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Private and Confidential

National Gas Transmission (NGT) Consultation Response – Peterborough and Huntingdon Compressor Emissions – Final Preferred Option and King's Lynn Compressor Emissions – Final Preferred Option

Dear Graham,

This letter is NGT's response to the Ofgem consultation on Peterborough and Huntingdon Compressor Emissions – Final Preferred Option and King's Lynn Compressor Emissions – Final Preferred Option, dated 19 May 2023. We have combined our consultation responses for all three sites into this document. NGT own and operate the gas transmission assets in Great Britain (GB), which are defined as Critical National Infrastructure by the UK Government. We meet the needs of our customers and GB consumers, enabling gas to be transported around GB safely and efficiently. We operate our network to meet both our customers' demands and entry and exit obligations.

Ofgem's proposed Final Preferred Option for all three compressor sites covered by this response is the counterfactual 'do nothing' option where the three legacy Avon units would be retained under the 500-hours Emergency Use Derogation (EUD)[1] allowed for in the Medium Combustion Plant Directive (MCPD), with significant asset health investment to improve units' availability.

<u>We do not support Ofgem's minded-to position for Peterborough, Huntingdon[2] and King's Lynn compressor stations</u>, and we have set out our reasons in this response and provided evidence in

[1] Under the MCPD non-comp iant units can be restricted to 500-hours over a five-year ro ing average with a maximum of 750-hours per individua year under EUD, this can be c assed as Essentia or Emergency Use for our operating strategies. This removes the use of the compressors for standard operation, where they can on y be run to prevent commercia constraints (Essentia Use) or exit constraints (Emergency Use) on the network. This derogation current y has no end date.

[2] For Huntingdon Compressor Station NGT's Fina Preferred Option is the insta ation of Dry Low Emissions (DLE) Abatement techno ogy on the remaining non-comp iant Avon. Ofgem state in their consu tation that shou d NGT identify a cost-effective retrofit, that wi permit unrestricted operation of the existing Avon at Peterborough and Huntingdon Compressor Stations, then Ofgem wou d expect NGT to imp ement that so ution and seek funding as part of the next price contro . Current y tria s for a DLE retrofit so ution are ongoing to determine if this so ution is viab e for the NTS compressor f eet. If DLE is unsuccessfu in tria s, then NGT's Fina Preferred Option for Huntingdon sha be reassessed.

support of our position in the associated appendices. In summary our high-level positions are as follows:

Peterborough and Huntingdon

- Peterborough and Huntingdon are essential in maintaining Security of Supply to UK consumers, are necessary assets to maintain market stability and are vital in meeting our 1-in-20 peak demand obligations in the Southeast and Southwest of England.
- There is a need for parallel running at the sites; for example real world data showed 91% of the compression hours at Peterborough in 2017/18[3] were for parallel running. Without parallel running in such a scenario we would not be able to meet our 1-in-20 peak demand obligation.
- **Credible outages can occur that last longer than three weeks[4], with standby units on 500-hours EUD at both Peterborough and Huntingdon stations, we would be unable to provide parallel running beyond 3 weeks thereby not being 1-in-20 compliant as per Transmission Planning Code (TPC)[5] approved by Ofgem.**
- It is credible that conditions requiring prolonged parallel running at Peterborough exist in the future and could even increase during the transition to NetZero. Hence, we must invest in a robust plan to mitigate against unplanned losses of these key assets.
- Peterborough and Huntingdon are the most effective sites for line-pack management services for the Southeast and Southwest. Compression upstream or downstream of Peterborough and Huntingdon is too far away to be able to react to sudden changes that can often be experienced, ultimately reducing our ability to manage the increasing need for flexibility.
- The retrofitting of Dry Low Emissions (DLE) systems is potential technology that could enable unrestricted running on existing compressor units. However, at this stage of technology proving, it is not advanced sufficiently to accept the risk at Peterborough of the technology enabling unrestricted running, given the limited time to implement an alternative solution by 2030

King's Lynn

- King's Lynn is the key compressor ensuring gas can enter and exit the National Transmission System (NTS) at Bacton terminal through the interconnectors and is the only compressor station that can move gas away from the Southeast when supplies from Bacton and Isle of Grain exceed demand.
- There is a need for parallel running at the site to ensure maximum import and export capability across the interconnectors can be met. Real world data from 2022 demonstrated both the unpredictable nature of the global gas market and the importance of a resilient network to support energy security. The need will remain now and into the future.

[3] 2017/18 was a sustained co d winter where the network experienced high ine-pack swings and ow supp ies from Is e of Grain enter the system.

[4] Three weeks is the average a 500-hours restricted unit can run in one year.

[5] TPC 2021 v0.4 compared against TPC 2019 v1.0.docx (ive.com)

- **Credible outages can occur that last longer than three weeks, with the standby unit on 500-hours EUD at King's Lynn there would be a shortfall of 286 mcm , which means we would not be able to meet high export scenarios at Bacton.**
  DLE technology on the existing Avon compounds risks from not only whether the DLE technology will be technically and commercially available prior to 2030 but also from the on continued use of a beyond designed life asset. Failure of these would result in the reducing export and import capability.

King's Lynn, Peterborough and Huntingdon role on the NTS

All three compressor sites are Critical National Infrastructure providing essential capability and reliability to the delivery of energy in multiple supply and demand conditions. This is one of the main reasons why these compressors stations have been prioritised[6] in our 2018 RIIO-T2 Business Plan and in our Compressor Emissions Asset Management Plan (CE-AMP) to enable compliance with the MCPD by 2030.

Peterborough and Huntingdon are central to the NTS operation. Both sites are required to meet our 1-in-20 peak demand obligation[7] and require fully capable back-up as outlined within the TPC. Operational strategies at higher demands are built around the foundational availability of both sites. Our Final Preferred Options are in line with existing network design standards to ensure we can meet Southeast and Southwest demands. The central location of Peterborough means it has multiple roles, able to move gas from North to South to meet southern demands (with Huntingdon), moving gas to South Wales during low Milford Haven supply times, and moving gas away from Bacton into the West of the network during high Europe importation.

Due to their central location, Peterborough and Huntingdon are generally the first compressors brought online, and the last ones to be taken offline, which reflects their high running and the requirement for unrestricted running with fully capable back-up. This is also the most efficient operation of the NTS compressor fleet, preventing multiple other compressors having to be brought online to achieve similar results, which reduces the NTS's operational efficiencies in spend, fuel, and emissions. As an example, during typical winter demands with low Milford Haven supplies, the primary compressor combination to support these flows would be parallel operation at Peterborough, if this would not be available with sufficient back-up, we could see increased running costs from £[redacted] to £[redacted]. The increased running costs manifest from additional units at Huntingdon and Churchover compressor stations being utilised. Another example of operational inefficiency is where there is a need to move significant volumes of gas from the North to the South of the network. If in such a scenario, parallel running at Peterborough is not available, this could nearly double running costs from £[redacted] to £[redacted] for running additional units at Carnforth and Alrewas[8]. Aside from additional running costs, the impact on the fleet which consists of further non-compliant with MCPD units, which in the future

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[6] Five of the e even sites that have non-MCPD comp iant compressors were priorities for RIIO-T2 due to their critica ity and the need for operationa acceptance of new units by 2030. The five sites are St Fergus, Wormington, King's Lynn, Peterborough and Huntingdon. A five sites were part of the estab ished Re-opener process and a Fina Preferred Options for these sites have now been submitted to Ofgem for approva .

[7] Nationa Grid (2021), Transmission P anning Code, Standard Specia Condition A9: Pipe-Line System Security Standards

8 We have provided further context on this ana ysis in the Peterborough and Huntingdon FOSR (section 7.4).

might not be able to cover for loss of parallel running at Peterborough. This is described further in this response.

King's Lynn has a critical role in ensuring gas can enter and exit the NTS at Bacton terminal through the interconnectors. King's Lynn is the most effective compressor to move gas away from the Southeast when supplies from Bacton and Isle of Grain exceed demand and therefore mitigate the risk of entry constraints restricting flows of LNG and EU gas into the GB market. The site ensures high Europe import and export can be achieved, by moving large volumes of gas towards or away from Bacton, as seen in 2022 with very high King's Lynn utilisation to enable sustained high export.

Reliable and unrestricted running of all units across the three sites facilitate uninterrupted parallel compressor operation at the sites as set out and required under the TPC. This in turn ensures the continuation of gas from supply to demand to meet the UKs energy demand.

Our concerns with the current assessments processes on Critical National Infrastructure

A key concern when submitting the Final Options Selection Reports (FOSRs) for King's Lynn, Peterborough and Huntingdon relates to both the extent to which economic analysis determines the outcome of the assessment and the need to account for the overall resilience of the network. Specifically, we are concerned with the general over reliance on the four equally weighted Future Energy Scenarios (FES) within the determination of the Final Preferred Options.

FES by design provides credible pathways to achieve NetZero in three out of the four scenarios based around consumer reaction to Government policy and delivery of technological solutions. Therefore, from the outset the use of FES within economic assessment processes provides a significant challenge where the assets in questions are not linked to economic benefits provided by NetZero technologies and associated growth sectors, but rather linked to the need to provide energy security for the future transition. As a consequence, it can be challenging to evaluate the value of natural gas investments through the current Cost Benefit Analysis processes.

