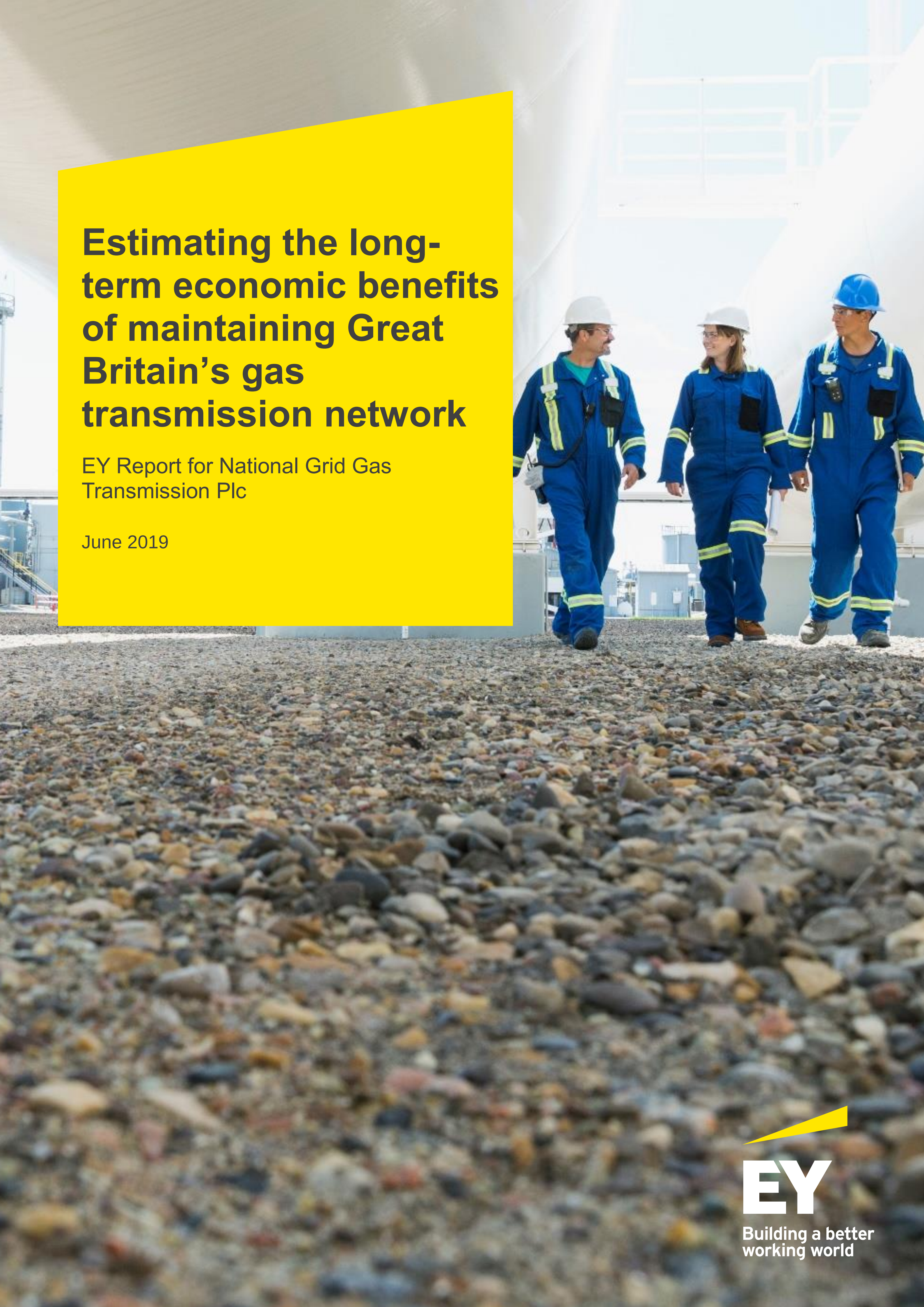
Estimating the long-term economic benefits of maintaining Great Britain's gas transmission network

EY Report for National Grid Gas Transmission Plc

June 2019



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Foreword

The energy landscape is changing as the UK responds to the challenge of meeting its long-term the climate change targets. The UK has an ambitious target to reduce our greenhouse gas emissions by 80% by 2050, while the Climate Change Committee has recently recommended a new UK emissions target of net-zero greenhouse gases by 2050.

To deliver on these targets, the UK will need to balance decarbonising the heat sector, industry and the power market with ensuring energy bills remain affordable.

The gas transmission network has played a huge role in providing energy for consumers for the last 50 years. National Grid Gas believes that the National Transmission System (NTS) provides benefits to GB PLC, through its ability to transport a diversity of gas supplies, providing gas-fired power stations with a flexible service that allows it to supply the electricity market. It also provides secure gas supplies for the heating in homes and industrial processes whilst maintaining a safe and reliable operation.

As we go into the future and the energy landscape changes, the role of the NTS may change. As the Future Energy Scenarios have illustrated, the volume of gas transported through the NTS may decline in future years as power and gas production becomes more decentralised. The NTS will, however, continue to provide benefits to GB PLC by helping to keep gas and power prices lower and less volatile, by continuing to provide safe and reliable gas supplies to energy intensive industries which will continue to rely on gas and by providing back up gas supplies and storage for gas distribution networks. The NTS could also provide real options for GB PLC in future if decarbonisation through electrification of heat and transport proves technically infeasible or unduly expensive.

To explore some of the benefits which the NTS delivers, and to help quantify those benefits, National Grid Gas Transmission has commissioned this report by EY. This work by EY looks at quantifying some of the long-term economic benefits of maintaining the current capabilities of the NTS to GB PLC:

- the long term economic benefits of maintaining the capability of the NTS for the GB gas sector;
- the long term economic benefits of maintaining the capability of the NTS for the GB electricity system;
- the long term economic benefits of maintaining the capability of the NTS for EIIs;
- the long term economic benefits of maintaining the capability of the NTS for GDNs; and
- the real option value created by maintaining the capability of the NTS.

Recognising that the future is uncertain the work considers these issues under a range of future energy scenarios.

The report shows that the NTS will deliver substantial long term economic benefits for GB PLC under a variety of scenarios. We believe that these benefits, alongside other work we have undertaken on the short-term costs and benefits of investment in the NTS, helps to articulate there is wider value that the NTS provides to GB consumers, whilst also highlighting a view on the potential impacts of making decisions on changing the capability of the network whilst the future is uncertain. In particular, it highlights that in enabling the decarbonisation of the energy industry the NTS can provide value to consumers through ensuring wholesale gas and electricity prices remain stable and therefore keeping consumer energy bills affordable.

As such, this report provides a valuable contribution to the evidence base to support our RIIO-2 business plan submission for our next price control period and to the wider debate about the future of gas.

Contents

1. Executive Summary

The National Transmission System (NTS) is the network for transporting gas at high pressure across Great Britain (GB). The NTS plays a fundamental role in the heat, power and industrial sectors of the GB economy by transporting gas from Britain's various sources of gas (domestic and international) to gas-fired power stations, and to businesses and households across the country.

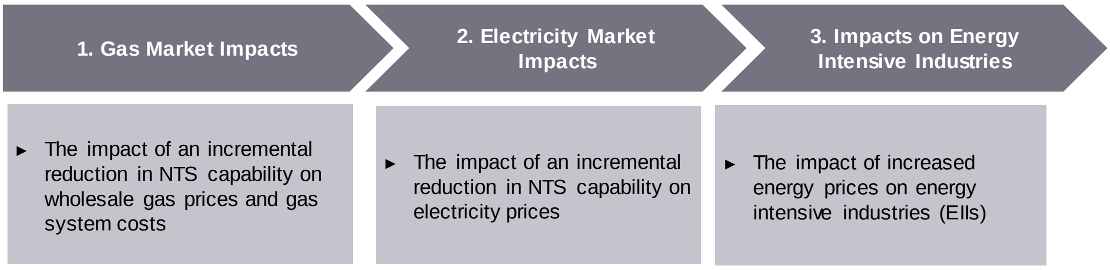
The role of the NTS is evolving, and will continue to evolve, as both heat and power are increasingly decarbonised, and as gas production and electricity generation are increasingly decentralised. In this context, National Grid Gas Transmission Plc (NGGT), Ofgem and wider stakeholders face important choices about the amount of investment required to maintain and develop the NTS, both during the upcoming RIIO-GT2 price control period (2021-26), and into the future.

In this context, NGGT has commissioned EY to explore the long-term[1] economic benefits of the NTS to GB in supporting the transformation to a low carbon energy future.

Approach to estimating long-term benefits of the NTS

This study explores some of the economic benefits of the NTS to GB by estimating the impacts on energy consumers of reductions in the capabilities of the NTS relative to current levels on gas prices, power prices and on the value of production by energy intensive industries (EIIs). The approach is summarised in Figure 1 below.[2]

Figure 1: Overview of approach to estimating selected benefits of the NTS[3]



In order to assess the impact of a reduction in the capability of the NTS, a range of indicative scenarios proposed by NGGT have been explored. The two scenarios with the most significant impacts are:[4]

- **Reduced entry capacity (Scenario 1A)**: A decrease in GB's ability to import gas from a reduction in entry capacity at two key gas terminals (Easington and St Fergus), resulting from the decommissioning of a selected number of compressor stations. The assumed reduction in entry capacity is equivalent to 19% of current GB entry capacity; and

[1] Whereas previous analyses by NGGT have considered the impact of an unexpected and short-term loss of gas transmission network capability on the energy system, this study has focused on long-term impacts on consumers associated with reduced investment in the network.
[2] This study has not considered the potential cost savings that could be achieved if NTS capability were not maintained at its current level. This study has also not considered the value of the NTS to upstream production, which relies on the NTS for a route to sell gas into the GB gas market.
[3] Other benefits are considered in the main body of the report, including impacts on gas distribution networks (GDNs) as well as resilience against black-start events where there is a failure of the electricity transmission network.
[4] This study has not independently developed scenarios or assessed the likelihood of each scenario occurring. The scenarios are intended to reflect a range of possible outcomes that could arise from insufficient investment in the network and are not intended to serve as the basis for economic assessments of investment in particular assets, for which a more detailed analysis would be required. A wider range of scenarios and sensitivities were also modelled and the results are presented in the main body of the report.

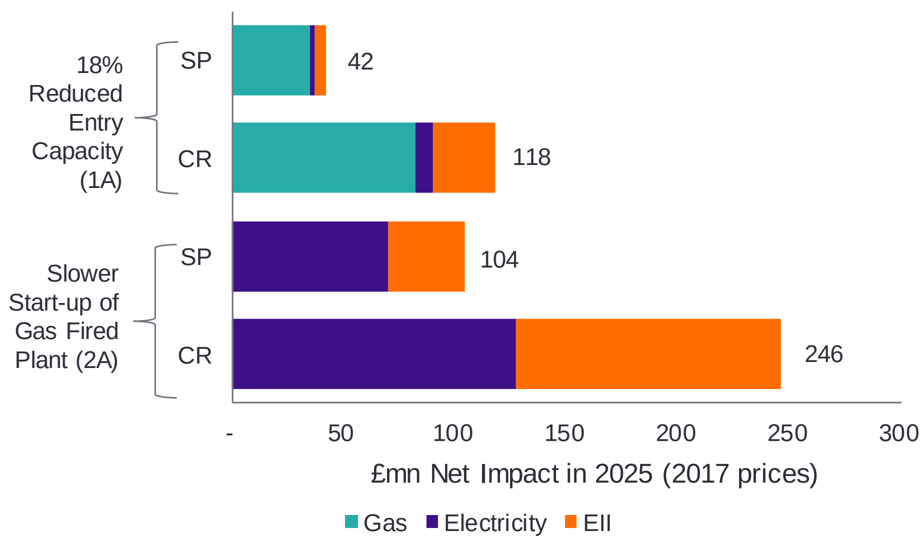
- **Slower start-up of gas-fired power stations (Scenario 2A)**: In this scenario the speed at which gas-fired power stations are able to ramp up is assumed to be reduced as a result of a loss of compressor stations on the NTS (which reduces the ability of the NTS to deliver gas to gas-fired power stations at short notice).[5]

The impacts of these scenarios are informed by a combination of modelling, stakeholder engagement and review of existing research, with modelling of the gas and electricity markets carried out by the Energy Policy Research Group (EPRG) at the University of Cambridge. The impacts have been assessed relative to a baseline where the capability of the NTS is maintained at current levels. The impacts are considered under two sensitivities, reflecting different assumptions about the volume of gas transported through the NTS in future. The assumptions underpinning these sensitivities have been drawn from National Grid's 2018 Future Energy Scenarios (FES), with a high gas volume case based on the FES Steady Progression (SP) scenario and a low gas volume case based on the FES Community Renewables (CR) scenario.[6] Impacts of each of the scenarios have been modelled for the years 2025 and 2035, to reflect the value of the NTS within the RIIO-GT2 price control period as well as over the longer term.

Estimated long-term benefits of the NTS

Modelling carried out for this study suggests that a failure to maintain the existing capability of the NTS could have significant impacts on GB. As shown in Figure 2 below, benefits identified from maintaining NTS capability in 2025 ranged between £42m and £118m per annum under Scenario 1A (19% reduced entry capacity), and between £104m and £246m per annum under Scenario 2A (slower start-up of gas fired plant). These impacts are principally driven by increased gas wholesale prices (in the case of Scenario 1A) and increased electricity wholesale prices (in Scenario 2A).

Figure 2: Impact in 2025 of reductions in NTS capability



Source: EPRG gas and electricity market modelling, EY analysis of economic impact on EIIs

Impacts are expected to be greater in the CR sensitivity than under the SP sensitivity and to be greater in 2035 than in 2025. This may appear counter-intuitive as the volume of gas

[5] Gas-fired units are assumed to not be able to ramp up by more than 50% of maximum nameplate capacity in less than 4 hours (or 8 hours to full capacity). The baseline ramping capability of gas-fired units is that they can technically ramp up to full capacity within one hour, provided gas is delivered by the NTS as required.
[6] Under CR, the UK is assumed to meet its 2050 decarbonisation targets and that electricity is increasingly provided by renewables on the electricity distribution network. Under SP, progress is made to decarbonise the energy sector but the UK is not expected to meet its 2050 decarbonisation targets and there is a slower rate of increase in renewables connected to the electricity distribution network.

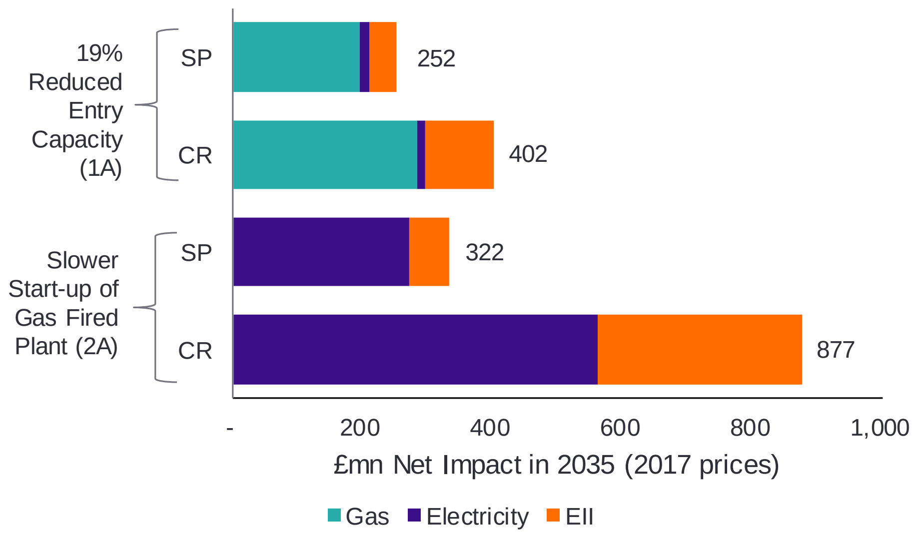
transported through the NTS is lower in 2035 than 2025 and is also lower under the CR sensitivity than the SP sensitivity. However, this is primarily driven by two factors:

1. Demand for gas is less sensitive to short-term price fluctuations under the CR sensitivity, such that demand doesn't fall significantly in response to an increase in price. As renewables provide a greater share of electricity generation under CR, gas supplied is increasingly used for backup electricity generation and for EII production. As gas demand for these purposes is less sensitive to short-term fluctuations in price, a small reduction in the volume of gas available can have a significant impact on wholesale gas prices.

2. As the volume of intermittent renewable generation increases over time, the NTS has an increasingly important role supplying gas to gas-fired power plants so those power plants can respond quickly to volatility in supply and demand for power.

