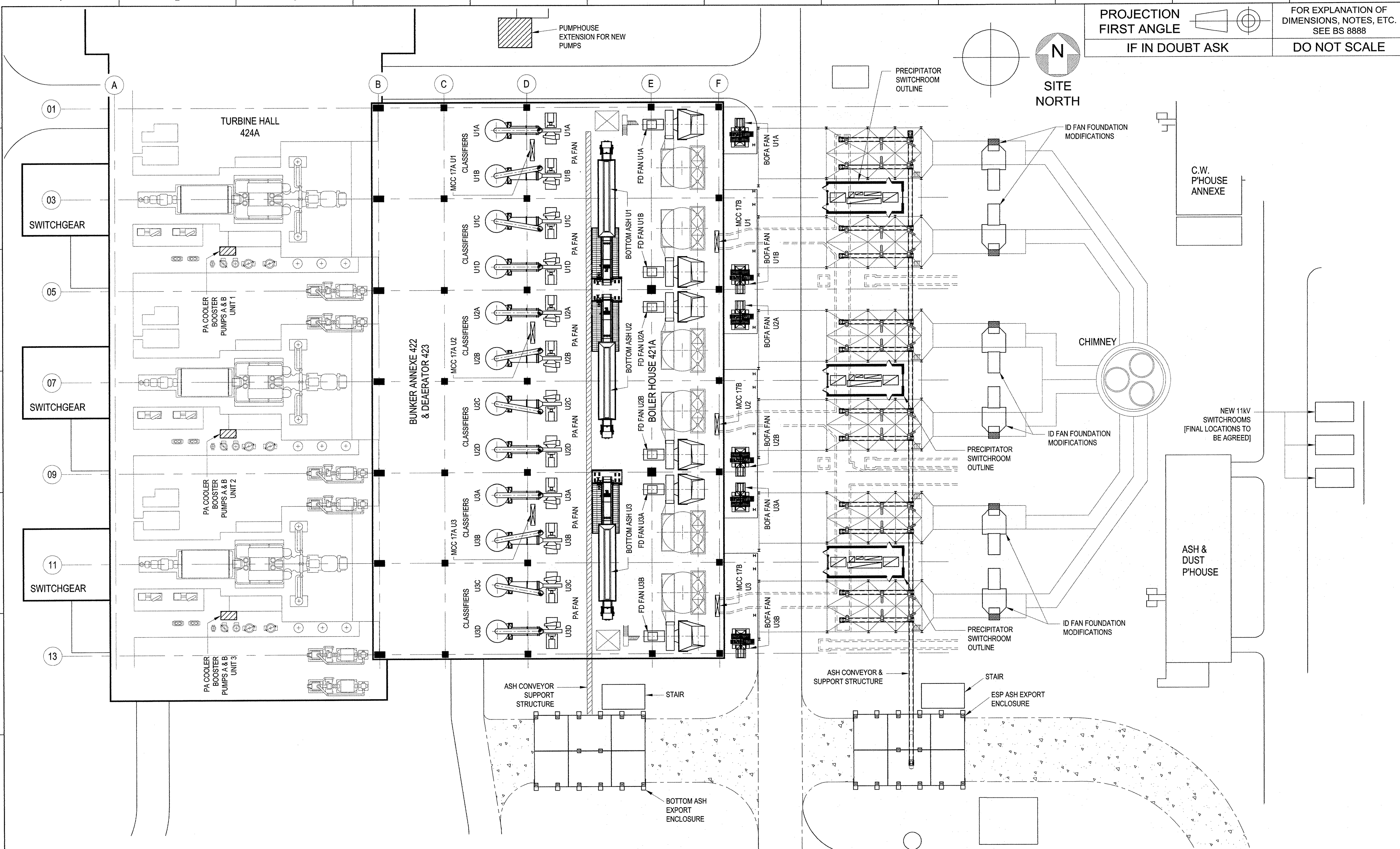
It should be noted that although the emissions abatement measures for large combustion plants are considered to generally be applicable, the LCP BRef acknowledges the limitation in implementing these at retrofitted plant, particularly with fuels like biomass, which due to their composition could pose substantial health and safety as well as operational risks for an installation.

The UK BRef TWG split view for the BAT-AELs for NOx emissions from biomass fired plant having an input of >300MWth, like the Lynemouth installation, and application of SCR and SNCR to these, recognises the technical issues faced by operators of such plant; particularly since most of these plant comprise coal fired plant retrofitted for biomass combustion, thereby needing to retrofit existing plant and equipment within the limited available space in most of the sites to ensure financial viability of such projects. It is also recognised that currently available data for confirming the applicability of these measures to retrofitted plant such as Lynemouth is insufficient, therefore posing a considerable risk for the operator whose retrofit projects are currently designed on the basis of performance guarantees based on the ELVs provided in Annex V of the IED.

