national gas transmission

ANNEX

OFFICIAL – FOR PUBLIC RELEASE

System Operator Annex

Version: 1.0

Issue: Final

December 2024

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RIIO-GT3 NGT_A10

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Executive Summary

This annex consists of the following four sections:

Our **System Operator Process and Strategy** section describes the role of the System Operator, our processes, strategies, interactions, and risks, in the context of a changing energy landscape.

The **Network Capability Assessment** describes our network capability modelling approach, the assumptions we have made, and the impact of our assessment on our business plan aligned to the FES 2024 Holistic Transition and Counterfactual pathways.

The **Biomethane and Green Gas Connections** section provides details of our proposal to accelerate unconventional gas connections to the National Transmission System (NTS), to support the UK government's ambition of increased biomethane injections into gas networks.

The **System Operator Incentives** section contains ambitious proposals to update our existing system operator incentives, building on the customer value that has been delivered through RIIO-T1/2 and providing detailed proposals for new targets, incentive strengths, caps/collars, costs, and options considered for the RIIO-GT3 period. It also proposes two new environmental incentives, that will be further developed in collaboration with stakeholders over the next two years.

1. System Operator Process and Strategy

1.1 Introduction

The purpose of this annex is to articulate the role of the System Operator (SO) and how we expect our activities and processes to evolve within the RIIO-GT3 period alongside the changing energy landscape.

Initially in this annex we set the context by providing an overview of the SO and the environment we have been operating within in the RIIO-T2 period. We then go on to talk about the areas we need to expand our capabilities within RIIO-GT3, covering:

- our day-to-day and mid-term processes and activities and how these overlap with the Transmission Owner, including identification and mitigation of any risks arising from that interaction.
- Identifying how system needs and investment needs are likely to change within RIIO-GT3; and
- what the SO will need to do and how it needs to transform from now until the end of RIIO-GT3 to accommodate the expected developments and equip us with the capabilities to drive the evolution of the energy industry.

The areas in which we need to expand our capabilities within RIIO-GT3 can be distilled into the following five deliverables:

1. We will continue to operate the network safely, efficiently, and reliably in an increasingly volatile environment, enabling access to the network to deliver asset investment and securing the capability of our critical IT systems.
2. We will identify opportunities to maintain and enhance operational resilience by growing our capability to understand the impact of changes within the energy market.
3. We will pave the way to net zero by facilitating the evolution of hydrogen blending in the gas transmission network, understanding the impact on the natural gas network of repurposing our assets to transport alternative gasses and support Strategic Network Planning processes, including the government's mission for Clean Power 2030.
4. We will work with our customers to enhance our capability to provide data and information to the gas market.
5. We will facilitate the transformation of the energy industry, by evolving natural gas commercial market frameworks and developing future energy market strategy.

It was important we tested our plans and the drivers with a broad range of stakeholders to ensure they align with their expectations and priorities. We held an industry webinar titled "Deep Dive on Gas System Operation" in which we took attendees through our plan, focusing on the areas of additional capability for RIIO-GT3. The webinar was attended by 53 stakeholders from across the value chain. We then held a Coalition event whereby we invited key industry stakeholders to participate in a "round-table" style virtual event where we could further deep-dive on particular topics. Feedback from these events, along with what we will do with this feedback, is included throughout this document.

For more information on stakeholder engagement, please refer to the Stakeholder Engagement and Decision Log[1].

1.1.1 Who we are

The System Operator is the sole operator of the gas National Transmission System (NTS) in Great Britain. We ensure natural gas is transported safely and efficiently from gas supply points (where it enters the NTS) to exit offtake points (where it is consumed or stored). We are part of the wider Gas Transmission business that ensures supply and demand is balanced in real time and facilitates access to NTS assets for maintenance, replacement or for the connection and commissioning of new assets. Through engagement with our customers and stakeholders we shape the energy markets of the future, providing analysis and insights into the ever-changing nature of energy. We ensure that the GB energy consumer continues to receive a safe, reliable, and efficient service.

1.1.2 Operating Environment

The operating environment within RIIO-T2 has been particularly volatile with the continued evolution of operational challenges. Despite this, we have continually adapted to facilitate 100% gas requirements for our customers whose use of the NTS has changed, needing more flexibility than ever before to respond to unprecedented conditions in the global gas market.

At the beginning of RIIO-T2 we were still within the throes of the Coronavirus pandemic, emerging from the national lockdowns and the country adopting new ways of working. This added complexity and variability to gas demand during this period as well as the start of the global gas price crisis as gas demand returned faster than gas supply capability. This had the knock-on effect of shippers and suppliers rapidly exiting the market. This was shortly followed by the outbreak of the war in Ukraine and the European Union's consequential move to reduce its dependence on Russian pipeline gas which resulted in:

- Much greater focus on the replenishment of European storage ahead of winter.
- Gas prices at record high levels with significant price differentials between UK and Europe.
- High demand on electricity interconnectors to Europe throughout the summer and autumn driving additional demand for UK gas powered generation.

[1] NGT_A16_Stakeholder Engagement and Decision Log_RIIO_GT3

This prompted significant changes in the operation and usage of the NTS, including maximising exports to Europe, and large swings in demand for gas to power between days. The continued decarbonisation of the economy has also had an impact as gas continues to fill the gap for power generation when renewables sources are not available.

Alongside the change in how we operate the network, these events also prompted a change in our role working with Ofgem and Government to understand the market outlook, potential risks, and mitigations. This included developing commercial framework changes, providing additional data and information, and working on initiatives to enhance gas security of supply.

The evolution of the operating environment described above, provides context to our strategy and proposals for RIIO-GT3, including for our system operator incentives. The fundamental shift that we have seen in the European gas supply outlook, and the continued growth in renewable generation in the UK, increases the likelihood of further volatility and shocks in the RIIO-GT3 period, for which we must have the necessary capabilities.

1.2 We will continue to operate the network safely, efficiently and reliably in an increasingly volatile environment, enabling access to the network to deliver asset investment and securing the capability of our critical IT systems.

The SO is responsible for the activities associated with the real-time operation of the NTS and market facilitation. We accurately forecast supply and demand and optimise system configuration accordingly to deliver an effective on-the-day operational strategy, executed on the day by the Gas National Control Centre. We aim to maximise the level of operational flexibility we can provide our customers, working to accommodate their requirements by making optimal decisions considering prevailing market conditions, available NTS assets and operational tools on any given day.

We work with the Transmission Owner (TO) to maximise the availability of compression and minimise the probability of system constraints. It is imperative that the TO and SO work together so that assets that are vital to the operation of the network are well maintained and that any investment works are carried out at a time when they are not heavily replied upon for the operation of the network (typically in the summer period). Failing to align appropriately would mean our inability to meet our customers network access requirements and potentially requiring constraint actions to be taken at a cost to consumers. We work closely with the TO to ensure the safety of the NTS by managing system pressures within safe limits and maintaining gas quality composition within legal limits.

Finally, we work collaboratively with the TO to optimise the access plan for taking NTS assets out of service to allow work on them to be safely undertaken, or to facilitate customers undertaking work on their assets. This includes network access planning to ensure new connections can be brought onto the network safely as well as outage planning to enable critical maintenance and upgrades to be done on the network to maintain its safety and reliability. Working closely with the TO to plan the deliverability of the asset investment is imperative to ensure we can deliver the necessary access required to deliver the required works. It also provides visibility to the procurement supply chain of when asset works will be carried out to enable forward contracting and supply, something which will become ever more important in RIIO-GT3 with the increased asset work required.

1.2.1 Network Access

The gas operating environment is becoming more and more volatile (prompted within RIIO-T2 by geopolitical events leading to unprecedented flows and gas prices, continued with the forecasted growth of renewable electricity generation in RIIO-GT3). Notwithstanding this, our customers need us to continue to transport gas to where it needs to be, when it is needed to maintain security of supply and to do this safely, efficiently, and reliably.

Our customers also need unrestricted, flexible access to, and utilisation of, the NTS. This requires a resilient network with reliable assets. Within RIIO-GT3 we need to deliver a significant programme of investment works, as outlined in the Asset Management Plan[2], to ensure our assets are appropriately maintained and upgraded where needed. To achieve this level of investment an increased volume of shutdowns (including scheduling and undertaking safety responsibilities for delivery of the shutdown) will be required.

The SO works with the TO to form the plan for delivery of the AMP, working to align activities and identify delivery timescales to maximise efficiency and minimise disruption on our customers. This results in a rolling three-year plan of the shutdowns required to be carried out, with particular focus given to developing firm plans for the following summer period. Within RIIO-GT3, enhanced planning and development of ways to minimise or remove outages or maximising delivery per shutdown will enable access to the network to deliver the AMP.

In the Coalition event, one stakeholder asked what **are we doing to optimise the use of the assets we already have** and using them as efficiently as possible which may mean encouraging gas onto the network? The asset maintenance work included within the AMP enables us to extend the life of the asset and is driven by the SO view of future need for that asset.

[2] NGT_A01_Asset Management Plan (AMP)_RIIO_GT3

To deliver the access to the network required to deliver the Asset Management Plan, we need to schedule and deliver shutdowns differently within RIIO-GT3. Currently, we plan shutdowns on the network to deliver asset investment works in the summer period, typically April to October due to flows generally being lower during this time. Over RIIO-T2, as the volume of asset investment has increased, the shutdown plan has become more congested meaning we have begun to plan some shutdowns on the NTS to deliver maintenance work in the "shoulder months" (March and November). However, this has been reactive to enable delivery of asset investment related RIIO-T2 Price Control Deliverables rather than standardising this approach. In RIIO-GT3, to help expediate the delivery of the volume increase in the AMP and maintain network reliability for our customers, we intend to plan to take shutdowns on the network over a longer period of time, into the "shoulder months", more routinely. This will mean when we are forming the shutdown plan which covers a longer period in the year, planning for more shutdowns, defining the short-term operational risk and strategy for a longer period and delivering the safety obligations needed for the network access over an increased period of the year.

When testing this with stakeholders at the Coalition event they stated, **"Talking about extending the maintenance window which I can understand why you might need to do that" "Extending the maintenance is something that you can expect with an aging network"**

Due to shutdowns becoming more difficult to secure within RIIO-GT3 or carrying a greater risk due to the increased volatility in use of the network, we will increase our capability to more firmly plan the shutdown programme for future years. This would mean as well as detailed planning for the following summer period, we would also be able to plan more robustly a couple of years ahead, taking a more strategic approach by continually looking at how the shutdowns can be optimised to deliver the AMP. Experience has told us that although at the beginning of a price control period, we will assess the deliverability of the proposed asset investments over the forthcoming years, including the ability to schedule the required shutdowns, this will inevitably change and evolve as time progresses and requires constant refinement and validation. In RIIO-T2 this has been largely reactive, whereas for RIIO-GT3 we need to do this more proactively to deliver the increased level of investment. This will have several benefits, the shutdown program will be able to inform the AMP delivery; it will mean we can take a more flexible and agile approach to planning shutdowns, making adjustments where it is optimal to do so; it will mean we can work more closely with our customers to give greater visibility of when shutdowns impacting them may occur; it will also enable the supply chain to ramp up to deliver materials required for the investment with greater certainty on timing.

To minimise future maintenance required on our assets, and therefore the number of shutdowns required, a further development we propose within RIIO-GT3 is to have the capability to feed into the design of assets to enable them to be designed in a way which makes delivering future maintenance works on them more simple, quicker, and therefore requiring a shorter shutdown period and thereby minimising disruption to our customers.

At the Coalition event, one attendee asked **"from a consumer perspective, what are the so-what's of extending the maintenance period?"**. Extending the period over which we take shutdowns on the NTS will enable us to deliver more asset health investment, which includes maintenance works, exploratory works for the future of the network, or for customer driven works. These shutdowns are negotiated and agreed with our customers, so they have no impact on supply to end consumers. The ability to carry out these works results in a more reliable network than would otherwise be the case and enables potentially more efficient future use of the network.

IT investments

Supporting IT investments are:

Ref#	IT Investment Line	Investment Description
IT 006[3]	Enhance SCADA	Conduct analysis and discovery work to assess SCADA and investigate opportunities presented by new technologies
IT 007	Enhance Commercial Apps (Liferay)	Conduct analysis to assess opportunities to enhance Commercial Apps capabilities building upon like for like replacement of Fusion in RIIO-T2 to support the control room digital transformation
IT 008	Video Wall Replacement	Conduct analysis and discovery work to assess Video Wall capabilities and replace it
IT 009	EDSS Replacement	Conduct analysis and discovery work to replace EDSS and investigate opportunities presented by new technologies to improve information flow robustness
IT 010	Operational Process Improvements	Review inefficiencies in operational processes and seize automation opportunities
IT 011	Future Telemetry Network	Enhance Telemetry resiliency through extending fibre to more sites as the primary method for receiving Telemetry data
IT 012	Energy Trading, Reporting and Notifications replacement	Conduct analysis and discovery work to replace and investigate opportunities presented by new technologies to improve gas energy market trading experience that meet enhanced data capability requirements
IT 018	Operational Safety & Compliance	Review current operational practices, and enhance operational safety of our workforce by providing better integrated capabilities and document management solution

[3] NGT_IJP03_Enabling Energy Security_RIIO-GT3

IT 019[3]	Enhance Control Room Telephony	Review current established telephony capabilities, and build out the offering through integrating telephony into the control room operations and enable environment for more effective collaboration between the control room and field operations
IT 043[4]	Gemini Sustain / Enhance	Activities required to maintain and enhance Gemini and UK link platforms, and support market participants needs
IT 044[4]	Gemini Replace	Opportunity to review current processes and look to reengineer these in line with demands from the industry to improve the experience for customers • Introduce new available technology to increase efficiency and effectiveness of the solution • Ensure that value for money is maintained within Commercial systems • Removal of all process and technical debt

1.3 We will identify opportunities to maintain and enhance operational resilience by growing our capability to understand the impact of changes within the energy market

1.3.1 Energy Market Modelling

We have Licence obligations to provide information to the market including the publication of the Summer and Winter outlooks and the Long-Term Development Statement. To date, we have been relying heavily on third parties for fundamental market data for us to provide the needed insights to engage with our stakeholders. This limits our ability to define the scope and focus of this core analysis.

To enhance our effectiveness, we need to develop our capability to understand the energy landscape across all key vectors in all timeframes. This includes greater insight into the impact of supply and demand dynamics on the network requirements; greater understanding of the power market and its impact on developing whole system options supporting long-term investment decisions; and thorough understanding of upstream dynamics and how these change throughout the winter. We plan to initially develop this capability within RIIO-T2, further enhancing within RIIO-GT3.

Enhancing our capability to obtain a deeper gas market knowledge, including related markets and to grow our fundamental analysis and forecasting capabilities will enable us to continue to be in a trusted position and provide more impactful insights to our customers and stakeholders. The RIIO-GT3 period will be a time of significant change in the energy landscape as we progress towards net zero, move closer to a whole energy system whilst continuing to see variability in the operating environment. Having greater capability in this area will enable us to continue to valuably contribute to these debates, offering a unique position and evaluating potential risks and opportunities.

1.3.2 Energy Resiliency

Within RIIO-T2 geopolitical events had a profound impact on the gas industry, bringing greater focus on the resiliency of energy supply and transportation. Within RIIO-T2 we worked closely with DESNZ and Ofgem on a combination of measures to improve the resilience of the NTS, recognising the need for its durability in the longer-term. This includes, providing further clarity in our Transmission Planning Code on our proposed network investments, ultimately leading to a fuller review of the way we do Transmission planning; reviewing and analysing the single points of failure on the NTS and agreeing with Ofgem the needs case for investment upfront to enable the regulatory decision to be around cost efficiency. Alongside this has also been, developing a methodology to ensure a stable risk profile is maintained, and implementing tools and strategies to ensure gas commodity security of supply.

1.3.3 Office of Resilience and Emergency Management

One of our key roles within the SO is to work with the TO when preparing for our response to manage a network gas supply emergency and provide the industry Network Emergency Coordinator role. Part of the introduction of NESO is their obligation to establish an Office of Resilience and Emergency Management (OREM) which will have a remit to develop a whole system approach to energy network emergency management. This represents a key change to the resilience and emergency management landscape. It is expected that the OREM will be established during RIIO-T2 but its responsibilities, accountabilities and interactions with the SO will continue to evolve during RIIO-GT3.

To build knowledge on and establish policy for their gas interest, OREM has a commissioning power in the NESO Licence over NGT and the other Gas Transporters. Within RIIO-GT3 we expect to receive a greater number of commissions and less formal information requests from NESO in this respect as they work to potentially develop new processes and policy obligations. We will need to comply with any new processes and policy obligations arising out of the establishment of the OREM and their development of whole energy system developments.

[4] NGT_IJP04_Enabling Market Efficiency and Regulatory Changes_RIIO-GT3

In the Coalition event a couple of attendees sought **clarity on how we expect emergency arrangements to change**. Any policy which might arise from OREM obligations may impact our pre-emergency and emergency gas frameworks which we will need to implement.

IT investments

Supporting IT investments are:

Ref#	IT Investment Line	Investment Description
IT 013[5]	Cyber Compliance	Review current cyber security standards and practices, and enhance them in line with our strategy and policy
IT 014	ECR Enhancements	Review current ECR capabilities against the ones of the NCC and build out as close of a replica in order to have the full capability to run the network in case of an NCC emergency
IT 015	Resiliency and Security of Supply	Review and make communications between us and the rest of the Gas network more resilient in case of a National Power Outage
IT 017	Whole System Energy Response	Review current collaborative external party data sharing practices, and build a resilient way of sharing data with external parties in near real-time on a shared platform / portal
IT 020	Future Pandemic Preparedness	Review current resiliency of our control room, its ability to function in case of extreme unforeseen circumstances and establish appropriate provision for remote working

1.4 We will pave the way to net zero by facilitating the evolution of hydrogen blending, understanding the impact on the natural gas network of repurposing our assets to transport alternative gases and support Strategic Network Planning processes, including the government's mission for Clean Power 2030

1.4.1 Blending

RIIO-T2 has been the start of a period of transition towards net zero as we have continued to support the fundamental changes occurring across the industry. Blending hydrogen with natural gas and customers entering this blended gas onto the NTS will be one of these fundamental changes and a vital step towards the UK achieving its net zero targets. It will help to ensure security of supply both in terms of diversification of gas supplies and the ability to continue to trade with EU member states as their gas mix increases in percentage of hydrogen content. The UK Government may publish a timeline for a decision on blending hydrogen by the end of 2024.

In preparation for that decision, the SO has been working closely with the TO on the FutureGrid Project which will allow us to gain an understanding of how the gas network will need to be developed to be able to transport a 2%, 5%, 10% and 20% blend of hydrogen. Additionally, the SO have been assessing the impact on the operation of the NTS containing a higher volume of hydrogen, leading the discussion with Gas Industry market participants to understand the development of market frameworks required to accommodate a blend of hydrogen and beginning to anticipate the changes to the Gas Safety Management Regulations that may be required. It is vital that the SO and TO are aligned on both the physical capability of our assets to transport gas containing an increased percentage of hydrogen and the capability of the network to operate physically and commercially.

Our ambition, jointly held with the distribution networks, is to be blend ready by the end of 2028. To support this, we will carry out the network analysis for blended connection requests as we anticipate the volume of connections to increase. Further refinement to market arrangements is likely to be needed to facilitate the operability of a blended gas network, particularly around the connections regime which currently works on a first come, first served basis which may not be appropriate for hydrogen blend connections due to the limitations of levels of blend within the network. Additionally, engagement with connected TSOs, EU TSOs, and Ireland will be continued within RIIO-GT3 to understand the evolvement of blending plans and impact of blending in GB.

1.4.2 Repurposing

In addition to blending hydrogen onto the gas transmission network, repurposing sections of the NTS to transport alternative gasses is another pathway which could enable the UK to achieve Net Zero targets. This could be repurposing assets to transport 100% hydrogen and carbon (for onward usage or storage in depleted gas fields). These options are being explored through National Gas' Transmission Owner lead Project Union project which is looking at creating a 100% hydrogen "backbone", and through Project Acorn, which is looking at repurposing a Feeder in Scotland to transport carbon. The SO have been working

[5] All investments are contained in NGT_IJP03_Enabling Energy Security_RIIO-GT3

closely with the Transmission Owner on both projects to optimise optionality and solution development, without which optimal engineering and operational solutions may differ. Within RIIO-T2 these projects are funded via alternative funding mechanisms.

Repurposing natural gas pipelines and other assets to transport alternative gases would have the impact of reducing the capability and/or resilience of the natural gas network and may also impact our ability to take shutdowns to facilitate maintenance. Within RIIO-GT3 we will carry out additional network analysis to understand the impact of repurposing on our network and develop options to mitigate any issues that are identified.

In the Coalition stakeholder event, we spoke to attendees about the need to understand the impact of repurposing on the capability of natural gas network and the ability to take shutdowns, they said it ***"sounds sensible"***

1.4.3 Strategic Network Planning

Historically, we have published our Annual Network Capability Assessment Report (ANCAR) on an annual basis. Our network capability assessment process enables us to calculate and demonstrate the physical capability of the NTS and assess whether this meets our customer requirements and associated obligations across GB both now and in the future. This assessment is carried out using a range of inputs and data including the Future Energy Scenarios (FES) outputs produced by NESO. The ANCAR identifies the network capability requirements which are then handed to the TO for costings of potential asset solutions to be developed.

The establishment of NESO creates additional responsibilities for us in the area of strategic network planning. NESO necessarily has a more strategic, long-term focus driven by the UK's obligation to deliver net zero energy system by 2050. Although our obligation to produce the ANCAR has been removed, and an obligation to produce a new Gas Network Capability Needs Report (GNCNR) placed on NESO, this does not negate the need for us to maintain and develop our existing analytical capabilities, not only for our own operational, network planning, business planning and regulatory purposes, but also to support the new activities of NESO. We will need to produce Strategic Planning Options Proposals to suggest solutions for any capability gaps identified in the GNCNR, in order to inform their Gas Options Advice Document. We also have an obligation to respond to ad-hoc requests from NESO to support their deliverables.