As shown in Figure 3 below, impacts are expected to increase by 2035, ranging between £252m and £402m per annum under Scenario 1A (reduced entry capacity), and between £322m and £877m per annum under Scenario 2A (slower start-up of gas fired plant). The increase in the size of impacts between 2025 and 2035 is driven by the same factors that lead to impacts being greater under a CR sensitivity than under a Steady Progression sensitivity – i.e., renewables account for a greater share of generation by 2035, reducing the price elasticity of demand for gas such that smaller reductions in gas supply can have greater impacts on gas wholesale price, which means that consumers bear a higher increase in energy costs.

Figure 3: Impact in 2035 of reductions in NTS capability



Source: EPRG gas and electricity market modelling, EY analysis of economic impact on EIIs

The benefits of maintaining the current capability of the NTS may, however, be larger than the headline figures stated above as the approach (i.e. modelling of long-term gas and electricity price impacts) excluded certain benefits:

► This study has focused on the impacts of increased gas and electricity prices on GB. Reductions in NTS capability would also be expected to have impacts on upstream production, as offshore gas producers rely on the NTS for a route to the GB gas market.

► The electricity and gas market models used in this study assume the market has perfect foresight of the impacts associated with reductions in NTS capability. This means that the modelling captures the steady-state benefits associated with the NTS when the gas and electricity markets are in equilibrium but does not capture the benefits of the NTS in terms of increased resilience of the gas and electricity markets to unexpected short-term shocks (for instance weather-related demand shocks or disruptions).

- The figures presented above only take into account the impacts on gas prices, power prices and energy intensive industrial customers. They do not take into account the impacts on Gas Distribution Networks (GDNs) (which may have to invest more heavily in gas storage if the NTS does not provide as reliable supplies of gas) or the option value which maintaining the NTS might provide (as a fallback if increased electrification or increased use of green gases do not turn out to be feasible or value for money ways of decarbonising heat and transport).

- The scenario benefits are also potentially additive: for instance, a failure to replace compressor stations could lead to both increased gas prices (as in Scenario 1A) and slower start-up times for gas-fired power stations (as in Scenario 2A). Greater impacts would be associated with a reduction in NTS capability if a range of scenarios occurred at the same time.

- Alternative scenarios, including a greater reduction in NTS capability, are possible, implying potentially greater impacts on GB.

It is clear from the analysis presented in this study that the potential benefits for GB of maintaining the current capabilities of the NTS could be significant, particularly in certain scenarios, given the impact to GB if reductions in the supply of gas lead to increased gas and electricity prices. This has implications for NGGT, Ofgem, BEIS and other stakeholders, as they consider the various options for expenditure on maintaining and enhancing the capabilities of the NTS.

2. Introduction

2.1 Current role of the NTS

The National Transmission System (NTS) is responsible for transporting gas within Great Britain (GB), utilising the NTS for three principal uses:

1. For power generation (accounting for around 29% of gas demand in GB);

2. For use in industrial processes, such as in paper manufacturing (c.24%); and

3. For use in domestic and commercial heat, via the GDNs (c.47%).[7]

Gas transported on the NTS typically comes from four sources: [8]

1. United Kingdom Continental Shelf (UKCS) – This refers to gas supplied from resources which are covered by UK mineral rights. This is primarily gas extracted from surrounding areas, such as the North Sea. In 2017, gas from the UKCS accounted for 47% of gas supplied to GB over the year and 19% of gas supplied at winter peak.

2. Norway – This is gas which is brought into GB directly from Norway via pipelines to the St Fergus and Easington gas import terminals. In 2017, gas from Norway accounted for 43% of gas supplied to the GB over the year, and 22% of gas supplied at winter peak.

3. Interconnectors (ICs) which link the NTS to the gas transmission systems of Continental Europe – Belgium and the Netherlands in particular. All gas traded through ICs between GB and Europe goes through the gas terminal at Bacton. In 2017, gas from interconnectors accounted for 6% of gas supplied to GB over the year and 19% at of gas supplied at winter peak.

4. Liquefied Natural Gas (LNG) – This is supplied from overseas via carrier ships into two import terminals – Milford Haven and Isle of Grain – and connects the GB gas market with global LNG markets. In 2017, gas from LNG accounted for 6% of gas supplied to the GB over the year and 21% at of gas supplied at winter peak.

The GB gas market has numerous entry points which allow the above supply sources to access the NTS when required. In addition to these sources, there are additional entry points to the NTS for gas storage as well as for the small amount of gas produced onshore (which currently accounts for less than 1% of gas supplied within GB[9]).

2.2 Future role of the National Transmission System

The role of the NTS is expected to change significantly over time in response to the decarbonisation of the GB energy system, as well as to changes in GB's energy mix. There are a wide range of credible scenarios for how the GB energy system will decarbonise, reflecting uncertainty around the regulatory and policy outlook, the cost and feasibility of different technologies, and consumer willingness to embrace new technologies.

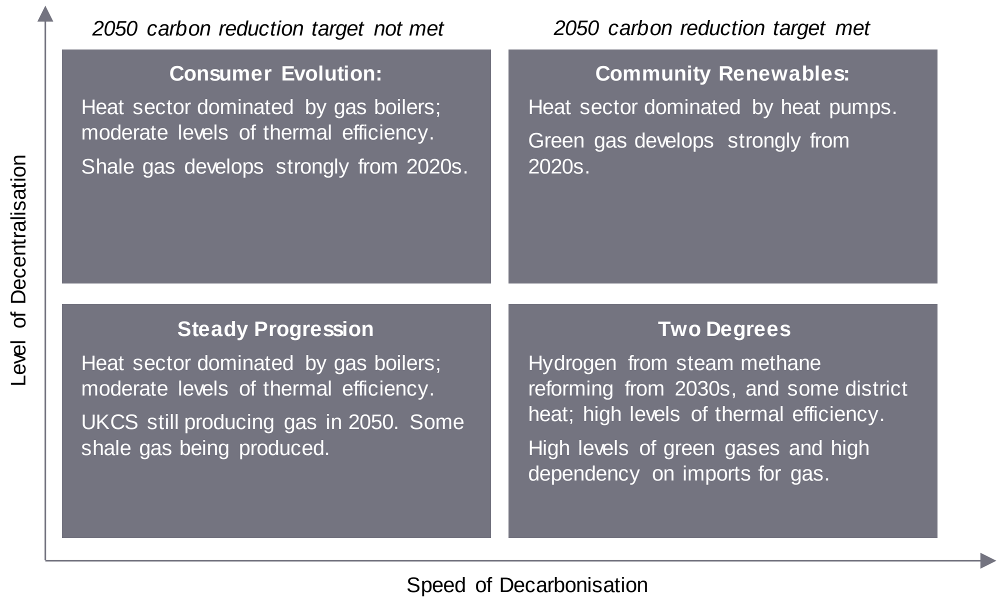
2.2.1 Future Energy Scenarios

Decarbonisation will have a number of implications for the NTS. National Grid's Future Energy Scenarios (FES) provide one set of credible pathways for the future of energy out to 2050, informed by National Grid's analysis and stakeholder engagement. The 2018 FES sets out four scenarios for the GB energy system reflecting a range of outcomes in terms of whether GB decarbonises in line with 2050 climate goals, as well as the extent to which

[7] National Grid 2018 Future Energy Scenarios
[8] National Grid 2018 Future Energy Scenarios
[9] National Grid 2018 Future Energy Scenarios

electricity generation takes place on a decentralised basis in future. These are illustrated in Figure 4 below.

Figure 4: Overview of 2018 FES scenarios



Source: 2018 Future Energy Scenarios

Steady Progression (SP) represents the scenario closest to the status quo – i.e., with limited change, while Community Renewables (CR) represents the greatest change for the NTS. Some of the key features of these scenarios are as follows:

- **Power generation**: Gas currently accounts for 34% of power generation in GB, and under the FES scenarios this is expected to decline (to between 19% and 33% by 2030), as there is greater deployment of low carbon generation, including renewables and nuclear power, particularly under the Community Renewables and Two Degrees scenarios. Further, a greater share of generation is expected to be produced at the distribution level (between 26% and 31% in 2030, compared to 23% today). However, uncertainty around the overall volume of electricity generation required, related to the potential for electrification of heat and transport, particularly in the 2030s – contributes to uncertainty around the volume of gas that the NTS will need to transport for use in power generation.

- **Industry**: in the FES scenarios it is expected that the use of gas for industrial processes will fall over the 2030s, by between 4% and 11% from 2017 levels. The principal alternatives to the use of gas in industry are hydrogen and electrification.

- **Heating**: Gas boilers provided 79% of domestic heat in 2017. The FES scenarios imply this is expected to decline to between 68% and 77% by 2030 as the heat sector begins to decarbonise. There are a number of potential alternative technologies to using hydrocarbon gas for heat, including:

  - ***Hydrogen***: Producing hydrogen through electrolysis of gas or water to provide a low carbon fuel.

  - ***Electrification***: Use of electric heaters, powered by low carbon power generation.

  - ***Hybrid***: Heating systems run on a dual fuel basis, i.e., drawing on a mix of gas and heat pumps.

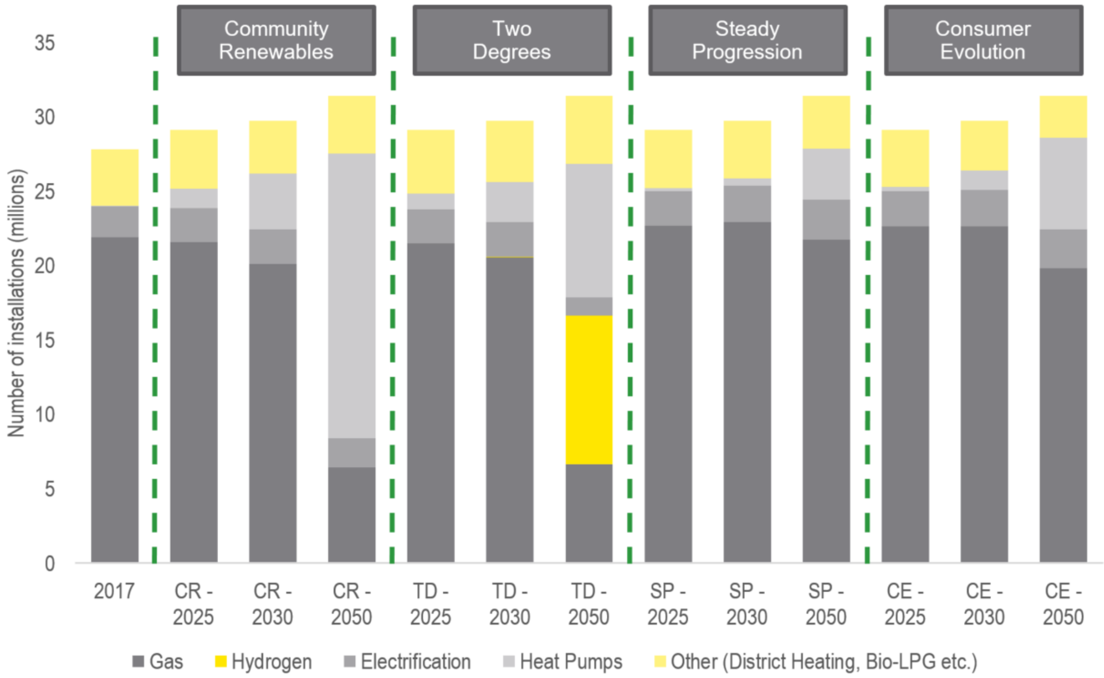
- **_District heating:_** Generating heat in a central location through low-carbon technology and distributing the heat through a localised heat network.

- **_Biogases:_** Injection of alternative gases, such as bio-SNG, into the gas network to lower the carbon intensity of gas use.

The principal technologies assumed to be used over the long term in the FES scenarios are hydrogen and electrification (or combinations of each). Alternative technologies such as district heating, heat pumps, or biogases are seen in these scenarios as useful for energy transitions or to address regional requirements.

Figure 5 shows the potential mix of technologies under different FES scenarios out to 2050.

Figure 5: Potential mix of heating technologies, 2025-2050

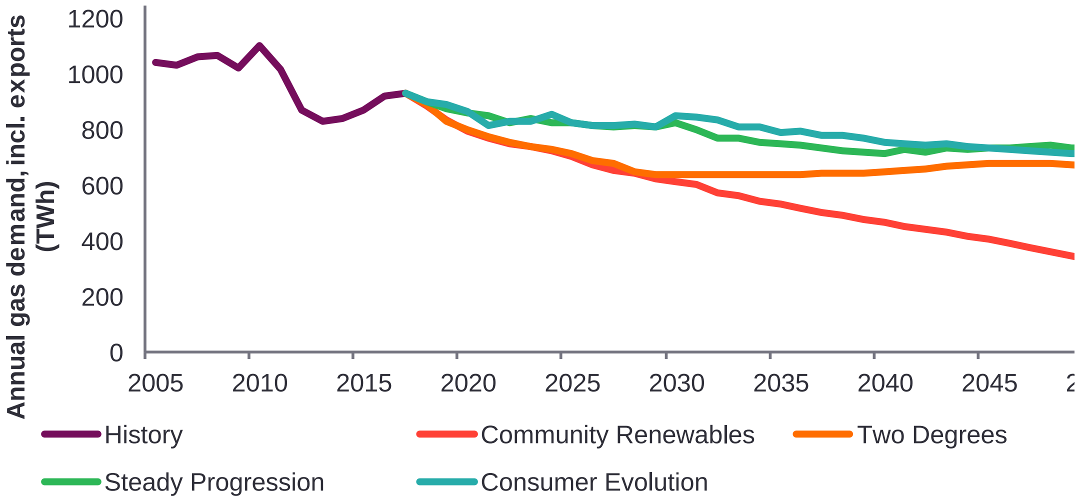


Source: 2018 FES

While gas from the UKCS accounted for just under half of volumes consumed in GB in 2017, the gas supply mix for GB at times of winter peak demand is more mixed – with supply split approximately equally between UKCS (19%), Norway (22%), the Continent (19%), LNG (21%) and Storage (19%), as well as a very small amount of green gas. The FES scenarios forecast the supply of both green and shale gas to increase by varying amounts by 2030; reaching almost 40% of GB's peak gas supply under the Steady Progression and Consumer Evolution scenarios, the majority being shale gas. However, the breakdown of winter peak gas supply remains almost identical to the 2017 percentage split under both the Community Renewables and Two Degrees scenarios.

The combination of reduced demand for gas for power generation, and increasingly distributed sources of gas supply means that decarbonisation is expected to lower the volumes of gas transported through the NTS under all FES scenarios relative to today. However the scale of reduction is greatest where the pace of decarbonisation is highest and where heat pumps, green gas and district heating (rather than electrification or hydrogen) have the dominant role in supplying heat. This corresponds to the Community Renewables scenario.

