Title: Amendments to environmental permitting regulations to improve air quality by application of emission controls to high NO_x generators in anticipation of the 2020 NO_x emission ceiling within the Gothenburg Protocol	Impact Assessment (IA)
IA No: DEFRA2039	**Date:** December 2017
Lead department or agency:	**Stage:** Final
Department for Environment, Food and Rural Affairs	**Source of intervention:** EU
Other departments or agencies:	**Type of measure:** Secondary legislation
Department for Business, Energy, & Industrial Strategy, Welsh Government	

Summary: Intervention and Options

RPC Opinion: Green (fit for purpose)

Cost of Preferred (or more likely) Option				
Total Net Present Value	**Business Net Present Value**	**Net cost to business per year** (EANCB 2014 prices)	**In scope of One-In, Three-Out?**	**Measure qualifies as**
£-49.03m	-£106.8m	£8.1m	Out of Scope	Non-qualifying provision

What is the problem under consideration? Why is government intervention necessary?

Poor air quality is the largest environmental risk to public health in the UK exacerbating the impact of pre-existing health conditions, especially for the elderly and children. Government has legal obligations on air quality including reducing emissions of pollutants; meeting limits on local concentrations of pollutants; and implementing regulations on particular pollutant sources. Domestic energy market incentives are leading to an increase in use of generators with high NO_x (oxides of nitrogen) emissions. These generators have the potential to cause breaches of the hourly NO_2 limit set for the protection of human health within the EU Ambient Air Quality Directive (EU AAQD). If the growth in their use remains unconstrained, this will result in an avoidable increase in national emissions, posing a risk to meeting the ceilings established within the Gothenburg Protocol. Therefore the Government is taking action to ensure the UK population's exposure to NO2 is within the maximum levels permitted under EU law. .

What are the policy objectives and the intended effects?

The objectives of the measures proposed are to deter a further increase in the use of high NO_x emitting generators and improve air quality. These measures will reduce emissions and concentrations of key pollutants harmful to human health and the environment helping us to meet national emissions ceilings and the EU AAQD. We will also ensure that unnecessary regulatory burdens, including reporting and other compliance arrangements, are minimised.

What policy options have been considered, including any alternatives to regulation? Please justify preferred option (further details in Evidence Base)

Option 0 - Baseline which includes the transposition of the Medium Combustion Plant Directive (MCPD) without further controls on high NO_x generators (see option 1 under MCPD transposition IA).
Option 1 (preferred) – Enable compliance with EU AAQD limits and emission ceilings and protect human health by introducing emission controls to address growth in emissions from high NO_x emitting generators.
Option 1 is preferred as it will deliver significant benefits to public health and the environment and prevent an increase in high NO_x emitting generators - avoiding potential breach of EU and international air quality limits and standards.

Will the policy be reviewed? Yes **If applicable, set review date:** 12/2019					
Does implementation go beyond minimum EU requirements?			No		
Are any of these organisations in scope? If Micros not exempted set out reason in Evidence Base.	**Micro** Yes	**< 20** Yes	**Small** Yes	**Medium** Yes	**Large** Yes
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)			**Traded:** 0.01		**Non-traded:** 0.12

I have read the Impact Assessment and I am satisfied that, given the available evidence, it represents a reasonable view of the likely costs, benefits and impact of the leading options.

Signed by the responsible Minister: Thérèse Coffey Date: 4/12/2017

Summary: Analysis & Evidence Policy Option 1

Description: Transposition of MCPD and introduction of emission controls for generators to enable compliance with AAQD and 2020 National Emissions Ceilings Directive

FULL ECONOMIC ASSESSMENT

Price Base Year 2014	PV Base Year 2018	Time Period Years 15	Net Benefit (Present Value (PV)) (£m)		
			Low: -66.5	**High:** 62.3	**Best Estimate:** -49.03

COSTS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant	Total Cost (Present Value)
Low	0.0	N/A	8.9	**110.9**
High	0.0		5.5	**91.3**
Best Estimate	0.0		10.4	**107.0**

Description and scale of key monetised costs by 'main affected groups'

The monetised costs for Option 1 are the costs of implementing controls on generators with high NO_x emissions in order to enable compliance with the 2020 NO_x ceiling and AAQD. Therefore, the total present value costs over the assessment period (2018-2032) include the cost of fitting abatement to comply with proposed emission limits (£50.6m), monitoring and compliance costs (£10.7m), and administration costs (£0.3m). In the energy balancing markets, the measures are expected to incentivise a switch from diesel to gas generators, with higher build costs of £45.4m.

Other key non-monetised costs by 'main affected groups'

Some impacts have not been monetised either because the evidence is not available or collecting the evidence would be disproportionately costly. For example, the higher build cost of gas may cause an increase in capacity market costs, however this could be offset by lower wholesale prices during peaks (above), making net impact on bills small; therefore it is deemed disproportionate to monetise. Some plants may also see a reduction in revenue as a result of a restriction on operating hours, however due to the lack of information around individual plant earnings; this has not been possible to monetise.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant	Total Benefit (Present Value)
Low	0.0	N/A	4.3	**44.6**
High	0.0		14.7	**153.9**
Best Estimate	0.0		5.5	**58.0**

Description and scale of key monetised benefits by 'main affected groups'

The monetised benefits include the benefits to human health arising from reductions in air quality and greenhouse gas emissions achieved by the controls placed on generators with high NO_x emissions. These benefits are valued based on the reduced emissions from fitting additional abatement technology and the switch from diesel to gas generators. The total PV benefit is £58.0m.

Other key non-monetised benefits by 'main affected groups'

The monetised benefits are likely to substantially underestimate the full social benefit. Reducing emissions of air pollutants from high NO_x generators will benefit natural ecosystems, biodiversity and the wider environment which cannot be monetised. It is not possible to monetise all health and welfare impacts either. The health impacts included here set out the impact on mortality; however we know that there is also a significant societal cost arising from morbidity, which is largely missed from the damage costs used in the analysis. Other secondary impacts that have not been monetised include higher sales of abatement equipment/green technologies and increased revenue for monitoring companies and test houses, as well as increased development of low emission technologies.

Key assumptions/sensitivities/risks **Discount rate** 3.5%

Low and high benefits represent the uncertainty in health benefits from improved air quality. An additional key uncertainty for Option 1 is regarding how the controls affect future investment in generators. The low and high scenarios demonstrate two extremes. The high cost assumes no change in the number of projected diesel plants, and the low cost assumes all projected diesel capacity entering the energy market switch to gas. The low NPV combines low benefits (low damage costs) with high costs (100% switch to gas) for plants in energy markets, and the high NPV vice versa.

BUSINESS ASSESSMENT (Option 1)

Costs: 8.1	**Benefits: 0**	**Net: -8.1.**	

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1. Executive Summary

Poor air quality is the largest environmental risk to public health in the UK, exacerbating the impact of pre-existing health conditions, especially for the elderly and children. Long term exposure reduces life-expectancy, mainly due to increased risk of mortality from cardiovascular and respiratory causes and from lung cancer. COMEAP's research notes that short-term exposure to NO_2 has been linked to some direct effects on morbidity while long term effects suggest impacts on respiratory and cardiovascular mortality, children's respiratory symptoms and lung function.[1] Air pollution also damages biodiversity and reduces crop yields.

Air pollution also damages biodiversity and reduces crop yields.

The Government has a legal commitment to improving the air we breathe and reducing the emissions and concentrations of harmful pollutants. The Government's plan to improve air quality by reducing nitrogen dioxide levels in the UK published in July 2017 includes measures to achieve this objective.

Incentives in the energy market have been encouraging greater use, and an increase in the number of, generators with high emissions of NO_x. These generators are primarily diesel fuelled and emit very high NO_x emissions relative to other forms of generators. High NO_x emitting generators can lead to local NO_2 concentrations capable of causing harm to human health and have the potential to cause breaches in hourly NO_2 air quality limits set in the Ambient Air Quality Directive (AAQD). The aggregate impact of emissions from all generators also affects national UK emissions totals and compliance with emission ceilings set through the Gothenburg Protocol and National Emission Ceilings Directive.

Generators with a thermal rated input between 1 and 50MW come under scope of the Medium Combustion Plant Directive (MCPD). However, the MCPD's provisions will not curb the anticipated increase in high NO_x generators and the consequent expected breaches of the AAQD limits and NO_x emission ceilings for 2020 and 2030, which are set for the protection of human health. For example, most diesel generators operate for less than 500 hours and therefore would be exempt from MCPD NO_x emission controls. Quick action is needed to curb an anticipated but avoidable rise in national NO_x emissions from high NO_x generators. The government intends to tackle this issue through additional measures targeted at electricity generating plants. Taking action early will reduce burdens on businesses by proactively preventing the proliferation of high NO_x generators which would subsequently have to be retrofitted at a high cost to business. It also gives existing operators more time to prepare as waiting until the NO_x ceiling has been transposed in 2018 gives very limited time to consider measures in time to meet the 2020 requirements. Controls on high NO_x generators will take effect from 2019 – once the 2020 ceilings have been transposed.

This impact assessment considers options for applying emission controls to electricity generating plants emitting high levels of NO_x in England and Wales. It has been updated since the consultation to reflect changes announced by Ofgem to the payments and exemptions provided to embedded generators; and to reflect the latest advice from COMEAP on the damage costs associated with air pollutants. The baseline option (Option 0) assumes that no emission controls above the transposition of the MCPD are introduced whereas Option 1 (preferred) introduces emission controls for high NO_x emitting generators, required to enable compliance with air quality limits and to curb avoidable increases in national NO_x emissions due to current energy market incentives.

We intend to regulate emissions from high NO_x generators by amending the Environmental Permitting (England and Wales) Regulations (EPR) 2016[2]. The EPR currently regulates some combustion plants and will be amended to transpose the MCPD, therefore it offers an approach to implementation which is well understood and will provide clarity for operators and promote compliance while keeping enforcement costs low.

Under the baseline, we assume that 1-50MW combustion plant (MCPs) will be subject to MCPD emission controls. These controls require permitting but have a long implementation phase and do not apply NO_x Emission Limit Values (ELVs) to plants which operate up to on average 500 hours per annum. However, because modelling indicates that MCPD emission controls will not be sufficient for addressing the risk to local air quality posed by high NO_x generators, further emission controls have been applied under our preferred Option, Option 1.

Under Option 1 we will require 1-50MW generators to comply with a specific ELV which is more stringent than some ELVs allowed under MCPD, and at an earlier date to deter market entry of high NO_x generators and encourage cleaner alternatives. The controls exempt plants used only to provide power during site emergencies. They also provide certain plant (classed as 'Tranche A') additional time to meet stringent emissions limits. However, any plants with high emissions will be required to meet controls aimed at protecting local air quality unless they run for less than 50 hours per annum. Generators operational after December 2016 (Tranche B generators) would be expected to meet tight emissions standards aimed at protecting local and national air quality

[1] COMEAP (2010) The Mortality Effects of Long-Term Exposure to Particulate Air Pollution in the United Kingdom. Committee on the Medical Effects of Air Pollutants. Available from: https://www.gov.uk/government/publications/comeap-mortality-effects-of-long-term-exposure-to-particulate-air-pollution-in-the-uk

[2] http://www.legislation.gov.uk/ukdsi/2016/9780111150184/contents

unless they are exempt e.g. because they operate for less than 50 hours per year or because they are solely used to provide back-up power during site emergencies. These controls should help to enable compliance with national emissions ceilings and the Ambient Air Quality Directive while minimising the impact on energy security.

Under Option 1 we will also apply emission controls to generators less than 1 megawatt thermal rated input(MW_{th}), which are not covered by the MCPD under Option 0, if they are providing balancing services to the National Grid. Provision of National Grid services is usually restricted to market operators who can deliver capacity greater than a particular threshold e.g. roughly 10 MW_{th} (3MW electrical output, $3MW_e$) (). However there is no requirement for these operators to provide a service with generators located at a single site. Third party companies known as "aggregators" work with companies that own diesel generators less than $3MW_e$ electrical out to produce aggregated bids to National Grid services. We have evidence from the National Grid that even generators at sites with an aggregated input smaller than $1MW_{th}$ (roughly $0.3MW_{th}$) are currently being used for this purpose. The current aggregated capacity of these is quite small (<$300MW_{th}$), however there is a large reservoir of small back-up diesel generators in the UK and failing to limit NO_x emissions from generators under $1MW_{th}$ could incentivise aggregators to shift towards using these, potentially undermining some of the benefits of the proposed regulation. Following a consultation we will be extending the controls to plants less than $1MW_{th}$. However, it was considered disproportionate to regulate emissions from all generators under $1MW_{th}$ and so we will regulate only those providing a service to the National Grid or participating in energy markets. The controls also provide Tranche A generators additional time to meet stringent emissions limits.

Changes since the consultation analysis

This impact assessment has been updated in light of consultation responses. The analysis has also been amended to reflect (I) updates to the damage costs associated with air pollutants, provided by the Committee on Medical Effects of Air Pollutants (COMEAP), (II) reductions in payments (of embedded benefits) that Ofgem provide to diesel generators for supporting the National Grid during peak times and (III) measures to simplify capacity market auctions by the Department for Business, Energy and Industrial Strategy. By far the largest impact is from the updated damage costs which result in lower health benefits from reductions in air pollutants than was previously assumed[3]. The Ofgem change means that fewer diesel generators are included in our baseline compared to the pre-consultation impact assessment. The combined changes to the evidence base have the effect of reducing the quantifiable value for money of taking action to reduce emissions from high NOx generators. The overall net present value (NPV) of the measures in the central scenario is -£49.03m, within a range of £62.3m to -£66.5m. However, these estimates are only able to reflect a proportion of the actual impact, excluding a range of impacts on public health, welfare, economic performance and the environment. Furthermore, the need to take action to deliver compliance in the shortest possible time does not diminish. The generators for which this regulation applies have the potential to cause breaches of the hourly NO_2 limit set for the protection of human health within the EU AAQD. If the growth in their use remains unconstrained, this will result in an avoidable increase in national emissions, posing a risk to meeting the ceilings established within the Gothenburg Protocol. Therefore the Government is taking action to ensure the UK population's exposure to NO2 is within the maximum levels permitted under EU law.

Results for the preferred option (Option 1)

The forecasted reductions in emissions from a national level as a result of these controls are presented for the preferred option in Table 1.1, below.

Table 1.1 Emission reductions delivered in 2030 by the controls on high NO_x generators, in kilo tonnes (Kt) and as a percentage of total UK emissions.

Kt (%)	SO_2	NO_x	PM	CO_2
Option 1	0.3 (0.2%)	2.1 (0.5%)	0.02 (0.04%)	12

The central NPV estimate of Option 1 is -£49.03m which includes the benefits from implementing controls on generators emitting high levels of NO_x. The full costs and benefits are presented in Table 1.2 below.

Table 1.2 Costs and benefits of Option 1 (£m, discounted)

2018-2032	LOW SCENARIO (£m)	HIGH SCENARIO (£m)	CENTRAL (£m)
Costs (cost to operators)			
Abatement costs	43.2	80.3	50.6
Administration costs	0.2	0.3	0.3

3 The damage cost functions have been revised down by 63% for NOx relative to those used in the consultation IA to reflect the latest advice from the COMEAP.

Monitoring costs	10.7	10.7	10.7
Operational/capital cost of technology switch	56.7	0	45.4
Total	110.9	91.3	107
Benefits (emissions reductions)			
Air Quality	41	143.2	50.9
CO2 (Traded)	0.1	0.4	0.2
CO2 (Non-Traded)	3.3	10	6.9
Total	44.4	153.6	57.7
NPV	-66.5	62.3	-49.03

*Please note any differences due to rounding.

Table 1.2 presents the costs and benefits that have been monetised. However, while as far as practicable all the impacts have been quantified and monetised, some impacts have not been quantified. The key impacts which were not quantified are the wider environmental societal benefits through improvements to ecosystems due to the reduction in emissions, and a number of human health benefits. Additionally, under Option 1, the revenue loss experienced by the reduced running hours from high NO_x generators in Tranche A, and the benefits to other plants who meet the proposed limits of greater access to revenue streams is not included. As there are costs and benefits to different plants, this is likely to be an economic transfer (revenue loss for one plant in the market is a revenue gain to another plant in the market) and likely to have minimal impact.

2. Introduction

Poor air quality is the largest environmental risk to public health in the UK, exacerbating the impact of pre-existing health conditions, especially for the elderly and children. Some of the health effects caused by exposure to elevated levels of pollution are outlined in Table 2.1 below.

Table 2.1 Health effects for very high levels of pollutant emissions

Pollutant	Health effects at very high levels
Nitrogen Dioxide (NO_2),	Collated research by COMEAP into the health impacts of NO_2 has shown that it is reasonable to associate NO_2 in outdoor air with adverse effects on health, including reduced life expectancy. As part of the COMEAP research, it was established that there were likely to be short term and long term effects as short-term exposure to NO_2 has been linked to some direct effects on respiratory morbidity, while studies of long-term exposure to NO_2 report associations with respiratory and cardiovascular mortality, children's respiratory symptoms and lung function.
Sulphur Dioxide (SO_2) and Ozone (O_3)	Sulphur Dioxide and Ozone are respiratory irritants that can cause constriction of the airways, inflammation of the respiratory tract and irritation of the eyes, nose and throat, potentially exacerbating asthma in susceptible people.
Particulates (PM, which includes PM_{10} and $PM_{2.5}$)	Fine particulate matter can penetrate deep into the lungs and other tissues, including the brain. Research in recent years has strengthened the evidence that both short-term and long-term exposure to $PM_{2.5}$ are linked with a range of negative health outcomes including shortening the lives of susceptible individuals through cardiovascular disease, stroke, cancers, respiratory and other diseases.

Air pollution is measured and regulated in two different ways: by concentrations and total emissions. The AAQD, which is transposed in England by the Air Quality Standards Regulations, sets limits for both short term and annual pollution concentrations. Total emissions were first regulated by the 1999 Gothenburg Protocol, under which States agreed to cap their annual emissions of certain pollutants by 2010 as a reduction from 1990 levels. The Protocol amendment of May 2012 set more stringent targets for reducing emissions and added new limits for other airborne pollutants, as a percentage of 2005 levels by 2020.

The EU National Emissions Ceilings (NEC) Directive is the European legislation that implements the limits agreed under The Gothenburg Protocol. The Directive initially set annual limits for each pollutant, including NO_x, which Member States had to achieve by 2010. The NEC Directive was amended in 2016 by setting 2020 ceilings (in accordance with the revision to the Gothenburg Protocol) and additional 2030 emissions ceilings - the continuing aim being to reduce the significant impacts air pollution can have by reducing domestic and transboundary emissions. The NEC Directive must be transposed by mid-2018.

The MCPD is supported by the UK as it will introduce cost effective reductions in pollutant emissions. It will provide an estimated 43% of the action needed to reduce SO_2, 9% to reduce PM and 22% to reduce NO_x emissions, to meet the 2030 national emission ceilings. Following the conclusion of the MCPD negotiations a large number of diesel engines made successful bids into the Capacity Market in 2015. This raised concerns because diesel generators have high NO_x emissions relative to other forms of energy generation applying for the Capacity Market and the projects proposed would not be subject to regulatory emissions controls, even with implementation of the MCPD.

In recent years there has been a significant drop in the amount of reliable, dispatchable generation capacity in the Great British (GB) power system, as coal and nuclear power stations have been decommissioned and replaced by intermittent forms of generation such as wind and solar. The Capacity Market is the key policy tool to ensure we maintain a secure supply of electricity and bring forward sufficient reliable electricity capacity. The Capacity Market operates as an adjunct to the electricity market and other revenues that can be earned from electricity balancing services and network charging arrangements. It is technology neutral, allowing any type of capacity to participate, provided it otherwise complies with relevant legislation. 'T-4' Capacity Market auctions seek to procure capacity four years in advance of the required delivery window, and award 'capacity agreements' to those successful. These agreements have one year duration for existing capacity, and up to 15 years for new generating capacity. A capacity agreement is not a contract, but it places a number of statutory delivery obligations on the holder in return for an ongoing payment stream over the period of the agreement.

