Title: Gas Safety (Management) Regulations 1996 impact assessment **IA No:** HSE-IA2022-001 **RPC Reference No:** **RPC-HSE-5134(2)** **Lead department or agency:** Health and Safety Executive (HSE) **Other departments or agencies:** Department for Business, Energy and Industrial Strategy (BEIS), North Sea Transition Authority (NSTA)	**Impact Assessment (IA)** **Date:** February 2023 **Stage:** Final stage **Source of intervention:** Domestic **Type of measure:** Secondary Legislation **Contact for enquiries:** Stuart.Burgoine@hse.gov.uk

Summary: Intervention and Options

RPC Opinion: Green fit for purpose

Cost of Preferred (or more likely) Option 2 (in 2019 prices & 2020 present value)			
Total Net Present Social Value	**Business Net Present Value**	**Net cost to business per year**	**Business Impact Target Status**
£43.5m	£43.1m	£0.7m	Qualifying Regulatory Provision BIT Score: Nil (de minimis)

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

Over the past 15 to 20 years, gas supplies from the UK Continental Shelf (UKCS) have been declining which has increased reliance on imported supplies, via pipelines, interconnectors and Liquefied Natural Gas (LNG) shipments in order to provide enough gas to meet demand in Great Britain (GB). The security of our gas supply has remained resilient but the current regime, in which gas quality standards are specified in the Gas Safety (Management) Regulations 1996 (GSMR), constrain the supply of gas from alternative sources and result in gas processing costs for some parts of the industry. Research and industry practices have evolved since GSMR was introduced requiring the Regulations to be updated, and the need to remove ambiguity regarding who the duty holders are in relation to health and safety in parts of the gas industry. As such, the Health and Safety Executive (HSE) and the Department for Business, Energy and Industrial Strategy (BEIS) have worked closely with the Institution of Gas Engineers and Managers (IGEM) to develop safe options for revising GSMR to modernise the Regulations and consider options to reduce costs and broaden the range of viable gas sources to support GB security of supply.

What are the policy objectives of the action or intervention and the intended effects?

HSE intends to adopt industry proposals of changing the method of determining gas interchangeability, to raise the limit of oxygen content permitted in the distribution network, and to make amendments to extend the Safety Case regime to all biomethane pipelines, extend the co-operation duties to LNG import terminals and to make changes to the gas emergency call handling service. The objectives of these amendments are:

- To maintain or improve the safety standards that have been achieved to date by the Gas Safety (Management) Regulations 1996 (GSMR)
- To ensure clarity and consistency in how pipeline operators and Liquified Natural Gas import terminals are regulated by GSMR
- To ensure that industry changes are reflected within the gas emergency call handling service and that it remains accessible to the public

HSE has also evaluated options around the possible inclusion of gas with a higher or lower Wobbe Number (WN) into the transmission and distribution networks in order to achieve the policy objective by widening viable gas resources from the UK Continental Shelf (UKCS) and therefore support security of supply. The proposal to increase the higher WN limit was not taken forward to consultation; nor was another proposal to transfer the governance of the gas quality specification into an industry standard, the reasons for which were set out in the consultation-stage impact assessment.

The policy objectives of the proposal for a lower WN limit, are:

- To adapt the prescriptive GB regulation for gas composition contained in GSMR Schedule 3 that is restricting sources of gas sitting outside of current specifications being conveyed in the transmission and distribution network
- To enable or make viable greater volumes of gas resources to be accessed from indigenous sources, contributing to greater security of GB's energy supply
- To reduce gas processing or blending, potentially enabling additional gas supplies as a consequence of reducing associated processing or blending requirements

HSE was content that the proposal to reduce the lower WN limit would maintain existing standards of health, safety and wellbeing and this proposal was taken to consultation. HSE's subsequent analysis suggests that this change does support the intended objectives set out above as volumes of additional gas would be made available by the change; and the change would also reduce some gas blending activity that is currently undertaken to bring some sources of gas within GSMR specification once it has been extracted. However, the additional volumes are low and the proposal leads to the potential for disruption to electricity generation, as a result of power generators and other stakeholders not being prepared to receive different gas specification. As a consequence, the overall impact of this change leads to greater energy independence, rather than greater security of supply. Nonetheless, this is a very helpful step in responding to current pressures on gas supply and creating more flexibility and resilience within our gas supply mix and will form one part of achieving the policy objective.

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

As this area of policy is already subject to regulation, the options for change are underpinned by legislation. The conveyance of gas is a major hazard. As such the approach towards policymaking adopts a precautionary principle, one in which the response is proportionate to the high level of risk. This inherently favours regulation and so legislative change is the preferred vehicle for achieving the policy objective. That said, there are elements of self-regulation within the regulatory framework, namely the Safety Case regime for dutyholders, which have influenced the policymaking. An example being the legislative change proposed to the continuously manned telephone service yet placing the duty to provide and run the service on industry, therefore providing a degree of autonomy for the industry to deliver this objective. It may be argued that the principles of co-regulation have been applied in formulating these proposals too, with an industry-convened Gas Quality Working Group being responsible for devising and presenting amendments listed in the first two bullet points of the changes to be taken forward. Economic incentives were also considered.

- **Option 1: Business as usual:** Progress none of the proposed changes to modernise GSMR and keep the Wobbe Number range as it currently is set out in the Regulations.
- **Option 2 (preferred option):** To make all of the proposed amendments that were taken to consultation after being assessed as safe, including reducing the lower Wobbe Number from ≥47.2 MJ/m³ to ≥46.5 MJ/m³.
- **Option 3 :** Progress the majority of the amendments that were taken forward to consultation after being assessed as safe, except the change to amend the lower Wobbe Number.

The changes HSE propose to take forward are:

- reducing the lower Wobbe Number from ≥47.2 MJ/m³ to ≥46.5 MJ/m³
- extend the current GSMR class exemption for oxygen in biomethane to a general ≤1 mol% oxygen limit at pressures at or below 38 barg for all gas sources
- remove the Incomplete Combustion Factor (ICF) and Soot Index (SI) limits and to introduce a relative density of ≤0.7 for gas interchangeability
- clarity that biomethane pipelines are to be considered to be part of the gas network
- clarity that co-operation duties apply to operators of liquefied natural gas (LNG) import facilities
- for a general duty on the industry to provide a continuously manned telephone service for gas escapes and emergencies

Option 2 is the preferred option due to the following reasons:

The six amendments that have been consulted upon, and that HSE plan to progress, contribute towards maintaining and improving the safety standards that have been achieved to date; they improve the extent of the regulations by ensuring that all pipelines conveying gas in a network have a safety case accepted by the HSE; provide greater clarity to duty holders about their gas conveyance and co-operation responsibilities and provide the opportunity to modernise the regulations and correct historical references by ensuring the continuation of the vital gas emergency call handling service and enabling a change in the regulations to ensure that there is continuity in service and continuity in service standards. The amendment concerning the lower WN also enables additional domestic gas production, allowing alternative sources of gas to be injected into our gas network and made available for consumption. This is currently a key government objective.

Gas supply emergencies present health and safety risks and have their own economic costs and so the additional quantities of gas that could be made available by changing the lower WN can minimise the risk of a gas supply emergency.

Option 2 can also help to maximise the economic potential of the UK Continental Shelf and support local economies with ties to the domestic gas production industry.

Option 3 delivers the policy objectives of modernising the regulations but does nothing to address the problems around gas supply and does not change the current prescription of gas quality within the regulations.

Changes to the conditions under which emergency Wobbe Number limits may be authorised have also been considered as a means of responding to the policy objectives. This would potentially have involved using the emergency limits under different or a greater number of scenarios or legislating for their use over longer periods thereby enabling a broader range of gas sources than currently permitted. However, the UK is not experiencing a gas emergency (and never has in the past), and the emergency limits are intended to manage risk for finite periods, not as a long-term, enduring security of supply measure. Current evidence also suggests this option would increase the risks associated with the hazard of gas conveyance and would therefore reduce health and safety standards. Were the emergency limits deployed over a longer period of time, or in greater circumstances, the safety concern of increased carbon monoxide (CO) production from gas fittings would be introduced.

Other options considered have been economic incentives to make gas sources more viable however this option has numerous challenges, expanded in the Evidence Base section.

Will the policy be reviewed? It will be reviewed. **If applicable, set review date: 5 years**

Does implementation go beyond minimum EU requirements?		N/A			
Is this measure likely to impact on international trade and investment?		Yes			
Are any of these organisations in scope?	**Micro** Yes	**Small** Yes		**Medium** Yes	**Large** Yes
What is the CO_2 equivalent change in greenhouse gas emissions? (Million tonnes CO_2 equivalent)		**Traded:**	**Non-traded:**		

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 Chief Economist E. Waely Date: 03/03/2023

Summary: Analysis & Evidence

Policy Option 1

Description: Business-as-usual baseline

FULL ECONOMIC ASSESSMENT

Price Base Year	**PV Base Year**	**Time Period Years** N/A	**Net Benefit (Present Value (PV)) (£m)**		
			Low: N/A	**High:** N/A	**Best Estimate:** N/A

COSTS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Cost** (Present Value)
Low	N/A		N/A	**N/A**
High	N/A		N/A	**N/A**
Best Estimate	N/A		N/A	**N/A**

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

Being the business-as-usual baseline, there are no additional costs or benefits.

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

Being the business-as-usual baseline, there are no additional costs or benefits. GB gas supplies from low-WN sources would also continue to be restricted. In addition, GSMR would remain unmodernised with respect to industry changes since 1996 so that safety standards continue to be applied inconsistently across areas where risk is present.

BENEFITS (£m)	**Total Transition** (Constant Price)	Years	**Average Annual** (excl. Transition) (Constant Price)	**Total Benefit** (Present Value)
Low	N/A		N/A	**N/A**
High	N/A		N/A	**N/A**
Best Estimate	N/A		N/A	**N/A**

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

Being the business-as-usual baseline, there are no additional costs or benefits.

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

Being the business-as-usual baseline, there are no additional costs or benefits.

Key assumptions/sensitivities/risks	**Discount rate (%)**	

BUSINESS ASSESSMENT (Option 1)

Direct impact on business (Equivalent Annual) £m:			**Score for Business Impact Target (qualifying provisions only) £m: N/A**
Costs: N/A	**Benefits: N/A**	**Net:** N/A	

Summary: Analysis & Evidence

Policy Option 2

Description: Retain GB's safe gas quality specification within GSMR Schedule 3 and amend the Wobbe Number values to those proposed by IGEM (IGEM/GL/10) and those assessed to be safe and consulted upon by HSE.

FULL ECONOMIC ASSESSMENT

Price Base Year: 2022	PV Base Year: 2023	Time Period Years: 10	Net Benefit (Present Value (PV)) (£m)		
			Low: -£43.5m	High: £163.8m	Best Estimate: £52.3m

COSTS (£m)	Total Transition (Present value, Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	£43.2m	5	£0.09m	**£44.0m**
High	£314.2m		£2.8m	**£337.9m**
Best Estimate	**£155.8m**		**£0.9m**	**£163.2m**

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

The greatest costs fall to power generators to modify and maintain equipment, between around £35m and £280m. Industrial gas users incur costs of between around £0.6m and £24m to modify equipment. Appliance manufacturers and domestic and commercial gas users share costs between nil and around £7.7m from increased engineer call-outs. Gas producers incur costs of between £3.5m and £9.5m for modifications and safety cases. Gas distributors incur costs between around £0.8m and £1.3m for adaptations. Familiarisation costs between £4.6 and £14m.

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

Adaptation and maintenance of electricity-producing turbines could involve longer turbine outages. While these are not expected to affect the continuity of electricity supply, they could lead to higher electricity gas prices for short periods.

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	Nil	5	£0.05m	**£0.5**
High	Nil		£55.4m	**£501.7**
Best Estimate	**Nil**		**£24.6m**	**£215.5**

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

Benefits are chiefly driven by additional gas production. If Network Entry Agreements (NEAs), which are bilateral commercial agreements between the national transmission system operator and gas supply terminals, cannot be agreed, no additional production will be enabled – this is our assumption in the 'low' case. This is a wort case scenario, but represents the uncertainty present in the international nature of the NEAs via the interconnectors. The value of possible additional gas production is estimated at between nil and around £500m. Averted gas processing is estimated to save around £0.5m. Possible emissions savings from indigenous gas production displacing imports is estimated at between nil and around £1.5m. Averted CO poisonings are estimated at between nil and around £1.0m.

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

Biomethane producers creating safety cases will ensure that the risks of their pipelines are managed in line with the standards intended by GSMR. Removal of the incomplete combustion factor and sooting index will simplify the calculations for gas interchangeability.Clarity that LNG import facilities have legal co-operation duties will provide legal assurance to their liaison with gas conveyors and the network emergency coordinator when necessary. Providing a general duty for an industry-operated emergency telephone service for gas escapes will ensure a service in perpetuity (as the regulations currently refer to British Gas, which is defunct).

Key assumptions/ sensitivities/ risks	Discount rate (%)	3.5% (1.5% for health impacts)

It is uncertain that the additional gas production would come about and that it would be enabled by the changes to GSMR in particular. Implementation procedures undertaken by the industry may also prevent additional gas at the lower end of the Wobbe Index from being injected into networks. Power generator turbine disruptions may lead to costs that cannot be monetised in this analysis – it is not clear their effect on the final NPV. Power generators adaptations are estimated to take five years – it is assumed that this can be accommodated by the available resource to modify turbines and that turbines could cope with low-Wobbe gas produced before the five years are complete. Some ongoing costs and benefits are estimated to be reduced by falls in gas demand to reach Net Zero.

BUSINESS ASSESSMENT (Option 2)

Direct impact on business (Equivalent Annual) £m:			Score for Business Impact Target (qualifying provisions only): Nil (de minimis)
Costs: £0.8m	Benefits: Nil	Net: £0.8m	

Summary: Analysis & Evidence — Policy Option 3

Description: Make several amendments to modernise GSMR without changing Wobbe Number requirements.

FULL ECONOMIC ASSESSMENT

Price Base Year 2022	PV Base Year 2023	Time Period Years 10	Net Benefit (Present Value (PV)) (£m)		
			Low: -£8.0m	High: -£3.1m	Best Estimate: -£5.6m

COSTS (£m)	Total Transition (Present value, Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Cost (Present Value)
Low	£2.8m	2	£0.1m	**£3.6m**
High	£2.8m		£0.7m	**£8.5m**
Best Estimate	**£2.8m**		**£0.4m**	**£6.0m**

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

The main costs would fall to biomethane producers for the production and periodic review of safety cases for their pipelines, which is estimated at a present value over 10 years of between around £3.5 million and £8.3 million. Gas distributors would incur one-off costs for adapting their monitoring and alarm systems for gas relative density of around £0.15 million.

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

BENEFITS (£m)	Total Transition (Constant Price)	Years	Average Annual (excl. Transition) (Constant Price)	Total Benefit (Present Value)
Low	Nil	2	£0.05m	**£0.5m**
High	Nil		£0.05m	**£0.5m**
Best Estimate	**Nil**		**£0.05m**	**£0.5m**

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

The savings accrue to gas producers no longer needing to nitrogen ballast gas in order to meet the requirements of the sooting index and incomplete combustion factor. This is estimated at a present value over 10 years of around £0.5 million.

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

Biomethane producers creating safety cases will ensure that the risks of their pipelines are managed in line with the standards intended by GSMR. Removal of the incomplete combustions factor and sooting index will modernise GSMR's scientific references. Clarity that LNG import facilities have legal co-operation duties will provide legal assurance to their liaison with gas conveyors and the network emergency coordinator when necessary. Providing a general duty for an industry-operated emergency telephone services for gas escapes will ensure a service in perpetutiy (as the regualtions currently refer to British Gas, which is defunct).

Key assumptions/ sensitivities/ risks	3.5%

By not widening the Wobbe range (under Option 2), GB could see a reduction in its ability and flexibility in responding to gas supply pressures.

BUSINESS ASSESSMENT (Option 3)

Direct impact on business (Equivalent Annual) £m:			Score for Business Impact Target (qualifying provisions only): Nil (de minimis)
Costs: £0.7m	Benefits: Nil	Net: £0.7m	

Evidence Base

A. Problem under consideration and rationale for intervention

1. Twenty-five years has passed since the Gas Safety (Management) Regulation 1996 (GSMR) came into force. In that time Great Britain's (GB) gas market has been liberalised, new producers have entered the market, the supply mix for GB gas demand has shifted from domestic production to imports and there is new emphasis on making our energy consumption greener. This has meant the gas network, as defined by the 1996 regulations, no longer encapsulates the current breadth of gas conveyance occurring in GB and the regulations need to be updated and modernised in order to ensure safety standards are consistently applied across the network. Dutyholders also need to be clarified in order to achieve this policy objective so amendments to the regulations are necessary.

2. The safe gas composition specification set out in Schedule 3 of GSMR originates from the early days of UK Continental Shelf (UKCS) production and the current limits reflect the composition of the majority of gas produced at that time. Gas networks and appliances were designed for the safe transportation and use of that gas. The Regulations apply to the conveyance of natural gas (methane) through pipes to domestic and other consumers and define the gas transmission and distribution network. A key part of the specification is the Wobbe Number (WN) or Wobbe Index (WI), an indicator of the interchangeability of fuel gases such as natural gas. Gases are said to be interchangeable when they may be substituted for one another without affecting the operation of gas burning appliances and equipment; and reflect the degree to which they give similar heat input to the appliance, ignite reliably, have a stable flame, and completely combust.

3. The safe gas composition specification aims to correct the potential negative externality of upstream gas producers and suppliers inserting gas into the network that could adversely affect the safe operation of downstream gas equipment; and the asymmetry of information and resources that mean upstream producers and suppliers are more aware of gas specification and capable of adjusting it than downstream users.

4. The transmission and distribution of gas is a major hazard regime which can result in loss of life, loss of property and inflict severe economic damage when things go wrong. It is therefore imperative that changes to the regulatory framework do not diminish the existing standards of safety.

5. Today, UKCS supplies meet around 50% of gas demand in GB. Additional volumes of gas in the UKCS are outside the gas quality specification set out in Schedule 3 of GSMR, which means this gas must be processed to comply with the safe gas composition specifications, or not recovered at all. The regulations are a constraining factor in obtaining further volume and further development of gas from the UKCS. Gas processing is an expensive activity and not only constrains indigenous production but also acts as a barrier to the importation of liquified natural gas (LNG). Solutions to reduce gas processing activity could help to broaden the range of viable gas sources and deliver other positive benefits too.

6. The future network will need to reflect current safe gas composition and the changing needs and sources of gas supply to the UK market. UKCS reserves exist to supply a significant proportion of GB demand for many decades to come.[1] Gas composition varies between reservoirs and the relatively narrow band of acceptable Wobbe range in the GB specification adversely impacts the ability to maximise economic extraction of these reserves.[2] Current global gas market forces are manifesting themselves in increases in gas price. Policy solutions to enhance security of supply are required.

7. The government has committed to net zero carbon emissions by 2050 and so the problems with the prescriptive nature of the gas quality specifications need to be seen in the context of the wider objective to reduce our reliance on fossil fuels. The gas network has a role to play in achieving this goal and will need to adopt strategies and changes to decarbonise as well as society needing to reduce our demand for gas. Current government policy in this area is focused on nuclear and renewable energy, heat pumps, hydrogen for heating and hydrogen blending in the gas network and a policy decision on blending is expected in 2023. As the current legal limit for hydrogen in the gas network is ≤0.1% (molar), changes to the gas quality specifications set out in Schedule 3 may be required in future.

8. Understanding and evidence of gas quality impacts have been advanced through this consultation. The evidence clearly shows that changes to gas quality have impacts across the whole life cycle of gas usage, some of which are severe, disruptive and expensive.

[1] The North Sea Transition Authority (formerly the Oil and Gas Authority) estimates around 20 years, although this estimate was made before the government's Net Zero commitment: [Oil and Gas Authority: Reserves and resources - Data downloads and publications - Data centre (ogauthority.co.uk)]

[2] IGEM/TSP/19/363 - Neptune Lower WI interim report

9. As such, there has been very careful consideration of introducing such impacts now, and the effect that these impacts could have on the direction and cost of future policy decisions. These have been weighted against security of supply considerations and improving health and safety outcomes.

10. This impact assessment (IA) aims to provide a robust analysis of the options, their benefits and the potential costs and broader impacts to the gas network and gas-users to inform policy and decision-making.

B. Policy objective

11. The policy objectives of the recommended changes are:

- To maintain or improve the safety standards that have been achieved to date by the Gas Safety (Management) Regulations 1996 (GSMR)
- To ensure clarity and consistency in how pipeline operators and LNG import terminals are regulated by GSMR
- To ensure that industry changes are reflected within the gas emergency call-handling service and that it remains accessible to the public
- To adapt the prescriptive GB regulation for gas composition contained in GSMR Schedule 3 that is restricting sources of gas sitting outside of current specifications being conveyed in the transmission and distribution network
- To enable or make viable greater volumes of gas resources to be accessed from indigenous sources, contributing to greater security of GB's energy supply
- To reduce gas processing or blending, potentially enabling additional gas supplies as a consequence of reducing associated processing or blending requirements

C. Description of options considered

12. HSE has been working closely with the Institute of Gas Engineers and Managers (IGEM), the Department for Energy and Industrial Strategy (BEIS), Office of Gas and Electricity Markets (Ofgem), the North Sea Transition Authority (NSTA), Energy Networks Association (ENA) and the wider gas industry to ensure that the latest gas processes and composition evidence is brought together and reviewed to assess whether potential investment barriers could be removed and whether wider access to gas supplies could be obtained.

C.1. Option 1 – business as usual

13. Retain GB's safe gas composition specification as set out within GSMR, Schedule 3, with industry seeking exemptions under Regulation 11 where necessary. Exemptions are timebound and can only be granted if there is evidence that 'the health and safety of persons who are likely to be affected by the exemption will not be prejudiced'.

14. This is the baseline against which the other options will be assessed. While Option 1 includes the potential for HSE to issue exemptions from the regulations, it is not proposed to model these exemptions in the baseline of this analysis, which would serve to lessen the costs and benefits assessed. HSE could under Option 1 issue a class exemption to practically achieve the changes to incomplete combustion factor (ICF) and sooting index (SI) as recommended in Option 3. A class exemption would not require dutyholders to apply for individual exemptions to HSE, and therefore the exemption process itself would not create any costs for dutyholders. Such a baseline would render the additional costs and benefits of regulatory change related to gas quality change under Option 2 nil. This would not be a useful baseline against which to assess the impacts of regulatory change. Therefore, this IA will assume a business-as-usual baseline without the issuing of a class exemption. This baseline assumption was reviewed by the Regulatory Policy Committee as part of their opinion on the consultation stage of this IA.