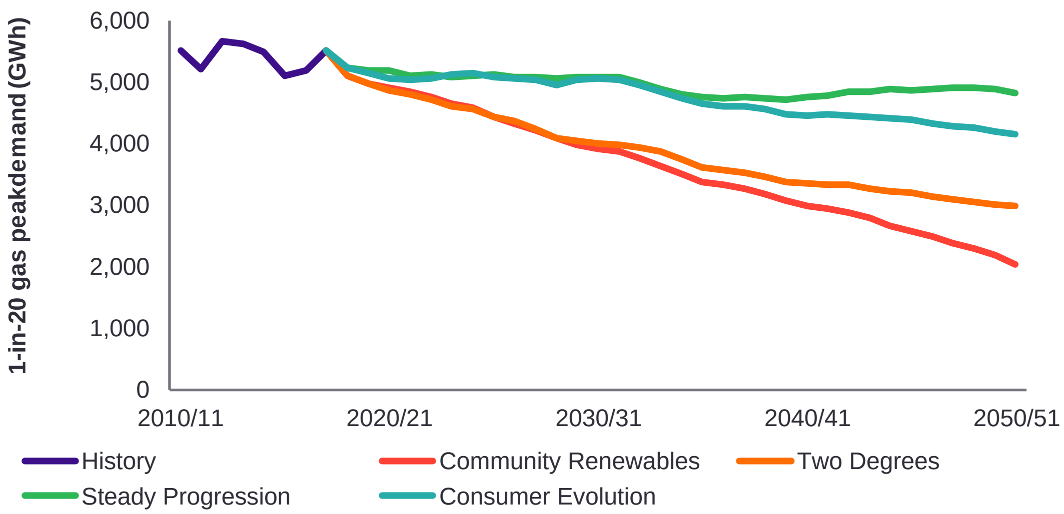
Figure 6: Annual gas demand under 2018 FES scenarios



Source: 2018 FES

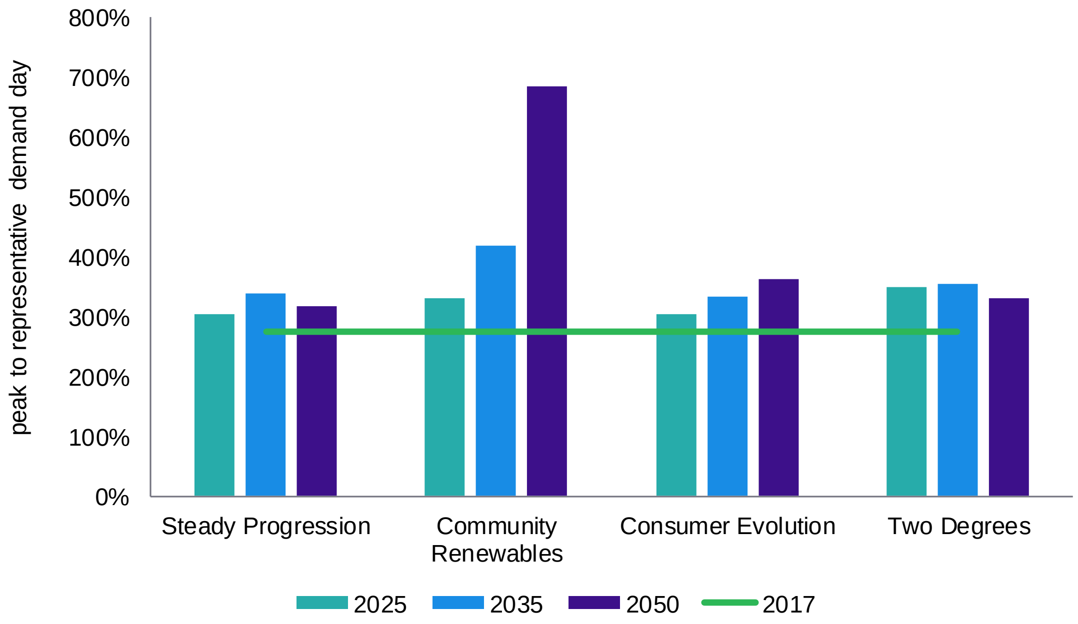
While the average daily volume of gas consumed in GB declines in the FES scenarios, it is expected that there will remain demand for gas as a backup source at times of winter peak (as shown in Figure 7 below), principally provided through the NTS. Peak gas demand volumes are also expected to reduce under all scenarios but at a much lower rate than average gas demand. This means that demand for gas at winter peak will account in future for a significantly higher proportion of overall gas transported through the NTS, particularly under the Community Renewables scenario.

Figure 7: Gas 1-in-20 peak demand



Source: 2018 FES

Figure 8: Ratio of peak demand to representative daily demand for gas under 2018 FES scenarios



Source: 2018 FES

2.2.2 Alternative decarbonisation projections

Other long-term heat decarbonisation scenarios reviewed for this study identify a broader range of solutions for possible technology deployment by 2050, including:

- Analysis by KPMG for the Energy Networks Analysis (ENA)[10] identified four potential 2050 scenarios for the heat sector consistent with climate change goals. In two of these scenarios (Prosumer and Electric Future), electricity provides 100% of heat used for commercial and residential purposes. The highest role envisaged for gas is in the scenario with high hydrogen deployment (Evolution of Gas), where 13% of heat for the commercial and residential sector continues to be supplied by gas in 2050.

- Analysis by Imperial College for the Committee on Climate Change (CCC)[11] identified three core pathways – H2, Electric and Hybrid scenarios. In the Electric pathway, all heating is provided in 2050 through resistive (i.e., electrified) heating and heat pumps, while in the H2 pathway, most domestic gas heating is supplied through hydrogen-based gas boilers.

2.3 RIIO-2 and BEIS Review of the Future of Gas

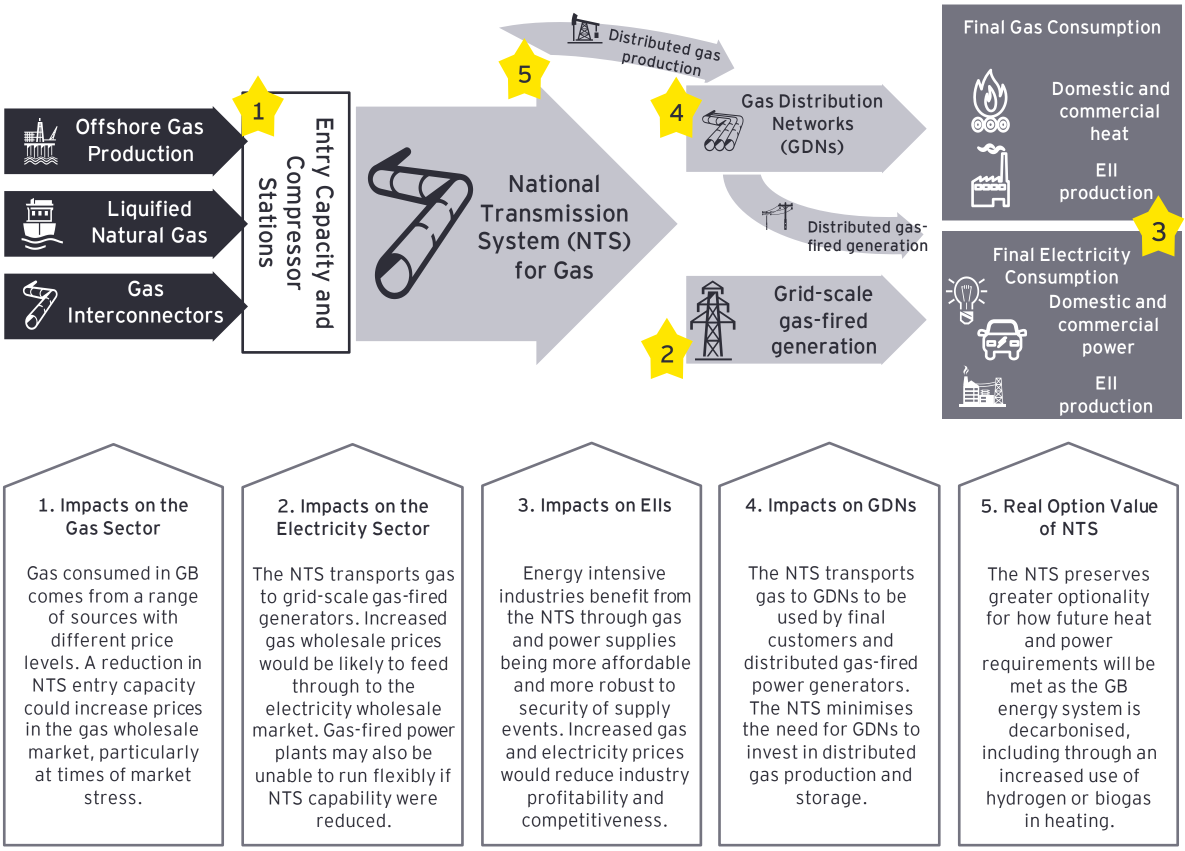
Reflecting the uncertainties around the outlook for GB's energy mix and the role of the NTS, BEIS and Ofgem face important decisions about the support provided to NGGT to maintain and, where appropriate, enhance the capability of the NTS to enable it to play its role. BEIS has commenced a review of the future of gas in heating.[12] Ofgem is considering similar issues as it conducts its review of NGGT's allowed revenues (including expenditure projections) for the RIIO-GT2 period (2021-26).[13]

10 https://www.energynetworks.org/assets/files/gas/futures/KPMG%20Future%20of%20Gas%20Main%20report%20plus%20appendices%20FINAL.pdf
11 https://www.theccc.org.uk/publication/analysis-of-alternative-uk-heat-decarbonisation-pathways/
12 https://www.gov.uk/government/publications/heat-decarbonisation-overview-of-current-evidence-base
13 https://www.ofgem.gov.uk/network-regulation-riio-model/network-price-controls-2021-riio-2/riio-2-publications-and-consultations

Major decisions from the UK government on decarbonisation of heat and transport and therefore the future of gas (including the NTS) are not expected until at least the early 2020s. Decision makers, assisted by stakeholders including NGGT and the GDNs, continue to gather evidence about the extent to which gas can be decarbonised and the cost of doing so.

While major decisions may be further away, NGGT is preparing its RIIO-GT2 business plan and Ofgem must decide how much it will allow NGGT to spend on maintaining and enhancing the NTS over the 2021-26 period before the end of 2020.[14] Expenditure on assets that ultimately do not get used, or are underutilised, would not deliver value for money for customers but, on the other hand, insufficient expenditure on the NTS could have implications for future levels of service delivery, and could also potentially lead to expenditure that would be higher than it would otherwise have been in RIIO-GT3 and beyond. Differences in service quality, or the "capability", of the NTS could also have impacts on gas and electricity prices paid by domestic customers, and by industrial and commercial customers and/or impose other costs on these users – and on GDNs – as they seek to adapt to an NTS which is no longer able to deliver the standards of service they have become accustomed to. The potential impacts are summarised in Figure 9 below.

Figure 9: Potential impacts of a reduction in NTS capability



Source: 2018 FES

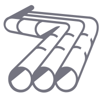
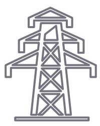
These risks for users of the NTS and for the wider GB economy need to be considered carefully to ensure the best outcome for current and future customers.

[14] Ofgem's indicative high-level milestones for RIIO-GT2 published here: https://www.ofgem.gov.uk/system/files/docs/2018/07/riio-2_july_decision_document_final_300718.pdf

2.4 Purpose of this report

In the context of the above and to assist it to prepare its RIIO-GT2 business plan, NGGT has commissioned EY to carry out a study of the long-term economic benefits of maintaining the capability of the NTS. Specifically, the study looks to assess the long-term economic benefits of maintaining the current capability of the NTS in five particular areas, as set out below in Table 1.

Table 1: Focus areas and definitions of the types of long-term economic benefits created by maintaining the capability of the NTS

Focus areas		Definition of the long-term economic benefits of maintaining the capability of the NTS
	Long-term economic benefits of maintaining the capability of the NTS for the gas sector	The impact that reducing the capacity and resilience of entry points into the NTS would have on gas prices and security of supply over the long term.
	Long-term economic benefits of maintaining the capability of the NTS for the electricity sector	The impact that reducing the capacity and resilience of entry and exit points to the NTS would have on electricity prices and security of supply over the long term.
	Long-term economic benefits of maintaining the capability of the NTS for energy intensive industries (EIIs)	The value of the economic activity that would be put at risk if the NTS were unable to maintain a low-cost and secure supply to industrial users of gas over the long term.
	Long-term economic benefits of maintaining the capability of the NTS for gas distribution networks (GDNs)	The value of the NTS over the long term in providing a backup supply of gas, or as a source of gas storage, for GDNs to draw on in a decarbonised energy system.
	Real option value of the NTS	The real option value of maintaining NTS capability so it is available if certain decarbonisation pathways in which the NTS has a smaller role turn out to be infeasible or would not deliver best value for money.

To assess the economic benefits of the NTS in the five focus areas above EY has been requested to undertake the following types of analysis:

1. Modelling of the impact of reducing network capability – including modelling of the gas and electricity markets as well as economic modelling of the impact on energy-intensive industry of increased energy prices and/or reduced security of supply;

2. A review of academic and industry literature analysing the implications of different decarbonisation pathways for the heat sector; and

3. Stakeholder engagement with a range of stakeholders, including GDNs, large energy users, and trade associations.

While each of the areas above have been considered carefully in this report, this study is not intended to provide an exhaustive view of the benefits associated with maintaining the current level of NTS capability. NGGT has previously undertaken work to consider the impact of an unexpected and short-term loss of gas transmission network capability on the energy system. In contrast this study has focused on long term impacts associated with reduced investment in the network, and not sought to re-consider these short-term implications of reductions in capability of the NTS. This study has also not considered other economic benefits created by the NTS, such as the jobs created and supported by investment in and expenditure on the

NTS, or the value of the NTS to upstream gas production, which relies on the NTS for a route to sell gas into the GB gas market. Other benefits, such as environmental benefits, are also not within the scope of this study. EY has also not been asked to quantify the costs associated with maintaining the current level of capability of the network. These other benefits and costs would also need to be considered as part of any cost benefit analysis associated with network investment decisions.

Reflecting the above objectives for this study, the report is structured as follows:

- Section 3 assesses the economic benefits of maintaining the capability of the NTS for the GB gas sector;
- Section 4 assesses the economic benefits of maintaining the capability of the NTS for the GB electricity system;
- Section 5 assesses the economic benefits of maintaining the capability of the NTS for EIIs;
- Section 6 assesses the economic benefits of maintaining the capability of the NTS for GDNs;
- Section 7 considers the real option value created by maintaining the capability of the NTS; and
- Section 8 summarises the conclusions from the study.

3. Benefits of maintaining NTS capability for the GB gas sector

3.1 Introduction

In this section we assess the long-term economic benefits of maintaining the capability of the NTS for the GB gas market. We do this by considering the impact of a reduction in NTS capability on the gas market, including on gas prices, price volatility and total costs to consumers. The findings are informed by analysis carried out by the EPRG using their Global Gas Market Model.

It is outside the scope of this study to consider the potential cost savings that could be achieved if NTS capability were not maintained at its current level. The findings therefore only represent an estimate of the benefits associated with maintaining NTS capability.

3.2 Identification of long-term economic benefits

The GB gas market has numerous entry points, as described in Section 2, allowing a range of gas supply sources. This provides a range of benefits to the GB gas market, including:

- **Diversity of supply**: A broad base of entry points can reduce GB dependence on a single trading relationship and mitigate the damage of potential supply shocks such as pipeline outages and geopolitical conflicts.
- **Flexibility of supply**: A broad base of entry points allows the market to accommodate the increasingly uncertain gas demand profile, e.g., enabling short-term gas imports in response to the variable nature of renewable electricity generation.
- **Cost of supply**: GB has one of the most competitively traded wholesale gas markets in the world (ACER, 2018)[15]. Having multiple entry points facilitates competition in the GB wholesale gas market, helping to maintain low wholesale prices.[16]

3.3 Approach to quantification of long-term economic benefits

Modelling of the impact of reducing NTS capability on the gas market has been carried out using EPRG's Global Gas Market Model. This analyses the interaction of supply and demand on a daily basis at a global scale. The model covers all existing global gas producers and consumers.[17] The GB gas market is modelled on a more granular basis within the model, including all entry points into the NTS.

Reflecting the uncertainty around the future role of the NTS, for the purposes of this report NGGT were asked to identify four plausible scenarios reflecting a reduction in the capacity of entry points to the NTS (based on reductions in capability of particular assets on the NTS). The following scenarios were developed in conjunction with NGGT:

[15] ACER (2018). 'Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2017 – Gas Wholesale Markets Volume', September 2018. Available at: https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202017%20-%20Gas%20Wholesale%20Markets%20Volume.pdf

[16] In this market, wholesale prices are set by the marginal cost of the most expensive source of gas supply to meet demand. The marginal supply cost of the most expensive source is a function of: (a) time, (b) the source of supplies (UKCS, NCS, LNG, Continental European supplies, demand-side response), and (c) a supplier's opportunity cost of sending/bringing gas to National Balancing Point (NBP) vs. to other regional traded hubs such as North America's Henry Hub, Continental European gas hubs (e.g., the Title Transfer Facility (TTF) in the Netherlands), North Asian's emerging gas hub (e.g., Platts Japan Korea Market) vs. selling through oil-linked forward contracts.

[17] On the supply side, the model includes all the main gas producing countries, such as Russia, U.S.A., Canada, Norway, Qatar, Australia, Algeria and other producing regions such as Central and South America, Middle East, Central Asia and so on. On the demand side, the model covers all existing consuming countries and regions, such as GB, Continental European markets, Russia and other countries of the Former Soviet Union, China, India, North America, Middle East and so on.

- **Scenario 1A: 19% Reduction in Entry Capacity**: Decommissioning a selected number of compressor stations which would result in the reduction in entry capacity within the Easington area and one of the sub-terminals of the St Fergus terminal.
- **Scenario 1B: 8% Reduction in Entry Capacity**: Shutdown of the Feeder 9 pipeline bringing gas from the Easington area into the NTS. This scenario has only been modelled for 2025 against the SP scenario. The loss of Feeder 9 means that capacity for a number of entry points are reduced for the entire year.
- **Scenario 1C: 4% Reduction in Entry Capacity**: Decommissioning a selected number of compressor stations would result in a reduction in entry capacity at Bacton Interconnector Point (IP) – the entry point that brings gas from Europe into the GB gas market.
- **Scenario 1D: 9% Reduction in Entry Capacity**: Decommissioning a selected number of compressor stations resulting in a reduction of entry capacity from the two LNG import terminals – Milford Haven and Isle of Grain. This scenario has only been modelled under a heavy winter demand baseline.

