Lynemouth Power Station: Appraisal of BAT for NOx, Dust and CO

Issue 1

November 2018

TECH/TEF/3026/18

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Abbreviations

AEL	Associated Emission Levels
BAT	Best Available Techniques
BOFA	Boosted Over Fired Air
BREF	BAT Reference Documents
CFB	Circulating Fluidized Beds
CO	Carbon Monoxide
DEFRA	Department for Environment Food and Rural Affairs
EA	Environment Agency
ELV	Emission Limit Value
ESP	Electrostatic Precipitators
FGD	Flue Gas Desulphurisation
IED	Industrial Emissions Directive
LCPD	Large Combustion Plant Directive
LCP	Large Combustion Plant
LNB	Low NOx Burners
OEM	Original Equipment Manufacturer
PF	Pulverised Fuel
RH	Reheater
SCR	Selective Catalytic Reduction
SH	Superheater
SNCR	Selective Non-Catalytic Reduction
TFTEI	Task Force on Techno-economic Issues
TNP	Transitional National Plan
TR	Transformer Rectifier

Summary

This report considers the application of Best Available Techniques (BAT) to Lynemouth for NOx, dust and CO emission in conjunction with the BAT Reference (BREF) Conclusions. The report considers available techniques to reduce emissions, their estimated costs and performance for the station following its conversion to 100% biomass (wood pellets).

The design of Lynemouth is fundamentally different to those of the plant used to derive the BREF limits and this design difference (or technical characteristic) results in disproportionate costs.

NOx

Lynemouth has applied primary measures (Low NOx Burners, Boosted Over-Fired Air) to reduce NOx emissions to 200mg/Nm^3. Further reductions in NOx through primary measures are not feasible; therefore secondary measures would need to be applied to reach BREF Associated Emission Levels (AELs). Secondary measures for NOx control utilise ammonia and will have implications on ammonia emissions to air and ash disposal implications due to ammonia slip.

Selective Non-Catalytic Reduction (SNCR), Selective Catalytic Reduction (SCR), and Hybrid SCR were considered as options to reduce NOx emissions. SNCR would be difficult to apply at Lynemouth due to the low residence time in the appropriate gas temperature window. In combination with low baseline NOx an SNCR is likely to have a poor NOx reduction rate. A SCR system would be of high cost and require extensive plant modifications. A Hybrid SCR system would have to overcome issues with applying both SNCR and SCR but would be of slightly lower cost. The table below summarises the options considered.

Modification	Baseline NOx (mg/Nm3)	NOx abatement efficiency	Final NOx (mg/Nm3)	Capital Cost – 3 Units (£m)	Annual Operating Cost @ 90% LF (£m/yr)
SNCR	200	15%	170	20.7	1.2
SCR	200	90%	20	68.5	3.9
Hybrid SCR	200	50%	100	45.7	3.5

Table 1: Summary of NOx Abatement Options

Dust

Lynemouth has had a unique regulatory path; with a late change in its exemption status from the Large Combustion Plant Directive (LCPD) as a result the plant does not have Flue Gas Desulphurisation (FGD), which is relevant for dust abatement. Without FGD it is technically much harder to achieve the same dust emissions abatement performance as plant with FGD – i.e. essentially a technical characteristic which makes is disproportionality costly to achieve the emission limits. Lynemouth's SO_2 emissions are within the BREF AEL range therefore it is not BAT to fit FGD for dust abatement.

Pulverised Fuel (PF) fired biomass plants generally have high carbon in ash and there is the probability of burning embers reaching dust abatement equipment. Due to this the application of bag filters at Lynemouth is not recommended as such a system would be prone to fire therefore bag filters are not considered feasible for Lynemouth. A new field could be added to each unit's Electrostatic Precipitators (ESPs) this would however require ductwork modification and the existing Induced Draft (ID) fans to be moved closer to the stack. It may be possible to add a new ESP pass to Units 1 and 3 but due to space considerations this would not be practical on Unit 2. The following table summarises the options considered.

Modification	**Baseline Dust (mg/Nm^3)**	**Final Dust (mg/Nm^3)**	**Capital Cost (£m)**	**Annual Operating Cost @ 90% LF (£m/yr)**
One Additional ESP Field (all units)	20	12	4.0	0.31
Additional ESP Pass (2 units)	20	13	3.0	0.41

Table 2: Lynemouth NOx Abatement Options

Carbon Monoxide

Carbon monoxide emissions have an inverse relationship with NOx; if carbon monoxide emissions are reduced it is likely that NOx will increase. On PF coal to biomass conversions such as Lynemouth residence times are lower than other boiler types making them more sensitive to CO formation. On PF biomass boilers fluctuations in fuel characteristics which can lead to deviations in mill and burner throughput, this makes achieving the correct local air to fuel ratios for both NOx and CO control difficult. Due to this the plant is will have high CO emissions if NOx emissions are to be kept as low as possible. NOx is considered to be a higher priority pollutant than CO as such emissions at Lynemouth have been optimised for lower NOx emissions.

1. Introduction

RWE has prepared this technical report in support of the derogation request being made by the plant operator, Lynemouth Power Ltd, from specific criteria listed in the Best Available Techniques (BAT) Conclusions published in the 2017 BREF. This document considers Lynemouth Power Station's Emissions performance in relation to the BREF and the application of BAT within the BREF. The focus is on providing a justification of BAT for NOx, dust and CO emissions.

1.1. Lynemouth Power Station

Lynemouth is a coal to biomass conversion which consists of three 140MWe units (420MW total). The power station was originally built as a captive power plant for the adjacent aluminium smelter. The station was converted from coal to 100% biomass (wood pellets) fired station with re-commissioning of the units in 2018. The station consists of three identical 140MWe units each of which have front wall fired tower boilers.

The Large Combustion Plant Directive (LCPD, 2001/80/EC) required member states of the European Union to legislatively limit flue gas emissions from combustion plant having thermal capacity of 50 MW or greater. Under the LCPD, plants that make direct use of the products of combustion in manufacturing process are exempted from emission limits.

The UK initially did not apply the LCPD to Lynemouth Power Station arguing that the energy that it generated was directly used for aluminium production therefore exempt from the application of the directive. In April 2010 the European Court of Justice ruled that that the LCPD should be applied to Lynemouth. The UK however never applied LCPD Emission Limit Values (ELVs) to Lynemouth.

The station has recently converted to 100% biomass firing to enable it to comply with the Industrial Emissions Directive. As the plant was never required to comply with LCPD ELVs when operating on coal no Flue Gas Desulphurisation System (FGD) was fitted. The station's SO_2 emissions on biomass are now within the IED ELVs and BREF AELs without FGD.

2. Regulatory Context and Sector BAT

The Industrial Emissions Directive (IED, 2010/75/EU) sets out the legislative requirements for Large Combustion Plant (LCP). The key requirements with respect to emission limits are as follows:

- Emission Limit Values (ELVs): The IED directly specifies ELVs (Annex V) which for plant currently in the Transitional National Plan (TNP) need to be met by end of June 2020.
- BAT Conclusions: The IED also requires that within four years of publication competent authorities set emission limit values that do not exceed the BAT Associated Emission Levels (AELs), although derogations are possible in particular circumstances.
- The IED allows Regulators to set higher emission limit values than those specified in the BAT conclusions if due to the geographic location, local environmental conditions or technical characteristics achieving the limits is disproportionately costly relative to the environmental benefits.

There is also a general obligation to apply BAT the definition of BAT includes the economic and technical viability and the requirement to achieve a high level of environmental protection as a whole. There are also obligations to ensure that Environmental Quality Standards are met.

2.1. IED and BREF Emission Limits

2.1.1. NOx and Dust

The following apply to Lynemouth for NOx and dust:

	Dust limits		**NOx limits**	
Averaging	**IED Annex V (mg/Nm^3)**	**Upper BREF AEL (mg/Nm^3)**	**IED Annex V (mg/Nm^3)**	**Upper BREF AEL (mg/Nm^3)**
Annual	None	10	-	160[1]
Monthly	20	-	200	-
Daily	22	16	220	200[1]
95th percentile of hourly means	40	-	400	-

[1] *If put into operation no later than 7 January 2014*

Table 3: IED and BREF Emission Limits

2.1.2. CO

CO is an indicative pollutant in the BREF, in recognition of the fact that there is a trade-off between NOx and CO emissions, and NOx is the higher priority pollutant. The EA's BREF interpretation document (Reference 3) reflects this, as well as the fact that some older plants were not specifically designed to meet current CO AELs. The document clarifies that higher than BREF CO limits can be set, without the need for a formal Article 15(4) derogation, though a BAT justification is required.