As such, FES expects the annual use of natural gas across the years to reduce over time, and to a slower extent across the peaks in those periods. However, the timing, pace and extent of the reduction is far from clear as this is influenced by many macro factors including: customer choice, technological, political, but crucially economical and societal influences. With the surrounding uncertainty, it is essential to answer the question what does the UK energy system need to safeguard the critical delivery of energy where gas demand and supply remain high for any number of reasons? As it stands, the resilient supply of natural gas through the transmission system provides the critical insurance policy by ensuring there is sufficient capability and resilience to supply gas to the current 28GWs of Gas Power Station capacity.

The recent events resulting from the invasion in Ukraine have seen a fundamental change to the global gas markets and the physical gas flows across the European networks. For our network in financial year 2022/23 we saw a 4-fold increase in the amount of gas exported from our network to the European Union (EU), totalling some 20bcm. This additional demand was in large part provided for by additional LNG arriving at the Milford Haven and Isle of Grain terminals resulting in a substantial West to East gas flow across our network. At the same time, to conserve EU gas storage stocks high electricity exports across the interconnector increased the domestic electricity production, increasing the stress on the wider GB energy system. These events are outside the range illustrated in FES, and most commentators, and show how quickly unforeseen events can happen and the significant impacts they can have. They also highlight the value of a resilient network in meeting the known and unknown challenges and maintaining energy security and maximising the ability to attract gas supplies to the GB market.

Future uncertainty and increasing focus

It is NGT's view that the uncertainty that persists around the long-term role of Russian gas within the European system adds to an already challenging environment to forecast likely energy futures. Although some progress on the longer-term direction of decarbonisation has been achieved through the publication of the H2 strategy, there are still many questions around how we achieve a resilient fully decarbonised power system, and what this means for natural gas. There is also further uncertainty around domestic heat decarbonisation, the role of Heat Pumps and Hydrogen in the longer terms and how such changes would be brought about. The longer-term direction on heat decarbonisation is expected in 2026, but in the meantime, the Government has an aspiration of building the supply chain for the installation of Heat Pumps to 600k units per year by 2028. Currently installation rates are significantly below this, an estimated 55k heat pumps were fitted in 2021. The significance of this is that many homes currently on gas would be assumed in FES modelling terms to convert to an alternative source yet are not doing so at the rates expected. This has the impact of underestimating the gas demand and the network capable of meeting demands out turning.

One of the outcomes from the war in Ukraine has been the Governments focus on 'commodity security'[9], i.e. ensuring we have sufficient gas coming into the country to meet the energy needs. The initial focus has been on the short term, given the shock to the EU and GB markets from the loss of Russian pipeline gas. However, the Government also recognises the need for a medium to long term focus (~10 years). It is expected that through the development of a Future System Operator, as set out in the Energy Security Plan, a new gas supply security assessment will be introduced to improve the foresight of risks to energy security from impacts on supply and by extension resilience of the whole energy system. Whilst this assessment is to be developed from 2023, it is expected that such an assessment will be based on a conservative view of the reduction in gas demand across the country – a peak demand scenario rather than a combination of scenarios. It is also recognised that for this to meet the intended aims of delivery energy security to end-users, it is essential that the onshore gas infrastructure is developed and maintained so that it does not become a blocker to the delivery of energy. Consequently, Government will also be reviewing the existing gas infrastructure standards that directly impact the network's capability together with the asset availability and reliability. This work has already begun in collaboration with DESNZ, Ofgem, ESO, NGT and is intended to deliver an output by Winter 2023. We believe such an output will complement the current standards and the economic tests which govern infrastructure investments.

Standards and Resilience

The principal standard applied to the NTS is the 1-in-20 peak demand Transmission Licence design obligation[10], where NGT must design a network (and associated assets) that is able to

[9] https://www.gov.uk/government/pub ications/powering-up-britain
[10] Gas Transporter Standard Licence Conditions 08 04 2021 (ofgem.gov.uk)

meet this calculated peak demand. However, this is a theoretical standard that assumes all assets are available when needed and there is currently no standard that relates to how often the network is capable of meeting this standard, otherwise known as resilience of the network.

In the absence of a resilience standard, we do have conditions under the Transmissions Licence, specifically 9.11 to have in place and comply with the provisions of a TPC approved by Ofgem. This code provides some further guidance, in addition to the design standard, against which NGT must maintain the NTS.

The latest TPC was approved by Ofgem in 2021. The TPC must cover all material technical aspects relating to the planning and development of the pipeline system and describe the methodology for determining the physical capability of the system. The TPC includes detailed planning assumptions and covers off many requirements of network planning and design, notably section 6.17.6 pertains to compressor standby requirements and is relevant to the investment proposal at Kings Lynn, Peterborough and Huntingdon – extract below:

"6.17.6 Compressor standby and station configuration

- *Compressor stations across the NTS are designed to meet the anticipated range of flow conditions. Some sites may be used for high demand conditions only, whereas other stations are equipped to allow a variety of different units to be used in parallel and in series configuration to achieve different pressure and flow characteristics.*
- *We ensure that compressor configurations are used effectively within network analysis models. We consider the range of configurations that may be used to accommodate flow patterns on the system to maximise the capability of the system, subject to other constraining factors (see above).*
- *Compressor failure (non-availability) is more likely to occur than a 1-in-20 demand day. Hence within or prior to a 1-in-20 demand day a compressor may have failed.* ***Therefore, we need compressor standby to comply with our obligation to develop the network to meet the 1-in-20 security standard. Standby is identified to ensure that the required transmission capability is maintained in the event of a credible loss of any single compressor unit*** *or operationally linked unit i.e. common mode of failure at a site.*
- *When assessing standby requirements, we consider:*
    - *required transmission capability; this is reviewed on an annual basis considering forecast supply and demand, capacity and other obligations*
    - *forecast compressor run hours; this considers a range of forecasted supply and demand levels*
    - *economic and efficient system operation; the trade-off between standby and other commercial solutions e.g. capacity buy-back and supply turn up*
    - *maintenance; system access (outages) associated with maintenance requirements*
    - *electricity and gas fuel security; the failure of electricity supply for an electric drive may require gas compression standby."*

As part of our Final Option Selection process, we consider forecast run hours that are representative of average demand conditions, but we would expect hours to be higher during colder years. Under colder conditions it should be expected that all compression will be required to run considerably longer than average. This could create significant operational challenges as over 60% of all the compression in the Southeast could potentially be subject to 500-hours EUD. These limits would need to be managed concurrently while ensuring exit pressures and supply security are maintained across the country. Any failures to the compliant units including essential maintenance, cyber related work and unplanned outage for example, would only exacerbate the situation, especially if the derogated unit hours have already been reduced to support operational strategies away from cold days. See Appendix 1 for further detail on impacts of high gas demand on the selection of a Final Preferred Option at Peterborough and Huntingdon compressor stations.

Impact of Final Preferred Options on compressor fleet

Ofgem have challenged NGT's consideration of the age of the compressor units to be retained as part of Ofgem's Final Preferred Options. Within the option selection we have considered the condition of those units as part of the developed Reliability Availability Maintainability (RAM) Study, which in turn is included in the CBA. NGT is concerned that Avon units with limited run hours provide limited back-up due to low availability thus reducing resilience over time. Sites with low availability and/or restricted running will need to be supported by sites with higher availability to maintain fleet resilience, limiting our ability to decommission units, intern reducing overall efficiencies in fleet spend, fuel, and emissions.

500-hours EUD will result in challenges linked to limited run hours. These include Stop Start risks, ongoing Asset Health investments, maintaining readiness when units are needed to operate, which can be a challenge to predict. Low unit utilisation would also mean that operational issues would only be identified when these units are required for operation, when no alternative is available, thus leaving the network exposed to having reduced compression available to meet gas demands. These issues are prevalent considering the age of the units in questions. King's Lynn Avon (B) and Peterborough (A) commissioned in 1973 and Huntingdon (C) 1992.

As stated above, to inform our option selection the asset health scope of the Avon units has been assumed based on the recommendations of the RAM Study; visual, non-intrusive site inspection, and feedback from site Operations team. Confirmation of the asset health scope for derogation and retrofit options would require condition assessment and detailed remnant life surveys to be conducted during FEED. There is a major risk that additional scope will be identified during survey, increasing costs and project timescales, potentially identifying significant underlying issues that would hinder ongoing operation to 2050.

It is NGT's view that maintaining aging compressors and other assets for significant periods of time, beyond their design lives, introduces unnecessary energy security risks due to age related fatigue, loss of engineering experience, dwindling support, lack of field service capability, no OEM support, low spares availability (often refurbishment only) and an inability to purchase long term support packages. This would create an unprecedented situation, significant complexity, and increased risk to Critical National Infrastructure and we would question whether it is credible to have the countries energy security secured to time expired assets where their unavailability can cause significant and disproportionate impacts on the public and the wider economy.

As noted, Ofgem indicated a willingness to invest in retrofit solutions should those become available. If retrofit DLE shouldn't be available for Huntingdon following the NTS trials, then other Emission Abatement technology, or derogation could be an acceptable solution for the site, providing Peterborough is able to provide supporting compression. Limiting the Peterborough back-up unit to just 500-hours EUD undermines compression availability across both sites. Our proposal to install DLE (with a fall-back option of increased risk with 500-hours EUD) at

Huntingdon is not acceptable in this scenario and the Final Preferred Option for Huntingdon compressor site must be revaluated.

The appendices outline additional details in support of our views, including additional detail on credible faults experienced on the compressor fleet.

Further Engagement and Next Steps

We appreciate the continued engagement with Ofgem regarding these projects. Timely final decisions on the Final Preferred Options will enable us to ensure we successfully deliver the emissions compliance and resilience required at King's Lynn, Peterborough and Huntingdon.