C.2. Option 2

15. This is the preferred option and progresses all proposals assessed as safe by HSE and those which have been consulted upon:

- decrease the lower WN limit from ≥47.2 MJ/m³ to ≥46.5 MJ/m³ (the existing lower emergency limit). Evidence suggests Network Entry Agreements would likely curtail the lower limit to ≥46.2 MJ/m³. This amendment changes the permitted gas quality specifications for transmission and distribution in GB, allowing a greater variety of gas composition to be used. It intends to broaden the range of viable gas sources that can be distributed
- extend the current GSMR class exemptions for oxygen in biomethane to a general ≤1 mol% oxygen limit at pressures at or below 38 barg for all gas sources. This amendment formalises the current class exemption that has been in place since 2013 which allows for a higher oxygen content within the gas composition as long as it is operated at pressures below 38 barg. This exemption has served to enable the use of biomethane in distribution networks which has the benefit of being greener than natural gas usage
- remove the Incomplete Combustion Factor (ICF) and Soot Index (SI) limits and to introduce a relative density of ≤0.7 for gas interchangeability. This amendment will update from previous research and testing conducted on appliances that were widely available in the 1970s and no longer reflect modern appliance behaviour. Introducing the relative density as the secondary parameter with WI and limiting it to ≤0.7 provides a simpler mechanism to account for the effects of burning hydrocarbons on CO production and sooting and would make GB consistent with European Committee for Standardization (CEN) standards and methods adopted in other jurisdictions such as the USA
- clarify that biomethane pipelines are to be considered to be part of the gas network. This amendment seeks to ensure that the safety case regime and other duties which GSMR places on conveyers of gas is being applied to biomethane pipelines, some of which have interpreted the regulations as not applying due to regulation 2(4) which states that pipelines conveying out-of-specification gas to a treatment or blending point are not part of the network and so not subject to the duties placed on those conveying gas in a network. HSE believes this is a necessary and proportionate measure to ensure that pipelines conveying gas are being controlled consistently and appropriately
- clarity that co-operation duties apply to operators of LNG import facilities. Whilst this is happening in practice already, a legal interpretation provided by the Government Legal Division (GLD) has suggested that LNG import facilities may not be covered adequately and so this amendment will ensure the co-operation duties are clearly applicable. As LNG import facilities are critical to GB's energy supply, it is important to ensure they liaise with gas conveyors and the network emergency co-ordinator when necessary
- provide a general duty on the industry to provide a continuously manned telephone service. As the current regulations place this duty specifically on British Gas PLC (which is no longer an operating entity), they require updating so that there continues to be a service that operates in perpetuity by industry to receive referrals of gas escapes and activate first call operatives to respond to an incident and make the situation safe.

C.3. Option 3

16. This option progresses the majority of the proposals taken forward to consultation to modernise the Regulations but does not include amending the lower Wobbe Number value.

C.4. Options considered but not taken forwards

17. The primary strategic objectives of the policy proposals discussed in this IA are safety, updating the Regulations to reflect modern practices and consideration of improving energy security of supply. The Gas Quality Working Group had previously developed evidence to inform proposals to revoke GSMR Schedule 3, transfer the specifications to an IGEM Gas Quality Standard (IGEM/GL/10) and amend the gas quality specification values to those proposed and consulted upon by IGEM (IGEM/GL/10) through its earlier work:

- decrease lower WN limit from ≥47.2 MJ/m³ to ≥46.5 MJ/m³ (the existing lower emergency limit)
- increase upper WN limit from ≤51.41 MJ/m³ to ≤52.85 MJ/m³ (the existing upper emergency limit)
- include a new WN upper emergency limit of ≤53.25 MJ/m³
- extend the current GSMR class exemptions for oxygen in biomethane to a general 1 mol%
- oxygen limit at ≤38 barg for all gas sources
- remove the ICF and SI limits and to introduce a relative density of ≤0.7 for gas interchangeability

18. This option has not been taken forward due to outstanding concerns about safety associated with a higher WN limit and therefore the corresponding safety reduction of an IGEM Gas Quality Standard that did increase the upper WN limit.

19. Whilst the Opening up the Gas Market (OGM) report[3] provided a good foundation for a review of GSMR, evidence submissions from the Gas Quality Working Group (GQWG)[4] have further developed understanding of the risks involved with the evidence showing an increased risk of CO poisoning should the upper WN limit be increased.

20. Mitigation of this risk is discussed within the evidence submission on CO poisoning risk. The most beneficial mitigation is argued to be increased prevalence of appliance servicing and inspection. This would mirror the mitigations used in Oban and the three other Scottish Independent Undertakings (SIUs) for their usage of higher WN gas. Aside from this, the industry evidence submission recommends that field adjustment is prevented in order to manage the risk; and the submission discusses various means to do this.

21. Increased servicing and inspection are inherently problematic to replicate for the entire gas network and upscale to the greater GB population. Regulations do not impose requirements for domestic end-users of gas to service gas appliances and mandating this practice would be entirely cost-prohibitive, potentially leading to fuel poverty for some consumers. Presently, there is no mechanism for ensuring appliances are regularly serviced. Inspection of appliances is costly and practically very challenging – requiring significant levels of skilled resource, infrastructure and end-user compliance. Prevention of field adjustment is somewhat easier to accomplish but HSE would require further demonstration of the effectiveness of such a mitigation and wider discussion with delivery partners before making legislative changes.

22. HSE undertook some research and analysis on the potential impacts of pursuing this option in 2021 and early 2022. This analysis showed that pursuing changes at both ends of the WN range has the potential for high adaptation costs for some downstream gas users, including domestic, commercial, industrial and power generators. These are driven by the need to replace, maintain or service some equipment to ready it for a wider gas quality range. Initial estimates compiled in consideration of this option were subject to a high degree of uncertainty due to lack of definite information on the current state and condition of gas appliances and equipment and pointed to possible present value adaptation costs in the high hundreds of £millions and possibly £billions over a 21-year appraisal period, driven chiefly by the effect of higher WN gas on equipment. Domestic and commercial gas users are not anticipated to incur adaptation costs under Option 3, where the WN range is not changed.

23. In terms of benefits and savings, reduced nitrogen-ballasting of gas supplies associated with a higher WN was estimated to generate significant savings. Initial industry estimates indicated that this could be as high as around £325 million per annum. Closer inspection of this figure indicated that it included assumptions about the future expansion of nitrogen ballasting at terminals, which was far from certain. The anticipated savings from current (and most likely to continue) nitrogen ballasting came to around £90 million per annum, although it should be noted that this would be expected to decline with falling forecast gas demand in UK to reach Net Zero. Evidence also suggests savings would accrue to a small number of upstream gas companies, who would face little incentive to pass savings on to consumers.

24. The GQWG submitted a proposal to transfer the governance of the gas quality specification into an IGEM Gas Quality Standard. This was intended to create an efficient means of changing GB gas quality in order to transition to a low carbon gas network, removing the legislative process and moving to a more goal-setting regulatory framework. The proposed governance process does not currently include a workable mechanism for HSE to guarantee that safety standards are not reduced. There are also concerns on the ability of government to introduce changes or influence the timing of changes under this system, presenting a risk of not being able to deliver government objectives such as hydrogen blending and decarbonising energy.

25. With ambitious timescales to meet government commitments on hydrogen blending, and decarbonising the energy system, which involve large-scale impacts and adaptations for the energy sector, HSE assess that retention of the gas composition specification is the best method at this time to deliver these government policies, with its consultation and impact assessment model, collective responsibility and Parliamentary scrutiny principles, statutory reviews and independence from the sector. Such projects will also require some degree of resourcing and financing, which the government is well placed to meet.

26. Another option considered but not taken forwards was to make regulatory changes to the emergency WN limits described in Regulation 8, Schedule 2 and Schedule 3 Part II of GSMR. The main intention of this option was to enable a greater variety and volume of gas to be conveyed in the network for longer periods and under less

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[3] SGN-Oban-Gas-Market-Report-Executive-Summary-2016.pdf

[4] IGEM-TSP-21-396 DLC189_D – Impact of widening WI range on CO poisoning risk

restrictive circumstances. This option did not satisfy the policy objective of maintaining or improving safety standards and would not generate the large volumes of gas as investment confidence for new field development would be less likely. The additional variety and volume of gas would still be subject to curtailment, as well as the uncertainty, lead in times and costs to parts of the industry associated with Option 2. This option would be coordinated by the network emergency co-ordinator, who would have the authority to permit out-of-specification gas to be conveyed in the network for a period specified in their authorisation, and who would be required to demonstrate they have adequate arrangements in place to decide when and for how long out-of-specification gas may be used, and detail the procedures they have established to safely restore gas supply to consumers once the emergency is over. Any additional volumes that could have been realised through such an approach would therefore not be seen under normal conditions.

27. Financial incentives were also considered. Such incentives could subsidise alternative sources of gas from the UKCS and gas producers operating there, meaning they could develop new gas fields and still make it economically viable to process this gas for it to meet the gas quality specification. Such an option, though, would not address the production curtailment that is currently encountered by producers as a result of blend gas availability[5] and so would not generate quantities required to significantly support security of supply objectives.

28. Additional financial incentives for biomethane production could also deliver the policy intent although the capacity for additional biomethane production is limited. Ideally, any financial incentives for biomethane production would need to be accompanied by billing reform due to The Gas (Calculation of Thermal Energy) Regulations 1996, and that would require legislative change. Billing reform would complement financial incentives well as it could mean less gas processing for biomethane producers. Alternative sources of gas could be obtained through financial incentives for LNG import facilities as this could counteract the cost of processing alternative sources of LNG. This, however, would not meet the policy objectives of greater diversity of supply from indigenous sources or reduced gas processing and would require legislative changes outside of HSE’s policy remit.

29. HSE recognise that hydrogen is likely to play a significant role in the decarbonisation of the gas network. However, at this stage, until the evidence of hydrogen usage as an energy component is finalised, we are not proposing to include changes to current hydrogen limits in the safe gas composition specification.

D. Research and consultation to inform this impact assessment

30. HSE has undertaken a considerable amount of research and consultation to inform the development of policy options and assess the potential impacts. In addition, HSE has fed into and drawn from an extensive industry consultation, led by IGEM whilst conducting its own public consultation. Much of this evidence-gathering explored impacts of raising the top and lowering the bottom of the WN range in GSMR, although the public consultation and interviews during and after consultation focused on lowering the bottom of the WN only. The main evidence-gathering activities are summarised below in chronological order:

- IGEM consultation/ meetings: IGEM is the professional engineering institution for the gas industry. The Institution writes and publishes technical standards by working with stakeholders and experts to inform and influence current and future gas and energy policy. The Gas Quality Working Group (with 23 members) was formed in 2016 to propose a standard covering the GB gas quality specification and carried out an extensive evidence-gathering exercise over three years and undertook a consultation on the proposed standard.

- Interviews with stakeholder groups: HSE held semi-structured, qualitative interviews with 13 trade associations, professional bodies and businesses representing the groups expected to be affected by the proposals. Interviewees were asked about the likely main impacts on their area of expertise and the rest of the market; whether evidence gathered through earlier consultation omitted any important impacts; and an indication of the potential magnitude of impacts. This information was used to inform further evidence gathering and specify the quantitative survey below.

- Stakeholder survey: HSE developed a comprehensive survey in January 2021 aimed at eliciting quantitative and qualitative business-level data about the impacts of the proposed change on all potentially affected constituents, from gas suppliers to end users. The survey asked respondents about the effects of simultaneously lowering the bottom and raising the top of the Wobbe range, which is understood to have greater impact in most cases than only lowering the bottom (the proposal in Option 2). This is because an absolute wider range allows for greater fluctuation in gas quality supplied, which can have a greater effect on the performance and safety margins of gas-fuelled equipment. As such, some estimates from the survey have not been taken forward into the analysis of Option 2 in this IA. Those that have were judged by the HSE expert review groups (see bullet below) as being suitable estimates have been included in this IA, but

[5] One method of processing low-WN gas to meet the GSMR specification is to blend it with higher-WN gas. However, this requires a steady and reliable supply of the higher-WN blend gas, which can be disrupted due to production schedules or maintenance of installations or pipelines. When the blend gas is not available, the lower-WN gas production can be curtailed.

with the proviso that they may tend towards overestimating costs, rather than risking underestimating them. The survey was distributed to relevant trade associations, professional bodies, dutyholders and others. HSE received 81 responses to the survey. The survey evidence is assessed in further detail in the relevant sections of the IA below.

- Interviews with appliance and equipment manufacturers: HSE conducted nine further semi-structured interviews with manufacturers and manufacturers' associations to explore the likely impact of the proposed changes on equipment in the field and whether new equipment could be pre-adapted. This was to provide additional evidence to support survey responses from users who were unsure of the impact on their own equipment.

- A public consultation from January to March 2022, accompanied by a question set covering the impacts of the proposed policy. The consultation received 55 responses through the online questionnaire platform, with a further 20 written responses.

- In parallel with the public consultation, 11 interviews and workshops with key affected sectors around power generation, gas engineer training and gas distribution.

- A review of all the evidence gathered by these activities by HSE-convened expert groups for the key affected sectors to aid interpretation and provide challenge. The groups included HSE sector experts, BEIS and NSTA analysts, BEIS policy leads and policy leads and representatives from Ofgem.

- A series of interviews and data reviews with a gas producer to explore likely costs and savings arising from changes to gas processing; and the availability of further gas reserves that could be made economical by changes to GSMR. HSE was joined in this part of the research by the NSTA, which provided analytical and policy expertise in challenging and assessing additional production estimates.

- We have explored with Ofgem and BEIS the effects that turbine outages to allow for adaptation and maintenance could have on electricity supply and on market prices. We have developed qualitative descriptions of the possible impacts through this collaboration, but have not been able to produce robust quantitative estimates for this final stage IA due to uncertainty as to which alternative power sources might be used to make up any shortfall and the dynamics of market response of supply and price.

E. Monetised and non-monetised costs and benefits of each option (including administrative burden)

E.1. Option 1 – Business as Usual (BAU)

31. This option would not deliver any improvement to the out-of-date legislative landscape that regulates the gas transmission industry and would fail to reflect the processes currently used by industry. Maintaining BAU would not modernise the Regulations or provide clarity to dutyholders. It therefore does not meet the policy objectives. However, the business-as-usual case is the notional baseline against which other impacts are assessed.

32. It should be noted that if GSMR were not changed in the manner proposed, HSE has the option to issue an exemption from any other part of the Regulations, provided that HSE is satisfied as to the safety of such a measure. This means that it is possible that the changes and impacts that this IA discusses could happen in a notional 'do not change the regulations' baseline. However, it would be perverse to assess the impacts of changing GSMR against a baseline where the same effect is brought about through non-legislative means – with the result that the costs and benefits of changing GSMR are effectively nil. As such, a 'business as usual' baseline is adopted with respect to the regulatory position. This baseline assumption was reviewed by the Regulatory Policy Committee as part of their opinion on the consultation stage of this IA.

E.2. Option 2 – Amend GB's safe gas composition specification but retain within GSMR, Schedule 3, plus other changes to modernise GSMR

33. Under Option 2, HSE would continue to specify the safe gas composition within GSMR and retain HSE's ownership and control of GB's gas quality specification. The bottom of the WI range would be lowered and future changes would continue to require HSE's assessment and changes to GSMR.

34. The shorter-term impact of Option 2 is driven by the proposed widening of the WI range, which will allow gases with a lower gas quality into the GB gas network. This has the potential to reduce gas processing costs and enable additional gas production for some producers but to also increase costs to users from ensuring that

equipment is compatible with a wider range and managing potentially greater fluctuations and variability in gas quality.

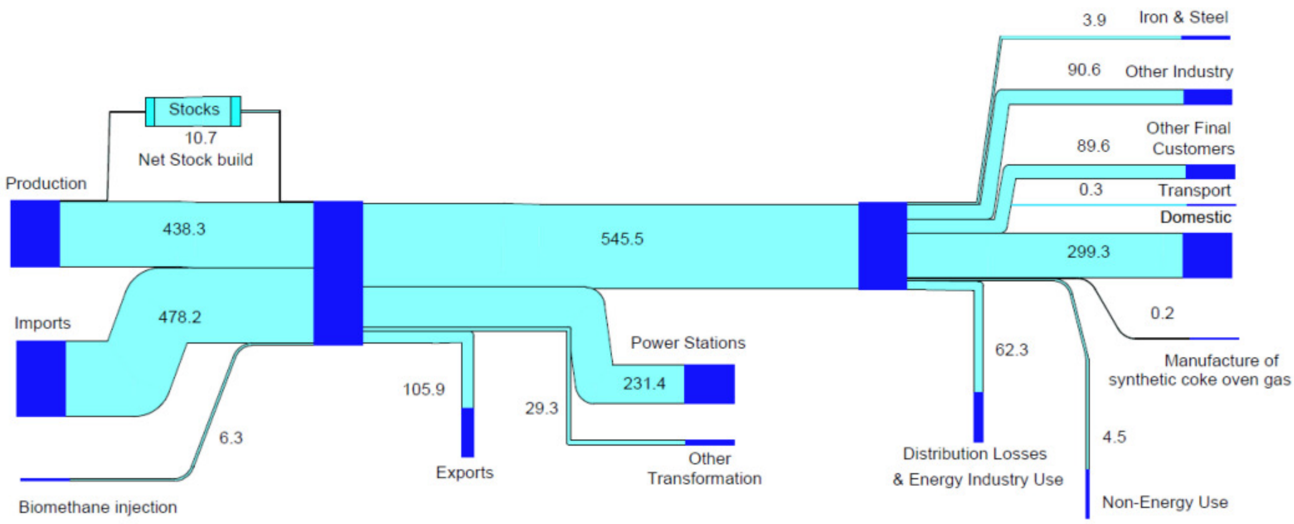
35. Changes to the lower WN would also drive all of the significant costs and benefits identified by the research undertaken to support this impact assessment and the policy decisions.

36. The summary for Option 3 can be at paragraphs 299 to 303.

E.2.1. Summary of affected sectors

37. The basic 'lifecycle' of gas in the UK starts with it entering the national transmission system (NTS) from the North Sea, via a pipeline or from biomethane production, or as LNG, travelling through the NTS and ultimately coming out of a pipe for use by an end-user. The proposed changes of widening the WN range under Option 2 have the potential to affect all operators involved in this lifecycle. The flow of gas in TWh terms is summarised in Figure 1.

Figure 1: Natural gas flow, 2020 (TWh)[6]



38. BEIS produce estimates of gas demand by sector, summarised below in Table 1. The domestic, commercial and public administration etc. sector is the largest consumer, followed by transformation, general industry and the energy industry.

Table 1: Summary of gas demand by sector, 2020 (GWh)[7]

Sector	Total gas demand (GWh)
Domestic, commercial, public administration etc.	390,000
Transformation (e.g., electricity generation)	260,000
Industry	95,000
Energy industry (e.g., oil and gas extraction; refineries etc.)	60,000
Non energy use total	4,500
Losses*	2,700
Road transport	310
Total demand	**810,000**

Note: figures rounded to two sig. fig., so may appear not to sum. *Refers to downstream losses. For an explanation of what is included under these losses, see Downstream Gas methodology on BEIS website at: https://www.gov.uk/government/publications/downstream-gas-statistics-data-sources-and-methodologies

39. For the purposes of evidence-gathering and analysis, HSE has defined the groups in Table 2. These groups were suggested by initial research and engagement with industry and IGEM as the most appropriate and suitable for the IA research. The potential impact of the proposed changes under Option 2 on these groups is assessed below.

[6] DUKES 2021 Chapters 1 to 7 (publishing.service.gov.uk)

[7] DUKES_4.2.xls (live.com)

Table 2: Definition of groups affected by proposed changes

Group	Description
Gas producers/ importers	Those bringing gas to shore via pipelines and via imports of LNG, and processing this gas to enter the NTS
Gas distributors: National Transmission System (NTS), Gas Distribution Networks (GDNs) and Independent Gas Transporters (IGTs)	Britain's gas transmission network, the National Transmission System (NTS), is the high-pressure gas network which transports gas from the entry terminals to Gas Distribution Networks, or directly to power stations and other large industrial users. Regional Gas Distribution Networks (GDNs) and Independent Gas Transporters (IGTs) transport gas to other end-users across GB. This group also includes interconnectors, which transport gas between GB and other countries – Belgium, Ireland, the Netherlands and Norway.
Domestic end-users	Households that use gas primarily for central heating (e.g., boilers) or cooking
Commercial end-users	Organisations and businesses using gas in a similar manner to domestic users (i.e., for heating and cooking), but on a larger scale – e.g., hotels, conference centres etc.
Industrial end-users	Organisations and businesses that do not use gas to heat water or use gas for cooking, but use gas in a more directed way (e.g., glass making, oil and gas extraction) or as a constituent of a chemical process (e.g., producing hydrogen; pharmaceuticals)
Power generators	Large-scale organisations using gas to drive sizeable engines and turbines generating electricity for businesses and consumers, e.g., EDF, Centrica (British Gas), E.ON, RWE npower, Scottish Power and Southern & Scottish Energy. Smaller power generators use gas to drive turbines and/or engines to generate electricity for their own needs rather than to sell.

E.2.2. General assumptions in this analysis

Appraisal period and discounting

40. In the consultation stage IA, we discussed that decision-making on changes to GSMR will need to consider business costs and investments in gas-fuelled domestic, industrial and commercial equipment. At that stage, we anticipated that significant investment in replacement equipment could be a consequence of the GSMR changes under Option 2. The lifecycle for many of these types of equipment will extend beyond the typical ten-year appraisal period of an IA and evidence gathered indicates that that period can be between 15 to 30 years, depending on the type of equipment in question. As such, the consultation stage IA followed the approach of the 2005 BERR impact assessment[8] of proposed changes to the Wobbe range in assessing costs over a longer appraisal period, comprising one year of transition and a further twenty years of costs and benefits. This approach was agreed by the RPC in their opinion of the consultation stage IA.[9]

41. Evidence generated through consultation, interviews with key stakeholders and reviews by HSE expert groups has indicated that significant investment in replacement equipment would not be necessary. Rather, the evidence points to adaptation or increased maintenance of existing equipment in some cases; and no actions needed at all in others.

42. What has emerged as one of the driving quantified benefits of the proposed changes are the additional reserves of gas from the UKCS that would be enabled by Option 2. While the profile of investment in gas production can extend beyond the typical ten-year appraisal period for an IA, evidence indicates that capital, operating and decommissioning costs will not be affected by the proposals to change GSMR, only production itself. Any changes to production are expected to be captured within the standard ten-year appraisal period. As such, in this final stage IA, we revert to the more usual ten-year appraisal period.