Therefore, based upon the technical evaluation of the plant options, it is considered that the Lynemouth Power station’s existing NOx and dust control systems are BAT for this installation and that the retrofit of further abatement measures is not technically feasible given the technical characteristics and layout of the installation which lead to considerable spatial constraints for the installation of additional abatement measures.

Appendix A Drawings


DO NOT SCALE
FOR ADDITIONAL ACCESS ROUTES VIA SP1 SITE REFER TO DRAWING: A0-420/0270
SP1 BIOMASS STORAGE FACILITY
REDUNDANT PLANT LAYDOWN
OUTFALL TO SEA
OFF LOADING SUBSTATION
SP5 COMPOUND AREA
BIOMASS HANDLING SUBSTATION
SP2 LAYDOWN AREAS
LPL CONTRACTORS COMPOUND
ENTRANCE TO SP2 CONTRACTORS AREA
UNIT 1
UNIT 2
UNIT 3
BIOMASS CABINS
TRAIN WEIGHING FACILITIES
NEW WEIGHBRIDGE (2no.)
CONTRACTORS CAR PARK
SP2 CONTRACTORS COMPOUND
PARK ROAD
LAYDOWN AREA APPROX 1900m²
SCAFFOLD LAYDOWN
RESTORED BRIDGE LINK
POTENTIAL REDUCED SPEED LIMIT TO PARK ROAD OF 40mph
LPL STAFF CAR PARK
SP2 PARKING
LPL MUSTER POINT
EXTEND EXISTING FIRE MUSTER POINT & FORM NEW PEDESTRIAN CROSSING
BRIDGE
TO PARK ROAD
NEW SITE INDUCTION ROOM
OVERSPILL CARPARK **
** CONTRACTORS OVERSPILL CARPARK
POTENTIAL SPACE FOR 267 CARS
THE POWER STATION WILL BE A FULLY OPERATIONAL SITE FOR PART OF THE WORKS AND THEREFORE ALL AREAS WILL BE CONSIDERED OPERATIONAL TO LPL AND THE SITE RULES WILL APPLY FROM CS001. THE EXTENT AND TIMESCALE OF THIS WILL BE DISCUSSED AND REVIEWED TO ADVISE CONTRACTORS ONCE AGREED.
LEGEND:
SP1 PRINCIPAL CONTRACTOR CONSTRUCTION WORKS – SP1 CDM AREA
AREA OF SP1 WORK WITHIN MAIN STATION BUILDING – POWER ISLAND PC AREA
PROPOSED LAYDOWN AREAS
CW WORKS AREAS
OVERHEAD CABLES RESTRICTED HEADROOM
LPL PREMISES BOUNDARY
SP2 PROGRESSIVE WORKING AREAS – SPECIFIC AREAS PHASED IN PLAN AND ELEVATION THROUGHOUT WORKS
EXISTING FENCING
NEW PALLISADE FENCE
SP5 CABLE ROUTE
FIRE MUSTER POINT
E 27-05-16 Amendments to Car Parking, cabin areas and SP1 layout P.G. P.W.
D 20-01-16 SP2 Working areas amended - Contract Documents P.G. P.W.
C 12-01-16 SP2 Working areas amended P.G. P.W.
B 15-01-15 SP2 Working areas P.G. P.W.
A 27-10-14 Detailed scope and enabling works added plus more lay-down areas P.G. P.W.
No. Date DESCRIPTION Made by Check'd by
REVISIONS
REFERENCE DRAWING
The copyright of this drawing belongs to LYNEMOUTH POWER LIMITED. The drawing is supplied on the express terms that it is to be treated as private and confidential and is not to be copied or communicated to any other person. It is not to be used for the purpose of construction or manufacture unless expressly authorised for that purpose on each occasion that it is used.
DRAWN P.GAVIN
DATE DRAWN 27-10-14
CHECKED
APPROVED
SCALE N.T.S.
LYNEMOUTH POWER
CDM COORDINATION DRAWING
LPS 13002 BIOMASS CONVERSION POWER ISLAND
SP2 WORKING AREA
DRAWING NUMBER A1-420-0271 rev.E



PRELIMINARY
NOT FOR
CONSTRUCTION

ISS	DATE	BY	VERF'D	APP'D	DESCRIPTION
F01	20-04-16	CJ OO AH / C.Jenkins	Paul Vaughan	B. Stove	ISSUED FOR REVIEW AND COMMENT