If you have any queries, please do not hesitate to contact myself or Neil Rowley, Head of Regulatory Performance (neil.rowley@nationalgas.com, 07785 381424).

Yours sincerely

Tony Nixon – By Email
Regulation Director, Commercial - On behalf of NGT

Appendix 1 – Peterborough and Huntingdon Compressor Emissions Final Preferred Option Evidence

Strategically Positioned, Multi-functional Compressor Stations

The importance of the central location of Peterborough and Huntingdon at strategic multi-junctions cannot be underestimated. The stations can move gas in multiple directions to correct zonal imbalances in supply and demand and ensure line-pack is maintained within safe operational limits. This movement of gas to strategically manage these imbalances and line-pack levels on the NTS serves two key purposes:

- Provision of pressure cover – This is essentially an insurance policy, giving headroom above the minimum or maximum offtake pressures for any unexpected changes in supply and demand or any asset failures. It gives us time to react and rectify the situation minimising interruption to system users. Peterborough and Huntingdon directly impact two system extremity points and ensure sufficient pressure cover is maintained.
- Zonal line-pack management - The Southeast and Southwest have limited line-pack capability compared to the level of demand in other zones, this is due to large demand in comparison to the volume contained within the local feeders. Active line-pack management is required to constantly ensure line-pack levels and flexibility are maintained within safe limits in these zones. This ensures the system can safely accommodate the range of potential flows under various short term/market responsive, operational scenarios from our customers. Given the increasing need for flexibility today and in future scenarios, the capability to manage and respond to increasingly volatile network conditions is essential.

The two purposes outlined above provide for the movement of strategic line-pack away from terminals to areas of demand. The consistent ability and necessity to operate this strategy provides an insurance policy to both the market (entry capability/Security of Supply) and our downstream customers (lowering risk of failure to meet minimum offtake pressures through pressure cover/constraint and emergency management). The value that these activities provide are not captured within the CBA. This is because these activities occur within day and all the risk modelling is based on end of day values[11].

Only Peterborough and Huntingdon can provide these services to the Southeast and Southwest. Compression upstream or downstream of Peterborough and Huntingdon is too far away to be able to react to sudden changes. Examples of sudden changes include: a trip at the Isle of Grain, a power station staying online longer than forecast, the daily forecast being inaccurate or a sudden turn up of power station demand. The operating strategy often utilised to be able to manage line-pack in the South is to pack the Southern Feeder with the use of Peterborough and Huntingdon supported by flow control valves at Whitwell and Huntingdon. If any of these sudden changes occur the flow control valves are opened to quickly respond. Compression downstream in the Southeast are the wrong side of these regulators so cannot be used to pack the Southern feeder. Meaning without resilience compression at Peterborough and Huntingdon we would lose this ability to respond quickly.

[11] It is current y not possib e to mode this due to comp exity and data sets size.

Compression at Peterborough and Huntingdon supports a significant proportion of the UK economy. It is imperative that the correct level of resilience and capability are maintained so that we can continue to provide 1-in-20 exit capability, active line-pack management and pressure cover in the Southeast and Southwest of the network. This ensures we can continue to offer Security of Supply and minimise the risk of interruptions to consumers. Section 3) (Managing the increasing volatility and flexibility of the NTS) within this appendix describes line-pack management impacts into the future. As noted in our FOSR, we demonstrated the economic and efficient outcomes of system operation associated with Peterborough and Huntingdon by showing increased running cost, should parallel running at Peterborough not be available.

Case Study – Peterborough and Huntingdon safeguard against conditions in 2017/18

Peterborough and Huntingdon safeguard against a sustained cold winter, where the network experiences high line-pack swings and low supplies from Isle of Grain enter the system. These were the conditions seen in 2017/18. The following section explores this in more detail.

In 2017/18 we saw significant run hours at all compressor sites supporting the Southeast. Peterborough and Huntington totalled 7,118 and 2,982 respectively. Importantly, 91% (3,248 per unit) of the Peterborough compression utilisation was parallel running to support the network. This year showed the essential requirement to have unrestricted high availability of units at the site. In such a scenario using the highly averaged calculation on unit availability from the RAM Study, the 3rd unit would be required to run 623 hours to support the unavailability of the other units. However, modelled availability and reality rarely match up and, in this instance, the least ran unit provided 1,558 hours of compression in that year.

In addition to the high run hours at Peterborough and Huntington in 2017/18, there was also a high requirement from supporting compression at Diss and Chelmsford to meet the demand in London and the wider Southeast zone. Specifically, compressors at Diss and Chelmsford ran for 2,058 and 1,073 hours respectively that year. These sites will be reviewed in line with MCPD, as part of our CE-AMP with funding to be requested at the next price control. As such there is uncertainty on the appropriate intervention to be undertaken to meet both emission compliance and network capability and resilience. However, if the units at these sites were restricted to 500-hours EUD then the sites would breach the allowance in such a scenario as 2017/18. Diss would be permitted 1,500[12] hours across the three non-compliant MCPD units (assuming 500-hours per annum per unit as per EUD) and Chelmsford 1,000 hours across the two non-compliant units (assuming 500-hours per annum per unit as per EUD). These examples would breach the 500-hours EUD were similar conditions to be experienced in 2030 or beyond and this is without any significant credible fault that can occur to compressors as illustrated in Appendix 3.

Were a major fault to occur on one of the lead, unrestricted compressor units over that year, then parallel running would be limited to 500 hours. With 3,248 hours of parallel running (6,496 hours of the total running) Huntingdon would need to try and cover for Peterborough. If we assume it could do this, it would also not have enough hours due to the 3rd unit being restricted. This scenario

[12] Compressor unit Emergency Use Derogation (EUD) under the MCPD imited to run 500-hours per year on a ro ing 5-year average, with a maximum imit of 750-hours in any one year.

would result in a shortfall of 175 hours of parallel running not being met. As demonstrated above, Diss and Chelmsford would also be running close to the 500-hours EUD limit, which means no other site after Huntingdon would be able to cover those hours.

As established as part of the line-pack management in the South, no other sites are able to do the same job as Peterborough and Huntingdon and we would be vulnerable to any unexpected changes in supply or demand in the Southeast and Southwest. The flow limit of Huntingdon operating in parallel is 105 mscm/d whereas Peterborough can flow up to 140 mscm/d giving a 35 mscm/d reduction in capability to move line-pack into the South. This means Huntingdon is not able to fully cover for the full loss of Peterborough.

The table below shows the run hours in the year described and other recent years where similar high running hours were experienced.

Individual Unit Running Hours (Financial Year)									
	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22
Peterborough A	2911	2370	522	30	2143	827	134	569	1812
Peterborough B	2186	1443	1426	2451	3417	1096	2	1813	201
Peterborough C	2077	1576	482	3221	1558	466	182	1897	425
Total	7174	5388	2430	5701	7118	2389	318	4279	2438
Huntingdon A	1800	865	238	1635	1892	595	459	613	449
Huntingdon B	1237	295	451	1381	1082	864	266	1068	986
Huntingdon C	195	1116	376	33	9	249	90	146	316
Total	3233	2276	1065	3049	2982	1708	815	1827	1751
Cambridge A	18	14	17	46	243	22	52	1158	32
Cambridge B	8	41	38	108	75	2	9	1	0
Cambridge C	28	156	161	186	69	24	23	61	55
Total	54	211	216	340	387	45	84	1220	87
Chelmsford A	8	22	12	67	961	61	1	8	22
Chelmsford B	105	89	22	813	112	7	6	3	5
Total	113	111	34	880	1073	69	7	62	27
Diss A	126	125	20	14	41	8	8	1188	10
Diss B	0	15	15	763	1457	5	2	4	4
Diss C	15	6	11	344	560	59	10	396	9
Total	141	145	46	1120	2058	72	19	1589	23

Insurance against possible future high Peterborough and Huntingdon running

As outlined previously in this response, we do not believe the use of the four FES scenarios and a purely economic determination provides for the necessary insurance to protect meeting possible future UK energy demand due to both the large range of uncertainty and the impact to the UK of an under invested gas transmission system. It is also not possible to provide modelling with a high level of certainty on what the future flow ranges will be given the uncertainties that exist. That said, below we have articulated the circumstances with which high parallel running at Peterborough and Huntingdon would occur. These being:

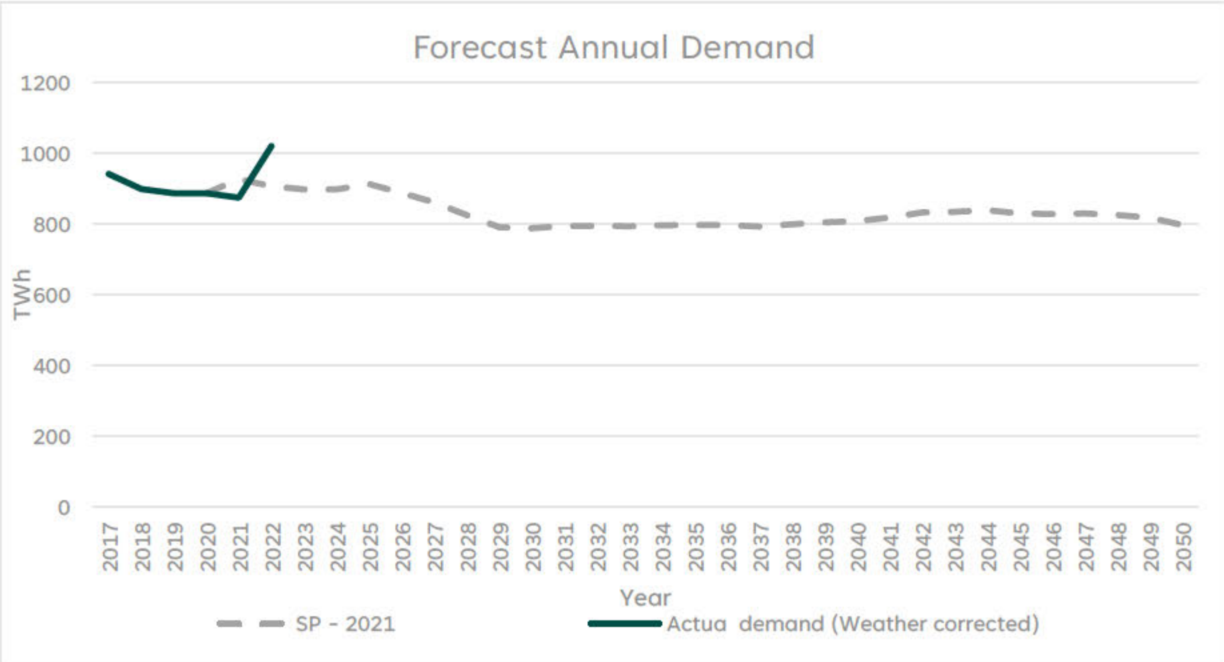
1) Future Gas Demand: the continuation of similar levels of gas demand, accepting a reducing in demand is expected to happen over time

2) Cold Winters: the likelihood that cold winters will be experienced in the future regardless of the gradual increasing average annual temperature through Climate Change
3) Managing volatility/flexibility: the increasing volatility and flexibility required by users of the NTS
4) Isle of Grain Supply: low output from Isle of Grain, we need to be able to manage the system without Isle of Grain flowing.

We believe all four of these factors are credible in 2030 and beyond and need to be planned for. Below we provide more information on each one.

1) Future Gas Demand

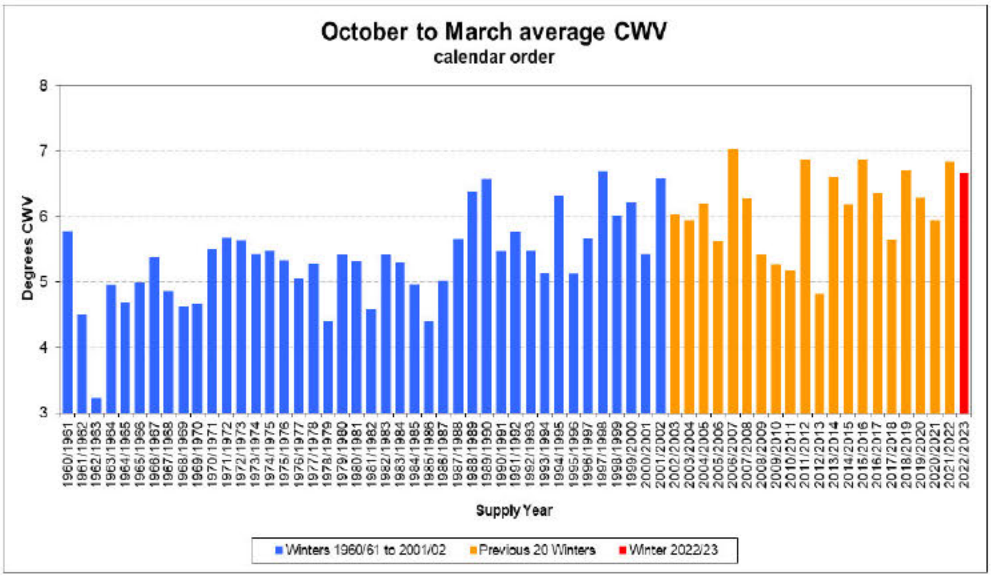
The chart below including actual weather corrected demand with Steady Progression 2021 (SP). It shows that we may only see a moderate reduction in annual gas demand in the medium to long term and would be consistent with the historical demands. In 2040, SP sees a reduction of around 90TWh from the ~900TWh seen in 2021. Peak demand in 2035 for SP only drops by 8% to 4458GWh from today. This demonstrates that it is possible to have circumstances that are broadly the same as today and with it the requirements of today.



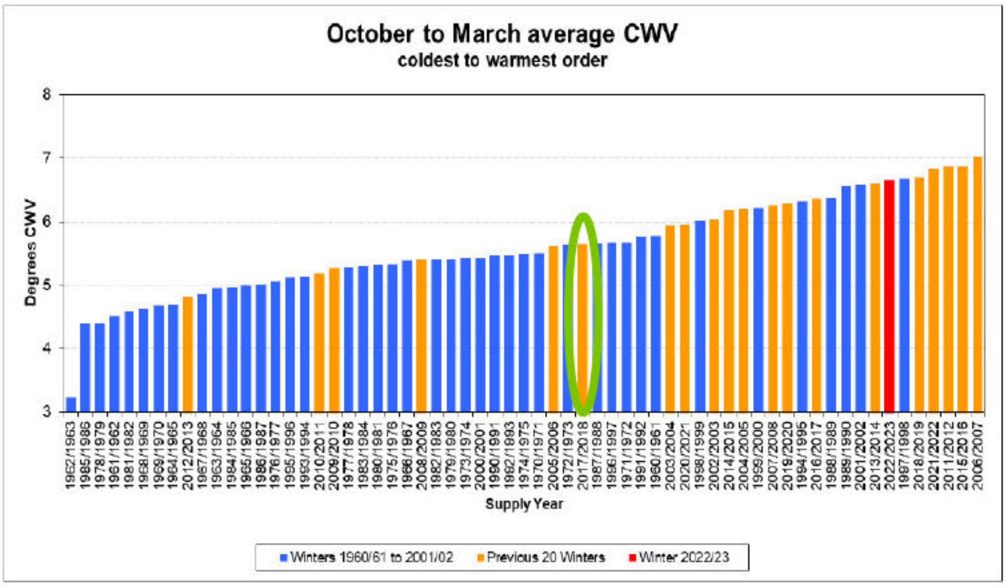
2) Cold Winters

Another major factor in the use of Peterborough and Huntingdon is how cold a winter we experience. Taken from the 2022/23 winter severity report, the below charts show that 2017/18 was the coldest winter we have seen in the last 10 years, but it is within the typical winters that can be expected[13]. In the last 20 years there has been five years that have been colder than 2017/18. The significance of a cold winter is the general higher gas demand than warmer winters, which increases the general compression requirement to move supply to demand, and the necessity for our network to be available and reliable.

[13] As taken from the 22/23 Winter Out ook Report: [Winter Out ook 2022-23 (nationa gas.com)]



[14]



This is another area where the use of FES data within the scenarios masks the benefits from running Peterborough and Huntingdon as they use seasonal normal temperatures, which eliminates this variance. However, going forwards cold winters still need to be planned for even as the average temperature could increase.

3) Managing the increasing volatility and flexibility of the NTS

Broadly speaking users of the NTS require increasing flexibility from the network. For example, as renewable electricity generation capacity has increased over the last 10 years, the role of gas fired power stations has changed from being a baseload electricity production to an intermittent

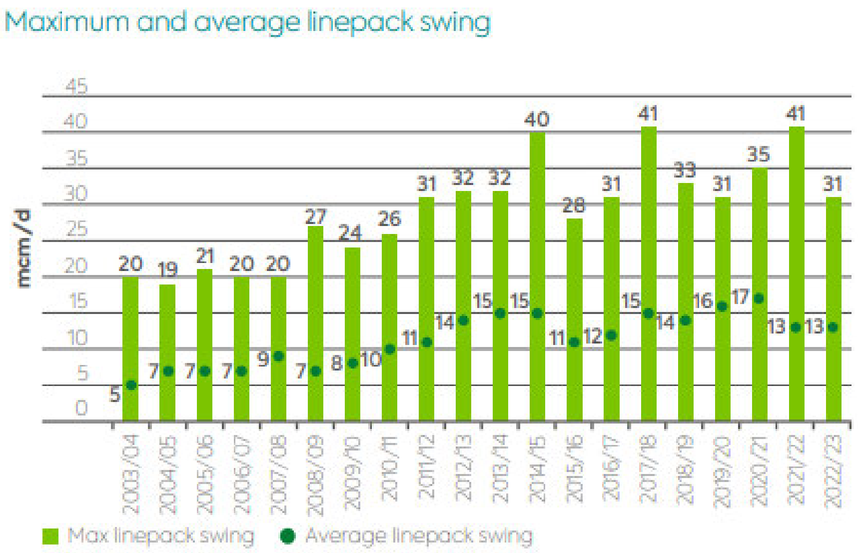
[14] CWV is a function of actua temperature, wind speed, so ar radiation, effective temperature and seasona norma effective temperature

source at times, subject to the weather and general electricity demand. Responding to the shortfall in generation to demand from low carbon and renewable sources.

Given there are a relatively low number of gas injection points into the NTS with limited capability to fundamentally change the flow rates in response to demand changes. The network provides the majority of the flexibility to manage the supply and demand mismatch. Principally the combinations of the network size, pipeline capacity, pressure balance and the control of compression have a bearing on the flow of gas and continually meeting supply. One of the ways this can be observed is through line-pack levels and the amount of line-pack swing[15].