43. In addition, the changes to these regulations will take place in April 2023. The appraisal period in this IA therefore runs from 2023 (Year 0) to 2032 (Year 9). However, the changes to the WN under Option 2 will not be implemented until 2025 to give downstream users additional time to make adaptations to their equipment. In the mid-estimate, this impact assessment models a two-year delay to account for time needed to update Network Entry Agreements (NEAs) and interconnector agreements (see paragraphs 46 to 50), which also serves as a reasonable model of the delay to implementation of the WN changes. In the 'high' estimate, we model additional

[8] Not currently published.
[9] HSE The Gas Safety Installation and Use Amendment Regulations 2018.pdf (publishing.service.gov.uk)

UKCS gas production being enabled due to the successful renegotiation of NEAs after only one year. Now that the policy has developed further to incorporate a separate commencement date for the lower WN change, this lower-Wobbe gas would not be permissible to inject into the NTS until April 2025. Instead, we now assume that an earlier negotiation of interconnector agreements would allow the additional UKCS gas to be exported across the interconnectors and so we consider that the 'high' estimate provides a reasonable maximum estimate of the opportunities for additional UKCS production in the year prior to the implementation of the lower WN limit for the NTS. However, it should be noted that actual figures will depend on the timing of additional production over the year and the seasonal directional flows of imported and exported gas across the interconnectors. It should also be noted that the 'high' estimate also includes a range of 'exposure costs' incurred by GB gas users and their equipment reacting to the delivery of lower Wobbe gas starting in 2024. While exposure costs would not actually be incurred in the 'high' estimate until lower-WN gas implementation in 2025, this produces only a small overestimate in costs and so we have assessed it proportionate to keep these slightly overestimated costs in the analysis.

44. Many of the estimates for economic activity and costs have been estimated from evidence based on 2022 levels and are then adjusted over the appraisal period by forecasts of gas use or UKCS production (see paragraphs 55 to 58).

45. The analysis adopts a discount rate for future values of 3.5%; except for health impacts, which are discounted at 1.5% as stated in Green Book guidance.

Network Entry Agreements and the timing of impacts

46. While GSMR sets out safe gas quality standards for conveyance in the grid, actual gas injection is managed by gas transporters using Network Entry Agreements (NEAs). NEAs define the parameters and associated limits of the gas that operators of entry points may inject into the grid; and similar agreements define the gas specification that is applicable for interconnectors[10] and storage facilities. National Grid estimate that it could take a year or more from the changing of GSMR for all such transmission agreements to be updated to allow the injection of gas in the lower part of the new Wobbe Number range with those operators that wish to do so. This timetable would be driven principally by a UNC modification process to enable such changes and when it would be possible for National Grid to update relevant agreements with the interconnector operators, which in turn is conditional on when and if reductions to lower limits for Wobbe Number that currently apply in Irish, Belgian, Dutch and German specifications and in continental Transmission System Operators (TSO) interconnection agreements can be implemented. However, it would be possible to admit volumes of low Wobbe Number gas into the NTS at an earlier stage at entry points where it can be demonstrated that such gas would not reach the interconnectors' offtake points, or conversely, to export volumes of low Wobbe Number gas down interconnectors should interconnector agreements be successfully renegotiated either before the legislative change comes into force in April 2025, or before NEA's are agreed with the relevant terminal.

47. To account for this in our analysis, we have assumed a range of delays in the agreements required to inject low-Wobbe gas into the GB network of between one year for the 'high' estimate (starting 2024/ Year 1) and two years (starting 2025/ Year 2) for the 'mid' estimate.[11] For the 'low' estimate, we model a scenario wherein the NEAs do not get agreed (or at least not in time to make viable further investment in UKCS production, given the limited life of the enabling infrastructure) and no additional gas is produced. This 'low' scenario reflects the complexity and chain of dependencies in the NEAs and interconnector agreements, which would comprise a series of bilateral agreements from Germany, through Belgium and the Netherlands before reaching the interconnector with GB.

48. Under this 'low' scenario, most of the benefits of the Wobbe change do not occur. We also anticipate that many of the ongoing costs would be averted, as these would be driven by equipment responding to the new low-Wobbe gas flows. For the one-off equipment adaptation costs, we anticipate that some gas users will have the flexibility to await the NEA change and delay adaptation costs (and, under the 'low' case, to avoid them altogether), while others will be incentivised to make adaptations as early as possible, which in the 'low' case, could mean undertaking what turns out to be nugatory work. Based on evidence gathered throughout the IA process, we assess that gas users will have greater flexibility to delay (and possibly avoid) one-off adaptation costs where they (a) have shorter lead-in times to book engineers to do the work and (b) their equipment will be less severely affected should it be exposed to the low-Wobbe gas. Based on this assessment, we have concluded that:

   a. Gas distributors will make adaptations as soon as possible in all cases to maintain the integrity of the network and as part of their role in leading the way on standards

[10] Undersea pipelines that connect the GB network with the networks of other countries.

[11] See paragraph 43 for a discussion of how delays due to NEA and interconnector agreements interact with the implementation period in this analysis.

b. Industrial users will be able to delay or avoid costs, except where their processes are particularly sensitive to the new gas

c. Gas producers (both UKCS and biomethane) will have sufficient flexibility to delay or avoid adaptation costs

d. Turbine operators' long planning schedule for maintenance and high sensitivity will mean they cannot delay or avoid one-off costs

e. Operators of reciprocating engines and combined heat and power units will have some flexibility to delay or avoid one-off costs, but not in all cases

49. Forecasting this degree of flexibility in advance is difficult. The outcomes described above are not meant to be a perfect forecast of the future, but to try to show the distribution of possible costs that could occur. We manage the uncertainty in this analysis through the estimation of ranges and sensitivity analysis, described throughout this analysis.

50. It should be noted also that we do not anticipate that NEAs could be agreed for a Wobbe number as low as 46.5MJ/m^3, the level proposed for GSMR under Option 2. While the Netherlands and Germany have a lower Wobbe limit below than proposed under Option 2, Belgium has a lower limit of 46.62MJ/m^3. National Grid anticipate that it will not be possible to agree any NEA with a lower Wobbe limit below 46.62MJ/m^3, at least not in the short term. This means that gas producers or importers in GB will not be able to inject gas into the network below 46.62MJ/m^3 and so we assume that this will be the de facto lower limit. We have adjusted our cost and benefits estimates to account for this where possible.

Network penetration

51. Any new gas enabled by the changes to GSMR will not flow to all gas users. Gas is injected into the network through intake points around GB; if new low-Wobbe gas is injected into the network in one area, local gas users will be more likely to have this gas delivered to them than users elsewhere (all else equal). The extent to which any new low-Wobbe gas spreads throughout the network is called network penetration.

52. Many of the ongoing costs assessed in this IA will be due to equipment and gas user responses to the new low-Wobbe gas – if they are not exposed to the gas, they will not incur the costs.

53. Initial estimates by IGEM in 2021[12] estimated that around 7.5% of gas users might be supplied with low-Wobbe gas. National Grid also assessed network penetration. The National Grid analysis indicates that new low-Wobbe gas could account for around 0.7% of gas in the network. The percentage of gas in the network does not necessarily equal the percentage of gas users supplied with the new gas; and that different gas users could be supplied on different days, widening exposure. The actual gas mix will also experience variability by geography, time of day and by fluctuations in the supply of gas from low-Wobbe sources, such as installation maintenance schedules and the availability of blend gas to raise out-of-specification gas within the new Wobbe range.

54. In this IA, we find it prudent to adopt a range between these two estimates of between 0.7% and 7.5% with a mid-estimate of 4.1%. However, given than in our 'low' case, no new low-Wobbe gas will flow at all (see paragraphs 46 to 47), the range of gas users supplied with new low-Wobbe gas we will adopt for cost assessment in this IA is between nil and 7.5%, with a mid-estimate of 4.1%.

Assumptions about trends in gas use

55. As part of the government's commitment that the UK should be a net-zero carbon emitter by 2050, the National Grid produced the Future Energy Scenarios (FES)[13] research on how natural gas usage might change over that period. The FES 2021[14] estimates used in the analysis use the Leading the Way scenario to model low gas usage (i.e. rapid decline in gas use) over the appraisal period; and the System Transformation scenario for high gas usage.

56. The FES expect total gas demand to fall from around 81 billion cubic metres (bcm) in 2020 to between around 1.7 bcm and 47 bcm by 2050, depending on the usage scenarios. By the end of the appraisal period (2032), UK gas demand is expected to fall to between around 43 bcm and 61 bcm.

[12] IGEM-TSP-21-396 DLC189_D – Impact of widening WI range on CO poisoning risk

[13] Future Energy Scenarios 2022 | National Grid ESO

[14] Note that the FES 2022 was published just as this IA was being finalised. As such, it was not possible to update the IA for the new FES estimates. Initial analysis indicates that the costs and benefits in this IA would not be changed significantly by adoption of the FES 2022 figures.

57. As summarised in Table 3, the estimated percentage decline is applied to ongoing costs to model declining gas usage where appropriate in the analysis. The FES estimates produce a breakdown by sector, and these are applied to the costs as described in more detail throughout this analysis. Note that this attempt to account for long-term trends in gas demand – in the short-term, demand (particularly for certain types of gas, e.g., LNG or low-Wobbe Southern North Sea gas) could change due to short-term price volatility or competing gas types – it has not been possible to control for this in the IA.

Table 3: Estimates of national gas usage 2022-2032

Calendar year	Year of appraisal period	Gas demand as % of 2022								
		Residential			Commercial			Electricity production		
		Low	Mid	High	Low	Mid	High	Low	Mid	High
2022	N/A	100%	100%	100%	100%	100%	100%	100%	100%	100%
2023	Year 0	98%	98%	99%	101%	101%	101%	88%	92%	97%
2024	Year 1	95%	97%	98%	102%	102%	102%	64%	78%	93%
2025	Year 2	92%	95%	97%	101%	102%	103%	44%	57%	70%
2026	Year 3	89%	93%	96%	100%	101%	102%	26%	40%	54%
2027	Year 4	85%	90%	95%	96%	97%	99%	17%	25%	34%
2028	Year 5	80%	87%	94%	91%	93%	95%	23%	32%	41%
2029	Year 6	74%	83%	92%	86%	89%	91%	25%	31%	37%
2030	Year 7	68%	79%	90%	80%	84%	87%	21%	30%	39%
2031	Year 8	63%	74%	86%	75%	78%	82%	17%	24%	30%
2032	Year 9	57%	69%	82%	69%	73%	77%	15%	19%	23%

58. UKCS gas production will not be driven by UK demand in the same way that gas usage will be. This is because additional UKCS production can be exported; or will displace imports. For costs and benefits related to UKCS production in this analysis, we have modelled over time using estimates of production profiles for specific fields and discoveries. In some cases, we have applied The North Sea Transition Authority's forecasts of general UKCS production, which are expected to decline due to reserves and infrastructure coming to the end of their lives.[15] This forecast is summarised in Table 4.

Table 4: NSTA forecast of UKCS gas production 2022 to 2032

Calendar year	Year of appraisal period	UKCS production (bcm)	Gas production as a percentage of 2022
2022	N/A	31.0	100%
2023	Year 0	29.6	95%
2024	Year 1	26.8	86%
2025	Year 2	24.2	78%
2026	Year 3	21.6	70%
2027	Year 4	19.4	63%
2028	Year 5	17.5	56%
2029	Year 6	15.7	51%
2030	Year 7	14.2	46%
2031	Year 8	12.9	41%
2032	Year 9	11.9	38%

Note: figures may appear not to sum due to rounding

[15] North Sea Transition Authority (NSTA): Production and expenditure projections - Data downloads and publications - Data centre (nstauthority.co.uk)

E.2.3. Gas producers and importers

59. Gas producers are the main direct beneficiaries of the changes under Option 2. Operators that are currently required to process gas to bring it within the existing GB gas specification could avoid some processing costs, where the gas is within the proposed wider WN range. Additionally, a wider WN range could increase the volume of gas that can be exploited profitably, with or without processing.

Data on gas producers and importers

60. According to the BEIS 2021 DUKES report[16], total gas supply to the UK in 2020 before exports was 917 GWh, of which UK production accounted for 439 GWh (48%) and imports 478 GWh (52%). Pipeline imports from Norway and the Continent accounted for 58% of imports, with LNG accounting for 42% (up from 15% in 2018).

61. Available data on the number of gas producers and importers indicates that there are around 50 companies operating around 208 installations on the UKCS; three LNG import terminals, with almost half of LNG sourced from Qatar; interconnectors connecting GB with Norway, Belgium, the Netherlands and Ireland; and around 100 suppliers of biomethane to the NTS.

Evidence on potential change in volume of production and import to GB market

62. Reduction in processing costs would, all else equal, be expected to stimulate supply to the market of the previously processed gas. Two respondents to the survey and the consultation estimated that they would increase gas production as a result of the proposed changes. Both source their gas from the UKCS.

63. We assume that the supply of gas onto the NTS would still need to balance with demand, which we assume to be finite and unaltered by Option 2. Therefore, our modelling assumes that any increases in supply from a source such as the UKCS would be offset by reduced supply through pipeline interconnectors from mainland Europe or from reduced imports of LNG.

64. A lower WN limit would bring into specification gas sources previously outside the WN range. It may also make it profitable to process some sources of gas outside a new wider WN range so they can be supplied to the GB gas network. These sources could include low-WI gas from the southern North Sea (SNS) and biomethane. As above, it should be noted that any additional supplies would likely displace other gas sources, rather than raising supply overall.

65. Evidence from interviews and research undertaken by gas producers indicates that enabling lower WN gas from the SNS to enter the system without propanation or blending could lead to more gas being economically viable for extraction. However, we would expect that this would be subject to wholesale price volatility and competition from other gas sources.

66. This native gas could also offset more carbon-intensive LNG imports; or less carbon-intensive pipeline imports. The net effect on emissions is discussed from paragraph 265.

67. Lowering the WN range could lead to increased investment in the development of biomethane[17] due to reducing the cost of processing biomethane and could improve market access of this gas, encouraging investment in its infrastructure. Biomethane's WN range is around 45.9MJ/m^3 to 48.2MJ/m^3; the proposed changes to the WN under Option 2 would encompass most of this range and could increase investment in biomethane and encourage growth in this energy supply, potentially supporting government strategies for energy security and Net Zero.

68. However, evidence from the survey and from the interviews indicates that conditioning outlined in The Gas (Calculation of Thermal Energy Regulations) 1996 around the flow-weighted average calorific value (FWACV) of gas – which requires that the calorific value of gas used for billing within a local distribution zone (LDZ) cannot be higher than 1MJ/m^3 above the lowest-calorie gas supplied to that LDZ – will lead to a continued demand for propanated biomethane in order to raise the calorific value of that gas to the FWACV. This means that gas producers in the biomethane sector may not realise the benefit of reduced gas processing as a result of the proposed decrease in the lower WN. Discussions with GDNs during consultation has confirmed this view.

69. Evidence from interviews and data gathered through consultation indicates that over the first two-to-three years some gas processing from the UKCS could be averted and there could be increases in production from existing sources. Greater production from new sources could begin thereafter, but it is uncertain whether this production

16 DUKES 2021 Chapters 1 to 7 (publishing.service.gov.uk)

17 Outlook for biogas and biomethane: Prospects for organic growth – Analysis - IEA

would be driven solely by change to gas specification in GSMR and would likely require other incentives such as economic investment.

70. Across Europe there is a variety of Wobbe Number ranges used across different countries for both the lower and upper end ranging from 46.44MJ/m^3 to 52.85 MJ/m^3. Discussions with interconnectors during consultation indicated that agreements for gas supply would need to be updated if the lower WN was amended – this is discussed further from paragraph 46.

Quantified cost estimates for gas producers and importers

Initial adjustments to operations

71. As part of the HSE survey, we asked gas producers and importers what they would have to do to determine how they would be affected and what, if anything, they would have to change under Option 2. We then tested the estimates during the public consultation.

72. Two gas producers sourcing their gas from the UKCS and from Norway reported costs of between around £30,000 to £100,000 to agree new procedures with National Grid, with a mid-estimate of around £65,000. These costs covered actions including assessing what further gas sources could be received and processed, implementing changes to National Grid entry specifications and updating interface procedures with National Grid. This gives a total one-off estimated cost of between around £60,000 and £200,000, with a mid-estimate of around £130,000. Consultation responses did not lead us to update these estimates.

73. Biogas producers reported to the initial survey that they might incur costs of around £2,000 per site. Responses to the public consultation indicated a range of between £2,000 and £10,000 to include alarm activation levels and updates to contractual arrangements. The HSE expert group that reviewed the evidence post-consultation believed that these costs may be an overestimate for biogas producers, given that we did not anticipate any increases in biomethane production. Across the approximately 100 biomethane production sites injecting into the grid, this gives an initial adjustment cost for biomethane producers of between around £200,000 and £1 million, with a mid-estimate of around £600,000.

74. Given the uncertainties in the timing of the updating of NEAs (see paragraphs 46 to 47), we anticipate that gas producers would have some flexibility in the timing of making these adjustments. As such we expect that they would be able to delay these costs to await the updates to NEAs – that is, until Year 1 in the high estimate; until Year 2 in the mid-estimate; and in the low cases, where NEAs are not updated, to avoid the costs altogether.

75. This would give a total present value cost of between around nil and £1.2 million, with a mid-estimate of around £680,000. These costs are only associated to Option 2.

Gas processing savings

76. Respondents to the consultation reported that they anticipated making some savings from processing gas – either due to the changes to the Wobbe range or the removal of the ICF and SI.

77. Two respondents reported that they would save around £4.6 million per annum for blending. However, further exploration of those costs revealed that they represented a financial burden to the organisations paying the costs, but they were a transfer from one business to another and did not represent an economic resource cost. As such, we have not included it in the calculations in this IA.

78. Another respondent reported cost-savings from no longer having to nitrogen ballast due to the removal of the ICF and SI. They reported that this might save around £100,000 in 2022. We anticipate that averting gas processing for the ICF and SI will be subject to an updated NEA for the changed gas quality, which we anticipate might take a year to agree. Note that this is a separate issue to the NEAs related to the Wobbe range discussed in paragraphs 46 to 47. We have applied the general UKCS production decline profile set out in Table 4 to profile the savings over time, as summarised in Table 5. The present value of the savings is estimated at around £460,000. Note that these savings also occur under Option 3 (see section E.3).

Table 5: Estimated gas processing savings

	Estimated processing savings (£k)
Year 0	Nil
Year 1	£86
Year 2	£78
Year 3	£70
Year 4	£63
Year 5	£56
Year 6	£51
Year 7	£46
Year 8	£41
Year 9	£38
Present value	**£460**

Note: figures may appear not to sum due to rounding

Additional gas production

79. Evidence gathered through discussions with gas producers, the 2021 HSE survey and the 2022 public consultation points to the potential for additional sources of gas on the UK continental shelf (UKCS) to be enabled by the proposed changes to GSMR under Option 2. These gas supplies are reported to be restricted currently by gas quality requirements and unavailability of processing resources (such as higher-Wobbe blend gas).

80. Gas production is sensitive to a number of factors, including price volatility, as well as gas quality. Decisions on investment are made regarding initial spending and production schedules that extend for several years – potentially over a decade. As such, there is considerable uncertainty as to the gas supply, in terms of the likelihood that production will go ahead, the exact quantities of recoverable gas and the future of gas prices and demand. In addition, it is not certain that it would be the change to gas quality requirements under GSMR alone that would enable any increase in production to go ahead.

81. Production from one identified UKCS field does not meet the current GSMR gas quality specification so has to be blended with production from other fields before entering the NTS. Limited availability of blend gas means that production from this field has been curtailed. The proposed revised gas quality specification, expected to translate to an NEA allowing gas down to 46.62MJ/m^3 (see paragraph 50), would allow additional production of gas from this field, which the operator suggests could be 15.75% of baseline production. Production from this field is now going off plateau meaning that there is increasing ullage (i.e. spare capacity) so there is potential for other fields to be tied back to the production hub.

82. Development of one discovery, which meets the current gas specification but has not been developed so far because of insufficient ullage in the above production hub, would be expected to be enhanced by Option 2 as the changes to GSMR might allow an additional 5% to be extracted. The discovery is not currently licensed so it would need to be applied for and awarded in a future licensing round. Even then there could be partner alignment issues frustrating a potential development. Using information from the previous operator, we can assess the likely costs and production profile for the discovery. Other nearby discoveries for which we have similar estimates seem unlikely to be commercially attractive.

83. For the two sources of additional gas that Option 2 might enable – an additional 15.75% of baseline production from an existing field and an additional 5% of baseline production from a discovery, if developed – we present below total monetised net benefits along with key non-sensitive assumptions, but the core evidence of gas production estimates and time profiles is commercially sensitive and not included in explicit detail.

84. In all cases, the additional production comes at zero additional cost, as the additional production comes from extra production uptime from no longer having to blend with higher Wobbe gas compared to the baseline. This additional uptime incurs essentially zero cost at the margin.

85. This additional production is also subject to delays caused by NEAs (see paragraphs 43; and 46 to 47) of one year (high case), two years (mid case) or the NEAs never being agreed (or at least not in time to affect additional gas production) (low case). However, it should be noted that, where the additional production is contingent on drilling additional wells in the existing field or setting up the discovery for extraction, delays of between one and four years are anticipated to allow for the investment and prospecting to take place.

86. There is a large number of so far undeveloped discoveries in the northern part of the Southern Gas Basin. Some of these do not meet the current GSMR gas quality specification but would meet the revised gas quality specification proposed in Option 2. Some similar discoveries have been developed despite not individually meeting the current gas quality specification because their production could be blended with production from other fields before entering the NTS. A lot of the undeveloped discoveries are small, remote from existing infrastructure and/or technically challenged and are unlikely to be developed even with a revised gas quality specification. Others could be developed with or without a change in gas quality specification. We are not in a position to give credible estimates of the scale of impact, if any; and so, they are not included in this analysis.

Gas price assumptions

87. We have used Wood Mackenzie 2022 Q2 gas price assumptions for uncontracted natural balancing point gas. There has been significant variability in gas prices and their future path is uncertain. We have adopted a range of gas prices using recent Wood Mackenzie forecasts from February 2022 for the low; and forecasts from May 2022 as the high. The mid estimate is an average. We have ignored oil (i.e., condensate/NGL) production as minimal and have therefore not needed to make assumptions about oil prices. These gas prices in pence/therm are below. The low/ mid/ high range is reflected in the range of present value costs.