2.2. UK Guidance on Derogations

DEFRA have provided guidance on derogations (Reference 4), and the requirement to demonstrate that the abatement costs are disproportionate to the environmental benefits. This specifies that the assessment should show how these costs are driven by the technical characteristics, geographical location or local environmental conditions of the plant and are disproportionate to the benefits. The guidance cites the following as relevant technical characteristics:

- The recent history of pollution control investment in the installation in respect of the pollutant(s) for which the derogation is sought;
- The general investment cycle for a particular type of installation;
- The configuration of the plant on a given site, making it more technically difficult and costly to comply;
- The practicability (particularly bearing in mind Health & Safety and other relevant legal obligations) of interrupting the activity so as to install improved emission control upon the pollutant(s)
- The effect of reducing the excess emission(s) upon other pollutant emissions, energy efficiency, water use or waste arising from the installation as a whole
- The intended remaining operational lifetime of the installation as a whole or of the part of it giving rise to the emission of the pollutant(s), where the operator is prepared to commit to a timetable for closure.

2.3. Potential Justifications for NOx and Dust Derogations at Lynemouth

In general high level terms the following “Technical Characteristics” could potentially be used to justify derogations for Lynemouth.

The LCP BREF (Reference 2) provides a summary of the plant used to derive AELs for biomass/and or peat plants >300MWth in Figures 5.47 (NOx) and 5.57 (dust). Both NOx and dust AELs were derived from a sample of five power plants, this small sample is unlikely to provide a robust basis for specifying plant limits.

The specific plants used are also not representative of coal to biomass conversions or of the particular technical characteristics of Lynemouth. For example, with respect to the dust emissions two of the five plants are Circulating Fluidized Beds (CFB), which due to lower carbon in ash will have better ESP collection efficiency than PF boilers. Two of the remaining plants have wet FGD which is also not representative of Lynemouth.

Similarly, with respect to NOx emissions two of the five plants are CFB plants which are not representative of a coal to biomass conversion - primary NOx is generally lower due to lower combustion temperatures and Selective Non-Catalytic Reduction (SNCR) is more applicable as gas temperatures have a longer time in the desired reaction window. A split view was submitted by the UK based on the fact that the BREF limits are not appropriate for coal to biomass conversions (Appendix A). This view was made on the basis that coal to biomass conversions could not achieve an annual average of NOx less than 160mg/Nm^3 even when applying a range of the proposed techniques. The view recommended a higher annual average of 180mg/Nm^3.

DEFRA’s guidance refers to the “history of pollution control equipment” and this is particularly important for the electricity generation sector which is characterised by large investments and long payback times. Lynemouth has had a unique regulatory path, with a late change in its exemption status from the LCPD. As a result the plant does not have FGD, which is relevant for dust abatement. Without FGD it is technically much harder to achieve the same dust emissions abatement performance as plant with FGD – i.e. essentially a technical characteristic which makes is disproportionality costly to achieve the emission limits.

2.3.1. Impact on the Environment as a Whole

DEFRA's guidance notes that this is a valid criterion for derogations therefore the dis-benefits of NOx abatement such as energy efficiency penalties, the impact of ammonia slip on local deposition and impacts on ash quality are potentially also justification for derogation either in isolation or as supporting arguments, depending on the environmental evaluation.

3. NOx Emissions

The BAT conclusions for the combustion of solid biomass and/or peat (Reference 1, BAT 24) states that in order to prevent or reduce NO_x emissions to air while limiting CO and N_2O emissions to air BAT is to use one or a combination of the techniques given below:-

- Combustion optimisation: - already applied at Lynemouth through the design of the combustion system, combustion optimisation during unit commissioning and the application of an advanced control system
- Low-NOx burners (LNB) – already applied at Lynemouth with the installation of Doosan Mark III Low NOx Biomass Burners.
- Air staging – already applied at Lynemouth through the installation of BOFA
- Fuel staging: - not applied at Lynemouth, this has been considered as a de-NOx option (Section 3.2.13.2)
- Flue-gas recirculation:- not applied at Lynemouth, this has been considered as a de-NOx option (Section 3.2.23.2)
- Selective non- catalytic reduction (SNCR):- not applied at Lynemouth, this has been considered as a de-NOx option (Section 3.2.3)
- Selective catalytic reduction (SCR):- not applied at Lynemouth, this has been considered as a de-NOx option (Section 3.2.4)

3.1. Technical Characteristics of the Station

Lynemouth was converted from coal to biomass (commissioned on biomass in 2018) during the conversion the station made the following modifications to each unit which relate to NOx emissions:-

- All 12 PF burners with Mark III Doosan Low NOx Biomass Burners
- Installed Boosted Over Fired Air
- Installed Dynamic Classifiers on each mill (4 off per unit)

In addition to the above modifications Lynemouth updated its furnace water nozzles; these remove fouling and white deposits from heat transfer surfaces in the boiler. RWE found that whitening of heat transfer surfaces whilst firing biomass raised furnace temperatures and contributed to thermal NOx formation at Tilbury Biomass Power Station.

The combination of the latest Low NOx burner technology, BOFA and dynamic classifiers enables Lynemouth to achieve primary NOx control whilst limiting CO emissions. Baseline NOx emissions are considered to be 200mg/Nm^3 which is the guaranteed emission value for Lynemouth's conversion from coal to biomass.

3.2. NOx Abatement Options

The following considers NOx abatement technologies referenced in the BAT Conclusions (Reference 1) and their application as Lynemouth. For those options deemed feasible estimated capital and operational costs and predicted emissions are provided.

3.2.1. Fuel Staging

Fuel staging, also termed reburning, is based on the creation of different zones in the furnace by the staged injection of fuel and air. The technique is based on the reduction of the flame temperature or localised hot spots through the creation of several combustion zones in the combustion chamber with different injection levels of fuel and air. The aim is to reduce nitrogen oxides back to nitrogen. Different fuels can serve as reburning fuel (pulverised coal, fuel oil, natural gas) but natural gas is generally used due to higher NOx reduction. In this option a reburning combustion zone which is fuelled by natural gas is installed between the final biomass burner level and the BOFA level.

Reburn is not considered a feasible option for Lynemouth as:-

- The technique has not been widely applied to wall fired pulverised biomass fired tower boilers
- There is insufficient space between the upper biomass burner level and BOFA making reburn difficult to install
- The LNBs installed at Lynemouth have been designed to an air and fuel operating envelope; Reburn would operate the burners outside these boundaries and is not recommended due to flame stability
- Baseline NOx emissions at Lynemouth are already lower than those shown in Figure 3.37 of the BREF (Reference 2) for coal of ~300mg/Nm^3 (emissions on biomass are not shown in the figure)
- Lynemouth Power Station does not has a natural gas supply due to which fuel staging would have a high associated capital cost for a gas pipeline
- Burning conventional natural gas at Lynemouth would preclude it from a 100% biomass station

3.2.2. Flue Gas Recirculation (FGR)

This option considers the recirculation of part of the cooled flue-gas taken after the air preheaters to the combustion chamber to supplement part of the fresh combustion air. This has the dual effect of cooling the temperature and limiting the O_2 content for nitrogen oxidation, thus limiting the NOx formation.