The chart below shows the line-pack swings trend has increased over the last 15 years, stabilising over the last 6 years. 2017/18 had a high average line-pack swing of 15mcm/d. The strategic location of Peterborough and Huntingdon allows them to have the most influence on linepack levels in both the Southeast and West of the network as described above. This contributed to the high compression hours and parallel running at the sites to support pipeline gas stock levels. The stress put on the NTS to support the users, when and where they use gas is not expected to reduce over time, if anything it will increase as the use of gas fired power stations becomes more variable to the intermittence of alternative renewable sources of electricity.

In a scenario where we have insufficient run hours at Peterborough and Huntingdon, which would happen in a sustained cold winter, with high line-pack swing and low Isle of Grain supplies, the only other site that could influence line-pack levels in the Southeast is Cambridge. However, it is much further away from the high line-pack zones in the north, it's not able to support the operating strategy of packing the Southern feeder due to its location downstream of Huntingdon and Whitwell flow control valves. This will significantly reduce our ability to react to within day changes which will impact how customers are able to take gas off the system and potentially risking a within day constraint.

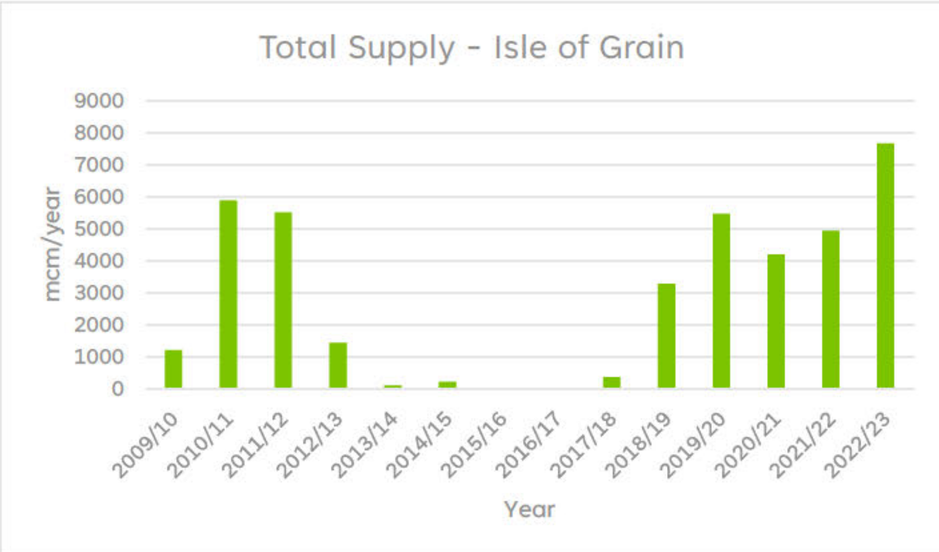


4) Isle of Grain Supply

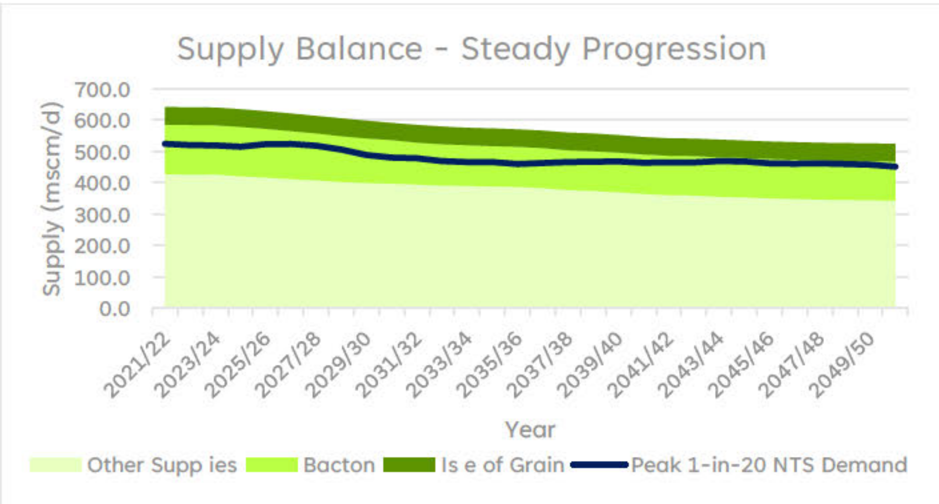
[15] the imbalances between overall gas demand and supply in the NTS which accumulate over the gas day

How much gas demand is required in the Southeast which needs to be pushed from either the North-South or West-East supply has a direct bearing on the need for parallel running at Peterborough. This requirement is somewhat mitigated by the Isle of Grain LNG terminal flows. Typically flows at the Isle of Grain terminal are erratic from year to year. The chart below shows that flows from Isle of Grain can be as low as between 0-1bcm/year and as high as between 5-8bcm/year. See below how we need to plan for future potential low Isle of Grain supplies.

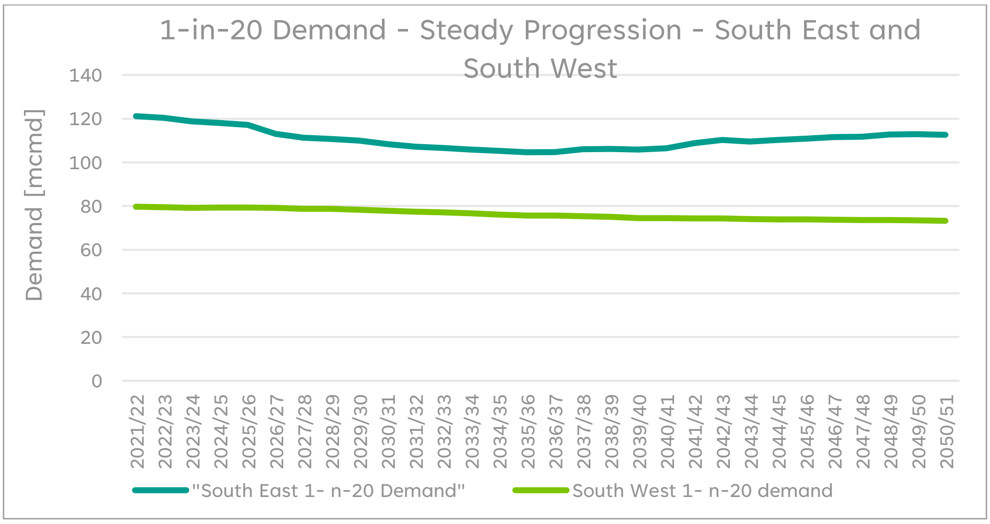
As can also be seen in 2017/18 the supply level from Isle of Grain was low. This contributed to the additional high run hours at Diss and Chelmsford to support exit demand in the Southeast as described above. If it had been a colder winter, there would likely have been more occasions when more compression would be required simultaneously to support demand.



We also need to plan for low supplies from Isle of Grain in future years. The chart below shows GB can meet balance in the high gas scenarios of SP without the need for any supply from the Isle of Grain.



In addition to the credible scenario of remaining high gas demand through SP, the below chart shows that peak demand in the Southeast and Southwest, two of the key areas supplied by Peterborough, could be at a similar level to those seen today.



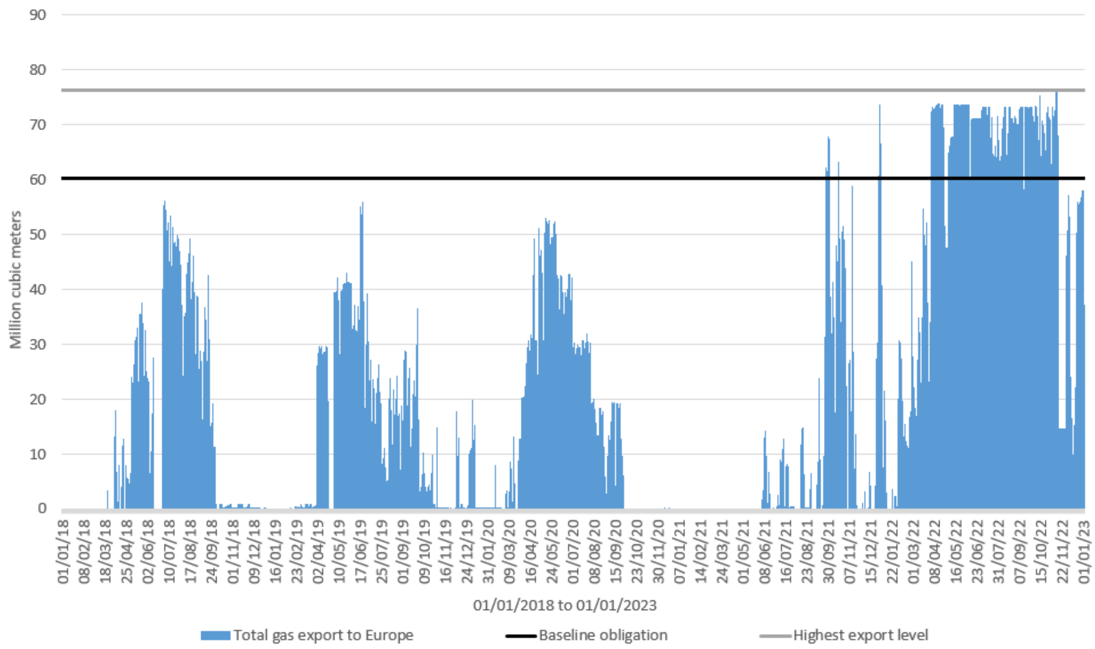
In this section we have provided evidence that there are credible scenarios where we will see similar gas demand in the future as required today and that we will need to continue to plan for cold winters even as the average temperature could increase. As a result, from versatile supply scenarios, the NTS will require increased flexibility to respond to changes of flow rates in response to demand changes. One of the ways this can be observed is through line-pack levels and the amount of line-pack swing, as demonstrated in this appendix line-pack swings remain high. In any scenario for Peterborough and Huntingdon the volatile supplies from Isle of Grain have to be considered. Where these conditions occur in the future, we would expect a high parallel running requirement similar to 2017/18. However, post 2030, without intervention we will have a significant proportion of the compressor fleet in the Southeast (60%) on 500-hours EUD. As the events of 2017/18 show, Huntingdon, Diss and Chelmsford were required to support Peterborough with Diss and Chelmsford running above the potential future restrictions of 500 hours. Applying a single credible fault at Peterborough on one of the primary units to this scenario, additional support would be required to make up for compression beyond the 500 hours permitted on the 3rd unit at Peterborough, which cannot be covered by Huntingdon and would result in a shortfall of 175 hours.