The first two T-4 auctions were held in December 2014 (which awarded agreements for the delivery period starting in October 2018) and in December 2015 (for the delivery period starting in October 2019). Since publication of the consultation on our proposed controls, a third T-4 auction was held in December 2016, followed by the first of the annual 'T-1' auctions in January 2017, which was held one year ahead of delivery, offering 1-year agreements (only) to top-up/fine tune the capacity requirement as needed for the coming delivery year.

Diesel generators can ramp up to full power quickly, have low build costs, partially due to not being required to have a connection to the gas grid. These characteristics mean that diesel generators provide an important energy security function to sites such as hospitals, schools and data centres in the event of emergencies such as power cuts. They are also able to provide frequency response services and additional standby capacity for the National Grid through contracting into services such as Short Term Operating Reserve (STOR)[4], alongside being able to participate in the balancing mechanism and wholesale market. The use of generators for these "energy balancing" services can be profitable for investors and is a source of flexibility for the System Operator. Additionally, exporting diesel generators with connection capacity below 100MW are eligible to receive payments in the form of 'negative' transmission charges (also referred as Triad avoidance[5]). However, Ofgem's recent decision on 'embedded benefits' is likely to significantly reduce those payments over the next three years.

Capacity Market agreements are awarded to bidders on the basis of price, so diesel generators that can readily access other income streams can be very competitive and are often able to out-compete other less polluting plants – resulting in additional emissions which could be avoided. Modern small gas generators are able to ramp up quickly and could therefore be an effective, lower NOx emission, alternative to diesel generators in many circumstances.

When the December 2015 T-4 auction results were available, Defra commissioned initial modelling to understand the impact of more high NO_x emitting generators on air quality. The modelling indicated that the 2020 national NO_x emission ceiling agreed under the Gothenburg Protocol could be missed due to the additional emissions from these generators. In addition, it indicated that these generators may pose a risk to local air quality by exceeding concentration limits for hourly levels of NO_2 set by the AAQD. This limit is the same as that advocated by the World Health Organisation in their guidelines for the protection of public health. In response to these findings Defra decided to carry out further analysis with a view to developing regulation to tackle this issue.

In the December 2016 T-4 auction, held after publication of our consultation, there was a marked reduction in bids from diesel generators, likely in response to the proposed emission controls as well as an expected review of embedded benefits by Ofgem. In the absence of policy intervention, the numbers and use of diesel generators would be expected to increase rapidly over the next few years. This is likely to lead to an avoidable increase in national NO_x emissions, which the UK has international (and European) obligations to reduce. The MCPD will not provide the controls required to adequately address this problem, so quick action is needed to address it. The Gothenburg Protocol set a national cap on annual emissions and it is up to countries to decide how these ceilings will be met. The 2020 ceilings agreed in 2012 will come into force when the revised National Emissions Ceiling Directive is transposed (due by mid-2018). The latest emission projections (which have been substantially revised since our consultation) suggest that in 2020 the UK will exceed the NO_x ceiling by 35kt.However, these projections do not take account of the growth in emissions from diesel generators. The additional capacity from the 2014 and 2015 auctions is estimated to result in 0.9kt of additional NO_x emissions in 2019. Therefore the continued growth of high-emitting generators expected without further action will further affect our capacity to comply with the ceiling. Delaying action in this area risks imposing unnecessary burdens on operators who would have little time to deliver reductions before 2020.

The set of incentives behind the growth in high NO_x generators could not have been foreseen when AAQD was first transposed, or when the 2020 emission ceiling was agreed. So it is now necessary to take this additional action on high NO_x generators in order to enable compliance.

In March 2016 BEIS' consultation on further reforms to the Capacity Market highlighted the role of diesel generators in contributing to harmful levels of air pollutants. The document announced Defra's intention to consult in 2016 on options, including legislation, which would set binding emission limit values on relevant air pollutants from diesel engines, with a view to having legislation in force no later than January 2019 and possibly sooner. We do not intend for these additional measures to be implemented until after the ratification of the Gothenburg protocol and transposition of the National Emissions Ceilings Directive.

<u>Existing legislation and controls</u> (see Figure 2.1 for overview)

[4] http://www2.nationalgrid.com/uk/services/balancing-services/reserve-services/short-term-operating-reserve/

[5] TRIAD is the methodology used to recover the costs of building and maintaining the electricity transmission network

Combustion activities are a large source of air pollution and so are already subject to some emission controls. Figure 2.1 demonstrates how the proposals considered in this impact assessment fit within current EU and domestic emission controls.

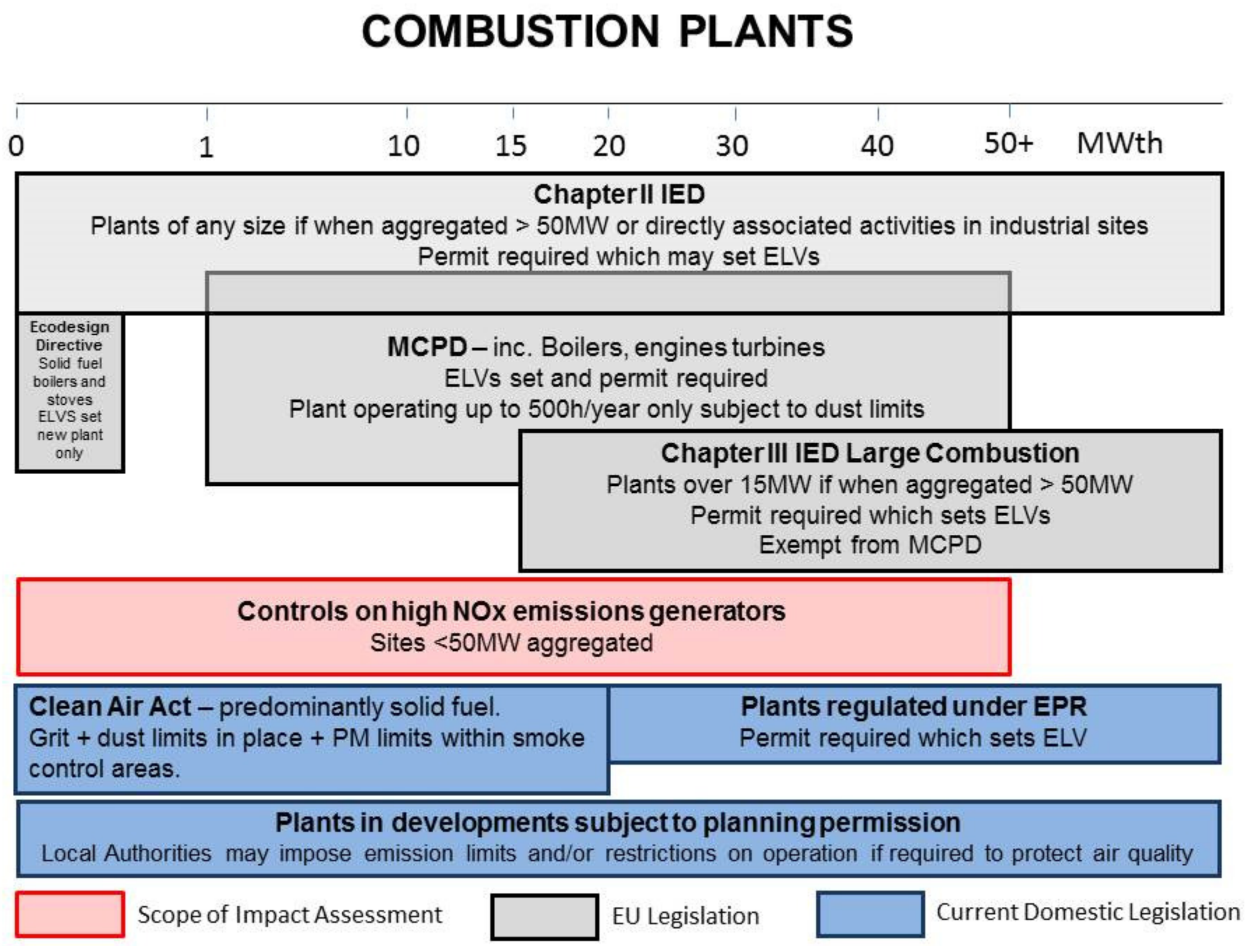
Emissions from some combustion plants, including all those over 20MW, are currently regulated under the Environmental Permitting (England and Wales) Regulations 2010 (as amended) (EPRs). These regulations transpose the Industrial Emissions Directive for plants on industrial sites with aggregated power over 50MW, and implement domestic provisions for plant between 20 and 50MW. The EPR requires all plants in scope to have a permit, which sets controls on emissions to air and requires operators to regularly test emissions and be subject to regular inspections.

The Clean Air Act 1993 controls the emission of dark smoke and places restrictions on the type of fuel and appliance which can be used in smoke control areas. The Act also specifies minimum stack heights for some plant.

In addition, installation of combustion plants may be subject to planning permission, where their impact to local air quality is assessed. If the assessment indicates that air pollutant concentrations at a sensitive receptor (e.g. a location where people are likely to be present or a sensitive habitat) are likely to exceed those set in the AAQD, local authorities may require these plants to mitigate their impact on local air quality.

Generators providing services through the Short Term Operating Reserve[6] are likely to be subject to a local air quality assessment through the planning process. However, many combustion plants, including diesel generators installed mainly for the purposes of providing back-up and located within existing buildings, are unlikely to be subject to planning requirements.

Figure 2.1 Regulatory landscape for Combustion Activities



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[6] See glossary for definition

Government is introducing controls on generators with high NO_x emissions in order to curb the anticipated increase in national NO_x emissions resulting from domestic energy market incentives and to protect local air quality. The controls will improve our capacity to comply with NO_x emissions ceilings (which will be more stringent in 2020) as well as the hourly concentration limits set in the AAQD, and as such is not gold plating of the MCPD. The controls (outlined in detail in Section 6.2) seek to improve local air quality in order to improve human health and reduce national emissions at a pace which does not undermine energy security. Addressing growth in emissions from high-NO_x generators is necessary to ensure the 2020 emission ceiling in particular is met and controls are also a cost-effective source of emission reductions looking ahead to the 2030 emission ceilings.

It is clear that action will be required to address emissions from high NO_x emitting generators to improve our capacity to comply with our international (and European) obligations. Under Option 1 we propose to bring into force emission controls early, although they will only apply when emission ceilings for 2020 and 2030 are already transposed into domestic legislation. This approach has the advantage of giving operators greater warning of future policy enabling them to make informed investment decisions, which could reduce their overall costs of compliance.

Proposed legislative approach

Option 0 is the baseline: In this scenario there is no implementation of additional controls on high NO_x emitting generators other than transposition of the MCPD.

Option 1 (preferred) introduces further emission controls for high NO_x emitting generators, which are required to enable compliance with the set air quality limits.

Under the preferred option, operators of plants which fall within the scope of the generator controls will be required to hold a permit and comply with the applicable permit conditions, which may include NOx emission limit values, restrictions on operating hours or regular emissions monitoring. For plants over 1MW, operators will also be required to meet emission controls to comply with the MCPD, but possibly from a later date. Amendments made to the EPRs will seek to:

1) Comply with hourly concentration limits set in the Ambient Air Quality Directive
2) Stem the projected increase in numbers of heavily polluting plants in favour of cleaner technology, thereby helping the UK to comply with its obligations under the Gothenburg protocol and National Emissions Ceilings Directive
3) Comply with requirements of the MCPD.

To make the combined impact of the MCPD and generator controls clear to industry we consulted on the proposals jointly and will introduce them through a single legal instrument.

Devolved Administrations

This Impact Assessment covers joint amendment of the EPRs by England and Wales to introduce controls on generators with high NO_x emissions. Northern Ireland have proposed in their public consultation to introduce controls for generators. Since very few of the Capacity Market diesel generators from the 2015 auctions were located in Scotland, the Scottish Government is still reviewing the case for adopting controls for generators with high NO_x emissions.

2.1 Definitions

Described below are the definitions of key terms used through this document. A full glossary of terms can be found in Annex E.

Plant type: For this impact assessment, plants are categorised according to their hours of operation and based on their role for energy security and overall contribution to total emissions, as follows.

- ***Working plant*** = those operating on average more than 500 hours per year which are subject to compliance with MCPD Annex II emission limit values.
- ***Stand-by plant*** = plant installed alongside working plant to provide for additional demand at peak times or in case of shut down of the main working plant, and operating fewer than 500 hours per year.
- ***Back-up plant*** = plant installed to provide emergency electricity generation in times of interruption to supply of mains grid electricity, operating rarely and normally much less than 500 hours per year (assumed to be less than 50 hours).

- ***Generator*** = any single stationary electricity generating combustion plant or any group of stationary electricity generating combustion plant located at the same site and providing electricity for the same purpose.

Abatement technology refers to techniques and technologies used to reduce pollutant emissions. Primary abatement prevents formation of pollutants and includes a switch to fuels which result in lower emissions, retrofitting of existing plant (e.g. by changing the burners) and selection of new plant with lower emission. Secondary abatement removes pollutants from the exhaust gases, such as filters for dust or selective catalytic reduction to destroy NO_x.

Megawatts (MW) – in this Impact Assessment unless otherwise stated this refers to Mega Watts of thermal input.

Emissions in mg/Nm^3: milligrams per normalised cubic metre. Normalised emissions are converted to reference conditions, which are the same as those used to set Emission Limit Values under the MCPD.

The definitions for **MW, working, standby and backup plant**s remain the same as in the MCPD. In addition, plants are further categorised as:

A tranche A generator is any generator that:
- If between 1 and 50MW:
  - comes into operation before 1 December 2016; or
  - is the subject of a Capacity Market Agreement for new capacity arising from the 2014 or 2015 auction (including those which have not come into operation by 1 December 2016); or
  - for which a Feed-in Tariff preliminary accreditation application has been received by Ofgem before 1 December 2016.
- If below 1MW:
  - is the subject of a Capacity Market Agreement for new capacity arising from the 2014, 2015 or 2016 auction (whether or not the generator has come into operation by 1 December 2016); or
  - for which a Feed-in Tariff preliminary accreditation application has been received by Ofgem before 1 December 2017.
  - which is the subject of an agreement to provide balancing services entered into before 31st October 2017

Generators meeting the conditions above will cease to be Tranche A generators if they enter new legally-binding power supply agreements.

Tranche B: Any generators other than Tranche A generators.

Demand Side Response (DSR) = provision of services by reducing electricity demand from the grid upon request. The reduction in demand can be achieved by reducing electricity use on a site or using alternative sources, including diesel generators.

2.2 Plant numbers

Controls for generators with high NO_x emissions will be applied to an estimated 5,520 generators by 2030 (nearly all – over 95% – would be classed as standby i.e. operating for less than 500 hours), although if further plants are projected in the capacity market, then this figure will increase year on year. Calculation of plant numbers is presented in the methodology section, where there is an explanation of how total plant numbers filter through compliance requirements and eligibility for specific exemptions in section 6.2 (Table 6.4).

3. Problem under consideration

Diesel generators (also referred to as compression ignition engines) produce high levels of NO_x emissions but have not previously been regulated because they have typically been used for emergency back-up power and therefore only run for very limited periods. Incentives in the energy market have been encouraging greater use and investment in generators with high NO_x emissions and this trend is projected to rise rapidly over the next few years. Modelling carried out by the Environment Agency indicates that generators of the type and operating pattern used for energy balancing are capable of breaching legally binding hourly local air quality limits set for the protection of human health.

On a MW basis diesel engines are cheap to buy relative to other generation assets, do not rely on a connection to the gas grid and are able to ramp up to maximum power quickly. This profile makes them able to provide a wider range of balancing services and access greater profit than other forms of electricity generation. Furthermore, although their fuel is more expensive, their lower installation cost means diesel generators are outcompeting less polluting alternatives in the Capacity Market (for example the average base case emissions of NO_x from diesel engines is 1200mg/Nm^3 compared to a base case of 190mg/Nm^3 for gas engines) and this is leading to a rapid increase in their numbers and hours of use which poses concerns for air quality. Although the capacity market is based on 'availability payments' which in themselves do not directly incentivise greater use, operators are encouraged to provide other services to provide a more competitive price.

The Government announced it intended to consult on emission controls for high NO_x generators in March 2016 and published its consultation in November 2016 in order to discourage investment in generators ahead of the December 2016 Capacity Market auction. The controls proposed in the consultation were supported as they would deliver cost-effective emission reductions and protect air quality while safeguarding energy security. There was also support for applying controls to sites under 1MW if providing balancing services to the power grid, to ensure a level playing field and to prevent an increase in use of such sites, which would lead to a preventable increase in national emissions of NO_x.

After consideration of the consultation responses (see Annex D), the proposed controls were amended as follows:

1) For plants which require secondary abatement to comply with the 190mg/Nm^3 NO_x ELV, the time for meeting the ELV was increased to 20 minutes for Tranche A generators and to 10 minutes for Tranche B generators. This was based on feedback that the 5 minutes originally proposed would not be achievable in many circumstances, and informed by an analysis of the impact on total emissions which benefited from data submissions on running time of the generators affected.
2) For Tranche A generators which require a permit from 1 January 2019, the deadline for compliance with permit conditions was moved to 1 October 2019. This will provide operators more time to make decisions on how to meet permit conditions and plan any investment needed, but still apply controls from the beginning of the supply agreements awarded in the 2015 Capacity Market auction.
3) Tranche A generators will be subject to the standard permit conditions only when their power supply agreements come to an end (so long as they do not enter new power supply agreements – see point 4). This will allow operators to meet their contractual obligations while protecting local air quality, as sites of concern will be subject to bespoke permits from 2019.
4) Operators of any Tranche A generators that wish to enter new power supply agreements after 31st October 2017 will be subject to the standard permit conditions if the new power supply agreement is still in force after 31st December 2018. This amendment will help to ensure a level playing field with investors in cleaner technologies.
5) To address concerns from stakeholders, emission controls were extended to generators under 1MW which provide balancing services to the grid, to ensure a level playing field. The timescale for application of such controls was adjusted to ensure investors and operators who entered power supply agreements before the controls are announced will benefit from transitional arrangements.

4. Rationale for Intervention

The rationale for intervention is to deliver health and environment benefits through cost-effective improvements to air quality, while ensuring operators have sufficient time to comply with controls on combustion plants.

The energy market is driving an increase in the use and number of generators with high NO_x emissions, such as diesel engines, because energy services are procured on the basis of cost. Generators emit air pollutants that can have a seriously harmful impact on human health and the environment. However, when deciding how much to use their plant, operators may not be aware of, and are not impacted by, the cost they impose to society of the air pollution from their operations. This is known as a negative externality. If generators were impacted by the true cost of their operations (i.e. taking account of the cost of the pollution), they might operate differently.

The resulting impact is a market failure, where revenue incentives encourage the use of diesel generators by not taking into account the social cost of their operation e.g. damage to public health caused by pollution. Emissions from generators of the type used for energy markets are not regulated at present and the MCPD will not provide sufficient control on emissions from these plants, many of which will be exempt from the ELV requirements due to their short running times. Additional measures are therefore needed for electricity generating plants with high NO_x emissions to correct this market failure.

5. Policy Objectives

The policy objective is to improve air quality across the UK, which will improve human health and assist in meeting the requirements of the AAQD, which is transposed in England by the Air Quality Standards Regulations, and revised National Emissions Ceilings which will be transposed by June 2018. This will be achieved through the introduction of new controls for high NO_x generators which aim to improve local air quality and prevent an increase in national emissions of NO_x by reducing emissions from this source and curbing the increase in the use and number of plants with high NO_x. The controls are designed to avoid a detrimental impact on energy security and seek to increase the incentive for cleaner technologies to replace more polluting generators in the energy balancing market.

6. Analysis of Options

This section describes Option 0 (baseline), which includes implementation of the MCPD in England and Wales) and Option 1, which includes the baseline plus implementation of emission controls for generators. Option 1 describes in detail the emission controls for generators, which were informed by public consultation and the analysis presented in this document. A summary of the consultation responses and actions taken is presented in Annex D.