Our activities to support the establishment of NESO were funded via a Totex Adjustment Mechanism. Our RIIO-GT3 business plan includes the necessary resources to support these additional responsibilities as we continue to collaborate with NESO in its Strategic Network Planning process and its evolution within the RIIO-GT3 period. This is expected to include additional analysis to evaluate the impact of the government's mission for clean power 2030, which is likely to have an impact on the role of gas in the generation mix.

In the stakeholder webinar, we asked attendees "have we identified the right priorities for the System Operator to support a low-cost transition to Net Zero?". 74% said yes, 26% said they weren't sure. We then asked "if you think we should be focussing on development in other areas, what are they"?. Attendees responded with "various sources of gas", "storage facilities", "Bio-gas", "synthetic fuels", "expansion of LNG terminal" and "global growth". Following Ofgem guidance, this plan is a methane plan with only hydrogen readiness activities included and therefore we believe it would not be the right place for us to consider these priorities.

IT investments

Supporting IT investments are:

Ref#	IT Investment Line	Investment Description
IT 005[6]	GSO Network Capability	Conduct analysis and discovery work to assess existing systems and applications, and investigate opportunities presented by new technologies to improve productivity, simulation accuracy and meet the needs of increasingly complex operational environment

[6] NGT_IJP03_Enabling Energy Security_RIIO-GT3

1.5 We will work with our customers to enhance our capability to provide data and information to the gas market

1.5.1 Data Science

Within RIIO-T2 we established data science capability within the SO, focussing on demand forecasting and system optimisation. We have also developed and deployed machine learning models for point forecasting, developed probabilistic forecasting models and integrated external data sources in-house. Within RIIO-GT3 there is going to be growing complexity and volume of data which will require us to scale and enhance our Machine Learning (ML) and Artificial Intelligence (AI) capabilities to transition from basic predictive models to more advances optimisation tools, ultimately leading to automated decision-making systems allowing for dynamic and responsive system management. Alongside this, as the use of AI becomes more integral to our operations, there will be the need to strengthen governance and risk management frameworks to ensure models are used safely and effectively, including monitoring and validations of model performance.

1.5.2 Data Provision

Within the SO we design, build and maintain a wide range of data models and analytical tools along with creating the visualisations and dashboards to distil this information. As well as supporting data-driven operational decision making and enabling additional reporting over the winter period to support preparedness activities, this data and information is used to support our external stakeholders, including Government and the wider energy industry. In RIIO-T2 we have implemented several initiatives under the New Information Project, to enhance the data and information we share with the industry. We introduced a new Gas Data Portal to deliver a compete refresh to our information provision service to enhance the user experience and allow a platform for future development; we have developed a data triage process where we assess a request for information and conduct feasibility analysis for its provision; we have increased the consistency of data formatting to enhance its portability to new data sources and improved the utilisation of alerts and monitoring capability to identify any data inaccuracies before publication. Within RIIO-GT3 data and information will continue to be important to our customers and stakeholders as they operate in an increasingly changeable environment. Therefore, we expect to undertake a similar level of developments in our capability to provide data and information as we have done in RIIO-T2.

During the Coalition stakeholder engagement event, attendees had particular interest in gas quality information. One attendee asked for actual and forecast data to be published online, whilst another requested more information on the long-term future for how gas quality will change over time along with more information on short-term fluctuations. This highlights the need from our customers and stakeholders for continued data and information as the energy landscape develops.

IT investments:

Supporting IT investments are:

Ref#	IT Investment Line	Investment Description
IT 016[7]	Predictive Forecasting and Network Simulation	Build on work delivered in RIIO-T2 to develop advanced predictive forecasting and network simulation capability that provides a visual representation of both historical and near real-time data for enhanced & automated decision making
IT 040[8]	Enhanced Data driven interoperability for an intelligent harmonized network	Data sharing capability composite models - 2D, 3D - asset information models, drawings Implementing data security, masking - trusted, semi trusted partners Implement and operate on digital spine Opportunity to remove dependence on external data
IT 046[9]	New Information Provision UI/UX Enhancements	The delivery of ongoing UI/UX enhancements to enable customers and stakeholders to make better decisions
IT 047	New Information Provision: Continued Development of New Information Provision APIs	Enhancement and maintenance of APIs to improve workflows internally and externally
IT 048	New Information Provision: External Data Sharing (Large Data Sets)	Development of additional data sharing capabilities to meet customer needs and boost interoperability
IT 049	New Information Provision: Smart Apps	Development of smart web apps to meet the demand of customers and stakeholders for new interfaces
IT 050	New Information Provision: Refresh	Implementing ongoing technical updates to the New Information Platform

[7] NGT_IJP03_Enabling Energy Security_RIIO-GT3
[8] NGT_IJP05_Data Foundations, AI and Smart Networks_RIIO-GT3
[9] NGT_IJP02_Customer and Stakeholder_RIIO-GT3

IT 102[9]	New Information Provision - Refresh	The transition of the current architecture from Partner Estate to our internal Data Platform estate, any existing development will need to be transformed to be compatible with the new hosting platform, this will include any existing: Mobile App infrastructure; API infrastructure; Components, Design and User Interface; Data Tables and Queries. The centralisation of Data Capability will enhance the reliability of data for customers & stakeholders, simplification of the journey of data and providing efficiency by reducing hosting costs.

1.6 We will facilitate the transformation of the energy industry, by evolving natural gas commercial market frameworks and developing future energy market strategy

1.6.1 Evolution of natural gas commercial market frameworks

The SO takes a leading role within the industry to facilitate the development of the UK gas whole system market frameworks and ensure that these are designed to deliver consumer value and are aligned with the UK's energy ambitions. Market frameworks govern the day-to-day operation of the gas transmission network. They operate to facilitate and enhance the resilience of the gas market and security of gas supply in all network scenarios. We seek to drive industry conversation to understand the most efficient options across timeframes, from delivery of changes to market frameworks required today, or alternatively development of changes needed in future years (the program for which has to date, been set by the Future of Gas Steering Group, and delivered through the Gas Markets Plan program). Predominantly, framework changes are to the Uniform Network Code (UNC) which sets out the common transportation arrangements for GB's gas industry but could also include amendments to methodology statements (which we have a Licence obligation to review regularly), Gas Transporter Licence or even primary and secondary legislations. The market framework change process is administered by the Joint Office for Gas Transporters (JO) in their role as Code Administrators for the Unified Network Code.

The information we provide supports the efficient functioning of the gas market by allowing market participants to make informed commercial decisions, as well as enabling the efficient physical operation of the network by allowing connected parties to optimise their operations based on network conditions. We do this through organising the Gas Operational Forum and Liaison insights meetings which provides us with the opportunity to meet with our customers and discuss key topics at regular intervals throughout the year. These interactions are often the first point of contact for customers with their queries and requests for data and general queries. Data, such as short-term SO market forecasts, is paramount to day-to-day operations for both National Gas and our customers. We, in the SO are responsible for maximising real-time system data transparency and for the development and maintenance of the Gas Data Portal which is the vehicle to providing much of the information and data we share with our customers. We also work with our colleagues in the Transmission Owner side of the business to produce a Gas Ten Year Statement, which is published annually to provide our customers and stakeholders with a better understanding of how we intend to operate and plan the NTS over the next ten years.

Our customers need market arrangements to continue to develop to facilitate their evolving use of the NTS. As outlined earlier, in RIIO-T2 we have seen unprecedented supply and demand profile changes, the gas market responding to changing market influences and increased focus on security of gas supplies. Gas market frameworks will need to adapt to this evolution across the spectrum to ensure that GB's gas market remains attractive as a gas trading hub; that market frameworks remain fit for purpose with the changing use of the NTS and that frameworks can develop to enhance gas security of supply.

The Joint Office for Gas Transporters (JO) is now operated under Encodar, a separate legal entity. This will afford the JO the flexibility to take on amended role(s) following the implementation of the Energy Codes Governance Review. One possibility is that the Joint Office could become a Code Manager, acting as an impartial, not for profit organisation that would facilitate the governance processes for modifications, including a process to prioritise modifications to ensure alignment with Ofgem's strategic direction. Encodar will continue to be funded by Gas Transporters. A higher level of funding has been proposed by the Board but was received too late for inclusion in our formal submission, and therefore has been captured in our Assurance Statement.

Charging: The gas transmission charging arrangements are the mechanisms by which National Gas Transmission collect the revenue from our customers which has been allowed by Ofgem as agreed through our Regulatory submissions.

Within RIIO-GT3 there will be the need to review the charging frameworks and associated access arrangements to ensure the UK market remains attractive. To do this, we want to consider the purpose, outcomes and impacts of the charging regime and ensure that these are relevant for the current and future natural gas market environment.

- **Purpose:** Assessment of the purpose of the charging framework will include reviewing the drivers it should support (i.e. ensuring the UK gas market remain attractive; encouraging investment in the network; the natural gas charging framework as an enabler to the net zero transition; or another purpose).
- **Outcomes:** Then moving onto what outcomes would achieve this purpose(s) (i.e. what behaviours should the charging regime encourage; is there a continued need for the natural gas charging regime to support GB being used as a transit country to Europe)

- **Impacts**: What evolutions to the charging regime could be made as an impact to the change in network operation (i.e. reviewing the mechanism, timing and reconciliation of shrinkage costs; amendments to support the expansion of gas storage; increased targeting of costs).

Our current activities in the charging area are predominantly focussed on charge setting activities, rather than charging transformational activities which are proposed here. Within RIIO-T2, we plan to commence these transformational charging activities, including reviewing the balance of revenue recovery between Entry and Exit customers and scoping out the "purpose, outcomes, impacts" review of the regime ready for it to ramp-up at the beginning of RIIO-GT3 which we feel is an appropriate time as NESO will be more established and more will be known about transmission hydrogen blending.

As mentioned in the Network Access section above, in the Coalition event, one stakeholder asked **what are we doing to optimise the use of the assets we already have** and using them as efficiently as possible which may mean encouraging gas onto the network? A further way this will be achieved is through the assessment of the **purpose of the charging framework** and what changes could be made to ensure the UK market remains attractive.

Capacity and Connections:

Historically NTS capacity was designed as a mechanism to signal customers' long-term network access requirements. These long-term signals would enable us to plan the network, determine the investment needs in the network and understand our customers level of required capability. Today, we are not seeing the same level of long-term capacity bookings and therefore the signals to invest in the natural gas network. Not having these long-term capacity signals also impacts our ability to effectively plan the network which will become more fundamental as we enter a period of transition within RIIO-GT3. Furthermore, within Ofgem's decision document on the Entry Capacity Release Methodology Statement review in April 2023 they state "we would also encourage NGT and industry to work closely together to identify and propose an appropriate long-term solution to the issues around reduced physical capacity at [redacted] during summer months, for instance the introduction of seasonal baselines". We believe looking to introduce seasonal baselines would be ineffective to do before reviewing the capacity regime itself as we would want to better understand the problem to which seasonal baselines may be a solution. Therefore, within the period, we will review the purpose and principles of the capacity regime, proposing reforms and adjustments where required.

During the Coalition stakeholder event, one attendee asked if, as part of this review we would be prepared to explore options on how we sell capacity to optimise the pipeline.

Closely linked to the Capacity regime is the Connections process. The current Planning and Advanced Reservation of Capacity Agreement (PARCA) is a fairly long and complex process requiring high levels of commitment from parties. As part of the review of the capacity regime we will expand this to cover the connections regime to ensure they complement one another and enable our customers to connect to our network and book capacity efficiently.

Security of Supply:

Within RIIO-GT3 a key area of focus will continue to be ensuring security of gas supplies particularly as the UK operating environment and the global gas market evolves. Ensuring security of gas supplies attracted increased focus in RIIO-T2 with the start of the Ukraine War and the reduction of Russian gas being supplied to Europe in addition to the high gas prices which shortly followed. That, coupled with the increasing volatile operating environment means that through RIIO-GT3, security of supply will continue to be a key focus. There will be a need to build on measures developed throughout RIIO-T2, including demand side response, but also wider measures to consider such as reviewing Margins Notice and Operating Margins. In addition, as the relationship with the end consumer becomes more and more important within RIIO-GT3 we need to build our understanding of the retail side of the market, including NDM algorithms and the change with smart-meter roll out, investigating ways to manage CV capping and propane enrichment, particularly in a blend.

Information Provision:

We currently provide relatively little public information relating to gas quality on the network, especially when compared to some of our EU counterpart TSOs, which the completion of the GS(M)R review has brought into sharper focus. A current project, "Enhanced Gas Quality Data Provision", plans to publish close to real time gas quality data measured at GDN offtakes and selected compressor and multi-junction sites on the Gas Data Portal. This is with the aim of helping customers adapt and prepare for changes to the lower Wobbe index and calorific value. This need for additional information is likely to continue within RIIO-GT3, particularly as the advent of hydrogen blending on networks brings the potential for greater variation in gas quality and a greater need for transparency for customers about what the quality is at different locations, including potentially forecasting of gas quality and specification. Engagement to understand the requirements from industry, feasibility analysis working out the methods to provide the data / information, option development and framework development to align new data provision methods would be required for greater information provision methods.

EU Market Developments:

Since Brexit, the UK is not obliged to implement European Law developments into national law. However, the gas market is a global market, and the UK market has strong connections to the EU, both physically and commercially, through the interconnectors to the Netherlands, Belgium, and the island of Ireland. Therefore, for the UK to continue to trade gas with the EU, and to preserve our security of supply, our commercial rules need to be compatible. Over RIIO-T2, there has been very little EU gas market development. However, in RIIO-GT3 this is likely to change. For example, the development of the European Decarbonised Gas Package is likely to be the start of a series of changes to policy and legislation, particularly as we transition to net zero. We therefore need to ensure we have the capacity and capability to influence its development, understand the impacts on the UK Gas Market and respond.

Whole System Frameworks:

With the increase in renewable electricity generation, gas will play an increasing role in providing system security to the electricity network when intermittent renewable electricity isn't generating. This consequentially means an increasingly variable demand for gas for power generation purposes. With this more pronounced interaction between electricity and gas transmission and distribution, we need to ensure that the markets work seamlessly together, complementing each other both now and into the future as the energy market expands into different sources of energy. Furthermore, Markets can shape investment on networks and so it will become vital within RIIO-GT3 to develop whole system frameworks which optimises investment across markets.

Currently, particular focus is not given to how gas market changes impact other markets. With the ongoing integration of energy markets expected to continue to expand within RIIO-GT3, developing all our market change under a whole-systems approach will be imperative. This is expected to be an additional consideration over all our market change activities.

During the stakeholder webinar we asked attendees whether they agree that there is a need to develop market frameworks during the next regulatory period. 96% of attendees agreed, 4% didn't agree with the reason given "there's already an existing market framework to some extent with very minimal changes as of now".

1.6.2 Future energy market strategy

A further evolution will be that NESO will have an obligation "to enable the performance of the FSO's gas market strategy function, including the Future of Gas (FoG) forums and Gas Market Action Plan (GMaP) projects". Although NESO has taken over the facilitation of the FoG forum and commenced their own GMaP program, previously being a responsibility of the SO, this does not remove the need for the capability within the SO to participate in these activities. In terms of the FoG forum, our role will change from facilitator to active participant as we expect to hold a seat at the Forum. As the sole National Gas Transmission Operator, we expect to heavily input knowledge, expertise and information into the development of NESO's GMaP projects. Although we are yet to understand the scale of NESO's market development activities within RIIO-GT3, we anticipate this to be significant based on the size of the gas market development function in the organisation. Furthermore, it will be imperative that we also continue to lead market strategy activities to review, supporting the business as it evolves and to provide benefits to our customers and stakeholders and ultimately end consumers.

IT investments:

Supporting IT investments are:

Ref#	IT Investment Line	Investment Description
IT 042[10]	Regulatory-driven Gemini system enhancements	Changes to Gemini and UK Link as required to comply with UNC and Licence obligations
IT 045[10]	Market-driven Gemini system enhancements (Data Provision)	This investment ensures that the System Operator, gas market participants, stakeholders, and regulatory authorities have the required data available to enable commercial and regulatory decisions to be made as appropriate

[10] NGT_IJP04_Enabling Market Efficiency and Regulatory Changes_RIIO-GT3

2. Network Capability Assessment

2.1 Overview

This assessment sets out the current network capabilities for all zones, for both entry and exit, for the RIIO-GT3 period. This annex also describes our methodology for putting together the network capability metrics and the forecast supply and demand in the zones. Finally, we address our plans for Licence Baselines in RIIO-GT3.

The current capability is assessed against the 2024 FES Holistic Transition (HT) and Counterfactual (CF) scenarios to identify points of concern for capability and resilience. The points have been assessed in the relevant Engineering Justification Papers (EJPs). We have also assessed operability, maintainability, Single Points of Failure (SPOFs) and current asset faults and included these in the appropriate EJPs.

In summary, the investments needed in the zones are mostly for asset health with some compressor re-wheels, driven by a requirement to improve availability, capability, and resilience. There is also a requirement to increase entry capability in South Wales due to the need for more Liquefied Natural Gas (LNG) imports. The majority of the funding requested for these investments is within baseline. Where there is uncertainty around the scope, volume or cost of specific investments we will utilise the Uncertainty Mechanism process.

2.1.1 Introduction

Since the beginning of the RIIO-T2 period we have had a Licence obligation to produce a network capability report for the current year and a view of the required level of physical capability in 10 years' time. The report is called the Annual Network Capability Assessment Report (ANCAR). The most recent document and past copies can be found on our website. The ANCAR document provides the initial and target network capability appropriate to the year it is published.

The National Energy System Operator (NESO) has taken over the obligation to publish the network capability for the gas network from 1st October 2024, with the first report due in December 2024. This document will be known as the Gas Network Capability and Needs Report (GNCNR). However, we will retain the capability to produce our own network capability analysis as the National Transmission System (NTS) system operator. Our continuing ability to produce our own network analysis will also be used to form our response to the GNCNR.

We have engaged extensively with NESO on our assessment of network capability and the assumptions underpinning our business plans. NESO have provided their view on these, which we have shared with Ofgem.

The network capabilities in this annex are applied to the business plan period covering RIIO-GT3, with the most up-to-date methodologies for network capability analysis. These are set out in the methodology section of this annex.

In this assessment we make use of the same 'flame chart' style visualisation tool as the ANCAR in displaying the intact physical capability, High Resilience Capability and zonal baselines[11]. These flame charts also show the frequency of forecast scenarios at different zonal net supply/demand levels and national demand levels.

We have selected the gas years at the start and end of the RIIO-GT3 period i.e. 2026/27 and 2030/31. Selecting these years enables us to show the differences our investments will make during in the period.

Network capability entry and exit zones.

[redacted]

Figure 1 - ANCAR zones of GB

The network capability flame charts, and supply and demand summaries are broken down by ANCAR zones as can be seen in Figure 1.

[redacted]

[redacted] do not have sufficient entry points and are omitted for entry capability. The Central region is a transit zone and therefore its entry capability is shown in combination with other zones.

The assessment is based on NESO's Future Energy Scenarios: NESO Pathways to Net Zero 2024 (FES24). In line with the Business Plan Guidance document we will provide a comparison between the Holistic Transition and Counterfactual pathways. We make a comparison of the Gas Distribution Network (GDN)

[11] NB. The entry flame charts in this annex are different from ANCAR in that they display net supply, explained in the Methodology section.

forecasts and FES24 pathways at a regional level, with the highest value used to define the regional 1-in-20 demand level. This figure is used to assess our compliance with the 1-in-20 security standard.

The Cost Benefit Analysis (CBA) models in our associated EJPs are based on FES 2023 Falling Short data due to time constraints to submit in December 2024. These CBAs will be updated with FES 2024 data for the updated submission in March 2025. We do not expect there to be any material difference to our investment decisions due to this update as there is not a significant difference between the FES 2023 Leading the Way and Falling Short scenarios and the FES 2024 Holistic Transition and Counterfactual scenarios, respectively.

It should be noted that the following adjustments have been made to the FES 2023 Falling Short data.

1. Reduction of Continental flows

The High LNG version of the FES scenarios still contained significant baseload imports from Continental Europe. Given imports had been essentially zero since the Russia-Ukraine crisis retaining these baseload flows in a high LNG sensitivity did not seem appropriate. Given this sensitivity was supposed to capture a high case for LNG it seemed reasonable to remove all baseload flows from this scenario, with continental imports still providing some flows at peak.

2. Reduction of Shale gas

Significant Shale Gas production was assumed in the Falling Short scenario. Given the uncertainty of large-scale deployment of shale gas we felt it was important to run a case without these volumes. It was felt that in this scenario UKCS production should already be maximised and the absence of shale gas shouldn't change these levels. Given the above change to Continental European imports the remaining supply sources, Norway and LNG, were both scaled up to make up for the loss of shale – both of these import sources should have sufficient available capability to meet this shortfall.

2.2 Methodology

The metrics in this annex represent the current Intact Capability and High Resilience Capability of the National Transmission System (NTS) with the assets currently on the network. They provide a framework to allow us to understand and communicate the implications of decisions in RIIO-GT3 and beyond.

The level of physical capability has firstly been calculated assuming all assets are 100% available, referred to as the "intact" network. The capability that can be met 99% of the time, High Resilience, has also been calculated. Different combinations of compressors and network asset optimisations can be used to deliver the same level of physical capability. The details of both of these are in the "Intact and High Resilience Capability" section.

To deliver these metrics, we have built on data and processes that are already used by our teams and presented them in a way that is intended to show the capability of the whole network. They can also be used to show how network capability cou ld change if assets were not available on a planned or unplanned basis and show how sensitivities of supply and demand may impact the network.