As described above no other compressor would be able to influence line-pack levels in the Southeast and potentially risking a within day constraint. Beyond the operational challenges described with managing a fleet of derogated units, this circumstance would erode the remaining resilience leaving the network with limited options to meet further challenges.

Appendix 2 – King's Lynn Compressor Emissions Final Preferred Option Evidence

Southwest, East and Import/Export

King's Lynn has a critical role in ensuring gas can enter and exit the NTS at Bacton terminal through the interconnectors. Bacton is the single largest demand on the NTS. King's Lynn is the most effective compressor at moving gas away from the Southeast when supplies from Bacton and Isle of Grain exceed demand. The site by running two compressors in parallel, ensures high European import and export can be achieved against a range of different network conditions, by moving large volumes of gas towards or away from Bacton. As seen in 2022, very high King's Lynn compressor utilisation enabled sustained high export to the EU (see below table of running hours). The below chart shows the export at Bacton between 2018 and 2022.



King's Lynn's ability at enabling high volumes of gas to transfer between the UK and EU gas markets has significant value for the UK Shipper community by supressing prices due to the large revenues received from capacity and commodity charges at the Bacton Interconnectors, as well as an increase in supplies creating a gas surplus, reducing prices for consumers. This sits alongside the traditional symbiotic relationship between the GB and European gas market where GB supplies support the refilling of EU gas storage in the summer and in turn supports the GB high demands through exporting back in the winter. However, it should be recognised that the physical flows across the interconnectors are subject to the global gas markets which are not extensively modelled as part of the FES. Meaning there can be no high confidence in what the actual flows in the future will be. What is important is that the network can reasonably accommodate maximum imports and exports.

Assessing compressor utilisation at King's Lynn and the investment requirement was based on historic data from 'Beast from the East' for import flow requirements. Together with 2022 flows for export requirements due to the invasion of Ukraine. Specifically, the year of the 'Beast from the East', 2017/18, the site totalled 1,887 run hours over the three units. The table below highlights these hours.

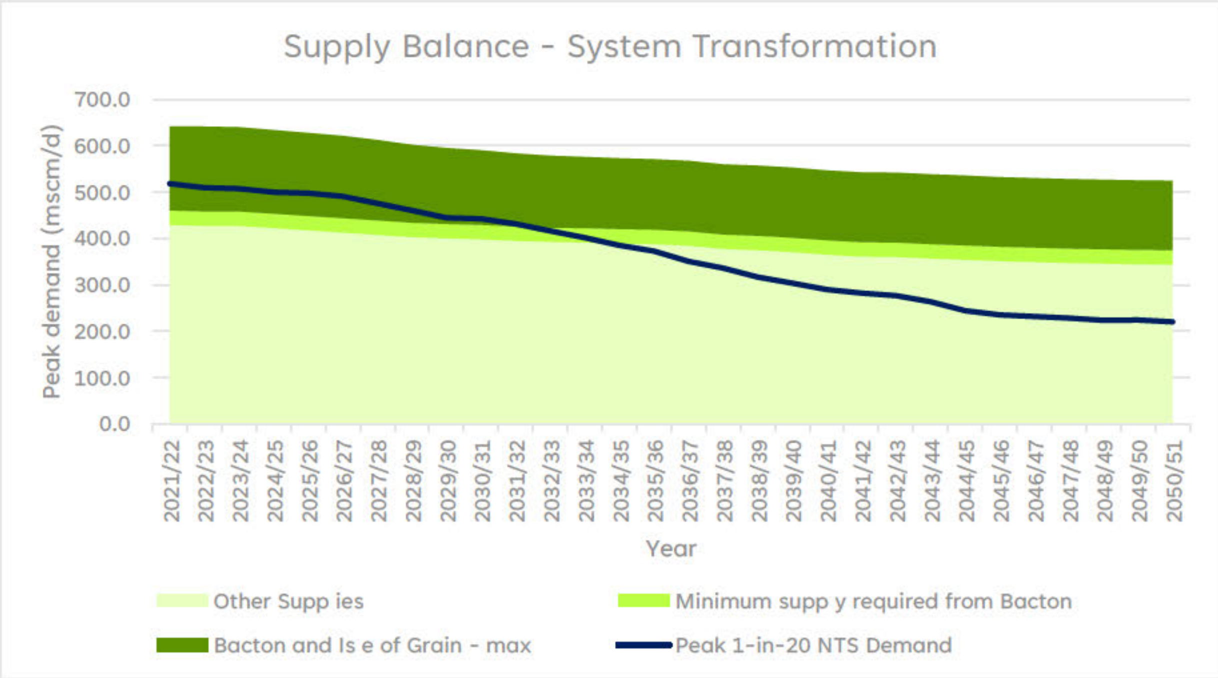
Within the FOSR we showed the required run hours on the third unit (the MCPD non-compliant Avon) based on actual 2022 flows. Due to the high exports, the back-up unit would be required to run for 662 hours. 162 hours over the rolling 500-hours EUD average use. Critically there were no major outages assumed on the calculation on the primary units (the two SGT400s). If there was a credible outage for three months (see Appendix 3) during this time, the run hours on the 3rd unit would have increase to 1,300 hours. There could have been a shortfall of 300 mcm which would cost £60m (using the DESNZ long term average price of 60 p/th). However, at the prices experienced in early 2022 of around 150p/th the cost would be around £150m.

King's Lynn Individual Unit Running Hours (Financial Year)							
Unit	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23
King's Lynn B	12	747	21	1	178	126	2891
King's Lynn C	22	10	72	40	778	109	2973
King's Lynn D	139	1131	26	30	628	199	1355
Total	173	1887	118	71	1584	434	7219

In the short to medium term, exports to Europe are expected to remain high, although it is recognised that European LNG terminals are being built to replace some of the lost Russian pipeline capacity.