6.1 Option 0: Implementation of the MCP Directive in England and Wales (baseline)

Under this option (the baseline scenario), the MCPD is implemented in England and Wales. 1-50MW plants are subject to permitting and emissions monitoring to comply with MCPD timescales (see Table 6.1) Generators operating on average up to 500h per annum are not subject to emission limit values (see Table 6.2 and Table 6.3 for details). It is relative to this baseline that the impacts of implementing emission controls on high NO_x emitting generators are assessed. The detailed methodology for estimating the number of plants and their emissions in the baseline scenario can be found in Section 7.1.

Table 6.1 MCPD operator requirements and timescale of application

Average Annual Operating Hours	Plant age[7]	Plant Size (MW)	Permit needed for operation	Applicable ELVs and deadline for compliance **(see Annex II of the Directive and table 6.4 for exceptions)**		Monitoring requirement **(for CO and pollutant for which ELVs apply within 4 months of permitting and then)**
Up to 500hours	New	1-5	From 20/12/2018	Only plants using solid fuels must comply with ELVs, and for dust only.	From 20/12/2018	Every 1,500h of operation, or at least every 5 years.
		5-20				
		20-50				Every 500h of operation, or at least every 5 years.
	Existing	1-5	From 1/01/2029		From 1/01/2030	Every 1,500h of operation, or at least every 5 years.
		5-20	From 1/01/2024		From 1/01/2025	
		20-50				Every 500h of operation, or at least every 5 years.
More than 500hours	New	1-5	From 20/12/2018	As set out on Annex II of the Directive	From 20/12/2018	Every 3 years
		5-20				
		20-50				Annually
	Existing	1-5	From 1/01/2029		From 1/01/2030	Every 3 years
		5-20	From 1/01/2024		From 1/01/2025	
		20-50				Annually

[7] An existing combustion plant is defined under the MCPD as one that is "put into operation before 20 December 2018 or for which a permit was granted before 19 December 2017 pursuant to national legislation provided that the plant is put into operation no later than 19 December 2018." A new combustion plant is defined as any plant other than an existing combustion plant i.e. any plant put into operation after 19 December 2018. To note that these definitions of new and existing plants are used in this table only.

Table 6.2 Baseline assumptions for implementation of the MCPD of relevance to generator controls

Flexibility	Proposed approach	Incorporated in analysis?
Exemption from MCPD Annex II ELVs for existing plant operating up to 500 hours per year as a five year rolling average	Applied in full – if an operator exceeds 500h of operation in any year, this must be notified to the regulator.	Yes
Exemption from MCPD Annex II ELVs for new plants operating up to 500 hours per year as a 3 year rolling average	Applied in full – if an operator exceeds 500h of operation in any year, this must be notified to the regulator.	Yes
Increase in NO_x ELV for new engines operating between 500-1500 hours provided they are applying primary abatement measures	Applied in full.	Yes

Table 6.3 Frequency[8] of compliance checks for the two scenarios

Checks per annum[9]	High risk[10] 1 working plant[11]	Medium risk 1104 working plants	Low risk 8079 working plants (plus those defined as back-up/stand-by)
Plant required to comply with ELVs	20-50MW 1 site inspection 1-20MW 1 remote check	20-50MW 1 remote check 1-20MW 0.3 remote check	20-50MW 0.5 remote check 1-20MW 0.3 remote check
Plant exempt from compliance with ELVs (to note the current proposal is to deem all low risk)	20-50MW 1 remote check 1-20MW 0.5 remote check	20-50MW 0.5 remote check 1-20MW 0.3 remote check	20-50MW 0.3 remote check 1-20MW 0.2 remote check

6.2 Option 1: Implementation of the MCPD and additional emission controls for generators

Under this option, the MCPD is implemented in England and Wales as set out in the baseline but additional requirements will be placed on high NOx emitting generators as outlined in the proposals below. These proposals were subject to consultation. Further details of how the proposals outlined below were developed and the comments received in the consultation are provided in Annex A and D.

[8] Frequencies are indicative

[9] 0.5 = one check every two years; 0.3 = one check every 3 years; 0.2 = 1 check every 5 years; 0.17 = 1 check every 6 years.

[10] For the purpose of this assessment, 20-50MW plant operating on solid fuels were assumed high risk, remaining plant using solid and liquid fuels other than gas oil were assumed medium risk, and all other plant (those using gas oil and gaseous fuels) were assumed low risk.

[11] Number of operating plants in 2030

Table 6.4 Proposals to control emissions from generators

Proposals to control emissions from generators
From 1 January 2019 and subject to the requirements of the MCPD in relation to plant that are MCPs, all generators[12] will require a permit to operate, except: a) Back-up generators (generators operating solely to supply power during an on-site emergency e.g. a power cut which do not test for more than 50 hours per year)[13] b) Generators operating on a site that is the subject of a nuclear site licence[14] c) (until 2025) Tranche A generators[15] with a rated thermal input of 5-<50MW and with an emission <500mg/Nm^3 and Tranche A generators with a rated thermal input of 5-<50MW and operating <50 hours/year d) (until 2030) Tranche A generators under 5MW Unless otherwise specified below, the regulator will be required to exercise their permitting functions so as to ensure that at least the four following standard requirements are applied to the generator[16] through the permit: • a NO_x ELV of 190mg/Nm^3 [17] • where secondary abatement is required to meet the 190mg/Nm^3, it must be met within 10 minutes of the generator commencing operation for Tranche B generators, and 20 minutes for Tranche A generators • there must be no persistent dark smoke emission • where the generator relies on secondary abatement to meet the 190mg/Nm^3 NO_x ELV, emissions must be monitored every 3 years. Where the regulator considers there may be a risk to air quality standards resulting from the operation of the generator, an operator will be expected to quantify the impact of emissions on sensitive receptors, e.g. by air dispersion modelling, incorporating as necessary, for example, any proposals for appropriate dispersion, abatement and restrictions on operating hours. The regulator, accounting for the results of such assessment, will be required to apply any further or different requirements as are necessary to ensure any breach of AAQD is avoided. In relation to the generators described at c) and d) above, the regulator will not be required to apply the standard requirements or any additional requirements to safeguard local air quality where operation of the generator is required only for the purpose of a legally binding pre-existing supply contract or agreement[18], in which case the standard requirements and any additional requirements to safeguard local air quality will be applied from the date the contract/agreement expires. In relation to Tranche A generators which require a permit from 1 January 2019, permit conditions will apply only from 1 October 2019 and the regulator will not be required to apply the standard requirements where operation

[12] "Generator" means:

- any single stationary electricity generating combustion plant; or
- any group of stationary electricity generating combustion plant located at the same site and providing electricity for the same purpose, with a rated thermal input of between 1MWth and 50MWth
- any single stationary electricity generating combustion plant or any group of stationary electricity generating combustion plant located at the same site with a rated thermal input below 1MWth if providing electricity under a power supply agreement.

This definition includes any MCP, but excludes any plant subject to the provisions of Chapter II, Chapter III or Chapter III of Directive 2010/75/EU (the industrial emissions Directive).

[13] No running time restrictions will apply to these generators when providing power on site during an emergency

[14] Generators operating with a defined nuclear safety role within arrangements approved by the Office for Nuclear Regulation under a Nuclear Site Licence

[15] "Tranche A generator" means any generator that:

a) for 1-50MW generators:
- comes into operation before 1 December 2016; or
- is the subject of a Capacity Market Agreement for new capacity arising from the 2014 or 2015 auction (including those which have not come into operation by 1 December 2016); or
- for which a Feed-in Tariff preliminary accreditation application has been received by Ofgem before 1 December 2016.

b) For generators under 1MW:
- is the subject of a Capacity Market Agreement for new capacity arising from the 2014, 2015 or 2016 auction (including those which have not come into operation by 1 December 2016); or
- for which a Feed-in Tariff preliminary accreditation application has been received by Ofgem before 1 December 2017.

Generators meeting the conditions above will cease to be Tranche A generators if they enter new legally-binding power supply agreements.

[16] Except:

- any generator used at a site to which it is not reasonably practicable to supply mains power; or
- any back-up generator for which the operator has demonstrated to the regulator a genuine need to carry out routine testing for more than 50 hours per year.
- Any tranche A generator with a rated thermal input 5-<50MW with NOx emissions 500mg/Nm^3 or greater

In these cases, the regulator will exercise their functions as necessary to ensure that the conditions set in permits will ensure that generators will not give rise to a breach of standards specified in Annex XI of the Ambient Air Quality Directive.

[17] under the MCPD reference conditions for engines and turbines (see Annex C)

[18] A contract or agreement to supply capacity or electricity to National Grid made before 1 December 2016

of the generator is required only for the purpose of a legally binding pre-existing supply contract or agreement, in which case the standard requirements will be applied from the date the contract/agreement expires.

Abatement costs

Generators that are required to meet the proposed emissions limit specified (190mg/Nm^3) may incur costs for fitting secondary abatement such as Selective Catalytic Reduction. Generators that are required to hold a permit with site-specific conditions to protect local air quality may be required to fit dispersion or abatement equipment or to modify running hours to ensure that hourly air quality limits are not exceeded at sensitive receptors surrounding the generator.

Administrative burden

Generators over 5MW in size with high NO_x emissions (in excess of 500mg/Nm^3 for Tranche A and 190mg/Nm^3 for Tranche B) are considered to pose a risk of breaching local air quality limits if they operate for more than 50 hours per year and therefore operators for these facilities will be required to hold a permit with site specific conditions unless they are covered by an exemption, and regulators will recover their costs through permitting. Operators of generators that run for more than 50 hours per year may be required to carry out dispersion modelling to ensure that air quality limits are not breached at the sensitive receptors in the vicinity of the generator.

Operators with working and standby generators between 5 and 50MW that would otherwise be required to hold a bespoke permit will be required to prove that the emissions from the site do not exceed the specified limits – in estimating costs we have assumed that this will be done through an emissions test.

Monitoring costs

In addition to the monitoring requirements set out on Option 0, we propose that generators that are required to meet the standard requirements set out in the proposals will at least be required to undertake a single emissions test at the point the plant is commissioned to prove the emissions do not exceed the emissions limit. Generators that rely on secondary abatement to achieve these limits will require a test at least once every 3 years.

Compliance check costs

We have assumed a worst case scenario that scheduled compliance checks should be carried out on generators required to hold a permit as per Table 6.4.

The burden for regulators and operators from non-compliance with the Directive is not estimated; non-compliance may result in operators moving to a higher risk category, which will lead to more frequent compliance checks, and a resulting increase in annual subsistence fees. The legislation will contain powers for criminal prosecution, but it is anticipated that these will act as a deterrent and be used only in very rare instances where operators persistently fail to achieve compliance with the Directive, particularly when this results in an impact to local air quality.

Emissions Testing and Monitoring Costs

The cost of emissions testing is based on meeting current Monitoring Certificate Scheme (MCERTS) standards, which are currently applied to plant over 50MW in the UK. We have assumed;

- that all generators will need to be tested at the point of commissioning and
- that it takes a single day to test all generators in a single site and
- that the same cost will apply to each generator regardless of size or complexity and
- that monitoring will be carried out every 3 years for generators with secondary abatement.

The cost of emission testing may be overestimated, as the regulator will explore with industry the scope for adopting less costly monitoring methods which are sufficient to demonstrate compliance.

7. Methodology

This methodology assesses the impact of implementing specific measures for high NO_x generators, to help avoid breaches of hourly limits for NO_2 set under the AAQD as well as an avoidable increase in NO_x emissions.

The overwhelming majority of the plants that would be impacted under the generators controls were classified as standby (categorised as running for less than 500 hours) under the MCPD, so the additional costs and benefits calculated use the characteristics of a standby plant. The proposed controls also apply to some plants with thermal capacity below 1MW if they provide balancing services to the grid, which would not be subject to any requirement under the MCPD.

The Impact Assessment has a 15 year assessment period which begins in 2018, when the first costs arising from implementation of the MCPD (baseline) will be incurred, and involves a calculation of the total net present value for the period. This 15 year appraisal period is needed to cover full implementation of the MCPD (complete in 2030). A longer assessment period was not selected due to the uncertainty of future technologies and the remaining operating life of existing plant.

From 2030 onwards, the large majority of plants in scope of the MCPD and diesel controls[19] will be subject to permitting and compliance with ELVs and monitoring, so the impacts will have reached a steady state and in future years will differ only as a result of new plants replacing existing plants on reaching the end of their operating life.

Regulator costs were estimated based on data provided by the Environment Agency and on the activities required for enforcement.

The impacts can be split into the following areas, which are detailed fully in the remainder of Section 7.

COST IMPACTS

- **Emission Abatement Costs** – These are the costs that will be incurred by plants which will require abatement to meet the emission limits - for purchasing, fitting and operating abatement technology (see **Section 7.2**).
- **Administrative, Monitoring and Compliance Costs** will consist of permitting, reporting, monitoring and compliance checks (inspections). These costs will fall to both plant operators and regulators; however, most of these costs will be recovered from operators. These costs will be incurred by all generators falling in scope of the controls, and vary by type, size and complexity of the plant (see **Sections 7.4** and **7.6**). Costs relating to start-up (registration process, raising awareness for new regime), training of regulators and some of the costs of non-compliance cannot be recovered and will be funded through Defra's delivery budget.

Section 6.2 sets out the controls applied to generators. Compliance with emission limits may require fitting abatement, and operators will also have responsibilities in the other cost categories (monitoring, inspection, permitting etc.). The distinction between new and old, and size of plant governs when they have to comply with the requirements (as set out in Section 6.2).

BENEFITS TO THE ENVIRONMENT AND HUMAN HEALTH

Monetised benefits

- **Health and environment –** The emissions limits will reduce air pollution from generators. This provides monetised benefits to society, mainly as improved human health. There are also co-benefits between air quality and (GHGs) greenhouse gases (CO_2) which have been monetised and included.
- **Infrastructure and operating costs –** for Tranche B plants, the cost of implementing the measures suggests that some projected capacity provided by diesel would instead be supplied by gas as that becomes more cost-effective. This benefit will consider the difference in the cost of constructing and operating a gas plant when compared with a diesel plant. This includes the change in fuel, as plants will face reduced fuel costs from using gas which is cheaper than diesel.
- **Benefits of technology switch –** it is anticipated that some of the forecast plants in Tranche B would become gas (spark ignition engines) instead of diesel (compression ignition engines) as gas is a cleaner technology and would be able to meet the emission limits set in the measures. Gas is significantly cleaner

[19] With the exception of Tranche A generators under capacity market agreements which remain exempt from compliance with standard permitting conditions until the end of their agreements. This represents a small number of plants and the analysis assumes a worst-case scenario in which all these plants are exempt until the end of the assessment period.

than diesel for both NO_x but it also emits lower levels of other pollutants including CO_2, SO_2 and PM resulting in higher benefits from the switch.

Non-monetised benefits

- **Health and environment –** Damage costs do not capture all health benefits so there are additional health impacts that are non-monetised. In particular, morbidity impacts are largely not included within the damage costs. Furthermore, there are also wider environment benefits from reduced emissions such as improvements to ecosystems but these benefits are not possible to monetise.
- **Revenue and fuel savings –** Many generators in Tranche A that do not currently meet the measures set out in Section 6.2, will face the choice between abatement or a reduction in operating hours. Those who choose to reduce their hours will face a reduction in revenue equal to the revenue earned in the baseline with unrestricted running time minus the revenue earned with a reduced 50 hour running time. They will also experience a fuel saving as they will be running for less time. It is assumed, however, that there would be enough existing and new capacity available to fill the hours reduced. There is a minimal risk that due to the complex nature of the electricity generating contracts, it may not be as easy to switch contracts and a shortfall of supply could be anticipated. However, given new capacity forecasted alongside the extended time period for plants in Tranche A to meet the conditions of the additional measures, the risk would be insignificant. As a result, this cost can be considered an economic transfer where the impact will be balanced by one part of the energy market facing a cost in terms of lost revenue (but a saving in fuel) and another plant benefits (from additional revenue but additional fuel costs), so there is no net impact. However, as there is little per plant data available, we were unable to estimate the level of revenue earned by each plant particularly due to the numerous revenue streams which operators have access to and the uncertainty around which ones they would prioritise.
- **Energy security and resilience** – the implementation of a slower period of introduction of a conservative ELV for generators in Tranche A is expected to minimise disruption to the energy market. Many of these plants have agreed contracts which, if they are unable to honour due to ELV restrictions, may lead to a reduction in the total generation capacity. While these plants are not considered to be substantial contributors to the overall capacity, they do play an important role of supporting energy supply in peak times. Therefore ensuring that these plants are able to fulfil their contracts is important, and the extended timeframe should minimise the risk of disruption. It was deemed disproportionate to monetise this as these plants form a small proportion of UK energy generation and with the staggered approach to the measures it is unlikely to cause an impact on energy security.
- The costs and benefits from changes in emissions are calculated as the difference between the introduction of the emission controls on generators, against a baseline where only the MCPD is implemented. The baseline is introduced in section 6.1 and the methodology for its calculation is explained in Section 7.1. These measures ensure operators comply with relevant ELVs, fitting abatement technology where needed. Operators of many of the generators affected by the proposals to limit emissions from high NO_x emitting generators also have the ability to reduce operating hours to ensure compliance.

7.1 Baseline

As the generators under consideration are not generally regulated at present (unless connected to an IED regulated installation or in the range 20-50MW), numbers and type of plant had to be estimated.

High NO_x generators under scope of the regulation presented in this impact assessment are a subset of plants in scope of the definition of MCP but the majority are exempt from the MCPD ELVs. Therefore, the method used to estimate the numbers of generators within scope of the controls is largely based on the method used to estimate the numbers of MCPs, as detailed in the MCPD impact assessment.

The estimation is based on fuel consumption and projections from the National Emissions Inventory(NAEI)/BEIS, incorporating assumptions about size, technology type, and operating hours from EU averages. This is supplemented with estimates of generator numbers from Capacity Market auction data, estimates of numbers of STOR plants provided by National Grid and estimates of the number of plants providing demand side response services from BEIS. Most of the analysis is based on data gathered and/or derived for a report produced for the European Commission, henceforth the Commission study (Amec Foster Wheeler, 2014). The assumptions and data are based upon the best available evidence (Figure 7.1), however it must be noted that it came from a diverse range of sources, which introduces some uncertainty.

The remainder of this subsection details the estimation process.

Figure 7.1 Baseline steps and corresponding inputs

Baseline Estimation Steps

1. **Estimate number of plants**
2. **Estimate the capacity of plants**
3. **Identify the sectoral distribution of plants**
4. **Estimate the fuel consumption of plants**
5. **Identify current emission levels using average plant emissions**
6. **Estimate projected total annual emissions**

Inputs

European Commission sector data

Load factors[1] from Entec (2006)

Activity forecasts (Ricardo-AEA 2014 NAEI)

EMEP CORINAIR emissions guide

Capacity Market Auction results (2014, 2015)

Energy price forecasts (BEIS)

CO_2 emission factors

DSR site estimates from BEIS

STOR site estimates from BEIS

Step 1: Estimate number of plants

A baseline scenario in which there is implementation of the MCPD but no emission controls on generators is estimated. It is relative to this baseline that the impacts of implementing emission controls on high NO_x emitting generators are assessed.

The baseline scenario was created through estimation of the number of generators currently operating in England and Wales, with associated capacity, sectoral distribution, average operating hours and unabated emissions. National fuel consumption data and average plant size and working hours per sector were used to estimate plant numbers per fuel.

The estimated plant numbers and assumptions about operating hours and unabated emissions by plant type, size and fuel used were used to estimate total emissions from 2018 through to 2030 with implementation of the MCPD, against which the emission reductions achieved by applying controls on high emission generators were calculated. Sections below detail the methodology used to calculate the base year and projected baseline demonstrated in Table 7.1. Please note that this table presents the number of generators subject to permitting at a given point in time; therefore, the increase in certain years corresponds to timings of the controls.