Intact and High Resilience Capability

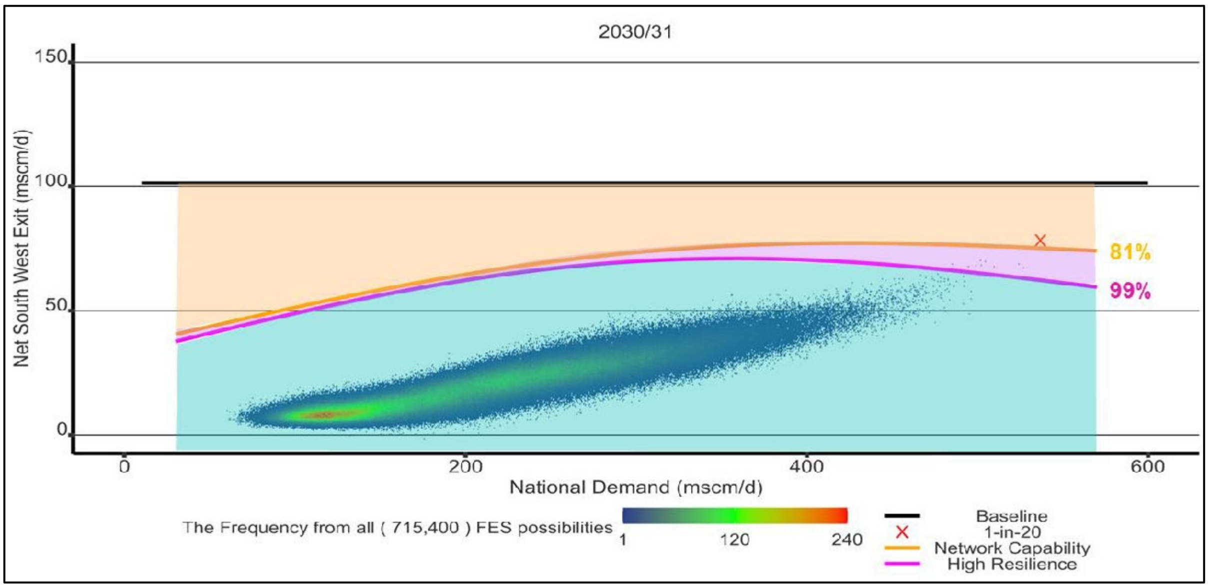


Figure 2 - Example flame chart

Intact Capability, also referred to as Network Capability, is the highest capability a zone can deliver. It is based on the assumption that all compressor stations and other assets in the zone have their full capability available. As this may require more than one compressor unit at each station, it may not be possible to achieve Intact Capability if one or more of the compressor units are not available for any reason.

High Resilience Capability is the compressor reliability we calculate a zone should always be able to deliver, given current and predicted levels of availability. It is calculated so that the likelihood of unavailable compressors preventing the High Resilience level of capability is below 1%. In order to achieve an availability of 99%, the capability has to be assessed with only a subset of compressors available, e.g. 99% of the time at least 2 of 4 compressors will be available. As these scenarios have fewer compression available, the level of High Resilience Capability will usually be lower than Intact Capability.

Calculating zone availability

Compressor availabilities at a unit level were used to calculate High Resilience Capability, and the likelihood of achieving Intact Capability in each zone.

The unit availability for the start of this business plan is based on the NGT Reliability Availability Maintainability (RAM) study findings and the remainder of planned investments during RIIO-T2. The unit availability values for the end of RIIO-GT3 are based on the following assumptions:

1. Investments already approved to be completed in the period to April 2031.
2. The asset health budget ensuring unit availabilities don't decline in RIIO-GT3.
3. Improvements to mitigate risks associated with our 1-in-20 security standard.
4. The investments requested in our RIIO-GT3 business plan, to decrease risks and consequently increase availabilities, as set out in our EJPs.

The investments in the EJPs are targeted to improve reliability and capability of our assets, and thus availability of compressor units and stations, which will reduce the likelihood of assets failures and any associated constraints. There is no required availability for assets, increased availability is a consequence of the most cost beneficial option to decrease risk.

The combinations of units required to deliver Intact Capability or High Resilience Capability are used to calculate zone level availabilities. The calculations are shown in Figure and 4 below:

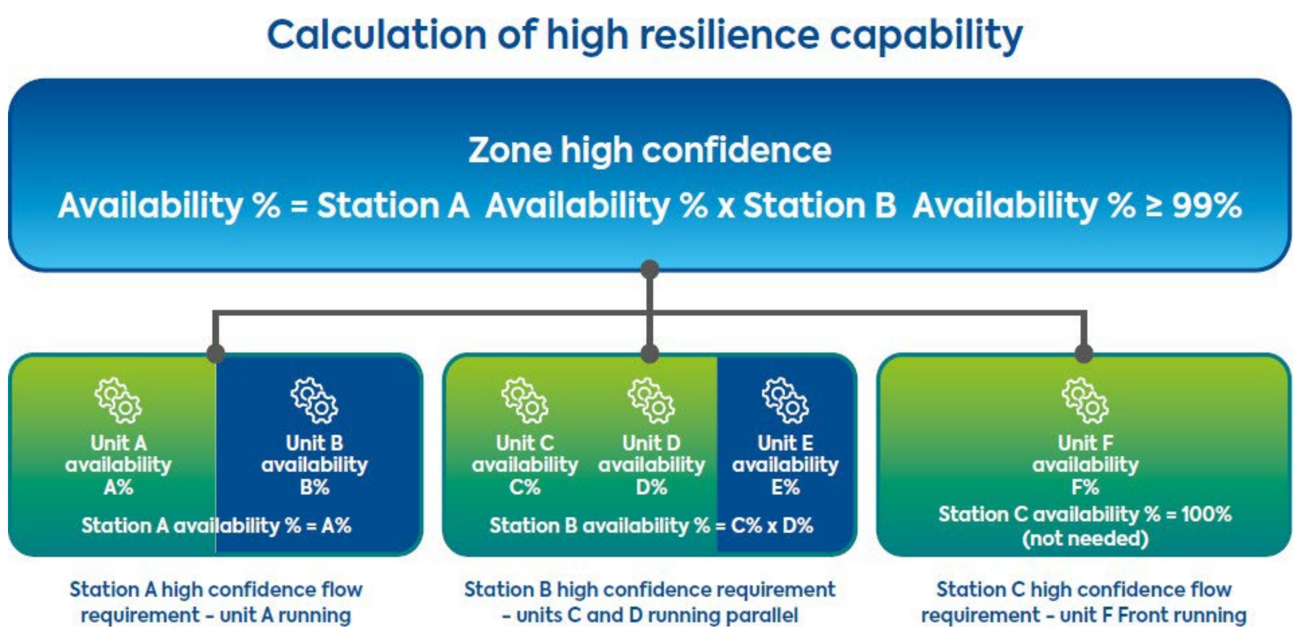


Figure 3 - Calculation of zonal intact availability

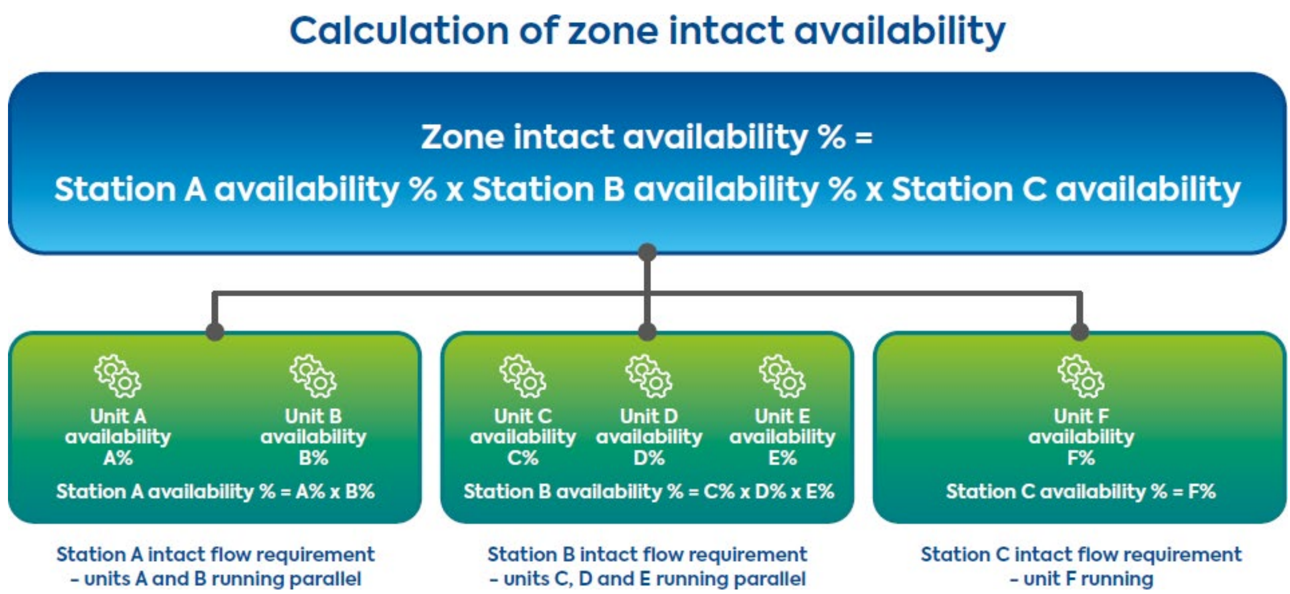


Figure 4 - Calculation of High Resilience Capability

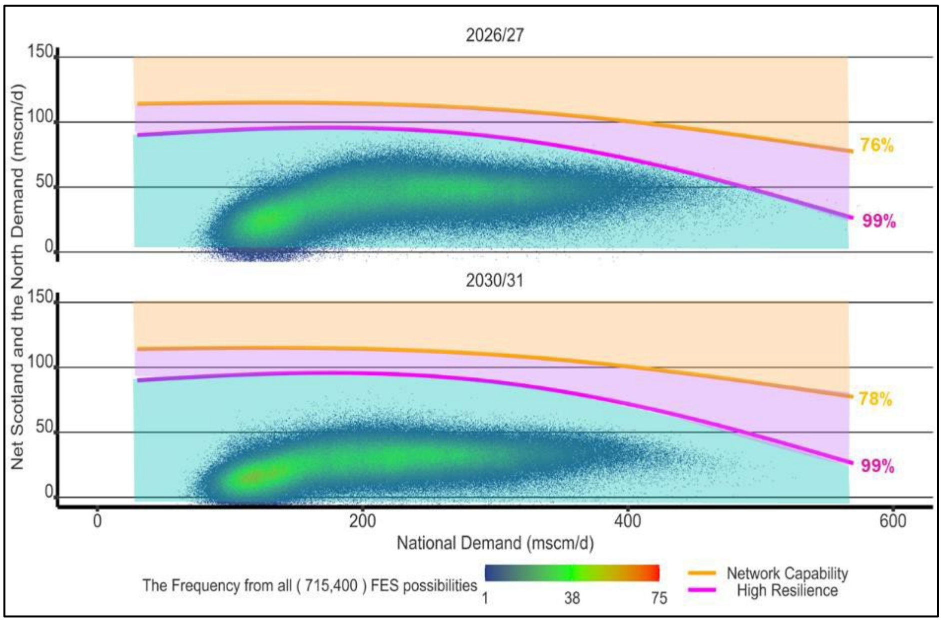
Calculating zone resilience

To measure the impact of availability on network resilience, we modelled the FES24 Holistic Transition and Counterfactual flow scenarios in each zone and analysed the likelihood that the network would be able to meet those scenarios. Constraint days in an entry zone are the number of days in a year that we expect the network will not be able to meet modelled supplies without commercial actions. The more resilient the network, the lower the number of constraint days. In the case of an exit zone, a constraint day represents a failure to meet exit pressures without commercial actions.

We calculated the highest entry and exit flows that the Intact Capability network (percentage value in yellow) and High Resilience Capability network (percentage value in purple) can meet across increasing levels of demand for each zone and included them on flame charts:

- Intact Capability is represented by the orange line - this line is higher because it represents our maximum capability.
- High Resilience Capability is represented by the pink line - this line is lower because it reflects the actual availability of compressor units in the zone.

An example for entry flows in [redacted] is shown below:



In the entry capability graphs in this annex we have plotted net zonal supply against national demand. Net zonal supply is the supply for the zone minus the demand in the zone. Using net supplies helps to mitigate the impact of zonal demand on capability. The higher the demand in a zone the higher the entry capability. Not using net capabilities can over or underestimate the level of capability in a zone. If there is a positive net zonal supply, then this will be transported to another zone. If there is a deficit, then this will be transported in from another zone.

Understanding our intact and High Resilience lines

The network may not be able to deliver any of the flow scenarios above Intact Capability (the orange line) without using commercial tools but should deliver over 99% of the flow scenarios below High Resilience Capability (the pink line). The actual capability on any given day will normally be between the two lines depending on asset availability. The likelihood of achieving Intact Capability is used to estimate the average number of flow scenarios that will not be met. This number is then converted into average number of days per year.

The capabilities shown by the lines shown are based on the assumptions in the analysis. One of these is that capability lines are based on average flex (profiling) levels. Actual capability will depend on a range of factors including the level of zonal linepack and the extent to which supplies and demands flex their flows within the day (profiling).

The total number of FES flow scenarios under the High Resilience Capability line (points in the blue area on the chart) represent scenarios that have a greater than 99% likelihood of being met given current levels of availability/reliability of compressor units and other assets.

The total number of FES scenarios under the Intact Capability line, but above the High Resilience line (the pink area), have a 76% likelihood of being met in 2026/27 in the above example, since this is the compounded zonal availability based on unit-level values. Flows above the Intact Capability line (the orange area) may not be able to be physically met depending on the extent of profiling.

The number of constraint days is estimated using the number of scenarios that might be met (pink area) multiplied by the likelihood that the Intact Capability will not be available. This is added to the total number of scenarios that cannot be met (orange area) to produce an expected number of scenarios not met (see illustration below).

The number of FES flow scenarios between the two lines which may not be met is dependent on compressor unit availability, which is therefore a key metric in ensuring network resilience. This assessment highlights the zones where capability and resilience are close to or below the expected flows. We have then undertaken optioneering on the identified zones to identify potential investments to improve the capability and/or resilience. The outcome of these can be seen in the Compressor Fleet Engineering Justification Papers (EJPs).

Targets

The network availability targets for the RIIO-GT3 period are the availability figures for "with proposed investment" shown in Table 25 and Table 26 at the end of the conclusion. These are shown for the year 2030/31 and as such are our target network availabilities for RIIO-GT3.

Caveats and Ongoing Development

We have used the data from FES 2023 Falling Short to construct our models for the cost benefit analysis and FES 2024 Holistic Transition and Counterfactual as the data in our graphs and tables in this document.

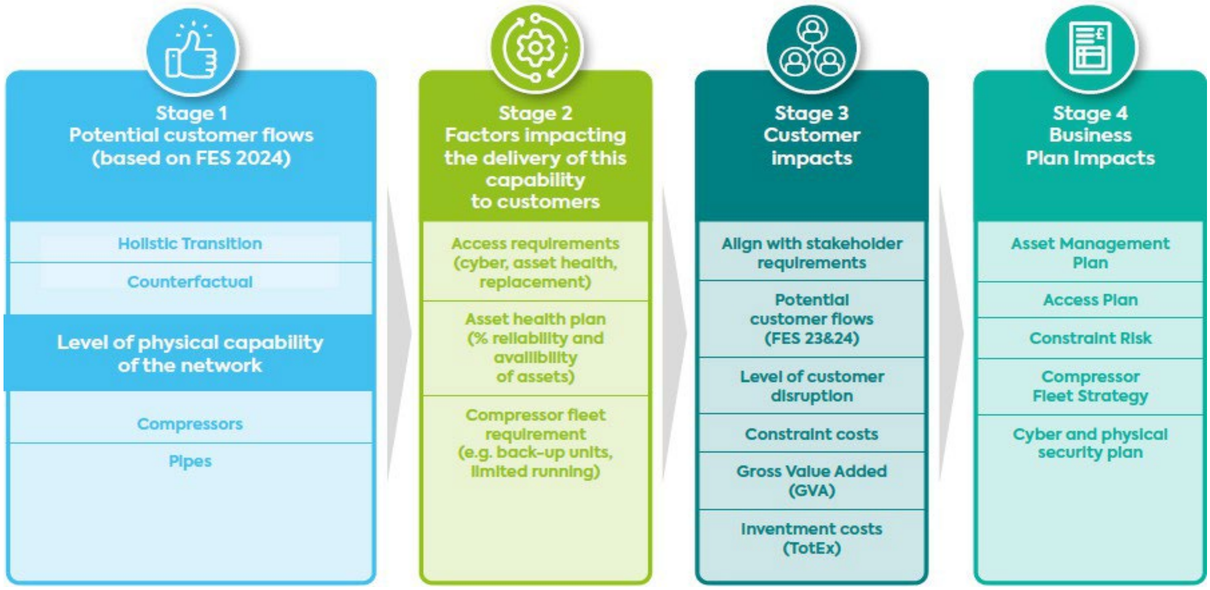
It is important to note that we, and the Department for Energy Security and Net Zero (DESNZ), do not expect regular imports from Europe through the winter for the foreseeable future but we do expect the markets to continue to function and for flows across the interconnectors to respond to market signals. Consistent with this, we have seen low levels of imports in the last two winters. The supply models are updated to reflect this change, and this is reflected in the data tables for the Business Plan.

It is assumed that the shortfall in supply from Europe and shale will be made up by increased LNG flows at [redacted] and Isle of Grain. Currently these changes in supply flow are not reflected in FES so we have made adjustments to our model to include them which is shown in the flame charts.

We continue to develop our models to account for declining gas supply from the UK Continental Shelf (UKCS). This decline is expected to be steeper than the forecast decline in total gas demand, therefore gas will need to be drawn from other sources to make up the shortfall. Again, this is expected to be an increase in supplies from LNG.

The Process to assess the Future Network Capability Need

The figure below shows how our business plan is underpinned by network capability. Our Cost Benefit Analysis (CBA) tool has been consistently used and proven over RIIO-T2.



Stage 1: We use our internal modelling tools to model the physical capability of the network[12]. Our network analysis tool models the capabilities of our compressors, our pipework and all our other supporting assets. This allows us to establish the level of physical capability across different zones of the network. Through this, we identify where there is potentially too much or too little network capability to meet stakeholder requirements/customer flows.

Stage 2: We consider factors affecting capability, as the network can't deliver full physical capability 100% of the time. We look at the range of customer flows (from stage 1) and the level of capability line (from stage 2) and explore the factors that might affect that capability. For example, the number of run hours a unit can run if it is subject to a derogation under environmental legislation. This means the capability will either reduce or we will be able to deliver it less than 100% of the time.

The asset health plan reflects what we need to do to maintain the level of risk on our network across RIIO-GT3 and beyond, and this will have an impact on the reliability of our assets. The amount of work that we can do will impact on the percentage of time that we can deliver a level of network capability.

We explore whether improving the reliability and availability of certain compressors would allow us to decommission others, developing the most efficient compressor fleet going forward and the impact on physical capability.

Stage 3: The key output of our network capability metrics is understanding the customer impact. This includes assessing the risk of disruption to customers' gas flows on and off the network (constraint risk) and the likelihood of a high demand peak 1-in-20 day. From this we can calculate a constraint cost and compare this with the proposed business plan investment costs . We iterate this, both internally through our CBA process and externally with our stakeholders, to test the assumptions on flows and appetite for disruption.

Stage 4: We develop our proposals: what asset health work is required to maintain our assets, address any obsolescence issues and deliver the required reliability and availability; what assets can be decommissioned; what compressors are needed, and do we replace, decommission or reduce their running hours; what access is needed to deliver our plan; where can we defer decisions to keep options open until the future becomes clearer. The decisions we are making in our business plan have a lasting impact on the cost, risk and the level of network capability we offer stakeholders.

This robust process gives us confidence that our business plan proposals will deliver the network capability our stakeholders need now and throughout RIIO-GT3, while keeping options open for the future.

2.3 Assumptions

The following assumptions have been made in the development of this Network Capability Annex for our investment proposals in the Compressor Fleet EJP.

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12 Information on our investment planning process can be found in our Gas Ten Year Statement https://www.nationalgas.com/insight-and-innovation/gas-ten-year-statement-gtys and the Transmission Planning Code https://www.nationalgas.com/sites/default/files/documents/TPC%202023%20v0.4.pdf

2.3.1 Future network flows

We need to ensure that our Compressor Fleet EJPs manage the risks associated with medium to long-term uncertainty. The most significant uncertainty is the future network use in a range of possible energy futures.

The UK government has set a target of net-zero greenhouse gas emissions by 2050. The changes required to meet this target are significant but for gas, they fall within the envelope of the current Future Energy Scenarios.

Based on an expected fall in total gas flows, along with the likely changes to where gas enters the transmission system, there is uncertainty around the long-term requirements for certain elements of the NTS. There is a risk that decisions to potentially remove assets from the network too early, or to limit their operation, may mean that the capability of the network is below the future realised capability requirement, adversely affecting our ability to accept gas onto the network and/or allow gas to be taken off the network as required. We consider these risks and potential consequences when selecting the most appropriate option to meet stakeholder needs.

To help us manage uncertainty, we have applied principles which complement the outputs of the Cost Benefit Analysis (CBA) in the Compressor Fleet EJPs and provide a more holistic decision-making framework. The combination of these two views has allowed us to make more informed, justified decisions in uncertainty, especially in cases where there is little difference in the Net Present Value (NPV) of credible options.