This option would require a new flue gas recirculation fan after the air preheater, new gas ducting and modifications to existing air ducting to accommodate more flow. As noted in the BREF the boiler would be less efficient due to a higher gas volume. The flue gas would be supplied to the burners requiring modification to accommodate. The ID fans would require modification to cope with an increase in gas volume due to a higher gas temperature. Flue Gas Recirculation is not considered as a feasible option for Lynemouth as:-

- An increase in flue gas flow through the boiler would affect the boiler's design which will result in a decrease in boiler efficiency, this may result in inability to achieve final steam temperatures and consequently inability to achieve full load
- The flue gas recirculation fan would operate in a high dust environment which will have a detrimental impact on the fan's life
- The LNBs installed at Lynemouth have been designed to an air and fuel operating envelope; FGR would operate the burners outside these boundaries and is not recommended due to flame stability
- FGR would result in higher gas temperatures to the Electrostatic Precipitators (ESPs) which would have a detrimental impact on dust emissions
- FGR is not expected to reduce NOx significantly given that primary NOx emissions are already low at 200mg/Nm^3

3.2.3. Selective Non- Catalytic Reduction (SNCR)

Selective Non-Catalytic Reduction (SNCR) utilises the reaction between ammonia and nitrogen oxides to reduce NOx emissions to nitrogen and water vapour. The reaction will only occur proceed within a specific temperature window.

Water diluted urea solution is typically the reagent used for SNCR installed on large coal or biomass fired units. Although the BREF states that the temperature window for SNCR is 800˚C to 1100˚C (Reference 2) the temperature window for urea based systems is typically higher at 900˚C to 1050˚C (Reference 5). The residence time required in this window is stated by the BREF to be a minimum of 0.2 sec (Reference 2) with best performance recommendation at about 1s or greater.

Exceeding this temperature range will cause reagent to thermally dissociate forming NOx increasing emissions. Lower than 900˚C and the DeNOx reaction will not occur causing the reagent to "slip" with the flue gas out of the boiler. Reagent injection rate is normally limited to prevent slip exceeding 5 to 10ppm. Slip is limited as ammonia itself is a pollutant, unreacted ammonia will condense on ash affecting its ability to be utilised and ammonia can react with SO_3 in the flue gas to form ammonia bisulphate which can foul airheater heat transfer surfaces.

Several factors determine whether SNCR is appropriate including flue gas temperatures, residence time, feasibility of installing reagent injection ports, and the NOx concentration. SNCR is not suitable for sources where the residence time is too short, temperatures are too low, NOx concentrations are low, reagent would contaminate ash product, or no suitable location exists for installing reagent injection ports. Sources with stable temperatures, uncontrolled NOx emissions above 400mg/Nm^3, and residence times of 1 second are generally well suited to SNCR and attain the highest levels of NOx control (Reference 9).

The application of SNCR technology to tower boilers (as at Lynemouth) differs to those with two passes (Radiant pendant surfaces are located above the furnace, and convective surfaces are arranged horizontally in the second pass), as described in Reference 8. Although the tower boiler design at Lynemouth allows reagent to be injected from all four sides of the boiler, the temperature of the gases is more stratified. Areas close to the boiler walls will have the coldest temperature which can produce high ammonia slip and in the centre the temperature is too hot over the whole load range so that the ammonia will burn to NOx. Gases will cool as they pass through superheater bundles close above the urea injection ports; this limits residence time in the desired temperature window, and makes targeting some areas of the gas flow difficult.

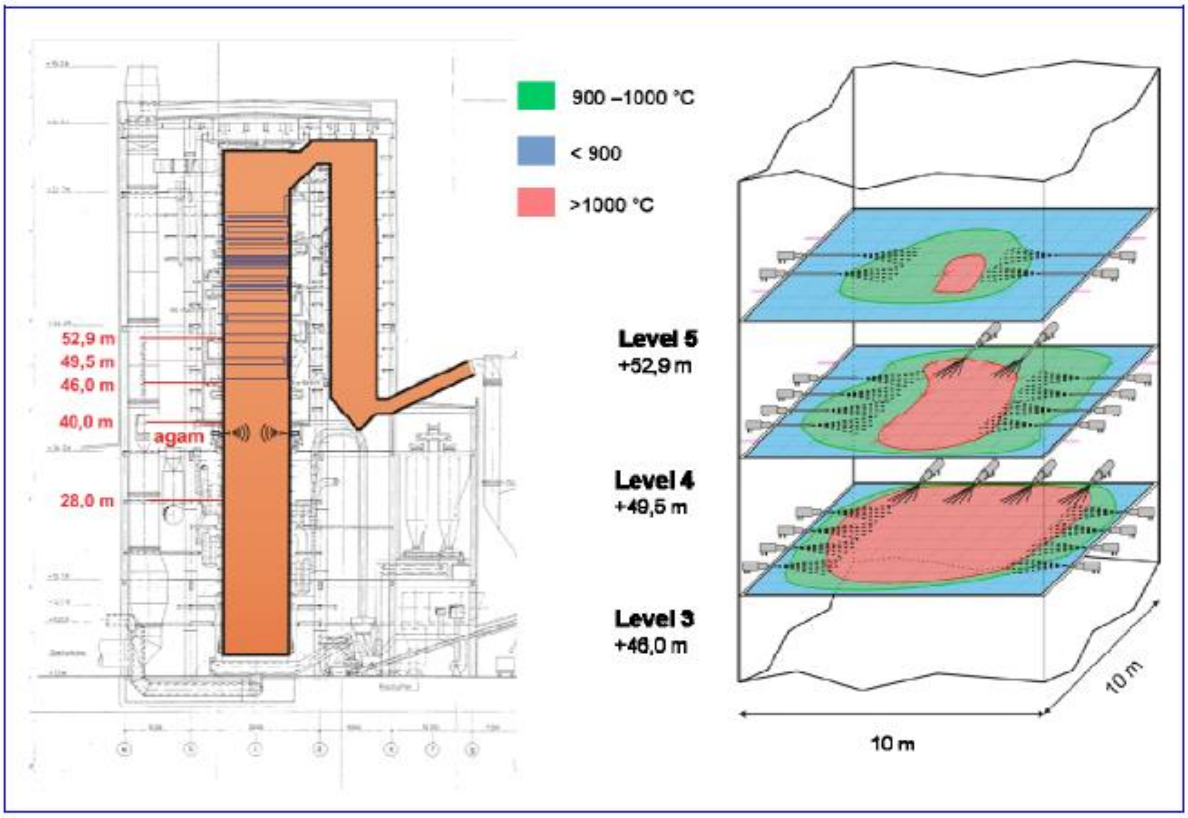

Figure 1: SNCR Process for a Coal-Fired Boiler in Germany (Reference 8)

Only the area marked in green colour between those two areas will have an optimum temperature range for the reactions (Figure 1), therefore, special measures have to be taken in order to achieve sufficient distribution of the reagent in the flue gas. One alternative is to inject the reagent in several levels simultaneously with different penetration depths and/or lances with different lengths. An optimum distribution of the reagent is however still difficult to realize.

The gas temperature drop across the superheaters is affected by deposits of fly ash and the operating cycle of the sootblowers. A SNCR system will however measure the flue gas temperature upstream of the superheaters this makes prediction of where the ideal temperature window is difficult. The injection of liquid urea close to unprotected heat transfer surfaces can also cause localised corrosion due to droplet impingement on the unprotected tubes from localised eddies (Reference 12).

The application of SNCR at Lynemouth is also made more difficult as it is front wall fired fuel is injected from one side of the furnace leading to more stratification of NOx in the flue gas compared to T-fired or opposed fired units.

Modelling of Lynemouth operating at full load on biomass (Reference 13) has indicated that flue gas temperatures at full load are:-

Location	Average Gas Temperature (°C)
Between Platen SH and Final SH	1142
Between Final SH and Final RH	1000
Between Final RH and Primary SH	902

Table 4: Average Boiler Flue Gas Temperatures at Full Load

Given the above temperatures the ideal position for SNCR is between the final Superheater (SH) and final Reheater (RH) at 1000°C. There is however only a 1 metre gap between the Final SH to RH making this temperature window extremely narrow. Additionally above this injection zone there are 27 RH elements with a 0.35m pitch between the tubes. The proximity of the heat transfer surfaces to the injection zone would make preventing urea impingement on tubes very difficult. In this position the boiler is 7m by 10m meaning the maximum average theoretical residence time will be ~0.15seconds (149kg/s gas flow at a density of 0.29m^3/kg), this is less than the 0.2 seconds minimum referenced in the BREF (Reference 2, Section 3.2.2.3.12) therefore NOx abatement is expected to be very low for a controlled ammonia slip.