The level of entry capacity assumed in each scenario are shown in Table 2 below. The lower level of entry capacity in the scenarios relative to the baseline reflect the assumed constraints on entry capacity. The names of the scenarios reflect the percentage reduction in entry capacity relative to the baseline.[18]

Table 2: Assumptions on NTS entry capacity (mcm/d)

Entry points	Baseline	Scenario 1A		Scenario 1B	Scenario 1C		Scenario 1D	
		S	W		S	W	S	W
St Fergus TOM	74	45	45	74	74	74	74	74
Easington	93	46	53	29	93	93	93	93
Garton(S)	38	19	22	12	38	38	38	38
Hatfield Moor (P)	0.03	0.01	0.02	0.01	0.03	0.03	0.03	0.03
Hornsea (S)	21	10	12	7	21	21	21	21
Hatfield Moor (S)	2	1	1	1	2	2	2	2
Theddlethorpe	55	27	31	17	55	55	55	55
Bacton IP	117	117	117	117	82	93	117	117
Milford Haven	86	86	86	86	86	86	31	42
Isle of Grain	63	63	63	63	63	63	32	32
Total	**837**	**690**	**674**	**772**	**802**	**813**	**751**	**762**

Notes: S – Summer; W – Winter; (P) – production; (S) – Storage; Entry points into the NTS not reported here are unaffected by the considered scenarios. Scenario 1A represents a 19% reduction in entry capacity; Scenario 1B represents an 8% reduction in entry capacity; Scenario 1C represents a 4% reduction in entry capacity; and Scenario 1D represents a 9% reduction in entry capacity. Total includes capacity from other entry points that is not assumed to vary between scenarios.

Source: NGGT

[18] In the case of Scenarios 1A, 1C, and 1D, the average of summer and winter capacity reductions have been used to inform the scenario name.

These scenarios have been compared to two “Baseline” scenarios, where existing NTS capacity at GB entry and exit points is maintained, corresponding to the SP and CR scenarios in the 2018 FES. Additional sensitivities were developed around the Baselines scenarios to reflect years with high winter demand.

The CR and SP baselines were modelled assuming ‘average’ winter conditions. Sensitivities to the baseline reflecting ‘high winter demand’ applied adjustments to the average winter demand baseline, provided by National Grid. These were uplift factors of 16.6% to residential demand and 11.3% to industrial and commercial (I&C) demand respectively for three winter months (December – February) for SP and CR as well as limiting the flows from Bacton IP to the ‘average’ winter baselines.[19] This increase in daily gas demand can be considered to be representative of a typical ‘higher than average’ winter gas demand.

Assumptions about global supply and demand of energy[20] under the baseline scenarios are taken from the International Energy Agency (IEA) 2018 World Energy Outlook (WEO), with the New Policies Scenario (NPS) and Sustainable Development Scenario (SDS) assumed to correspond to the SP and CR scenarios respectively.

Modelling of the impact of the scenarios makes the following assumptions:

- ► Gas transmission network charges have been modelled based on the NGGT Capacity-Weighted Distance (CWD) model[21] and FES forecasts of peak demand day for the respective years (2025 and 2035) and scenarios (SP and CR) were used to derive Reserve Prices at each entry and exit point of the NTS.[22]
- ► The transmission services revenue to be recovered from the capacity-based transmission tariffs has been assumed to stay the same for the period to 2035 for both baselines and sensitivities. This assumption reflects NGGT’s view that the costs associated with compressor stations are typically sunk investment costs that would need to be recovered irrespective of whether the stations were closed, with avoidable operating expenditure accounting for only a small proportion of overall costs.
- ► Cross border tariffs between markets zones in Continental Europe are annual tariffs averaged across all interconnection points and assumed unchanged. In reality, there are different transportation products (e.g., daily, monthly) with corresponding tariff structures which may (or may not) result in additional flows between market zones in Europe.
- ► Daily gas demand profiles are based on the average of daily gas demand in 2013-17 and hence the impact of weather on gas demand in future years is assumed to be the average impact witnessed in the last 5 years.
- ► The Global Gas Market Model and the Pan-European Electricity Dispatch Model are perfect-foresight models, i.e., they seek to optimise dispatch decisions given knowledge of the level of demand and of supply constraints. This means that modelling may understate the benefits of maintaining NTS capability in scenarios where unexpected stress events occur and it takes time for the market to respond by, for instance, re-routing LNG supplies or starting up generators.

[19] This is to reflect the fact that under a cold snap or prolonged cold winter gas demand in north-west Europe could also be very high and hence supplies from the Continent might be limited.
[20] GB gas demand in residential, industrial and commercial and other sectors are taken from FES; gas demand in the power sector is determined by EPRG’s Pan-European power dispatch model.
[21] Available at Joint Office of Gas Transporters, NTS Charging Methodology Forum https://www.gasgovernance.co.uk/ntscmf

[22] The result of the modelling transmission tariffs yields an average increase of network charges of 0.47% p.a. for all entry points under the SP FES and 4.53% p.a. under the CR FES while all charges for exit points will see an increase of 0.32% p.a. under the SP FES and 2.38% under the CR FES.

3.4 Estimates of long-term economic benefits

The results of the modelling are set out in Table 3 for 'average' winter demand and in Table 4 for a typically cold winter season. The modelled reduction in the capacity of the NTS causes an increase in average wholesale gas prices by +0.01% to +5% and wholesale cost by +0.01% to +6% under almost all scenarios. The largest impacts observed are under Scenario 1A, with significantly higher impacts observed in a high demand winter.

Table 3: Impact of NTS entry constraints on GB wholesale gas market prices (£/MWh-th) and wholesale cost (£m/year) under 'average' winter demand

		Scenario Impact				Scenario Impact		
	Baseline wholesale price £/MWh	1A: 19% reduction in entry capacity	1B: 8% reduction in entry capacity	1C: 9% reduction in entry capacity	Baseline wholesale cost £m[23]	1A: 19% reduction in entry capacity	1B: 8% reduction in entry capacity	1C: 9% reduction in entry capacity
SP 2025	18.30	0.06* (+0.3%)	0.12* (+0.7%)	0.02* (+0.1%)	10,981	35 (+0.3%)	78 (+0.7%)	16 (+0.2%)
CR 2025	15.15	0.22* (1.5%)	*Not modelled*	0.01* (+0.1%)	7,954	82 (+1.0%)	*Not modelled*	6 (+0.1%)
SP 2035	20.41	0.47* (+2.3%)	*Not modelled*	0.003* (+0.02%)	11,653	195 (+1.7%)	*Not modelled*	2 (+0.0%)
CR 2035	11.60	0.61* (+5.2%)	*Not modelled*	0.00 (+0.0%)	4,790	285 (+6.0%)	*Not modelled*	0 (+0.0%)

Table 4: Impact of NTS entry constraints on GB wholesale gas market prices under 'high' winter demand

		Scenario Impact			Scenario Impact	
	Baseline wholesale price £/MWh	1A: 19% reduction in entry capacity	1D: 9% reduction in entry capacity	Baseline wholesale cost £m	1A: 19% reduction in entry capacity	1D: 9% reduction in entry capacity
SP 2025	18.49	0.22* (+1.2%)	0 (+0.0%)	11,805	124 (+1.1%)	1 (+0.0%)
CR 2025	15.29	0.55* (+3.6%)	0.11* (+0.7%)	8,521	216.7 (+2.5%)	79.1 (+0.9%)
SP 2035	20.87	0.67* (+3.2%)	0.002 (0.0%)	12,737	272 (+2.1%)	2 (+0.0%)
CR 2035	12.72	0.57* (+4.5%)	0.0 (0.0%)	5,678	244 (+4.3%)	0.0 (+0.0%)

*Note: * statistically significant at p<0.05. Note Scenarios 1B and 1C not modelled for high winter demand.*

Source: EPRG analysis based on its Global Gas Market Model

[23] To avoid double counting, here EPRG measure the impact on residential, industrial and commercial and other customers whereas the impact on gas demand for power generation is analysed in Section 5.

It is also noted that impacts are more pronounced on a CR baseline than on a SP baseline. This is because demand for gas under the CR baseline is more price inelastic than under the SP baseline, with the effect that a reduction in gas supply translates into a larger increase in gas prices.

These results demonstrate that restrictions on the capacity of the NTS can have a significant impact on the GB gas market and lead to an increase in wholesale gas costs. They also demonstrate that the impact of reductions in network capacity can actually be greater in a scenario with lower consumption of gas: the significantly larger consumer impact of capacity restriction under the CR scenario reflects the fact that power generation in this scenario is more dependent on renewable energy, which leaves customers more exposed to the impact of high gas prices at times of intermittency, especially during peak hours.

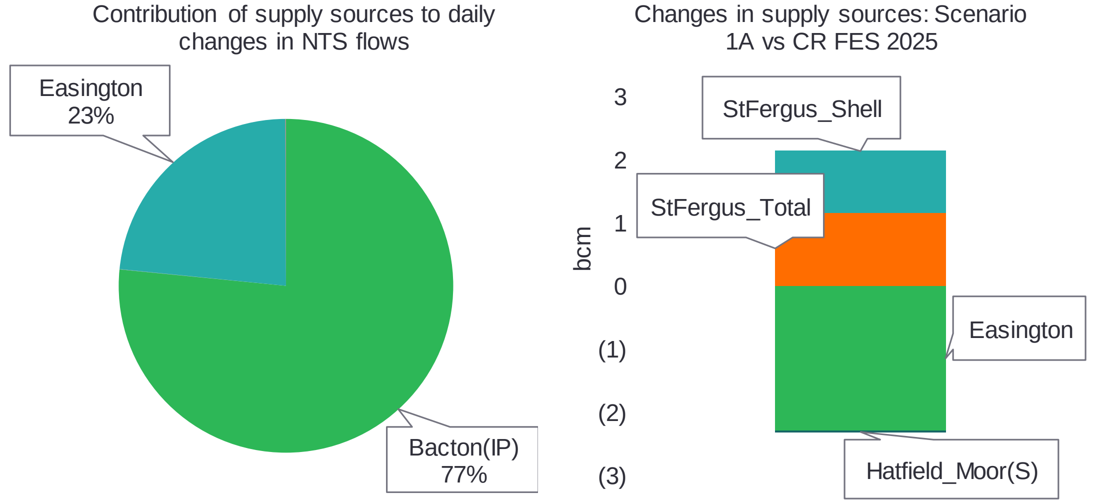
Analysis of the impact on annual wholesale gas price volatility[24] suggests there would be only a marginal effect across the majority of scenarios. The differences in annual standard deviations of wholesale prices are only statistically significant[25] for:

- A 19% reduction in entry capacity (Scenario 1A) under the CR FES 2025 baseline, where the annual volatility decreased by 3.9 p.p. (percentage points) (high winter demand baseline); and

- A 19% reduction in entry capacity (Scenario 1A) under the CR FES 2035 baseline, where annual volatility increases by 0.9 p.p. (high winter demand baseline) and by 3.2 p.p. ('average' winter demand baseline).

Two main sources of gas act as swing supplies in the summer (Jun-Aug) under the Baseline. Almost 80% of changes in daily supplies during the summer come into Bacton from Continental Europe and 20% come from Norway into Easington (see Figure 10 left panel). Thus, once the entry constraint envisioned under Scenario 1A is put in place, the capacity to ship gas into the Easington and other import terminals is reduced, leading to other more expensive entry routes into the NTS being used resulting in an increase in wholesale gas prices. In particular, Scenario 1A affects supplies from the Easington terminal, which is replaced almost entirely by other Norwegian gas into the St Fergus terminal (Figure 10 right panel).

Figure 10: Sources of gas supplies in Jun-Aug in CR 2025 baseline (high winter demand sensitivity)



[24] Measured as coefficient of variation: ratio of annual standard deviation of daily gas prices to the mean.
[25] To infer statistical significance of differences in standard deviations of wholesale prices an F-test is used.

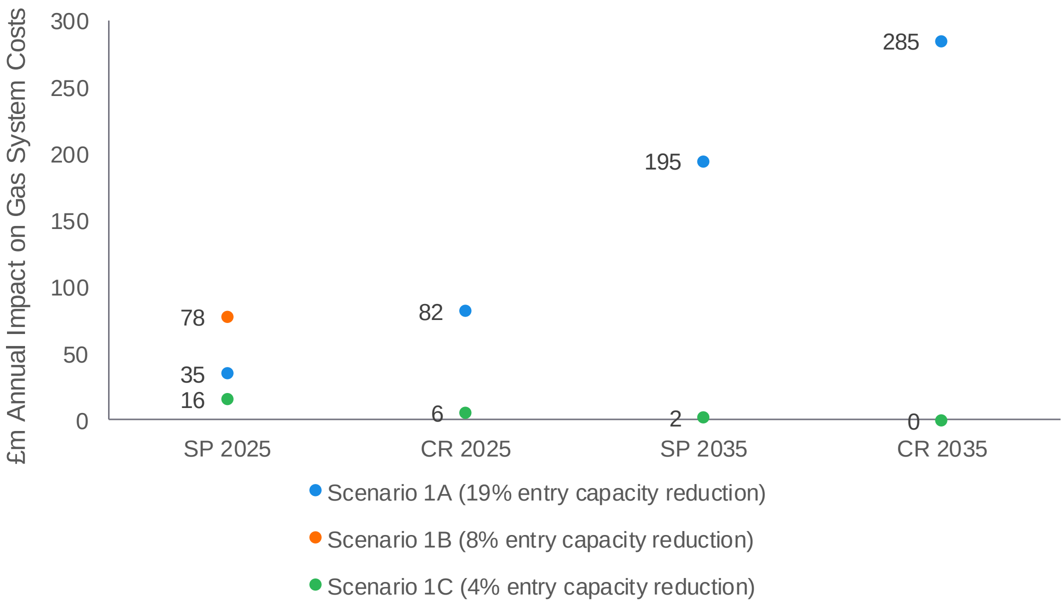
Source: EPRG analysis based on its Global Gas Market Model

3.5 Conclusions

The modelling carried out for this study of the impact of specific potential constraints on the capability of the NTS on gas prices (summarised in Figure 11) indicates:

- The NTS could have a benefit in reduced gas market costs in 2025 of up to £82m in 2025 rising up to £285m in 2035 where there is a 19% reduction in entry capacity (Scenario 1A). A £78m impact is estimated as a result of an 8% reduction in entry capacity (Scenario 1B), while the modelled impacts associated with a 4% reduction in entry capacity (Scenario 1C) are more marginal.
- The NTS could have a benefit in terms of additional resilience against a high winter demand, where the impact of a 19% reduction in entry capacity (Scenario 1A) is significantly higher.
- The estimated long-term economic benefits of maintaining the capability of the NTS for the gas market is potentially greater under a CR baseline (i.e., with high renewable penetration) than under a SP baseline (with lower renewable penetration). This is because the value the NTS provides will in future increasingly be as a back-up source of fuel for intermittent sources of energy supply.

Figure 11: Impact of NTS constraints on gas system costs



Source: EPRG gas market modelling.

Overall, the modelled scenarios indicate that maintaining the current capacity of the NTS through to 2035 provides significant benefits to GB in ensuring that the wholesale gas costs are not unreasonably high due to lack of NTS capacity to deliver gas to GB consumers when and where needed.

4. Benefits of maintaining NTS capability for the GB electricity sector

4.1 Introduction

In this section we assess the long-term economic benefits of maintaining the capability of the NTS for the GB electricity market. We do this by considering the implications for the electricity market of the potential increase in gas prices identified in Section 3. We also consider how a reduction in NTS capability could constrain how flexibly GB power plants can operate and what implications this would have on GB wholesale power prices and security of supply.

Impacts quantified in this section only consider the long-term economic benefits of the NTS (in avoided generation costs or security of supply) and have not considered the potential costs of maintaining the current level of capability of the NTS in the form of increased network charges.

4.2 Identification of long-term economic benefits

The NTS plays a significant role in ensuring that the GB electricity market is able to provide a secure and low-cost supply of power. The NTS does this principally in two ways:

- **Supply of low-cost gas**: As identified in Section 3, the NTS ensures a low-cost and resilient supply of gas to the market. This then feeds through to the GB wholesale electricity price as gas is often the fuel of the marginal plant that sets the wholesale electricity price. Gas is currently the largest source of electricity generation, accounting for 40% of generation in 2017.[26] Though this is expected in all FES scenarios to reduce over time due to increased reliance on renewables (and improvements in energy efficiency and storage), gas plants are expected to continue to be the marginal price-setter in the market in most time periods in 2025 and 2035.