2.3.2 Principles for managing uncertainty

- The underlying principles of the Compressor Fleet EJPs are to ensure we provide the required levels of service to our customers and consumers. To do this, the following basic principles have been applied:
- Where there is significant uncertainty around the need for a compressor due to changes in flows, we will consider no or low-regret investment options that maintain the appropriate level of reliability/availability or make use of regulatory uncertainty mechanisms.
- Investment decisions will be informed by a robust CBA and consideration of non-monetised risks and benefits.
- Where we propose to reduce the number of existing compressor units, this assumes sufficient reliability of the remaining units on our network. Maximising the reliability/availability of the remaining units will mean investing more heavily in the retained units to make sure they have the levels of capability and reliability required. Overall, this will provide better value to the consumer.
- Where we propose to reduce the number of existing compressor units, we will also consider their potential role in enabling a future transition to Hydrogen or the implementation of CCUS solutions.
- We will consider the condition of existing units in our decision-making, such as: reliability, availability, obsolescence, availability of spares and Original Equipment Manufacturer (OEM) support.
- We will consider the advantage and disadvantages of variety across our compressor fleet. For example, variety of unit types may provide greater security against cyber threats but also require a greater variety of spares.
- While we are currently unaware of further emissions legislation coming into force, we will ensure that our solutions represent Best Available Techniques (BAT) to reduce the likelihood of further investment due to more stringent emissions limits. To this end we are testing Dry Low Emission (DLE) compressor trains on some of our units.
- Where we propose to build new units and there is significant uncertainty in flows, we will analyse the future flow ranges and be guided by the BAT assessment to invest in the appropriate units. This may mean investing in multiple smaller units rather than a large single unit, to ensure flexibility and the ability to manage low flows.
- BAT principles will apply to determine the preferred running order of units on site. This will ensure we are always running the cleanest and most efficient units possible.
- Where our analysis indicates we may no longer need a compressor unit or station, we will assess the options of continuing to operate versus decommissioning as soon as possible, looking at stakeholder network capability needs. The benefits of immediate decommissioning include removal of hazards, provision of spares for other units on the network and prevention of investment on an asset providing no benefit to consumers. However, delaying decommissioning may allow the unit to enable the transition to Hydrogen. The timing of any decommissioning will be driven by forecast flows, ongoing feedback from our customers and the requirement for the unit to support the overall deliverability of investment and maintenance on the network.
- Where units are derogated under emissions legislation there will be an ongoing review of the need for those units.

2.3.3 Baselines

In our review of capacity arrangements during RIIO-T2 our stakeholders indicated that they would not find a review of baselines beneficial at this time. Therefore, for our business plan for RIIO-GT3 we have proposed to review baselines in RIIO-GT3 as part of a wholesale regime review that is necessitated by progress towards net zero.

2.4 Zonal demand and supply

2.4.1 Supply and demand assumptions

Under our Licence we are required to plan and develop the pipe-line system to meet the peak aggregate daily demand, the 1-in-20 peak demand. In Ofgem's Business Plan Guidance (BPG) we were asked to consider two FES 2024 scenarios, Holistic Transition (HT) and Counterfactual (CF). HT is the fastest likely pathway to Net Zero while the CF provides for a credible pathway where Net Zero is not met. Both pathways are presented in this section.

The CF provides the most challenging demand forecast. There is progress on decarbonisation compared to today, however it is slower than in the other scenarios and fails to meet the UK Net Zero target by 2050. As a prudent operator the system should be planned for the most challenging demand scenario. This ensures security of supply and that we remain compliant with our licence if the route to Net Zero is not as fast a predicted in other pathways. The CF demand scenario is detailed for Zone 1 in Table 2 and the Zonal Demand Summary section below, along with the HT scenario, for comparison, this is continued in all zones.

In all zones there is a mixture of Gas Distribution Network (GDN) offtakes and Direct Connect (DC) offtakes. GDN offtakes connect to the lower pressure local distribution networks operated by SGN (formerly Scotia Gas Networks), Wales and West Utilities, Northern Gas Networks and Cadent to take gas to people's homes and businesses. DC offtakes are large industrial sites and power stations that connect directly to the NTS.

To calculate the Gas Security Standard 1-in-20 peak demand for the GDN offtakes in each zone we have used a combination of FES future flow predictions and section H data. The actual 1-in-20 peak demand forecast for each offtake is provided by the GDN each year in line the Offtake Arrangement Document (OAD) section H of the Uniform Network Code (UNC). However, the section H data is only provided until 2029 so after this date we have used the FES future flows. For the GDN offtakes we have taken the highest value for each year from HT, CF and section H, therefore giving a prudent worst case 1-in-20 peak demand.

To determine the 1-in-20 demand for Direct Connects we have used 90% of the Baseline Obligation of all the currently connected sites in each zone. This reduction accounts for the required power supply margin and is consistent with the historic maximum not exceeding 90% of the available capacity in the zone.

2.4.2 Zone 1 - Scotland and the North

Zonal Demand

Scotland and the North has very few conventional power stations, just two that are operational at [redacted] is the only one with a significant baseline and flows above 5mcm/d in the last five years. The current sold level for [redacted] is below its current maximum capability of 15.6 mscm/d, which is consistent with the back-up power contract it has for peak winter months.

Interconnector to Island of Ireland

Table 1 shows the demand at the [redacted].

Offtake Name	Baseline Obligation (2026)	Sold Level (Current)	Five Year Max Flow	Maximum Day (15/12/22)	1-in-20 Demand
[redacted]	48.93	22.12	27.47	27.47	48.93

Table 1 - Interconnector Demand - Zone 1 - Scotland and the North (mscm/d)

The single largest demand point in zone 1 is the [redacted] transmitting gas to the island of Ireland. With the Corrib Gas field declining the peak forecast for the interconnector is increasing. Proposed changes in the interconnector contract with Gas Networks Ireland (GNI) as outlined in Zonal Demand Changes mean the 1-in-20 Demand is set to the same level as the Baseline Obligation going into RIIO-GT3.

Zonal Demand Summary

Table 2 shows the forecast 1-in-20 peak demand for the zone during RIIO-GT3. We do not expect the drop in demand in 2030 to occur, with the GDN likely to continue to indicate their 1-in-20 peak demand is above the value provide in the FES. This is the demand level the network must be designed to meet for us to be compliant with the Gas Design Standard. The ability of the network to support this demand is assessed in the Capability and Resilience section.

There remains a large amount of unsold capacity in the zone. The total obligated demand release at the start of RIIO -GT3 is 167.60mscm/d. With a substantial proportion of this excess Baseline obligation at GDN offtakes it creates a risk that they can book additional capacity up to the Baseline Obligation during exit capacity auctions and increase the 1-in-20 peak demand in the zone at short notice. This risk is managed through the exit process as defined in Offtake Arrangements Document (OAD) section H of the Uniform Network Code (UNC), with the GDNs providing advanced forecasts for any potential changes.

	2026	2027	2028	2029	2030
Distribution Network HT Peak Demand (mscm/d)	61.70	59.56	58.13	56.04	53.66
Distribution Network CF Peak Demand (mscm/d)	67.07	65.67	65.34	64.86	64.30
Distribution Network Section H Demand (mscm/d)	72.77	71.92	69.35	69.50	N/A
Direct Connects Peak Demand (mscm/d)	27.52	27.52	27.52	27.52	27.52
[redacted]	48.93	48.93	48.93	48.93	48.93
1-in-20 Demand - Worst Case - Scotland and the North(mscm/d)	149.22	148.37	145.80	145.96	140.76

Table 2 - Zone 1 - 1-in-20 Demand (mscm/d) – FES24

Zonal Supply

The main three supply points for Scotland and the North are St Fergus, Teesside, and Barrow. All three consist of multiple sub-terminals and as such are designated as Aggregated System Entry Points (ASEPs).

ASEP	Monthly Release Obligation	Five-year Maximum Flow
[redacted]	138.46	106.40
[redacted]	41.09	32.60
[redacted]	31.39	7.20
Total	210.93	146.20

Table 3 details the obligated release and highest entry levels seen for the last 5 years. As can be seen in comparison with Table 2 the zonal supply is more than enough to meet the demand in zone 1. Historically, this has resulted in a need for compression in this zone to move the excess gas from the North to the demand centres in the South.

ASEP	Monthly Release Obligation	Five-year Maximum Flow
[redacted]	138.46	106.40
[redacted]	41.09	32.60
[redacted]	31.39	7.20
Total	210.93	146.20

Table 3 - Scotland and the North ASEP Obligations and five-year maximum flows (mscm/d)

2.4.3 Zones 2 and 3 - Central

The Central zone is a combination of two ANCAR zones as can be seen in Figure 5. The zones have been combined as they carry out a similar function of gas transportation from North to South down the East and West coasts.

[redacted]

[redacted]

Zonal Demand

The central region covers a large geographical area and has many GDN offtakes to serve its towns and cities. It also contains some key industrial clusters and many power stations. Because many of these power stations are only utilised on a short-notice basis, e.g. when renewable electricity sources are unable to generate enough power to meet demand, this means they do not book capacity on a long-term basis. This makes their future flows difficult to predict.

Zonal Demand Summary

The differences seen in the Obligated, Sold and Forecast flows for both GDN and DC demands highlight the level of uncertainty in the area. For DC demands the total Obligated release level has no current indicators for change. The lack of long-term capacity bookings makes it difficult to predict future flows for power stations in the zones.

	2026	2027	2028	2029	2030
Distribution Network HT Peak Demand (mscm/d)	66.91	63.88	62.41	60.10	57.26
Distribution Network CF Peak Demand (mscm/d)	72.16	69.96	69.77	69.21	68.56
Distribution Network Section H Demand (mscm/d)	75.07	70.06	69.01	68.98	N/A
Direct Connects Peak Demand (mscm/d)	21.65	21.65	21.65	21.65	21.65
1-in-20 Demand - Worst Case - North West (mscm/d)	96.73	91.72	91.42	90.87	90.21

Table 4 - Zone 2 - 1-in-20 Demand (mscm/d) – FES24

	2026	2027	2028	2029	2030
Distribution Network HT Peak Demand (mscm/d)	39.51	38.29	37.19	35.76	34.17
Distribution Network CF Peak Demand (mscm/d)	43.29	42.73	42.58	42.24	41.82
Distribution Network Section H Demand (mscm/d)	45.55	45.09	44.69	44.69	N/A
Direct Connects Peak Demand (mscm/d)	37.71	37.71	37.71	37.71	37.71
1-in-20 Demand - Worst Case - North East (mscm/d)	83.26	82.79	82.40	82.40	79.53

Table 5 - Zone 3 - 1-in-20 Demand (mscm/d) – FES24

Table 4 and Table 5 show the Forecast 1-in-20 peak demand for the zones during RIIO-GT3. These are the demand levels the network must be designed to meet for us to be compliant with the Gas Design Standard. The ability of the network to support this demand is assessed in the Capability and Resilience section.

In both zones there remains a large amount of unsold capacity. The total Baseline Obligation release for the North West zone at the start of RIIO-GT3 is 123.61mscm/d and for the North East zone it is 99.89 mscm/d. A substantial proportion of these excess Baseline obligations are at GDN offtakes which creates a risk that they can book additional capacity up to the Baseline obligation during exit capacity auctions and increase the 1-in-20 peak demand in the zone at short notice. This risk is managed through the exit process as defined in Offtake Arrangements Document (OAD) section H of the Uniform Network Code (UNC), with the GDN's providing advanced forecasts for any potential changes.

Zonal Supply

There is one main supply point in the [redacted] supplemented by several Medium Range Storage (MRS) sites spread throughout the North East and North West. Easington consists of multiple sub-terminals and as such is designated as an Aggregated System Entry Points (ASEP). Table 6 details the obligated release and highest entry levels seen for the last 5 years.

Offtake Name	Maximum Release Obligation (mscm/d)	Five Year Maximum (mscm/d)
[redacted]	129.89	90.90
[redacted]	38.78	23.61
[redacted]	2.31	2.23
[redacted]	Incl in [redacted]	12.95
[redacted]	27.38	3.98
[redacted]	22.34	22.77
[redacted]	21.52	11.75
[redacted]	Incl in [redacted]	12.20
[redacted]	30.46	25.50
Total	272.68	205.89

Table 6 - Central Region Supply Obligations and Five-Year Maximum Flows (mscm/d)

2.4.4 Zone 4 - South Wales

Zonal Demand

The South Wales zone has one active Power Station, [redacted], which was officially opened in 2012. The power station has a direct impact on the entry capability at [redacted] [redacted] is located close to the [redacted] terminal and so gas entering at the terminal used by [redacted] does not need to be transported across [redacted] to other demand locations. When Pembroke demand is low then the entry capability at [redacted] decreases in direct proportion.

With the Sold capacity and 5-year max being close to the Baseline Obligation the full Baseline Obligation of the active DC in the zone has been taken as the 1-in-20 DC peak demand.

Zonal Demand Changes

[redacted] Power Station is a new power station in construction. Capacity has been allocated using the current Exit Capacity Substitution Methodology following the completion of the Planning and Advanced Reservation of Capacity Agreement (PARCA) phase 1. A minimum connection onto the NTS is also due to be completed in 2024. The final stage of the project is for the Shipper to book the allocated capacity triggering the change to the Baseline Obligation which happened on 1st October 2024.

Zonal Demand Summary

When zonal demand is high the requirement for compression is reduced. If the overall demand of the zone decreases then there is an increased need for the operation of compressor units when entry supplies are high, to transport gas away to zones of demand in the Midlands and the South.

The Forecast 1-in-20 peak demand over the RIIO-GT3 period can be seen in Table 7. This uses the 2024 FES FS scenario for the GDN demand and the total Baseline Obligation for currently connected DC demands.

	2026	2027	2028	2029	2030
Distribution Network HT Peak Demand (mscm/d)	27.67	26.56	25.74	24.79	23.20
Distribution Network CF Peak Demand (mscm/d)	29.16	28.46	28.30	28.07	27.85
Distribution Network Section H Demand (mscm/d)	32.96	32.29	32.05	31.92	N/A
Direct Connects Peak Demand (mscm/d)	14.33*	14.33*	14.33*	14.33*	14.33*
1-in-20 Demand - Worst Case - South Wales (mscm/d)	47.30	46.62	46.38	46.25	42.18

Table 7 - Zone 4 - 1-in-20 Demand (mscm/d) – FES24
**Includes 2.38mscm/d for Hirwaun PS*

Zonal Supply

There is one Aggregated System Entry Point (ASEP) supply terminal in the region located at [redacted]. The terminal contains two sub-terminals: [redacted]

ASEP	Monthly Release Obligation (mscm/d)	Five year Maximum (mscm/d)
[redacted]	87.69	88.20
Total	87.69	88.20

Table 8 - Milford Haven ASEP Obligations and Five-year maximum flow

[redacted] is one of two NTS LNG entry points terminals (with the Isle of Grain terminal) on the National Transmission System (NTS), comprising two terminals, [redacted]. Its importance has increased in recent years with flows expected to continue to increase over the coming years as we see supplies from the UK Continental Shelf decline.

2.4.5 Zone 5 - South West

Zonal Demand

To determine the 1-in-20 peak demand for DCs in the zone, the Baseline Obligation of [redacted] power station has been reduced to the 5-year maximum level, due to half the site being decommissioned. The adjusted total has then been reduced to 90% of the maximum.

Zonal Demand Changes

[redacted] Power station is due to be operational in February 2025. The capacity has been allocated using the Capacity Substitution Methodology and the changes reflected in the table below.

Zonal Demand Summary

	2026	2027	2028	2029	2030

Distribution Network HT Peak Demand (mscm/d)	55.19	53.85	52.38	50.60	48.30
Distribution Network CF Peak Demand (mscm/d)	60.56	60.07	59.77	59.28	58.83
Distribution Network Section H Demand (mscm/d)	58.34	58.16	58.06	58.31	N/A
Direct Connects Peak Demand (mscm/d)	19.30	19.30	19.30	19.30	19.30
1-in-20 Demand - Worst Case - South West (mscm/d)	79.87	79.38	79.08	78.59	78.13

Table 9 shows the Forecast 1-in-20 peak demand for the zone during RIIO-GT3. There remains a large amount of unsold capacity in the zone. The total Baseline Obligation release for the zone at the start of RIIO-GT3 period is 101.36 mscm/d. With a substantial proportion of this excess Baseline obligation on GDN offtakes it creates a risk that they can book additional capacity up to the Baseline obligation during exit capacity auctions and increase the 1-in-20 peak demand in the zone at short notice. This risk is managed through the exit process as defined in Offtake Arrangements Document (OAD) section H of the Uniform Network Code (UNC), with the GDN's providing advanced forecasts for any potential changes.

	2026	2027	2028	2029	2030
Distribution Network HT Peak Demand (mscm/d)	55.19	53.85	52.38	50.60	48.30
Distribution Network CF Peak Demand (mscm/d)	60.56	60.07	59.77	59.28	58.83
Distribution Network Section H Demand (mscm/d)	58.34	58.16	58.06	58.31	N/A
Direct Connects Peak Demand (mscm/d)	19.30	19.30	19.30	19.30	19.30
1-in-20 Demand - Worst Case - South West (mscm/d)	79.87	79.38	79.08	78.59	78.13

Table 9 - Zone 5 - 1-in-20 Demand (mscm/d) – FES24

Zonal Supply

[redacted] storage is the only supply point within the zone. The site operates on a commercial basis taking gas off or putting gas on the network when it is economically beneficial for them to do so. Table 10 shows the Baseline Obligation for the supply from [redacted] and max flow seen in the last five years.

It is also important to note that other supply points outside of the zone in the South East (Isle of Grain) and South Wales (Milford Haven) have a significant impact on the capability of this Zone due to the reduced transmission distance to the South West from these supply points.

Site	Baseline Obligation (mscm/d)	Five Year Max (mscm/d)
Barton Stacy (Humbley Grove storage)	15.90	7.20
Total	15.90	7.20

Table 10 - Humbley Grove ASEP Obligations and Five-year maximum flows (mscm/d)

2.4.6 Zone 6 - East Midlands

Zonal Demand

[redacted] *Interconnector Demand*

Offtake Name	Baseline Obligation (2026)	Sold Level (Current)	Five Year Max
[redacted] Interconnector Exit IP (mscm/d)	60.16	10.00	76.40

Table 11 – Shows the [redacted] Interconnector Demand – Exports from UK (mscm/d)

The largest demand point in the zone is at [redacted] from which interconnectors transmit gas to mainland Europe. The Baseline Obligation is shared by two interconnectors, Interconnector UK (formerly termed as Bacton Interconnector UK) and [redacted] BBL. The 2022 Russia/Ukraine conflict resulted in record high volumes of gas being exported through Bacton terminal, see Figure 6, to mainland Europe to support demand and levels of strategic storage to replace Russian imports to the EU. While these flows reduced in the latter half of 2023 there remains uncertainty on the magnitude and longevity of these changes meaning interconnector demand is difficult to predict.

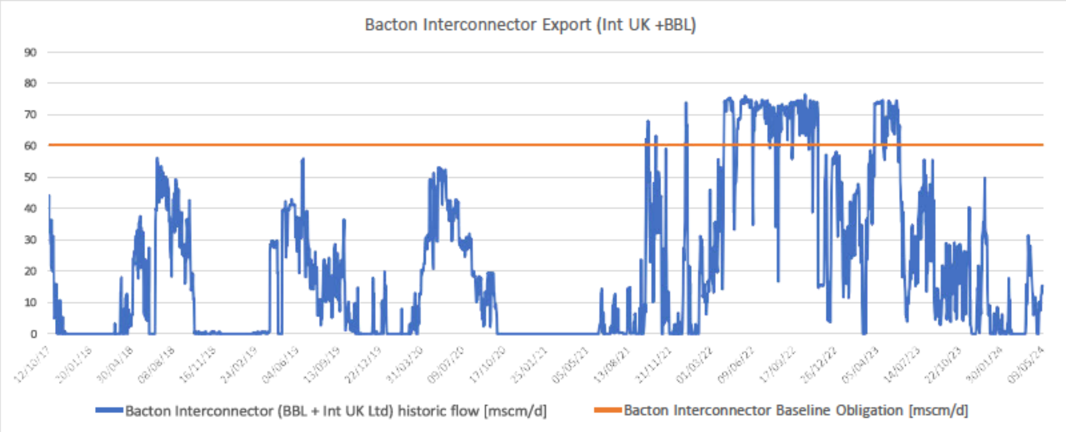

Figure 6 - Historic [redacted] Interconnector Export flows from NTS vs Baseline Obligation [mscm/d]

Zonal Demand Summary

Table 12 shows the Forecast 1-in-20 peak demand for the zone during RIIO-GT3. This is the demand level the network must be designed to meet for us to be compliant with the Gas Design Standard. The ability of the network to support this demand is assessed in the Capability and Resilience section.

The Interconnector demand has been excluded from the 1-in-20 peak demand because it is assumed to only operate as a supply point at peak levels of demand due to it historically always having been a supply at high winter demand levels.

	2026	2027	2028	2029	2030
Distribution Network HT Peak Demand (mscm/d)	4.53	4.35	4.22	4.03	3.84
Distribution Network CF Peak Demand (mscm/d)	4.97	4.86	4.84	4.80	4.75
Distribution Network Section H Demand (mscm/d)	5.35	5.28	4.58	4.58	N/A
Direct Connects Peak Demand (mscm/d)	22.34	22.34	22.34	22.34	22.34
1-in-20 Demand - Worst Case - East Midlands (mscm/d)	27.69	27.62	27.18	27.13	27.09

Table 12 – Zone 6 - 1-in-20 Demand (mscm/d) – FES24

Zonal Supply

There are no supply points in the East Midlands but the zone is critical in supporting supply points at the Easington Terminal, North East storage sites and the [redacted] Terminal.