A further injection window could be located between the RH and primary SH but this would have similar problems – this distance between the two banks is again approximately 1m and the pitch between primary superheater banks is narrow. The maximum residence time is ~0.15 seconds meaning NOx abatement would also be low in this injection window.

Emissions Performance

Table 3.27 of the BREF states that SNCR typically achieves NOx reduction of 30-50% from baseline levels on large coal fired units (which generally have much higher baseline NOx than Lynemouth) but states that performance is highly dependent on operating conditions. The BREF Conclusions states that SNCR for existing combustion plants is applicable within the constraints associated with the required temperature window and residence time for the injected reactant therefore consideration of the SNCR temperature window is key. As stated above the temperature window for SNCR is narrow at Lynemouth.

A proportion of the urea injected for SNCR will "slip" as ammonia rather than react with NOx. Ammonia slip is required to be limited to less than 15mg/Nm^3 (BAT Conclusions annual average, Reference 1), equivalent of 20ppm). It is however necessary to limit slip for other reasons as it can react with SO_3 and form ammonia bisulphate which will foul the airheaters. High ammonia in ash will also cause odour issues which limits the utilisation of fly ash.

In general there will be a lower reduction in NOx as the baseline NOx decreases. This is because the baseline NOx comes closer to the equilibrium NOx concentration. For typical coal and oil-fired boilers, critical NOx levels are approximately 125mg/Nm^3 at 6% O_2 in the upper furnace (70-90ppm, 0.1lb/MMBtu from Reference 6). Lynemouth's baseline NOx is close to the minimum theoretically achievable NOx value therefore temperature and residence time must be close to ideal to achieve good NOx reduction.

Figure 2 was developed for RWE's Tilbury Biomass Phase 2 and demonstrates SNCR performance against baseline NOx using reference plant information provided by a boiler contractor. SNCR performance is very plant specific and the spread of data seen in the graph reflects the variation in performance in plants. The graph and other supplier reference lists do not contain details of any biomass pulverised fuel plants operating with emissions at or below 200mg/Nm^3 prior to SNCR abatement technology being applied.

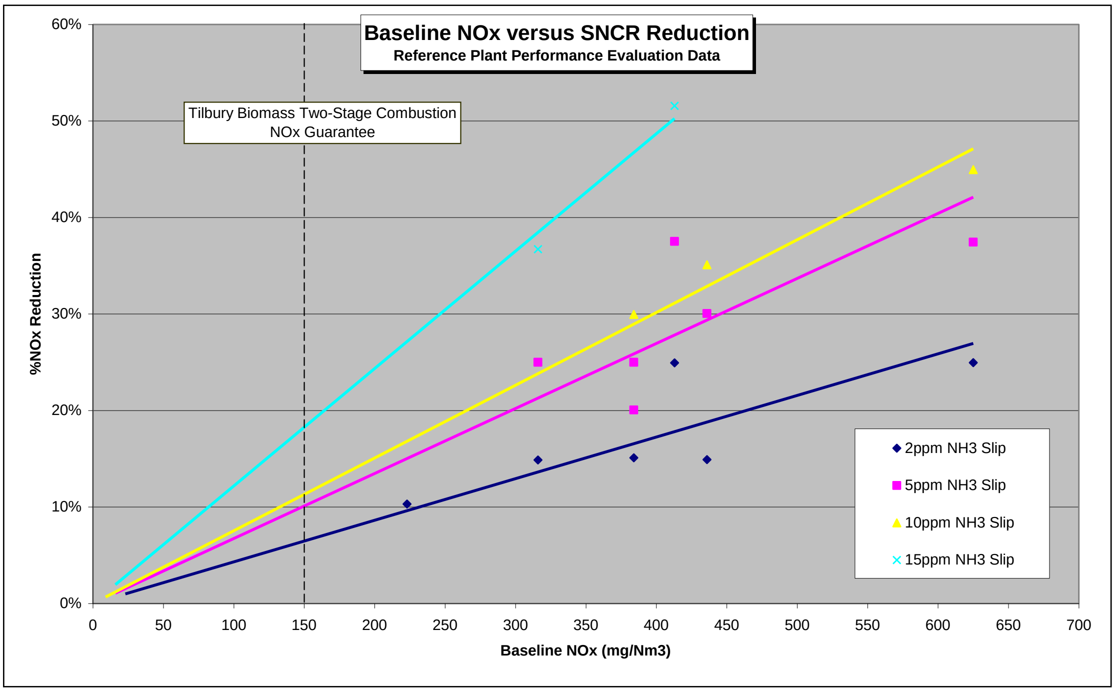

Figure 2: SNCR performance with Baseline NOx based (from Reference Plants)

The data supports the Lynemouth specific assessment that from the low baseline NOx of 200mg/Nm^3 SNCR will only result in ~15% abatement of NOx if the ammonia is limited to 5-10ppm (normal SNCR range). SNCR reductions of up to 25% have been predicted as being possible but will result in high slip levels of up to 15ppm, however given the limited residence time of the temperature window at Lynemouth a 15% reduction in NOx from baseline levels has been assumed.

Capital Costs

Capital items for an SNCR system include urea storage, pumps, blowers, a number of injector levels, furnace temperature measurements and ammonia slip measurements in the flue gas.

Reference 15 estimated SNCR capital costs to be €15-30/kWth (2005 prices), based on the inflation rates from the Bank of England and current exchange rates this is equivalent to £18.6-37.3/kWth (2018). Reference 15 is quoted in the work done by Task Force on Techno-economic Issues (TFTEI) whose work is complementary to the work carried out by the EIPPC Bureau of European Commission´s Joint Research Centre to draft the BAT Reference (BREF) documents (Reference 13). Based on this range an SNCR on all units would cost £20.7-41.3m at Lynemouth. Reference 9 has a much wider for the capital cost of SNCR of $4-44/kWe (for power generation units based on data for 2005-2007). From this range (with inflation and exchange rates) the cost for Lynemouth equates to £1.8-20m. The capital cost of an SNCR system has been estimated at £20.7m for Lynemouth (lower end of the Reference 15 estimate).

Operating Costs

The primary costs of an SNCR system will be consumption of DeNOx reagent which in this case is assumed to be urea. There will also be power consumption, reduction in the thermal efficiency of the boiler (due to evaporation of water in the boiler) and a dilution water requirement. Operating costs were based on a price of urea of 175 £/tonne for 40%wt solution and a 1.1:1 normalised urea to NOx stoichiometry. Each unit has been estimated to require 4.5t/d of 40%wt urea and 30t/d of high quality dilution water.

Costs have been estimated at £0.35/MWh (consisting of £0.21/MWh for urea and £0.15/MWh for additional heat) at 90% load factor this equates to £1.2myr.

	Annual Station Operating Costs (£/yr)
Reagent	680,000
Thermal Losses	500,000
Total	**1,200,000**

3.2.4. Selective Catalytic Reduction

Selective Catalytic Reduction (SCR) uses a catalyst to reduce nitrogen oxides with anhydrous or aqueous ammonia. Static mixers are installed before the SCR to create a more homogeneous gas inlet stream to the SCR. Reagent is injected upstream of the catalyst and the reaction produces nitrogen and water vapour. The catalyst requires a temperature of around 300–450°C for the reaction to proceed (Reference 2). Several layers of catalyst may be applied to achieve a higher NOx reduction; SCRs are typically designed to achieve 90% reduction of baseline NOx emissions.

Ammonia slip should be as low as possible to avoid carry over to the fly ash and in order to avoid the risk of ammonia (NH_3) reacting with sulphur trioxide (SO_3) during cooling of the flue-gas, which can lead to fouling and corrosion of surfaces from ammonium bisulphates.

Normally anhydrous or aqueous ammonia is stored on site for use in the SCR. This may have implications under the Control of Major Accidents and Hazards (COMAH) Regulations 2015 (“COMAH”) due to the hazardous nature of these substances.

A SCR at Lynemouth would most likely consist of two layers, one active layer and one initially empty to be filled when the 1st layer has deactivated. SCRs are commonly installed in either a high dust arrangement before the airheaters and particulate removal device where gases are hot or low dust after the particulate removal system (this arrangement requires the flue gases to be reheated to the desired SCR temperature).