- **Flexibility of plant dispatch:** The NTS also plays an important role in delivering gas where needed at short notice. The NTS currently transports gas to power stations on an hourly basis largely without constraint. However, an erosion in the capability of the NTS over time could affect the ability of the NTS to provide gas to gas-fired power stations at short notice and constrain the ability of gas-fired generation to respond to short-term fluctuations in demand for electricity and alter their gas offtake. The impact of this is potentially to increase electricity market costs and to increase the risk of a disruption to the power supply (load shedding). The impact of a constraint on the flexibility of gas-fired plant is expected to increase over time as a greater proportion of generation comes from intermittent renewables and gas-fired generation increasingly acts as a source of flexible back-up generation.

4.3 Approach to quantification of long-term economic benefits

The benefits of the NTS to the electricity market have been modelled by EPRG using their Pan-European Electricity Dispatch Model. This simulates European power markets at hourly time resolution to identify the total generation costs of meeting hourly demand. The model's objective is to minimise the total costs (fuel and carbon costs and variable OPEX) of meeting hourly demand, while respecting techno-economic constraints of power plants such as ramping constraints (how quickly a plant's output can increase or decrease), and system security constraints (operating/spinning reserve requirements). Demand is assumed to be price inelastic, with country-specific values of lost load (VoLL) assumed in the model where demand is not met. For this study, EPRG has modelled coal, gas and oil-fired power stations as well as pumped storage, while treating all other technologies (e.g., wind, solar and

[26] BEIS Dukes 5.3, July 2018 (https://www.gov.uk/government/statistics/electricity-chapter-5-digest-of-united-kingdom-energy-statistics-dukes)

nuclear) as exogenous[27]. The model simulates 25 market bidding zones[28] including GB and assumes full coupling of these market zones.

In agreement with National Grid, EPRG has defined electricity market baselines under the SP and CR FES scenarios for 2025 and 2035 for an average winter demand of gas. Additional sensitivities have been carried out for some scenarios against a baseline of high winter gas demand, reflecting a 1-in-20 year view.

The impact of the NTS increasing gas prices has been identified by modelling the four scenarios set out in Section 3. An additional scenario has also been modelled to reflect the potential impact of an erosion of NTS capability constraining the ability of gas-fired plant to generate flexibly:

- **Scenario 2A**: **Slower start-up of gas-fired power stations:** Loss of compressor stations resulting in reductions in network flexibility to deliver gas to gas-fired power stations at short notice affecting how quickly gas-fired power plants on the transmission network can start up.[29]

Note that not all scenarios were modelled against all baselines due to limitations on the number of modelling runs that could be accomplished within the time available to carry out this study.

4.4 Estimates of long-term economic benefits

4.4.1 Impact on wholesale electricity prices and costs

The impacts of the scenarios modelled on wholesale electricity prices are shown in Table 5 and the impact on energy system costs are shown in Table 6. These show that the benefit in maintaining the capability of the NTS in terms of reduced electricity system costs could be up to £127m in 2025, increasing to up to £561m in 2035.

Table 5: Impact of NTS entry constraints on GB wholesale electricity prices[30] (£/MWh) under 'average' winter demand

		Scenario Impact			
	Baseline wholesale price £/MWh	19% Reduction in Entry Capacity (1A)	8% Reduction in Entry Capacity (1B)	4% Reduction in Entry Capacity (1C)	Slower start-up of gas-fired power stations (2A)
SP FES 2025	35.22	0.007* (+0.02%)	0.017* (+0.05%)	0 (0.00%)	0.243* (+0.69%)
CR FES 2025	36.42	0.028* (+0.08%)	*Not modelled*	0 (0.00%)	0.415* (+1.14%)
SP FES 2035	35.38	0.046* (+0.13%)	*Not modelled*	0 (0.00%)	0.792* (+2.24%)
CR FES 2035	32.42	0.031* (+0.09%)	*Not modelled*	*Not modelled*	1.567* (+4.83%)

*Note: * Statistically significant at $p<0.05$. Scenario 1D not modelled for average winter demand.*

Source: EPRG analysis based on its Pan-European Electricity Dispatch Model.

[27] This is reasonable assumption given that these technologies have very low marginal cost to generate electricity.
[28] These include: SEM (in Ireland), Great Britain, France, Belgium, the Netherlands, Switzerland, Germany, Austria, Italy, Denmark, Norway and Sweden. Italy, Denmark, Norway and Sweden were subsequently divided into their respective bidding zones, as is currently the case
[29] In consultation with National Grid, EPRG assumed in this scenario that gas-fired units would not be able to ramp up by more than 50% of maximum nameplate capacity in less than 4 hours (or 8 hours to full capacity). The baseline ramping capability of gas-fired units is that they technically can ramp up to full capacity within one hour, provided gas is delivered by the NTS as required.
[30] Wholesale electricity price has been defined as total variable conventional generation costs (coal, gas and oil-fired power stations) plus the cost of procuring operating reserves (part of balancing costs related to procuring spinning up/down reserve) and any potential costs associated with curtailment of VRE and load shedding (priced at VoLL). Wholesale electricity prices do not include any capital or fixed costs.

Table 6: Impact of NTS entry constraints on GB electricity system costs (£m) under ‘average’ winter demand

	Baseline electricity system costs £m	Scenario Impact			
		19% Reduction in Entry Capacity (1A)	8% Reduction in Entry Capacity (1B)	4% Reduction in Entry Capacity (1C)	Slower start-up of gas-fired power stations (2A)
SP FES 2025	11,253	2 (+0.0%)	5.07 (+0.1%)	0 (0.0%)	70 (+0.6%)
CR FES 2025	11,213	8.35 (+0.1%)	*Not modelled*	0 (0.0%)	127 (+1.1%)
SP FES 2035	11,904	14.58 (+0.1%)	*Not modelled*	0 (0.0%)	271 (+2.3%)
CR FES 2035	11,367	12.3 (+0.1%)	*Not modelled*	*Not modelled*	561 (+4.9%)

Note: Scenario 1D not modelled for average winter demand.

Source: EPRG analysis based on its Pan-European Electricity Dispatch Model.

Further analysis of the above results indicates that:

- Higher wholesale gas prices in GB typically have a secondary (indirect) impact on wholesale electricity prices – increasing them by up to 0.1% above the baseline price, as shown in scenarios with a 19% and 8% reduction in entry capacity). However, the magnitude of impacts is less than the magnitude of impacts on gas prices (shown in Table 3). This is because gas is not the marginal plant for all periods in future and as energy system costs also reflect other costs, such as balancing services or curtailment payments, which would be less affected by an increase in the wholesale gas price.

- The modelled impact of constraining the ramping times of gas-fired plants on electricity prices (Scenario 2A) is found to be more significant than those from an increased gas price, ranging from 0.7% to 1.1% in 2025 and increasing to between 2.2% and 4.8% in 2035. The higher impact is because constraints on gas-fired plant start-up times (Scenario 2A) introduce inefficiencies to the operation of the GB electricity system.

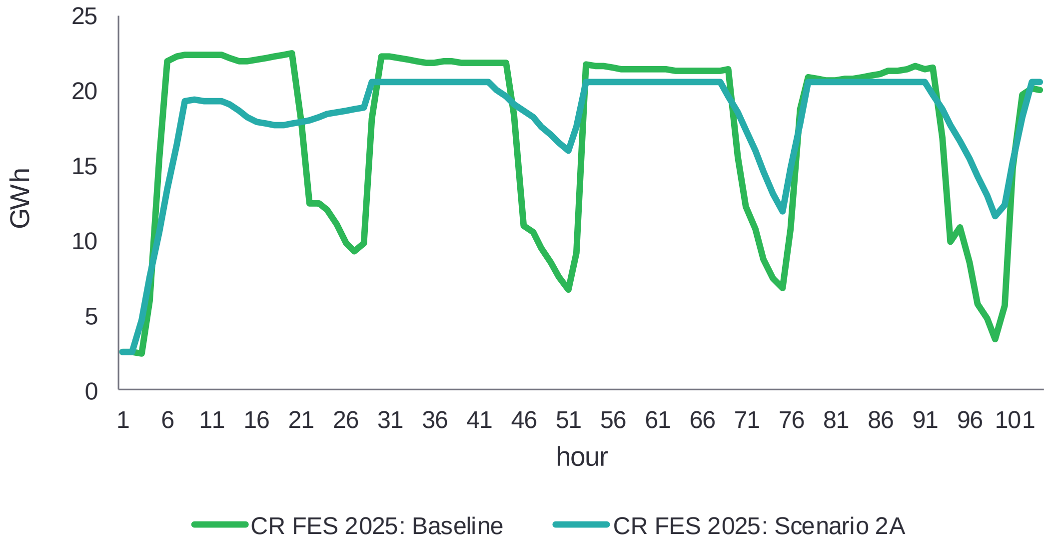
- Figure 11 below shows total gas-fired generation under Baseline and Scenario 2A for a sample of more than 100 consecutive hours in January (2025), further illustrates the impact of Scenario 2A (slower start-up times for gas-fired plant) on plant dispatch. In these hours:

  - Gas-fired generation is under-generating when it is economically efficient to generate more. This calls in other more expensive generating options (such as distributed generation and demand response) to meet peak demand periods.

  - Constraints in Scenario 2A affect the ability of gas-fired plants to ramp-down as well as start-up quickly. This leads to gas-fired generation over-generating when it would be economically efficient to ramp down. As a result, gas-fired generation displaced generation from more cost effective technologies, pushing up wholesale prices and system costs.

  - The changing operating strategy of gas-fired units results in either greater consumption (in Scenario 2A under the CR FES baseline total annual increase in gas-fired generation is around 10% higher than the baseline consumption) or lower consumption of gas (in Scenario 2A under the SP FES total annual gas-fired generation is around 6% lower than the baseline consumption) for power.

Figure 12: Gas-fired generation under Baseline and Scenario 2A (slower start-up of gas fired power stations): January 2025



Source: EPRG analysis based on its Pan-European Electricity Dispatch Model.

EY has additionally looked at the impact of NTS entry constraints on GB wholesale power market prices under a 'high' winter demand scenario for Scenarios 1A (19% reduction in entry capacity) and 1D (9% reduction in entry capacity). The modelled impacts shown in Table 7 below illustrate a higher impact of these scenarios on wholesale market prices and costs under a high winter demand than under an average winter demand.

Table 7: Impact of NTS entry constraints on GB wholesale power market prices under 'high' winter demand

		Scenario Impact			Scenario Impact	
	Baseline wholesale price £/MWh	19% Reduction in Entry Capacity (1A)	9% Reduction in Entry Capacity (1D)	Baseline wholesale cost £m	19% Reduction in Entry Capacity (1A)	9% Reduction in Entry Capacity (1D)
SP FES 2025	35.22	0.02* (+0.1%)	0 (+0.0%)	11,253	6.57* (+0.1%)	0 (+0.0%)
CR FES 2025	36.42	0.07* (+0.2%)	0.01* (+0.0%)	11,213	14.89* (+0.1%)	5.36* (+0.0%)
SP FES 2035	35.38	0.06* (+0.2%)	0 (0.0%)	11,904	13.27* (+0.1%)	0 (0.0%)
CR FES 2035	32.42	0.08* (+0.2%)	0 (0.0%)	11,367	25.95* (+0.2%)	0 (0.0%)

Note: Scenarios 1B (8% reduction in entry capacity) and 1C (4% reduction in entry capacity) not modelled for high winter demand.

Source: EY modelling based on results from EPRG's Pan-European Electricity Dispatch Model.

4.4.2 Impact on security of electricity supply

We have additionally considered the impact of the ramping constraints in Scenario 2A (slower start-up times for gas-fired plant) on GB security of electricity supply, including on the probability of load shedding (interruption of electricity supply) and on resilience to a black start event (a failure of the electricity transmission network).

4.4.2.1 Probability of load shedding

Restricting the ramping limits of gas-fired generation effectively means that total capacity available on the system is lower on an hourly basis.[31] Table 8, for example, shows that even if all gas-fired units were to offer their capacity in the spinning reserve market there would not be enough capacity to meet spinning reserve requirements (4.3 GW, on average in 2025, whereas maximum ramping capacity available is 3.9 GW under SP FES in 2025) when their ramping rates are limited (Scenario 2A).

Further, ramping limits might increase the expected loss of load probability as, for example, under CR FES 2025 there are 757 hours when available spinning capacity is below 25% of the total requirement while under SP FES 2025 there are 170 hours when available spinning capacity is below 25% of the total requirement. Under the baseline ramping capability there is enough capacity to fully meet reserve requirements (in both CR and SP FES 2025).

Table 8: Available gas-fired generation capacity for Baseline and Scenario 2A (slower start-up times for gas-fired power stations)

Capacity (GW)	Available capacity: Baseline	Available capacity: Scenario 2A			Average spinning reserve requirement
		1st hour	4th hour	8th hour	
SP FES 2025	30.9	3.9	15.4	30.9	4.3
CR FES 2025	25.5	3.2	12.8	25.5	4.1

Source: EPRG analysis based on its Pan-European Electricity Dispatch Model.

The spinning reserve requirement is a contingency against the loss of a large share of intermittent generation and the largest piece of electricity infrastructure (N-1).[32] This contingency is important as reserve capacity acts to mitigate very high and sharp intraday or balancing power prices in the event of sudden supply shocks. The deterministic nature of EPRG's electricity dispatch model (the model assumes the market has perfect foresight of changes in supply and demand) means that the model is likely to understate the potential impact of NTS capacity reductions on intraday and balancing prices as a result of reducing the availability of spinning reserve capacity.

The increased probability of a load shedding event would be likely to have welfare implications for consumers, including disruption to customers who experience a power outage, and higher wholesale prices (as generators are able to charge a higher price for their power in a stress event). These impacts are captured implicitly through higher electricity prices in the modelling of electricity system costs carried out for this study.

4.4.2.2 Resilience to black start event

Constraints on ramping limits in Scenario 2A may also be expected to weaken resilience to a black start event, i.e., where there is a failure of the GB electricity transmission network. CCGT generation is currently a significant contributor to GB's black start capability, with a number of stations contracted by the System Operator to have the capability to start up generation without relying on power from an external source. If these gas plants faced significant delays in starting up as a result of NTS exit constraints, then that would have a

[31] in Scenario 1C, this is limited to 1/8 of total gas-fired capacity per hour

[32] As a rule of thumb, an electricity system with large share of wind generation would require spin up reserve equal to at least 20% of day-ahead forecasted total wind generation plus the largest conventional generation unit on the system (e.g., a nuclear power station or an interconnector) (see: Qadrdan, M., Wu, J., Jenkins, N., and Ekanayake, J. 2014. 'Operating Strategies for a GB Integrated Gas and Electricity Network Considering the Uncertainty in Wind Power Forecasts', *IEEE Transactions On Sustainable Energy,* Vol. 5, No. 1, January 2014)

knock-on effect on expected black start recovery times. This could have a single-event cost in the order of £600m in the event of a black start event.[33]

4.4.3 Conclusions

The modelling carried out for this study of the impact of changes in NTS capability on electricity system costs indicates:

- Maintaining NTS capability could have a benefit to the electricity market in terms of lower market costs of up to £127m in 2025 rising up to £561m in 2035 in Scenario 2A (slower startup times for gas-fired plant), i.e., where the reduction in NTS capability led to constraints on how flexibly gas-fired plants can be dispatched.

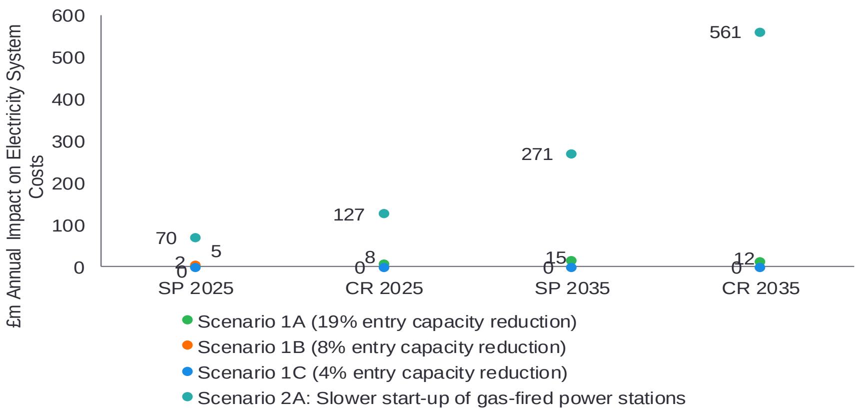
- Smaller values were identified under scenarios modelled with a reduction in entry capacity (Scenarios 1A, 1B and 1C) where the impact of the NTS constraints only affects the electricity market indirectly through higher gas prices. This partially reflects the fact that increased electricity costs are already accounted for in the increased gas system costs reported in Section 3 (i.e., where gas is purchased for use in electricity production at higher cost) and netted off here to avoid double counting.