Table 6: Estimated gas prices in pence/therm (2022 prices)

Year	Year of appraisal period	Gas price (pence/ therm)		
		Low	Mid	High
2022	N/A	236	337	439
2023	Year 0	137	197	258
2024	Year 1	99	129	159
2025	Year 2	86	102	118
2026	Year 3	62	68	74
2027	Year 4	62	68	74
2028	Year 5	62	68	74
2029	Year 6	62	68	74
2030	Year 7	62	68	74
2031	Year 8	62	68	74
2032	Year 9	62	68	74

Summary of gas producer costs and benefits

88. The additional production sources discussed above have different likelihoods to go ahead, although these likelihoods cannot be quantified. The additional production from the currently producing field is the most likely to go ahead, while the development of the additional discovery is less likely given that a licence and significant capital investment would be required.

89. Distributing these scenarios between the low, mid and high scenarios required of the impact assessment template is a matter of interpretation. In this analysis, we will assume:

   a. under the ‘low’ case, the NEAs do not get agreed and so additional gas production is nil;

   b. under the ‘mid’ case, the NEAs are agreed after two years. Additional production from the existing field is thereafter increased by 15.75%, including the production of one additional well. However, the additional discovery is not developed;

   c. under the ‘high' case, the NEAs are agreed after one year. Additional production from the existing field is thereafter increased by 15.75%, including the production of four additional wells. The additional discovery is also developed.

90. The total net present value of costs and benefits to gas producers in present values over 10 years is estimated at between around £460,000 and around £500 million, with a mid-estimate of around £210 million. This is summarised in Table 7.

Table 7: Summary of present value gas producer and importer costs and savings (present values, £millions)

	£millions		
	Low	**Mid**	**High**
Costs			
Initial adjustments	Nil	£0.7	£1.2
Benefits			
Gas processing savings	£0.5	£0.5	£0.5
Additional production from existing field	Nil	£210	£480
Additional production from additional discovery	Nil	Nil	£16
Net present value	**£0.5**	**£210**	**£500**

Note: figures rounded to two sig. fig., so may appear not to sum

E.2.4. National Transmission System (NTS), Gas Distribution Networks (GDNs), Independent Gas Transporters (IGTs) and interconnectors

91. The NTS, GDNs and IGTs in broad terms comprise the network, storage facilities and related apparatus that transports gas to a wide range of end-users. These comprise: the National Transmission System (NTS), which supplies gas to power stations and large industrial users; four Gas Distribution Network (GDN) operators, that transport gas from the NTS to commercial and domestic users; and twelve independent gas transporters (IGTs), who operate smaller, local networks.

92. Although the delays to the updating of NEAs (see paragraphs 46 to 47) could provide gas distributors with an opportunity to delay (or even to avoid) adaptation costs related to the Wobbe Number range, in practice we would anticipate that gas distributors would make their adjustments in Year 0 of the appraisal period in the low, mid and high estimates. This reflects their role in leading the way for industry standards in gas quality compliance and operation.

Quantified impact for NTS, GDNs and IGTs

Determining impact and what needs to change

93. Responses to the HSE survey indicated potential costs to determine what would have to change of between around £50,000 and £150,000 per network operator, with a mid-estimate of around £100,000. These costs were accounted for by testing or surveying of equipment and making changes to equipment controls.

94. In the consultation stage IA, we applied this cost to IGTs as well as the NTS and GDNs. Evidence from the consultation and interviews conducted now indicates that it is highly unlikely IGTs will bear these costs as very little will change for them. If we apply these costs to the NTS and four GDNs, this would give an **estimated total one-off cost** of between around £250,000 and £750,000, with a **mid-estimate of around £500,000**.

Remapping NTS compressors

95. The NTS operates around 80 compressors. These are mechanical devices for increasing the pressure of the gas – essentially large jet engines within the network that run on the gas that they pressurise.

96. As a result of the proposed changes to the WN range under Option 2, NTS report that ten of these would probably have to be remapped to prevent excess emissions or the engine becoming unstable. These ten compressors are assessed by National Grid to be particularly sensitive to changes in the WN or calorific value of the gas. National Grid report that they would only know for sure that the compressors needed to be remapped (and how they should be remapped) once they could observe the new gas flows.

97. National Grid estimate that each of these compressors would cost between around £10,000 and £15,000 to remap, with a mid-estimate of around £13,000. National Gird report that, if the changes in gas flow were sufficiently volatile, the remapping may need to be repeated. However, they anticipate that the commercial considerations from gas suppliers/ producers will mean that the cheapest method of providing a certain gas quality will be the one used, and that the suppliers/ producers would not be switching between different fields rapidly. As such, they expect a degree of uniformity; and that those changes can be managed by the process of the initial mapping.

98. This gives an **estimated one-off cost** of between around £100,000 and £150,000, with a **mid-estimate of around £130,000**.

Monitoring and alarm systems for Wobbe range

99. In order to update monitoring software and set new alarm points[18] for the proposed Wobbe range, the NTS reported that the costs would be very low – only around £4,000. Two GDNs estimated costs of £35,000 and £90,000 respectively for changes to software and alarm points at offtake points. A third GDN did not estimate costs, although they described similar actions to the two above. The fourth GDN estimated £1 million to adjust tolerances and alarms, which the HSE expert review group did not find credible; as such, it has not been adopted in this analysis.

100. If we assume that the third and fourth GDNs undergo the same costs as the first two, this gives a total **estimated one-off cost of around £250,000**.

Monitoring and alarm systems for relative density

101. The NTS currently measures the relative density of the gas in its network. In order to implement the proposed new requirement of relative density of ≤0.7, National Grid will need to implement additional monitoring and introduce alarm systems to notify of any readings that require action to be taken. National Grid report that this can be managed through the natural course of planned maintenance at no additional cost in most cases. However, there are three or four sites where National Gird believe more immediate action would be required as they expect those sites to be more likely to see gas that might approach the 0.7 relative density limit. National Grid estimate that implementing new monitoring and alarm systems at these sites would cost around £40,000.

102. In addition, National Grid would have to request that some of their customers at NTS entry points update their monitoring and alarm systems for relative density. They estimate that this could come to around eleven sites operated by gas storers and LNG terminals. National Grid anticipate that each might charge around £10,000 for the work, giving an estimated total cost of around £110,000.

103. This would give a **total estimated cost** to National Grid for monitoring and alarm systems for relative density of **around £150,000**. This cost also occurs under Option 3 (see section E.3).

Other costs explored for gas distributors and interconnectors

104. During consultation and through interviews with gas distributors, we also explored the potential for a range of other costs that might be incurred.

105. Consultation responses and evidence from interviews indicates that no costs will be incurred in relation to the **maintenance** or **replacement** of equipment used by gas distributors. Interviewees told us that the changes to gas quality proposed do not affect assets used for conveying gas (although they could affect their assets that use the gas as fuel – see discussion of compressor costs at paragraphs 95 to 98).

106. Gas distributors did not expect that their **insurance** or **warranties** on equipment would be affected by the changes.

107. We discussed **gas supply agreements** with distributors and interconnectors during interviews. IGTs and GDNs did not expect any costs as their agreements to supply gas do not specify gas quality – they simply rely on receiving compliant gas from the NTS. National Grid discussed necessary changes to NEAs – these are discussed in paragraphs 46 to 48. The NTS and Belgian and Dutch interconnectors reported that such updates to agreements could be included in ongoing business-as-usual engagement at no additional cost. Gas Networks Ireland reported around €200,000 to update their Code of Operations to reflect the GSMR changes. However, we are not considering non-GB costs in this analysis.

108. Gas distributors noted that increased variability in gas quality could lead to some uncertainty for **billing and shrinkage**. Responses indicated that they expected monitoring (discussed in paragraphs 99 to 100) could manage this issue.

Summary of costs to gas distributors

109. Taken together, the **present value costs to gas distributors** are estimated to be between around £750,000 and £1.3 million, with a **mid-estimate of around £1.0 million**.

[18] Alarm points are set values for parameters monitored in the gas that will trigger an alarm if approached or breached – e.g., if the gas were to move out of the allowable Wobbe range.

E.2.5. Power generators

Background on power generators

110. There are four main categories of natural gas fuel power generators used in GB production: reciprocating engines, Open Cycle Gas Turbines (OCGTs), Combined Cycle Gas Turbines (CCGTs), and Combined Heat and Power systems (CHP). Most of the gas-fuelled power generating capacity comes from CCGTs.

111. Reciprocating engines are a common technology similar to motor vehicle engines. These are piston engines that produce electricity and can be tuned to many fuel sources.

112. OCGT stations use a gas turbine that produces electricity. These turbines are in decline and many are either being decommissioned or converted into CCGTs.

113. CCGT stations combine in the same plant gas turbines and steam turbines connected to one or more electrical generators. This enables electricity to be produced at higher efficiencies than is otherwise possible when either gas or steam turbines are used in isolation. The gas turbine produces mechanical power (to drive the generator) and hot exhaust gases (waste heat). The waste heat is fed to a boiler, where steam is raised at pressure to drive a conventional steam turbine that is also connected to an electrical generator.

114. CHP stations produce energy and capture heat for use other than electricity generation. In GB, natural gas-fuelled CHPs utilise any of the above generating systems with the addition of a gas steam engine. CHPs are most likely to be found in the industrial and commercial sectors.

115. Power generators were asked in the 2021 survey about how their equipment would respond to both the potential range of the proposed new WN (the potential to receive higher and lower Wobbe gas than currently); and the potential fluctuation (the rate of change that could occur between higher and lower Wobbe gas) that may occur under Option 2 (note costs and impacts for power generators are not present under Option 3). Fluctuation can be exacerbated by 'slugging', whereby the quality of gas coming from the supply can change instantly if gas of different qualities has not been sufficiently mixed.

116. The responses revealed a high level of uncertainty: respondents were unsure if existing equipment could safely deal with the potential range and variability. Some responded that they expected that they would have to invest in new monitoring and control systems in order to manage the changes.

117. Most survey respondents were uncertain if equipment could manage the proposed range. Where equipment is not able to manage the proposed changes, possible costs of equipment damage or interruptions to energy supply from shut-downs were discussed. Most thought that their facilities' control and monitoring system would not be able to manage fluctuations. For those who thought their facilities could manage the WN change, they reference manufacturers still needing surveys to review; however, in a subsequent follow-up interview, a turbine manufacturer was able to make some estimates of impact and mitigation costs. This evidence formed the basis of the consultation stage IA estimates.

118. We tested the estimates from the consultation stage IA as part of the 2022 public consultation and with a workshop convened by the Energy UK. Their responses were reviewed by a HSE expert group and have enabled us to update the estimates from the consultation stage IA, as discussed below.

Quantified cost estimates for power generators

Number of gas turbines in scope

119. BEIS produce figures of the numbers of CCGTs and OCGTs in operation and those being built or planned. Evidence from interviews with manufacturers of such equipment indicates that turbines from before the mid-1990s would probably not require modification – although this might seem counterintuitive, the argument was that older equipment is less finely tuned and so less sensitive to Wobbe range changes. This was our assumption in the consultation stage IA. However, the Energy UK workshop disagreed with this assessment, and so the pre-1996 turbines are no longer excluded from our cost analysis.

120. The total numbers of turbines used in this analysis are summarised below in Table 8. The lower estimate for turbines is based on the number built; the mid-estimate on the number built and under construction; and the high on the number built, under construction and consented by BEIS. This reflects different scenarios wherein new turbines might or might not be able to be adapted to the Wobbe range as part of construction – evidence from interviews was not conclusive on whether engineering solutions could be adopted during initial construction without additional cost.

121. It is worth noting that not all equipment would experience the same changes in gas quality under Option 2. Depending on where they are placed in the country, they could be exposed to more or less of the new gas as it moves through the national network. For example, a plant close to an offtake for a particular gas source could experience very little variation, whereas equipment in the centre of the country (in a 'zone of confluence') could see more significant swings. As discussed in paragraphs 51 to 54, we assume that a range of between zero and 7.5% of turbines would be affected by new low-Wobbe gas, with a mid-estimate of 4.1%. While it might be prudent for turbine operators to undertake some initial actions to ensure the efficient operation of their equipment, turbines that do not receive the low-Wobbe gas will not bear ongoing costs, such as for increased tuning or maintenance.

122. This analysis will assume that all turbines would undergo one-off costs for review and modification as a precautionary measure – this is probably an overestimate, as some turbine operators will be sufficiently confident about the gas quality they can expect to receive not to need to do this. However, there are strong precautionary incentives to safeguard turbines from possible gas quality fluctuations given the cost of the equipment and the long lead times to get technical specialists to attend.

Table 8: Estimated power-generating gas turbines

Appliance type	Low	Mid	High
CCGTs	45	46	57
OCGTs	12	13	18
Total	**57**	**59**	**75**

123. In addition, reciprocating engines are used to generate power. Evidence from interviews indicates that there could be around 60,000 in operation; and that perhaps 10% are gas-powered, giving around 6,000 in total.

124. CHP units produce energy and capture heat for use other than electricity generation. In GB, natural gas-fuelled CHPs utilise any of the above generating systems with the addition of a gas steam engine. CHPs are most likely to be found in the industrial and commercial sectors. There are no definitive estimates for the numbers of CHPs in GB. The DUKES report[19] estimates that there are around 2,700 CHP schemes – it is likely that many schemes will comprise more than one CHP, so this would likely be an underestimate of the number of CHPs. During interviews, one manufacturer estimated that there might be around 6,000 CHPs in operation.

125. A power generator manufacturer association estimated during interviews that they did not expect the 'vast majority' of reciprocating engines and CHPs to be replaced or need modification if HSE were to lower the bottom *and* raise the top of the Wobbe range. This was because they are not particularly sensitively tuned; and it is often not economical to adapt them, but rather to let them reach the end of their usual operational life and then simply replace them with a new engine that is calibrated as needed. In the consultation stage IA, based on evidence received from manufacturers and HSE expert assessment, we did not anticipate that reciprocating engines or CHPs would experience significant costs under Option 2, which would not see as significant changes to gas quality as the scenario that the manufacturers association was discussing.

126. However, responses during consultation indicated that owners and operators believed that costs would be incurred, although their qualitative responses indicated that this might be mainly for the larger units. As such, we have updated our consultation stage assessment with costs for reciprocating engines and CHPs, below.

OEM studies for turbines

127. Power generators indicated that engineering studies would be required for their turbines before changes could be made. The studies would be produced by the original equipment manufacturers (OEMs), who retain the contract for the maintenance and modification of the turbines.

128. Specific costs were for an OEM study were unclear from respondents, other than that they can cost 'hundreds of thousands of pounds'. In this analysis, we have interpreted this as a range of between around £100,000 and £300,000, with a mid-estimate of around £200,000.

129. Across the turbine numbers summarised in Table 8, this would give a total estimated cost of between around £5.7 million and £23 million, with a mid-estimate of around £12 million.

130. The delays to NEAs or if they were not agreed at all (discussed in paragraphs 46 to 47) could provide some scope to delay or avert adaptation costs in some cases. However, for power generators we estimate that the need to build adaptation into existing planned maintenance schedules (booked years in advance) and the severity of the impact on turbines if adaptations were not made in time would compel turbine operators to make the one-

[19] DUKES 2021 Chapter 4 Natural gas (publishing.service.gov.uk)

off adaptation costs as soon as possible. This means that, in the low case where NEAs are never agreed and the low-Wobbe gas does not flow, the costs would be nugatory.

131. Power generators have described to us the challenges around booking OEM time and anticipate that demand across the industry following the GSMR changes would make this harder. As such, we anticipate that the costs for OEM reports would be borne equally over three years from Year 0 to Year 2.

132. This gives an **estimated present value one-off cost for OEM reports** of between around £5.5 million and £22 million, with a **mid-estimate of around £11 million**.

Costs of control systems for turbines

133. For turbines, interviews with manufacturers indicated that modification of control systems for the Wobbe range might cost between around £360,000 and £440,000 for control systems upgrades, with a mid-estimate of around £400,000. We tested this estimate at consultation. Responses indicated that the upper end of the range could be higher to account for auto-tuning systems. As such, we have adjusted the cost range to between around £360,000 and £800,000, with a mid-estimate of around £580,000.

134. Across the turbine numbers in Table 8, this gives a total cost of between around £21 million and £60 million, with a mid-estimate of around £34 million. As discussed in paragraph 130, we do not consider these costs to be avoidable or delayable even in the cases where NEAs are not agreed.

135. Power generators told us during consultation that they expect making necessary upgrades to their turbines could take around five years to undertake engineering surveys to understand the issues and book OEM time. As such, we assume in this analysis that the upgrades to control systems will take place equally over Years 0 to 4.

136. This gives an **estimated present value one-off cost for control system upgrades** of between around £19 million and £56 million, with a **mid-estimate of around £32 million**.

Costs of tuning for turbines

137. Estimates from a turbine operator indicate that each turbine might require tuning at a cost of between around £8,000 to £80,000, with a mid-estimate of around £44,000. In the consultation stage IA, we understood this to be a one-off cost. We tested this assessment during consultation. Responses indicated that the cost estimate range could be narrowed to between around £30,000 and £50,000, with a mid-estimate of around £40,000. Responses also indicated that the additional tuning would likely need to be repeated and could become an ongoing cost as the turbines would need to be adjusted to changes in gas quality over time or over the course of a year, as seasonal fluctuations can occur.

138. Responses at consultation did not give an indication of the necessary frequency – indeed, they indicated that this was dependant on actual observed gas quality changes and therefore impossible to predict. However, they did indicate that turbines are perhaps retuned once or twice a year already for seasonal variance in either gas quality or ambient temperature. Taking this as a cue, we will assume in this final stage IA that turbines will require an additional one or two annual tunings due to the GSMR changes, with a mid-estimate of 1.5 additional tunings.

139. Across the turbines numbers summarised in Table 8, adjusting for network penetration of low-Wobbe gas as discussed in paragraph 121, this would give a total annual cost of between nil and around £560,000, with a mid-estimate of around £145,000.

140. As noted in paragraphs 46 to 47, we assume that the lower Wobbe gas would not be injected into the network for between one and two years; and in the low case, not to be injected at all. As such, we would not expect additional costs for turbine tuning to be incurred until the lower Wobbe gas is injected.

141. Turbine tuning costs would also be subject over time to changes in gas consumption, and so are adjusted by the forecasts of gas demand for electricity production summarised in Table 3 to give the profile of costs summarised below in Table 9. These figures are an overestimate as some of the turbines that form the mid and high estimates in Table 8 are not yet built and so would not be expected to incur this cost until some years into the appraisal period. They give an **estimated present value cost over 10 years of** between around nil and £2.1 million, with a **mid-estimate of around £320,000**. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2), although it is not unreasonable to expect highly Wobbe-sensitive gas turbine operators to take early preventative action.

Table 9: Profile of increased turbine tuning costs (£thousands)

	£thousands		
	Low	**Mid**	**High**
Year 0	Nil	Nil	Nil
Year 1	Nil	Nil	£520
Year 2	Nil	£82	£390
Year 3	Nil	£58	£300
Year 4	Nil	£37	£190
Year 5	Nil	£46	£230
Year 6	Nil	£45	£210
Year 7	Nil	£44	£220
Year 8	Nil	£34	£170
Year 9	Nil	£28	£130
Present value	**Nil**	**£320**	**£2,100**

Note: figures may appear not to sum due to rounding

Increased maintenance of turbines

142. Manufacturer interviews indicate that under the baseline, each turbine undergoes a partial engine refurbishment, costing around £4 million, after every year of operational time. Depending on how often the turbine is in operation, this could be between every four to two calendar years or so, giving an annual average cost of between around £1 million and £2 million, with a mid-estimate of around £1.3 million.

143. Interviews with manufacturers indicate that they expect that each turbine might need to undergo one or two additional partial refurbishments each decade, due to the change in the Wobbe range. We have interpreted this as being equivalent to an additional 10% to 20% of annualised maintenance cost per turbine: between around £100,000 and £400,000, with a mid-estimate of around £200,000. We tested this estimate during consultation and the HSE expert group review of the responses concluded that it was probably about right.

144. Across the turbine numbers summarised in Table 8, and adjusting for network penetration of low-Wobbe gas as discussed in paragraph 121, this would give a total annual cost of between nil and around £2.3 million, with a mid-estimate of around £480,000.

145. As noted in paragraphs 46 to 47, we assume that the lower Wobbe gas would not be injected into the network for between one and two years; and in the low case, not to be injected at all. As such, we would not expect additional costs for turbine maintenance costs to be incurred until the lower Wobbe gas is injected.

146. These costs would be subject over time to changes in gas consumption, and so are adjusted by the forecasts of gas demand for electricity production summarised in Table 3 to give the profile of costs summarised below in Table 10. These figures are an overestimate as some of the turbines that form the mid and high estimates in Table 8 are not yet built and so would not be expected to incur this cost until some years into the appraisal period. They give an **estimated present value cost over 10 years of** between around nil and £8.3 million, with a **mid-estimate of around £1.1 million**. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2), although it is not unreasonable to expect highly Wobbe-sensitive gas turbine operators to take early preventative action.

Table 10: Profile of increased maintenance costs (£thousands)

	£thousands		
	Low	**Mid**	**High**
Year 0	Nil	Nil	Nil
Year 1	Nil	Nil	£2,100
Year 2	Nil	£270	£1,600
Year 3	Nil	£190	£1,200
Year 4	Nil	£120	£770
Year 5	Nil	£150	£920
Year 6	Nil	£150	£830
Year 7	Nil	£150	£890
Year 8	Nil	£110	£680
Year 9	Nil	£92	£520
Present value	**Nil**	**£1,100**	**£8,300**

Note: figures may appear not to sum due to rounding

Impacts on electricity supply

147. During the maintenance, tuning and adaptation work discussed above, turbines will need to be shut down. Turbines already undergo periodic maintenance, and this is timed to coincide with periods of lower electricity demand (such as the summer or weekends) wherever possible, to limit lost output.

148. Typically, we have learned that a turbine over a four-to-five-year period might undergo one major maintenance outage lasting perhaps 30 to 40 days; and perhaps two further shorter ones of around ten days each for other work.

149. The work to turbines discussed above could involve additional (or longer than otherwise) turbine outages. Evidence from turbine operators does not indicate that electricity generation is expected to be disrupted from the point of view of electricity users as such work on turbines would be spread out over time, driven by the incentive to meet demand and the availability of turbine maintenance technicians (as all turbines would require at least some initial modification). However, we are aware that there are staffing challenges with engineers to perform the work. If planned outages are extended to accommodate the additional work this could raise costs, particularly if this extends outages into the winter period.