2.4.7 Zone 7 - South East

Zonal Demand

The South East zone has a large number of Power Stations. The sold levels for the Directly Connected sites are low showing this are not a good indicator of future flow levels. The five-year maximum total at an individual site level is 27.2 mscm/d, the highest combined DC demands in the last five years is 21.6 mscm/d on the 23 November 2021. The 1-in-20 demand for Direct Connects has been estimated based on 90% of the Baseline Obligation of all the currently connected sites. This allows for the large gap between the current baseline and five-year maximum but also allows for the maximum to increase in line with the additional generation capacity connecting.

Zonal Demand Changes

The [redacted] Power Station has closed, and all offtake arrangement were terminated in 2016. There is a new obligation at [redacted] Station (From August in 2025) that has obtained capacity via capacity substitution from the GDN offtake at [redacted]

There is also a large Baseline Obligation at [redacted] that is not fully utilised. A project to install new build combined cycle gas turbine plant (CCGTs) with a capacity of 1.8GW is in development with a forecast commissioning data of 2026.

With the zone constrained no further capacity will be allocated via substitution. A Planning and Advanced Reservation of Capacity Agreement (PARCA would be required to investigate options to enable any capacity to be released. One such PARCA has entered into Phase 2 PARCA Works, for [redacted] Power Station, with an indicative registration date for baseline capacity of 1 April 2031.

Zonal Demand Summary

Table 13 shows the Forecast 1-in-20 peak demand for the zone during RIIO-GT3. We do not expect the drop in demand in 2030 to occur, with the GDN likely to continue to indicate their 1-in-20 peak demand is above the value provide in the FES. This is the demand level the network must be designed to meet for us to be compliant with the Gas Design Standard. The ability of the network to support this demand is assessed in the Capability and Resilience section.

There does remain a large amount of unsold capacity in the zone. The total Baseline Obligation release for the zone at the start of RIIO-GT3 period is 161.24 mscm/d. With a substantial proportion of this excess Baseline obligation at GDN offtakes it creates a risk that they can book additional capacity up to the Baseline obligation during exit capacity auctions and increase the 1-in-20 peak demand in the zone at short notice. This risk is managed through the exit process as defined in Offtake Arrangements Document (OAD) section H of the Uniform Network Code (UNC), with the GDN's providing advanced forecasts for any potential changes.

	2026	2027	2028	2029	2030
Distribution Network HT Peak Demand (mscm/d)	91.54	87.54	84.90	81.46	77.74
Distribution Network CF Peak Demand (mscm/d)	99.77	96.98	96.35	95.44	94.58
Distribution Network Section H Demand (mscm/d)	105.24	102.86	102.64	102.92	N/A
Direct Connects Peak Demand (mscm/d)	25.16	25.16	25.16	25.16	25.16
1-in-20 Demand - Worst Case - South East(mscm/d)	130.40	128.02	127.80	128.08	119.74

Table 13 – Zone 7 - 1-in-20 Demand (mscm/d) – FES24

Zonal Supply

The main supply points into the region are from [redacted] and the [redacted] The [redacted] Terminal contains two Aggregated System Entry Points (ASEPs); [redacted] Interconnection Point (IP) that covers the two European interconnectors and [redacted] UKCS for the sub-Terminals of [redacted]. Table 14 details the obligated release and highest entry levels seen for the last 5 years.

ASEP	Monthly Release Obligation (mscm/d)	Five year Maximum (mscm/d)
[redacted]	119.80	110.5
[redacted]	44.82	41.6
[redacted]	64.59	73.9
Total	229.21	226.00

Table 14 – [redacted] Obligations and Five-year maximum flows (mscm/d)

2.5 Zonal Capability, Resilience and Run Hours

2.5.1 Assumptions

Flame charts are provided with both the Holistic Transition and Counterfactual FES 2024 scenario data combined on each flame chart within each zone. The end of RIIO-T2 compressor availability graphics include all investments approved in RIIO-T2, but not necessarily yet completed.

The compressor run hours for stations in each zone are presented per financial year. The forecast compressor run hours are based on the preferred operating strategy for each zone and on an average demand and therefore don't account for outages or compressors needed on a 1-in-20 demand day. Therefore, some stations, e.g. [redacted] have low forecast run hours. The average case forecast compressor run hours are presented in this chapter because they were used for the base case for the CBA assessments in the EJPS. For the sensitivities the high case forecast run hours were used, these can be found in the Business Plan Data Tables[13].

[13] NGT_Business Plan Data Tables_RIIO-GT3, data table no.7.5

2.5.2 Zone 1 - Scotland and the North

Exit Capability and Resilience

Figure 7 shows the exit capability and resilience of the Scotland and the North zone at the start and end of RIIO-GT3. They assume the current levels of capability and resilience are maintained throughout the period.

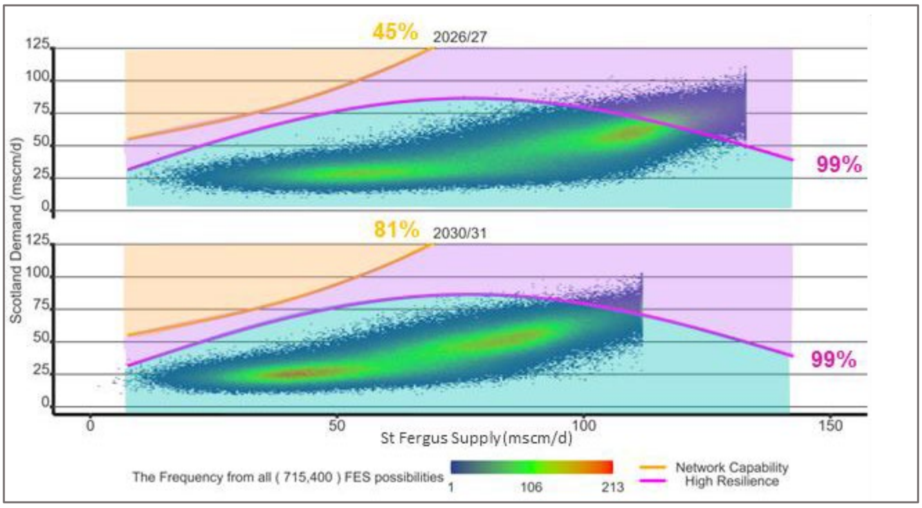

Figure 7 - Scotland and the North flame chart at the start and end of RIIO-GT3

Figure 7 shows that we have sufficient capability to meet the 1-in-20 exit requirement for Scotland throughout the RIIO-GT3 period in almost all scenarios. The main resilience risk faced by the network in Scotland and the North is the loss of a sub-terminal at St Fergus Aggregated System Entry Point (ASEP). This is covered in NGT_EJP012_Compressor Fleet – Network Investments and Zone 1 (Scotland)_RIIO-GT3 and could be mitigated by options such as station reconfiguration at Nether Kellet to allow flow reversal to Scotland.

Figure 8 shows the expected availability at the end of RIIO-T2 for Exit for Scotland and the North is very low. Primarily this is due to the low availability of Kirriemuir compressor station as unit E is too large to be used when maximising exit capability. The increased percentage for intact capability shows the preferred option at the end of RIIO-GT3. To improve the resilience of [redacted], and the zone, options have been included in the Cost Benefit Analysis to assess the benefit of re-wheeling unit E so that it is optimised for expected flows. Following the re-wheel unit E would be useable at low [redacted] flows to support exit. The re-wheel is cost beneficial on carbon savings as it reduces run hours on other units.

Figure 8 - Scotland and the North exit compressor availability at the end of RIIO-T2

Entry Capability and Resilience

There are three entry points in Scotland and the North, [redacted] All three of these entry points principally receive gas from the United Kingdom Continental Shelf (UKCS). Supply from [redacted] terminals is forecast to decline during the RIIO-GT3 period and [redacted] is forecast to stay essentially flat, this can be seen in Figure 9. [redacted] also receives supplies from Norwegian gas fields through the [redacted] pipelines.

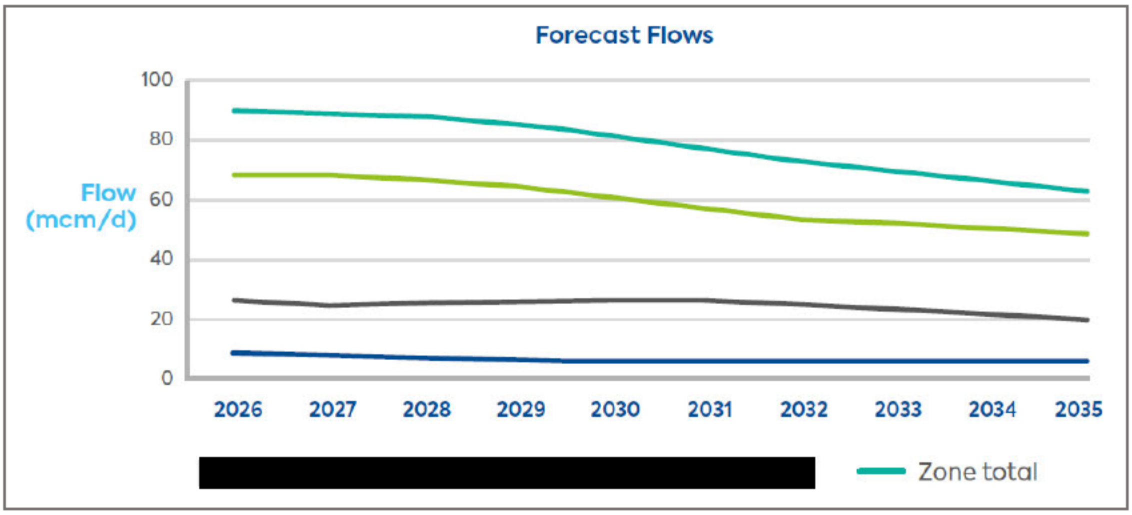

Figure 9 - Forecast supply flows - Scotland and the North – FES 2023 Falling Short[14]

Figure 10 shows the intact and High Resilience Capability lines for Scotland and the North. There is an excess of capability in the zone with both the intact and High Resilience Capability above the expected flows. For this reason there is no driver for investment to increase entry capability in the Scotland and the North zone.

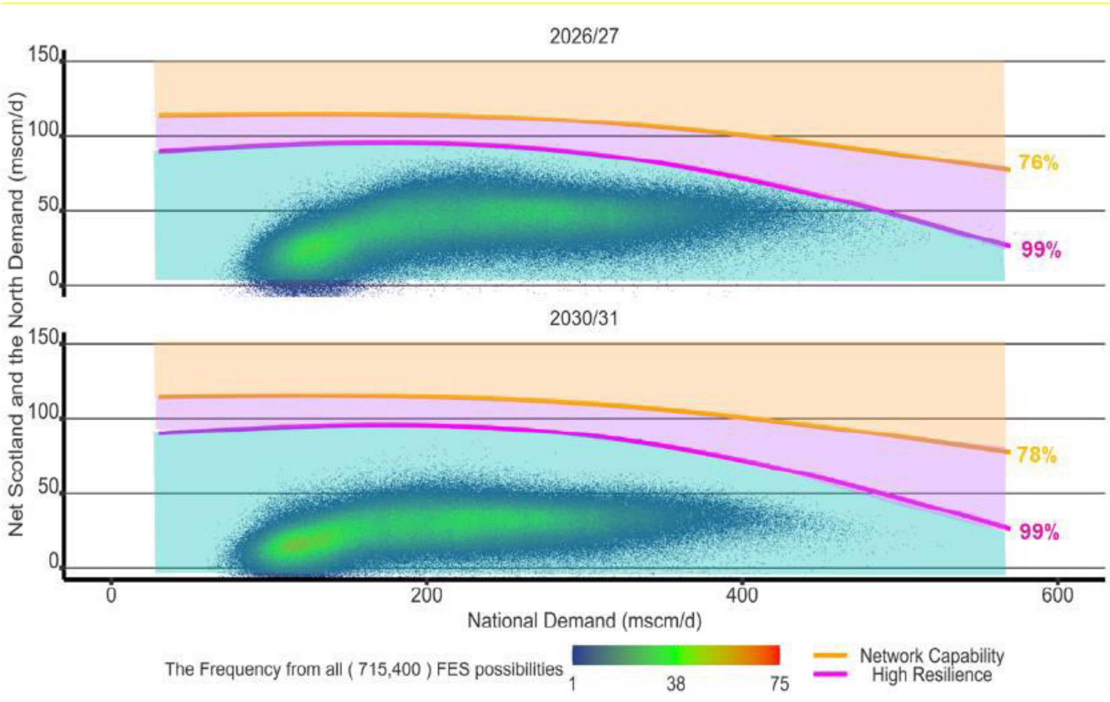

Figure 10 – Scotland and the North Entry charts

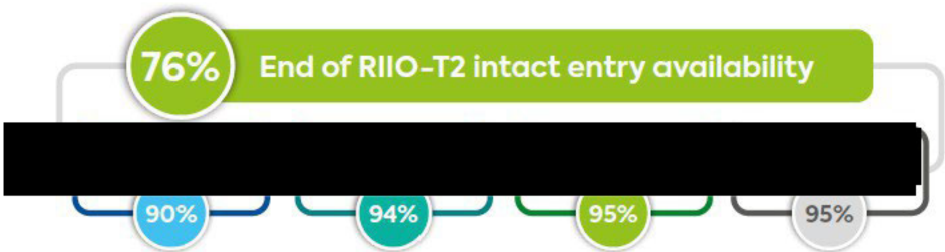

Figure 11 shows the expected availability at the end of RIIO-T2 for Scotland and the North. The zonal entry availability is different to the zonal exit availability as [redacted] is useable for maximising entry and has a better reliability than other

[14] FES 2023 is the latest data available for this chart

units at the site. [redacted] compressor station is considered solely for entry as it is used to maximise entry capability and can only flow gas North to South.

Figure 11 - Scotland and the North entry compressor availability at the end of RIIO-T2

Compressor run hours

Table 15 and Table 16 show the historic and forecast compressor run hours for the four compressor stations supporting Scotland and the North.

Site	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2022/24
[redacted]	3290	1948	2838	11141	8589	5015	3549	2318	3851	0	4013
[redacted]	387	166	2075	1532	1776	3165	794	1033	1319	5176	2327
[redacted]	1951	1602	3836	9936	10939	6410	2793	4184	3176	6955	3187
[redacted]	235	179	78	1889	529	366	60	156	21	32	4
Total	5863	3894	8827	24497	21832	14956	7196	7692	8367	12163	9531

Table 15 - Scotland and the North historic compressor run hours.

Site	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
[redacted]	4727	4499	4272	4044	3817	3589	3386	3183	2980	2777	2574
[redacted]	2115	1976	1837	1699	1560	1421	1285	1148	1012	876	740
[redacted]	5323	5285	5247	5209	5170	5132	5077	5022	4967	4912	4857
[redacted]	0	0	0	0	0	0	0	0	0	0	0
Total	12165	11761	11356	10951	10547	10142	9748	9353	8959	8565	8170

Table 16 - Scotland and the North forecast compressor run hours

Compression at [redacted] consistently sees high run hours to support the entry pressure of the [redacted] terminal. In 2022/23 the site was on outage while the control systems were replaced. The reduction in run hours resulted in a large increase in the run hours at [redacted] and [redacted]. [redacted] and [redacted] support [redacted] and [redacted] to provide the maximum level of entry capability. They are also used for linepack distribution and onward transmission when supplies in the north are greater than the demand. [redacted] has seen reduced run hours but does provide resilience for the other stations as well as supporting the east coast transmission route, especially while feeders on the west coast transmission route are on outage.

2.5.3 Zones 2 and 3 - Central

Entry Capability and Resilience

Relative to other zones, expected Exit and Entry flows in these zones are small, however they are considered transit zones and are required for interzonal flow. Compression in this region is required to support entry flows in Scotland and the North as well as exit flows in the zones to the south.

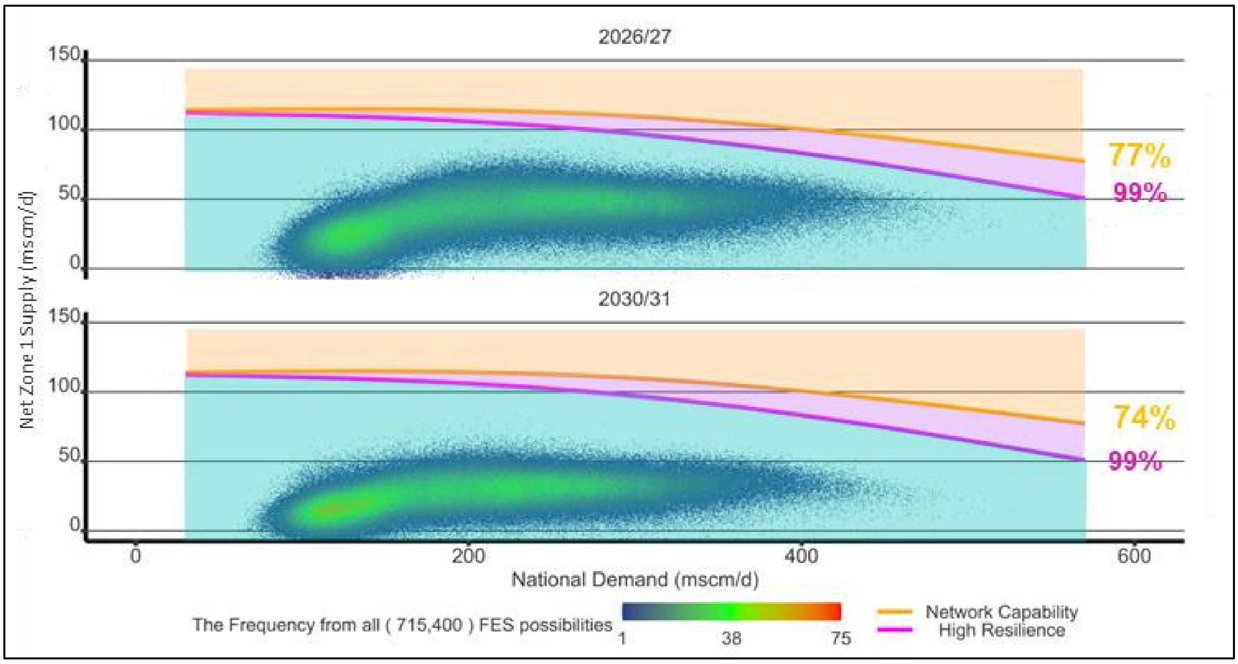

Figure 12 – Scotland and the North Entry Capability and impact of Central Compression on capability

Figure 12 shows the entry capability of Scotland and the North and a High Resilience line representing the effect that losing Central compression has on Scottish entry capability. We can see here that whilst partial loss of central compression has a minor effect on the entry capability of Zone 1, both lines are above the flame - therefore we don't expect to see any constraints due to this.

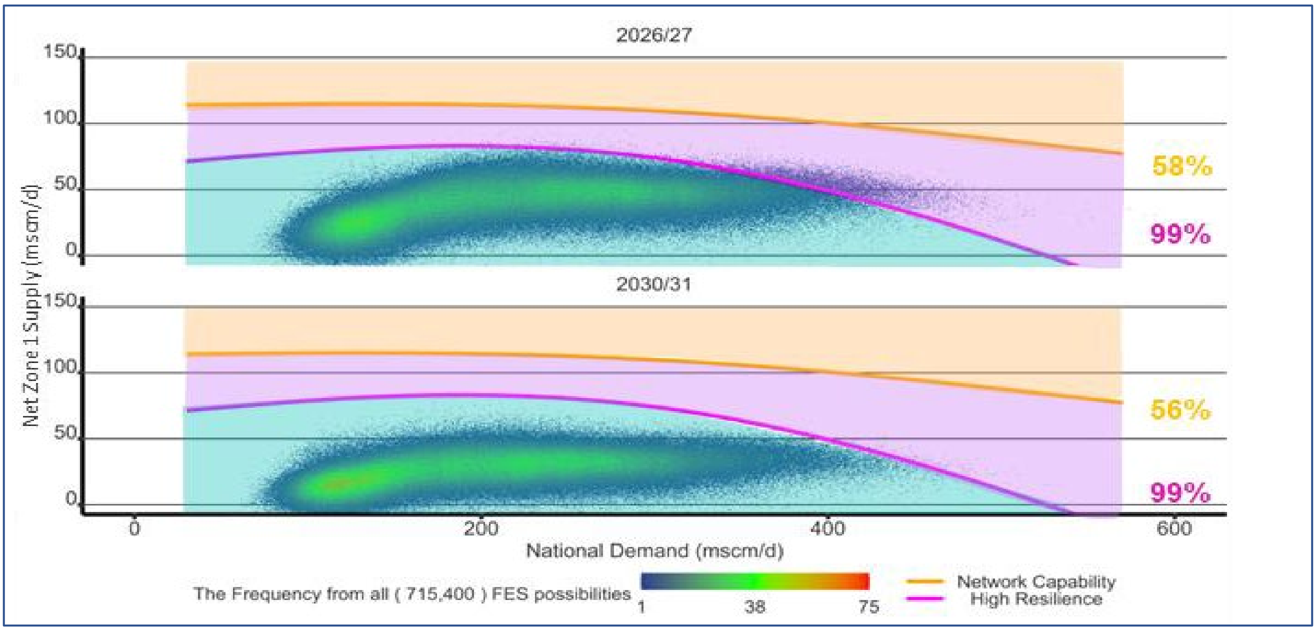

Figure 13 - Scotland and the North Entry Capability and combined Scottish and Central High Resilience Capability.

Figure 13 shows the same Scottish entry graph but with a combined High Resilience line showing the effect of loss of both Scottish and Central compression on entry capability in the zone. We can see that the new High Resilience line is much lower than both the Scottish and Central High Resilience lines, further illustrating the impact of compression in both these zones on Scottish entry capability. There are a limited number of days above the high resilience line at the start of RIIO-GT3. These values assume the decommissioning of Carnforth B. Retention of the unit increases the intact availability of the zone from 77% to 83% (or 58% to 63% when combined with zone 1). This would reduce the risk of constraints at the start of RIIO-GT3 and enable the planned works in zones 1, 2 and 3.