- The estimated value of the NTS to the electricity market is potentially greater under a CR baseline (i.e., with high renewable penetration) than under a SP baseline (with lower renewable penetration), and is also modelled to increase significantly between 2025 and 2035 under all sensitivities. This is because the value of the NTS in supporting flexible dispatch of gas-fired plant will in future be increasingly important as gas is used flexibly to manage intermittency associated with high levels of renewables penetration.

- By supporting flexible dispatch of gas-fired plant, the NTS also contributes to security of supply and reducing the likelihood of load shedding. This impact is captured implicitly in the modelling of slower start-up times for gas-fired plant (Scenario 2A). The NTS additionally increases the resilience of the GB electricity market to a black start event, potentially reducing the recovery time by an hour and the value of lost load by £600m in the event of a single nationwide black start occurrence.

The results of the modelling carried out in the section are summarised in Figure 13 below.

Figure 13: Impact of NTS constraints on electricity system costs



Source: EPRG analysis based on its Pan-European Electricity Dispatch Model

[33] This assumes that exit constraints delay a nationwide recovery by 1 hour. This is based on an assumption that 4.3 GW of standby capacity is needed to deal with an unexpected loss of the largest generating infrastructure (drawing on FES CR figures) and the model finding that under Scenario 2A only 3.9GW of reserve capacity is available in the first hour under a SP scenario or 3.1GW under a CR scenario. This shortfall implies an additional wait time of 66-77 minutes under the SP and CR scenarios respectively. Customer demand in that hour is assumed to be 34 GWh (reflecting 2025 average hourly demand in the SP and CR scenarios). Customer value of lost load (i.e. willingness to pay to avoid a blackout) is £17,000/MWh, representing the weighted average value of domestic customers and SMEs. This figure is commonly used by both BEIS and Ofgem, see: 'The Value of Lost Load (VoLL) for Electricity in Great Britain, Final Report for Ofgem and DECC (2014)', https://www.ofgem.gov.uk/ofgem-publications/82293/london-economics-value-lost-load-electricity-gbpdf.

5. Benefits of maintaining NTS capability for energy intensive industries

5.1 Introduction

In this section the long-term economic benefits of maintaining the capability of the NTS for energy intensive industries (EIIs) are assessed. The range of benefits the NTS provides to EIIs have been assessed through a process of stakeholder engagement with industry trade bodies,[34] and by quantifying the potential loss to the economy if industry were exposed to higher gas and electricity costs as per the scenarios modelled in Sections 3 and 4.

Impacts quantified in this section only consider the long-term economic benefits of the NTS (in reducing gas and electricity wholesale prices) and have not considered the potential costs to EIIs of maintaining the current level of capability of the NTS in the form of increased network charges.

5.2 Identification of long-term economic benefits

The NTS is currently used to support a secure and low-cost supply of gas, which is used by EIIs in a range of processes – both for heat and as an input to power generation. As noted in Sections 3 and 4, reductions in the capability of the NTS could lead to increased prices for gas and electricity as well as reduced security of electricity supply. The impacts of reducing NTS capability on businesses would be felt most significantly by EIIs, for whom energy costs are a significant part of their overall productions costs and who are more likely to be at risk of leakage (i.e., moving production to another country where energy costs are lower).

Our engagement with industry stakeholders has identified a number of insights around the scale of the potential impact on industry:

- There are significant differences between EIIs around how gas is used. Across industry, electricity typically accounts for around 80% of energy expenditure and gas 20%.[35] However some industries make greater use of gas in heat processes. For instance, gas is used directly in industrial processes for production of cement and lime.

- The ability of industries to pass on increases in gas costs will likely depend on context. Many stakeholders noted the already challenging context of operating in the UK due to the comparatively high level of carbon taxes, electricity prices and network charges (as well as current uncertainty around Brexit).

- Security of gas supply was flagged as at least as significant a consideration as gas prices: Some industrial processes rely on a continuous stable supply of gas to maintain production, and that the production process does not allow for interruption. For instance gas-fired kilns are operated on campaigns of 6-10 years and cannot be shut-down mid-campaign for lack of fuel, so complex back-up fuel arrangements would need to be installed at all GB sites. A back-up fuel arrangement is expensive and potentially high carbon (e.g., oil supplies) and heavily regulated. A number of stakeholders argued that if the gas supply were to become less secure, it would become critical to put in place arrangements such as interruptible contracts to ensure gas supplies were prioritised for industries most affected by a loss of supply.

- Industry may have limited ability to adopt alternative technologies if they need to reduce their reliance on gas or electricity. Manufacturing facilities tend to have long asset lives of 10-20 years, so decisions made today will affect industrial processes into the 2040s.

[34] The trade associations consulted included the British Lime Association, the Mineral Products Association, the Major Energy Users Council, the Food and Drink Association, and the Confederation of Paper Industries.
[35] DECC 2015 Update on Energy and Emissions Projections

Stakeholders noted that there are few viable and cost-effective alternatives to the use of fossil fuels in manufacturing today.

5.3 Approach to quantification of long-term economic benefits

In order to quantify the value of the NTS to EIIs we have considered the impact of the energy price increases associated with the five scenarios modelled in Sections 3 and 4. The methodology we have followed to arrive at an economic value is summarised in Figure 14 below.

Figure 14: Approach to quantifying the economic value of the NTS to EIIs

1. Estimate price elasticity of energy demand for EIIs	2. Estimate economic footprint of EII sector	3. Gross Impact of Increased Energy Prices	4. Net Impact of Increased Energy Prices
► Literature review of studies of EII price elasticity of gas and electricity demand ► Review of measures to mitigate EII "carbon leakage" – e.g. through EII exemptions for energy policy costs	► Estimate economic footprint of current EII Gross Value Added (GVA) and employment ► Estimate indirect and induced economic activity through multipliers. ► Project size of sector in 2025 and 2035	► Estimate impact of changes in gas and electricity prices on sector GVA as a result of scenarios modelled in Sections 4 and 5 reflecting reduction in NTS capability	► Estimate impact of energy price increases on Net Value Added (NVA) by accounting for how the economy would respond to a reduction in EII employment by redeploying activity elsewhere in the economy

The potential economic impact of a reduction in network capability on the GB has been quantified through use of an Input-Output model. The Input-Output methodology describes the relationships between sectors of the economy and allows for the quantification of such additional demand for labour, goods and services through the computation of industry-specific multipliers.

The following methodology has been applied for quantifying the economic impact of a reduction in network capability under the modelled gas and power market scenarios identified in this report.

- ► A price elasticity of industrial demand for energy of -0.5 is assumed, based on the literature review described in Section 5.4.1.

- ► A baseline level of economic output associated with the use of electricity and gas is identified. To do this, the output of sectors identified as being energy intensive industries has been quantified. The baseline level of output was then adjusted in line with the projected use of gas and electricity in the FES scenarios. This is consistent with the industrial sector in GB investing in energy efficiency measures and low-carbon technologies that would reduce their exposure to energy prices.

- ► The gross economic impacts of the scenarios modelled in Sections 3 and 4 are estimated.[36] The price elasticity of energy demand has been applied to the modelled increase in energy prices and the relevant baseline to derive the loss of output that arises from the reduction in network capability and resilience in the modelled scenarios.

- ► The gross economic outputs are calculated to include the following types of impact:

  - ► Direct impacts: This is the impact on employees employed within the affected industrial sectors.

[36] This impact is 'gross' in that it represents the size of the economic impact before assuming that workers affected would be likely to find employment elsewhere in the economy.

- Indirect impacts: This is the impact on employees employed along the supply chain providing goods and services to the affected industrial sectors.

- Induced impacts: This is the reduction in the level of employment that would have generated as a result of people directly and indirectly employed by the industrial sectors spending their wages.

- The 'net' economic impacts of the modelled scenarios are identified. A computable general equilibrium (CGE) modelling approach has been applied to identify the impact on the GB economy after allowing that workers who would lose their jobs in industry or elsewhere as a result of energy price increases would be likely to find employment elsewhere, mitigating the size of the loss to the GB economy. To do this it has been assumed that workers would be redeployed to sectors that are less productive than those they were in.

5.4 Estimates of long-term economic benefits

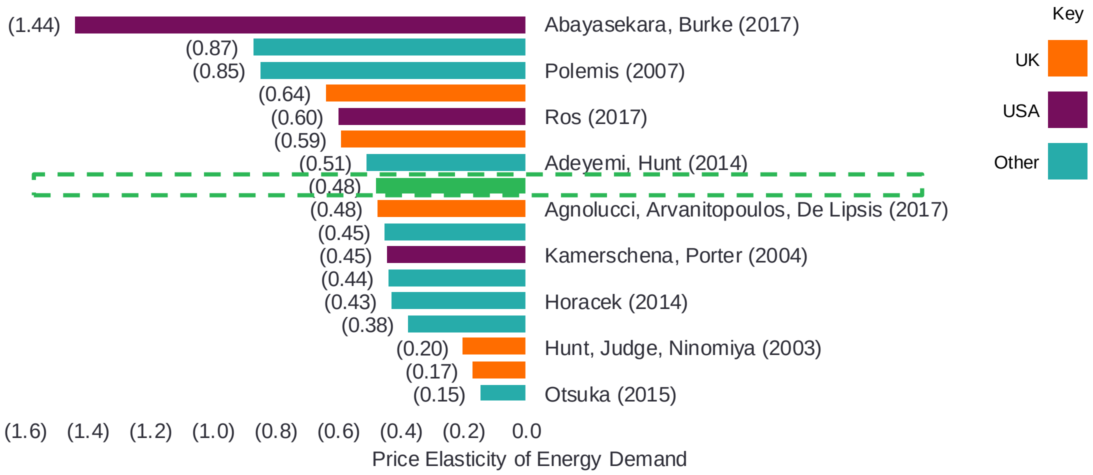
5.4.1 Estimating price elasticity of energy demand for EIIs

The cost of electricity is expected to account for 81% of energy costs in 2020 for EIIs, with 19% from gas.[37] For EIIs in receipt of bill exemptions for decarbonisation policy levies, electricity accounts for 76% of energy costs, with gas accounting for 24% of energy costs.[38] Given that gas prices are the principal driver of wholesale power prices, the impact of a reduction in the capability of the NTS on industry is likely to be principally through increasing wholesale electricity prices.

A literature review has been carried out of the impact of energy price increases on energy intensive industries in order to identify how EIIs might respond to the type of energy price increases identified in Sections 3 and 4 that could arise if NTS capability were to erode over time. The literature review was conducted for a variety of geographies, focusing primarily across developed markets such as the UK, US and Europe.

In general, the long-run price elasticity of demand (PED) identified for EIIs is around -0.5 (i.e., a 1% increase in price leads to a 0.5% reduction in volume demanded). The results of the literature review of EII price elasticities of energy demand are illustrated in Figure 15 below.

Figure 15: Literature review of price elasticity of energy demand across industry[39]



Source: EY Literature review

[37] DECC 2015 Update on Energy and Emissions Projections
[38] DECC 2015 Update on Energy and Emissions Projections
[39] Energy here is defined as either electricity, gas or both

The industry response to energy prices identified in the literature varies considerably across manufacturing sub-industries, and is higher in energy-intensive sectors such as aluminium, steel and cement. The considerable range across PED estimates is also due to other factors, such as the heterogeneity of markets analysed, and the exposure of sectors to global competition. EIIs are considered to be most at risk of carbon leakage (i.e., production offshoring to areas that do not have the same standard of carbon policies) if they face both high electricity costs and if they are highly exposed to international competition.

5.4.2 Economic Footprint of EII Sector in the Baseline

As shown in Table 9 below, the direct GVA associated with EIIs is estimated to be £28bn in 2018, while the sector employs around 400,000 people. Including the multiplier effect of people involved indirectly in industry as well as induced employment, the total activity associated with EIIs is estimated at just under £60bn and employment of 1.3m people. The direct activity represents 47% of total GVA and 29% of total employment associated with the relevant industries, with the rest of sector GVA accounted for by indirect and induced activity sustained through multiplier effects. The size of the industrial sector is assumed in the baseline to change in line with changes in the industrial consumption of electricity and gas projected in FES scenarios.

Table 9: Economic impact in baseline steady progression scenario, 2018

	Direct	Indirect	Induced	Total
GVA (£m)	27,628	17,864	13,658	**59,150**
Employment (000s)	378	549	373	**1,300**

Source: EY analysis of EPRG gas and electricity modelling and of ONS data

5.4.3 Impact of Reduction in NTS Capability on EII Gross Value Added

As shown in Table 10 below, maintaining current level of NTS capability is modelled to preserve between 50 and 1,600 jobs in 2025 by keeping energy prices low and maintaining industry competitiveness. This increases to between 50 and 8,200 in 2035. The value of the NTS is most significant under Scenario 2A (slower start-up of gas-fired power stations), where an erosion of NTS capability has the largest impact on wholesale electricity prices.

Table 10: Summary of gross annual employment contribution per scenario

	Gross Impact on Employment (# jobs)					
	Scenario 1A		Scenario 1B	Scenario 1C	Scenario 1D	Scenario 2A
	AWD	HWD	AWD	AWD	HWD	AWD
SP FES 2025	-150	-1,400	-300	-50	*NM*	-850
CR FES 2025	-700	*-250*	*NM*	-50	-350	-1,600
SP FES 2035	-1,100	*-550*	*NM*	-50	*NM*	-3,100
CR FES 2035	-2,700	-2,200	*NM*	*NM*	*NM*	-8,200

Notes: AWD – 'Average Winter Demand'; HWD – 'High Winter Demand'; NM – 'Not modelled'. Scenario 1A represents a 19% reduction in entry capacity, Scenario 1B represents an 8% reduction in entry capacity, Scenario 1C represents a 4% reduction in entry capacity, Scenario 1D represents a 9% reduction in entry capacity, and Scenario 2A represents slower start-up times for gas-fired power stations.

Source: EY analysis of EPRG gas and electricity modelling and of ONS data

As shown in Table 11 below, the total loss of GVA associated with Scenario 2A is between £56m and £198m in 2025, increasing to £102m and £528m in 2035. Impacts on GVA in other scenarios is lower, with the most significant impacts associated with Scenario 1A.

Table 11: Summary of gross annual GVA contribution per scenario

	Gross Impact on GVA (£m)					
	Scenario 1A		Scenario 1B	Scenario 1C	Scenario 1D	Scenario 2A
	AWD	HWD	AWD	AWD	HWD	AWD
SP FES 2025	-8.7	-33.4	-20.6	-2.4	*NM*	-55.9
SP FES 2035	-70.8	-97.6	*NM*	-0.5	*NM*	-198.4
CR FES 2025	-46.1	-17.1	*NM*	-2.6	-21.5	-101.8
CR FES 2035	-174.5	-142.6	*NM*	*NM*	*NM*	-525.8

Notes: AWD – 'Average Winter Demand'; HWD – 'High Winter Demand'; NM – 'Not modelled'. Scenario 1A represents a 19% reduction in entry capacity, Scenario 1B represents an 8% reduction in entry capacity, Scenario 1C represents a 4% reduction in entry capacity, Scenario 1D represents a 9% reduction in entry capacity, and Scenario 2A represents slower start-up times for gas-fired power stations.

Source: EY analysis of EPRG gas and electricity modelling and of ONS data

5.4.4 Impact of Reduction in NTS Capability on EII Net Value Added

After accounting for the potential redeployment of employment displaced to less productive sectors of the economy, the impact of the scenarios modelled on Net Value Added is estimated at between £1m and £119m in 2025 given average winter demand, increasing to between £2m and £316m in 2035. These impacts should be considered in addition to the (more significant) impacts on higher gas and electricity prices identified in Sections 3 and 4.

Table 12: Net annual economic impact on GVA per scenario

	Net Impact on GVA (£m)					
	Scenario 1A		Scenario 1B	Scenario 1C	Scenario 1D	Scenario 2A
	AWD	HWD	AWD	AWD	HWD	AWD
SP FES 2025	-5.2	-20.1	-12.3	-1.4	*NM*	-33.5
SP FES 2035	-42.5	-58.5	*NM*	-0.3	*NM*	-119.1
CR FES 2025	-27.7	-10.2	*NM*	-1.6	-12.9	-61.1
CR FES 2035	-104.7	-85.6	*NM*	*NM*	*NM*	-315.5

Notes: AWD – 'Average Winter Demand'; HWD – 'High Winter Demand'; NM – 'Not modelled'. Scenario 1A represents a 19% reduction in entry capacity, Scenario 1B represents an 8% reduction in entry capacity, Scenario 1C represents a 4% reduction in entry capacity, Scenario 1D represents a 9% reduction in entry capacity, and Scenario 2A represents slower start-up times for gas-fired power stations.