150. The costs of a turbine outage to the turbine operator in terms of lost output can be considerable – one operator estimated them as being between around £100,000 to £200,000 per day in the summer; and perhaps £300,000 to £600,000 per day in the winter. The loss of production of one turbine does present an opportunity for another turbine or another source of electricity to come online and meet the demand, thereby constituting a transfer of the value of the output. If the changes proposed to gas quality specification do lead to additional, or prolonged turbine outages the alternative electricity source is likely to be less efficient and therefore incur a higher cost of production; and the loss of productive output overall can lead to short-term increases in electricity prices. Outages of specific turbines are not expected to mean wholescale power outages. Nonetheless, given the costs to turbines operators, a delayed commencement date has been proposed in order to limit any impacts and enable impacted sectors time to adapt and prepare for a wider specification of gas quality.

151. Discussions with Ofgem indicates that such effects are possible, although they would be difficult to detect and attribute to the outage of any particular turbine. Ofgem explained that prices change frequently over the course of a day and the electricity supplied to customers of any day is the result of previous decisions made in both long-term and short-term markets. Impact can also be exacerbated by the weather on any day, such as how much wind there is to generate electricity.

152. It has not been possible in this analysis to estimate the likelihood or impact of such outages or the possible effects on electricity supply and prices.

Reciprocating engine costs

153. As discussed in paragraphs 125 to 126, we initially estimated that reciprocating engines would incur no costs; after consultation, we are updating this assessment. Consultation responses indicated that some adaptation costs could be expected, particularly for the larger units.

154. An association of power generator manufacturers estimated in an interview with HSE that 'the vast majority' of reciprocating engines (and CHPs) would not need any modification. In this analysis, we have interpreted this quantitatively as 75% to 95% not needing any modification, with a mid-estimate of 85%. Based on the reciprocating engine numbers of around 6,000 set out in paragraph 123, this would give between around 300 and 1,500 reciprocating engines requiring some modification, with a mid-estimate of around 900.

155. In terms of adjustment cost estimates, figures from the 2021 HSE survey and interviews with a manufacturer and manufacturers association are summarised below. Note that these were based on a previously considered policy of raising the top and lowering the bottom of the Wobbe range, so are possibly an overestimate of what will be needed under Option 2, which proposes only lowering the bottom.

a. For a control panel, between around £50,000 and £100,000, with a mid-estimate of around £75,000

b. For internal monitoring equipment, around £15,000

c. For one-off tuning, between around £1,200 and £4,000, with a mid-estimate of around £2,600

d. This gives a total cost of between around £66,000 and £120,000, with a mid-estimate of around £93,000

156. Across the number of affected reciprocating engines in paragraph 154, this gives a total cost of between around £20 million and £180 million, with a mid-estimate of around £84 million. As with turbine operators, we would expect the costs to be incurred over five years.

157. Based on evidence gathered on reciprocating engines as part of this impact assessment, we anticipate that reciprocating engines operators would have some flexibility in terms of timing adaptation costs to account for NEA delays (see paragraphs 46 to 47). As such, we anticipate that adaptation costs would be incurred from Year 1 in the 'high' case and from Year 2 in the 'mid' case. In the 'low' case, where NEAs are not agreed and no new low-Wobbe gas is enabled, we anticipate that perhaps half of operators might be able to avoid costs altogether, while the other half would make changes that ended up being nugatory from Year 2. This is summarised below in Table 11. This would give an **estimated present value one-off cost** of between around £8.9 million and £170 million, with a **mid-estimate of around £75 million**. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2), although it is not unreasonable to expect highly Wobbe-sensitive reciprocating engine operators to take early preventative action in some cases.

Table 11: Estimated adaptation costs for reciprocating engines by year (£millions)

	£millions		
	Low	**Mid**	**High**
Year 0	Nil	Nil	Nil
Year 1	Nil	Nil	£37
Year 2	£2.0	£17	£37
Year 3	£2.0	£17	£37
Year 4	£2.0	£17	£37
Year 5	£2.0	£17	£37
Year 6	£2.0	£17	Nil
Present value	**£8.9**	**£75**	**£170**

Note: figures may appear not to sum due to rounding

CHPs

158. Similarly to reciprocating engines, above, an association of power generator manufacturers estimated in an interview with HSE that 'the vast majority' of CHPs would not need any modification. In this analysis, we have interpreted this quantitatively as 75% and 95% not needing any modification, with a mid-estimate of 85%.

159. Based on the reciprocating engine numbers of between around 2,700 and 6,000, with a mid-estimate of around 4,300 set out in paragraph 124, this would give between around 130 and 1,500 reciprocating engines requiring some modification, with a mid-estimate of around 650.

160. In terms of adjustment cost estimates, based on figures from the 2021 HSE survey and interviews with a manufacturer and manufacturers association, they are estimated to be similar to those for reciprocating engines, only without the need for a new control panel.

  a. For internal monitoring equipment, around £15,000

  b. For one-off tuning, between around £1,200 and £4,000, with a mid-estimate of around £2,600

  c. This gives a total cost of between around £16,000 and £19,000, with a mid-estimate of around £18,000

161. Across the number of affected reciprocating engines in paragraph 159, this gives a total cost of between around £2.2 million and £29 million, with a mid-estimate of around £11 million. As with turbine operators, we expect the costs to be incurred over five years.

162. As with reciprocating engines, we understand that operators of CHPs would have some flexibility in timings costs in relation to NEA delays. As such, we anticipate that adaptation costs would be incurred from Year 1 in the 'high' case and from Year 2 in the 'mid' case. In the 'low' case, where NEAs are not agreed and no new low-Wobbe gas is enabled, we anticipate that perhaps half of operators might be able to avoid costs altogether, while the other half would make changes that ended up being nugatory from Year 2. This is summarised below in Table 12. This would give an **estimated present value one-off cost** of between around £1.0 million and £26 million, with a **mid-estimate of around £10 million**. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2), although it is not unreasonable to expect highly Wobbe-sensitive CHP operators to take early preventative action in some cases.

Table 12: Estimated CHP adaptation costs by year (£millions)

	£millions		
	Low	**Mid**	**High**
Year 0	Nil	Nil	Nil
Year 1	Nil	Nil	£5.9
Year 2	£0.2	£2.4	£5.9
Year 3	£0.2	£2.4	£5.9
Year 4	£0.2	£2.4	£5.9
Year 5	£0.2	£2.4	£5.9
Year 6	£0.2	£2.4	Nil
Present value	**£1.0**	**£10**	**£26**

Note: figures may appear not to sum due to rounding

Total estimated costs for power generators

163. As summarised in Table 13, the **total estimated present value cost to power generators** for Option 2 is between around £35 million and £280 million, with a **mid-estimate of around £130 million**.

Table 13: Total estimated present value costs to power generators (£m)

	£millions		
	Low	**Mid**	**High**
OEM studies for turbines	£5.5	£11	£22
Control systems for turbines	£19	£32	£56
Tuning for turbines	Nil	£0.3	£2.1
Maintenance for turbines	Nil	£1.1	£8.3
Impact of turbine outages on electricity supply and price	Unknown	Unknown	Unknown
Adaptation for reciprocating engines	£8.9	£75	£170
Adaptation for CHPs	£1.0	£10	£26
Total	**£35**	**£130**	**£280**

Note: figures may appear not to sum due to rounding

E.2.6. Domestic and commercial end-users; and increased engineer call-outs

164. In the consultation stage IA, we assessed that no costs would be borne in respect of domestic and commercial appliances arising from Option 2, whether in the form of replacement, modification or reduced life expectancy of the appliance. We tested this assessment in consultation; there was broad agreement in the responses, but several appliance manufacturers reported that they expected to bear costs resulting from increased call-outs from concerned appliance owners when they are operated on lower WN gas. Operating on lower-Wobbe gas may cause boilers to make a humming or reverberating sound or to suffer from reduced performance. The HSE expert evidence review panel agreed that this was reasonable.

165. Where the appliances are under manufacturer warranty, any increase in call-outs would be a cost to the manufacturer (at least initially – it is not clear whether this would be passed on to consumers through higher prices). Where the appliances are not under warranty, this will be a direct cost to the appliance owner (e.g., the household or commercial operator).

166. As well as the costs of the call-outs themselves, manufacturers expect that uncertainty about the cause of the issue with the boiler (as changes in gas quality could be transient) could result in unnecessary replacement of components.

Baseline call-out figures for domestic appliances under warranty

167. One major appliance manufacturer has provided us with data on their call-out activity from 2019 and 2020. Based on their market share of boiler sales, we have estimated a market total.

168. Across the sector, we estimate that there are between around 440,000 and 460,000 call-outs involving an actual repair (i.e., replacing a component) for appliances under warranty, with a mid-estimate of around 450,000. To capture the full value of these call-outs, it is prudent to estimate them using the cost that householders are willing to pay for non-warranty engineer call-outs. Although the cost to the warranty-holding manufacturer will not be as high as that, it provides a reasonable willingness-to-pay value of the opportunity cost. For a boiler service, this is estimated based on interviews with manufacturers and trade associations to be between around £150 and £170 for a service with a mid-estimate of around £160 (note these costs do not include any replacement parts). This gives an economic cost of these repair visits (not including replacement parts) of between around £66 million and £78 million, with a mid-estimate of around £72 million.

169. In addition, there are between around 174,000 and 184,000 maintenance call-outs (which do not involve any component replacements) for appliances under warranty, with a mid-estimate of around 179,000. Costed on the same basis as the repair call-outs, maintenance have a cost of between around £26 million and £31 million, with a mid-estimate of around £29 million.

170. As discussed in paragraph 54, we anticipate that between zero and around 7.5% of gas users might receive the low-Wobbe gas, with a mid-estimate of around 4.1%. As such, we assess that it is reasonable to expect that only this proportion of domestic gas appliances would be in scope of any changes to behaviour or performance that could lead to increased call-outs.

Possible increases in call-outs for domestic appliances under warranty

Repair call-outs

171. The appliance manufacturer we interviewed estimated that the volume of repair call-outs where an unnecessary repair took place might increase by 1%, although they expected that this might decrease over time as engineers became more familiar with the Wobbe change. The unnecessary repair was estimated to cost around £250 in terms of parts.

172. If the 1% increase applied only to the zero to 7.5% of domestic users experiencing the lower Wobbe gas, this would give an additional number of repair call-outs of between nil and around 350, with a mid-estimate of around 180. This would imply an increase in repair call-out costs of between nil and around £59,000 per annum in terms of engineer resources, with a mid-estimate of around £29,000.

173. For the unnecessary repair costs, this would come to between nil and around £86,000, with a mid-estimate of around £46,000.

174. This would give a total annual cost on increased repair call-outs (including both engineer resources and repair costs) of between nil and around £150,000, with a mid-estimate of around £75,000.

Maintenance call-outs

175. For maintenance call-outs, the manufacturer we interviewed estimated that these could increase by around 5% in duration; and around 10% by volume. Again, these changes would likely be limited to zero to 7.5% of domestic users expected to experience the lower Wobbe gas.

176. For the maintenance call-outs duration increase, if we apply this as a cost increase to the zero to 7.5% of the total maintenance call-out costs in paragraph 169, this would give a cost of increased duration of between nil and around £120,000, with a mid-estimate of around £59,000.

177. For the maintenance call-out volume increase, this would give an increase of between nil and around 1,400, with a mid-estimate of around 740. Assuming that these are also of 5% greater duration as well, this would indicate a cost increase of between nil and around £250,000 per annum, with a mid-estimate of around £120,000.

178. This would give a total increase in annual costs for maintenance call-outs (including both volume and duration) of between nil and around £360,000 per annum, with a mid-estimate of around £180,000.

Total increase in domestic call-out costs under warranty

179. This would give a total increase in the cost of domestic call-outs under warranty (both maintenance and repair call-outs) of between nil and around £510,000, with a mid-estimate of around £260,000.

180. As noted in paragraphs 46 to 47, we assume that the lower Wobbe gas would not be injected into the network for between one and two years (or at all in the 'low' case). As such, we would not expect additional call-out costs to be incurred until that time also.

181. Adjusting these figures by the projections of gas demand for residential use in Table 3 gives the cost profile summarised below in Table 14. Present value costs over 10 years are estimated at between nil and around £3.6 million, with a mid-estimate of around £1.4 million. There is considerable uncertainty around these figures as domestic appliance performance and consumer behaviour is difficult to predict. The figures below are likely an overestimate as the manufacturer we interviewed expected costs to decline as engineers become more familiar with the issue, which is not reflected in the below. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2).

Table 14: Estimated increase in call-out costs for domestic appliances under warranty (£thousands)

	£thousands		
	Low	Mid	High
Year 0	Nil	Nil	Nil
Year 1	Nil	Nil	£500
Year 2	Nil	£240	£490
Year 3	Nil	£240	£490
Year 4	Nil	£230	£480
Year 5	Nil	£220	£480
Year 6	Nil	£210	£470
Year 7	Nil	£200	£460
Year 8	Nil	£190	£440
Year 9	Nil	£180	£420
Present value	**Nil**	**£1,400**	**£3,600**

Note: figures may appear not to sum due to rounding

Increases in manufacturer call centre costs

182. The appliance manufacturer we interviewed expected that calls to their call centre could increase, both in terms of calls from customers and technical support calls to aid engineers in the field. As with the expected increases in call-outs themselves, there is significant uncertainty around these figures.

183. Adjusting the figures from the manufacturer we interviewed for their estimated market share, we estimate that across the whole sector there are around 1.3 million technical support calls each year; and between around 2.3 million and 2.4 million customer calls.

184. The manufacturer provided figures that the average technical support call lasts around 4.5 minutes; and the average customer call around 7 minutes. This gives:

a. For technical support calls, around 100,000 hours

b. For customer calls, between around 273,000 and 280,000 hours, with a mid-estimate of around 276,000 hours

185. The manufacturer told us that the wage for call centre workers is £14.70 per hour. Adding on 20% to create a full economic cost gives £17.64 per hour. This gives total call costs as follows:

a. For technical support calls, around £1.76 million

b. For customer calls, between around £4.81 million and £4.93 million, with a mid-estimate of around £4.87 million

c. In total, between around £6.58 million and £6.70 million, with a mid-estimate of around £6.64 million.

186. The manufacturer estimated that call volumes for technical support could increase by between 10% and 30%, with a mid-estimate of 20%; and for call centre calls, by around 10%. However, as noted in paragraph 54, only between zero and around 7.5% of gas users are expected to receive the lower Wobbe gas on a regular basis, with a mid-estimate of 4.1%. If we apply the increases in volume only to the affected customers, we get the increases in call volumes below:

a. For technical calls, between zero and around and 30,000, with a mid-estimate of around 11,000

b. For customer calls, between zero and around 18,000, with a mid-estimate of around 9,700

187. The manufacturer also estimated that call durations could increase to allow any gas quality issues to be explored or explained. The estimated technical support calls could increase in duration by between around 10% and 15%, with a mid-estimate of around 12.5%; and that customer calls could increase by around 10%. If we applied these to the additional calls only, we would generate the additional hours below:

a. For technical support calls, between nil and around 2,600 hours per annum, with a mid-estimate of around 920 hours

b. For customer calls, between nil and around 2,300 hours, with a mid-estimate of around 1,200 hours

c. In total, between nil and around and 4,900 hours, with a mid-estimate of around 2,200 hours

188. Using the cost of time of £17.64 discussed in paragraph 185, this would give an estimated total additional call centre cost of between nil and around £86,000, with a mid-estimate of around £38,000.

189. As noted in paragraphs 46 to 47, we assume that the lower Wobbe gas would not be injected into the network for between one and two years (or at all in the 'low' case). As such, we would not expect additional call centre costs to be incurred until that time also.

190. As with the increase in call-outs, we would expect these calls to fall over time as gas demand falls. Adjusting for the falls in gas demand for residential use estimated in Table 3 gives an estimated present value cost of between nil and around £610,000, with a mid-estimate of around £210,000, as summarised in Table 15. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2).

Table 15: Increased call centre costs (£thousands)

	£thousands		
	Low	**Mid**	**High**
Year 0	Nil	Nil	Nil
Year 1	Nil	Nil	£85
Year 2	Nil	£36	£84
Year 3	Nil	£35	£83
Year 4	Nil	£34	£82
Year 5	Nil	£33	£81
Year 6	Nil	£32	£80
Year 7	Nil	£30	£78
Year 8	Nil	£28	£74
Year 9	Nil	£27	£71
Present value	**Nil**	**£210**	**£610**

Note: figures may appear not to sum due to rounding

Possible increases in call-outs for domestic appliances not under warranty

191. For domestic appliances not under warranty, domestic users themselves would bear the cost of any call-outs. As such, they may be less incentivised to call out an engineer. However, we will base the costs that follow on warranty estimates above, noting that this will tend to overestimate the costs.

192. For the appliances under warranty, we have estimated an increase in visits of:

a. For repair visits, between zero and around and 350 visits a year, with a mid-estimate of around 180

b. For maintenance visits, between zero and around 1,400 visits a year, with a mid-estimate of around 740

c. This gives a total of between zero and around 1,700, with a mid-estimate of around 920

193. Evidence from Benchmark indicates that around 59% of domestic boilers are under warranty.[20] If this level of call-out activity were replicated for domestic appliances out of warranty, this would imply:

[20] Updated-6421-Fixing-Fit-and-Forget-Culture-Report.pdf (benchmark.org.uk). Based on Question 2, removing 'don't knows'.

a. For repair visits, between zero and around 240, with a mid-estimate of around 130

b. For maintenance visits, between zero and around 960, with a mid-estimate of around 510

c. This gives a total increase in visits out of warranty of between zero and around 1,200, with a mid-estimate of around 640

194. Evidence from interviews with manufacturers indicates that a call-out charge could be between around £150 and £170, with a mid-estimate around £160. This would give a total charge-out cost for appliances out of warranty of between zero and around £200,000, with a mid-estimate of around £100,000.

195. In addition, if the unnecessary repairs still carried a cost of £250, this would give an unnecessary repair cost of between zero and around £60,000, with a mid-estimate of around £32,000.

196. Taken together, this would give a total cost of between zero and around £260,000, with a mid-estimate of around £130,000.

197. As noted in paragraphs 46 to 47, we assume that the lower Wobbe gas would not be injected into the network for between one and two years (or at all in the 'low' case). As such, we would not expect additional call-out costs to be incurred until that time also.

198. Adjusting these costs for the profile of expected gas demand for residential use in Table 3 gives the profile of costs set out below in Table 16. Present value costs are estimated at between nil and around £1.9 million over 10 years, with a mid-estimate of around £750,000. These costs are highly uncertain and likely an overestimate as domestic users out of warranty might not be as incentivised as those under warranty to call out and engineer in all cases. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2).

Table 16: Estimated costs to domestic users for call-outs to appliances out of warranty (£thousands)

	£thousands		
	Low	**Mid**	**High**
Year 0	Nil	Nil	Nil
Year 1	Nil	Nil	£260
Year 2	Nil	£130	£260
Year 3	Nil	£120	£250
Year 4	Nil	£120	£250
Year 5	Nil	£120	£250
Year 6	Nil	£110	£240
Year 7	Nil	£110	£240
Year 8	Nil	£100	£230
Year 9	Nil	£93	£220
Present value	**Nil**	**£750**	**£1,900**

Note: figures may appear not to sum due to rounding

Possible increases in call-outs for commercial appliances

199. Commercial end-users are much like domestic appliance users with appliances that are used for space-heating, water-heating or cooking, but on a larger scale. Stakeholders in this group include hospitals, hotels, conference centre, leisure centres, schools, retail, and offices.

200. The manufacturer we interviewed indicated commercial users could also see increased engineer call-outs. However, we have rather less detailed estimates of the impacts of these for commercial users than for domestic, including the proportion of pieces of equipment under warranty.

201. The total annual cost to domestic appliances estimated above (including both those under and not under warranty) comes to between nil and around £770,000, with a mid-estimate of around £390,000 (before adjusting for declining gas demand). We could use this to make an inferred estimate for commercial gas equipment.

202. According to the consultation stage IA[21], there are between around 49 million and 52 million domestic gas appliances, with a mid-estimate of around 51 million. The number of pieces of commercial equipment are estimated at between around 1.1 million and 1.9 million, with a mid-estimate of around 1.6 million. This would imply that commercial gas equipment numbers are between around 2.2% and 3.7% of domestic numbers, with a mid-estimate of around 3.1%. This might imply that, in terms of volume, commercial call-outs could be considerably less than domestic.

203. Data published by BEIS[22] on the costs of domestic boilers indicates that they can cost (in 2020 prices) between around £2,400 and £6,700. Estimates from the Hy4Heat commercial equipment report[23] indicate that commercial boilers can cost (in 2020 prices) between around £12,900 and £58,100. This would imply that equipment in the commercial sector can cost between around 5.3 and 8.7 times that of domestic appliances, with a central estimate of around 7.0. This might imply that, even if volumes of call-outs are lower, costs per call-out could be higher.

204. If we take these two relativities together (lower volume and higher cost) and apply them to the domestic costs in paragraph 201, we get an estimate of the costs for commercial call-outs of between nil and around £250,000, with a mid-estimate of around £85,000.

205. As noted in paragraphs 46 to 47, we assume that the lower Wobbe gas would not be injected into the network for between one and two years (or at all in the 'low' case). As such, we would not expect additional call-out costs to be incurred until that time also.

206. These costs are likely an overestimate because, even if the commercial equipment costs more than domestic, this does not indicate that the costs of the engineer's time will be similarly proportionately higher, which will make up a large part of costs.

207. Once again, if we adjust for declining gas demand for commercial use as summarised in Table 3, we get the profile of costs set out below in Table 16. This gives a present value cost of between nil and around and £1.8 million, with a mid-estimate of around £760,000. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2).

Table 17: Estimated costs of increased call-outs for commercial equipment (£thousands)

	£thousands		
	Low	**Mid**	**High**
Year 0	Nil	Nil	Nil
Year 1	Nil	Nil	£250
Year 2	Nil	£86	£250
Year 3	Nil	£85	£250
Year 4	Nil	£82	£240
Year 5	Nil	£79	£230
Year 6	Nil	£75	£220
Year 7	Nil	£71	£210
Year 8	Nil	£66	£200
Year 9	Nil	£62	£190
Present value	**Nil**	**£510**	**£1,800**

Note: figures may appear not to sum due to rounding

21 CD291 - Revision of the Gas Safety (Management) Regulations 1996 - Health and Safety Executive - Citizen Space (hse.gov.uk)
22 The cost of installing heating measures in domestic properties (publishing.service.gov.uk), Table 2
23 Report (squarespace.com), Appendix F

Summary of call-out costs

208. The total costs of increased call-outs for Option 2 are summarised below in Table 18 at between nil and around £7.8 million, with a mid-estimate of around £3.2 million. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2).