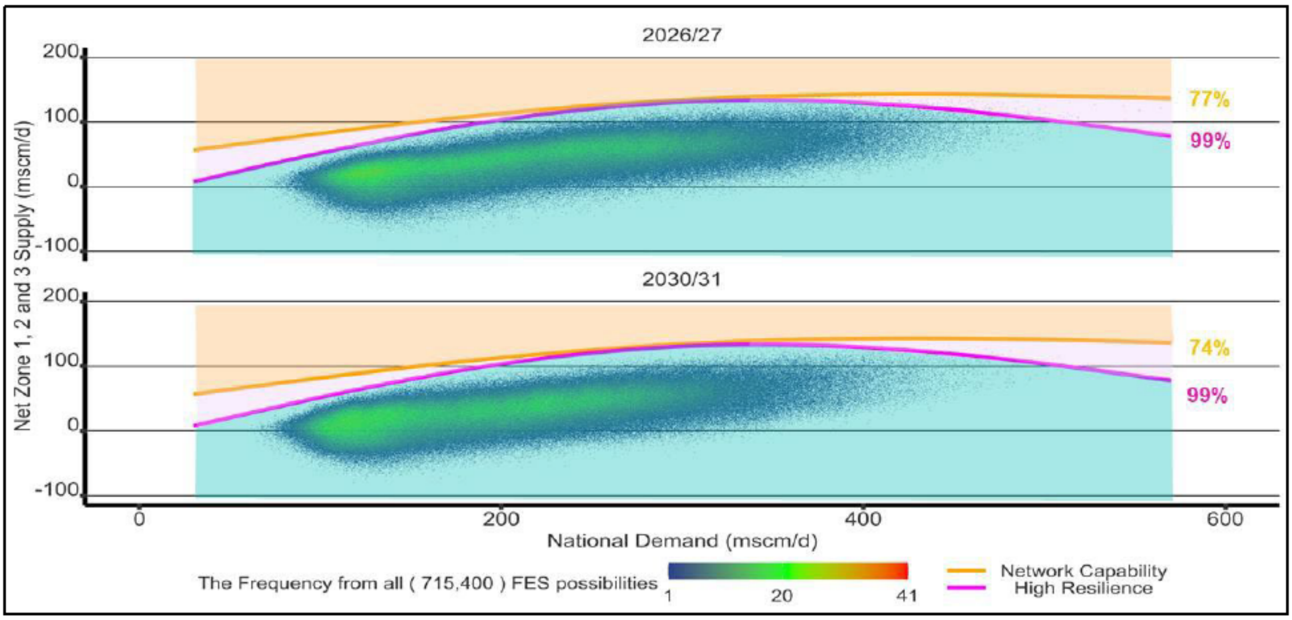

Figure 14 - Northern Entry Capability and combined Scottish and Central High Resilience Capability.

Figure 14 shows the capability to move gas from the North of the country into the South. This combines all supply and demands in zones 1, 2 and 3. This shows the amount of excess supply in the North that can be moved into the South to support demand. The High Resilience line shows the level capability that can be provided 99% of the time based on the availability of compression in the central region only.

Figure 15 shows the expected availability at the end of RIIO-T2 for compression in the Central region. The Central region is therefore a region where availability should be maintained in RIIO-GT3. Based on all the flame charts there is sufficient capability now and during RIIO-GT3 to support the required Entry capability.

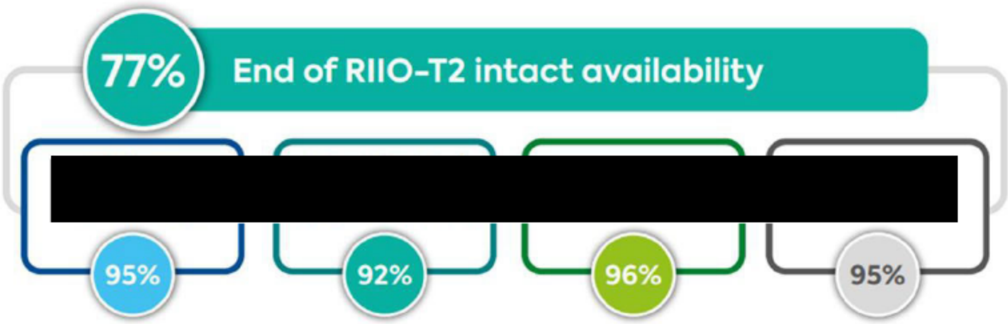

Figure 15 - Central Entry Compressor Availability at the End of RIIO-T2

Exit Capability and Resilience

Due to these zones mainly being required to support the bulk transmission of gas from the North to the South there is an excess of exit capability in the region. There is no zonal resilience considered because we would always expect to deliver the exit flow commitment due to only a subset of compression being required to support exit flows in the region.

Compressor Run Hours

Table 17 and Table 18 show the historic and forecast run hours for the five compressor stations in the region.

Site	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
[redacted]	3156	275	782	5058	6006	3013	346	134	92	39	2852
[redacted]	38	21	157	41	2	24	238	186	67	630	809
[redacted]	510	273	1028	6133	3737	1835	160	322	1338	5217	655
[redacted]	2073	2912	3822	5389	6748	838	635	252	4841	1448	3921
[redacted]	152	106	129	55	1734	639	267	638	452	2949	2184
Total	5928	3586	5917	16676	18227	6349	1645	1532	6790	10283	10421

Table 17 - Central region historic compressor run hours

Site	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
[redacted]	192	163	135	107	79	51	43	36	28	20	13
[redacted]	96	82	68	54	40	25	22	19	15	12	8
[redacted]	1661	1423	1185	947	709	471	407	343	279	215	151
[redacted]	5559	4986	4413	3840	3267	2694	2472	2249	2027	1804	1581
[redacted]	1997	1994	2196	2032	1711	1287	1222	1157	1092	1062	1031
Total	9504	8648	7996	6979	5806	4529	4166	3803	3441	3112	2784

Table 18 - Central region forecast compressor run hours

Reduced run hours are due to shutdowns and maintenance. The increased duty at Alrewas in the last two years of Table 17 on historic run hours is due to assisting higher entry levels at [redacted] The high run hours at [redacted] in 2022/23 are because the station was supporting export pressures at [redacted] interconnector point. In 2023/24 maintenance at [redacted] and feeder maintenance down the East coast meant that the compressor station was run less than in previous years. This meant a West coast strategy was favoured to transmit gas from North to South which increased the run hours on [redacted] in 2023/24.

2.5.4 Zone 4 - South Wales

Entry Capability

Figure 16 shows the capability and resilience of the South Wales zone at the start and end of RIIO-GT3.

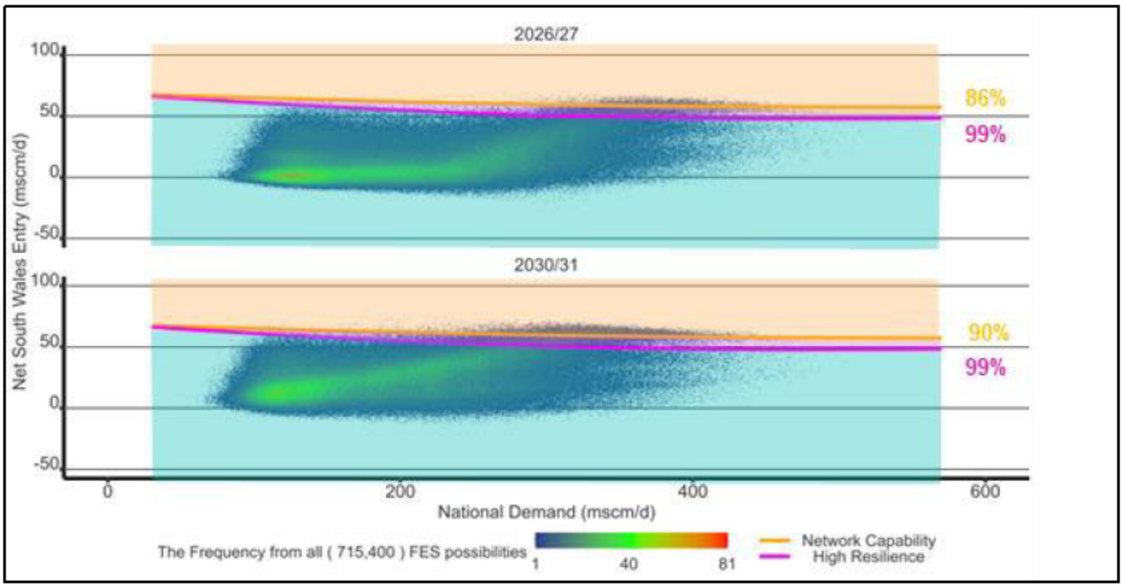

Figure 16 - South Wales Entry Capability at the start and end of RIIO-GT3

Figure 16 shows an increase in the number of days above our capability by 2030/31. It also shows how important our ability to deliver the Intact Capability is, with the average number of days above the High Resilience line increasing from 10 to 22 by the end of the RIIO-GT3 period. FES24 demonstrates an increase in import dependence in both the HT and CF scenarios as can be seen in the FES charts in Figure 17 and Figure 18. In the HT scenario the current level of import dependency is 48%, increasing to 56% at the start of RIIO-GT3. Import dependency then increases by 8% over year 2 and 3 of RIIO-GT3 and is at 67% by the end of price control period.

In the CF scenario the import dependency starts at a higher level and rises more rapidly. The current level is 53%, increasing to 61% by the start of RIIO-GT3 then by a further 4% in each of years 2 and 3 of RIIO-GT3. Import dependency is at 74% by the end of RIIO-GT3.

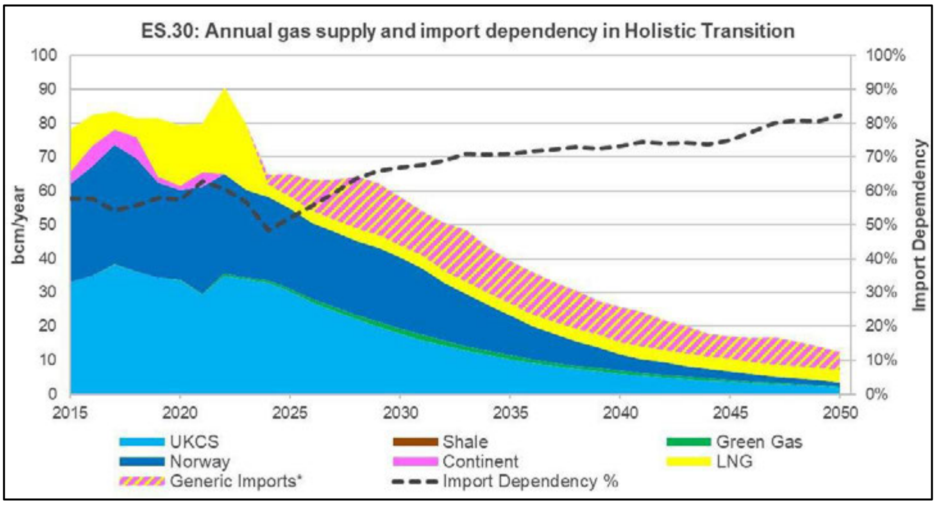

Figure 17 - Holistic Transition - Annual gas supply [(FES24 Data Workbook)]

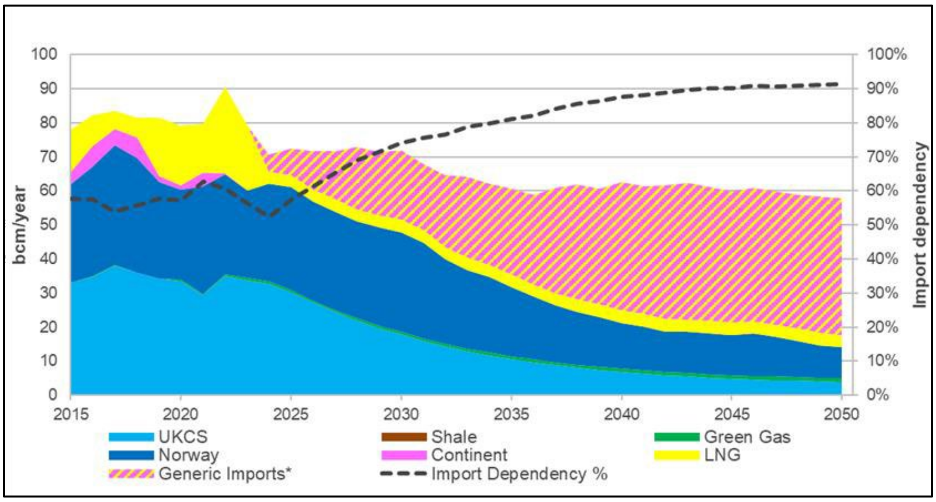

Figure 18 - Counterfactual - Annual gas supply (FES24 Data Workbook)

FES 2024 reflects the changes in the sources of imports into to UK following the Russia/Ukraine conflict. Prior to this there was an assumed base level of imports from Europe. This has now been reduced to zero with any supplies received from mainland Europe being captured in the Generic Imports category. The balancing order has also been adjusted with supplies from Europe now only expected under high demand condition when required to balance UK demand. Figure 17 and Figure 18 also show how UKCS supplies are expected to reduce between now and the end of RIIO-GT3. Both of these changes are the reason for the increasing risk of supplies being above our capability and reflect the growing importance of LNG in meeting UK demand.

Optioneering has therefore considered how the zonal capability can be improved and to assess the need for investment in light of increasing import dependency, this is detailed in NGT_EJP038_Network Capability: West Import Resilience Project_RIIO-GT3.

Entry Resilience

Figure 19 shows the station level break down of the intact availability for the South Wales compression at the end of RIIO-T2.

Figure 19 - South Wales Intact Entry Availability at the end of RIIO-T2

In 2025/26 it is estimated that overall zonal availability will be 86%. With capability closely matched to the obligated release in the zone, and high expected flow levels, optioneering has considered how the zonal availibility can be improved with asset health investment across a range of options as can be seen in the NGT_EJP038_Network Capability: West Import Resilience Project_RIIO-GT3 as above and NGT_EJP014_Compressor Fleet - Zones 4 and 5 (South Wales and South West)_RIIO-GT3.

Exit Capability

Figure 20 and Figure 21 show the capability of the South Wales zone at the start and end of RIIO-GT3. They assume the current levels of capability are maintained throughout the period.

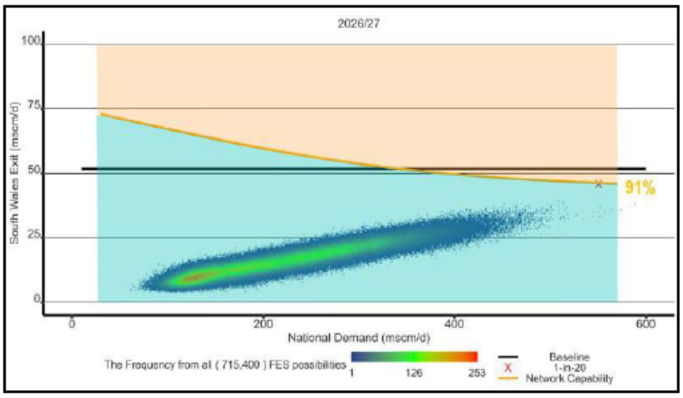

Figure 20 - South Wales Exit Capability for the start of RIIO-GT3

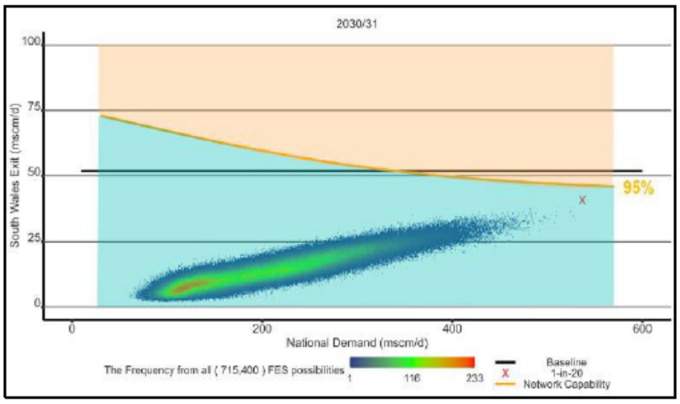

Figure 21 - South Wales Exit Capability for the end of RIIO-GT3

South Wales has sufficient exit capability, including 1-in-20 peak demand now and beyond the next ten years.

Exit Resilience

Figure 22 shows the station level break down of the intact availability for the South Wales compression able to support exit demands at the end of RIIO-T2.

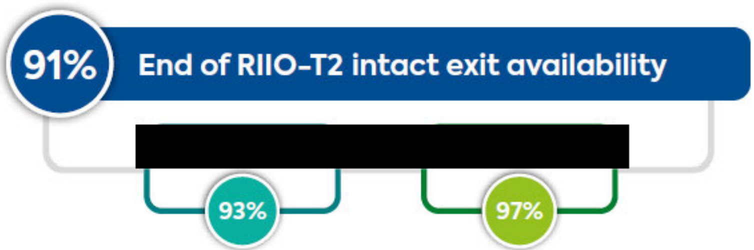

Figure 22 - South Wales Intact Exit Availability

In 2025/26 it is estimated that overall zonal availability for exit will be 91%.

Compressor run hours

Table 19 and Table 20 show the historic and forecast run hours for the three compressor stations supporting the South Wales zone.

Site	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
[redacted]	0	0	7	23	7	38	1937	2114	1382	3656	1366
[redacted]	1132	1441	1966	1303	2156	818	3078	3008	2552	5310	1593
[redacted]	475	224	727	2447	249	160	1252	1655	1198	3232	854
Total	1607	1665	2700	3774	2411	1017	6267	6777	5132	12198	3813

Table 19 - South Wales historic compressor run hours

Site	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
[redacted]	800	983	1166	1349	1532	1715	1769	1823	1878	1932	1987
[redacted]	4947	5472	5807	6142	6477	6749	6811	6874	6936	6998	7061
[redacted]	704	866	1028	1190	1351	1513	1561	1609	1658	1706	1754
Total	6451	7321	8001	8680	9360	9977	10142	10307	10472	10637	10802

Table 20 - South Wales forecast compressor run hours

The run hours for the last five years have been some of the highest on the National Transmission System (NTS). This shows the growing importance of these assets and with UK Continental Shelf supplies expected to reduce faster than national demand the need for these assets is forecast to increase. This is a driver to improve entry resilience of the compressor fleet in the zone. The compressor at [redacted] wasn't fully commissioned until 2019/20 hence the low running hours before then.

2.5.5 Zone 5 - South West

Exit Capability and Resilience

Figure 23 shows the capability and resilience of the South West zone at the start and end of RIIO-GT3. They assume the current levels of capability and resilience are maintained throughout the period. This graph is plotted with net zonal demand to illustrate the effect of supplies in this zone.

The red cross shows the 1-in-20 Peak demand for the zone for that year, as calculated in Chapter 3 - Zonal Demand and Supply – Zone 5 - South West section. At both the start and end of RIIO-GT3 the current Intact Capability, the orange line, is below the 1-in-20 peak demand of the zone. This means any requests for additional capacity in the zone would need to go through the PARCA process. The capability assumes supplies at [redacted] and [redacted] are at the forecast minimum. To support the 1-in-20 demand one or both sites would need the supply level to be above their minimums.

The forecast 1-in-20 Peak level has been above the capability in the zone since ANCAR 2024 this is due to an increase in forecast flows in FES 2023 data for the South West. In this document we have used the higher of Section H GDN booked flows and FES 2024 GDN forecast flows to give the 1-in-20 case, and this is reflected in the below flame chart.

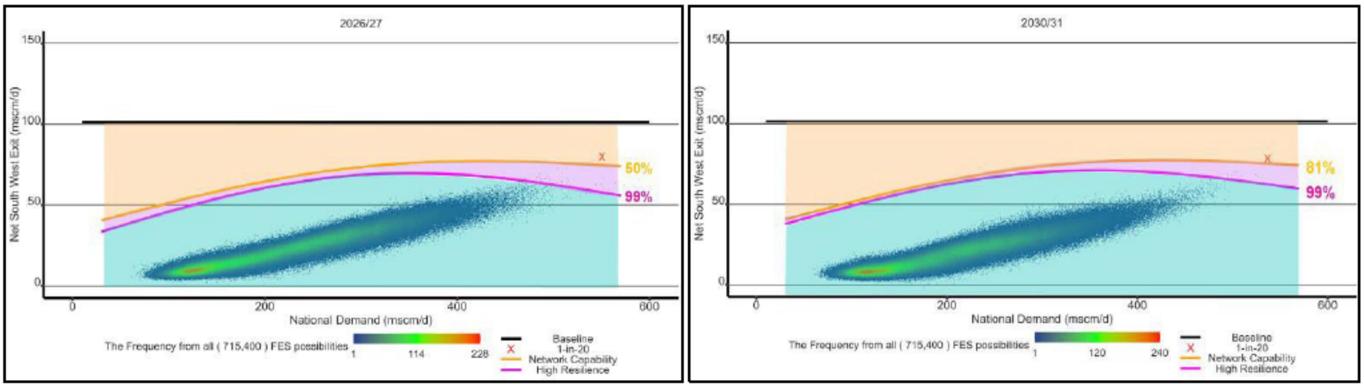

Figure 23 - South West Exit flame charts at the beginning and end of the RIIO-GT3 period

Figure 23 also shows the High Resilience line (in pink). This is the capability we can provide 99% of the time. The flame chart does show the number of days close to and above the High Resilience line reducing as overall demand reduces over the RIIO-GT3 period. However, the intact availability is still low.