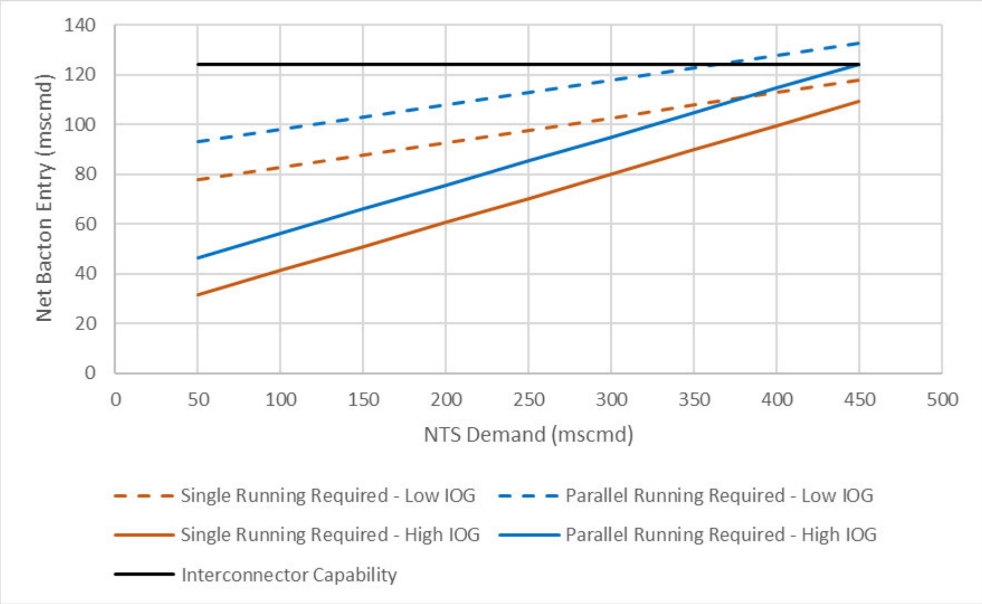
Evolving use of King's Lynn

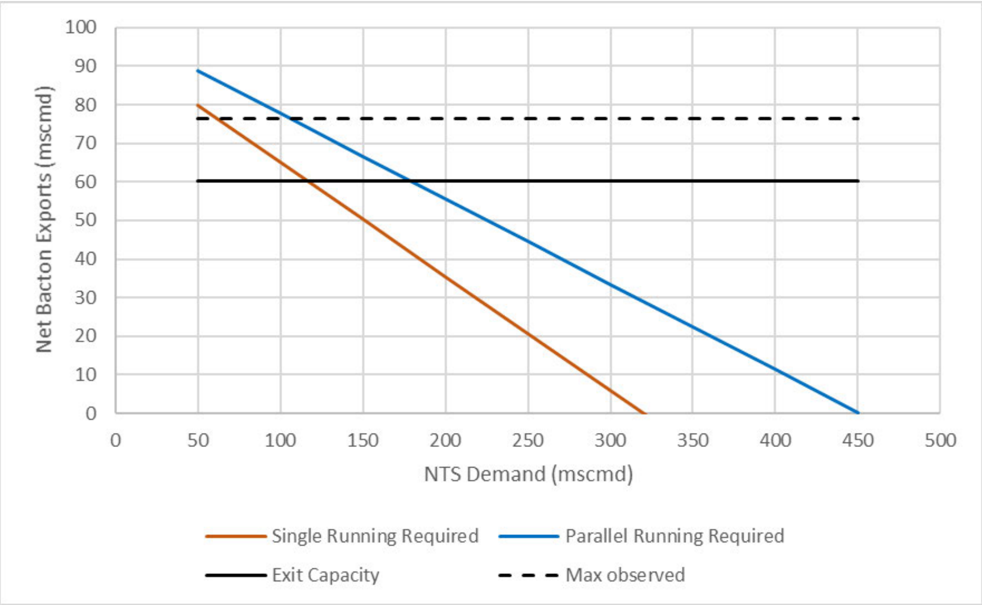
As we transition to NetZero and national demand declines the use of compression at Kings Lynn will evolve. In all three NetZero scenarios it will become feasible to balance national demand without the need for any supply from Bacton and the Isle of Grain. In these scenarios King's Lynn will be required to support demand in the Southeast. In the System Transformation scenario supply could be below the assumed minimum in our Network Capability analysis in 2032. (This happens in 2025 in Leading the Way and 2030 in Consumer Transformation).



With UKCS supplies expected to decline in the future years and the reduced levels of supply from Europe due to the invasion of Ukraine, we also need to be prepared for this scenario occurring. The network capability in the Southeast without supplies from Bacton and the Isle of Grain is reduced by ~15 mscm/d, even with King's Lynn operating in parallel to move gas through Bacton to the Southeast via feeders 3 and 5. If King's Lynn was not available the network capability would be reduced by another 15 mscm/d and our capability would be below the 1-in-20 demand level in 2032.

An unrestricted third unit at King's Lynn is vital to enable GB's transmission network to be resilient to a wide range of operational scenarios, minimising both entry and exit constraint risks. This is demonstrated through both recent flows and forecasted flows. NGT does not agree with the risks imposed at King's Lynn, and to the network as a whole, by having the third unit restricted to 500-hours EUD. A single credible (significant) failure event on either of the primary compressor units will mean that maximum capability at Bacton will only be available for a further 500-hours of operation (~three weeks a year). After this, capability will be reduced to the single unit capability lines shown on the Entry/Exit charts below. Following a single credible failure event on the primary units, any issues with the proposed (re-lifed) remaining Avon unit (originally commissioned in 1973) would lead to an immediate restriction to these capability levels. This would reduce Great Britain's ability to react to events such as the war in Ukraine and maintain energy security to our current levels.


140
120
100
80
60
40
20
0
Net Bacton Entry (mscmd)
0
50
100
150
200
250
300
350
400
450
500
NTS Demand (mscmd)
Single Running Required - Low IOG
Parallel Running Required - Low IOG
Single Running Required - High IOG
Parallel Running Required - High IOG
Interconnector Capability


100
90
80
70
60
50
40
30
20
10
0
Net Bacton Exports (mscmd)
0
50
100
150
200
250
300
350
400
450
500
NTS Demand (mscmd)
Single Running Required
Parallel Running Required
Exit Capacity
Max observed

Appendix 3 – Case Study – Credible Outage Scenario and Impact on Run Hours (exceeding 500-hours EUD)

Asset Health investment has been included within our option selection process for option retaining existing Avon units to improve their availability. Although this would improve the reliability as outlined in the RAM Study, there will still be periods of planned and unplanned outages impacting the lead units on both sites[16]. Currently two existing units on each site, Peterborough Unit B and C and Huntingdon Unit A and B, are being replaced with new units under the Industrial Pollution Prevention and Control (IPPC) Directive. This leaves Peterborough Unit A and Huntingdon Unit C non-MCPD compliant and require intervention by 2030.

Ofgem's draft determination poses utilising the derogated hours under the emissions legislation for the provision of a single standby compressor limited to 500-hours EUD annual running time across all three critical compressor stations. As noted, Section 6.17.6 of the approved TPC clarifies the need for standby compression to meet the 1 in 20 security standard, specifically:

"Therefore, we need compressor standby to comply with our obligation to develop the network to meet the 1-in-20 security standard. Standby is identified to ensure that the required transmission capability is maintained in the event of a credible loss of any single compressor unit."

There are many situations where a "credible loss of a single compressor" will mean standby is required for more than 500-hours.

Limiting the standby unit running hours means any outage exceeding 500-hours on any of the primary compressor units could lead to a scenario where the standby compression hours are exhausted and network capability is diminished. Below we have described two credible scenarios where restricted run hours on the standby compressor units pose significant risk to the operations of the NTS.

- If this scenario were to occur at either Peterborough or Huntingdon when heading into winter or during the winter months, the ability to deliver winter demands and/or a peak day would be at significant risk.

- If this scenario were to occur at any time in the year at Kings Lynn, then the length of time that maximum Bacton terminal capability (both import and export) could be delivered for is limited to 500-hours only.

In both cases above, the events that can lead to these risks are not unprecedented and moreover it is a matter of fact that outages exceeding 500-hours have been observed many times across the NTS compression fleet and are therefore to be expected. Scenarios to the effect have been described in Appendix 1 and 2.

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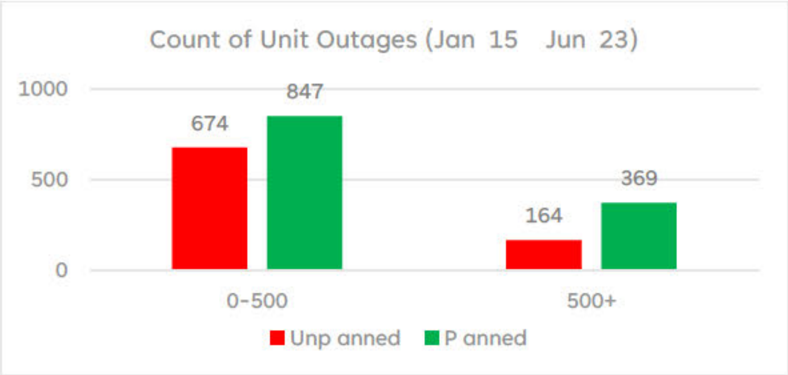
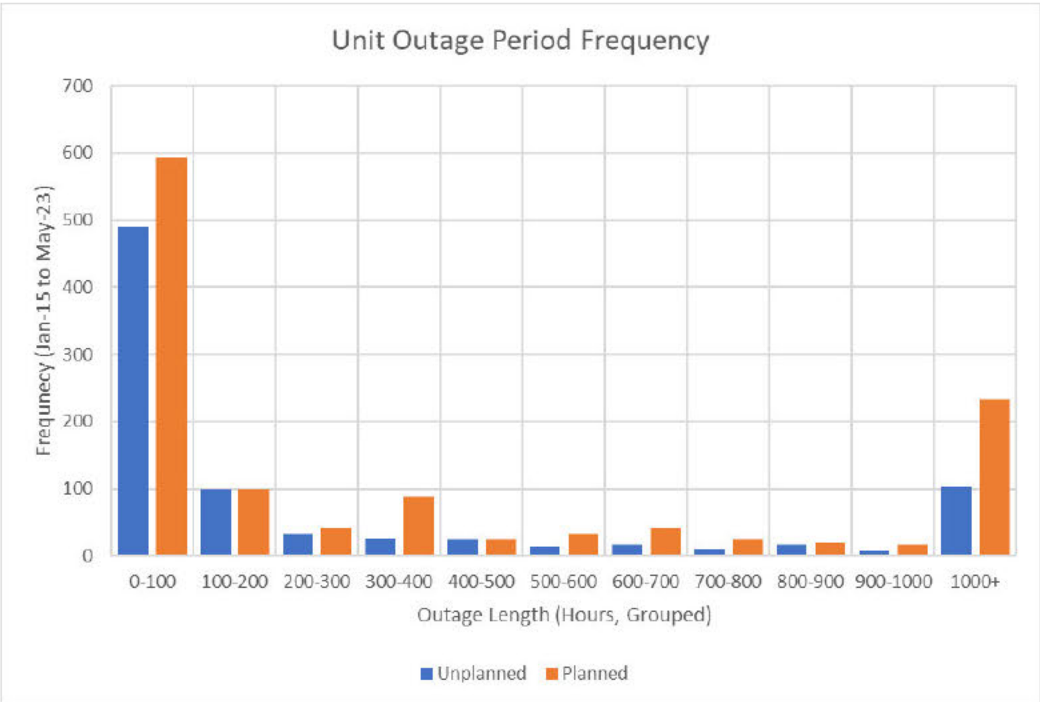
[16] Current performance of a typica Avon compressor unit on the NTS is 64.3%. We expect to enhance Avon avai abi ity for any retained Avon's at Huntingdon to the A3 scenario (as detai ed in the DNV RAM mode). The enhancements wou d bring the avai abi ity up to 79.5% (which is a 15% improvement).