The high-dust arrangement is the most commonly implemented and avoids the need to reheat flue gas to the temperatures required by the catalyst. Flue gases at Lynemouth are approximately 320°C (Reference 13) at the inlet to the airheaters this is at the lower end of the reaction window for SCR. At this temperature a large volume of catalyst would be required to achieve the desired removal rate. Operating at a gas temperature below 350°C in a high dust environment risks the capillary condensation of ammonium sulphate which results in catalyst deactivation (Reference 19). To increase the SCR operating temperature a section of the existing economiser may be removed and a new lower temperature economiser added after the SCR, if this approach is taken the new economiser should be designed with a constant rise to prevent “steaming” in the economiser.

Table 2.3 of Reference 20 provides a description of the SCR system requirements for a 120MW coal burning utility boiler. This estimates the SCR to be a vertical flow reactor measuring 13.5m by

13.5m by 9.5m high. The height of such a reactor with additional space for reagent and NOx mixing would not fit in in the existing run at Lynemouth from the economiser outlet duct to the airheater inlet which is approximately 9m. A SCR system would therefore require a new structure separate from the existing gas path. It is likely that the SCR structure would sit outside the boilerhouse above the flue gas ducting leading to the ESP. New flue gas ducting would take the flue gas from the outlet of the economiser vertically upwards; gases would then pass down through static mixers, an ammonia injection system and over the SCR catalyst. After the SCR the flue gas would be routed back to the existing airheaters. Space for this structure would be particularly difficult on Unit 2 as it is constrained by Units 1 or 3 on its sides.

Biomass fuels with high levels of alkali, potassium, arsenic, phosphorus and fluorine show higher catalyst deactivation behaviour, (Reference 2). Dong Energy's Avedøre Power Station experienced deactivation of its SCR catalyst when firing wood pellets (Reference 10), the wood's relatively high content of potassium and chloride partly vaporizes during combustion, forming a fine aerosol of potassium chloride (KCl) and potassium sulphate (K_2SO_4) particles which poisons the catalyst. Avedøre Power Station (Reference 10) found that the catalytic deactivation averaged 25% per 10,000hrs before reducing to 15% per 10,000hrs after the station co-injected coal ash to control catalyst deactivation.

A low dust SCR system is more favourable for catalyst life as many of the poisoning components of the flue gas are no longer present. In this arrangement the flue gas after the ESPs would pass through a gas-gas heater followed by a steam coil preheater to the SCR system, then back through the other side of the gas-gas heater to the stack. This arrangement would have a higher capital and operating cost as well as complexity. It is considered that the high dust arrangement would be more favourable for Lynemouth.

In either case the Induced draught system at Lynemouth would need to be uprated to overcome the pressure drop associated with the SCR system. This is likely to be achieved through the installation of a supplementary booster fan after the existing Induced Draught Fans. The ESPs and ductwork leading up to the suction fans would operate at a lower pressure than currently and depending on their design modifications may be required to ensure operation of these items at the lower pressure.

Emissions Performance

It is estimated that a SCR system would provide a reduction in NOx emissions of 90% from baseline levels. A supplier indicated that a SCR would be capable of achieving 10-20mg/Nm^3 of NOx (Reference 16). Some ammonia injected for SCR will "slip" as ammonia rather than react with NOx. Ammonia slip is required to be limited to less than 15mg/Nm^3 (BAT Conclusions annual average), SCR typically has lower levels of ammonia slip than SNCR and a slip level of less than 5mg/Nm^3 is likely to be achievable.

Capital Costs

A SCR would comprise of a new reactor structure, ducting, SCR catalyst, flue gas mixers, ammonia storage, evaporation and injection systems, dilution air blowers and an additional flue gas suction fan to overcome the pressure drop of the SCR. Due to the additional pressure drop ductwork and ESPs may be required to operate at pressures lower than designed and as such require modification to accommodate.

It is assumed that a two layer (one initially empty layer) high dust SCR is fitted to each unit which are designed to achieve 90% removal. Capital costs associated with SCR are relatively high and will be site specific. Reference 15 estimates SCR capital costs to be €50-70/kWth (2005 prices); based on the inflation rates from the Bank of England and current exchange rates this is equivalent to £62-87/kWth (2018). Using this range SCR installation on all units at Lynemouth would cost £68.5 to 95.9m.

Table 3.26 of the BREF (Reference 2) estimates SCR costs (excluding the cost of catalyst) based on flue gas flow rates from a review of Austrian and German plants (2000-2005 market prices). Each Lynemouth unit has a full load gas flow rate of approximately 500,000Nm^3/hr, from the referenced table capital costs are €9.2m per unit this equates to approximately £39m for three units allowing for inflation and currency conversion. Catalyst requirement for these 3 units is estimated to be 180m^3 per unit the BREF (Reference 2) has a cost of EUR 15,000/m^3 this equates to a cost of £2.4m per unit. From this the cost of SCR on all units at Lynemouth would be in the region of £46m (~£50/kWth). This is considered to be on the low side cost estimates for the SCR at Ratcliffe Power are in the region of £200-300m, (£40-60/kWth) (2010 prices). Based on this the lower end of Reference 15's range of £62/kWth has been used, SCR for three Lynemouth units is assumed to cost £68.5m.

Operating Costs

The operating costs associated with SCR are primarily reagent costs, additional fan power consumption and catalyst replacement costs. As Lynemouth fires biomass the life of the catalyst will be lower compared to coal fired units (as discussed early in this report). Catalyst life has been estimated at 40,000 hours (approximately 5 years) at which time it is assumed the catalyst is regenerated at half the cost of a new catalyst.

The SCR will impose an additional power consumption due to the operation of blowers, pumps and fans, this has been estimated at 0.7% of the stations power output. The cost of lost power generation has been based on Lynemouth's current Contract for Difference strike price of £117/MWh (Reference 17).

Reagent costs have been estimated based on anhydrous ammonia at a cost of £480/t. The SCR is assumed to achieve 90% abatement on the inlet NOx with anhydrous ammonia injected at a 1:1 NOx to NH_3 molar ratio. Approximately 1 t/d of anhydrous ammonia will be required per SCR unit at full load.

	Annual Station Operating Costs (£/yr)
Catalyst	725,000
Reagent	620,000
Works power	2,710,000
Total	**4,060,000**

Table 5: SCR Operating Costs for Lynemouth

3.3. Hybrid SCR

Hybrid SCR also known as in-duct SCR or slip SCR is a version of the high-dust SCR arrangement. A catalyst system is combined with a SNCR system to consume the remaining injected reagent still present in the flue-gas at the boiler outlet and to add an additional NOx reduction stage. More urea is injected at the SNCR stage in order to achieve better NOx reduction and allow some ammonia to "slip". The slipped ammonia will then react with NOx on the SCR catalyst further in the process. This type of SCR requires much less catalyst than conventional SCR, providing overall high removal efficiency and low ammonia slip at a reduced capital cost. As the catalyst is installed in dust it will however be exposed to higher gas velocities than conventional SCR reactors and leading to erosion of the catalyst.

In this option a SNCR system is installed in the furnace at the temperature window as discussed in Section 3.2.3. The SNCR is operated with a high slip (of approximately 40ppm) to achieve a high NOx removal rate. A thin layer of SCR catalyst is installed "in duct" between the economizer outlet and the airheater inlet. The catalyst is used to further remove NOx from the flue gas as well as the unreacted ammonia. The final slip of ammonia with the flue gas can be less than 5ppm.

At Lynemouth the SCR catalyst could be installed inside the existing flue gas ducting from the economiser to the airheaters. As described in the SCR section of this report the economiser would require modification to raise gas temperatures to >350°C to prevent ammonium sulphate condensation.

This type of system is not widely applied to Large Combustion Plants with limited reference plant compared to SCR and SNCR systems.

Emissions Performance
A supplier provided an estimate of 50% NOx reduction with an "optimised" SCR system (Reference 16) therefore emissions are expected to be 100mg/Nm^3. The performance of this type of system is however heavily dependent on the suitability of the furnace to SNCR, and as discussed in Section 3.2.3 Lynemouth furnace is not well suited to this.