Table 7.1 Plant numbers by capacity size and category

Number of plants	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Plant numbers by capacity															
Tranche A 0-1MW	0	0	0	0	0	0	0	0	0	0	0	0	1236	1236	1236
Tranche A 1-5 MW	0	0	0	0	0	0	0	0	0	0	0	0	2170	2150	2129
Tranche A 5-50 MW	0	40	41	43	45	46	48	63	62	61	60	59	58	56	55
Tranche B 0-1MW	0	0	0	0	0	0	304	330	330	330	330	431	456	482	507
Tranche B 1-50MW	0	32	227	421	616	810	1005	1104	1203	1302	1401	1501	1600	1699	1798
Total	0	72	268	464	660	857	1357	1497	1595	1693	1791	1990	5520	5623	5726

Plant number by category															
Working	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Stand-by	0	72	268	464	660	857	1357	1497	1595	1693	1791	1990	5520	5623	5726
Back-up	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	0	72	268	464	660	857	1357	1497	1595	1693	1791	1990	5520	5623	5726

2030 baseline projection

Using supplementary data from the NAEI team and European data (Amec Foster Wheeler, 2013), it was possible to split plants into size category (capacity class) by fuel type (gas, oil and biomass).

Less information was available for plants running shorter hours. Therefore, following consultation with National Grid on the capacity available in existing energy balancing market revenue streams (600MWe), specifically short run hour streams such as STOR (Short Term Operating Reserve), the figures from the European data were deemed too low for diesel and gas plants, and were updated accordingly. This existing capacity was sense checked with results of 2014 and 2015 Capacity Market auctions where plants bidding identified as existing or new build. The vast majority (by capacity) of these are assumed to be 1-5MW, which is typical of plants with shorter operating hours. Data on numbers of DSR sites from the National Grid was also used to disaggregate capacity market plant numbers into an additional category: 0-1MW.

The total number of plants in operation was projected to 2032 using growth figures for each fuel type derived from data provided by the NAEI team (in 2013). A growth threshold of 10% was assumed; meaning it was assumed that a change in activity less than 10% could be met by the existing number of plants as part of the flexibility in their working output capacities. A change beyond the threshold would result in a decrease or increase in number of plants needed.

Whilst the main dataset has been derived for three main capacity classes, data from the NAEI team was used to help categorise the plants.

Following the outputs of the 2015 Capacity Market Auction provided by BEIS, additional gas and diesel standby plants have been projected to reflect the increase demonstrated in the auction. This was estimated to be between 500MWe-1000MWe (central estimate of 700MWe) biannually following from 2014/2015 results.

Incorporating the evidence specified and with additional consultation with stakeholders, it is therefore estimated that in 2019, there will be around 70 plants subject to generators controls, which increases to about 5,500 by 2030.

The projected numbers of plants and their age were based on estimating the renewal rate associated with an estimated lifetime of 36 years. Lifetime was assumed to be twice the average plant age (18 years) as indicated by data from the consultation.

Step 2: Estimate the capacity of plants

The estimation of the total capacity of combustion plants has been undertaken using the EU average capacity per plant shown in Table 7.2 below[20], multiplied by the numbers of projected plants in 2030. The average plant size in each capacity class was determined from complete data gathered from Member States both on numbers of plants and the capacity per plant in Amec Foster Wheeler (2012) and the more recent study published in February 2014 from the European Commission. The EU averages and data sets include Member States who already regulate generators. For generators sized 0-1MW, the average capacity was calculated from data provided by BEIS.

Table 7.2 Assumed average capacity per plant

Capacity Class	Assumed EU average plant capacity (MW)
0-1 MW	0.3

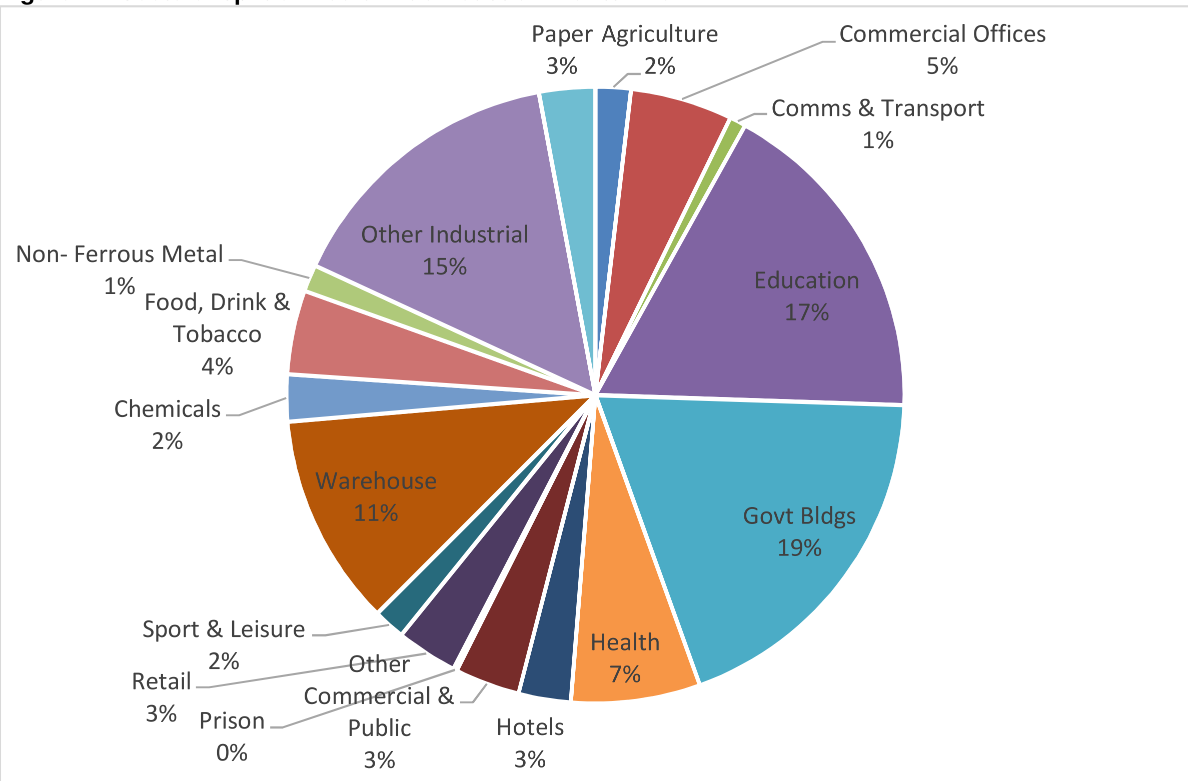
[20] Amec Foster Wheeler (2012)

1-5 MW	2.4
5-20 MW	9.5
20-50 MW	29.5

Step 3: Identify the sectoral distribution of plants

Information on the number of generators operating in the UK across different business sectors was developed in collaboration with Ricardo; this is illustrated in Figure 7.2 below. This information was used to develop the assessment on distributional effects, as presented later in this report. The assessment undertaken by Amec Foster Wheeler did not include the additional standby plants assessed under the additional controls as the ELVs set in the MCPD are for plants operating over 500 hours, therefore the cost impact split between industries is based on plants operating for longer hours. However, as there was little data on the specific industries of standby plant ahead of the consultation, we assumed the sector split for stand-by plants would be broadly similar to plants that operate for longer hours. This assumption was consulted upon but no additional data was provided. Section 11 details the business impact assessment.

Figure 7.2 Sectoral split of Medium Combustion Plants in UK



Source: Ricardo-AEA, 20 October 2014.

Step 4: Estimate the fuel consumption of plants

Total fuel projections and capacity etc. are used to estimate plant numbers as above. Once plant numbers are estimated, their fuel consumption must be estimated in order to calculate emissions.

Fuel consumption for high NO_x generators has been estimated by using:

- Projected number of plants as estimated above, average capacity data from the Commission study, and;
- An assumed average load factor of 1% under 8,760 hours i.e. 100 hours per year

Step 5: Identify current emission levels

Current annual emissions from generators in the UK have been derived based on assumed operating hours and emission rates from these plants. These emissions are based on a combination of the "general case" ELVs developed and applied in the Commission study (essentially the maximum values applied to national legislation across Europe), emission factors derived from the EMEP CORINAIR emissions guidebook (primarily for biomass SO_2 emissions) and data that have been returned by stakeholders as part of the informal consultation for this study.

As Tranche A and Tranche B generators have different requirements, the split was done for these two categories separately. Information is based on real plant performance, and what percentages of each type of generator (Tranche A/B and size) have BAU emission levels already below the ELVs imposed by the controls. The data is collated in 2014, and assumed to apply for all years 2018-2032. Annex 0 provides the number of each abatement technology actually fitted by 2030 to plant that need to abate in order to meet ELVs and the scale of how many are already compliant with emissions limits. This is also introduced further in section 7.2 below.

For those generators entering revenue contracts, the run times of the plants are assumed to be lower than regular standby plants. This is because generators, specifically diesel, typically run for less time as they are used for fast response or reserve capacity and often do not need to run for long periods of time. Consultation with industry, National Grid and BEIS has verified the shorter run time; therefore it is assumed that these plants will run for an average of 30-300 hours per year. It is likely that this could be lower for diesel generators where fuel is more expensive and higher for gas generators, where fuel is cheaper therefore an estimate of 100 hours was chosen, which was consulted upon.

Step 6: Estimate total annual emissions

Base case emissions of generators under the emissions controls have been estimated based on projected fuel consumption, the emission levels described above and application of specific flue gas volumes.

These basecase emissions are demonstrated in Table 7.3 below.

Table 7.3 Basecase emissions of all plants under the generators controls

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
Quantity SO_2 (t/yr)	0	2	11	20	29	38	47	52	57	62	66	71	76	81	85
Quantity NOx (t/yr)	0	8	52	97	141	186	230	253	276	299	322	345	368	391	414
Quantity PM (t/yr)	0	0	1	1	2	2	3	3	3	3	4	4	4	4	5

The results section presents the impact of the controls on combustion plants on emissions reductions. This impact is additional to existing legislation such as the Gothenburg Protocol, EU legislation and UK legislation.

7.2 Impacts from Abatement Costs

All generators that wish to continue to operate other than in emergencies will be required to meet additional controls.

The base case emission levels for each capacity class and fuel are compared against the scenario limit values to determine the required emission reductions. This indicates whether additional abatement measures would need to be implemented in order to meet the scenario limit values.

Abatement costs come from the best available evidence sourced by Amec Foster Wheeler, which includes the recent Amec Foster Wheeler study for the Commission (Amec Foster Wheeler, 2014). The modelling identifies the most suitable abatement technology for each sub-group of plant. Suitability for each sub-group depends on the necessary emissions reduction required for each pollutant, whether the plant is new or old, and its fuel type and capacity class. Annex 0 presents the methodology in further detail with a list of measures and assumptions.

If a plant choses to fit abatement, the costs faced are expected to be lower than for larger plants and those that operate for longer hours (covered by the MCPD). This is because the abatement equipment for smaller plants costs less and because abatement requires reagent to operate effectively - the amount of reagent used will increase as the operating hours and size of the plant increase. If plants need to fit abatement to meet the requirements, the majority of which would be diesel, original operating costs would apply to plants that run for 2000 hours per year. Plants (generators) that enter revenue streams would typically run for shorter times of an estimated 100 hours on average[21]. Therefore for these plants, the cost of operation (not installation cost) was reduced down to 1/20th of the cost to ensure consistency with their shorter run times.

It is assumed that the cost of the abatement fitted would have to be outweighed by the benefit of the revenue streams possible in order for plants to choose to fit the abatement.

[21] As these plants aren't required to register, there is little information available around operating hours. Discussions with National Grid suggest that plants in revenue streams such as TRIAD can operate between 30 – 200 hours. Therefore 100 hours is assumed as an average that is applied to all standby plants in energy balancing markets, which was tested during consultation.

7.3 Operating and construction costs

The controls to protect human health from high NO_x emitting plants will result in additional costs for diesel generators such as additional abatement costs or reduced operating times; therefore some of the forecasted diesel capacity would be taken up by gas plants.

Following consultation with industry stakeholders and BEIS, it has been identified that there are different construction costs for diesel and gas plants[22]. Other plants were not considered as a significant proportion of the bids into the capacity market were from diesel and gas sites. Diesel plants are typically cheaper to install, although due to the high fuel costs, they are more expensive to run. For gas plants, the price of gas means they are inexpensive to run but the build costs are relatively higher.

In order to capture this difference, industry and other government departments have provided initial cost estimates on the build costs of a diesel or gas plant. Due to the sensitivity of the data, an annualised cost for each plant size has been provided and shown in Table 7.4 below. There is limited information on the fixed costs for smaller plants, such as infrastructure costs, which account for a substantial part of the overall plant costs. However these assumptions were subject to consultation and did not raise specific concerns.

It is assumed that the infrastructure cost would be split over the site (it would only require one gas line to be built etc.) therefore the cost would be split between the plants on this site.

Using BEIS fuel forecast estimates for gas and diesel, Table 7.4 demonstrates the difference in cost per year over an expected 15 year plant lifetime. The difference between diesel and gas is relatively high for plants below 20-50MW. This, in part, can be explained by the fixed costs being appropriate to a larger plant but also because of the assumed run time of the plant. A direct switch has been assumed so this cost difference required diesel and gas to run for the same period of time, 100 hours. In reality, gas is likely to run for longer periods (400- 500 hours), so a comparison for this run time would increase the price of diesel versus gas.

Table 7.4 Operating and Construction Costs

	Diesel engines annualised cost (£/year)	Gas engine annualised cost (£/year)	Cost increment Gas vs Diesel (£k/year)
0-1MW[23]	n/a	n/a	7.81
1-5MW	£61,614	£69,420.	7.81
5-20MW	£234,440	£258,453	24.01
20-50MW	£594,439	£593,586	-0.85

7.4 Impacts from administrative costs

Under the MCPD, standby plants are already assumed to face permitting costs, monitoring CO and NOx and light-touch compliance (inspection) checks; these costs are detailed in the MCPD impact assessment. However, generators (the majority standby) under the proposed emission controls will face additional administration costs compared to those only covered by the MCP Directive. These additional costs are presented in the following section.

It should be noted the administration for HNGs will utilise the register developed by the Environment Agency. The upfront transitional cost of setting up the register is captured in the MCPD impact assessment, and therefore forms the baseline of this impact assessment.

Permitting costs

One-off permitting costs

We have assumed that Tranche A electricity generating plants operating for longer than 50 hours in 2018 would face a standard emissions test in order to see if they breach 500mg/Nm^3ELV. This cost is annualised over a lifetime of 15 years. If this is the case, plants will be required to get a permit and undertake dispersion modelling to assess if they are likely to cause a breach. The costs for these actions are outlined in Table 7.5 below.

[22] Where diesel plants are referred to this means compression ignition engines and where gas plants are referred to it means spark ignition engines or turbines

[23] Data was not available for 0-1MW plants so the incremental cost was assumed to be the same as for 1-5MW. This is probably an overestimate.

Table 7.5 Additional administration costs for electricity generating plants breaching proposed ELV's

	One-off permit costs (2014 £)
Standard Emissions Test	1,000
Permitting + Bespoke Modelling	6,621
Total	**7,621**

The population data demonstrates that 50% of plants are likely to be in an urban location. Therefore, it is assumed that only the plants in rural locations would choose to obtain a permit with site-specific conditions in order to operate for longer hours because they will be less likely to impact on local receptors and would see the cost of applying for the permit to be outweighed by the revenue to be generated.

In 2024, it is assumed that those generators with a permit with site-specific conditions that operate in excess of 50 hours are operating for energy balancing markets or would otherwise be affected by MCPD and would therefore reduce hours rather than meeting the lower ELV which would require them to fit abatement at a greater cost. As a result, the permit costs are annualised over a seven year period as those plants that hold a bespoke permit would only hold them until 2025 or until the end of their power supply agreements.

These costs would be on a site by site basis as often standby plants are not individual units on sites but can be clusters of three or more. Additionally, the emissions of a site (e.g. an installation as defined in the Environmental Permitting Regulations) should be considered together rather than individually as this would change the level of emissions faced by local receptors and could cause a greater impact on health. The Capacity Market outputs suggest an average site size of 20MW therefore it is assumed that these costs would be spread between ten plants (to represent a site) as average diesel plants are 1-5MW, so a midpoint of 2MW is assumed. For larger sites, three plants per site are assumed as demonstrated by data collected for assessment of working plants affected by the MCP Directive (see Table 7.6).

Table 7.6 Number of plants assumed per site estimate

Capacity	Plants per permit
0-1MW	10
1-5MW	10
5-20MW	3
20-50MW	3

<u>Recurring permitting costs</u>

For those plants which become operational after 1 December 2016 that choose to fit abatement, a permit would be required to operate from January 2019. New diesel plants are the only engine type that are likely to breach the ELV as new diesel engines are forecast to continue to have high basecase emissions of 1200mg/Nm^3. These plants will be treated in the same way as high risk plants under the MCPD proposals, as outlined in Section 6.1 (Table 6.3).

Estimates of permitting costs are based on figures provided by the Environment Agency, the appointed regulator. All costs would be borne by the regulator in the permitting process and are assumed to then be passed onto the operator.

As with the one-off costs of permits, the costs of the permit are applied on a site by site basis. The costs in Table 7.7 below are converted into a per plant cost using the same assumption of numbers of plants per site as above. These costs are different to the costs for working plants as they reflect the lower number of operating hours expected by these standby plants (100 hours instead of >500hours), and therefore lower resource to verify as part of the permitting process.

Table 7.7 Annualised recurring permitting costs per site, 2030

Capacity (MW)	Annual recurring costs per site (£,2014 prices)
0-1	1,725
1-5	1,725
5-20	1,725
20-50	2,891

7.5 Impacts from loss of operating hours – revenue and fuel savings (Non-monetised)

Tranche A plants that operate for longer than 50 hours per year, are near to a sensitive receptor and are unable to comply with the ELV of 500mg/Nm^3 in 2018 will be subject to an assessment and may be required to disperse or abate emissions or may choose to reduce operating hours. This reduction in hours represents a potential revenue loss for these plants.

Additionally, the revenue earned by plants in Tranche B has the potential to dictate their behaviour in terms of whether forecasted plants will remain as diesel. If the cost of abatement to meet the proposed ELV's outweighs the potential revenue earnings, then cleaner technology that can meet the ELVs more cost-effectively is likely to replace diesel.

There is limited publicly available information on the amount each plant earns from participating in electricity generating services. Therefore, we consulted with industry experts and National Grid to give an indication of the potential revenue available. Table 7.8 demonstrates the conclusion of this data gathering exercise, and highlights the multiple options available to plants. Following this consultation, there was a clear consensus that plants operating in these streams are likely to be able absorb the cost of fitting standard abatement to meet the proposed ELVs.

Table 7.8 Revenue streams available to electricity generating plants (estimates from National Grid and industry experts)

Service/ revenue stream	Definition	Capacity of diesel in service (MWe)	Availability payment (£/MWe)[1]	Hours Available/ annum*	Utilisation payment £/MWhr[1]	Utilisation Hours	Total payment (diesel) /kW/yr
FFR	Plants that operate for Firm Frequency Response provide a fast balancing service for fluctuations in frequency. Plants are paid for hours available and hours utilised.	200	£7/or less assume £4 off-peak	20/day	£69-1600/MWh	5 (est.)	£33 (est.)
STOR	Plants that operate for Short Term Operating Reserves are typically contracted. Paid for hours available and hours utilised.	650 (450 Short Term 200 Long Term)	£3-8/MW per hour [£3 only not operating over winter, £8 all year)	10.5/day [3,860 hours of availability]	£130-150/MWh Short term, £235/MWh Long term	13835MWh (diesel total 2014) 20 hrs Short term, Long term STOR runs very infrequently (assume 1 hr)	£14.18 (est.)
Triad Avoidance (TNUoS)	During Nov-Feb, when energy use is high, generators connected to the distribution network are paid if they use their generators during "Triads" (the three half hour periods of peak demand for energy). Large industrial and commercial users run their generators to	420	(TRIAD payments for specific hour(TRIAD payments for specific hours)	(TRIAD payments for specific hours)	£69-1600/MWh[24]	30-250	£45 (est.)