Outages manifest for a wide variety of reasons, and these can be categorised at the highest level into planned and unplanned. The chart below shows the split of outages categorised this way for all NTS compressor units over the period January 2015 to May 2023. There were 164 unplanned outages logged in our core ALERT system that exceeded 500-hours in length. Not all of these were truly “unplanned” (some were project extensions or station level issues for example), but many were unforeseeable and would have required alternative compression availability. Regardless of planned or unplanned, all of these events risk the requirement to use some or all of the derogated 500-hours availability.



The graph below shows the outage length frequency across over the reporting period, with 100 outages being over 1,000 hours long.



The table below demonstrates a sample of unplanned unit outages observed across the NTS fleet over the last 10 years, further highlighting there is a high likelihood that the above risks will manifest. For example, an outage at Bishop Auckland lasted for over three years due to OEM issues with installation of the dry gas seal. This demonstrates it is not prudent to operate with such limited standby compression capability at critical sites.

Site	Unit	Issue	Cause	Type	Outage Start	Outage End	Length (Days)	Length (Hours)

[redacted]

[redacted]

Appendix 4 – Consultation Question Responses Peterborough and Huntingdon Compressor Emissions

Question 4.1: Do respondents agree with our assessment of the evidence presented in the Final Option Selection Report?

We agree with Ofgem's assessments regarding the need case, options considered, CBA key parameters, Best Available Technique and their analysis of our risk register and project programmes. We do however disagree with Ofgem's conclusion on our Security of Supply Case studies[17] we have provided as part of our FOSR submission. We disagree with Ofgem's options, which would resolve credible outage scenarios (as described in Appendix 3 of this response) by deploying commercial constraint management or operational strategy options. We have provided further evidence in this response regarding NGT's view on why unrestricted running of all units on both sites is essential in meeting future uncertain gas flows and that those conditions dictating parallel running at Peterborough could exist in the future. In Appendix 1 we have provided further evidence of how parallel running at Peterborough and Huntingdon will be required to insure against future high gas demands. The impact of operational strategies on the wider compressor fleet is also detailed in the response above and in Appendix 1. It remains our position that the additional evidence provided regarding Security of Supply must be considered alongside current CBA (and therefore FES predicted run hours) and it cannot be assumed that the CBA captures those impacts as described in the response and in our FOSR submission.

Question 5.1: Do respondents agree with our proposed Final Preferred Option?

NGT does not agree with Ofgem's Final Preferred Options for Peterborough and Huntingdon compressor stations. Considering all information provided as part of our FOSR submission and as part of this response, the evidence shows that any solution with restricted run hour standby compression is not acceptable for critical sites such as Peterborough and Huntingdon compressor station. This is contextualised by the limitations of FES regarding high gas demand scenarios (such as during extreme weather events) and the uncertainty around gas supplies in the future in particular the unknown regarding the Russian/Ukraine conflict and impact on the global gas market. Within this response we demonstrated that resilience is particularly important considering credible outages of lead units on site and how limited run hours would put at risk meeting 1-in-20 peak demand obligation. The central location of Peterborough and Huntingdon means that the selection of the Final Options to comply with MCPD has impacts on the remaining non-compliant units across the network in the Southeast and Southwest.

Given our 1-in-20 obligations it would not be appropriate to rely on on-the-day products if we are not able to run the 500-hour EUD compressor as Ofgem suggest in their minded to position. We would need to secure commercial solutions ahead of the day (if possible). Commercial contracts would be very expensive and provide limited assurance to reduce demand or increase supplies. Demand reductions are difficult to enforce due to interactions with electricity capacity

[17] In section 7.4 of our FOSR submission we have provided ana ysis inc uding the centra ro e on the NTS of Peterborough and Huntingdon, a Gross Va ue Added Ana ysis, operationa strategy and efficiency ana ysis as we as ana ysis around the 1-in-20 peak demand ob igation, which we reference within this response a so.

markets and the very high penalties on generators. Supply turn-up contracts are also very expensive and provide no guarantees the supply will be available when called upon.

Non-compliant Avons are still subject to detailed remnant life surveys to determine the Asset Health required to increase current availability and reliability levels, but it is NGT's view that regardless of this the 500-hours restriction would not give the required insurance to account for credible outages. As such Government will also be reviewing the existing gas infrastructure standards that directly impact the network capability together with the availability and reliability. This work has already begun in collaboration with DESNZ, Ofgem, ESO, NGT and is intended to deliver an output by Winter 2023. We believe such an output will supplement the current standards and the economic tests which rightly govern the infrastructure investments.

Question 5.2: Do respondents agree with our proposals approach to potentially removing restrictions on the operation of the retained Avons at both Peterborough and Huntingdon Compressor Stations?

We agree with Ofgem that once deemed available, proven and accepted by the relevant Regulatory bodies, retrofitting an existing Avon gas turbine with the DLE emission abatement technology is an effective means to reduce emissions and comply with legislation. For this reason, Avon DLE emission abatement retrofit was included within our option selection process and has been selected for our Final Preferred Option at Huntingdon compressor station. The installation of a retrofit solution at Huntingdon would not be carried out until the solution meets the criteria as described above, which means any NTS trials would have been successfully completed.

However, maintaining a non-compliant Avon at Peterborough compressor station is not the right solution. The significance of the site, as highlighted within this response, requires us to maintain resilience and crucially implement a unrestricted running solution with high confidence prior to 2030. Any reduction to the site's resilience, through maintaining an Avon, will put us at risk not being able to meet credible high gas demand scenarios or provide the resilience required during an event of credible outages (described in Appendix 1, 2 and 3 of this response).

There are several issues associated with proving the DLE technology that mean there is risk to the viability of the technology to meet the MCPD requirements. These include: trials to prove the long term suitability, Timely progress of the technology to allow time to implement prior 2030 account for the risk of delay within multiple stages of development, validity of the technology in NOx reduction my obtaining environment permits, and successful commercial supply chain offering competitive and full support services. These risk factors need to be taken into account against the network capability and reliability needs

As described above, in addition to the need to prove the technology, any Avon DLE retrofit solution will have increased asset health maintenance exposure and higher probability of unavailability due to technical issues as a result of the age of the units. Until we have no confirmation of the asset health scope for retrofit options from the condition assessment and detailed remnant life surveys which are being conducted during FEED, the units carry a major risk that additional scope will be identified with increasing costs and project timescales, potentially identifying significant underlying issues that would hinder ongoing operation to 2050.

Furthermore, the Compressor Emissions-Asset Management Plan (CE-AMP) considers possible emission focused investment for all compressors sites. The proposals presented deliver the most cost-effective network solution to meet the current and future needs of consumers, ensuring the required network reliability, availability and emissions legislation is met. If investment is reduced at the more critical sites, then not only will it reduce the efficient operation of the network but it'll need investments to be increased at the other sites to counter the lower availability and / or restricted running at the more critical sites. The CE-AMP includes the interaction between the compressor sites in its assessment, including consideration of which compressors would be first on, and last off. This approach tries to minimise the possibility of a network failure in a scenario where multiple compressors have reached their 500-hours EUD limits.

Appendix 5 – Consultation Question Responses King's Lynn Compressor Emissions

Question 4.1: Do respondents agree with our assessment of the evidence presented in the Final Option Selection Report?

We agree with Ofgem's assessments regarding the need case, CBA key parameters, Best Available Technique and their analysis of our risk register and project programmes. We do however disagree with Ofgem's view regarding our options selection and to remove the options of a potential electric compressor drive over a gas driven compressor. As noted in the FOSR, we established during engineering evaluation that a gas turbine compressor installation at King's Lynn was found to be of comparable cost to an electric drive compressor at ±30% cost certainty. And we remain of the position that a decision on the specific technology should be made during the FEED phase following confirmation of the Final Preferred Option.

We disagree with Ofgem's conclusion on our Security of Supply Case studies[18] we have provided as part of our FOSR submission. We have provided additional context in this response regarding credible outage scenarios (as described in Appendix 3 of this response), which as such are not as Ofgem suggested represented in the Best Available Technique analysis or the CBA as it is being used today.

We believe it is essential to be able to maintain maximum capability at King's Lynn beyond ~ three weeks in the event of a credible fault of one of the Siemens SGT-400s. King's Lynn is the only compressor station that can support maximum export to Europe and import back to the UK. Bacton, along with Milford Haven, Isle of Grain, Easington and St Fergus, is a key entry and exit point to meet national security of supply.

Question 5.1: Do respondents agree with our proposed Final Preferred Option?

We do not agree with the proposed final preferred option as outlined in this response.

Question 5.2: Do respondents agree with our proposals approach to potentially removing restrictions on the operation of the retained Avon (Unit B)?

We agree with Ofgem that once deemed available, retrofitting an existing Avon gas turbine with the DLE emission abatement technology is an effective means to reduce emissions and comply with legislation. For this reason, Avon DLE emission abatement retrofit was included within our option selection process and has been included within the option selection for our other compressor sites.

However, maintaining a non-compliant Avon at King's Lynn compressor station is not the right solution. The significance of the site, as highlighted within this response, requires us to maintain

[18] In section 7.4 of our FOSR submission we have provided ana ysis inc uding Bacton supp y and demand sensitivities and rea wor d assessments inc uding 2022 gas f ows and 2017/18 'Beast from the East' ana ysis. We have a so provided evidence regarding ong term assessments on sustained high Bacton exports.

resilience. Any reduction to the site's resilience, through maintaining an Avon, will put us at risk not being able to meet credible high gas demand scenarios or provide the resilience required during an event of credible outages (described in Appendix 2 and 3 of this response).