Table 18: Total increased call-out costs (present values, £thousands)

	£thousands		
	Low	Mid	High
Domestic appliances (under warranty)	Nil	£1,400	£3,600
Domestic appliances (out of warranty)	Nil	£750	£1,900
Commercial appliances	Nil	£510	£1,800
Call centre costs	Nil	£210	£610
Total	**Nil**	**£2,900**	**£7,800**

Note: figures may appear not to sum due to rounding

E.2.7. Industrial end-users

Background on industrial users

209. Industrial end-users are those organisations and businesses that do not use gas to heat water or use gas for conventional cooking; rather they use gas in a more directed way (e.g. glassmaking) or as a constituent of a chemical process (e.g. producing hydrogen) and so the proposed changes to gas quality under Option 2 will result in impact for industrial users.

210. Industry groups include chemicals, pharmaceuticals, paper, iron & steel, glass manufacturers, petrochemical plants, non-ferrous metals, mineral production, mechanical engineering, electrical engineering, vehicles production, textiles, paper, and construction.

211. Views from the industrial interviews indicated an expectation that the gas systems should mostly be able to manage a widening of the WN range at the top and bottom, but that some systems would require upgrading. Comments from stakeholders suggest that a wider WN range of gas would increase both variability and fluctuations, but this increase can largely be managed within the parameters of: a) existing equipment (e.g. burners); and b) existing systems (e.g. control and monitoring systems).

212. Some interview responses indicated that upgrading could be done with new equipment or simply retuning to manage a new WN range. However, other interview responses expressed some uncertainty around how these systems would be impacted by a wider WN range as industry users are unfamiliar with the quality of the gas they receive, and they will need to learn about the supply to implement interventions.

213. Emissions changes around oxygen trim and NOx were flagged; one respondent was uncertain how CO levels would be affected. There is a tight range for pollution and large burners must comply with emissions and efficiency legislation. It is possible that new emissions abatement equipment could be needed to manage the proposed change.

214. We received only a handful of responses to our 2021 survey from industrial users. The one detailed response from a paper and paperboard manufacturer expected that the overall impact of widening the WN range at the top and bottom would be negative. This end-user operates a combed heat power (CHP) facility for electricity and heating. They expected cost increases for monitoring gas quality through gas chromatography at £15,000.[24] Otherwise, the respondent thought the WN change would be manageable with current equipment.

215. Industry sector sentiment from the 2021 survey on the overall impact of widening the WN range at both the top and bottom indicated a split between those who believe the impact will be negative; and those who think there will be no impact. However, three of the respondents who said there would be 'no impact' went on to describe potential negative impacts for other gas users or for wider society, including safety concerns and a reduction in public faith in the gas industry.

[24] CHPs are discussed in paragraphs 158 to 162.

216. An appliance manufacture association believed that equipment impacts are unknown, so safety is a “grave” concern for existing and new equipment. They thought that thorough testing of range (variability) and fluctuation is needed for existing equipment and believed that no costs can be estimated without testing.

217. The association also expected challenges in that gas quality monitoring equipment is not widely used and existing control systems are not suitable for WN gas quality change. Some equipment could be upgraded while others will need to be replaced, but testing would be required to determine this. To complete maintenance on gas equipment, engineers would need additional training and deployment of handheld WN devices which are not currently used.

218. For the other equipment manufacturers, there is uncertainty about the impacts. Research into the impacts of widening the WN range at the top and bottom on one respondent’s equipment is expected to cost £250,000. This research will assess appliances at the proposed extremes of WN range to determine the extent of efficiency, NOx emissions, heat exchanger temperatures, thermostat compliance, and ensure safe combustion. The other manufacturer expressed concerns about equipment safety and performance but did not state any specific cost.

219. Comparing the evidence from the initial interviews and the survey, there are somewhat contradicting responses as to the extent of the impact of widening the top and bottom of the WN range and the extent to which existing systems can cope with the changes. Many of the costs that were identified in the interviews are repeated in the survey responses, but the latter suggest a large impact where interviews suggest a smaller one.

220. We sought further quantified evidence from respondents during consultation. We received only at most a few responses for each type of equipment. Review by the expert review group indicated that the reported costs appeared low for the types of equipment being considered and suggested they could be ten times greater – we have erred in favour of ten times higher costs in this analysis.

Quantified cost estimates for industrial users

Number of pieces of industrial gas equipment in GB

221. The 2020 Hy4Heat WP6[25] report estimated the number of pieces of industrial gas equipment. The Hy4Heat estimates comprise only those pieces of equipment with thermal capacity greater than 1 MW, to avoid overlap with smaller pieces of equipment captured under the ‘Commercial’ heading; and that is connected to the <7 bar network, which Hy4Heat estimate captures around 70% of gas use in the industrial sector. As a rough correction for the 7+ bar network, the numbers of pieces of industrial gas equipment below have been uprated by 1/0.7 to make up the gap – this probably has the effect of overestimating the total as the missing equipment on the 7+ bar network is likely to use more gas per piece of equipment than on the <7 bar network. As the Hy4Heat report makes estimates of the number of pieces of industrial equipment in 2019, and we assume these figures are still representative. As summarised in Table 19, we estimate there to be around 5,900 pieces of equipment.

Table 19: Estimates of industrial gas equipment in GB

Appliance type	Estimate
Steam boilers	2,000
Ovens	1,000
Boilers (hot water)	860
Direct dryers	860
Furnaces (other)	430
Other	390
Kilns (ceramics)	230
Furnaces (metal melting)	86
Furnaces (glass)	57
Kilns (lime)	21
Kilns (other)	14
Total	**5,900**

Note: figures may appear not to sum due to rounding

[25] WP6 Understanding Industrial Appliances Report (squarespace.com)

222. Also according to the Hy4Heat report, these pieces of industrial equipment were found across the following sectors in 2019 as summarised Table 20.

Table 20: Industrial gas use in TWh/year (2019)

Appliance type	TWh/year
Food and drink	15
Chemicals	11
Electrical and mechanical engineering	8
Basic metals	6
Ceramics	4
Glass	4
Paper	4
Vehicle manufacture	4
Other non-metallic minerals	3
Lime	1
Refining	-
Other	5
Total	**65**

Adaptation costs

223. As part of the consultation, we asked respondents whether they operate, service or produce the types of equipment set out in Table 19. For those that did, we asked what proportion would require some action (such as modification) to operate following the GSMR change, what would be involved and what it would cost. The results are summarised below.

224. As noted above, we did not receive many responses – only twelve different respondents across the eleven equipment types, although several of those respondents were able to respond on multiple equipment types and some represented professional associations, who can be expected to have a wider view than individual organisations.

225. To estimate the proportion of equipment that would need some action, we have generated a range taking an average of estimates given as a top. To estimate the bottom of the range, we have taken an average of the estimates given, including those who report that they operate, service or produce the equipment in question, but did not make an estimate of the proportion that would need action; these respondents are interpreted as indicating 0% will need action. This is a strong interpretation of their response – for example, they might not have given a proportion estimate because they do not know – but it helps to provide a lower estimate for use in the analysis.

226. As noted in paragraph 220, the expert review panel believed that the costs quoted for adaptation of the equipment sounded low for the types of equipment in question, which are often expensive and bespoke. The panel suggested that costs could be ten times greater than many of those given in the consultation responses. As such, we have adopted a cautious approach and applied this 10x multiplier to the costs across the board.

227. It is not expected that the costs for adapting industrial equipment would all be incurred in one year. We anticipate it would take time to book in engineers and consultation responses indicate that at least some of the work would be undertaken as part of routine scheduled maintenance. As such, we assume that adaptations will take three years to complete.

228. We anticipate that the delays caused by NEAs (see paragraphs 46 to 47) would provide an opportunity for some industrial operators to delays or (in the 'low' case) to avoid adaptation costs. While we anticipate that adaptation for low Wobbe gas could take three years, we anticipate that most industrial users will be able to delay the commencement of this work until the regulations change, meaning that costs will be incurred in Years 1 to 3 in the 'high' case; and Years 2 to 4 in the 'mid' case. For the 'low' case, where the NEAs are not agreed and the low Wobbe gas does not flow, we anticipate adaptation costs can be avoided. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2), although it is not unreasonable to expect highly Wobbe-sensitive industrial equipment operators to take early preventative action in some cases.

229. The exceptions to this are the most sensitive industrial gas users, ceramic kiln and glass furnace operators, who we anticipate will make immediate changes to their equipment irrespective of the NEA progress in Years 0 to 2.

230. This modelling of the behaviour of industrial gas users with respect to NEA delays may not be a perfect forecast of activity, but we assess that it gives a reasonable indication of the flexibilities available to industry based on discussion with the HSE expert review group.

231. For **steam boilers**, responses indicated that a range of between around 25% and 100% could require some adjustment. This gives between around 500 and 2,000 steam boilers, with a mid-estimate of around 1,300. Costs were estimated at between around £4,000 and £5,000, with a mid-estimate of around £4,500. The work required a reset of combustion controls and air-intakes. The total present value cost for steam boilers is estimated at between nil and around £9.3 million, with a mid-estimate of around £5.1 million.

232. For **industrial ovens**, responses indicated that a range of between around 46% and 77% could require some adjustment. This gives between around 460 and 770 industrial ovens, with a mid-estimate of around 620. Costs were estimated at between around £1,500 and £5,000, with a mid-estimate of around £3,300. The work required was described as a reset of combustion controls and increasing burner temperature if set-point target temperatures cannot be met. The total present value cost for industrial ovens is estimated at between nil and around £3.6 million, with a mid-estimate of around £1.8 million.

233. For **hot water boilers**, responses indicated that a range of between around 18% and 63% could require some adjustment. This gives between around 150 and 540 hot water boilers, with a mid-estimate of around 350. Costs were estimated at between around £1,500 and £5,000, with a mid-estimate of around £3,300. The work required was described as a reset of combustion controls and recommissioning of burners. The total present value cost for hot water boilers is estimated at between nil and around £2.5 million, with a mid-estimate of around £1.0 million.

234. For **glass furnaces**, responses indicated that a range of between around 50% and 100% could require some adjustment. This gives between around 29 and 57 glass furnaces, with a mid-estimate of around 43. Costs were estimated at around £10,000. The work required was described as including an adjustment of the fuel ratio controller. The total present value cost for glass furnaces is estimated at between around £280,000 and £550,000, with a mid-estimate of around £410,000.

235. For **lime kilns**, an industry body has reported that they do not anticipate any changes will be required.

236. For **'other' equipment**, responses indicated that around 50% could require some adjustment. This gives around 190. According to responses, these 'other' pieces of equipment included heaters, air curtains, tunnel finishers[26] and tumble dryers. Costs were estimated at between around £2,500 and £6,000, with a mid-estimate of around £4,300. The work required was described as including testing of adaptability to the new gas and adapting combustion and air controls. The total present value cost for 'other' equipment is estimated at between nil and around £1.1 million, with a mid-estimate of around £740,000.

237. For the remaining types of gas equipment – **direct dryers, metal-melting furnaces, other furnaces, and other kilns** – we did not receive any consultation responses. If we were to assume that the percentage of these that would require some action was equal to the average of those given above, this would be between around 38% and 78% of around 1,400 pieces of equipment. This would come to between around 530 and 1,100 pieces of equipment, with a mid-estimate of around 820. If we were to assume that the cost of any adaptation was equal to the average of those given above, this would come to between around £3,900 and £6,200 per piece of equipment, with a mid-estimate of around £5,100. This would give a total present value cost of adaptation of between nil and around £6.4 million, with a mid-estimate of around £3.7 million.

238. **Ceramic kilns** are also included within these 'remaining types' of gas equipment, albeit with a different time distribution (see paragraphs 228 to 230). Applying the range of between around 38% and 78% of the 230 ceramic kilns requiring some action gives between around 86 and 180 ceramic kilns, with a mid-estimate of around 130. Applying the average costs in paragraph 237 gives a total present value cost of adaptation of ceramic kilns of between around £330,000 and £1.1 million, with a mid-estimate of around £650,000.

239. This would give a **total estimated present value cost for adapting industrial equipment** under Option 2 of between around £600,000 and £24 million, with a **mid-estimate of around £13 million**. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented

[26] A tunnel finisher is a machine used in the textile industry to remove wrinkles from garments.

until 2025 (Year 2), although it is not unreasonable to expect highly Wobbe-sensitive industrial equipment operators to take early preventative action in some cases.

E.2.8. Familiarisation

240. Dutyholders and stakeholders would need to familiarise with the changes to the WN range under Option 2 to understand how they would be affected and what they would have to do to respond. We asked in the consultation what this would involve and how long it would take for respondents to familiarise themselves and their organisations.

241. **Gas engineers** told us in the consultation that they would spend between around one and ten hours familiarising themselves and their organisation with the changes. A separate interview with the Gas Safe Register indicated that they would produce updated information with support from HSE for gas engineers to inform them of the changes, but that additional training would not be required. As such, one to ten hours appears a reasonable estimate.

242. Data for the Interdepartmental Business Register (IDBR) indicates that there are around 40,665 businesses involved in 'plumbing, heating and air conditioning'.[27] According to the Annual Survey of Hours and Earnings (ASHE), the average hourly wage of an engineering professional[28] is £22.33. Uprating by 20% to give a full economic cost comes to £26.80 per hour. This gives an estimated one-off cost for familiarising gas engineers of between around £1.1 million and £11 million, with a mid-estimate of around £6.0 million.

243. For **terminals**, consultation responses indicated that they would need around 50 hours to familiarise. There are eleven terminals.[29] If we assume they also face a cost of £26.80 per hour, this gives a total estimated one-off cost for familiarising gas terminals of around £15,000.

244. For the five **interconnectors**[30], consultation responses indicated around 100 hours might be needed. Costed at £26.80 per hour, this gives an estimated one-off cost for familiarising interconnectors of around £13,000.

245. Responses from **manufacturers of gas appliances** indicated that the larger manufacturers might spend around 10,000 hours, including time needed to update published manuals on appliance performance. Smaller manufacturers might need 100 hours.

246. Responses from larger manufacturers also indicated that they might each need to spend around £300,000 testing their appliances to see what manual and performance changes might be required.

247. If we take 'larger' to mean having 250 employees or more, there are five such manufacturers according to the IDBR; and 240 with fewer than 250 employees.[31]

248. Costed at £26.80 per hour (see paragraph 242), this would give an estimated total cost of familiarising for manufacturers (including testing costs for larger manufacturers) of around £3.5 million.

249. Responses from **gas distributors** indicated that only GDNs would need to familiarise, estimated to take a total of between around 350 and 480 hours, with a mid-estimate of around 410 hours. Costed at £26.80 per hour, this would give an estimated total cost of gas distributor familiarisation of between around £9,300 and £13,000, with a mid-estimate of around £11,000.

250. We would expect that the familiarisation costs for some other groups could be included in some of the other estimated costs, such as OEM reports for power generators (see paragraphs 127 to 132); or that they are already fully familiar with the impacts, such as gas producers. For some other groups, such as industrial users, familiarisation costs remain unclear.

251. Estimated to be borne in Year 0 of the appraisal period, this gives an **estimated total familiarisation cost** of between around £4.6 million and £14 million, with a **mid-estimate of around £9.5 million**.

[27] Inter-Departmental Business Register (IDBR) - Office for National Statistics (ons.gov.uk), SIC code 43220

[28] SOC code 212

[29] Three LNG terminals (South Hook, Dragon and Isle of Grain) and eight natural gas terminals (CATS Teesside, Easington/ Dimlington, Bacton, Rampside Barrow, St Fergus, Theddlethorpe and Burton Point).

[30] Norway, Belgium, Netherlands, Northern Ireland and the Republic of Ireland

[31] SIC code 2521 'Manufacturers of central heating radiators and boilers'; and SIC code 2752 'Manufacturers of non-electric domestic appliances'

E.2.9. Reduced fatalities from carbon monoxide poisoning

252. Having lower Wobbe gas in the network is expected to slightly reduce the number of fatalities from carbon monoxide (CO) poisoning when the gas is burned in appliances. This is because the gas has lower calorific value and consequently CO production is reduced in malfunctioning appliances that have abnormally low air-fuel ratios. The aforementioned GQWG evidence submission on gas quality demonstrated that reducing the lower WN would have the effect of reducing fatalities. That said, CO poisonings would continue to be dependent upon other external factors, such as inadequate flueing or ventilation.

253. The Office for National Statistics[32] in 2021 produced figures for CO poisoning deaths from 2010 to 2020, shown in Table 21. The numbers have declined from a peak in 2013 of 197 to 116 in 2020.

Table 21: Deaths from CO poisoning 2010 to 2020

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Number of deaths	177	171	182	197	195	178	159	155	127	120	116

254. Analysis by IGEM and reviewed by HSE estimates that the proposed lower Wobbe range could result in between around 0.032 and 0.072 fewer deaths each year, with a mid-estimate of around 0.052. As discussed in paragraphs 46 to 47, we do not expect any new low-Wobbe gas to flow in the 'low' case, and so we anticipate no saved lives in the 'low' case.

255. HSE produce estimates of the costs to society of a fatality as part of the Costs to Britain estimates.[33] The estimates are summarised below in Table 22. Costs include lost productivity, healthcare costs, administrative costs and non-financial human costs (pain, grief and suffering). Costs are net of transfers between groups (such as tax losses and benefit payments).

Table 22: HSE estimates of the costs to society of a fatality (£thousands, 2022 prices)

Cost component	£thousands
Financial cost	£500
of which, individual	*£260*
of which, employer	*£120*
of which, government	*£120*
Non-financial cost	£1,400
Total	**£1,900**

Note: figures may appear not to sum due to rounding

256. Across the averted fatalities in paragraph 254, this would give total annual benefits of between nil and around £140,000, with a mid-estimate of around £100,000.

257. As noted in paragraphs 46 to 47, we note that the lower Wobbe gas would not be injected into the network until two years hence (or at all in the 'low' case). As such, we would not expect any averted fatalities until that time also.

258. We would also expect this benefit to decline with declines in gas demand over time as the underlying baseline CO poisonings would also decline, all else equal. Adjusting the benefits of reduced CO poisonings over time by gas demand for residential use (as summarised in Table 3) gives a **total estimated present value benefit over 10 years** of between nil and around £1.0 million, with a **mid-estimate of around £610,000**. Note that non-financial benefits are discounted at 1.5%, rather than 3.5%. As discussed in paragraph 43, this could be an overestimate in the high case due to the lower-WN limit not being implemented until 2025 (Year 2). These total benefits (summarised in Table 23) are broken down as follows:

a. To individuals:

- Non-financial benefits of between nil and around £800,000, with a mid-estimate of around £460,000

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32 Carbon monoxide deaths and poisonings for the past 10 years - Office for National Statistics (ons.gov.uk)

33 Costs to Britain of workplace fatalities, self-reported injuries and ill health, 2018/19 (hse.gov.uk)

- Financial benefits of between nil and around £130,000, with a mid-estimate of around £75,000

b. To employers, between nil and around £59,000, with a mid-estimate of around £34,000

c. To government, between nil and around £61,000, with mid-estimate of around £35,000

Table 23: Estimated benefits of recused CO poisonings over appraisal period (£thousands)

	Financial benefits (£thousands)									Non-financial benefits (£thousands)			Total (£thousands)		
	Individuals			Employers			Government			Individuals					
	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High	Low	Mid	High
Year 0	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	Nil	**Nil**	**Nil**	**Nil**
Year 1	Nil	Nil	£18	Nil	Nil	£8.3	Nil	Nil	£8.5	Nil	Nil	£100	**Nil**	**Nil**	**£140**
Year 2	Nil	£13	£18	Nil	£5.8	£8.2	Nil	£5.9	£8.4	Nil	£70	£100	**Nil**	**£95**	**£130**
Year 3	Nil	£12	£18	Nil	£5.6	£8.1	Nil	£5.8	£8.4	Nil	£69	£99	**Nil**	**£93**	**£130**
Year 4	Nil	£12	£18	Nil	£5.5	£8.0	Nil	£5.6	£8.2	Nil	£67	£98	**Nil**	**£90**	**£130**
Year 5	Nil	£12	£17	Nil	£5.3	£7.9	Nil	£5.4	£8.1	Nil	£65	£96	**Nil**	**£87**	**£130**
Year 6	Nil	£11	£17	Nil	£5.1	£7.8	Nil	£5.2	£8.0	Nil	£62	£95	**Nil**	**£83**	**£130**
Year 7	Nil	£11	£17	Nil	£4.8	£7.6	Nil	£5.0	£7.9	Nil	£59	£93	**Nil**	**£80**	**£130**
Year 8	Nil	£10	£16	Nil	£4.5	£7.3	Nil	£4.7	£7.5	Nil	£55	£89	**Nil**	**£75**	**£120**
Year 9	Nil	£9.3	£15	Nil	£4.2	£6.9	Nil	£4.4	£7.1	Nil	£52	£84	**Nil**	**£70**	**£110**
Present value	**Nil**	**£75**	**£130**	**Nil**	**£34**	**£59**	**Nil**	**£35**	**£61**	**Nil**	**£460**	**£800**	**Nil**	**£610**	**£1,000**

Note: figures may appear not to sum due to rounding

E.2.10. Wider gas market impacts and emissions

259. In this analysis, we assume that the supply of gas onto the NTS will still balance with demand, which we assume to be finite and unaltered by the options proposed. Therefore, our modelling assumes that any increases in supply from a source such as the UKCS will be offset by reduced supply through pipeline interconnectors to mainland Europe or from reduced imports of LNG.

260. We do not possess evidence to verify which sources of supply will be displaced in the UK supply mix as a result of increases from an alternative source, such as the UKCS, for example.

261. To assess impacts over the future, we will use the NSTA projections of UKCS production and UK gas demand.[1]

Impact on supply and import dependency

262. Data collected via the consultation and analysed by the NSTA suggests that two producers would increase their supply of gas from the UKCS as a result of the proposed changes to GSMR. These are as discussed in Section E.2.3. The production data has been provided to NSTA and HSE on a commercially confidential basis and so is not replicated in full in this IA. The additional production is limited, peaking at around 1.0% of baseline UKCS production in 2026 and 2027. The effect on import dependency is similarly very minor and does not affect the overall upward trend over time.