Ammonia slip is required to be limited to less than 15mg/Nm^3 (BAT Conclusions annual average) , a hybrid SCR typically has lower levels of ammonia slip than SNCR and a slip level of less than 5mg/Nm^3 is likely to be achievable.

Capital Costs
The BREF (Reference 2) states that a hybrid SNCR/SCR solution costs less than two thirds of the cost of a full SCR system. The capital cost of such a system has therefore been estimated at two thirds of a full SCR system at £45.7m for three units.

Operating Costs
The operating costs associated with SCR are primarily reagent costs, additional fan power consumption and catalyst replacement costs. As Lynemouth fires biomass the life of the catalyst will be lower compared to coal fired units (as discussed early in this report). The hybrid SCR reactor will be installed induct meaning gas velocities will be high leading to more erosion. Catalyst life has therefore been estimated at 30,000hours (approx. 3.75 years) at which time it is assumed the catalyst is regenerated at half the cost of a new catalyst. It is estimated that the catalyst volume requirement for a hybrid SCR is half of that required for full SCR.

Additional power consumption is required for urea injection systems, additional fan power and blowers. It is estimated that the hybrid option requires half the power of a full SCR system, 0.35% of the unit's power output.

The DeNOx reagent is assumed to be urea, a the hybrid system will require a higher injection rate than SNCR, the BREF (Reference 2) states that a 1-2.5 NH_3 to NOx ratio is representative of SNCR for most sites therefore a 2:1 injection rate was used. At this ratio 49t/d of urea are required per unit. Each unit has been estimated to require 4t/d of 40%wt urea and 27t/d of high quality dilution water. Costs have been estimated at £0.64/MWh (consisting of £0.37/MWh for urea and £0.27 /MWh for additional heat) at 90% load factor this equates to £2.1m/yr for the station.

	Annual Station Operating Costs (£/yr)
Catalyst	350,000
Reagent	1,250,000
Thermal Losses	900,000
Works power	1,350,000
Total	**3,850 ,000**

Table 6: Hybrid SCR Operating Costs for Lynemouth

3.4. Summary of NOx Abatement Options

The following table summarises feasible NOx abatement options for Lynemouth:-

Modification	Baseline NOx (mg/Nm^3)	NOx abatement efficiency	Final NOx (mg/Nm^3)	Capital Cost – 3 Units (£m)	Annual Operating Cost @ 90% LF (£m/yr)
SNCR	200	15%	170	20.7	1.2
SCR	200	90%	20	68.5	4.1
Hybrid SCR	200	50%	100	45.7	3.9

Table 7: Summary of NOx Abatement Options

4. Dust

The following section considers the Best Available Techniques for particulate abatement at Lynemouth Power Station.

The BAT conclusions for the combustion of solid biomass and/or peat (Reference 1 BAT 26) states that in order to prevent or reduce dust and particulate emissions to air BAT is to use one or a combination of the techniques given below:-

- Electrostatic Precipitators (ESP) - applied at Lynemouth, further application considered in Section 4.2.4
- Bag Filter – Not applied at Lynemouth considered in Section 4.2.2
- Dry or semi-dry FGD – this technique is mainly used for SOx, HCl and/HF control and so is not considered applicable to Lynemouth for dust abatement (Section 4.2.1)
- Wet flue-gas desulphurisation - this technique is mainly used for SOx, HCl and/HF control and so is not considered applicable to Lynemouth for dust abatement (Section 4.2.1)
- Fuel choice – Not considered feasible for Lynemouth to use a lower ash fuel (ash content already extremely low)

4.1. Technical Characteristics of the Station

As previously discussed in this report Lynemouth did not fit FGD when operating on coal. It has since converted to fire 100% biomass which due to its low sulphur content and ash properties has low SO_2 emissions which are inherently lower than the BREF Associated Emission Levels. A consequence of not fitting FGD is higher dust emissions.

The station has Electrostatic Precipitators (ESPs), these were originally build by Lodge in 1970 as a two-flow three field precipitator arrangement per boiler basis (A1, A2, A3 and B1, B2, B3). Each field originally operated at 60Kv and 350mA.

An upgrade/refit of the ESPs was carried out across all three boiler units that replaced the existing Lodge transformer rectifier (TR) set controllers with ABB EPIC units which gave better control and allowed pulsed energisation of the TR sets.

To improve dust collection efficiency further an extra field (A0 and B0) was installed upstream of the existing fields between 1995 and 1998 by ABB. Due to the presence of pre-existing equipment underneath the new fields, no new hoppers could be installed, the new fields were therefore installed with shallow flat-bottomed ducts in which a mechanical scraper drags the collected dust into the pre-existing field #1 hoppers. These new fields operate at up to 70kV and 800mA and were also controlled by EPIC controllers. This addition was due to requirements to reduce the emissions as per Environment Agency requirements. The guarantee was for 50 mg/Nm^3 which the new installation met when the station was fired on coal.

During the biomass conversion the transformer rectifiers were replaced with Switched Integrated Rectifiers to improve dust collection. All of the existing TR sets were replaced with modern variants of high frequency power supplies to provide a low-ripple, high DC power to each field. The ESPs were also overhauled to an “as new” condition to maximise dust abatement.

Primary air coolers were installed for operation with biomass fuel; these reduce the primary air temperature into the mills for safe operation on biomass but also provide higher boiler efficiency by reducing the flue gas temperature. This reduction in flue gas temperature and mass flow rate has the effect of improving the operation of the ESP through the reduced flue gas velocity making it easier to capture particulates.

The conversion of Lynemouth to 100% biomass has reduced the dust burden on the ESPs due to the low ash content of the fuel; however the ash is high in carbon (due to the low volume of ash). High carbon in ash lowers the ash resistivity making it more difficult to capture.

Lynemouth has guaranteed dust emissions of 20mg/Nm^3 for operation on biomass fuel.

4.2. Dust Abatement Options

The following considers dust abatement technologies referenced in the BAT Conclusions (Reference 1) and their application as Lynemouth. For those options deemed feasible estimated capital and operational costs and predicted emissions are provided.

4.2.1. Flue Gas Desulphurisation

The BAT Conclusions (Reference 1) reference dry, semi-dry or wet FGD systems as BAT for dust abatement but states that their applicability is mainly for SOx, HCl and/or HF control. As Lynemouth's emissions of these pollutants are within the BREF AEL ranges it is not considered BAT to fit FGD for dust abatement therefore it is not considered further.

4.2.2. Bag Filters

A bag filter unit consists of one or more isolated compartments containing rows of bag filter bags or tubes. Dust-laden gas usually passes up along the surface of the bags then radially through the fabric. Particles are retained on the upstream face of the bags, while the now cleaned gas stream passes to the system's outlet. The filter is operated cyclically, alternating between relatively long periods of filtering and short periods of cleaning. During cleaning, dust that has accumulated on the bags is removed from the fabric surface and deposited in a hopper for subsequent disposal.

A bag filter could be added to polish the gas stream after the gases have passed through the existing ESPs. Alternatively an ESP may be converted to a bag filter by modification of the casing and internals. The application of this technology would be expensive as a section of the ESP may need to be removed to fit and the ID fans would need to be upgraded to accommodate the additional pressure drop. The operational costs of a bag filter would be high due to increased ID fan power consumption and a high maintenance requirement for bag replacement.

Biomass fly ash from PF fired boilers such as Lynemouth typically have a high carbon due to low ash content of the fuel and incomplete burn out. The low ash content of the fuel means there is little dilution of unburnt carbon. In such boilers is not unreasonable to expect burning embers to be present at the particulate collection device, and RWE had experience of burning embers in the ESP hoppers at Tilbury after the conversion from coal to biomass. Lynemouth Power Station has also found burning embers in their ESP hoppers. The high concentration of carbon in fly ash and burning embers presents an unacceptable fire risk when bag filters are used instead of ESPs for biomass PF fired units.