[24] These are negative charges or avoided charges for not using the network distribution system.

	avoid drawing power from the transmission network during Triads to avoid transmission charges.						
DUoS	DuoS (Distribution Use of System) charges are levied by the UK's regional DNOs (Distribution Network Operators) and go towards the operation, maintenance and development of the UK's electricity distribution networks. Payments for specific hours run.	Not confirmed	n/a (TUoS payments for specific hours)	n/a (TUoS payments for specific hours)	£56-94/MWh	Min 5hrs	Not confirmed

However, in order to prevent high concentrations of NO_2 and reduce overall NO_x emissions from generators providing these services, NO_x abatement needs to be met quickly. This is because emissions of NO_x build up quickly within the first 20 minutes of operation and the running time of diesel generators acting for these services can be fairly short. The limit for compliance with the NO_x ELV of 20 minutes for Tranche A and 10 minutes for Tranche B generators may limit the ability for plants to fit appropriate abatement, particularly Tranche A generators which are less likely to see abatement as a cost effective decision over their remaining lifetime.

In order to continue to operate, some generators in Tranche A will therefore choose to reduce their hours to 50 (the average operating time of standby plants in revenue streams is assumed to be 100 hours based on stakeholder consultation and National Grid information) if they consider the cost of abatement higher than the revenue loss incurred.

As there is little information around the location of generators in relation to a sensitive receptor, population data has been used in the UKIAM model[25] to categorise the geographical distribution of sites of diesel units, based on the 2015 plants from the 2015 capacity auction. This demonstrated that approximately 50% would be in a rural or suburban location where there is likely to be less risk of a sensitive receptor in close proximity to the generator. Therefore it could be assumed that 50% of generators would cause undue health impacts due to their position near sensitive receptors and would therefore reduce their hours. A lower ELV of 190mg/Nm^3 for generators that are not exempt in 2025 would mean that any plant which could benefit from an exemption from permitting (in particular back-up generators providing power on-site during an emergency) would reduce their hours in 2025. We have therefore assumed that the remaining 50% of generators would reduce their hours in 2025[26] as this action would be more cost effective than fitting abatement that would be active within 20 minutes. Arrays of diesel engines located on sites with no power demand will not be able to benefit from this exemption and would be required to fit suitable abatement to operate for any purpose other than to fulfil a contract or agreement made before 1 December 2016. Information on how many generators are in sites of this kind is relatively weak so it is possible the costs of abatement are underestimated, however no further data was received during the consultation.

We have assumed arrays of generators on sites with no power demand which choose to reduce operating hours to avoid fitting secondary abatement would incur a revenue loss by reducing their hours available from 100 to 50, along with a fuel saving from the reducing running hours (greater savings for diesel as the fuel cost is higher). Consultation with BEIS and industry experts has suggested that it is very likely that they can continue to operate profitably with more limited hours, and this would be a cheaper option than fitting abatement.

It is worth noting that we do not assume that capacity overall will reduce due to the new capacity projected to come through, therefore revenue can be treated as a transfer from one area of the energy market to another. This is

[25] For more detail on the UKAIM - https://www.imperial.ac.uk/environmental-policy/research/environmental-quality-theme/current-projects/iau/iam/ukiam/

[26] To the exception of plants with capacity market agreements going beyond 2025

because other generators which meet the emission limits will be able to benefit from these available revenue streams and will be paid to provide this capacity. However, in the short term diesel is viewed as relatively cheap due to low build costs, although running costs (from fuel) are higher. Therefore if new capacity (Tranche B) is being filled by alternative generators such a gas, which can be more expensive to build, there may be a very marginal increase in the cost to consumer in the short term. This is detailed in Section 13.

Overall, the cost to the generator running shorter hours will be a benefit to those generators that will take up the requirements of the contract, which demonstrates a redistribution of income from one plant to another with no net societal cost faced.

We consulted on the number of revenue streams each generator is in or will be able to enter and have monetised the impact in this final IA.

7.6 Monitoring costs

Generators covered by the controls already incur monitoring costs under the MCPD, which are presented in the MCPD impact assessment. This section only presents the additional monitoring costs incurred by generators captured by the controls. As those plants would now be expected to meet the proposed ELV of 190mg/Nm^3, monitoring in addition to that expected in the MCPD will be required to ensure that this limit is being met. Therefore any plant choosing to fit technical abatement would need to monitor emission levels to demonstrate compliance. Specifically, in addition to all concerned plants needing to initially complete a test, they will subsequently also need to regularly monitor emissions.

The costs of monitoring for these generators would extend to monitoring NO_x along with the cost of CO monitoring, which is required by all standby plants in the MCPD. All relevant plants will monitor and record emissions of CO every five years under the MCPD requirement, whereas the NO_x monitoring must be done every three years for generators using abatement equipment to achieve the required ELV. Each plant must be monitored rather than each site, as the ELVs apply to stacks (to monitor emissions at the flue) not sites. The costs have been calculated as for plants under the MCPD, scaled for smaller individual plants with shorter operating hours, and are demonstrated in Table 7.9 below.

Note these costs do not capture those anticipated in MCPD (e.g. PM monitoring) aside from CO monitoring, which is included as it is applicable to all standby plants.

Table 7.9 Additional monitoring costs per generator under emission controls

Plant Size	NO_x and CO only monitoring costs (£, 2014)
0-1MW	£188
1-5MW	£1,666
5-20MW	£2,377
20-50MW	£3,798

7.7 Benefits to the Environment and Human Health

Emission reductions from abatement

Total emissions reduced for SO_2, NO_x and PM are estimated by applying abatement efficiencies to the fuel specific emissions.

The abatement efficacies are those from the specific abatement measures selected in the compliance modelling. Specifically, the model compares the baseline (unabated) emission concentration for the plant type against the relevant measures to meet energy balancing markets to determine if a reduction in emission concentration is required, and if so, what percentage reduction is needed. The model then selects the relevant measure to achieve the required reduction; for example, if a reduction of 50% is needed and there are measures suitable for that category of plant able to achieve 40% reduction or 70% reduction, then the measure achieving 70% reduction is applied to ensure compliance. Consequently, the emission reduction modelled is higher than would be needed purely to comply. For most abatement measures, this is a realistic situation. A small number of measures (e.g. Selective Catalytic Reduction, SCR) could in practise be set up to only achieve the required reduction without an overshoot, and reduce slightly the operational costs.

Emission reductions from reduced hours and change in fuel type

Alongside the emission reductions estimated as a result of the additional restrictions for existing plants within the energy balancing markets choosing to apply abatement efficiencies, there are additional emission reductions from reduced operating hours, compared to base case emissions.

For plants operational before December 2016 and those with 2014/15 Capacity Market agreements, it is assumed that a proportion choose to reduce their hourly run time as it would be more cost effective for the plant than fitting abatement. This reduction in hours therefore reduces the level of emissions. This reduction is modelled by calculating the difference in the annual waste gas flow rate multiplied by the level of emissions in the base case of 100 hour run time compared to the scenario of reduced run time of 50 hours. Please see section 6.2 for details of ELVs under the option.

For plants which become operational after 1 December 2016, it has been assumed that a proportion of the forecasted diesel capacity would be replaced by gas as the measures for high NO_x generators would deter diesel from entering the energy balancing market. While we assumed that there would be no additional benefit in the NO_x reductions from an abated diesel generator and a gas generator (both assumed to meet 190mg/Nm^3), gas generators have lower SOx, PM and CO_2 emissions as gas is a cleaner fuel for multiple pollutants and GHG's. These additional benefits have been captured as part of the assumed technology switch from diesel to gas.

Monetised Benefits

(1) Air Quality

The Green Book guidance recommends the impact pathway approach in many circumstances when impacts are above £50m annually. The bespoke impact pathway approach was considered, however, in this circumstance, the uncertainty around the spatial distribution of plants and their operating patterns meant that damage costs are more appropriate.

The beneficial impact is considered in terms of the damage avoided if emissions reductions are achieved. This 'damage' avoided is calculated in money terms using a damage cost. The IGCB damage cost functions form official government Green Book guidance on valuing impacts from Air Quality. They predominantly capture the health benefits from reduced emissions. Since the consultation, our central estimates of damage costs associated with reductions in emissions have been amended and in particular revised down by 15% for NOx emissions. The analysis in this IA is based on forthcoming updated damage costs by the COMEAP which reflect the latest advice and takes a consistent approach to that used in support of the government's recently published 'Air quality plan for nitrogen dioxide'.

As damage costs are sensitive to factors such as geographic location of emission sources and meteorology, there are damage cost functions for particulate matter (PM) and NO_x that are categorised by geographic area. For the purpose of the MCP analysis and additional measures for high NO_x generators, we have calculated a weighted average damage cost specific to each pollutant that is based on the sectors involved (based on sectoral split as per Figure 7.1). This is to enhance representativeness of damage costs in relation to specific MCP and generators impacts.

Table 7.10 below presents the damage cost weighted by the average of the sectors involved.

Table 7.10 Damage Cost Functions for SO_2, NO_X and PM (£2014 per tonne of pollutant reduced)

	Central Estimate	Low Central Range [b]	High Central Range [b]
NO_X	£4,269	£3,546	£11,762
SO_2	£2,375	£1,208	£5,053
PM [C]	£29,470	£13,885	£70,775

a) Based on IGCB damage cost functions (IGCB, 2012 for SO_2 and PM – Defra, 2015 for NO_X).
b) Variation between the central values reflects uncertainty about the lag between exposure and the associated health impact.

The damage cost functions have been inflated to 2014 prices (using GDP deflators), and additionally uplifted by 2% per annum until 2014. In years beyond 2014, they are only uplifted by 2% per annum when applied to future year emission reductions. The uplift captures the higher willingness of the population to pay, and therefore value of health benefits as incomes (economic growth) rises.

The potential benefits of the reduced emissions from the assumed reduced hours and change in fuel are also calculated using the application of damage cost functions as outlined above. The same weighted average of the damage costs has been applied to capture the spread of plants across different industries and locations. This is something we consulted upon as there was little data available, but no further data was provided

(2) Greenhouse Gases (GHGs)

A change in greenhouse gas emissions was also calculated from a change in fuel consumption. The implementation of abatement also results in the abatement of greenhouse gases, mainly carbon dioxide. We have monetised the environmental benefit of reduced CO_2 using the central BEIS traded and non-traded carbon values to calculate the impact. The traded value is used for larger plants over 20MW that fall into the scope of the EU Emissions Trading System, while the non-traded value of carbon is used for smaller plants.

The environmental benefit of reduced CO_2 from the assumed reduced hours and change in fuel was also calculated using the central BEIS traded and non-traded carbon values.

Non-monetised Benefits

It is important to note when applying and interpreting damage cost functions that a number of impacts are not taken into account in the quantification; this includes a number of human health impacts (in particular morbidity), as well as impacts on ecosystems and cultural heritage. Therefore, the benefits estimated through the application of damage cost functions may be underestimated.

Not all impacts can be fully monetised; there are additional benefits that are non-monetised associated with reductions in soil and surface water contamination, reducing acidity and the potential for these substances to bio-accumulate in the food chain and humans. Reduction in the emissions of organic substances should also lead to a downward trend in the release of carcinogens.

7.8 Further assumptions and uncertainties

A more comprehensive discussion on key risks and assumptions is discussed in Section 9, along with results from sensitivity testing key assumptions. Section 9 also presents a full assumptions log.

7.9 Quality Assurance

Quality assurance refers to processes which can help ensure the analysis' inputs and outputs meet its quality requirements, manage risk of errors and ensure the analysis is fit-for-purpose. It is a key means of ensuring analysis is robust. A high level of quality assurance was considered proportionate for the modelling supporting this analysis. As such, the process set out in the official HM Treasury Aqua Book was fully completed. This involved checks throughout the analytical life cycle by analysts, commissioners of analysis, those supporting the assurance effort, and stakeholders. Specific checks performed on this analysis include:

(a) *Specification Confirmation* - Defining what a piece of analysis should deliver, the deadlines and quality requirements, along with recording any changes to scope.

(b) *Developer Testing (including validation and verification)* - Reviewing and checking of the analysis during development, primarily by the analytical team.

(c) *Input Data Checks* - An understanding of the data needed to shape the development process. Its definition, availability, timeliness, quality and quantity

(d) *Input Assumptions Checks* - Ensuring that all assumptions are transparent, clearly understood and are agreed by stakeholders.

(e) *Independent Validation* - Validation was focussed on checking that the analysis will meet the customer's actual needs, i.e. that we are doing the right analysis.

(f) *Independent Verification* - Reviewing, inspecting, testing, checking, auditing, or otherwise establishing, and documenting, whether the analysis conforms to the specified requirements, i.e. checking we are doing the analysis right.

(g) *Documentation* – The resources (including this IA) that assist in recording the problem, the analysis and the associated uncertainty to other analysts and customers.

(h) *Communicating Uncertainty* - Disseminating analytical risks and unknowns in a piece of analysis and its outputs to decision makers. This includes the details of section 9 of this IA and the high/low scenarios presented throughout.

8. Results

8.1 Overview

Table 8.1 demonstrates the total impacts of implementing the controls on high NO_x generators. Monetised health and environmental benefits across the 15 year appraisal period, relative to the baseline are £58m, against costs of £107m, in present value (today's terms). The next subsection summarises each cost and benefit category.

Table 8.1 Cost and benefits (£m, PV)

2018-2032	LOW SCENARIO (£m)	HIGH SCENARIO (£m)	CENTRAL (£m)
Costs (cost to operators)			
Abatement costs	43.2	80.3	50.6
Administration costs	0.2	0.3	0.3
Monitoring costs	10.7	10.7	10.7
Operational/capital cost of technology switch	56.7	0	45.4
Total	110.9	91.3	107.0
Benefits (emissions reductions)			
Air Quality	41.0	143.2	50.9
CO2 (Traded)	0.1	0.4	0.2
CO2 (Non-Traded)	3.3	10.0	6.6
Total	44.4	153.6	57.7
NPV	-66.5	62.3	-49.03

*Please note any differences due to rounding.

8.2 Key costs and benefits of implementing the generators controls

This section details the estimated emission reduction and associated costs of implementing the emissions controls on high NO_x generators.

The results present the outcome over a 15 year assessment period. The assessment begins in 2018, when the first costs will be incurred, and ends in 2032, where it would be anticipated that the generator controls will have been implemented in full. As a reminder, the analysis assumes a worst-case scenario in which all generators with capacity market agreements are exempt for the whole assessment period.

Year-by-year results (i.e. annualised costs for individual years) are presented to demonstrate the impact per individual year when the measures on those plants that are part of the energy balancing markets come into effect. From 2032 onwards, the impacts will be similar for future years given that there are no further changes to emission controls from that year. The changes will be as a result of the closure of existing plants on reaching the end of their operating life and opening of new plants, and changes in the projected use of different fuel types. However, although the numbers of plants are not projected further than 2032, the growth in plants as a result of the capacity market could mean a growth in the numbers anticipated.

The main ranges around the central estimate represent the two key sensitivities. The first is the anticipated behaviour change of new (operational from 1 December 2016) plants which, due to the uncertainties around the impact of the measures, is the main sensitivity surrounding the total cost impacts of the directive. The scenarios tested are as follows:

Scenario 1: No change in diesel, all diesels fit abatement

Scenario 2: 80% of projected diesel capacity becomes gas

Scenario 3: 100% of projected diesel capacity becomes gas

The second is the variation in the damage cost values attributed to reduced emissions. It is standard HMT Green Book practise to present the uncertainty in valuing human health.

All prices are in 2014, and a 3.5% discount rate has been used in present value figures as per Green Book guidance. The base year for the NPV is 2018.

In the remainder of this section, each of the following monetised impacts is discussed in more detail:

COSTS

- **Abatement costs for plant operators –** Compliance with the additional measures for electricity generating plants will lead to additional costs for plants between 0-50MW and lower that are not exempt from compliance with emission limits. These plants may need to fit abatement in order to reduce their NO_x, PM and SO_x emissions to meet the ELVs set in the regulation. These costs will vary depending on the plant type, the age of plant and the most cost effective abatement measure chosen. The central estimate is that this will lead to an additional to baseline cost of £50.6m (£43.2m and £80.3m) in present value terms for businesses.
- **Administrative and compliance (inspection) check costs –** The costs include the additional permitting requirements and compliance checks required by the additional measures for high risk electricity generating plants (those with high NO_x emissions). The central estimate is that this will lead to an additional to baseline cost of £0.3m in present value terms for businesses
- **Monitoring costs –** The costs include the fees for an accredited consultant to conduct the monitoring surveys and prepare a monitoring survey report to the operator annual or tri-annually in order to meet the Directives monitoring requirements. The central estimate is that this will lead to an additional to baseline cost of £10.7m in present value terms for businesses
- **Cost of switching plant type in projections –** Under the additional generators controls, it is assumed that the capacity of some forecasted diesel standby plants would be replaced by gas as gas will not have to fit abatement as it is assumed to meet the ELV. This cost captures the difference of building and running a gas plant as opposed to diesel (capital and operating costs). The range presented will capture the varying levels where this change in fuel type occurs. The central estimate is that this will lead to an additional to baseline impact of £45.4m (range: £0 – where no switch occurs and £56.7m) in present value terms for businesses

Non-monetised costs

- **Revenue loss for plant operators –** Under the generator controls, some standby plants operating before 1 December 2016 or those with successful bids in the 2014 and 2015 Capacity Markets will choose to reduce their hours instead in response to the additional measures set. This will be considered as a transfer as it is assumed that overall capacity would still be needed so other compliant plants would now be able to take up these contracts, therefore revenue would transfer from one non-compliant plant to another compliant plant. However, it is a cost faced by the plants considered within this scope but due to the lack of information around specific revenue streams, it cannot be monetised.

MONETISED BENEFITS TO THE ENVIRONMENT AND HUMAN HEALTH

- **Monetised air quality benefits –** The main benefit of the implementation of the generators controls will arise from the reduction in air pollutant emissions. By reducing the number of plants operating without abatement and ensuring that these plants are monitored for their emission levels, this will improve air quality and benefit human health and the environment. This captures the reduction in both chronic mortality effects (which consider the loss of life years due to air pollution) and morbidity effects (which consider changes in the number of hospital admissions for respiratory or cardiovascular illness). However, it does not quantify all human health impacts. The total air quality benefits from the generators controls are valued at £50.9m in present value terms.

- **Monetised CO_2 Emissions benefits** – Certain measures intended to reduce emissions of air pollutants also affect CO_2 emissions from UK plants. As some of the larger plants would fall into the scope of the EU Emissions Trading System (ETS), the reduction in costs to UK businesses of purchasing extra EU ETS allowances from abroad is assessed. Therefore, any change in CO_2 emissions in the UK is valued using the traded cost of carbon. Smaller plants will fall under the non-traded value of carbon, where although they are not traded as part of the EU ETS, the emissions still contribute to the global carbon value and need to be considered and as other industries may not need to abate as much as a result. The total CO_2 emissions benefits from the additional generators controls are valued at £6.8m in present value terms.

8.3 Abatement costs

The central year on year breakdown is shown in the table below where the annual total cost of abatement increases over the appraisal period as each measure is introduced. Table 8.2 below also demonstrates where stages of the additional measures (2024, 2029) come into effect and a greater number of plants are impacted, as shown by the higher cost.

Table 8.2 Year on year discounted cost of abatement for standby generators (£m, 2014 prices) Central Scenario [80% of diesel standby plant capacity projected switches to gas]

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total PV
CENTRAL – Scenario 2																
£m	0	0.2	0.3	0.4	0.5	0.6	0.7	0.8	0.8	0.9	0.9	0.9	15.1	14.5	14	**50.6**

Note: any differences in totals due to rounding

As demonstrated by the tables above, under the central scenario, only 20% of projected diesel would continue to operate and therefore would fit abatement. This results in relatively low costs of abatement as other forms of fuel (gas) is assumed to meet the ELV with no additional abatement required.

Sensitivity of the behaviour change

Anticipated behaviour change of plants is a key driver of the cost of abatement. If more plants switch to gas, then fewer need to fit abatement equipment.

Therefore we have sensitivity tested two more extreme scenarios, where there is no change or 100% change in fuel. Scenario 1, where 100% of forecasted diesel plants will continue to be diesel, is demonstrated in Table 8.4 below, and has been tested with all projected diesel plants fitting abatement to meet the ELV set in the measures. However, as there is little known about technology available to meet these measures, the scenario uses the costs of current abatement and is therefore likely to underestimate any cost associated with adopting new abatement technologies. It should be noted that this scenario is unlikely, since at least some shift to gas is expected where natural gas is available, to avoid periodic monitoring and running costs and investment in secondary abatement.