Figure 24 - South West intact availability expected at the end RIIO-T2 period

Figure 24 shows the station level break down of the predicted intact availability for the South West at the end of RIIO-T2. The low level of availability is due to the low level of availability at [redacted]. It is also due to the inherent mathematical difficulty of achieving high zonal availability with five contributory compressor stations. The counterfactual for the Cost Benefit Analysis (CBA) assumes asset health investment at these sites is completed to the A1 level of the NGT Reliability Availability Maintainability (RAM) model. The flame charts above show there is continued requirement for [redacted] to meet the 1-in-20 peak demand in the region, as they would all need to be running to maintain resilience at peak demand. As a prudent operator we will consider options to improve the zonal availability to ensure compliance with Standard Special Condition A9 – Pipe-line system security standards.

Compressor Run Hours

Table 21 and Table 22 show the historic and forecast run hours for the five compressor stations supporting the South West.

Site	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
[redacted]	7174	5388	2430	5701	7118	2389	318	4279	2437	1804	1189
[redacted]	3233	2276	1065	3050	2982	1708	815	1827	1751	814	992
[redacted]	1132	1441	1966	1303	2156	818	3078	3008	2552	5310	1593
[redacted]	32	20	30	53	102	77	65	221	185	79	82
[redacted]	670	236	164	808	806	436	111	294	180	9	6
Total	12240	9362	5655	10915	13164	5429	4388	9628	7105	8016	3862

Table 21 - South West historic compressor run hours

Site	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
[redacted]	3024	5203	4714	4470	4429	4421	4382	4344	4306	4267	4229
[redacted]	1512	1487	1347	1277	1265	1263	1252	1241	1230	1219	1208
[redacted]	4947	5472	5807	6142	6477	6749	6811	6874	6936	6998	7061
[redacted]	24	20	16	11	7	3	2	2	1	1	0
[redacted]	103	86	69	52	36	19	16	12	9	6	3
Total	9609	12268	11953	11953	12214	12454	12464	12473	12483	12492	12501

Table 22 - South West Forecast compressor run hours

[redacted] compressor run hours are consistently high. This is due to them performing multiple roles. [redacted] support linepack levels and demand in the whole of the South. The years with lower run hours at [redacted] are due to planned outages during the summer months while new units were constructed. The significant increase in operation at [redacted] over the last five years is due to the increased level of Liquified Natural Gas (LNG) at the [redacted] terminal.

Compression at [redacted] has only one use, to support the exit demand in the South West. The compressors' use is driven by the demand level downstream of the sites. During mild winters both stations can see low run hours.

The forecast run hours are based on average weather conditions, meaning that 1-in-20 compressors such as [redacted] show as low run hours. Sensitivities to these are done in the CBA for cold winters.

2.5.6 Zone 6 - East Midlands

Exit Capability and Resilience

The East Midlands zone has the highest single point of demand in the whole of the network, the [redacted] Interconnector demand. Figure 25 shows [redacted] export capability as this is the key demand in the zone. [redacted] Interconnector demand and Brisley GDN offtake are the only demands downstream of [redacted] compressor station, which is the only compressor site in the zone providing capability.

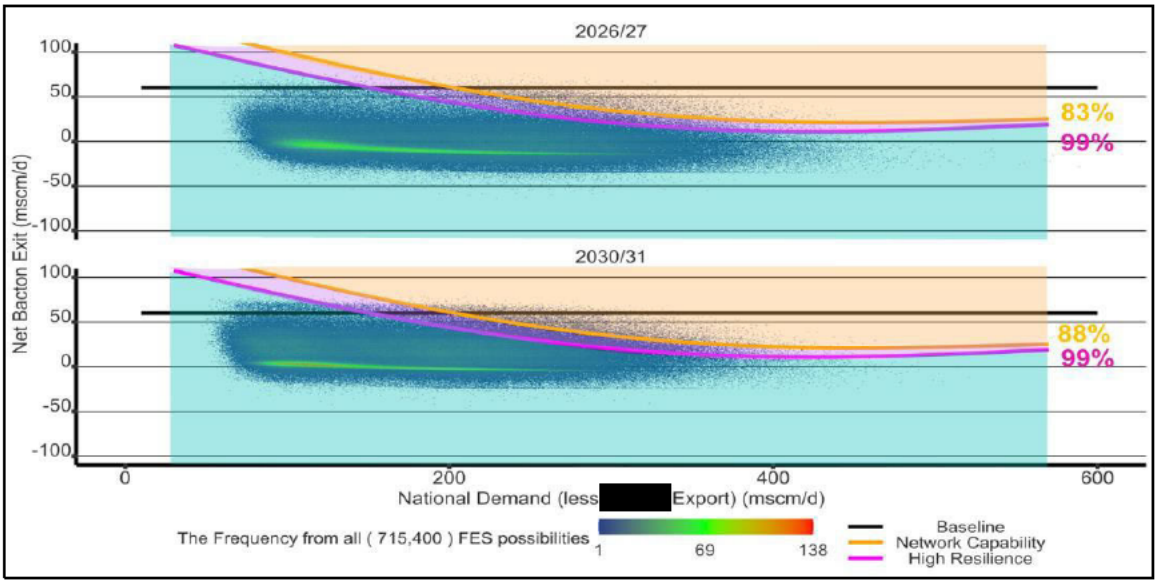

Figure 25 - East Midlands Exit Network capability.

The capability lines in Figure 25 show exit capability while assuming supplies at minimum, as this is a 'worst case' demand scenario. The Intact Capability line shows that the East Midlands network mostly has sufficient capability to meet exit requirements. On days where the charts are showing a constraint, we would expect above minimum flows at [redacted] LNG terminal.

Figure 26 shows the expected availability at the end of RIIO-T2 for the East Midlands is low. These values have been predicted assuming all RIIO-T2 investment is completed. King's Lynn is the only compressor station in the region able to support the exit capability of the [redacted] Interconnectors. Investment in the units has been funded through the RIIO-T2 uncertainty mechanism. It includes asset health investment on all three units and compressor re-wheels on the two SGT400 units. No further investment has been considered during the RIIO-GT3 period.

Figure 26 - East Midlands Exit Compressor availability at end of RIIO-T2

2.5.7 Zone 7 - South East

Exit Capability and Resilience

Figure 27 shows the exit capability and resilience of the South East zone at the start and end of RIIO-GT3. They assume the current levels of capability and resilience are maintained throughout the period. This graph is plotted with net zonal demand to illustrate the effect of supplies in this zone. Supplies at [redacted] benefit the zone more than those at [redacted] due to the site being closer to the high demand offtakes.

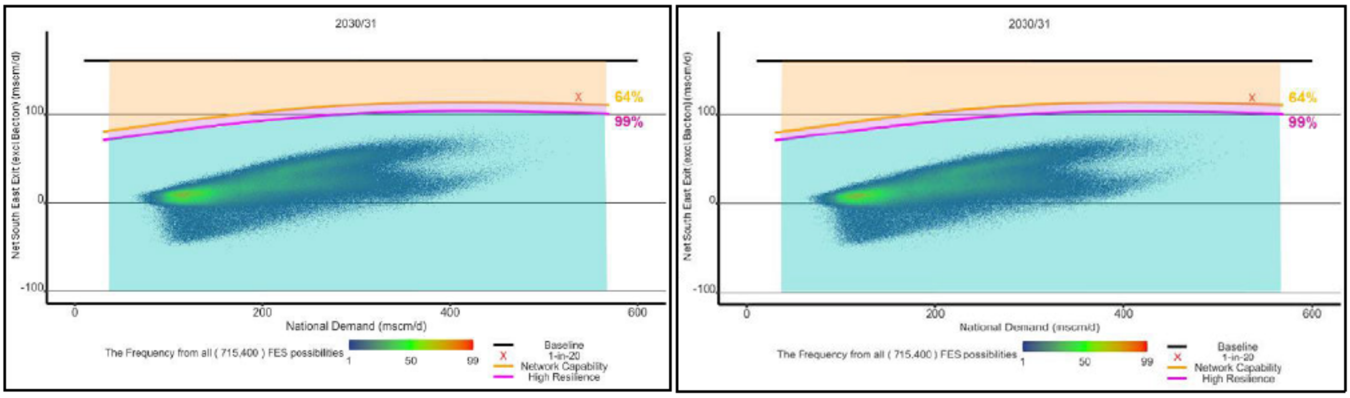

Figure 27 - South East Exit Capability and High Resilience

Figure 27 also shows the High Resilience line (in pink)[15]. This is the capability we can provide 99% of the time. The 1-in-20 peak demand is above the Intact Capability at both the beginning and end of RIIO-GT3, however we would assume supplies in the zone to be above minimum in this event. As outlined in section 2.4.7 on demand and supply any new capacity request would have to follow the PARCA route, as with [redacted] Power Station PARCA which is currently in phase 2. A flame chart that accurately shows the capability and risk in this complex, interdependent, zone is difficult to construct, and alternatives are being explored as part on the Grain PS PARCA phase 2 works. Figure 28 shows the intact availability is low.

Figure 28 - South East exit compressor availability at the end of RIIO-T2

Figure 28 shows the station level break down of the intact availability for the South East at the end of RIIO-T2. These values have been predicted assuming all RIIO-T2 investment is completed. The low level of availability is due to the low level of availability at [redacted] compressor stations. It is also due to the inherent mathematical difficulty of achieving high zonal availability with five contributory compressor stations. The flame charts above show there is continued requirement for [redacted] to meet the 1-in-20 peak demand in the region. As a prudent operator we will consider options to improve the zonal availability to ensure compliance with Standard Special Condition A9 – Pipe-line system security standards. The counterfactual for the Cost Benefit Analysis (CBA) assumes asset health investment at these sites is completed to the A1 level of the [NGT Reliability Availability Maintainability (RAM) model](). Options within the CBA in Compressor Fleet - Zones 6 and 7 (East Midlands and South East) EJP[16] looks at completing additional asset health investment in the zone to further improve the compression resilience.

Wisbech Compressor Station

Compression at Wisbech is currently disconnected due to asset health issues preventing the operation of its units. The units have historically had low run hours and when they have run it was due to multiple other stations being on outage. To understand the long-term future for the site the benefit of the units to provide to Network Capability in the South East has been assessed.

Figure 29 shows the additional Network Exit Capability provided by compression at Wisbech. This chart differs from Figure 27 with the inclusion of [redacted] in the net South East Demand calculation. In Figure 27 this was kept constant with Supply at [redacted] reduced first before South East demand increased. To ensure the 'worst case' exit capability is determined the [redacted] level has been reduced before South East demand is increased. This moves supply as far away from the area as possible to fully test the capability of the area. At demand levels below ~300 mscm/d it is possible to reduce supplies at both Bacton

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[15] This line is different to the one in ANCAR as we have used the latest analysis in this annex
[16] NGT_EJP016_Compressor Fleet - Zones 6 and 7 (East Midlands and South East)_RIIO-GT3

and IoG to zero. At higher demand levels this is not possible, and supply is required at either [redacted] In this scenario the 'worst case' for the capability is to retain supplies at [redacted] because it is further away from the demand centre and requires the most compressor capability.

The results show that at high demands [redacted] compressor reduces the level of supply required in the South East at [redacted] by ~14 mscm/d (from 78 to 64 mscm/d). However, there is currently no cost benefit to returning the units to service due to expected supplies in the zone being sufficient to meet demand. The final decision on decommissioning the units should be deferred until there is greater certainty on the benefit, they may provide to enable Project Union.

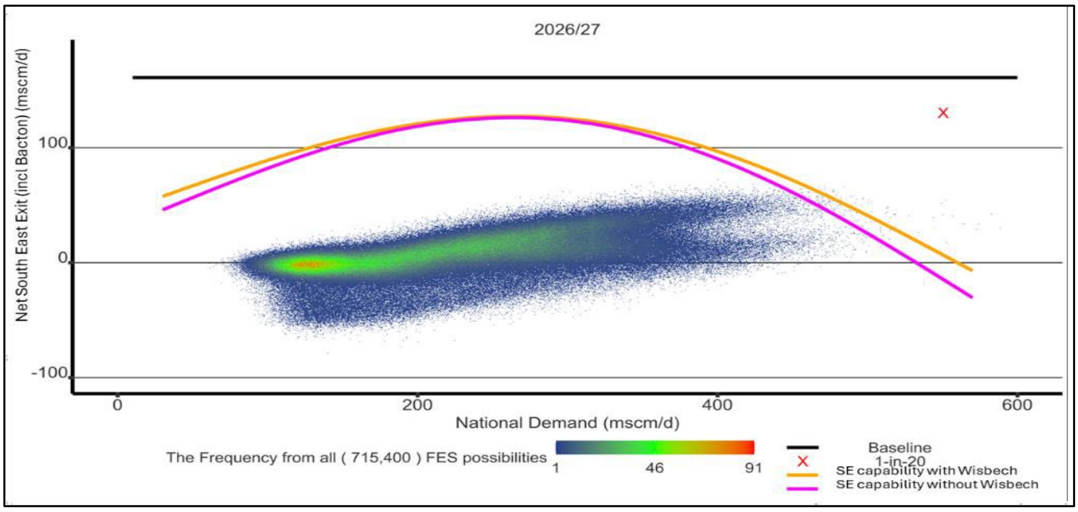


Figure 29 South East Exit Network capability with and without Wisbech compressor

Entry Capability and Resilience

Bacton and Isle of Grain are considered entry points for the South East, as the gas from these facilities is used to support the high demand centres in the zone.

Figure 30, Figure 31 and Figure 32 show the Intact Capability lines for South East entry with [redacted] flows at various set levels. The shape of the lines indicates that there is a constraint in the zone. When the net supply level at [redacted] is negative zonal demand is higher that the supply from Isle of Grain LNG. Following the commencement of Russia/Ukraine war we expect entry flows from Europe to be low, but the capability to import supplies at high demand levels remains critical for GB energy security under peak conditions.

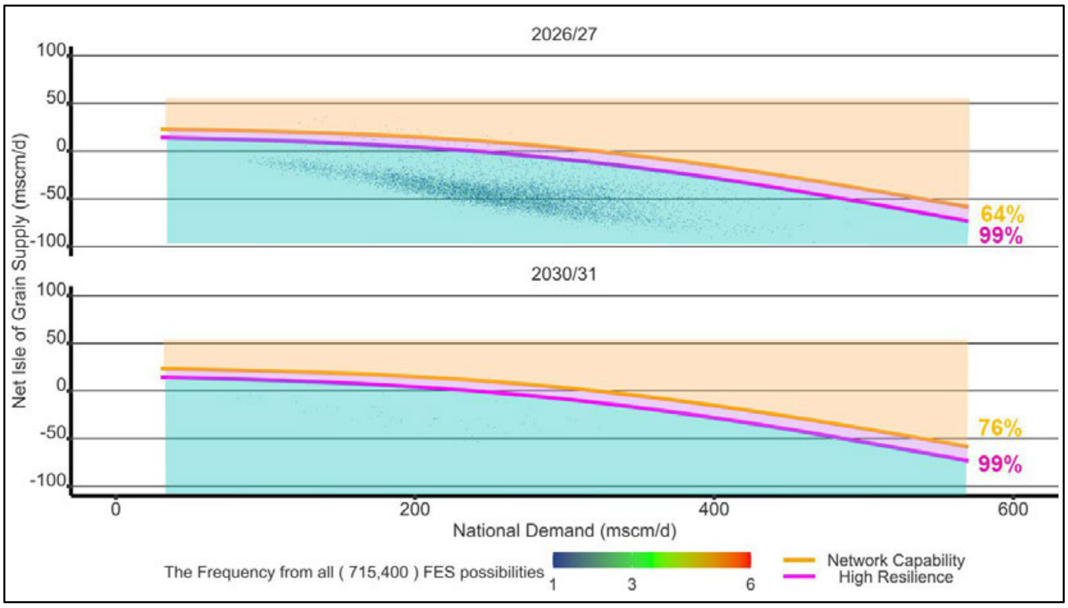


Figure 30 [redacted] entry capability with Bacton flows above 30mscm/d for 2026/27 and 2030/31

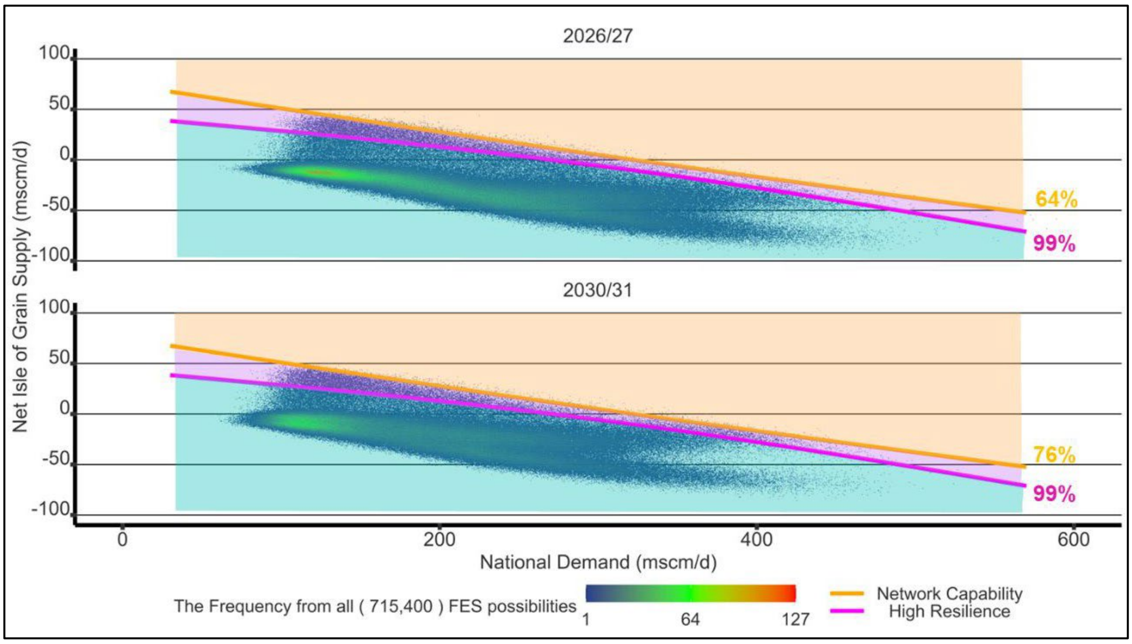


Figure 31 - [redacted] entry capability with Bacton flows between 30 and -20mscm/d for 2026/27 and 2030/31

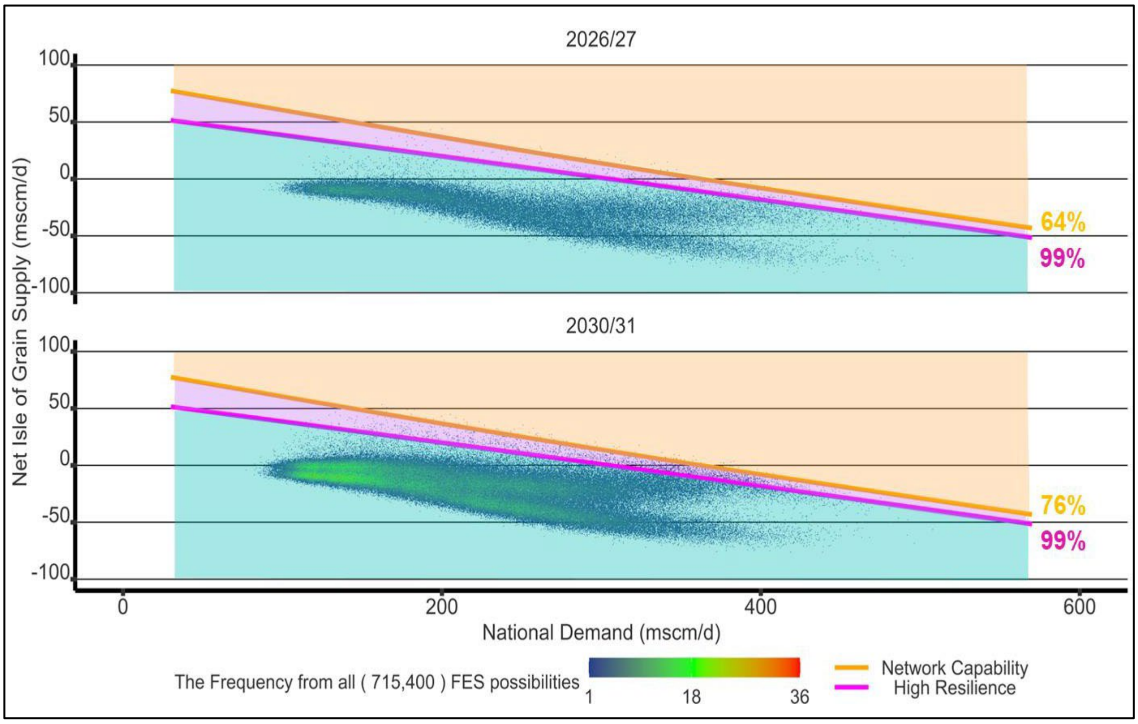


Figure 32 - [redacted] entry capability with Bacton flows below -20mscm/d for 2026/27 and 2030/31

The number of days above the Intact and High Resilience Capability lines is increasing during RIIO-GT3. It is therefore important to consider options to improve the current capability. Options in NGT_EJP015_Compressor Fleet - Zones 6 and 7 (East Midlands and South East)_RIIO-GT3 assess the benefit of enabling compression at [redacted] to be reversed to aid Entry capability improvements at the [redacted] Terminal. There is also the possibility of funding compressor re-wheels via a volume driver at [redacted] to improve capability in the zone to facilitate higher LNG flow from [redacted]. Additional asset health investment to improve resilience is also considered.