263. Any increased gas flows from UKCS producers enabled by this regulatory change could reduce GB's dependence on gas imports, relative to the counterfactual, if gas imports are the marginal source of gas. Import dependency under the baseline is forecast to rise from 61.2% in 2023 to 75.7% in 2032. The additional gas estimated to be enabled by Option 2 makes at most a 0.4% point decrease in 2025; and progressively less in subsequent years. We are unable to verify the marginal source of the gas impacted by the WN changes. However, we know from DUKES that UKCS provides a steady baseload and actually increased production even in years like 2020 when we witnessed a large fall in demand for gas as the pandemic took hold. During such periods, imports into the UK for gas decreased significantly, suggesting that imports tend to be the source of gas that flexes in the UK market.

Impact on Wholesale Price and on Consumers

264. We do not anticipate any reductions in the gas prices from the proposals under Option 2. Operating cost savings from reduced gas processing are minimal (present value over 10 years around £460,000, see paragraphs 76 to 78) and we do not assess that there are incentives to pass these savings on to customers in any case. Although gas production from the UKCS is expected to increase under Option 2, the gas market is global and the quantities expected to be produced are not sufficient to affect overall supply. As such, we do not anticipate any effects on gas prices.

Potential Impact on Emissions

265. We consider that this stimulus to flows of UKCS gas could reduce the carbon footprint of gas in the UK supply mix. The additional production of gas from the UKCS potentially enabled by Option 2 would entail virtually zero incremental emissions, as it would use existing infrastructure whose emissions are not sensitive to throughput. If this additional UKCS production were to displace imported gas, this imported gas's emissions from production could be as low as 17kgCO_2e/boe for the Norwegian interconnector or as high as 144kgCO_2e/boe for USA LNG. It is impossible to say for sure which import would be replaced.

266. If we were to assume that additional UKCS gas production enabled by Option 2 were to displace gas from the cleanest source (the Norwegian interconnector), then this gives a minimum estimate of saved emissions in production. There are approximately 170,000 boe in a bcm of gas, giving emissions per bcm of Norwegian interconnector gas of around 2.9 million kgCO_2e/bcm. The cost of emissions per tonneCO2e are estimated by BEIS[2] and have been adjusted below to 2022 prices using GDP deflators – see Table 24.

267. As discussed elsewhere in this IA, data on additional production has been shared with NSTA and HSE on a commercially confidential basis and is not replicated in this IA in detail. We assess that displacement of imported gas would generate **present value savings** of between nil and around £1.5 million, with a **mid-estimate of around £590,000**.

[1] North Sea Transition Authority (NSTA): Production and expenditure projections - Data downloads and publications - Data centre (nstauthority.co.uk)
[2] Valuation of greenhouse gas emissions: for policy appraisal and evaluation - GOV.UK (www.gov.uk)

268. Note that these savings account only for the production of the additional UKCS gas, not for its burning; and are limited to UK emissions – any otherwise imported gas displaced under Option 2 would be directed elsewhere.

Table 24: BEIS costs per tonneCO2e (2022 prices)

	Cost per tonneCO_2e (£, 2022 prices)		
	Low	Mid	High
2023	£130	£259	£389
2024	£132	£263	£395
2025	£134	£268	£401
2026	£136	£272	£408
2027	£138	£276	£414
2028	£140	£280	£420
2029	£142	£284	£426
2030	£144	£288	£432
2031	£146	£293	£440
2032	£148	£297	£446

E.2.11. Other changes and modernisations to GSMR

269. Option 2 also includes changes to modernise GSMR. These changes are largely intended to improve standards of safety and mitigate risk but also account for and reflect the present-day operation of the gas network. These changes are the basis of Option 3.

Formalise the class exemptions for oxygen in biomethane to a general ≤1 mol% oxygen limit at pressures at or below 38 barg

270. GSMR places a limit on the oxygen content of gas that may be distributed in networks of ≤0.2% (molar). This is set down in Schedule 3. This created a problem for biomethane producers wishing to supply gas to the network as biomethane composition typically has oxygen concentrations higher than permitted by the regulations.

271. In 2013, following an evidence review of the safety of increasing the oxygen content in gas networks, the HSE granted a class exemption from GSMR Schedule 3 to allow network conveyance of gas with an oxygen content ≤1% (molar) at pressures up to 38 barg. This class exemption was made so that biomethane producers no longer had to request exemptions from GSMR.

272. The proposal would now be to formalise this class exemption within the regulations. As this policy is already in place in practice, we are not attributing any costs or benefits to its introduction here.

Continuation of a call-handling service

273. Regulation 7 requires British Gas plc to provide a continuously manned telephone service for gas users to be able to report a gas escape. This regulation exists to help manage the risk to safety that arises from gas escapes by coordinating an attendance and prevention response from the relevant gas conveyor. British Gas plc are no longer the dutyholders for this service and the reporting duties that come with it.

274. The proposal is for the service to continue without a named entity in the form of a general duty on the industry to provide an emergency call-handling service. All references to British Gas p.l.c. would be removed. The new wording to reflect the dutyholder of this service would be the ‘Emergency Reporting Service Provider’ (ERSP).

275. The ERSP will also have a duty to include a safety case; to provide a continuously manned telephone service (which together with other gas conveyors shall be contactable within GB by the use of one telephone number); and for enabling persons to report an escape of gas from the network of the gas conveyor or from a gas fitting supplied with gas from that gas conveyor.

276. The ERSP will be required to contact the relevant gas conveyor, or their emergency service provider (where different), immediately when an emergency arises from a gas escape or suspected emission of CO. The service provider needs to prepare and maintain efficient methods of collecting and recording up-to-date information on the geographical areas covered by each gas transporter and/or emergency service provider. It will also need to

establish arrangements to demonstrate that notifications are passed on promptly, that there are certain standards of service and that adequate business continuity arrangements are in place to maintain the service during unplanned disruptions.

277. This service is currently provided by Cadent and we do not anticipate any change of provider and so it follows that any costs should be minimal. The consultation-stage impact assessment estimated that there would be minimal costs arising from this change and consultation responses agreed with this conclusion.

Inclusion of biomethane pipelines

278. Inconsistencies have arisen with the application of GSMR, with some pipelines connecting the biomethane production plants considered to be on the network and some not. This results in some pipelines operated with a safety case, and some without, which HSE considers to be inappropriate management of risk.

279. The policy intention is to ensure that all parts of the network that are conveying gas periodically have a safety case in place that is helping to manage risk and that these pipelines are regulated consistently.

280. This would be a new duty on the operators of biomethane pipelines that do not have a safety case already in place and would mean an additional administrative cost to such operators of having to prepare and compile a safety case. Evidence from a renewable energy trade association indicates that there are around 100 biomethane sites in scope; and that producing a safety case (with the help of a consultant) would cost around £25,000. This would imply a one-off cost to biomethane producers to develop safety cases of around £2.5 million. This figure is probably an overestimate because (a) some operators will operate multiple sites, which will bring the cost per site down somewhat; and (b) some biomethane producers could already have a safety case for the pipeline.

281. Once safety cases are submitted, HSE will review them and charge for this review. HSE estimate that the review would take around 15 hours for each safety case, which will be charged at the GSMR rate of £154 per hour, which comes to around £2,300 per safety case; or around £230,000 in total.

282. HSE propose to give biomethane producers a two-year transition period to prepare and submit their safety cases. If the costs above were spread over Years 0 and 1 in the appraisal period, this would give a present value one-off cost of around £2.7 million.

283. Once accepted, safety cases are required to be reviewed every three years. The Renewable Energy Association estimated that a safety case could cost around £25,000 annually to maintain. HSE experts believe this is unreasonable and estimate that a cost of around £3,000 would be more reasonable for the three-year review based on the time the review is expected to take. If we took the £25,000 as referring to the three-year cost and took a range between these costs and assumed that one third of the 100 safety cases were reviewed each year from Year 2, this would give an annual cost of between around £100,000 and £830,000, with a mid-estimate of around £470,000.

284. HSE Experts report that their review of a three-year safety case review is minimal if no material changes are made. Where material changes are made (estimated to be around 20% of the time), the charge by HSE to review could be up to the £2,300 described in paragraph 281 (although would probably be less). This would come in total to around £15,000 per annum.

285. Borne from Year 2 to Year 9, this would give an estimated present value cost of three-year reviews (including both business costs and HSE charges) of between around £770,000 and £5.6 million, with a mid-estimate of around £3.2 million.

286. This would give a **total estimate present value cost** of between around £3.5 million and £8.3 million, with a mid-estimate of **around £5.9 million**. These costs are also incurred under Option 3 (see section E.3).

Clear co-operation duties for operators of liquefied natural gas (LNG) import facilities

287. GSMR Regulation 6 places duties on several parties to co-operate with gas conveyors and the network emergency co-ordinator (NEC) to allow them to comply with their responsibilities under the regulations. Gas conveyors transport gas on behalf of shippers and suppliers and have duties to ensure that safe pressures are maintained in the network. They rely on other parties using the network to co-operate with them in discharging this duty.

288. The NEC co-ordinates the actions of the gas conveyors and these other parties if there is a widespread gas supply emergency. Currently, the co-operation duty covers gas production facilities, onshore processing terminals, and gas storage facilities but may not cover LNG import facilities (the legal view provided to HSE is that the current definition of a ‘gas production facility’ and a ‘gas processing facility’ cannot be applied to an LNG facility). It is important for the NEC to be able to ensure the co-operation of LNG terminals.

289. In practice coordination already happens due to shared understanding and mutual interest, but whilst there is an opportunity to amend GSMR, it is sensible to ensure that the co-operation duties apply to LNG import facilities. This will be done by either creating a new definition applicable to an LNG site, or amending existing definitions.

290. Consultation responses indicated that costs would be very minimal.

E.2.12. Enforcement costs

291. Enforcement of the new Regulations would form part of HSE's normal inspection work and reactive investigations. Extra costs and time spent reviewing additional safety cases of biomethane operators have already been estimated. There would be no other costs or additional time spent inspecting as a result of these new Regulations.

E.2.13. Summary of potential costs and benefits of Option 2

292. As summarised in Table 25, total estimated present value costs are between around £44 million and £340 million, with a mid-estimate of around £160 million.

293. Estimated benefits total a present value of between around £460,000 and £500 million with a mid-estimate of around £220 million.

294. This gives an **estimated net present benefit** of between around -£44 million (a net cost) and +£160 million, with a **mid-estimate of around +£52 million**.

295. Often in impact assessments, the lower bound net present value is found by subtracting the high cost estimate from the low benefit estimate; and the high net present value vice versa. This is done where the higher bound and lower bound estimates reflect ranges of uncertainties on costs or prices that could occur concurrently. In this final stage IA, the lower bound and higher bound estimates reflect mutually exclusive scenarios – one where the NEAs are agreed in one year ('high' case) and one where they are not agreed at all ('low' case). As such, this final stage IA calculates the low net present value by subtracting the low cost estimate from the low benefit estimate; and the high net present value by subtracting the high cost estimate from the high benefit estimate.

296. As discussed above, further additional costs related to electricity turbine outages have not been possible to estimate in this analysis.

297. The impacts assessed to be direct are those that fall to the dutyholders in scope of GSMR – that is, gas distributors and biomethane producers in respect of their new safety case requirements. Other business groups are considered to be indirect:

a. Gas producers are further up the supply chain from gas distributors and will respond to the changes via a business incentive

b. Power generators and industrial users are further down the supply chain

c. Increased call-out costs occur following behaviour change of gas customers

d. The savings to employers from fewer CO poisoning accrue through the employment arrangements of the deceased, and are so indirect

298. The equivalent annual net direct cost to business of Option 2 in 2019 prices and 2020 present values is estimated at £0.7 million. This is below the de minimis for the Business Impact Target (BIT) of £5 million, and so would count as nil for the BIT.

Table 25: Summary of estimated monetised costs and benefits of Option 2 (£millions, present values over ten years, in 2022 prices)

	£millions			
	Low	Mid	High	Direct or indirect?
Costs				
Gas producers and importers	Nil	£0.7	£1.2	Indirect
Gas distributors	£0.8	£1.0	£1.3	Direct
Power generators	£35	£130	£280	Indirect
Increased call-outs (business)	Nil	£2.1	£5.9	Indirect
Increased call-outs (households)	Nil	£0.8	£1.9	N/A
Industrial end-users	£0.6	£13	£24	Indirect
Familiarisation (direct)	£0.04	£0.04	£0.04	Direct
Familiarisation (indirect)	£4.6	£9.5	£14	Indirect
Biomethane safety cases	£3.5	£5.9	£8.3	Direct
Total costs	**£44**	**£160**	**£340**	
Benefits				
Gas producers and importers	£0.5	£210	£500	Indirect
Saved lives (individuals)	Nil	£0.5	£0.9	N/A
Saved lives (employers)	Nil	£0.03	£0.06	Indirect
Saved lives (government)	Nil	£0.04	£0.06	N/A
Emissions	Nil	£0.6	£1.5	N/A
Total benefits	**£0.5**	**£220**	**£500**	
Net present value	**-£44**	**£52**	**£160**	
Direct business net present value	***-£4.2***	***-£7.0***	***-£9.7***	***Direct***
Indirect business net present value	***-£39***	***£59***	***£170***	***Indirect***
Total business net present value	***-£44***	***£52***	***£160***	

Note: figures may appear not to sum due to rounding

E.3. Option 3 – Modernise elements of GSMR without changing requirements on gas quality

299. Option 3 would provide an opportunity to modernise GSMR to take account of significant changes to the industry since 1996, by updating, expanding or removing definitions and duties related to biomethane pipelines and LNG import terminals and changing the duty to provide an emergency call handling service to industry rather than British Gas. These changes ensure all risk occurring within the current gas network is subject to regulation and applies safety standards consistently in all areas where risk is present.

300. Option 3 would deliver the objective related to safety, and on those relating to the modernisation of GSMR. Although it would not deliver on the other objectives related to security of supply and costs to industry, it will avoid the electricity supply risks, costs to other parts of industry and distributional issues associated with Option 2.

301. The costs and benefits of this option are included within those in Option 2 where they are present, which is discussed in detail below – in particular, the following:

a. Gas processing savings to gas producers due to the removal of the incomplete combustion factor and sooting index, with a present value saving over 10 years of around £460,000 (see paragraphs 76 to 78)

b. Monitoring and alarm system costs for gas distributors for relative density with a one-off cost of around £150,000 (see paragraphs 101 to 103)

c. Safety case costs for biomethane producers' pipelines with a present value cost over 10 years of between around £3.5 million and £8.3 million, with a mid-estimate of around £5.9 million (see paragraphs 278 to 286)

302. As discussed in section E.2.13, we assess monitoring and alarms and biomethane pipeline safety cases to be direct costs; and the saved gas processing to be indirect.

303. As summarised in below Table 26, this gives an estimated net present value over 10 years of between around -£8.0 million and -£3.1 million, with a mid-estimate of around -£5.6 million. This would give an equivalent annual net direct cost to business (EANDCB) of around £0.6 million (in 2019 prices and 2020 present values). This is below the de minimis for the Business Impact Target (BIT) of £5 million, and so will count as nil for the BIT.

Table 26: Summarised monetised costs and benefits of Option 3 (present values, £thousands)

	£thousands		
	Low	**Mid**	**High**
Costs			
Monitoring and alarm for relative density	£150	£150	£150
Safety cases for biomethane pipelines	£3,500	£5,900	£8,300
Benefits			
Saved gas processing	£460	£460	£460
Net present value	**-£8,000**	**-£5,600**	**-£3,100**

Note: figures may appear not to sum due to rounding

F. Sensitivity analysis

304. We will look at cost-benefit sensitivity in two key areas under Option 2: the likelihood of the additional gas production to go ahead; and variation in the gas price in future years.

305. On the **likelihood of the additional gas production not to go ahead**, the additional discovery is the least likely to progress. Analysis from the NSTA indicates that the investment case in the discovery is marginal and that the discovery would be competing for investment with other opportunities in the global market. If the additional discovery (which features only in the 'high' NPV) were not to go ahead, this would subtract a present value benefit of around £16 million from the high case, but still leave a positive overall NPV of around £150 million in the high case.

306. For the additional production from the existing field, additional production is currently estimated at 15.75%. It is uncertain how much of this gas is wholly additional versus being brought forward from later production; and the extent to which any additional production could be attributable to GSMR. However, analysis shows that this increase in production would only have to decrease to around 12% before the NPV of the policy started to dip below zero on the 'mid' assumptions; and to around 10.5% before is started to dip below zero on the 'high' assumptions. This indicates that the additional production enabled by Option 2 from the current field could undershoot current expectations by up to between around 24% and 33% and still maintain a positive NPV overall.

307. On the **gas price**, the analysis currently uses the Wood Mackenzie estimates from February 2022. These see gas prices at between 137 and 258 pence/therm in 2023 before declining to between 62 and 74 pence/therm from 2026 onwards. There is of course significant uncertainty around future gas prices, especially years ahead of time. Any increases in gas prices, such as if they maintain something like their current high level for a number of years, would increase the NPV (and strengthen the investment case for the additional field, although it is less certain whether investors would have access to such information on the path of future gas prices).

308. It could be that gas prices will return from their current high levels to much lower figures than before. If prices fell to, say, 40 pence/therm from 2026 onwards, this could make the additional discovery uneconomic. For the existing field, net social benefits would begin to turn negative if the price dropped to 40 pence/therm from 2026 – this is the break-even point of the gas prices in our analysis. Although there is a great deal of uncertainty in future gas prices, 40 pence/therm from 2026 is not currently considered likely by BEIS.

309. It could be that gas prices will return to a lower stable price much quicker than the Wood Mackenzie figures estimate. Due to the delays to additional gas production built into the modelling caused by the NEAs, the estimates are not particularly sensitive to this assumption.

G. Impact on small and micro businesses

310. Micro businesses are those employing between one and nine people (on a full-time-equivalent basis). Small businesses are those employing between ten and 49 people (on a full-time-equivalent basis).

311. These Regulations govern the safety and management of gas inserted into GB networks. It would present serious risk to exempt small and micro businesses from adhering to the gas quality requirements. Injecting gas into the grid that has not been assessed as safe by HSE could lead to physical risk from CO poisoning when the gas is burned; and the potentially dangerous performance of gas-burning equipment, such as temperature and flame-lift, which could lead to physical risks and uncertainty as to performance. Given the level of harm that can occur, it is proportionate that all safety measures apply across the breadth of activity involved as exemptions would increase risk. As such, no exemption for small or micro businesses is being considered from gas quality requirements. This applies to the proposals to reduce the lower WN limit, increase the oxygen content limit and introduce a relative density value as the means of deriving gas interchangeability.

312. The specific requirements of GSMR relating to gas quality apply to gas distributors. These are large companies.

313. Upstream of the gas distributors, gas producers are typically large companies, but not always. There is potential for the additional discovery gas production under Option 2 to be undertaken by a small business, although this is uncertain.

314. Biomethane producers operate mostly within the agricultural sector. We do not have data on the employment size of biomethane producers in particular, but according to the Interdepartmental Business Register[3], essentially all businesses raising animals[4] (one source from which biomethane is produced) are small or micro.

315. The costs that are incurred by biomethane producers are for producing safety cases for biomethane pipelines (see paragraphs 278 to 286 – occurs under both Options 2 and 3); and making changes to equipment and alarm set-points for the Wobbe range of between around £2,000 and £10,000 per site (see paragraph 73 – Option 2 only). There is no indication that these costs are disproportionate for small and micro businesses. The cost of producing a safety case will be proportionate to the level of risk and complexity of the safety management system for the pipeline in question, rather than to the level of employment. The costs to make adjustments for gas production will depend on the quality of gas produced, rather than employment size.

316. The other amendments that are intended to be made concern the co-operation duties and the emergency call handling service (Option 2 and 3). Co-operation duties are to be extended to LNG import terminals and so there is no impact on small or micro businesses associated with that change. The relevant changes regarding the emergency call-handling service are the proposal that no network may operate without the service in place. This would have an indirect impact upon small and micro businesses should this new regulation be triggered. The purpose of this regulation is to ensure that gas is not being conveyed without a service in place to report gas escapes and ensure an emergency response attends to site to prevent the escape. These control measures form important safety functions and it would not be appropriate to exempt small or micro businesses as the consequences could result in a diminution of safety standards.

317. Under Option 2, several downstream gas users are expected to incur adaptation costs for gas equipment. Of these, we might expect some costs for small and micro businesses amongst reciprocating engine and CHP operators, commercial appliance operators and industrial equipment operators. We did not receive sufficient data from the consultation to determine whether costs would differ by employment size. As the costs attach to gas-fired equipment, we would expect that costs would scale with equipment, rather than with employment. We might expect quantities of equipment and numbers employed within a business to both increase as a business grows, and therefore there is no indication that costs would be disproportionate for small and micro businesses.

318. Whilst no exemptions are being considered for small and micro businesses from these new regulations, HSE does recognise that mitigations should be considered and adopted where possible to reduce the regulatory burdens on small and micro businesses. The primary impact on small and micro businesses of these proposals is the amendment which will change the lower WN limit. Given that this change does result in significant impacts

[3] UK business: activity, size and location - Office for National Statistics (ons.gov.uk)

[4] Estimated using SIC codes 141 (raising of dairy cattle), 142 (raising of other cattle and buffaloes), 143 (raising of horses and other equines), 144 (raising of camels and camelids), 145 (raising of sheep and goats), 146 (raising of swine/ pigs), 147 (raising of poultry), 149 (raising of other animals) and 150 (mixed farming)

and costs to businesses, many of which will be small or micro gas consumers, HSE, alongside BEIS, has decided that this amendment will be subject to a separate commencement date to the five other amendments. The commencement date for this proposal will not be before spring 2025, giving business time to adapt and prepare for a wider specification of gas quality. Providing clarity that biomethane pipelines are part of the gas network and will therefore require a safety case will also affect small and micro businesses. In response, HSE intends to allow an extended transitional period before this regulation takes effect, providing additional time for biomethane operators to prepare safety cases should they not have an existing one. This could also enable costs to be spread over two years.

319. Alongside an extended transition period, HSE will provide tailored guidance to biomethane producers on how to prepare a safety case and how HSE assesses safety cases. This should serve to ease the regulatory burden that this proposal places on these small and micro businesses.

H. Wider impacts

320. There is no indication that Option 2 would limit **competition**. The measures would not limit the range of suppliers (in fact, Option 2 increases the scope for additional sources of low-Wobbe gas). The measures would not limit the ability of businesses to compete, nor the incentive to do so vigorously. Consumer choice and information would not be limited. The competition impact of Option 3 is nil.

321. In terms of **trade**, as discussed from paragraph 263, any additional production of indigenous gas under Option 2 is expected to displace imports and thereby to reduce UK import dependence (although not by much). The trade impact of Option 3 is nil.