Scenario 3 (Table 8.3) demonstrates where 100% of projected diesel fuel is filled by gas.

Table 8.3 Year on year cost of abatement for standby generators (£m, 2014 prices) Low Scenario [100% change to gas in plants projected], discounted

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total PV
LOW Overall – Scenario 3																
£m	0	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	0.2	14.4	13.8	13.2	**43.2**

Table 8.4 Year on year cost of abatement for standby generators (£m, 2014 prices) High Scenario [No change in fuel of plants projected], discounted

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total PV
HIGH Overall – Scenario 1																
£m	0	0.3	0.9	1.5	2	2.5	3	3.2	3.4	3.5	3.6	3.7	18	17.5	17	**80.3**

8.4 Administrative and compliance (inspection) check costs

The administration costs are the costs faced by plants for operator and regulator time and effort for processing an environmental registration/permit, inspection, data recording and reporting.

Permitting, compliance checking and reporting activities will result in a range of one-off and recurring costs to regulators and operators, however this IA includes only the costs which are additional to those incurred for compliance with the MCPD (for 1-50MW plants). Additional permitting costs will be incurred for generators that require more complex permits, or at an earlier date, than set under the MCPD.

Most standby plants in the MCPD are classified as low risk when they register and seek a permit, however with the Environment Agency modelling, even modern diesel generators with base case emissions of 1200mg/Nm^3 are likely to cause a breach in recommended local air quality hourly limits and therefore, meeting the lower ELV of 190mg/Nm^3 is important so as not to risk a breach. Therefore those diesel plants that may choose to apply for a permit with site-specific conditions have been reclassified as high risk as they would need to be monitored to ensure they are meeting the conditions of the permit: this will be reflected in higher permitting and compliance check costs.

Permitting costs will affect back up, working and standby plants. The breakdown for registration and administrative costs per plant is demonstrated in Table 8.5 below.

Table 8.5 Recurring administrative costs per site (2014, £/year)

	Recurring cost per site (2014 £/year)			
	0-1MW	**1-5MW**	**5-20MW**	**20-50MW**
Registration: subsistence (high risk)	868.8	868.8	868.8	2,035.4
Registration: subsistence (low risk)	91.2	91.2	91.2	91.2
Registration: subsistence (high risk - low risk)	**777.7**	**777.7**	**777.7**	**1,944.2**

Year on year administrative costs for plants under generator controls are presented in Table 8.6 below for the central scenario. Total NPV for the overall low scenario is 0.3 and for the high scenario is 0.5.

Table 8.6 Year on year cost of administration for generators controls (£m, 2014 prices), discounted

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total NPV
CENTRAL SCENARIO																
£m	0	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	0.02	**0.3**

Note: any differences in totals due to rounding

8.5 Monitoring costs

The monitoring cost captures the cost of monitoring whether a plant is meeting an ELV which would include the fees for an accredited consultant to conduct the monitoring surveys and prepare a monitoring survey report to the operator. Under the MCPD, working generators over 1MW will be required to monitor emissions annually (if over 20MW) or tri-annually (if 1-20MW) in order to meet the Directives monitoring requirements. Standby and backup generators are required to monitor emissions at least once every 5 years, depending on their operating hours. Under the MCPD, working generators must monitor emissions of the pollutants for which they have ELVs, and all generators must monitor CO.

The emission controls for generators set additional monitoring requirements for plants that chose to fit abatement, which will need to monitor to ensure they are not breeching the ELV; this requirement may also apply from an earlier date than under the MCPD. The cost per plant is highlighted in Table 8.7 below.

Table 8.7 Additional NO_x Monitoring costs for generators subject to the high NO_x generator controls

Recurring cost per site (2014 £/year)			
0-1MW	*1-5MW*	*5-20MW*	*20-50MW*
746.24	746.24	746.24	746.24

The results are presented in Table 8.8 below.

Table 8.8 Year on year cost of monitoring (£m, 2014 prices), discounted

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total NPV
CENTRAL																
£m	0	0	0.1	0.2	0.3	0.3	0.5	0.6	0.6	0.6	0.6	0.6	2.1	2	2	**10.7**

8.6 Impact of capacity switching fuel types

This represents the impact faced if some of the capacity forecasted were filled by gas instead of the projected diesel in the baseline. The cost of building a gas plant over a diesel plant is higher in terms of build cost, although the cost to run the plant is cheaper due to the low fuel costs.

The results below demonstrate that in the central scenario where 80% of the forecasted diesel plants have a direct switch to gas, there would be a cost of £45.4m.

This impact has been sensitivity tested by testing the extreme cases where 100% of capacity would continue to be diesel (Scenario 1) or 100% of the capacity would be filled by gas (Scenario 3) (Table 8.10). This has highlighted that a 100% switch to gas may be unlikely due to the higher cost of set up. However, it is worth noting that these costs assume an exact switch of run time and plant size in order to allow a direct comparison. In practise, it is likely that gas would run for longer hours which, if compared, would represent a different picture due to the higher running cost of diesel.

Table 8.9 Year on year cost of capacity fuel switch (£m, 2014 prices), discounted

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total NPV
CENTRAL																
£m	0	0.11	0.89	1.61	2.29	2.91	3.5	3.7	3.9	4.07	4.23	4.37	4.5	4.61	4.71	**45.4**

Table 8.10 Year on year cost of capacity fuel switch (£m, 2014 prices), discounted

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total PV
High Overall – Scenario 1																
£m	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Low Overall - Scenario 3																
£m	0	0.14	1.11	2.02	2.86	3.64	4.37	4.63	4.87	5.09	5.28	5.46	5.62	5.76	5.89	**56.7**

8.7 Revenue Impacts (non-monetised)

Plants in Tranche A would face a revenue loss if operators choose to reduce their operating hours. This impact is assessed purely for existing plants as these plants are already built and the measures would restrict their ability to operate as in the baseline, if they breach the measures set. The cost is also not included in the overall cost figures, as it is not a true cost to society because the cost is seen as a redistribution of income from one generator to another (See Section 10).

With generators entering contracts before December 2016, it is assumed that 50% of these generators will reduce their hours to 50 hours (to the identified safe running time from the Environment Agency modelling) in 2018 and face revenue loss from this point, while we have assumed that, (with the exception of plants under capacity market agreements before December 2016) the rest of the existing generators would reduce their operating hours to 50 hours in 2024, when stricter ELVs will need to be met. The 50% behaviour change in each year represents the urban/rural split as outlined in Section 7. This assumption was validated during consultation.

The cost of lost revenue is likely to be mitigated somewhat by the fuel savings from reducing running hours (cost of operating for 100 hours compared with the cost of operating for 50 hours), however it is still significant for these generators.

Plants in Tranche B would not be impacted as these generators are not yet built so do not face a revenue loss compared to the base case. As a result there would be no changes between scenarios as these scenarios affect the behaviour of investors choosing the fuel type of generators they intend to build.

8.8 Monetised benefits to the environment and human health

The main benefit of the implementation of the additional controls will arise from the reduction in air pollutant emissions. By reducing the number of plants operating without abatement and ensuring that these plants are monitored for their emission levels, this will improve air quality and have a positive impact on human health and the environment (including greenhouse gases).

Emissions reductions of air pollutants

Table 8.11 below highlights the total emission reductions of key pollutants as a result of the implementation of the controls specific to high NO_x polluting generators.

Table 8.11 Total emission reductions from generator controls (kt) 2018-2032

SO_2	NO_X	PM	CO_2
2.9	11.0	0.2	128.1

Table 8.12 demonstrates the full breakdown of these emission reductions by pollutant across the entire period, demonstrating the profile of reductions.

Table 8.12 Year-on-year breakdown of emissions reduction by pollutant (kt/yr)

Quantity abated (kt/yr)	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032
SO_2	0	0	0.1	0.1	0.1	0.2	0.2	0.2	0.2	0.3	0.3	0.3	0.3	0.3	0.4
NO_x	0	0.1	0.1	0.2	0.3	0.4	0.5	0.5	0.6	0.6	0.6	0.7	2.1	2.2	2.2
PM	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

The level of emission reduction has been sensitivity tested for each scenario as different generators have different base case emissions. Under Scenario 1, it is assumed that all projected diesel remains as diesel. As a result, the emission reductions are relatively low as diesel only reaches 190mg/Nm^3 when fitted with appropriate abatement.

Under Scenario 3, it is assumed that all projected diesel will switch to gas. New gas plants are assumed to have a lower basecase emission level in other pollutants so additional abatement of SO_x and PM would occur, therefore a higher number of gas plants in the future results in higher emission savings than the other scenarios compared to the base case.

Carbon emissions

Table 8.13 below highlights the total emission reductions of carbon as a result of the implementation of the additional measures. This amounts to a cumulative saving of128kt of CO_2 in the central scenario.

Table 8.13 Total CO_2 emissions reduction 2018-2032 in each scenario

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total
Central Scenario 2 (kt/yr)																
CO_2	0	2.4	3.7	5.1	6.4	7.8	9.1	9.8	10.4	11	11.6	12.2	12.2	12.8	13.5	128.1
Low Overall Scenario 3 (kt/yr)																
CO_2	0	2.4	4.1	5.7	7.3	9	10.6	11.4	12	12.6	13.2	14.5	14.6	15.4	16.1	149
High Overall Scenario 1 (kt/yr)																
CO_2	0	2.1	2.2	2.3	2.4	2.4	2.5	2.5	2.4	2.4	2.4	2.3	1.6	1.6	1.6	30.8

Similarly to the emission reductions of NO_x, SO_2 and PM, the variations of the projection of future generators have a substantial impact on the level of emissions saved.

Monetised Benefits - Air Quality

Table 8.14 below demonstrates the benefits generated as a result of the controls on high NO_x generators. The central case of Scenario 2 demonstrates that implementing these measures would generate £50.9m benefits, of which £21m is from fitting abatement and reducing hours, while £29.9m is from the fuel switch.

The sensitivity of the central scenario 2, high and low, present the uncertainty associated with valuing health benefits in the damage costs. Please note that in all three scenarios above, the level of emissions reduction does not change. The sensitivity captures the uncertainty surrounding the valuation of health benefits for a given level of emissions reduction.

More broadly, the previous section of this IA presents higher (or lower) emissions reductions depending on whether more (scenario 3) or less (scenario 1) diesel plant switch to gas. This sensitivity was also tested and presented a range closer to the central than the sensitivity presented below. Therefore, the sensitivity presented below is robust to other uncertainties in the air quality benefits.

Table 8.14 Year on year monetised benefits from measures on plants entering the energy balancing market (PV, £m, 2014 prices), discounted

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total NPV
Scenario 2 - Abatement Measures and Reduced Hours	0.00		0.14	0.20	0.26	0.32	0.37	0.42	0.44	0.47	0.49	0.51	5.86	5.76	5.66	20.9
Scenario 2 - Fuel (technology) switch.	0	0.1	0.5	0.9	1.4	1.8	2.1	2.3	2.5	2.7	2.8	3.0	3.1	3.3	3.4	29.9
Scenario 2 Total	0.0	0.1	0.7	1.1	1.6	2.1	2.5	2.7	2.9	3.1	3.3	3.5	9.0	9.0	9.1	50.9
Scenario 2 High Total	0.0	0.2	0.6	1.0	1.3	1.7	2.0	2.2	2.3	2.5	2.6	2.7	7.3	7.3	7.3	41.0
Scenario 2 Low Total	0.0	0.9	2.2	3.6	4.8	6.0	7.2	7.8	8.3	8.8	9.2	9.7	24.8	24.9	25.0	143.2

The total monetised benefits in the central scenario are valued at £50.9m (Scenario 2) (not including GHG benefits).

Monetised Benefits – Greenhouse gasses

Table 8.15 below demonstrates the benefits of reducing carbon emissions generated as a result of implementing the controls on generators. The central case of Scenario 2 demonstrates that implementing these measures would generate cumulative benefits of £6.8m.

Table 8.15 Carbon benefits 2018-2032 (discounted)

Year	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	Total NPV
								Scenario 2								
£m	0	0	0.1	0.2	0.2	0.3	0.4	0.4	0.4	0.5	0.5	0.5	0.5	0.6	0.7	5.3

8.9 Summary of results

Table 8.16 Present value of total costs and benefits over 15 year appraisal period (2018 – 2032), £m 2014 prices

£m, 2014		Sensitivity		Best estimate
Scenarios		**Low Scenario**	**High Scenario**	**Central Scenario**
Generators controls	PV Costs	110.9	91.3	107
	PV Benefits	44.4	153.6	57.7
	NPV	**-66.5**	**62.3**	**-49.03**

*Where 22.7m of benefits are from GHG and the remainder Air Quality.

Table 8.16 demonstrates the total costs and benefits for the impact of the controls on high NO_x generators. All three scenarios carry forward the number of plants estimated in section 7.1, and Approach 1 for compliance (inspection) checks.

Scenario 2 is the central scenario for costs and for high/low benefits (damage costs). The high overall scenario combines low cost (Scenario 1) with high benefit, and the low overall scenario combines high cost (Scenario 3) with low benefit. That is, the range presents the sensitivity around the assumptions on behaviour change of diesel to gas (Scenario 1-3) and the valuation of health benefits for a given reduction in emissions (Scenario 2).

Compliance Costs

The full costs to high NO_x generator operators in England and Wales is demonstrated in Table 8.17 below with a central estimate of £107m. The low cost scenario is Scenario 1 and the high cost Scenario 3.

Table 8.17 NPV of costs for the low, high and central scenarios of behaviour changes

2018-2032	Low cost (£m)	High cost (£m)	Central (£m)
Costs			
Abatement costs	43.2	80.3	50.6
Administration costs	0.2	0.3	0.3
Monitoring costs	10.7	10.7	10.7
Cost of fuel (technology) switch	56.7	0	45.4
Total	110.9	91.3	107

For the main analysis, it has been assumed that costs will be funded through internal finances as per the results in the previous section. However, in practice, some firms would have to fund some of the upfront CAPEX through external financing. Costs as a function of a firm's ability to finance is given consideration in the distributional impacts assessment in the following section.

Monetised Air Quality Benefits

The benefits of implementing the generators controls are demonstrated in Table 8.18. Table 8.18 demonstrates the range with varying damage costs which is very significant with a central estimate of £50.9m, with variations of the damage costs on the central scenario showing a range from £41m to £143.2m. The sensitivity to the proportion of plants switching fuel type was also tested and presented a range closer to the central than the sensitivity provided above. Therefore, the sensitivity provided above is robust to other uncertainties in the air quality benefits.

Table 8.18 PV for air quality impacts with varied damage cost scenarios 2018-2032 (£m, 2014 prices)

	LOW Benefits (£m)	HIGH Benefits (£m)	CENTRAL (£m)
Abatement measures and hours reduction	19.6	65.9	21
Benefit of technology switch	21.5	77.3	29.9
Total	**41**	**143.2**	**50.9**

Authority Disaggregation

The original analysis was produced for a UK perspective. However, this impact assessment presents plant for England and Wales, emissions reductions and consequent costs and benefits, and not those of the UK. The disaggregation from the UK results was based on 84% of plants being located in England, 7.5% in Scotland, 5.2% in Wales and 3.1% in Northern Ireland. It was assumed that plants are distributed equally regardless of capacity, technology and fuel type.

8.10 Options results summary

The previous section demonstrates that the NPV for Option 1 is (-£49.03m).

Option 1 is the preferred option for the following reasons:

a) It provides the greatest protection of public health and the environment, delivering air quality improvements valued at over £50.9m with additional benefits in reducing carbon emissions.

b) It enables the UK to comply with important air quality legislation by preventing breaches in the safe hourly NO_x levels laid out in the AAQD and curbing an increase in high polluting generators by encouraging their replacement with cleaner technologies thus contributing towards the NO_x, PM and SO_2 emissions ceilings, which will become more stringent from 2020.

9. Risks & assumptions

9.1 Key Sensitivities

Plant capacity, and therefore fuel consumption and associated total emissions, are based on mean plant capacity data from EU averages. The same average capacity is assumed for every plant within the same size category, regardless of fuel or technology type. This results in total emission reduction and associated benefits being highly influenced by this assumption.

Number of Plants

Prior to implementation of the MCPD and generator controls, operators of plants below 20MW have not been required to register the size or type of their plant, or their activities e.g. operating hours. The limited information on the number of plants below 20MW was a key sensitivity in estimating the impact of the implementation of the MCPD .

Relatively limited data was received from stakeholders so the majority of the analysis is based on data gathered and/or derived for the Commission study and estimations in number of plants and projections in activity data from the NAEI. This was supplemented by data provided by the National Grid regarding the number of below 1MW generators providing ancillary services to the grid.

The growth in number of standby plants has been estimated based upon the results of the capacity market auctions in 2014 and 2015, which may not be representative of the additional growth expected, as this only represents two years; the drop in bids from diesel generators on the 2016 capacity market auction, presumably at least partly in response to the proposed emission controls, means that its results cannot be used to forecast a growth in their number under the baseline. It is difficult to estimate future plant numbers, however the costs and benefits would be proportionate to one another.

Damage cost functions

When measuring the impact of emissions, an impact pathway approach is preferred in some circumstances. An impact pathway approach models the spatial distribution of changes in emission from a specific source. This approach is time consuming and costly. Given the uncertainty around the spatial distribution of plants and their operating patterns damage costs were more appropriate to use.

For this impact assessment, damage costs were used to calculate the indicative impact of emission changes. Damage costs are standardised average values of the impact to society of a given change in emissions. Damage cost values are published in the Green Book guidance, and are used as standard practice throughout government.

As health advice and expert medical recommendations from COMEAP are updated when new research emerges, the damage cost functions are revised to reflect this where appropriate. At the time of the consultation and writing of the final IA, the damage cost function used for NOx was £11,672. This has been revised down by 63% to £4,269 in line with the latest advice from the COMEAP.

A limitation is that damage costs are a UK average, and not specific to the geographical source of emissions change. For example, they don't adjust for the site specific population exposure to the pollution, where reductions in pollutants in a more densely populated region would generate greater benefits. Moreover, damage costs are an underestimate for two reasons. Firstly, they capture partial health impacts, such as those to mortality (cost of life years brought forward), but largely not to those on morbidity (short-term impacts). Secondly, they do not explicitly capture impacts to ecosystems and cultural heritage.

Switch in fuel

The degree to which operators choose to switch from diesel to gas engines in response to the proposals is the largest source of uncertainty for several reasons.

Firstly, gas and diesel plants are assumed to be interchangeable with regards to plant characteristics and revenue earnings. There is little data available on individual plants and therefore little is known of the precise revenue sources of each plant and the capacity available in each revenue stream in the energy balancing market. Therefore the assumption of access to revenue streams such as payments from supply to the capacity markets, STOR and TRIAD may not be a representative income rate for all plants, particularly as gas plants are more likely to enter markets where longer running times are required due to the lower fuel cost. However, there is little available data on this, so we cannot monetise the impacts which are likely to be significant to plants in Tranche A (although it is assumed they could continue to operate profitably at 50 hours).

Similarly, the average running time for each plant is assumed to be the same in order to complete a cost comparison of building gas over diesel generators. However, with the cheaper fuel, the running hours of gas are likely to be longer so the cost difference will not be truly representative.

The central scenario assumes that the majority of operators would choose gas generators to avoid the need for secondary abatement to comply with the NO_x ELV but assumes that some generators (20% of diesel generators) would apply abatement. We further have tested this assumption during consultation but no additional data was provided by stakeholders. With technological development, abatement that can easily and cost-effectively achieve emissions reductions to the required level may become widely available, and therefore diesel generators would be more likely to adopt abatement. If this becomes the case, then there is uncertainty as to whether there would be the predicted reduction in diesel.

9.2 Other sensitivities

Abatement measures

Generators are grouped into status categories based on Tranche A or B, capacity class, and fuel type. For each status category, the model is only able to choose one abatement measure; therefore, one abatement measure is selected and applied to all plants within each status category.

In practice, plants that fall within a status category will have different emissions reductions needed to meet an ELV, and therefore a different level of abatement effort, and associated cost than assumed. The impacts on emissions and compliance cost estimated are expected to be modest, as a result of averaging and aggregating. However, in some circumstances, as operators will choose abatement measures which are the most cost effective for their specific plants, costs could be an underestimate.