The BREF (Reference 2) states that in biomass plants where the ash has a high amount of unburnt matter, and there is a risk of sparks or glowing particles reaching the bag filter, a pre-collector upstream of the bag filter is recommended to reduce the risk of hopper fires and bag damage. Bag filter fabrics which are fire-resistant are unproven and reliable char burning traps are not a mature technology. Due to this there would be a high risk of fire if bag filters were installed at Lynemouth.

This option is not considered feasible due the increase fire risk associated when operating with high carbon in ash.

4.2.3. Additional ESP Field

An additional ESP field could be added such that each ESP has five fields. The new fields could be located at the current exit of the ESPs with new hoppers and dust removal systems. Currently there is a 5.5m length duct from the last ESP field to the duct turn before the entrance of the ID fans. The last field at Lynemouth measures 3.7m and the duct expansion transition and isolation damper 3m. A total length of 6.7m would therefore need to be accommodated a new field and ductwork; this could be achieved by moving each of the ID fans towards the stack or possibly by a new more complex duct route. Each of these options would be complex and require modification of existing ductwork.

Emissions Performance
The ash concentration in wood pellets is very low and typically ranges from 0.2%-1.5%wt. At these concentrations ash loading at the ESP inlet is low at 320-2400mg/Nm^3. The collection efficiency of the ESP is therefore lower than on coal. The dust not collected in the 4th ESP field will be high in carbon therefore collection efficiency will be low in the new additional field. Collection efficiency of an ESP can be estimated from the Modified Deutsch-Anderson Equation:-

$$\eta = 1 - e^{-w_e(\frac{A}{Q})}$$

Where:-

η = Collection Efficiency
w_e = effective migration velocity
A = Collecting Area
Q = Gas flow rate

In the case where the field length is extended other variables can be assumed to be constant. Using an average ESP dust loading of 1360mg/Nm^3, the current dust collection efficiency is 98.5%, therefore the grouped variable of $-w^{-e\ (A/Q)}$ is equal to 0.014. If an additional field is added this term will increase by 5/4 therefore the new collection efficiency is 99.5% and the final dust load 7mg/Nm^3. It is however overly optimistic to assume that the migration velocity will be the same throughout the ESP. In practice this will decrease along the ESP as the dust will have a smaller particle size and more carbon in ash, it is estimated that the migration velocity will half in the final field leading to an emission of 12mg/Nm^3 with an additional field.

Capital Costs
Capital costs for such an option are likely to be high due to the difficulty in locating the additional fields. Capital costs in Table 5.31 of the BREF are estimated to be in the €13-60/kW, based on the average of this range and treating one quarter of the flue gas this would cost £3.4m for three units to build the additional fields. In addition to this there would be costs to move the ID fans and reroute duct work, estimated at £200k per unit. Total costs would therefore be £4.0m for the station.

Operating Costs
The new fields pass would each have a power consumption of approximately 56kW per zone (112kW per unit). This equates to an annual cost of £310k/yr for the station.

4.2.4. Additional ESP Pass

Adding an additional ESP pass would offer the largest improvement in dust collection efficiency. This option considers the addition of an additional ESP pass in parallel to the existing two on each unit, each with four fields. This option would reduce the flue gas duty in each existing pass by 33% and would be more effective than adding extra fields because the ash loading at the ESP inlet is already very low compared to operation on coal.

The construction of a new pass would be difficult to achieve due to very limited space. It is likely to be possible to create a new pass for Unit 3 to the south of the unit and a new pass for Unit 1 to the north of the unit. Creating a new pass for Unit 2 is not considered practical due to the space constraints.

Capital Costs
Capital costs for such an option are likely to be high due to the difficulty in locating the additional pass. Capital costs in Table 5.31 of the BREF are estimated to be in the €13-60/kW, based on the

average of this range and treating one third of the flue gas this would cost £3.0m for two units. It is expected that costs would be much higher than this estimate in reality due to the layout of the station.

Operating Costs

Each new pass would have a power consumption of approximately 224kW per unit (56kW per zone). This equates to an annual cost of £410k/yr for the station.

Emissions Performance

Based on information from suppliers (Reference 16) this option is expected to achieve an emission in the range of 10mg/Nm^3 from the modified units. The station would therefore have an average emission of 13mg/Nm^3.

4.3. Summary of Dust Abatement Options

Modification	Baseline Dust (mg/Nm^3)	Final Dust (mg/Nm3)	Capital Cost (£m)	Annual Operating Cost @ 90% LF (£m/yr)
Additional ESP Field (all units)	20	12	4.0	0.31
Additional ESP Pass (2 units)	20	13	3.0	0.41

Table 8: Summary of Dust Abatement Options

5. Carbon Monoxide (CO) Emissions

The following section considers the Best Available Techniques for dust abatement at Lynemouth Power Station.

5.1. Technical Characteristics of the Station in relation to the BREF

Lynemouth is a coal to biomass conversion with CO emissions greater than the maximum indicative BREF AEL for CO of 80mg/Nm^3 (Reference 1). Lynemouth uses a combination of primary measures to reduce NOx in combination with low CO:-

- BOFA
- Biomass Low NOx Burners
- Dynamic Classifiers

The NOx emissions performance of a boiler is directly linked to the thermal rating of the boiler, or the Burner Zone Heat Release (BZHR) – essentially the concentration of heat release. Lynemouth has a small boiler relative to its thermal rating compared to other boilers, this makes achieving low primary NOx difficult. Carbon monoxide emissions are therefore higher at Lynemouth due to the requirement to reduce NOx emissions and the lower residence time within a smaller boiler.

Carbon monoxide emissions have an inverse relationship with NOx; if carbon monoxide emissions are reduced it is likely that NOx will increase. On PF coal to biomass conversions such as Lynemouth residence times are lower than other boiler types making them more sensitive to CO formation. On PF biomass boilers fluctuations in fuel characteristics which can lead to deviations in mill and burner throughput, which makes achieving the correct local air to fuel ratios for both NOx and CO control difficult. Due to this the plant is will have higher CO emissions if NOx emissions are to be kept as low as possible. NOx is considered to be a higher priority pollutant than CO as such emissions at Lynemouth have been optimised for lower NOx emissions.

6. Conclusions

The design of Lynemouth is fundamentally different to those of the plant used to derive the BREF limits and this design difference (or technical characteristic) results in disproportionate costs to meet these limits. Only five power plants have been used to derive the BREF AELs (Reference 2) for NOx and dust for biomass plants >300MWth, the specific plants used are not representative of coal to biomass conversions or of the particular technical characteristics of Lynemouth.

A split view was submitted by the UK based on the fact that the BREF limits are not appropriate for coal to biomass conversions (7.Appendix A). This view was made on the basis that coal to biomass conversions could not achieve an annual average of NOx less than 160mg/Nm^3 even when applying a range of the proposed techniques. The view recommended a higher annual average of 180mg/Nm^3.

NOx

Lynemouth has applied primary measures (LNBs, BOFA) to reduce NOx emissions to 200mg/Nm^3. Further reductions in NOx through primary measures are not feasible; therefore secondary measures would need to be applied to reach BREF AELs. Secondary measures for NOx control with have associated ammonia emissions to air and ash disposal implications.

The boiler at Lynemouth is not well suited for SNCR due to NOx stratification as the boiler is fired from one side, non-uniform gas temperature profile due to tower boiler design and limited space in the desired temperature window; there is a maximum of 1m height before heat transfer elements encroach on the injection window. The residence time in the SNCR reaction window has been estimated to be a maximum of 0.15seconds. This is lower than the recommended minimum residence time in the BREF. Due to this and the low baseline NOx, removal efficiency with SNCR has been predicted to be low at 15% which would not achieve the upper BREF AEL for NOx.

The installation of a SCR system would require extensive modification of the boiler's gas path to accommodate. A high dust system would be of lower capital and operating cost compared to a low dust system. In this arrangement the SCR would require a new separate structure built over the ESP inlet ductwork. Ductwork would be installed to take gas from the outlet of the economiser to the SCR and back to the airheaters. The economiser would need to be modified to achieve the desired gas temperature for the reaction; ID fans would also need to be upgraded for the pressure drop of the SCR. A SCR could be designed to achieve a 90% NOx removal efficiency but would have a high cost.