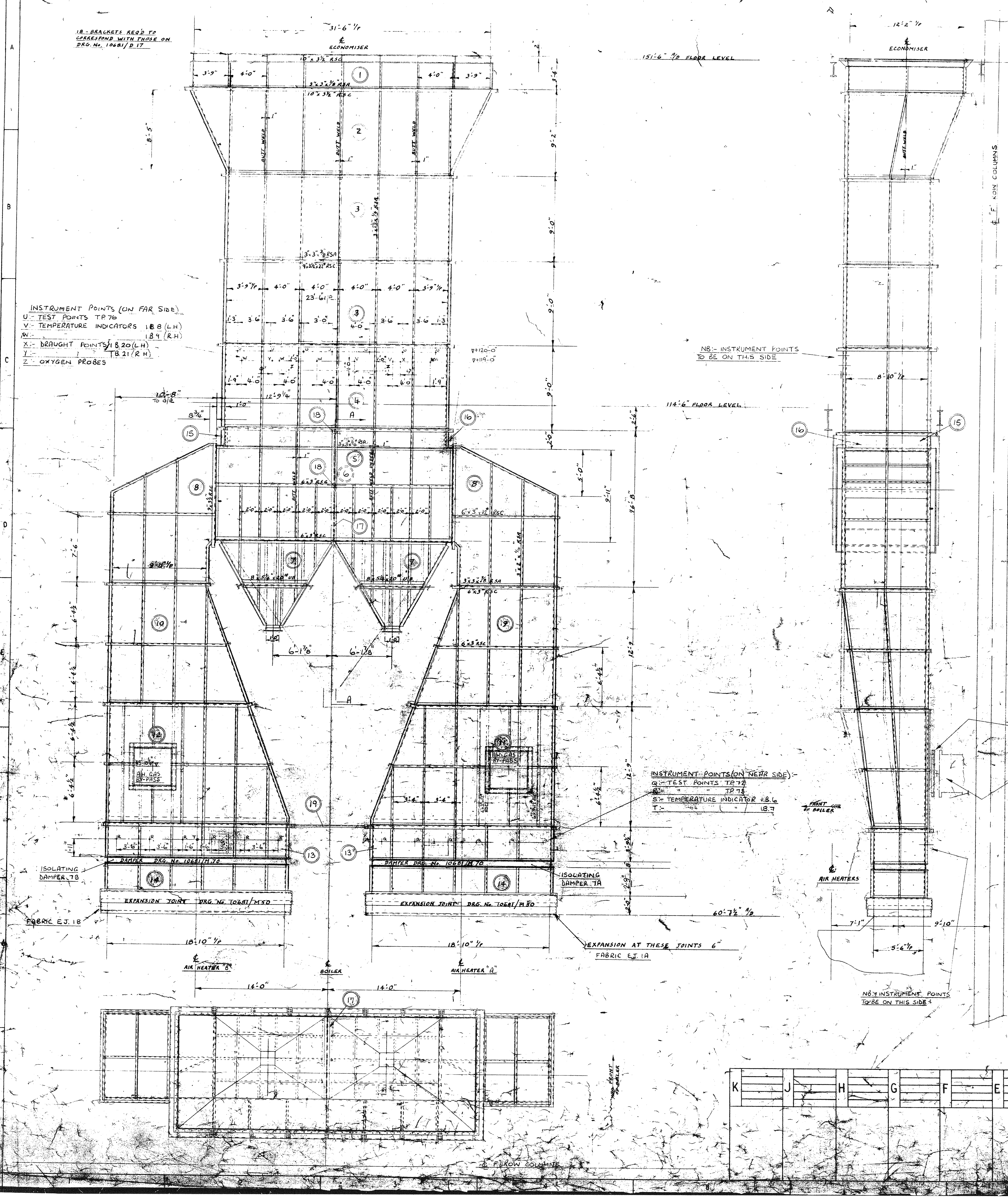
CREATED BY: C H JENKINS
START DATE: 12-04-16
DB DOCUMENT No
DMS No
SCALE: 1:250