Source: EY analysis of EPRG gas and electricity modelling and of ONS data

5.5 Conclusions

The modelling carried out for this study of the impact of changes in NTS capability on electricity system costs indicates that:

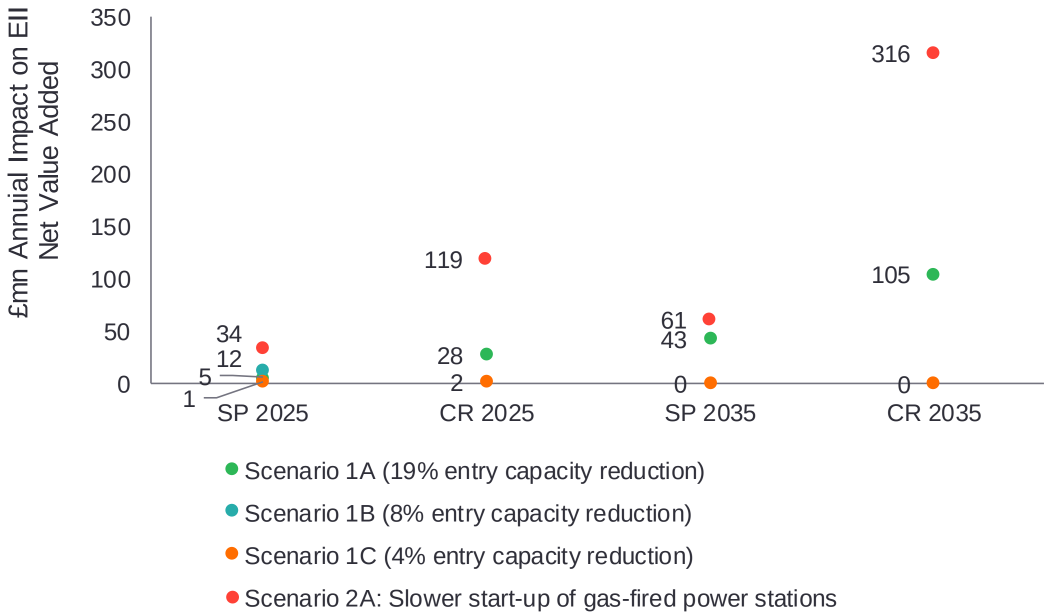
- The NTS could have a value to EIIs in 2025 of up to £119m in 2025 rising to £316m in 2035 in Scenario 2A, i.e., where the reduction in NTS capability led to constraints on how flexibly gas-fired plants could be dispatched. Smaller values were identified under other scenarios modelled.

- The estimated value of the NTS to the electricity market is potentially greater under a CR baseline (i.e., with high renewable penetration) than under a SP baseline (with lower renewable penetration). This is because the value of the NTS in supporting flexible dispatch of gas-fired plant will in future be increasingly important as gas-fired plant is increasingly used flexibly to manage intermittency associated with high levels of renewables penetration.

- Stakeholder engagement with industry has underscored the importance of continuity of gas supply to some industries, with risks identified of damage to production equipment if a stable supply of gas cannot be maintained. This suggests that the valuation of the NTS to EIIs is likely to be conservative as it does not capture the potential disruption to business if the security of electricity or gas supplies were compromised.

- The results of the modelling carried out in the section are summarised in Figure 16 below.

Figure 16: Impact of NTS constraints on economic activity of EIIs



Source: EPRG gas and electricity market modelling, EY analysis of economic impact

6. Benefits of maintaining NTS capability for gas distribution networks

6.1 Introduction

The NTS is currently used to transport gas to GDNs who in turn distribute it to homes and businesses. As the heat sector decarbonises there could be a reduced role for unabated gas in the heat sector, with the implication that less gas is transported through the NTS for distribution through the GDNs. However, the NTS is still expected to continue to serve as an important source of gas for GDNs, particularly at times of winter peak demand.

In this section we assess the long-term economic benefits of maintaining the capability of NTS for gas distribution networks (GDNs). In particular, we have been asked by NGGT to look at the role of the NTS in:

- Providing a backup supply of gas for GDNs to draw on; and
- Providing assured pressure capability.

6.2 Identification of long-term economic benefits

The long-term economic benefits of maintaining the capability of the NTS for GDNs have been qualitatively reviewed. This is through reviewing industry literature to understand the implications of decarbonisation pathways on how gas is used in future in the distribution networks. Engagement with GDNs has also been held to gain insights on how a reduction in NTS capability would impact on GDNs.

6.2.1 Literature review

The literature on decarbonisation pathways has been reviewed to identify implications for GDNs in maintaining a secure gas supply. This included through review of decarbonisation scenarios in FES as well as those developed by KPMG for the ENA as well as by Imperial College for the CCC. The literature reviewed has focused on studies of GB decarbonisation pathways as these are most relevant.

2018 FES data shows that the vast majority of gas currently supplied to end-users within GB is transported through the NTS (over 99% in 2017). In future there is expected to be an increase in gas produced on the distribution network as a result of increases in the production of shale gas and bio-gases.[40] However, as shown in Figure 17 below, the NTS is expected to continue to carry the majority of gas supplied within GB – with the proportion ranging between 91% and 99% in FES scenarios for 2030.

[40] Hydrogen may also be produced on the distribution network, though it may be more economical to produce it on a centralised basis.

Figure 17: GDN gas consumption by source

Source: FES 2018

Most studies reviewing the network implications of different pathways focused on the costs associated with decarbonisation: Under scenarios with high deployment of hydrogen for heat, the principal network costs identified in the decarbonisation of heat are in the construction of steam methane reformers (SMR) to produce hydrogen. By contrast, in scenarios with high electrification of heat, the principal network costs are in reinforcing the electricity transmission network, with some costs on the gas network for decommissioning of GDNs.

These costs findings are illustrated in Table 13 below in the cost breakdown for the ENA. The ‘Evolution of Gas’ scenario represents a case where there is a gradual (city by city) shift towards the use of hydrogen technologies, with the NTS having a similar role to today but with a large proportion of gas transported used to feed the SMR facilities that create the hydrogen which feed the distribution system. Under the ‘Electric Future’ scenario, there is a high degree of electrification of heat and transport, with GDNs ultimately being decommissioned and the NTS being scaled back.

Table 13: Cost breakdown of ENA 2050 decarbonisation pathways

Cumulative cost to 2050 (£bn)	Evolution of Gas[41]	Prosumers[42]	Diversified Energy Mix[43]	Electric Future[44]
Incremental commodities	21	17	20	115
Electric networks	-	22-26	1-2	26-43
Gas networks	43-52	7.2-8.8	19-23	7.2-8.8
Heat networks	-	-	62-77	-
Household adoption	40-49	205-237	54-66	126-152
Total	**104-122**	**251-289**	**156-188**	**274-318**

Source: ENA, 2050 Energy Scenarios

While there has been analysis of the role of the NTS under different decarbonisation pathways, there has been limited evidence identified in the literature on the implications for GDNs of the erosion of NTS capability – for instance the implications for GDNs to invest in local gas storage if the supply of gas through the NTS were to become less reliable in future. Decarbonisation pathway assessments typically have considered options for delivering sufficient low-carbon heat to meet peak demand noting challenges around producing and storing hydrogen or around generating and transporting sufficient electricity. This has been supported by projects undertaken by GDNs considering how peak energy demand could potentially be met by other energy sources, including storage solutions.[45]

6.2.2 Stakeholder engagement

We have engaged with a range of stakeholders as well as carrying out a literature review of studies on potential 2050 decarbonisation pathways to support our assessment. The stakeholder engagement conducted for this study included sending a survey to GDNs as well as relevant trade associations, and in some cases conducting follow-up interviews. Evidence was collected from three GDNs (Cadent, Wales & West Utilities, and Scotia Gas Network) as well as from Energy UK on the significance to GDNs of maintaining the NTS and the potential implications if NTS capability or resilience were to be reduced.

Stakeholders commented on the extent to which GDNs expected to reduce their reliance on the NTS for gas imports as a result of reduced gas demand volumes, distributed gas production, as well as increased local gas storage. The feedback provided is summarised as follows:

- **Reliance on NTS for gas imports**: Some GDNs expected a significant increase in the proportion of gas produced onto the distribution network (including shale and biogases), reducing the GDNs' reliance for gas on the NTS. However, all GDNs indicated that they expected to continue to be dependent on importing the large majority of their gas through the NTS for the foreseeable future, with some GDNs citing Steady Progression as the current most likely scenario (i.e. without further policy change from Government), and claiming that FES scenarios were likely to under-estimate the volume of gas requirements from the NTS. All of the GDNs who responded saw maintaining the capability of the NTS as a minimum requirement under all possible decarbonisation scenarios, noting that while annual demand for gas is expected to reduce under some

[41] Heat for residential and commercial use primarily delivered in 2050 by hydrogen (47%) and electricity (33%). Natural gas has an ongoing role in heat (13%). The NTS provides gas to the SMR steam facilities that create the hydrogen used to feed the distribution network.
[42] Heat for residential and commercial delivered in 2050 by electricity. There is a reduced role for the NTS in servicing gas generators and industrial users.
[43] Heat for residential and commercial is principally delivered in 2050 by electricity (50%) and hydrogen (17%). Natural gas has an ongoing role in heat (8%). There is a greatly reduced role for the NTS.
[44] Heat for residential and commercial is delivered in 2050 by electricity. There is a greatly reduced role for the NTS.
[45] An example is the 'Cornwall Energy Island' project, being carried out by Wales and West Utility (WWU).

scenarios they expected an ongoing reliance on the NTS to provide gas at times of peak demand.

For GDN's to become self-reliant for gas would require a number of the following conditions to hold:

- A significant uptake in energy efficiency measures to reduce energy needed for heating;
- A move to an electrification of heating or hydrogen solution (particularly where hydrogen is produced through electrolysis);
- Installation of heat pumps to help manage demand at times of peak demand; and
- Increased customer acceptance of disruptive infrastructure solutions, such as water storage within homes, to help further manage peak demand.

Stakeholder responses recognised that it is likely that the degree of reliance on the NTS as well as the nature of energy solutions applicable in each region are likely to vary.

- **Need for gas storage**: Some GDNs identified that there are a number of reasons to think that there may be an increased need for gas storage on the distribution network in future:
  - The increases in decentralised gas production and generation are increasing the need for local storage to help manage constraints around moving gas within the region.
  - Hydrogen has a lower linepack than natural gas (i.e. the amount of gas that can be held in the network), potentially reducing the level of storage capacity the GDNs currently have if they move in future to a hydrogen solution.
  - However, it was identified that there had been a reduction in local gas storage capacity over recent decades, as GDNs have relied on flexibility from the transmission system to manage diurnal and seasonal demand swings.
- **Provision of assured pressure gas**: In addition to providing a source of gas to the GDNs, the NTS provides a further role in assuring gas pressures. This is valuable in enabling gas to be transported within regions and to manage the growing flexibility requirements for the network, as the flows of both gas and electricity on the distribution network are increasingly bi-directional.
  - There has been a significant investment into development of gas-fired power generation connected to the gas distribution network, with the capacity of gas reciprocating engines expected to increase from 500 MW in 2017 to between 2.3 and 4.6 GW by 2025 (in FES CR and SP baselines).[46] The effect of this increase in distributed gas generation has been to significantly increase the volatility of gas demand for the GDNs, as gas generation varies in response to fluctuations in demand and the intermittency of renewable generation, with the spikes in gas demand from GDNs coinciding with times of peak electricity demand. It was noted by respondents that has made it more difficult for GDNs to maintain pressure on their networks.
  - Stakeholder engagement has identified that some GDNs are considering requirements for investment to support greater variability of gas demand on the network. These investments included increased diurnal and seasonal storage,

[46] This has largely been driven to date by incentives from the capacity market as well as embedded benefits associated with the nature of electricity network charging, though investment in new distributed gas generation may continue in future as reciprocating engines provide a more flexible form of generation than transmission-connected large-scale CCGTs.

compression capabilities, smart control systems and gas quality measurement processes.

- However, the investments required for GDNs to manage the requirements for increased flexibility and bi-directional gas flows on the network may not be fully offset by maintaining or enhancing NTS capability for assured pressure as gas will be increasingly required to be moved within regions, necessitating investment in local compressor stations.

6.3 Quantification of long-term economic benefits

We have estimated the potential long-term economic benefits of maintaining the capability of the NTS for GDNs in providing a backup supply of gas, even as the heat sector is decarbonised and less gas is expected to be used in heating. The estimated benefits are based on the storage costs that the GDNs avoid by being able to rely on the NTS for a secure gas supply. To calculate this, we have identified the level of gas storage that GDNs would have to build if they could not rely on the NTS to provide gas when required.

This scenario reflects the potential risk that under-investment in the NTS could reduce the reliability of the network and increase the likelihood that regions (particularly those on the extremities of the GB network) could be temporarily disconnected from the NTS to manage network constraints. It is recognised that this does not represent a likely or acceptable short-term scenario for the GB market, and our stakeholder engagement has suggested that GDNs continue to rely on the NTS for gas supplies and do not expect to need to become self-sufficient. However, the value provides an upper end estimate of the scale of benefits of the NTS reflecting the potential costs that GDNs could need to incur if they could not rely on the NTS at times of peak demand.

It has been assumed that GDNs would invest in a level of gas storage that would enable the daily extraction of sufficient gas to meet a reliability standard of 1-in-20 (i.e., peak demand for a 1-in-20-year winter could be met). Estimates have been identified of NTS peak offtake for a 1-in-20-year winter by GDN licence area and by FES scenario in the Gas Transmission Ten Year Scenario plan. [47] This indicates that peak daily demand for gas on the NTS could be between 3,500 and 4,000 GWh in 2025.

The costs of onshore gas storage have been inferred from two salt cavern facilities currently under construction in the UK, the Island Magee project in County Antrim (Northern Ireland) and the Stublach gas storage project in Cheshire. Based on consideration of these projects it has been inferred that natural gas storage has an average capital cost of £1/Cubic Meter (CM). However, there are constraints around the daily withdrawal rates of the facilities, so the cost on a £/CM daily withdrawal capacity inferred is £16.70. This equates to an annualised cost of £1.30/CM daily withdrawal capacity, assuming a 5% real WACC, 5-year construction time and 20-year recovery period.[48]

Table 14: Capital costs for new gas storage projects

Project	Capital cost £m 2017 prices	Storage capacity (mCM/d)	Withdrawal capacity (mCM/d)	Storage unit cost (£/CM/d)	Withdrawal unit cost (£/CM/d)
Island Magee	£400m	500	22	0.8	18.2
Stublach	£500m	400	33	1.3	15.2
Average	£450m	450	27.5	1.0	16.7

Source: Hydrocarbons Technology[49]

[47] https://www.nationalgridgas.com/sites/gas/files/documents/GTYS%202018%20Charts%20workbook.xlsx
[48] Assumptions on indicative rate of return based on University of Oxford study of gas storage in Great Britain; https://www.oxfordenergy.org/wpcms/wp-content/uploads/2013/01/NG-72.pdf
[49] Island Magee: https://www.hydrocarbons-technology.com/projects/islandmagee-storage-project/
Stublach: https://www.hydrocarbons-technology.com/projects/stublach-gas-storage-project/

Based on this analysis, it is possible to estimate the cost that the GDNs would incur if the capability of the NTS were reduced, such that GDNs had to construct storage facilities to avoid reliance on the NTS completely in a 1-in-20-year winter event. This cost is estimated at £460m and £530m per year. This cost is shown broken down by GDN licence area in Table 15 below.

Table 15: Avoided annual gas storage costs due to the NTS by region (£m)

GDN License Area	Steady Progression	Community Renewables
East Midlands	54	48
Eastern	43	38
North East	33	29
North Thames	54	47
North West	64	57
Northern	27	24
Scotland	44	39
South East	58	51
South West	31	27
Southern	42	35
Wales North	6	5
Wales South	25	23
West Midlands	47	41
Total cost to GDNs	**529**	**464**

Source: EY analysis of the cost of gas storage projects and National Grid projections of gas demand by Local Distribution Zone (LDZ)

6.4 Conclusion

The volume of gas expected to be transported on the NTS to GDNs is expected to reduce over time as alternative heat technologies are deployed and as gas is increasingly produced on the distribution network. However, our stakeholder engagement has identified that GDNs are likely to continue to rely on the NTS for provision of the large majority of gas supplied.