Table 9.1 provides an overview of some relevant assumptions and associated uncertainties. We have consulted on these uncertainties with stakeholders, and the results of these discussions are also presented in the table.

Table 9.1 Assumptions and associated uncertainties around impacts

Assumption	Associated uncertainty
Number of plants and respective emissions – current and projected to 2032	The number of plants is a key driver to the costs as the assumed number of plants correlates with the levels of emissions and therefore cost of abatement and emissions reductions. As result, should there be substantial variation from the assumed number of plants; the costs could be very different from what we have calculated in the assessment. Data collected during consultation from BEIS and the National Grid on the number of generators providing DSR services was used to supplement the initial estimates.
The change in number of diesel or gas plants in the future is entirely depending on operators reactions to the proposed measures. It has been assumed that operators of some diesel plants bidding into the capacity market from December 2016 will not see the measures as a viable investment, and therefore, the capacity would be filled by gas plant.	The proportion of diesel capacity that switches to gas depends on whether investors continue to see diesel as a viable option. We assume in the central scenario that only 20% of diesel plants will be fitted with the required technology to comply with the emission controls proposed. This assumption appears realistic considering the marked drop in successful bids from diesel generators on the 2016 Capacity Market auction. We have consulted on this assumption but no additional data was provided by stakeholders.

The number of plants entered into energy balancing contracts before 2016 that choose to reduce their hours is based on an assumption of where they are located.	It is assumed that some plants in contracts would rather reduce hours than take a permit with site-specific conditions which requires fitting abatement. At least some generators will have been subject to an air quality assessment through the planning process and will have planning conditions designed to comply with Ambient Air quality limits in the vicinity of the plant. In addition the Environment Agency modelling made conservative assumptions, so a larger number of plants are less likely to cause a breach of the NO_x hourly limit and impact a receptor. No additional information on this uncertainty was obtained during the consultation.

Current emission levels

Assumptions had to be made about current emissions for gas and diesel generators (determined by emission rates and operating hours) since data available is limited. An average emissions level of each category and type of plant is assumed as individual data on existing plants is not available. Therefore if the actual plants are cleaner or more polluting, the benefits would vary accordingly.

10. Distributional Effects

Small and micro-businesses can be affected disproportionately by the burden of regulation. New regulatory proposals are designed and implemented in a manner aiming to mitigate disproportionate burdens where appropriate. As such, the default assumption set in the Better Regulation Framework Manual (June 2013) is that there will be a legislative exemption for small and micro-businesses where a large part of the measure can be achieved without including small and micro-businesses within the scope of the policy proposal.

The Better Regulation Framework Manual defines micro and small businesses according to a staff headcount. Micro-businesses are those employing up to 10 FTE staff members while small businesses employ between 11 and 49 FTE staff. The Manual provides guidance on Small and Micro-business Assessment including a range of potential mitigation measures if the proposed policy option does have an impact on small and micro-businesses.

10.1 **Sectors affected**

Electric power generation sector

The sector which will be mainly affected by the controls on high NO_x generators is the electric power generation sector. Analysis of ONS business population estimates[27] suggests that around 97% of businesses in this sector are small and micro businesses but that these businesses employ only around 15% of all workers in the sector. If the number of workers employed is assumed to be proportional to the size of the business, we can estimate that large and medium businesses have a combined market share of around 85% in this sector. This is felt to be a sensible assumption given a lack of evidence.

It is unclear to what extent the businesses in the Capacity Market are representative of the electric power generation sector as a whole. However due to a lack of evidence on this, it has been assumed that the business population in the Capacity Market is broadly similar to the overall business population of the sector. The consultation did not provide additional information on this issue.

Other sectors

Other sectors where high NOx emitting back-up generators are common (e.g. industrial sites, hospitals, data centres) might be affected to some extent. This is only if they choose to provide grid services, probably through aggregators. Few are likely to do so because they would need to comply with the proposed controls in this circumstance. However, the impact on their income is expected to be very small, and it was therefore deemed disproportionate to assess it.

10.2 **Distribution of health impacts**

Benefits are derived from the reduction of emissions to air and associated avoided costs for reduction of damage to society. For this reason it isn't meaningful to distribute these benefits across sectors. The Interdepartmental Group on Costs and Benefits (IGCB) damage cost functions "*include estimates of the health impacts (both deaths and sickness) of all four pollutants. Supplementary Green Book guidance)* so those vulnerable to respiratory and heart disease (i.e. old, young, those with existing conditions, and people living in areas with higher ambient air pollutant concentrations (urban areas)) will be more adversely affected and therefore the damage avoided is higher from reducing emissions.

[27] ONS Business Population Estimates (2015), https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/467445/bpe_2015_detailed_tables.xls

11. Measurement of the Impact on Micro and Small Enterprises

Our evidence base around small and micro businesses in the energy balancing market is relatively weak compared to the evidence base for MCPs. However, if we assume that businesses in the market are broadly representative of the electric power generation sector as a whole, we can calculate some indicative impacts on small and micro businesses as a result of the proposed policy changes for high NO_x emitting generators.

In order to calculate these indicative impacts, the overall costs which are likely to vary with market share (abatement costs and the cost of switching fuel) have been multiplied by the total market share controlled by small and micro operators. Then, the costs which are more likely to vary with the number of businesses (administrative costs and monitoring costs) have been multiplied by the percentage of total businesses in the sector which are small and micro. These costs have then been added together to get a rough estimate for the total costs to small and micro businesses for the 15 year appraisal period of between £57m and £67m. This is far lower than the equivalent expected costs to medium and large businesses of between £162m and £237m. While these numbers are necessarily indicative estimates due to the lack of evidence, they do suggest that the great majority of the burden from this policy is likely to fall on medium and large businesses (see Table 11.1).

Table 11.1 Estimated costs to small and micro business from the policy changes for high NO_x generators (2018-2032)

	LOW (£m)	HIGH (£m)	CENTRAL (£m)
Costs which are assumed to vary by market share			
Abatement costs	43.2	80.3	50.6
Cost of fuel switch	56.7	0	45.4
Costs which are assumed to vary by number of businesses			
Administration costs	0.2	0.3	0.3
Monitoring costs	10.7	10.7	10.7
Total costs to small and micro businesses	57.0	64.6	66.7
Total costs to medium and large businesses	162.1	236.8	218.2

Consideration has been given to excluding small and micro businesses from the scope of the policy; however doing so would reduce the benefits of the policy (perhaps by around 15%, based on the market share) and the indicative analysis at this stage suggests that this policy will not place a disproportionate burden on these businesses. Additionally, as a significant share of these high NO_x generators are used in small and micro businesses, excluding them from the scope of the regulation would create a loophole which would affect our capacity to deter an increase in the use of such generators.

Guidance and communications will be developed for plant operators which will be expected to reduce and further minimise any impacts for micro and small businesses.

11.1 Financial and Affordability

While the assessment considers the average annual costs per enterprise, compliance costs would involve upfront capital costs that need to be financed either through own or borrowed resources. If firms seek to spread the upfront capital costs over a number of years, they will have an additional cost of capital financing. This cost is not included in the average annual cost.

11.2 Direct Costs and Benefits to Business Calculations (following One-In-Three-Out methodology)

Following the Equivalent Annual Net Cost to Business (EANCB) requirements, costs and benefits calculated here use a 2014 price base year and a 2015 PV base year. Consistent with the Environmental Permitting Regime, and other cost recovery schemes, we envisage charging operators appropriate fees to recover regulator costs, thus avoiding additional burdens on public finances (please see Section 7.4 for details). As such, the costs to business include all abatement, administration, compliance (inspection) and monitoring costs associated with the generator controls.

The EANCB as a result of the high NO_x emitting generator measures is -£8.1m, which includes the benefit of fuel savings to firms switching from diesel to gas. This part of the policy is considered out of scope of 'One-in, Three-out'.

The additional measures for generators are intended both to address an issue which will affect our ability to meet NO_x emissions ceilings, particularly the 2020 ceilings contained within the amendment to the Gothenburg protocol and to help us to comply with the NO_x limits set out in the EU Air Quality Directive.

By consulting on this policy before the next Capacity Market auction in December 2016 we sent a signal of our future intentions to businesses aimed at encouraging them to invest in alternatives to the high NO_x emitting generators which are currently incentivised by the Capacity Market mechanism. This allowed businesses maximum flexibility compared to if we delayed because the costs of retrofitting high NO_x generators can be greater than the additional costs of purchasing a lower NO_x generator at the outset. In the consultation we asked if sites under 1MW should be subject to similar emission controls, which was strongly supported, and we are implementing controls for those plants applying a timescale that will similarly provide flexibility for industry and encourage use of lower emission technologies.

The impacts of the 2008 EU Ambient Air Quality Directive were initially estimated when it was first transposed[28]. However the incentives created by the Capacity Market were not foreseen at the time because the Capacity Market had not been created. Therefore all of the impacts calculated in this policy will be additional to the impacts calculated in the original analysis for this Directive.

We do not intend for these additional measures to be implemented until after the ratification of the Gothenburg protocol and therefore they will not constitute gold plating of the NO_x emissions ceiling. Developing and bringing into force the controls now rather than delaying, such as until the revised ceilings are transposed, gives operators fair warning of what is intended without bringing forward requirements on them. This will enable new operators to choose the least cost path to future compliance – which could mean continuing with a diesel generator and fitting abatement equipment in the future or opting for an alternative fuel.

Since the controls are necessary to comply with both the NO_x emission ceiling in the Gothenburg Protocol which is implemented by the National Emissions Ceiling Directive (for all generators) and the Ambient Air Quality Directive (for generators with a capacity greater than 5MW), all impacts from this policy are therefore out of scope of One-In, Three-out as a result of being necessary to comply with EU requirements.

All costs and benefits have been assessed at 2015 prices and uplifted to 2018 PV base year. However the EANCB figure is calculated at 2014 (real) prices and 2015 Present Value base year. Methodology is consistent with the Green Book and supplementary guidance.

[28] Defra (2007) 'An Economic Analysis to inform the Air Quality Strategy: Updated Third Report of the Interdepartmental Group on Costs and Benefits'
https://www.gov.uk/government/uploads/system/uploads/attachment_data/file/221088/pb12637-icgb.pdf

12. Competition assessment

The competition assessment guidelines[29] set out four questions to establish whether a proposed policy is likely to have an effect on competition. In particular, the assessment needs to establish whether the requirement to comply with the emission limit values for the generators with a thermal input of 0-50MW would affect the market by:

- Directly limiting the number or range of suppliers?
- Indirectly limiting the number or range of suppliers?
- Limiting the ability of suppliers to compete?
- Reducing suppliers' incentives to compete vigorously?

A brief summary of the four questions and a response considering the requirement is presented in Table 12.1.

Table 12.1 Competition Assessment Filter Questions

Do the proposed requirement to carry out a CBA	Response	**Comment**
Q1. …directly limit the number or range of suppliers?	No	The proposed requirement to comply with the proposed ELVs does not seek to directly limit the number of suppliers
Q2. …indirectly limit the range of suppliers?	No	The proposed requirement to comply with the proposed ELVs is not likely to limit the range of suppliers. In particular, the proposed requirement does not prevent entry or exit from the electricity generation market. Furthermore, anticipated compliance and administrative costs are driven by the size of the HNG (0-5 MW, 5-20 MW and 20-50MW) and apply the same requirements across different ownership models. As detailed in this assessment, several options are available to operators subject to the regulation: reduce operating hours, shift to cleaner fuels (e.g. gas), or fit abatement. The reduction in operating hours is unlikely to limit the range of engine suppliers and engine operators (electricity suppliers). This may actually lead to an increase in the range of suppliers as, for the same electricity demand to be met, more engines running for fewer hours may be required. Similarly, the shift to gas engines is unlikely to have a significant impact on the range of suppliers. Many engine suppliers produce both gas and diesel engines. For small manufacturers focused on one type of engine, the regulation might reduce demand for diesel manufacturers and increase demand for gas manufacturers. However this impact is likely to be minimal as manufacturers also supply other markets (e.g. NRMM, other countries…). In terms of suppliers of abatement technologies aiming to reduce pollutant emissions, these are manufactured by a range of companies ranging from the engineering or chemical companies to the energy specialist. For example, the large engineering equipment manufacturers Siemens (DE), Hitatchi (DE), Alstom (FR), ABB (CH), Andritz (AT), Fluor (UK), Perkins (UK), all provide engines and abatement techniques for NO_x. Some manufacturers are more specialised. For instance, Howden (UK) is a leading provider of rotary regenerative heat exchangers used for SCR. Johnson Matthey (UK) is a leader in providing chemical catalysts. Whilst a majority of the engines and abatement technology manufacturers are large companies, a significant number of SMEs are involved in the installations or the fitting of these technologies. Moreover, some more specific (specialist) technologies, particularly relevant for combustion engines, may be developed by smaller manufacturers. Overall, there is no one dominant supplier or dominant approach across the generators affected by the proposed regulation. Furthermore, the requirement to comply with the proposed ELV does not specify application of any particular abatement technology leaving the choice to the operators.
Q3. …limit the ability of suppliers to compete?	No	The proposed regulation would bring smaller scale combustion processes in line with regulation for combustion plants greater than 50 MW, thereby reducing any (potential) perverse effect on these generators at the threshold above and below 50 MW.
Q4. …reduce suppliers' incentives to compete rigorously?	No	The proposed requirement does not seek to limit the incentives for suppliers to compete. In particular, application of the rules across the board would impose similar constraints on all operators.

Overall, the requirement to comply with the ELVs for standby generators is unlikely to have adverse impacts on competition. Additional compliance and administrative costs that companies across different sectors would be facing may result in significant burden affecting profitability and commercial viability of these enterprises. However,

[29] OFT http://www.oft.gov.uk/shared_oft/reports/comp_policy/Quick-Guide1-4.pdf

application of the new requirements for high NO_x generators would impose similar constraints on all operators across the board.

13. Social impact assessments

In general terms, when an operator is faced with additional compliance and administrative costs, a range of potential responses exist ranging from absorbing the additional cost through reduction of profit margins up to fully passing these on within the prices of products and services. The companies could also aim to reduce their cost base, for instance, by cutting labour and/or other production costs.

13.1 Distributional impact on households

Households are not expected to run generators that are the subject of this impact assessment. Any household impact would be indirect, most likely through energy prices.

In the central scenario (Scenario 2) and Scenario 3, we forecast an increase in gas used to fill future capacity as it would be able to meet ELVs without requiring additional abatement. However, the increase in gas may potentially impact the cost of electricity, through a change in the cost of the energy balancing services. This cost is currently included on consumer energy bills and represents around 1% of the electricity bill. Currently diesel is primarily used in the energy balancing market as it responds to demand quickly and cheaply. Therefore a switch to gas has the potential to increase consumer energy prices because gas is a more expensive option to respond to energy balancing requirements due to the setup of gas services. This will be offset in part by the lower fuel costs from running a gas plant but there is the potential for energy prices to marginally increase to the consumer, which National Grid have estimated to be around 0.02%.

An increase in energy prices is most likely to affect households as energy costs make up a large portion of a household's income. An ongoing concern in energy policy is that increases in energy prices may be regressive in nature (i.e. impact more on lower income households) as lower income groups spend a larger proportion of their disposable income on energy compared to higher income groups. An ONS study estimated that the poorest fifth of households spent 11% of their income but the richest fifth spend 3%.

However, as the cost of energy balancing services is a small proportion of the overall electricity cost, this increase in electricity prices is likely to have a very marginal impact.

13.2 Employment and Labour Markets

Overall, implementation of the regulation may have positive secondary impacts on the level of employment in abatement technology suppliers and emissions monitoring companies, while potentially having adverse primary impacts in sectors that will incur additional compliance and administrative costs. Secondary impacts (costs and benefits) have not been explicitly monetised in this assessment but primary costs have.

Implementation of regulations requiring fitting of abatement technology will lead to costs for the firms affected whilst also representing income for firms that manufacture and install these technologies. When considering supply of abatement technologies, the UK and EU as a whole has a well-established abatement technology supply chain as the majority of the technologies currently being applied by large combustion plants are also relevant for these smaller plants.

It is unclear how these two effects will reach a balance but it might be a reasonable assumption that the effect will in aggregate be fairly neutral.

14. Conclusions

Poor air quality is the largest environmental risk to public health in the UK, exacerbating the impact of pre-existing health conditions, especially for the elderly and children. Long term exposure reduces life-expectancy, mainly due to increased risk of mortality from cardiovascular and respiratory causes and from lung cancer. COMEAP research indicates that short-term exposure to NO_2 is linked to some direct effects on morbidity while long term effects suggest impacts on respiratory and cardiovascular mortality, children's respiratory symptoms and lung function. Air pollution also damages biodiversity and reduces crop yields[30].

Medium combustion plants (MCPs) in the 1-50MW range are a significant, largely unregulated source of emissions of NO_x, PM and SO_2, which impact on air quality. An important tool for controlling emissions from this source, the MCPD, came into force in December 2015 and must be transposed within 2 years. The legislation was fully supported by UK during negotiations as it represents a cost effective way of controlling emissions and offers a number of important exemptions and flexibilities necessary to keep burdens on business low and any impacts on energy security to a minimum. Furthermore as air pollution is transboundary, effective MCPD implementation across Europe will further improve UK air quality. The impact of implementing the MCPD in the UK is assessed in a separate impact assessment.

However, schemes intended to increase capacity and provide balancing services in the electricity market are incentivising greater use of particularly polluting generators, which are in the main a subset of MCPs. These generators are primarily diesel engines and emit very high NO_x emissions relative to other forms of generators, which can lead to breaches in hourly NO_2 air quality limits set in the AAQD, designed to protect human health. These high NO_x generators are relatively cheap to run for short periods and therefore it is currently financially attractive to use them for providing services to the grid, including installation of large arrays of these plants which a particular concern for local air quality. Unfortunately the MCPD scope and implementation timescale do not provide sufficient controls for these high NO_x generators, or serve to deter an increase in use. Therefore further measures are required to prevent breaches of air quality legislation and impacts on human health and environment. Taking action early will reduce burdens on businesses by proactively preventing the proliferation of high NO_x generators which would subsequently have to be retrofitted at a high cost to businesses. It also gives existing operators more time to prepare as waiting until the NO_x ceiling has been transposed in 2018 gives a very limited time to consider measures in time to meet the 2020 requirements.

The present impact assessment has assessed the introduction of emission controls for high NO_x emitting generators, required to enable compliance with air quality limits and to curb avoidable increases in national NO_x emissions due to current energy market incentives.

The results of the analysis are presented in Table 14.1 below:

Table 14.1 Central NPV of each impact for Option 1 (2018-2032)

2018-2032	Option 1, Central Scenario (£m, PV)
Costs (cost to operators)	
Abatement costs	50.6
Administration costs	0.3
Monitoring costs	10.7
Operational/capital cost of technology switch	45.4
Total	107.0
Benefits (emissions reductions)	
Air Quality	50.9
CO_2	6.8
Total	57.7
NPV	-£49.03

*Please note any differences due to rounding.

30 COMEAP (2010) The Mortality Effects of Long-Term Exposure to Particulate Air Pollution in the United Kingdom. Committee on the Medical Effects of Air Pollutants. Available from: https://www.gov.uk/government/publications/comeap-mortality-effects-of-long-term-exposure-to-particulate-air-pollution-in-the-uk

The implementation of the generator controls is the favoured option for two key reasons:

a) It provides the greatest protection of public health, delivering air quality improvements valued at over £50.9m with additional benefits in reducing carbon emissions and a significant number of benefits which have not been monetised.

b) It enables the UK to comply with important air quality legislation by preventing breaches in the safe hourly NO_x levels laid out in the AAQD and curbing an increase in high polluting generators by encouraging their replacement with cleaner technologies, thereby helping the UK to comply with its obligations under the Gothenburg protocol and National Emissions Ceilings Directive.

The impacts assessed within the document are based on the best available knowledge of the current high NO_x generators active within the UK along with the assumed behaviour of these plants when faced with these restrictions. However, it is recognised that there are uncertainties around the modelling and the implementation and delivery of our preferred option. We will monitor the effectiveness of the controls primarily through the Environment Agency's implementation plan.