A hybrid SNCR / SCR system could be installed but would have to cope with the same issues as above. Additionally this type of system has however not been widely applied to Large Combustion Plants. It is estimated that such a system might be capable of 50% NOx removal but would have a high cost.

Dust

Lynemouth has had a unique regulatory path, with a late change in its exemption status from the LCPD. As a result the plant does not have FGD, which is relevant for dust abatement. Without FGD it is technically much harder to achieve the same dust emissions abatement performance as plant with FGD – i.e. essentially a technical characteristic which makes it disproportionality costly to achieve the emission limits.

PF fired biomass plants generally have high carbon in ash and there is the chance of burning embers to be present in the dust abatement equipment. Due to this the application of bag filters at Lynemouth is not recommended and not considered feasible.

A new field could be added to each unit's ESPs; this would however require the ID fans to be moved closer to the stack. This option is however unlikely to meet the upper range of the BREF AEL with a station average emission of 12mg/Nm^3 estimated.

It may be possible to add a new ESP pass to Units 1 and 3 but due to space considerations this would not be possible on Unit 2. This option is however unlikely to meet the upper range of the BREF AEL, with a station average emission of 13mg/Nm^3 estimated.

Carbon Monoxide

Carbon monoxide emissions generally have an inverse relationship with NOx; if carbon monoxide emissions are reduced it is likely that NOx will increase.

Carbon monoxide emissions have an inverse relationship with NOx; if carbon monoxide emissions are reduced it is likely that NOx will increase. On PF coal to biomass conversions such as Lynemouth residence times are lower than other boiler types making them more sensitive to CO formation. On PF biomass boilers fluctuations in fuel characteristics which can lead to deviations in mill and burner throughput, which makes achieving the correct local air to fuel ratios for both NOx and CO control difficult. Due to this the plant is will have higher CO emissions if NOx emissions are to be kept as low as possible. NOx is considered to be a higher priority pollutant than CO as such emissions at Lynemouth have been optimised for lower NOx emissions.

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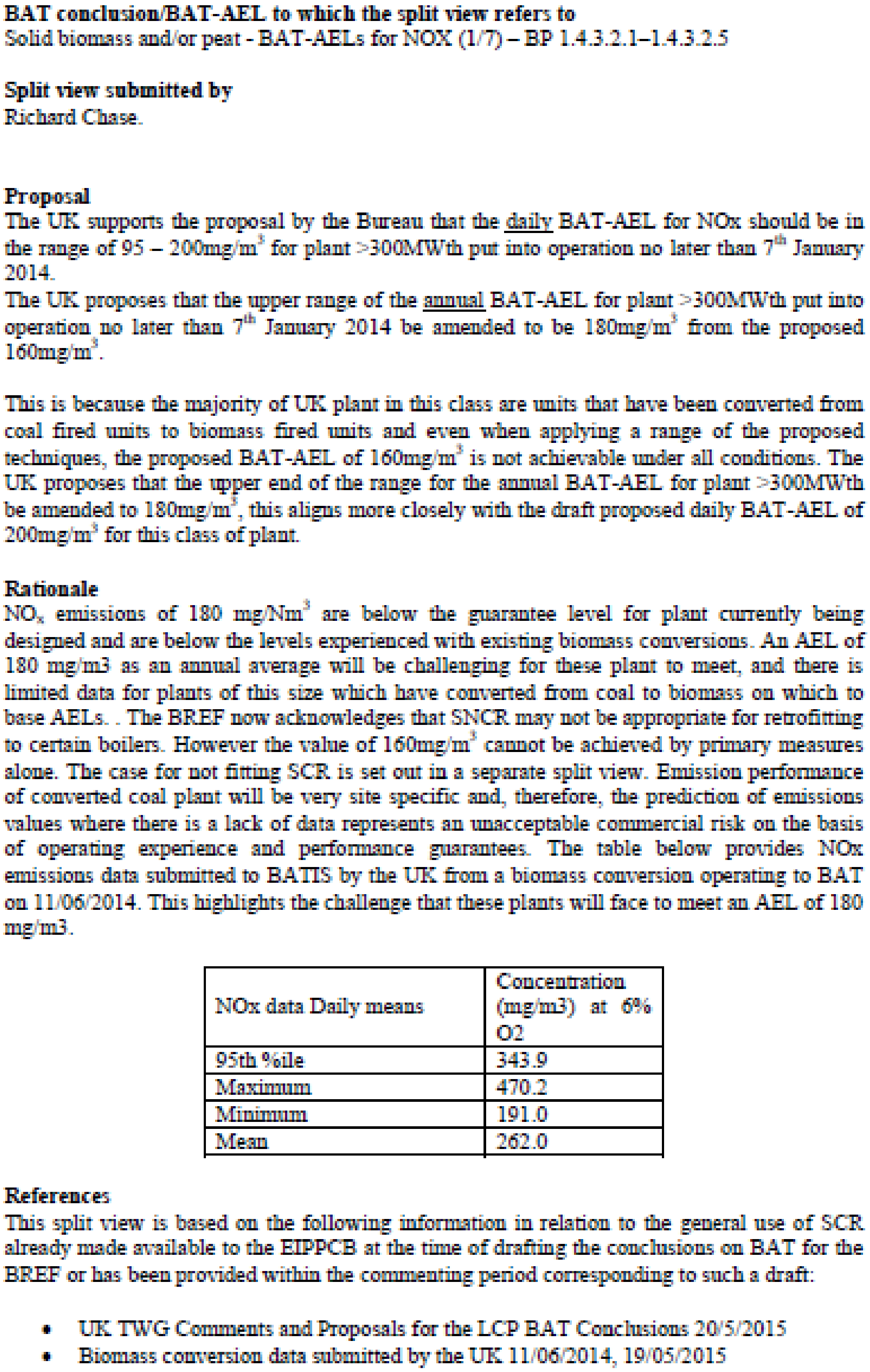
Appendix A. UK Split View – BAT AELs for NOx from Biomass Plant



BAT conclusion/BAT-AEL to which the split view refers to
Solid biomass and/or peat - BAT-AELs for NOX (1/7) – BP 1.4.3.2.1–1.4.3.2.5

Split view submitted by
Richard Chase.

Proposal
The UK supports the proposal by the Bureau that the daily BAT-AEL for NOx should be in the range of 95 – 200mg/m^3 for plant >300MWth put into operation no later than 7th January 2014.
The UK proposes that the upper range of the annual BAT-AEL for plant >300MWth put into operation no later than 7th January 2014 be amended to be 180mg/m^3 from the proposed 160mg/m^3.

This is because the majority of UK plant in this class are 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 not achievable under all conditions. The UK proposes that the upper end of the range for the annual BAT-AEL for plant >300MWth be amended to 180mg/m^3, this aligns more closely with the draft proposed daily BAT-AEL of 200mg/m^3 for this class of plant.

Rationale
NO$_x$ emissions of 180 mg/Nm^3 are below the guarantee level for plant currently being designed and are below the levels experienced with existing biomass conversions. An AEL of 180 mg/m3 as an annual average will be challenging for these plant to meet, and there is limited data for plants of this size which have converted from coal to biomass on which to base AELs. . The BREF now acknowledges that SNCR may not be appropriate for retrofitting to certain boilers. However the value of 160mg/m^3 cannot be achieved by primary measures alone. The case for not fitting SCR is set out in a separate split view. Emission performance of converted coal plant will be very site specific and, therefore, the prediction of emissions values where there is a lack of data represents an unacceptable commercial risk on the basis of operating experience and performance guarantees. The table below provides NOx emissions data submitted to BATIS by the UK from a biomass conversion operating to BAT on 11/06/2014. This highlights the challenge that these plants will face to meet an AEL of 180 mg/m3.

NOx data Daily means	Concentration (mg/m3) at 6% O2
95th %ile	343.9
Maximum	470.2
Minimum	191.0
Mean	262.0

References
This split view is based on the following information in relation to the general use of SCR already made available to the EIPPCB at the time of drafting the conclusions on BAT for the BREF or has been provided within the commenting period corresponding to such a draft:

- UK TWG Comments and Proposals for the LCP BAT Conclusions 20/5/2015
- Biomass conversion data submitted by the UK 11/06/2014, 19/05/2015

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