If the GDNs were unable to rely on the security of importing gas from the NTS at times of winter peak they would be likely to face requirements to invest in local gas storage facilities to ensure that the 1-in-20 reliability standard can be met. This could impose an annual cost of between £460m and £530m per year, based on estimates of the cost of building local gas storage facilities to enable to GDNs to avoid relying on the NTS for a day.

7. Real Option Value created by maintaining the NTS capability

7.1 Introduction

There are a range of low-carbon technologies that are envisaged to play a role in a future decarbonised heat sector, as well as a range of credible pathways for achieving a decarbonised energy system in line with 2050 targets for CO2 reduction. The role over time of the NTS may differ under each pathway, although there remains significant uncertainty around which pathway is most feasible or economically efficient. The NTS can therefore provide an economic value as an insurance policy, i.e., by preserving the capability of the network so it is available if certain pathways in which the NTS has a smaller role turn out to be infeasible or prohibitively expensive.

This section considers:

- The range of scenarios that might be available for decarbonising the heat network, the role of the NTS in each, and the pathways for achieving them;
- The uncertainties associated with committing to pathways; and
- The benefits from maintaining the NTS to retain a broad range of options for meeting 2050 decarbonisation targets.

7.2 Decarbonisation pathways

As articulated in Section 2.2, there are a number of low-carbon technologies that could be expected to play a role in the heating sector by 2050, including use of hydrogen, heat pumps, electrification of heat, district heat networks, and the use of carbon capture usage and storage (CCUS).

Among the long-term scenarios reviewed in this study, including those developed in the BEIS Clean Growth Strategy, Imperial College's study for the CCC, and KPMG's study for the ENA, there are typically a number of common scenarios considered:

- Full electrification of heat, with investment in renewable or nuclear electricity generation to ensure that this solution is low-carbon;
- A pure hydrogen network, with the gas distribution network reconfigured to deliver hydrogen; and
- A hybrid approach, whereby solutions are developed on a regional basis and/or where a range of technologies (including heat pumps, natural gas, and CCUS) are deployed to help meet peak demand, and where the solutions implemented might differ on a regional basis.

7.3 Uncertainties around pathways

There remains considerable uncertainty across a range of areas around what constitutes an optimal decarbonisation pathway:

- Policy uncertainty – e.g., around the level of carbon budgets beyond 2030, renewable incentives, and BEIS policy.
- Regulatory uncertainty – e.g., around Ofgem decisions on which investments to permit in price controls and how networks will recover costs as the role of networks change.

- Technological uncertainty – around the cost and feasibility of deploying emerging technologies (e.g., CCUS) in future at scale.
- Customer acceptability – i.e., customer willingness to accept disruptive interventions to heat technology.

The analyses of the optimal long-term energy mix (i.e., that meets the UK's 2050 climate change targets) reviewed in this study indicate that there could be a cost-effective role for hydrogen in the mix. Analysis by KPMG for the ENA (summarised in Table 16 below) indicated that a mixed energy system, with an ongoing role for gas in the mix, was the least cost solution.

Table 16: Summary of assumptions in ENA 2050 future scenarios

	Evolution of Gas	Prosumer	Diversified Energy	Electric Future
Heating mix for residential and commercial	13% gas, 33% electricity, 47% hydrogen; 7% bio	100% electricity	8% gas, 50% electricity, 17% hydrogen; 8% bio; 17% DH	100% electricity
Implications for NTS	Similar to today; NTS feeds SMR facilities	NTS volume reduced	NTS volume greatly reduced	NTS volume greatly reduced
Practical obstacles	Low – medium	Very high	Medium – high	High
Incremental cost per consumer to 2050	£4,500-£5,000	£11,000-£12,500	£6,800-£8,000	£12,000-£14,000

Source: ENA, 2050 Energy Scenarios

Analysis by Imperial for the CCC found broadly similar costs for its three lead pathways (hybrid, electric and hydrogen) under central assumptions, with a hybrid approach looking least cost. However Imperial College also concluded that the hydrogen pathway was likely to have significantly higher costs in a high-decarbonisation scenario, due to the costs involved in supplying peak demand through hydrogen alone.[50]

In addition to uncertainties around costs, Imperial also identified a range of challenges around the feasibilities of different scenarios:

- **Hydrogen**: The transition to a hydrogen system may require simultaneous switching, and service pipes within the home may need upgrading, creating significant disruption to households. There is also uncertainty around the technology costs associated with hydrogen, such as whether the optimal technology for producing hydrogen involves electrolysis of natural gas or of water, and the costs involved in hydrogen storage.
- **Electrification**: Electrification of heat is expected to lead to an 80% increase in the volume of power consumed. This would be likely to lead to a significant increase in requirements for the electricity transmission and distribution networks as well as investment in low carbon generation (for instance through nuclear).

[50] Page 13 of 'Analysis of Alternative UK Heat Decarbonisation Pathways,' https://www.theccc.org.uk/wp-content/uploads/2018/06/Imperial-College-2018-Analysis-of-Alternative-UK-Heat-Decarbonisation-Pathways.pdf

- **Hybrid**: The fitting of heat pumps in properties requires a certain amount of space and level of insulation. There is also uncertainty around the scale of opportunities for introducing district heat solutions and the regulatory and policy challenges associated with ensuring customers are protected where district heat is implemented.[51]

Across all scenarios there will be significant challenges to resolve around the overall costs of decarbonisation, technological challenges (for instance around the deployment of CCUS technology at scale), and regulatory and policy challenges (such as how to coordinate decarbonisation activities across the heat, power and transport sectors).

There are some investments that are likely to be no-regret options under a range of scenarios, for instance action to promote energy efficiency or the deployment of low carbon heat networks and heat pumps for off-grid customers. Analysis by Frontier Economics for BEIS indicated that whichever scenario is being pursued, roll out of capital investment is essential from 2030.[52] The incremental roll out (with the possibility of changing strategy if new information comes in after 2030) is possible to some extent in all scenarios. However, Frontier Economics concluded that changing strategy is likely to be particularly costly once GB has pursued a high hydrogen scenario due to the level of upfront capital costs involved in constructing a new national hydrogen network.

Given investment lead times, it is unlikely that multiple pathways can be followed much beyond the mid to late 2020s while still allowing for the completion of a full hydrogen conversion by 2050. This is because large hydrogen investments begin to be sunk from around 2030. However, the strategy could be adjusted as new information comes through over the next decades.

7.4 Conclusion

Uncertainty around the long-term energy mix is likely to persist into the 2020s and 2030s, for instance as significant investment is needed into electricity networks and low carbon generation, and the limits to the feasibility of different technology deployments is better known.

The role of the NTS is expected to differ significantly between scenarios – including in terms of the volumes of gas transported as well as the broader range of services provided to GDNs and EIIs in helping provide a low-cost and secure supply of gas. Studies of decarbonisation pathways for the CCC and ENA and evidence from stakeholder engagement suggest that the NTS is expected to play a more significant role in scenarios involving hydrogen than in scenarios with high electrification of heat.

The modelling carried out in this study suggests that maintaining the existing level of NTS capability could continue to provide a significant benefit of up to £285m per year for gas consumers in a Community Renewables scenario where the use of the NTS sees the greatest reduction.

Given the extent of uncertainty around the decarbonisation pathway, as well as the challenges in implementing a strategy of pure hydrogen or electrification of heat, maintaining NTS capability provides value as an insurance policy in retaining a low-cost and secure source of gas if other long-term pathways prove infeasible or not value for money.

[51] The role of regulation in ensuring consumers are protected in district heating solutions was identified in the CMA's study into the heat networks market, updated in May 2018. https://assets.publishing.service.gov.uk/media/5af31b9640f0b622d18b2d3f/Update_paper_heat_networks.pdf
[52] 'Market And Regulatory Frameworks For A Low Carbon Gas System', https://www.frontier-economics.com/media/2250/beis-low-carbon-gas.pdf

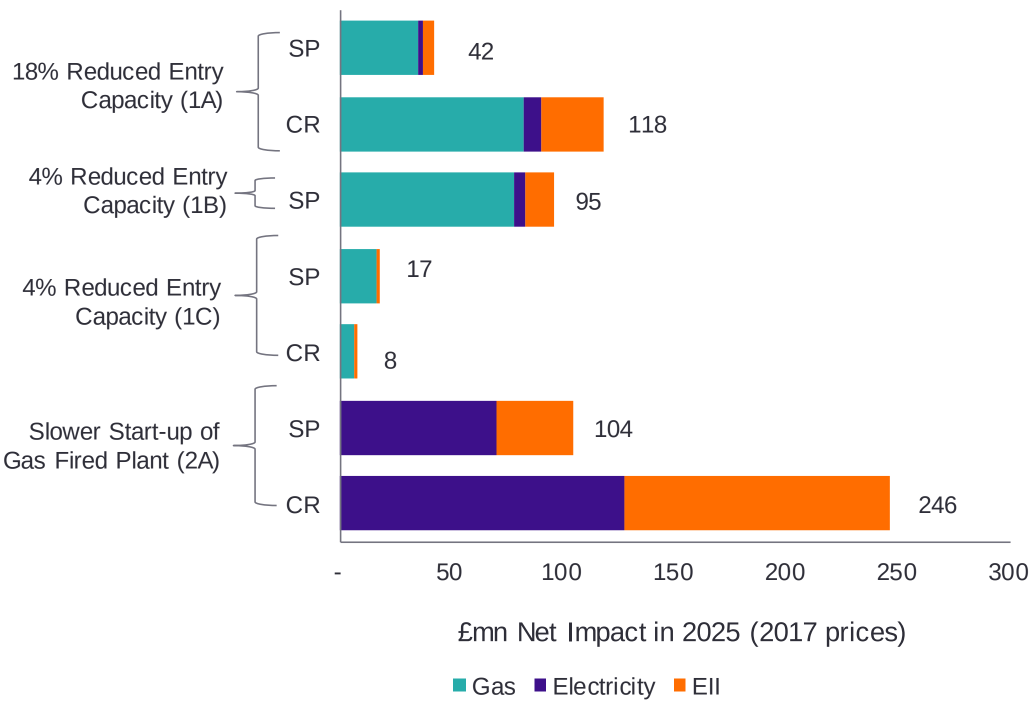
8. Conclusion on the long-term benefits of maintaining NTS capability

Analysis for this study has identified that reductions in the capability of the NTS, either in the form of decreased entry capacities and/or reduced security of supplies, could have significant detrimental long-term impacts on the GB economy via higher gas and electricity prices, via lost output from energy intensive industries and via additional costs which GDNs would have to incur to mitigate risks arising from less certain supplies of gas from the NTS.

The overall scale of these benefits depends on a range of factors, including the extent of degradation of the NTS's capability, the demand for gas and the extent of decarbonisation across the GB energy sector.

As shown in Figure 18 below, analysis conducted for this study suggests that the impact of reduced capability of the NTS in 2025 could range between £42m and £118m under Scenario 1A (19% reduced entry capacity), and between £104m and £246m under Scenario 2A (slower start-up of gas fired plant). These impacts are principally driven by increased gas wholesale prices (in the case of Scenario 1A) and increased electricity wholesale prices (in Scenario 2A).

Figure 18: Impact in 2025 of reductions in NTS capability



Source: EPRG gas and electricity market modelling, EY analysis of economic impact on EIIs

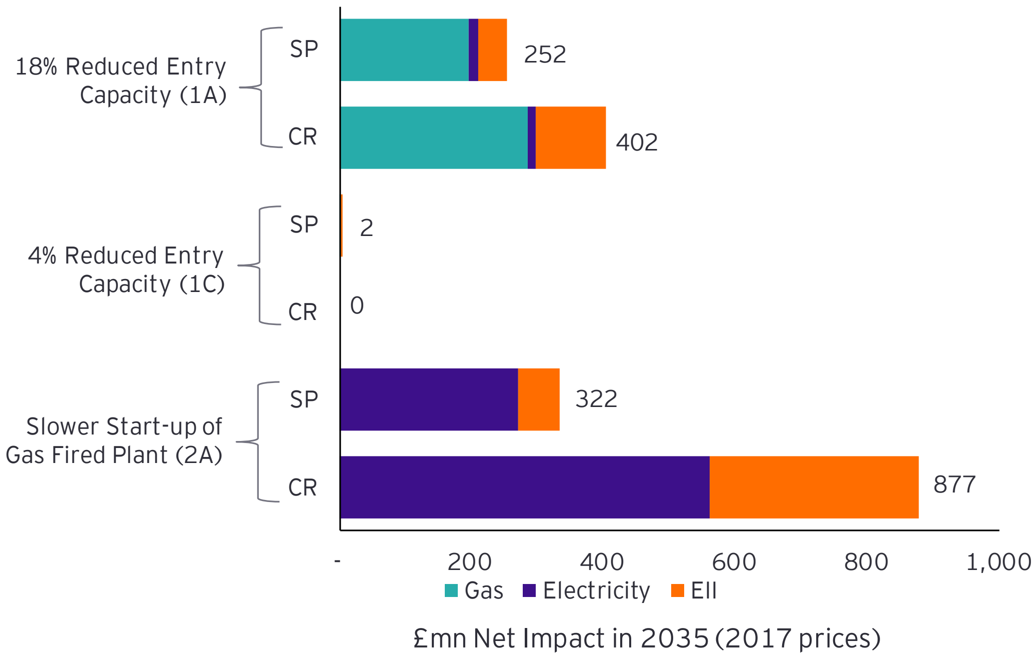
Impacts are expected to be greater in the CR sensitivity than under the SP sensitivity and to be greater in 2035 than in 2025. This may appear counter-intuitive as the volume of gas transported through the NTS is lower in 2035 than 2025 and is also lower under the CR sensitivity than the SP sensitivity. This is primarily driven by two factors:

1. Demand for gas is less sensitive to short-term price fluctuations under the CR sensitivity. As renewables provide a greater share of electricity generation under CR, gas supplied is increasingly used for backup electricity generation and for EII production. As gas demand for these purposes is less sensitive to short-term fluctuations in price, a small reduction in the volume of gas supplied can have a significant impact on wholesale gas prices.

2. As the volume of intermittent renewable generation increases over time, the NTS has an increasingly important role supplying gas to gas-fired power plants so those power plants can respond quickly to volatility in supply and demand for power.

As shown in Figure 19 below, impacts are expected to increase by 2035, ranging between £252m and £402m under Scenario 1A (reduced entry capacity), and between £322m and £877m under Scenario 2A (slower start-up of gas fired plant). The increase in the size of impacts between 2025 and 2035 is driven by the same factors that lead to impacts being greater under a CR sensitivity than under a Steady Progression sensitivity – i.e., renewables account for a greater share of generation by 2035, reducing the price elasticity of demand for gas such that smaller reductions in gas supply can have greater impacts on gas wholesale price.

Figure 19: Impact in 2035 of reductions in NTS capability



Source: EPRG gas and electricity market modelling, EY analysis of economic impact on EIIs

The long-term economic benefits of maintaining the current capability of the NTS may, however, be larger than the headline figures stated above as the approach used to estimate those benefits excludes certain benefits:

- The electricity and gas market models used in this study assume the market has perfect foresight of the impacts associated with reductions in NTS capability. This means that the modelling captures the steady-state benefits associated with the NTS when the gas and electricity markets are in equilibrium but does not capture the benefits of the NTS in terms of increased resilience of the gas and electricity markets to unexpected short-term shocks (for instance weather-related demand shocks or disruptions).

- The figures presented above only take into account the impacts on gas prices, power prices and energy intensive industrial customers, but do not take into account the impacts on GDNs (which may have to invest more heavily in gas storage if the NTS does not provide as reliable supplies of gas) or the option value which maintaining the NTS might provide (as a fall back if increased electrification or increased use of green gases do not turn out to be feasible or value for money ways of decarbonising heat and transport).

It is also important to note that the scenario benefits are also potentially additive: for instance, a failure to replace compressor stations could lead to both increased gas prices (as in Scenario 1A) and ramping constraints on gas-fired power stations (as in Scenario 2A). Greater impacts would be associated with a reduction in NTS capability if a range of scenarios occurred at the same time. Moreover, alternative scenarios, including greater reductions in NTS capability, are possible, implying potentially greater impacts on GB.

It is clear from the analysis presented in this study that the potential long-term benefits for GB of maintaining the current capabilities of the NTS could be significant, particularly in certain scenarios. These long-term economic benefits – alongside short-term benefits and wider economic, environmental and societal costs and benefits – should be taken into account by NGGT, Ofgem, BEIS and other stakeholders when evaluating the role that the NTS could play in GB’s future energy mix and when determining the expenditures required to deliver the appropriate level of capability of the NTS.

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