15. Annex

A. Development of proposals for controlling emissions from high NO_x generators

The Environment Agency modelling identified that generators with high NO_x emissions posed a risk to local air quality by causing high local concentrations of NO_2 which exceed legally binding limits set for the protection of human health.

The modelling used conservative assumptions about emissions levels and high-risk configurations of generators and was used to identify size, time and emission limits beneath which breaches of the EU Ambient Air Quality Directive (where concentrations of NO_2 exceed 200 micrograms per cubic metre more than 18 times per year) would be unlikely (occur less than 1 in 20 years). The modelling indicated that a breach was unlikely for;

- large generators (just under 50MW) with emissions less than 190mg/Nm^3,
- large generators (just under 50MW) of diesel plant with very high emissions (>3000mg/Nm^3) that operate for 50 hours
- small generators (5MW or less)

unless they were located within 150m of a sensitive receptor (place where people are likely to be exposed).

When the modelling was complete several options for controlling emissions were assessed. Due to the lack of data about plants <50MW, particularly those with a shorter run time, this was a qualitative assessment. BEIS and National Grid were involved in the policy development process and asked to review the likely impacts of possible control options for generators on energy security and balancing services. During the consultation we presented the qualitative assessment of options (included in the consultation IA) which explained the rationale for the proposals, and stakeholders were engaged to understand the impacts for providers of balancing services, based on technology limitations, costs and timescale required for investment, as well as concerns about local air quality and unfair competition from unregulated generators.

After consideration of the consultation responses (see Annex E), the proposed controls were amended as follows:

6) For plants which require secondary abatement to comply with the 190mg/Nm^3 NO_x ELV, the time for meeting the ELV was increased to 20 minutes for Tranche A generators and 10 minutes for Tranche B generators. This was based on feedback that the 5 minutes originally proposed would not be achievable in many circumstances, and informed by an analysis of the impact on total emissions which benefited from data submissions on running time of the generators affected.
7) For tranche A generators which require a permit from 1 January 2019, the deadline for compliance with permit conditions was moved to 1 October 2019. This will provide operators more time to make decisions on how to meet permit conditions and plan any investment needed, but still apply controls from the beginning of the supply agreements awarded in the 2015 Capacity Market auction.
8) Tranche A generators will be subject to the standard permit conditions only when their power supply agreements come to an end, unless they enter a new power supply agreement after 31st October 2017 which remains in force after December 2018. This will allow operators to meet their contractual obligations while protecting local air quality, as sites of concern will be subject to bespoke permits from 2019.
9) To address concerns from stakeholders, including BEIS and OFGEM, emission controls were extended to sites under 1MW which provide balancing services to the grid, to ensure a level playing field; the timescale for application of such controls was adjusted to ensure investors and operators who entered power supply agreements before the controls are announced will benefit from transitional arrangements.

B. Abatement measures and costs methodology

The impact assessment model is based on an abatement matrix which details abatement measures for each pollutant (NO_x, SO_2 and PM), technology type (boiler, engine and turbine), fuel and capacity class, alongside its abatement efficiency and costs. After entering the set of ELVs, the model compares these against baseline emission levels (projected into the relevant year) and calculates the necessary emission reduction needed to achieve the ELVs. Given the reduction needed, the model selects the most cost effective measures and calculates total emission reduction and costs. These figures are based on the data from the abatement matrix, multiplied by the number of plants applying those measures. The process is done separately for new and existing plants. It is done separately because an adjustment factor has been applied to the costs of the abatement measures to reflect the lower cost of installing abatement as part of installation of a new plant when compared to the higher cost of retrofitting a measure to an existing plant.

Compliance costs for potential abatement measures are based on the abatement matrices developed by Amec Foster Wheeler for the Commission in recent studies. A number of literature sources were reviewed in order to compile information on possible abatement measures for generators and associated pollution abatement efficiencies and costs. The following sources were reviewed:

- JRC (2007) Small combustion installations: Techniques, emissions and measures for emission reduction. Joint Research Centre;
- AEA (2007) Assessment of the benefits and costs of the potential application of the IPPC Directive (EC/96/61) to industrial combustion installations with 20-50 MW rated thermal input. Final Report to the European Commission;
- (Summary of) Best Available Techniques in Small 5-50 MW Combustion Plants in Finland;
- EGTEI (2010) Options for limit values for emissions of dust from small combustion installations < 50 MW;
- VITO (2011) Beste Beschikbare Technieken (BBT) voor nieuwe, kleine en middelgrote stookinstallaties, stationaire motoren en gasturbines gestookt met fossiele brandstoffen;
- ECN (2008) Onderbouwing actualisatie BEES B: Kosten en effecten van de voorgenomen wijziging van het besluit emissie-eisen stookinstallaties B;
- Amec Foster Wheeler's multi pollutant abatement measures database.

The majority of the costs are taken from VITO (2011), with some additional costs taken from AEA (2007) and Amec Foster Wheeler (2013). Figures are inflated to 2014 prices in all cases[31]. The literature sources include a range of costs for measures, which represent the uncertainty around the cost estimates for the abatement measures and variation in installation specific variables, and so a low and high range of costs are used in this analysis. A list of abatement measures is provided on Annex Figure 1. For some abatement measures, the low and high costs are the same, which is assumed to reflect a single underlying cost data source; whilst for other abatement measures (SCR and SNCR in particular) there is a significant difference between the low and high costs.

<u>Identify the abatement measures</u>
Abatement measures and their associated emission reduction efficiencies are based on the abatement matrices developed by Amec Foster Wheeler for the Commission in recent studies (Amec Foster Wheeler, 2014).

Annex Figure 2 lists a consolidated version of the abatement measures considered in the generators controls Impact Assessment as well as their abatement efficiency and the technologies and fuels affected. Where a range is shown for abatement efficiency this indicates different efficiencies are expected when the measure is applied to different size-fuel-technology type categories. Abatement efficiencies presented are an indication of the emission reduction that the measure can achieve on average and are therefore suitable for modelling the impact across groups of plant; the reduction realised in individual plant could be slightly higher or lower depending on site specific features.

[31] Capital (CAPEX) and operational (OPEX) costs have been identified in the reference sources to allow for flexibility in annualising the data; default values of a 3.5% discount rate and an annualisation period of 15 years have been used in the central case. Costs have been presented in 2014 prices using the GDP deflators available from HMT (ONS June 2015).

Annex Figure 1 List of measures considered in the generators IA and their associated abatement efficiency

	Technologies that can fit this measure	Fuels affected	NO_X abatement efficiency	SO_2 abatement efficiency	PM_{10} abatement efficiency
Low NO_X burner / Advanced lean burn	Engines and turbines	Natural gas, Other gaseous fuels	40% - 50%	-	-
SCR (Selective catalytic reduction)	All technologies	All fuels	70% - 90%	-	-
Hours reduction (from 100hpa to 50hpa)	All technologies	All fuels	50%	50%	50%

Annex Figure 2 List of measures considered in the generators IA and their associated uptake frequency

Pollutant	Measure	Number fitted in 2030	
		New	**Existing**
NO_x	Lean burn / low NO_x burners	12	24
	SCR	2,749	1,007

Please note the number of fitted is not the number of plants. Some plants need to fit multiple abatement technology to meet ELVs for multiple pollutants. Some plants required to meet emissions limits are already compliant under BAU and therefore do not need to fit abatement technology.

Expanded versions of the above abatement matrix are used within the model to automatically identify which abatement measure would be required to achieve compliance with the scenario ELVs. Given that to date the majority of plants have not been regulated, there has been no driver to optimise emissions performance. A threshold has been set at 10% emission reduction. Below 10%, it is assumed modifications to existing equipment and operating practice can be implemented to achieve the necessary reduction with minimal additional cost[32]. If an emission reduction of greater than 10% is required, then the lowest cost measure that can achieve the required reduction is selected.

An adjustment factor has been applied to the costs of the abatement measures to reflect the lower cost of installing abatement as part of installation of a new plant, compared to the higher cost of retrofitting a measure to an existing plant. For primary measures, this premium is assumed to be 60%, consistent with Amec Foster Wheeler's recent modelling for the Commission's impact assessment. For secondary measures, the premium is 40%. This is 60%/40% adjustment is for CAPEX only. The CAPEX/OPEX distinction matters for some measures such as pure fuel switch, where there is no CAPEX in some applications.

[32] An assumption consistent with the Commission study

C. Behavioural response assumptions

For engines and turbines generating electricity, there could be two alternatives to fitting abatement:

1. Stop auto-generating electricity and switch to buying from the grid. This will result in higher cost per unit of electricity and may also require an upgrade to the supply contract and/or physical connection, also at additional cost.

2. To purchase or hire portable gensets, which do not fall under the MCPD but instead have emission limits under NRMM standards. Given the low number of expected cases of such a switch, a comparison of the costs and benefits of the MCPD against the NRMM standards has not been performed.

In specific circumstances, where one of the outlined alternative options is lower in cost than fitting abatement, the option may be taken and therefore the behavioural response for some operators may be different than the one assumed to be representative of the vast majority of operators. Due to the relative small scale and uncertainty it was not considered further.

D. Consultation responses

Annex Table 6 Summary of consultation responses and actions taken

Question	Summary of responses	Action taken
Do you agree with the proposed definition of "generators"? If not please explain your reasons and propose an alternative definition.	*Most agreed but felt that NRMM/mobile generators should be included in the definition to avoid making a loophole.*	*Proceed with proposed definition, which makes clear mobile generators cease to be mobile if connected to permanent infrastructure.*
Do you agree with the emissions limits proposed and that where secondary abatement is applied it must abate emissions to the required Emission Limit Value within five minutes?	*Majority agreed with the 190mg/Nm^3 emission limit. Strong concern that majority of plant would be unable to meet the five minute limit.*	*Proceed with 190 mg/Nm^3 emission limit; increase deadline for compliance to 20 minutes for Tranche A and 10 minutes for Tranche B.*
Do you agree with the proposed timescales for implementation, which reflect those specified in the Medium Combustion Plant Directive?	*Some felt that the timescales were overly stringent others not strict enough given the current threat of poor air quality. It was asked that the timescales were joined for those having to comply with both MCPD and generator controls.*	*Delaying compliance with permit conditions for Tranche A generators which require a permit from January 2019 to October 2019.*
Do you agree that generators with Capacity Market Agreements from 2014/ 2015 auctions that are not already operating should be regulated in the same way as generators that are already operating?	*There was support to the proposed approach due to concern over financial risk and uncertainty if generators with Capacity Market Agreements at the time of publication of the consultation did not have transitional arrangements.*	*Proceed as proposed that generators not yet in operation but which entered power supply agreements under the 2014 and 2015 Capacity Market Auction will be included in Tranche A.*
Do you believe that generators with an aggregated rated thermal input <1MW (at a single site) should be required to comply with low emission limits?	*The majority believed generators with an aggregated rated thermal input <1MW (at a single site) should be required to comply with the same emission limits. However they wanted them included in the IA.*	*Extend controls to sites under 1MW providing balancing services to the grid.*
Is there a case for allowing back-up generators to be tested at peak times of demand?	*The majority agreed there was a case for allowing testing at peak times, as preventing would result in loss of capacity, which would have to be made up from other sources leading to an increase in emissions.*	*Proceed as proposed that plants should be allowed to test at peak times.*
Do you agree with the proposed approach to controlling particulate emissions from generators?	*Consultees asked that 'visible persistent emissions' be carefully defined in guidance, and how Defra will measure whether the problem persists or not.*	*Amend to "persistent dark smoke emissions" to enable regulator to address a visible problem and remove ambiguity but not set emission limits for PM.*
Do you agree with the proposed exemptions from emission controls?	*It was agreed nuclear sites be exempted from the proposals. There were calls for the exemption for backup generators to be clearly defined.*	*Proceed as proposed.*
Do you agree that permitted generators should be required to monitor their emissions every three years only if they have adopted abatement?	*A number asked that all generators should be required to monitor regardless of whether they require secondary abatement.*	*Proceed as proposed - permitted generators that rely on secondary abatement to achieve emissions limits will require emissions monitoring at least once every three years. Regulator will have power to direct operator to test to demonstrate compliance if required.*
Do you foresee any challenges to using the Environmental Permitting Regulations for implementing the MCPD and controls on generators?	*The majority felt it was right to use the Environmental permitting regulations but where concerned about increasing the complexity of the regulations. There were also concerns the fees and charges are insufficient to enable cost recovery and would need to be so if Local Authorities were the regulator.*	*Proceed as proposed by using the Environmental Permitting Regulations.*
We will ensure duplicating and conflicting controls are removed whilst ensuring that the current level of environmental protection is maintained. ***Do you agree with this approach?*** ***If not please explain.***	*Most agreed it would reduce burden on industry as long as it was clear what the replacing provision is, what it removes and why.*	*Proceed as proposed: no changes needed for Sulphur Content of Liquid Fuels Directive; retain Clean Air Act provisions on emission of stack heights. Include a control on emissions of dark smoke.*
Which of the following approaches do you consider to be the best option for choice of the regulator:	*It was a close split between the Environment agency and a combination of the Environment Agency and Local authorities. It*	*Option B - EA regulates all plants in England and NRW regulates all plants in Wales. Part B plant permits to be transferred to EA.*

A) Plants where regulator must determine the permit conditions to safeguard local air quality and those in Part A1 installations are regulated by EA in England and NRW in Wales, and other plants are regulated by LAs ***B) EA regulates all plants in England and NRW regulates all plants in Wales*** ***C) LAs regulate all plants***	*was asked that whoever was the regulator they provide further clarity.*	
Are there any situations where you consider the identity of regulator needs to be further clarified?	*Some asked for further clarity on mobile plants. Another issue was the overlap with waste permits.*	*Need to consider situation of waste sites in guidance.*
Do you agree with the assumptions made/ evidence provided in the policy analysis and associated impact assessment e.g. number of plants, operating hours, emissions? ***If not, please provide details.***	*Some noted that some areas where omitted from the impact assessment such as mobile generators.*	*Amend the IA to reflect changes of proposals described in this table.*

E. Glossary

Terminology	Definition
Abatement technology	*In this report* refers to techniques and technologies used to reduce pollutant emissions. Primary abatement prevents formation of pollutants and includes a switch to fuels which result in lower emissions, retrofitting of existing plant (e.g. by changing the burners) and selection of new plant with lower emission. Secondary abatement refers to technology which removes pollutants from the exhaust gases, such as filters for dust or selective catalytic reduction to destroy NO_x.
Amec Foster Wheeler	Amec Foster Wheeler Foster Wheeler plc is a British multinational consultancy, engineering and project management company headquartered in London, United Kingdom that provided analysis for this impact assessment
AQ	Air quality
AQMAs	Air Quality Management Areas
Back-up plant	Plant installed to provide emergency electricity generation in times of interruption to supply of mains grid electricity, operating rarely and normally much less than 500 hours per year (assumed to be less than 50 hours).
BEIS	Department of Business, Energy and Industrial strategy
CA	Competent Authority
Capacity Market	The Capacity Market is the key policy tool to bring forward sufficient reliable electricity capacity to ensure we maintain a secure supply of electricity.
CAPEX	Capital Expenditure
CO	Carbon Monoxide
CO_2	Carbon Dioxide
Combustion plant	Any technical apparatus in which fuels are oxidised in order to use the heat thus generated
Cyclone	A type of filtration system fitted to abate pollution impacts of Biomass, Other solid fuels, Liquid fuels.
DEFRA	Department for Environment Food and Rural Affairs
DRGD	Dry Flue gas Desulphurisation
EA	Environment Agency
EANCB	Equivalent Annual Net Cost to Business
EGR	Exhaust Gas Recirculation
ELVs	Emission Limit Values; means the permissible quantity of a substance contained in the waste gases from a combustion plant which may be discharged into the air during a given period

EMEP CORINAIR	Emission Inventory Guidebook
Energy Market	Energy market is the trade and supply of energy
EPR	Environmental Permitting Regulations
ESI	Electricity Supply Industry
ESP	Electrostatic Precipitators
ETS	Emissions Trading Systems
FGD	Flue gas Desulphurisation
Filters	Form of abatement where different materials are fitted to plants to filter out particulate pollution
FTE	Full time Equivalent
GB	Great Britain
GHGs	Greenhouse gases
Government	Defra and Welsh Government
GOS	Gross Operating Surplus
IED	Industrial Emissions Directive
IGCB	Interdepartmental group on costs and benefits
Installation (as defined in EPR)	(a) a stationary technical unit where one or more activities are carried on, and (b) any other location on the same site where any other directly associated activities are carried on,
Kt	Kilo tonne
KW	Kilowatt
LA	Local Authority
LCP	Large Combustion Plant
Lean burn/low NO_x burners	A form of abatement using larger quantities of air in the fuel mix for internal combustion engines.
MCERTS	Monitoring Certification Scheme
MCP	Medium Combustion Plant
MCPD	Medium Combustion Plant Directive
Member states	Members of the European Union
mg/Nm^3	Milligrams per normalised meter cubed

MS	Member State
MW	Megawatt - a unit of power equal to one million watts Unless otherwise stated the use of MW in this report refers to MW thermal
MWth	Thermal rated input in MW – the maximum fuel energy rate of the combustion plant.
MWe	Megawatts electric - electric output of a power plant in megawatt. The relationship between thermal input and electrical output of a generator depends on its efficiency – an engine that is 33% efficient would have a thermal input 3 times greater than its electrical output.
NAEI	National Atmospheric Emissions Inventory
NO_2	Nitrogen Dioxide
NO_x	Nitrogen Oxide
NPV	Net present value
ONS	Office of National Statistics
OPEX	Operating expense
PJ	Peta joules
PM	Particulate Matter
PM_{10}	Particulate Matter 10 micrometres or less in diameter
$PM_{2.5}$	Fine particulate matter (2.5 micrometres or less in diameter)
PV	Present Value
Rpm	Revolutions per minute
SBS	Structural business statistics
SCR	Selective catalytic reduction
SME	Small and medium sized enterprises
SNCR	Selective non-catalytic reduction
SO_2	Sulphur Dioxide
Solid Fuels	Refers to fuel made of solid substance, typically coal or wood
SO_X	Oxides of Sulphur
Stand-by plant	Plant installed alongside working plant to provide for additional demand at peak times or in case of shut down of the main working plant, and operating fewer than 500 hours per year.
STOR	Short Term Operating Reserve

t	Tonnes
T-1	Capacity Market auctions held one year ahead of delivery offering 1-year agreements (only) to top-up/fine tune the capacity requirement as needed for the coming delivery year.
T-4	T-4' Capacity Market auctions seek to procure capacity four years in advance of the required delivery window, and award 'capacity agreements' to those successful
TRIAD	The Triads are defined as the three half-hours of highest demand on the Great British electricity transmission network between November and February each year. The triad charging system is a tool used by National Grid to smooth demand for electricity at peak times and is used to recover the costs of building and maintaining the electricity transmission network. The cost of electricity for large industrial and commercial users of electricity whose consumption is half hourly metered is determined by their demand during the Triads. Large users of energy therefore have an incentive to reduce their demand during the Triads by running their generators to avoid drawing power from the transmission network during Triads (this is known as Triad avoidance). Generators connected at the distribution level are paid to produce power during the Triad peaks. Some generator operators are contracted by large energy users (or third parties on their behalf) to run during periods when triads are likely. Triads are declared by National Grid retrospectively so generators are run whenever the operator believes a triad is likely to occur.
UKIAM	UK integrated assessment model (UKIAM) he UK integrated assessment model (UKIAM), has been developed using Defra funding by Imperial College London to investigate cost effective strategies for reducing UK emissions which maximise improvements in environmental protection in the UK while complying with future UK emission ceilings imposed to reduce transboundary air pollution in Europe. UKIAM brings together information on projected UK emissions of SO_2, NO_2, NO_x, NH_3, CO_2, N_2O, CH_4, PM_{10} and $PM_{2.5}$ to calculate the simultaneous effect of abatement measures on a combination of pollutants, and comparison of future scenarios. This includes calculating the effects with respect to changes in greenhouse gas emissions as well as human exposure to air pollution, urban air quality, and the natural ecosystems.
Working plant	Operating on average more than 500 hours per year which are subject to compliance with emission limits.