322. In terms of **emissions**, as discussed from paragraph 265, any additional production of indigenous gas from the UKCS under Option 2 is expected to produce zero (or close to zero) incremental emissions. Therefore, if this displaces imported gas that does produce emissions as part of production, we can expect a net reduction in UK emissions from production of gas. However, it should be noted that it is likely the gas that the UK would have imported will be shipped elsewhere, so we should not expect global emissions to be reduced. The emissions impact of Option 3 is minimal.

323. The effect on **consumers gas and electricity prices** under Option 2 is uncertain. We do not expect that increases of indigenous gas production will affect gas prices – prices are set in a global market and the quantities produced are negligible in global terms. We do not expect major, or sustained effects on electricity prices either although power generators have warned that restrictions in turbine capacity during periods of modification and maintenance could lead to short-term increases in electricity prices overall. We have not been able to quantify the full effect of this and so higher electricity prices for consumers remains a possible risk of Option 2. Consumers could also face increased engineer call-outs costs – either directly, or through increased costs of appliance warranties. We do not anticipate any consumer impacts of Option 3.

I. Comparison of the consultation and final stage IAs (Option 2)

324. The consultation stage version of this impact assessment was submitted to the Regulatory Policy Committee (RPC) for review in November 2021. The IA then formed part of the consultation, from January to March 2022.[5]

325. The consultation stage IA was a partial assessment of the costs and benefits described in this final stage IA. Further evidence was gathered during and after consultation to complete the analysis as described in this final stage IA. As such, only a handful of cost components are common between the consultation and final stage IAs.

326. One overarching difference between the two IAs is the appraisal period. In the consultation stage IA, this was set at twenty-one years to capture the expected investment cycle in new industrial or other gas equipment. Evidence gathered during consultation indicated that such investment would be unlikely and so the appraisal period for this final stage IA is set to the usual ten years. The shorter appraisal period in the final stage IA will serve (all else equal) to lessen the impact of ongoing costs and benefits.

327. Another overarching difference is NEA changes. This was not identified as an issue in the consultation stage IA, but in the final stage IA has served to (a) alter the timings of additional gas production in the 'mid' and 'high' cases (and to prevent it entirely in the 'low' case); and (b) to set a de facto lower Wobbe limit of 46.62MJ/m^3, rather than the 45.2MJ/m^3 proposed for GSMR. These changes have reduced, delayed or removed the benefits of additional gas production and of the costs of adapting equipment (in some cases).

[5] CD291 - Revision of the Gas Safety (Management) Regulations 1996 - Health and Safety Executive - Citizen Space (hse.gov.uk)

328. The cost components that have been estimated in both the consultation and final stage IAs are summarised below in Table 27. The summarised costs all relate to the proposed changes to the Wobbe range.

Table 27: Partial comparison of consultation and final stage IA estimates (present values, £millions)

	£millions								
	Consultation stage			Final stage			Difference		
	Low	Mid	High	Low	Mid	High	Low	Mid	High
Costs									
Gas producers									
Determining change*	£0.1	£0.2	£0.3	Nil	£0.7	£1.2	-£0.1	£0.5	£0.9
NTS, GDNs IGTs									
Determining change	£0.9	£1.7	£2.6	£0.3	£0.5	£0.8	-£0.6	-£1.2	-£1.8
Power generators									
Control panels	£17	£20	£29	£19	£32	£56	£2.3	£12	£27
Tuning	£0.4	£2.2	£5.2	Nil	£0.3	£2.1	-£0.4	-£1.8	-£3.1
Maintenance	£43	£100	£300	Nil	£1.1	£8	-£43	-£100	-£290
Benefits									
Gas producers									
Gas processing	£56	£65	£72	£0.5	£0.5	£0.5	-£56	-£64	-£72

Note: figures may appear not to sum due to rounding
*Now referred to as 'initial adjustments'

329. The estimated costs for **gas producers to determine what changes they would have to make** have been eliminated in the 'low' case (where we expect gas producers will be able to avoid them if no new low-Wobbe gas is allowed into the network); and gone up by between around £480,000 and £860,000 in the 'mid' and 'high' cases. This is due to changes in assumptions for biomethane producers: we now assume that all will bear the cost of determining what will change for them, rather than between 25% and 50% as in the consultation stage IA; and we have increased the costs per site at the top of the range from £2,000 to £10,000 based on consultation responses and review by the HSE expert group.

330. The estimated costs for **the NTS, GDNs and IGTs to determine what changes they could have to make** have gone down by between around £600,000 and £1.8 million. This is because we no longer apply this cost to IGTs as evidence during consultation indicated that they would not bear any costs as very little would change for them.

331. For **power generators**, there has been a mixture of increased and decreased costs. We have made three overarching changes: we no longer exclude turbines built before the mid-1990s from our estimates, which pushes costs up; we now adjust ongoing costs due to the network penetration of lower-Wobbe gas, which pushes costs down; and we now adjust ongoing costs for projected electricity generation gas demand using sector-specific estimates, rather than total estimates, which pushes costs down. Also, looking at the specific lines in Table 27:

a. The cost per control panel has gone up at the top of the range from around £440,000 to around £800,000 following consultation evidence and HSE expert panel review. In addition, control modifications now take place over five years, rather than all in one year, as assumed in the consultation stage IA – this is in line with evidence from the industry

b. The range of cost for tuning per turbine has narrowed following consultation responses from between around £8,000 and £80,000 to between around £30,000 and £50,000. Additional tuning was assumed to be a one-off cost in the consultation stage IA; we now understand it to be ongoing

c. The cost of maintenance per turbine remains unchanged for the consultation stage IA. However, the effect of adding in network penetration estimates and updating forecasts of gas demand has been to significantly reduce cost estimates

332. The **benefits of saved gas processing** have come down from between around £56 million and £72 million to around £460,000. Initial estimates in the consultation stage IA were based on responses to the 2021 HSE survey that asked about both raising the top and lowering the bottom of the Wobbe range, albeit with a desk-based adjustment for lowering the bottom of the Wobbe range only. When we sought to update these figures during consultation, newer evidence indicated that the costs reported constituted an economic transfer from one business to another, rather than a valuation of actual economic resources. As such, much of the cost-saving was ruled out of this analysis.

J. Rationale and evidence to justify the level of analysis used in the IA (proportionality approach)

333. This IA is one that justifies a high level of effort: it has potentially large impacts; the balance between costs and benefits is initially unclear with trade-offs between different groups; and the impacts span several areas and groups of stakeholders, including gas producers, domestic users, market trends and greenhouse gas emissions.

334. We have undertaken extensive evidence gathering from several sources, as set out in summary of research/ consultation section. As a result, we have a strong qualitative understanding of impact in many areas and have collaborated with other government departments and industry bodies to develop our quantitative assessment for this final stage IA.

K. Risks and assumptions

335. A key assumption in the analysis is that under Option 2, additional gas outside of the current range would be inserted into the network. While there is no requirement in the regulations that this must occur, the weight of evidence and the economic incentives would appear to make it likely. If such wider-WN gas supplies are not inserted into the network then the benefits would not accrue and the additional volumes of gas would not be obtained. Certain impacts around equipment efficiency and maintenance, or the wider market impacts would not occur. However, we would anticipate that some stakeholders would still make preparatory adjustments.

336. Under Option 2, government would make a legislative change to reduce the lower WN limit to 46.5MJ/m^3. The implementation of this legislative change is subject to a degree of uncertainty as it would be dependent upon the change process undertaken by the industry. This requires interconnector agreements, Unified Network Code modifications and NEA renegotiations. As we have referenced frequently in this IA, there is a risk that these implementation processes do not result in the legislative changes translating into the operational environment, or at least not as far as the intended legislative change. We have assumed, based on our discussions with National Grid in the aiding of the IA, that the lower ceiling of NEAs is going to be 46.62MJ/m^3. This has already had the effect of reducing the volume of additional gas that we estimate may otherwise be achieved through Option 2, and there is a risk that additional volumes are not realised at all. In the low estimates in this IA, we have modelled a worst-case scenario where NEAs are not agreed, and the policy change associated with Option 2 does not result in any additional gas. This would represent a failure in delivering the policy objectives. And in the high estimate for Option 2, we assume that additional gas production from the UKCS can be exported down interconnectors until the point at which the new lower WN limit comes into force, or if later, the point at which NEA's are agreed at the relevant terminal. This assumes interconnector agreements are agreed within one year, and that the terminal operator, interconnector operator and NTS can facilitate and agree to the export of this gas.

337. Similarly, with Option 3, in which the proposal to reduce the lower WN limit is not taken forward, the policy objectives related to security of supply are not delivered.

338. Option 2, as demonstrated by this IA, would mean increased infrastructure costs in the gas supply chain; and analysis and discussions with BEIS and Ofgem indicate that this could result in higher consumer prices for electricity over short periods. This is another risk with Option 2 and so there will be a delayed commencement date for this proposal to mitigate against such risks.

339. There are also assumptions around the extent of the penetration of any new gas supply enabled by the proposals to reduce the lower WN limit under Option 2. We have used evidence from IGEM and National Grid to help us model this. It follows that the extent of fluctuations in gas quality is also assumed. The costs attributed to gas quality to the affected sectors could therefore be overestimates and sectors may make changes to their equipment or operations unnecessarily.

340. A further assumption is that the technology and expertise exist to facilitate and support the changes stakeholders would have to make to operate equipment with a wider WN range under Option 2. This is a reasonable assumption as several European countries have wider WN ranges than GB and have technological solutions. However, we understand that these resources could take time to be deployed, which is why we assume extended periods for adaptations to be completed.

341. Baseline changes in the gas market will also influence the extent of compliance costs resulting from any changes to the WN range. Any baseline increases or decreases in gas demand would affect the extent of costs over the appraisal period. In addition, any expected baseline increases in variability or gas supplied within the existing WN range could itself necessitate investment in new equipment or enhanced monitoring and control irrespective of the proposed changes to GSMR. We have attempted to account for long-term gas use changes using the Future Energy Scenarios estimates (see paragraph 55).

342. Amendments to clarify that biomethane pipelines are to be considered as part of the network could disincentivise biomethane injections into the gas grid, jeopardising the ability of the gas network to reduce emissions or transition towards net zero and jeopardising the provision of this source of gas supply. We do not believe however that this proposal will be the main economic consideration that dictates whether a biomethane injection site continues, or whether new sites come to market.

343. The amendments that are planned for the emergency call-handling service also carry risks to the policy objectives. Sufficient provisions must be in place to ensure that the service continues in perpetuity, regardless of provider status, operation or business disruption. The proposals must also avoid the unintended consequence of the whole gas network having to cease operation should a network not have a service in place. Failure to deploy the right regulatory provisions could see standards of safety, health and wellbeing reduce.

L. Monitoring and Evaluation

344. These regulations have served public safety and the industry well since they were introduced in 1996. Gas transmission and distribution is critical to the nation's energy consumption and thankfully few serious incidents have occurred when compared to the millions of transactions taking place every day.

345. Gas supply has remained stable and reliable, and GB has never experienced a gas supply emergency. This has enabled millions of people to heat their homes and cook their food, and for business to operate their goods and services. Gas consumption plays a major part in power-generation too, providing electricity supply through gas turbines and other technology.

346. Official statistics relating to domestic gas safety indicate that piped natural gas can be regarded as a very safe fuel. Fatalities attributed to domestic gas are very low and reported incidents have reduced significantly over the 25 years the current regulatory regime has been operating. The approach to gas escapes has been successful and the national gas emergency telephone number provides an appropriate forum for the general public to report incidents.

347. The regulations have enabled the domestic oil and gas industry to flourish, placing itself at the heart of the UK's energy and industrial strategy and has also enabled new sources of gas to come to market, such as biomethane and LNG, diversifying our energy mix and providing resilience in our energy supply.

348. There will be a statutory requirement to review these regulatory changes at five years. The evaluation tool for this is the Post Implementation Review (PIR). The publication of the PIR report will be available to view on the legislation.gov.uk website.

349. The evidence gathered for the PIR from stakeholders will seek to establish if the Regulations remain fit for purpose and have achieved their original objectives. The PIR will also establish if government intervention by regulation is still required and remains the most effective way to control the risks. Any unintended costs or impacts will be sought to test the assumptions made in this IA and if they remain relevant.

350. The plan set out below includes plans associated with reviewing changes to the lower Wobbe number limit as set out in Option 2.

Objective 1: to maintain or improve the safety standards that have been achieved to date by the Gas Safety (Management) Regulations 1996 (GSMR)

351. There are several amendments under Options 2 and 3 that have been proposed with the aim of maintaining or improving safety standards. Reviewing outcomes associated with these objectives will contribute to reviewing success against Objective 1.

352. The proposal to replace the Incomplete Combustion Factor and Soot Index with a relative density measure is intended to modernise these health and safety regulations based on the latest scientific knowledge. Its direct impact on health and safety outcomes is expected to be negligible, albeit positive. Any issues that have arisen as a result of this amendment will be reviewed through stakeholder engagement during the planned PIR.

353. Though expert opinion concludes that the amendments should lead to no negative safety outcomes, it is prudent to monitor negative unintended outcomes where possible, especially where concerns have been raised during consultation.

354. The ultimate desired outcome here is that there is no increase in gas incidents (fatal and non-fatal) related to the lowering of the Wobbe Number limit, from the outset of the change in regulations.

355. Gas-related health and safety incidents arising from carbon monoxide poisoning, other exposures, and explosion/fire are relatively infrequent in the available data, and so statistical analysis of change over time will be low-powered and is unlikely to be viable in the short term. The monitoring of available data will therefore be combined with qualitative insight from HSE Operational colleagues to understand the role the change in gas composition may have played in such incidents.

356. The main dataset available is the Reporting of Injuries, Diseases and Dangerous Occurrences Regulations (RIDDOR), through which HSE monitor gas related incidents from carbon monoxide poisoning, other exposures, and explosion/fire. The dataset is limited to incidents in the workplace and so does not cover domestic incidents. As a secondary data source, the ONS can undertake ad hoc analysis of deaths from accidental poisoning by carbon monoxide which includes all locations (using death certificates records). The ONS data is not limited to health and safety legislation and covers a wider range of poisoning situations (but narrower range of gas related incidents). Given there are no safety concerns with the proposed changes, the statistical power to detect change over short time period is limited, and the analysis would have to be specially commissioned, it is proposed that the ONS data is used as a secondary data source for the planned PIR.

357. Confounding factors affecting gas related incidents will be explored as part of the post implementation review stakeholder consultation and considered during analysis.

Objective 2: to adapt the prescriptive GB regulation for gas composition contained in GSMR Schedule 3 that is restricting sources of gas sitting outside of current specifications being conveyed in the transmission and distribution network

358. This is a technical objective which will be met by decreasing the lower WN limit and incorporating the HSE class exemption limit of ≤1 mol% for oxygen in gases conveyed at pressures at or below 38 barg.

Objective 3: to enable or make viable greater volumes of gas resources to be accessed from indigenous sources, contributing to greater security of GB's energy supply

359. This objective will be achieved if the amount of gas accessed from indigenous sources under Option 2 is greater than it would have been without the amendments to GSMR 1996, in the short to medium term.

360. Greater volumes of indigenous gas is an outcome that will be measured by monitoring the volume of gas resources accessed from indigenous sources. The amount of gas from indigenous sources is monitored at present and will continue to be monitored after the intervention (the amended legislation), enabling an interrupted time-series approach to be achieved. The extent to which any increase in gas from indigenous sources can be attributed to the amended regulations will draw on the review of Objective 4.

361. Option 2 is expected to allow some volumes of additional gas to be produced after one year in the high estimate. Additional volumes requiring development of gas resources or new oil and gas licences may be realised from 2027. The monitoring is undertaken by the NSTA as the data becomes available. HSE will review the outcome after five years during the planned PIR.

Objective 4: to reduce processing or blending of currently out-of-spec gas, potentially enabling additional gas supplies as a consequence of reducing associated processing or blending requirements

362. The proposal to decrease the lower WN limit for normal supply from ≥47.2 MJ/m^3 to ≥46.5 MJ/m^3 means that less processing will be required of gas which is currently under the limit to bring it to specification.

363. Consultation with industry stakeholders will enable us to determine if:

a. processing activity reduces for gas sources that are currently processed to bring them up into the lower end of the specification, and

b. gas sources that are currently unviable due the excessive amount of processing required, become viable as the processing required is reduced.

364. The class exemption limit of ≤1 mol% for oxygen in gases conveyed at pressure up to 38 barg, reduces the need for processing biomethane. Incorporating this exemption into the regulations maintains the current situation, and therefore is not expected to lead to a change.

Objective 5: To ensure clarity and consistency in how pipeline operators and Liquified Natural Gas import terminals are regulated by GSMR

365. The proposed amendment to 1) provide clarity that co-operation duties apply to operators of LNG import facilities; and 2) provide clarity that biomethane pipelines are to be considered to be part of the gas network, will provide consistency across GSMR.

366. For 1), this clarification is largely for consistency, formalising arrangements which are already in place in practice. It is therefore considered proportionate that this intermediate outcome is reviewed through stakeholder engagement during the planned PIR.

367. For 2), this amendment is a preventative measure. Health and safety incidents associated with biomethane pipelines are infrequent and so statistical analysis of incidents associated with the intervention is not an effective review strategy. The amendment newly requires biomethane pipeline operators to produce safety cases where they are conveying out-of-specification gas. Safety cases work to minimise risk by ensuring that safety is explicitly considered; and mitigations are put in place.

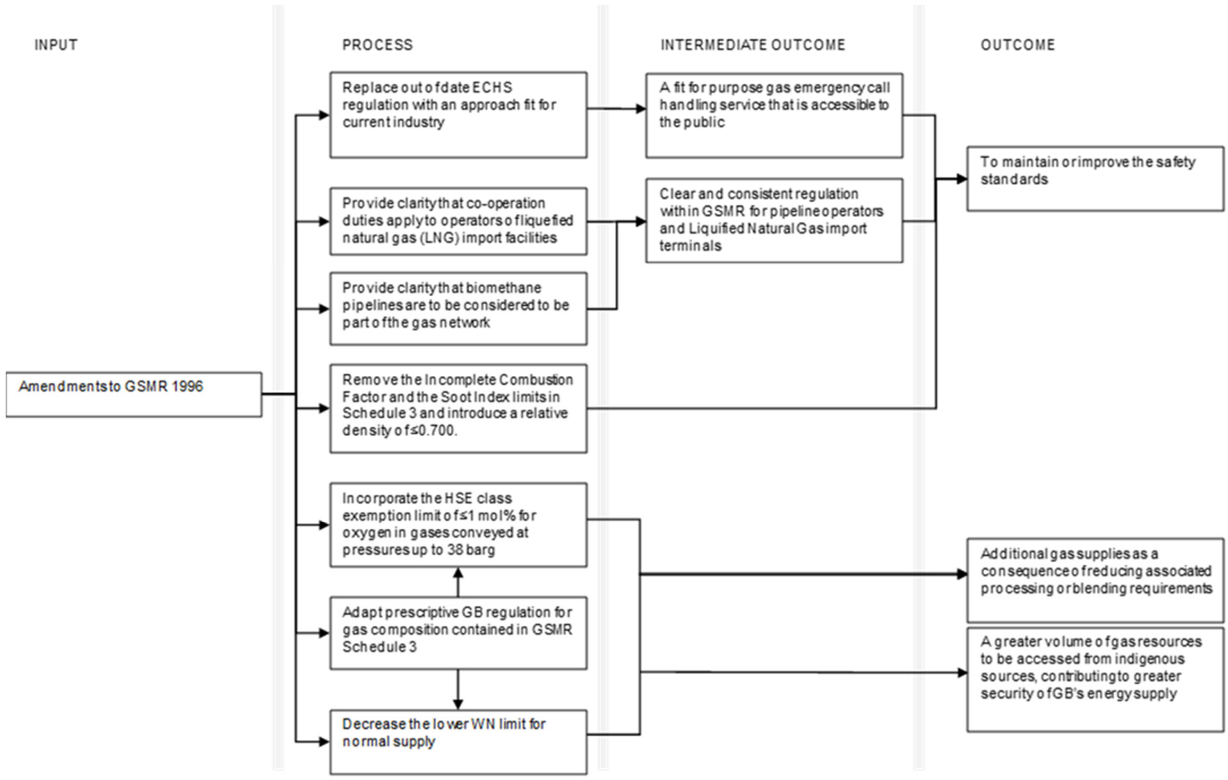
368. Monitoring the implementation process of safety cases is therefore considered a proportionate approach, in lieu of being able to quantify change in incidents statistically. The aim will be to achieve a 100% coverage of safety cases across the biomethane pipeline network within a two-year implementation period. The coverage of safety cases will be monitored by HSE Energy Division.

369. A qualitative assessment of the requirement for safety cases for biomethane pipelines will be undertaken through stakeholder consultation during the planned post-implementation review.

Objective 6: to ensure that industry changes are reflected within the gas emergency call-handling service and that it remains accessible to the public

370. The conditions set out in the amendment to replace the existing out-of-date regulation are intended to minimise risk. To review the success of this objective, HSE will therefore assess whether the conditions set out by the amendments are being met. Ongoing feedback from HSE operational divisions to policy colleagues will enable any safety concerns arising associated with the amendment to be raised in a timely manner. A broader assessment of the objective will be undertaken by stakeholder consultation during the planned PIR.

Figure 4: High-level change model



M. Summary and preferred option with description of implementation plan

371. Option 2: The preferred option is to make the proposed amendments HSE set out at consultation:

- reduce the lower WN limit for normal supply from ≥47.2 MJ/m^3 to ≥46.5 MJ/m^3
- extend the current GSMR class exemptions for oxygen in biomethane to a general ≤1 mol% oxygen limit at pressures at or below 38 barg for all gas sources
- remove the Incomplete Combustion Factor (ICF) and Soot Index (SI) limits and to introduce a relative density of ≤0.7 for gas interchangeability
- clarity that biomethane pipelines are to be considered to be part of the gas network
- clarity that co-operation duties apply to operators of liquefied natural gas (LNG) import facilities
- for a general duty on the industry to provide a continuously manned telephone service

372. The changes to GSMR will be made via an amending secondary legislation statutory instrument (SI) with a coming-into-force date of April 2023. A separate coming-into-force date of spring 2025 will apply to the amendment which reduces the lower WN limit. Transitional arrangements will apply to the amendment that clarifies that biomethane pipelines are to be considered as part of the gas network.

373. HSE has engaged with key stakeholders to ensure they are informed about the proposed Regulations and expect this to continue in the lead up to the Regulations coming into force and beyond. This has already involved participating in a number of meetings to discuss the proposals and to support dutyholders in understanding the transition to the new arrangements. The HSE website will be updated to provide an introduction to and overview of the new Regulations. L80 guidance on GSMR will also be updated.