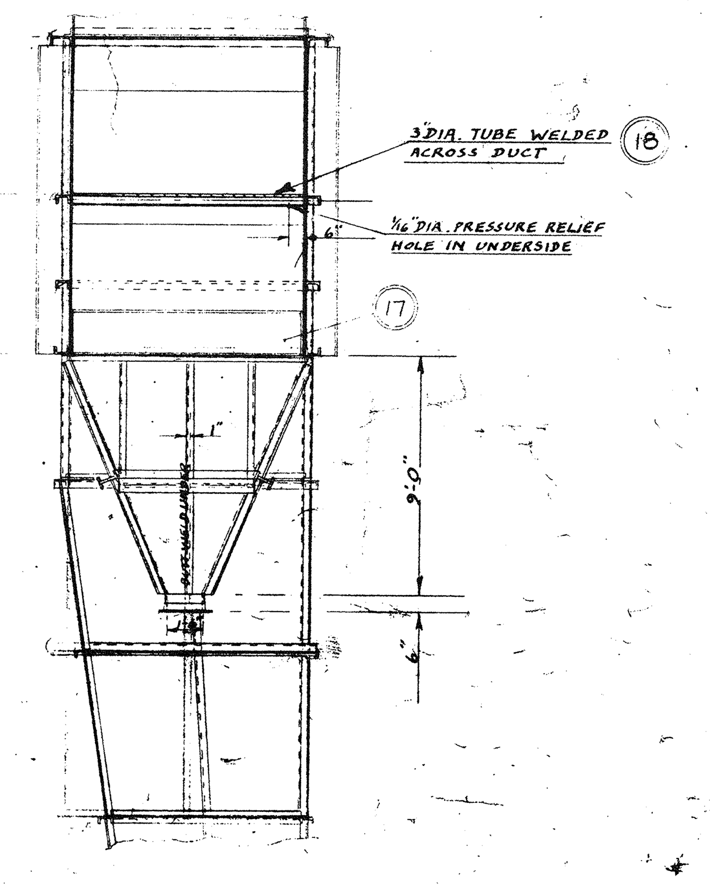
DOOSAN

DOOSAN BABCOCK

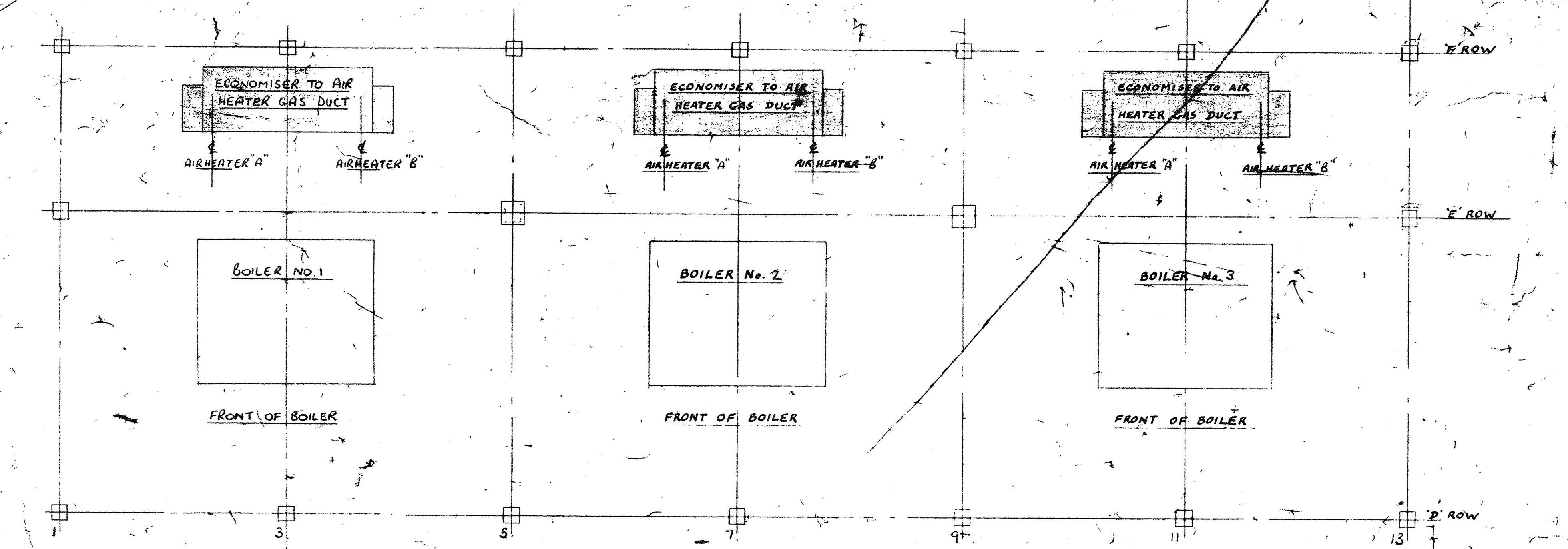
DRG TITLE: EQUIPMENT LAYOUT - 17'-0" LEVEL GENERAL ARRANGEMENT
PROJECT: 104785 LYNEMOUTH BIOMASS
NO. OF UNITS IN PROJECT: 3
DRAWING No. 104785-C0300-DGA-AR00-0015
REV: F01

ORIGINAL SIZE A1





SECTION 'A'-'A'



KEY PLAN

DUCT SECTIONS REQUIRED PER BOILER (3 BOILERS IN CONTRACT)

REF. No.	NO. OFF	DETAIL DRAWING NO.
D.21/1	1	10681/D.22
" /2	1	" /D.23
" /3	2	" /D.24
" /4	1	" / "
" /5	1	" /D.81
" /6	1	" / "
" /7	2	" /D.86
" /8	2	" /D.82
" /9	1	" /D.83
" /10	1	" / "
" /11	1	" /D.84
" /12	1	" / "
" /13	2	" /D.85
" /14	2	" / "
" /15	1	" /D.81
" /16	1	" / "
" /17	1	/ "
" /18	2	/ "
" /19	2	" /D.81

MISCELLANEOUS ITEMS REQUIRED PER BOILER (3 BOILERS IN CONTRACT)

DESCRIPTION	REF.	NO. OFF	DETAIL DRAWING NO.
FABRIC E.J.	1A	1	10681/M50
" "	1B	1	" "
ISOLATING DAMPER	7A	1	10681/M70
" "	7B	1	" "

REFERENCE DRAWINGS.

C.C. DRG. No 10681/D1 GENERAL ARRG^T OF DUCTS
JAMES HOWDEN DRG. No. Z 73706. OUTLINE OF AIR PREHEATER
SENIOR ECONOMISERS LTD. DRG. No. PJ 6058 ECONOMISER TYPE 1A.

GENERAL NOTES

ALL PLATES ARE 1/4" THK. MILD STEEL
ALL JOINTS TO BE TACK BOLTED WITH 5/8" DIA BOLTS AND THEN FULLY WELDED INSIDE AND SPACE WELDED OUTSIDE.
ALL CONNECTIONS ONTO EQUIPMENT i.e. EXPANSION JOINTS, DAMPERS TO BE BOLTED WITH 5/8" DIA BOLTS, AT NOT MORE THAN 4" PITCH & 1/8" THK ASBESTOS TAPE JOINTING.
PRESSURE AND TEMPERATURE OF THIS SECTION IS -6.65" W.G. AT 635° F.

IMPORTANT ERECTORS NOTE.

EACH DUCT SECTION MUST BE BOLTED IN POSITION AND THEN FULLY TIGHTENED UP BEFORE THE NEXT SECTION IS RAISED INTO POSITION. AFTER ALL DUCTWORK IS BOLTED INTO POSITION, JOINTS TO BE FULLY WELDED.

FP-195-421A-7500-ROC/240 ARRGT. OF ECONOMISER TO AIR HEATERS GAS DUCTING

FP.195.421A.7500.ROC/240

K	J	H	G	F	E	D	C	B	A
						16.6.71	11-12-70		
						E. STOODLEY		T. MUNDAY	
						ERECTORS NOTE ALTERED	N° OF OXYGEN PROBES ADDED TO C.L.	POSITIONS OF OXYGEN PROBES ...	

APPROVED BY CLIENT
APPROVED SL/CE
REVISION BY
DATE OF REVISION

CLARKE CHAPMAN AND CO. LTD. GATESHEAD ENGLAND

BOILER NUMBER	ORDER NUMBER	COLOUR CODE	BUDGET COST REF.
1	10681-130	RED	
2	10681-230	GRAY	
3	10681-[illegible]	[illegible]	

DRAWN BY B. Maguire
DATE 14/5/69
CHECKED BY
DATE

ARRG^T OF ECONOMISER TO AIR HEATERS GAS DUCTING

SCALE [illegible]
DRG. NO. [illegible]
CONTRACT 'ALCAN'
REVISION [illegible]

Appendix B Site Photos

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APPENDIX B – SITE PHOTOGRAPHIC LOG

Client Name: Lynemouth Power Limited	**Site Location:** Lynemouth Power Station	**Project No.** 60565526

Photo No. 1	**Date:** 29-08-18	
Description: Back side of boiler showing possible location for wall-mounted SNCR reagent injection		
Photo No. 2	**Date:** 29-08-18	
Description: Side view showing transition from boilerhouse air heater outlet to ESP inlet		

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APPENDIX B – SITE PHOTOGRAPHIC LOG

Client Name: Lynemouth Power Limited	Site Location: Lynemouth Power Station	Project No. 60565526

Photo No.	Date:
3	12-07-18

Description:

Side view of ESP outlet ducting to ID fan and stack

Photo No.	Date:
4	12-07-18

Description:

Rear view of ESP showing ducting into stack

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