Figure 33 shows that the expected availability at the end of RIIO-T2 for the South East is low. These values have been predicted assuming all RIIO-T2 investment is completed. There is also limited capability in the current network to move gas out of the South East. [redacted] is the most effective compressor in this regard, and [redacted] can provide capability in certain scenarios, however the current design of the multi-junction only allows flows to be directed towards Bacton and Whitwell with Huntingdon on the suction.

Figure 33 - South East Entry Compressor availability at end of RIIO-T2

Compressor run hours

Table 23 and Table 24 show the historic and forecast run hours for the seven compressor stations supporting the South East and East Midlands zones.

Site	2013/14	2014/15	2015/16	2016/17	2017/18	2018/19	2019/20	2020/21	2021/22	2022/23	2023/24
[redacted]	7174	5388	2430	5701	7118	2389	318	4279	2437	1804	1189
[redacted]	3233	2276	1065	3050	2982	1708	815	1827	1751	814	992
[redacted]	141	145	46	1120	2058	72	20	1589	23	23	28
[redacted]	113	111	34	880	1073	69	7	11	26	6	15
[redacted]	54	211	216	340	387	45	84	1220	86	122	655
[redacted]	246	51	467	782	74	31	13	25	30	2	0
[redacted]	302	31	28	173	1887	118	71	1584	434	7219	1419
Total	11262	8214	4287	12045	15578	4432	1330	10535	4787	9990	4298

Table 23 - South East and East Midlands historic compressor run hours

Site	2024/25	2025/26	2026/27	2027/28	2028/29	2029/30	2030/31	2031/32	2032/33	2033/34	2034/35
[redacted]	3024	5203	4714	4470	4429	4421	4382	4344	4306	4267	4229
[redacted]	1512	1487	1347	1277	1265	1263	1252	1241	1230	1219	1208
[redacted]	22	18	15	12	8	5	4	4	3	3	3
[redacted]	11	9	8	6	4	2	2	2	2	2	1
[redacted]	1102	1109	1115	1122	1128	1135	1151	1166	1182	1198	1213
[redacted]	0	0	0	0	0	0	0	0	0	0	0
[redacted]	2090	1624	1710	1835	1683	1316	829	570	473	467	485
Total	7760	9450	8909	8722	8518	8142	7621	7327	7196	7156	7140

Table 24 - South East and East Midlands forecast compressor run hours

[redacted] compressor run hours are consistently high. This is due to them performing multiple roles. [redacted] support linepack levels and demand in the whole of the South. The years with lower run hours at [redacted] are due to planned outages during the summer months while new units were constructed. The higher running hours at [redacted] in the 2016 and 2017 financial years are due to [redacted] taking duty from [redacted] when it was on outage. In the 2016 and 2017 financial years run hours increased at [redacted] due to network constraints combined with high [redacted] flows. In 2020/21 [redacted] ran more due to an operational issue. [redacted] run hours in 2020/21 were higher due to constraints on the network meaning it was used to support demand in the South East. The forecast run hours are based on average weather conditions so 1-in-20 compressors such as [redacted] show as low run hours. Sensitivities to these are done in the CBA for cold winters.

2.6 Conclusions

The case for investment in Scotland and the North in RIIO-GT3 is driven by the need to ensure the zonal compressors are wheeled correctly and run as efficiently as possible. Therefore we propose a re-wheel of [redacted] unit E, re-wheels of [redacted] units 1A and 1B and a compressor site reversal at [redacted] These will increase the zonal availability for exit from 45% at the end of RIIO-T2 to 81% at the end of RIIO-GT3.

The investments needed in the Central region (North West and North East zones) in RIIO-GT3 are re-wheels of [redacted] units A and B and a re-wheel at [redacted] of unit C. This investment at [redacted] will support our compliance with environmental legislation (MCPD) as the C unit will be able to take duty from the more polluting A and B [redacted] that will be derogated from 2030. These will decrease availability slightly but improve resilience.

The case for investment in South Wales in RIIO-GT3 is driven by the need to increase entry capability and maximise resilience. Therefore, the works proposed in NGT_EJP038_Network Capability: West Import Resilience Project_RIIO-GT3 and NGT_EJP014_Compressor Fleet - Zones 4 and 5 (South Wales and South West)_RIIO-GT3, as above, include:

- to retain both [redacted]
- re-wheel and hold additional spares at [redacted]
- 9 km of new feeder between [redacted]

These will increase the zonal availability for entry from 86% at the end of RIIO-T2 to 90% at the end of RIIO-GT3.

In the South West the case for investment is driven by the need to increase resilience. Therefore, asset health investment on the remaining [redacted] units within the zone at [redacted] are the most beneficial. We also propose to re-wheel [redacted] units A and B and creating a spare for [redacted] by refurbishing a removed unit. By carrying out these works the zonal resilience for exit would increase from 50% at the end of RIIO-T2 to 81% at the end of RIIO-GT3.

In the East Midlands no investments are proposed to improve capability or availability.

The case for investment in the South East is driven by the need to increase intact availability for entry and exit. This includes asset health improvements to the fleet in the zone and a compressor site reconfiguration at [redacted]. These would increase exit availability from 42% at the end of RIIO-T2 to 64% at the end of RIIO-GT3. Entry availability would increase from 64% at the end of RIIO-T2 to 76% at the end of RIIO-GT3.

There are also other investments for, and studies on, potential re-wheels, disconnections, decommissioning, and various asset health options proposed for RIIO-GT3. These are explained in more detail in the Compressor Fleet EJPs[17], where you can also find the detailed optioneering and cost benefit analysis for all the zones.

A summary of the forecast zonal and compressor station intact availabilities is shown below. This is shown for the end of RIIO-T2 and the end of RIIO-GT3 broken down by counterfactual and with proposed investments. This is shown for entry and exit availabilities. The end of RIIO-T2 availabilities include all investments approved in RIIO-T2, but not necessarily yet completed.

Zone	Compressor Station	By Compressor Station			By Zone		
		End of RIIO-T2	End of RIIO-GT3		End of RIIO-T2	End of RIIO-GT3	
			Counterfactual	With proposed investment		Counterfactual	With proposed investment
Scotland and the North	[redacted]	90%	90%	90%	76%	78%	78%
	[redacted]	94%	94%	94%			
	[redacted]	95%	96%	96%			
	[redacted]	95%	96%	96%			
Central	[redacted]	95%	95%	96%	77%	77%	74%
	[redacted]	92%	92%	92%			
	[redacted]	96%	96%	97%			
	[redacted]	91%	91%	87%			
South Wales	[redacted]	95%	95%	95%	86%	86%	90%
	[redacted]	93%	93%	98%			
	[redacted]	97%	97%	97%			
South West	N/A - no entry points of note in zone						
East Mids	N/A - no entry points in zone						
South East	[redacted]	83%	87%	87%	64%	74%	76%
	[redacted]	77%	85%	87%			
	[redacted]	N/A - Can only be used to support Bacton entry not Isle of Grain					
	[redacted]	N/A - Can only be used to support Bacton entry not Isle of Grain					

Table 25 - Entry Availabilities summary

[17] NGT_EJP013_Compressor Fleet – Network Investments and Zone 1 (Scotland)_RIIO-GT3, NGT_EJP014_Compressor Fleet - Zones 2 and 3 (Central) _RIIO-GT3, NGT_EJP015_Compressor Fleet - Zones 4 and 5 (South Wales and South West)_RIIO-GT3, NGT_EJP016_Compressor Fleet - Zones 6 and 7 (East Midlands and South East)_RIIO-GT3

Zone	Compressor Station	By Compressor Station			By Zone		
		End of RIIO-T2	End of RIIO-GT3		End of RIIO-T2	End of RIIO-GT3	
			Counterfactual	With proposed investment		Counterfactual	With proposed investment
Scotland and the North	[redacted]	90%	90%	90%	45%	34%	81%
	[redacted]	53%	41%	94%			
	[redacted]	95%	93%	96%			
	[redacted]	N/A - not utilised to support exit					
Central	[redacted]	95%	95%	96%	77%	77%	72%
	[redacted]	92%	92%	92%			
	[redacted]	96%	96%	97%			
	[redacted]	91%	91%	85%			
South Wales	[redacted]	N/A - not utilised to support exit			91%	91%	95%
	[redacted]	93%	93%	98%			
	[redacted]	97%	97%	97%			
South West	[redacted]	93%	93%	98%	60%	68%	83%
	[redacted]	97%	97%	97%			
	[redacted]	94%	94%	94%			
	[redacted]	72%	81%	94%			
	[redacted]	98%	98%	98%			
East Mids	[redacted]	83%	87%	87%	83%	87%	87%
South East	[redacted]	97%	97%	97%	43%	59%	64%
	[redacted]	94%	94%	94%			
	[redacted]	77%	85%	87%			
	[redacted]	70%	82%	85%			
	[redacted]	87%	93%	94%			

Table 26 - Exit Availabilities summary

It should be noted that some counterfactual numbers include some baseline investment, for instance in the South West and South East zones.

3. Biomethane and Green Gas Connections

3.1 Biomethane and Green Gas Connections Purpose

This section describes the key activities that we will set out within the RIIO-GT3 period to promote the development of biomethane and green gas connections to the National Transmission System (NTS).

3.2 Why the NTS is the best option for green gas connections

3.3 Ambitious and challenging

There is currently one biomethane site connected to the NTS, with another site due to commission later in 2024. Whilst there has been interest from multiple parties for connections to the NTS, there are high costs and longer timelines associated with NTS connections. The initial connection charge is £1.5m-£2m and can take up to three years to implement. Whilst the connection cost requires intervention from Ofgem, we are proactively addressing the issues which impede on timelines. For example, we are introducing standardised green gas connection designs and procuring long lead items to manage stock levels, to ensure we can be agile to demands.

Our intelligence suggests there could be up to 51 new biomethane sites wanting to connect to the NTS, with an associated volume of up to 3.8TWh (terawatt-hours).

We are aiming to have these connected by 2030. Since 2020 there have been two entry connections, one of which was biomethane injection. Our proposal will see a significant increase in new connections, which underlines the ambition we have for biomethane on the NTS.

We may utilise a funding mechanism for the associated costs, to enable the development of green gas/net zero projects, outside of the RIIO-GT3 submission. One possible mechanism which could be used is the Net Zero Pre-Construction Work and Small Net Zero Projects Reopener (NZASP).

3.4 Enabling policy, commercial and industry activities

Whilst NGT is improving internal processes and procedures for the connection process to gain efficiencies, we will be reliant upon enabling policy, commercial and industry activities to facilitate the uptake in biomethane and green gas connections. Below is a summary of these areas:

Enabling Area	Description	Development
Policy	Tariff socialisation	• Creation of a framework to apportion costs of connections, to stimulate growth in transmission level connections for biomethane and other low carbon gas supplies. • Framework implementation would need to be considered once methodology has been agreed.
Policy/ Commercial	Economic appraisal	• Adoption of an economic/environmental test. • Agreement with Ofgem needed on who administers the appraisal process, most suitably National Gas.
Commercial/ Industry	Green Gas Certification	• Incentivise businesses to inject biomethane and green gases onto the NTS through tradeable certification of green gases. • The NTS allows for gas molecules to be transported from the north of Scotland to the South of England, so it would be physically possible for companies to claim their gas comes from green sources. • This creates a market for green gas and encourages growth.
Industry	Connection Process	• National Gas to focus on streamlining the connection process to ensure it is not a limiting factor in developments. • Standardisation of connection designs and reducing timelines to connect biomethane and other green gas sources.
Industry	Planning and Consents	• Working with industry players to ensure that all land and planning requirements are understood, to avoid delays with connections. • Potential for strategic locations of the country for connections to maximise opportunities.
Industry	Engagement	• National Gas will engage with biomethane producers and gas consumers alike to ensure that our proposals for the expansion of biomethane and green gas connections meet the requirements of industry. • Feedback will be used to inform the improvements and proposition.

3.5 Incorporating stakeholder feedback

We have increased engagements with biomethane producers over the past 12-18 months to understand the reasons why fewer biomethane connections have been made on to the NTS. These engagements have either related to specific biomethane connection enquiries or generic discussions with producers via the Biomethane Forum. The general feedback has been around the timeliness and the cost of connections to the NTS, which is why our focus on cost socialisation and streamlining the connection process are high on the agenda.

The Customer and Stakeholder team will be engaging further with biomethane developers to share our proposals with them and to get their specific feedback on them, which we will incorporate into the final solutions we propose.

3.6 Measuring success

Based on associated volumes of up to 3.8 TWh per year in gas flows and data for carbon dioxide captured each year, this could equate to an estimated carbon saving of approximately 500,000 CO_2/tonne/year. Whilst these values are the ultimate goal, our ability to deliver these carbon savings will be a shared responsibility with the biomethane producers, who will be reliant on their funding and ability to develop their schemes.

New KPIs will focus on reducing the application-to-offer process times from six months to three months and reduce costs for connections through efficiencies and process improvements. We will work with Ofgem, the Department for Energy Security and Net Zero (DESNZ) and biomethane producers to develop these measures accordingly.

3.7 How we'll deliver our proposals

We believe the work packages outlined above are ambitious and will help grow the biomethane market in Great Britain. We have already begun work on these initiatives in RIIO-T2 and will anticipate that these activities will continue into the beginning of RIIO-GT3 and beyond. We will engage with stakeholders on the development of these proposals and implement framework changes as appropriate.

4. System Operator Incentives

4.1 Introduction

Over the past 12 months, we have engaged extensively with our customers and stakeholders to review our current suite of incentives to ensure that they remain consistent with the above customer values and continue to drive the right behaviours.

The consultation feedback has shown that the RIIO periods have seen our suite of incentives work as intended and have incentivised us to take the right actions to create consumer value. The incentive principles have been tested and widely supported by our stakeholders across various engagement channels. Consultation feedback has helped shape our RIIO-GT3 incentive proposals and measures.

This proposed package of incentives will drive us to continue to improve our performance in areas we are told are important, to support the efficient operation of the wholesale gas market and reduce the environmental impacts of our operations.

Our stakeholders told us that reducing our impact on the environment is important, so we have developed new incentives to focus on our reducing greenhouse gas emissions. Our incentives align to the Ofgem regulatory outcomes and are backed by robust evidence and justification which can be found below.

We consulted 25 organisations, with initial principles and proposals, collecting feedback through meetings, webinars, and written responses. Stakeholders influenced our final proposals and have stated they expect Ofgem to set appropriate performance measures.

Consulted organisations include transporters, shippers, industrial customers, trade associations, storage operators, consumer advocates, LNG operators, consultancy organisations, environmental agencies, offshore producers, terminals, and the Independent Stakeholder Group.

For more information on stakeholder engagement, please refer to our Stakeholder Engagement and Decision log[18].

Unless otherwise specified, all costs within the incentive performance tables are given in 2023/2024 prices. Commentary relating to historical costs in specific years will be nominal values unless otherwise stated.

[18] NGT_A16_Stakeholder Engagement and Decision Log_RIIO_GT3

4.2 Capacity Constraint Management

4.2.1 Capacity Constraint Management (CCM) Purpose

Our capacity release obligations determine the quantity of capacity that we make available at each Entry and Exit point on the NTS and reflect the maximum theoretical physical capability of the network under peak conditions. In reality, the network does not have sufficient capability to deliver flows at that level simultaneously at all entry and exit points. Furthermore, when network demands are lower (e.g., in summer months) capability is lower across the network. The difference between network capability at low compared to high demands results in capacity release obligations which often exceed physical capability. This inherent constraint risk increases when NTS capability is reduced by unexpected asset failure or maintenance.

Several operational and commercial tools exist which allow us to proactively and reactively manage this constraint risk. The incentive drives us to use these tools in ways that minimise the operational and financial impact of constraints on our customers. When releasing non-obligated capacity (more than baseline obligations) the incentive drives us to assess the level of additional constraint risk introduced against the financial reward resulting from the scheme sharing factors and parameters.

In our RIIO-T2 business plan we identified drivers of constraints, and we consider these remain appropriate for RIIO-GT3. These include the inherent risk of commercial release obligations exceeding physical capability, unforeseeable asset health events, maintenance activities, impact of known IED and additional IED requirements, incremental capacity, network flexibility and impact of EU regulatory change.

4.2.2 Capacity Constraint Management Incentive

The CCM incentive encourages us to maximise capacity release and minimise constraint costs against a set target. If we manage constraint costs below the target through effective operational and constraint management strategies, we receive a revenue from the incentive. If costs exceed the target, we incur a penalty. Both revenues and penalties are subject to the cap and collar detailed below.

4.2.3 Performance to date

The RIIO-T1 period established a +/-£20m cap and collar, including a 44.36% Sharing Factor whereby the remaining 55.64% of any under or overspend was passed back to Shippers. The RIIO-T2 scheme was reduced to +£5.2/-£5.2m cap and collar, with the sale of non-obligated Entry and Exit capacity being subject to a 14% and a 39% sharing factor. Capacity Constraint Management Table 1 shows how we have performed against RIIO-T1/T2 incentive performance parameters.

Capacity Constraint Management Table 1

Incentive Year	Constraint Management Costs (£m) in 23/24 prices	Incentive performance (£m) in 23/24 prices
2013/14	£0.6m	£17.7m
2014/15	£0.4m	£17.3m
2015/16	£0.0m	£17.1m
2016/17	£1.6m	£17.7m
2017/18	£1.5m	£18.2m
2018/19	£0.0m	£17.2m
2019/20	£2.4m	£18.0m
2020/21[19]	£2.0m	£18.8m
2021/22	£0.0m	*£6.5m
2022/23	£1.5m	£5.7m
2023/24	£0.0m	£4.6m

*Capped performance

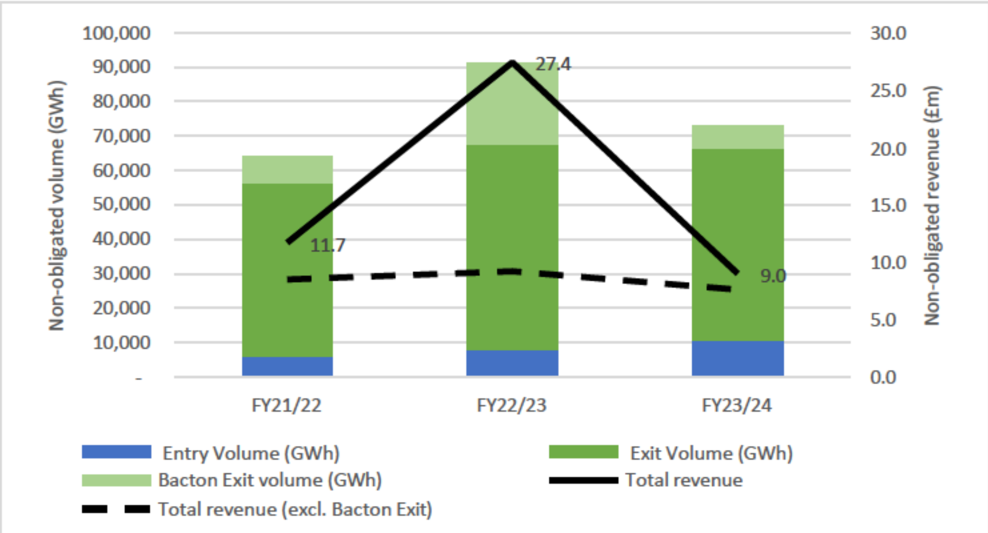
[19] In February 2021 UNC Modification 678A (UNC678A) "Amendments to Gas Transmission Charging Regime (Postage Stamp)", increased elements of CCM incentive performance; these were agreed to be neutralised and resulted in the CCM performance for 2020/21 being adjusted.

Non-obligated capacity

Non-obligated capacity is a discretionary firm product - capacity above the obligated baseline may be requested by Users and released by us following a case-by-case risk vs reward assessment. Under the current scheme, 14% of revenue from non-obligated capacity sales feeds into the incentive revenue, which then has a further sharing factor of 39% applied. In simple terms, we retain ~5.5% of non-obligated revenue - for every £1m of revenue generated we are rewarded with £55k.

The Capacity Constraint Management Chart 2 below summarises the volumes and revenues of non-obligated capacity released in the last three financial years. The unforeseen increase in exports to the EU in 2022/23 increased the non-obligated revenue by 135% and the non-obligated volume by 30%.

Capacity Constraint Management Chart 1 – RIIO-T2 Non-obligated Volumes and Revenues



Since implementation of the new charging regime in October 2020, there has been a gradual shift to short-term non-obligated capacity requests, as customers strive to tailor their capacity bookings to flows. This behavioural shift has required us to adapt our risk vs reward assessments and use more agile methodologies which support prompt decision making prior to allocation.

We will consider releasing non-obligated capacity if we have sufficient network capability and when market need is evidenced. Network capability is a product of several factors which will vary from day to day, and even within-day. The key factors which determine capability are prevailing supply and demand and the availability of assets. Our risk/reward assessments frequently lead us to reject requests for non-obligated capacity. In the first 3 years of RIIO-T2, we have rejected circa 340 requests for non-obligated capacity following risk vs reward assessments. If allocated, these would have generated ~£17m in revenue (pre-sharing) and equated to a total of 81,279 GWh out of 309,304 GWh requested (~26% rejected).

We believe that there will continue to be demand for non-obligated capacity in RIIO-GT3. Due to the scale of asset health investment and policy decisions related to hydrogen and CCUS development we expect that the risk vs reward assessment will become increasingly complex.

In most circumstances, the release of non-obligated capacity introduces additional constraint risk. The reduced network resilience that results from the increase in maintenance work in the last two years of RIIO-T2 and throughout RIIO-GT3 will create a challenging backdrop when considering non-obligated capacity release. Our belief is that the current sharing factors applied to non-obligated capacity revenue do not appropriately incentivise us to maximise the release of non-obligated capacity given the associated risk, nor do they reflect the customer value that non-obligated capacity creates (estimated later in this document).

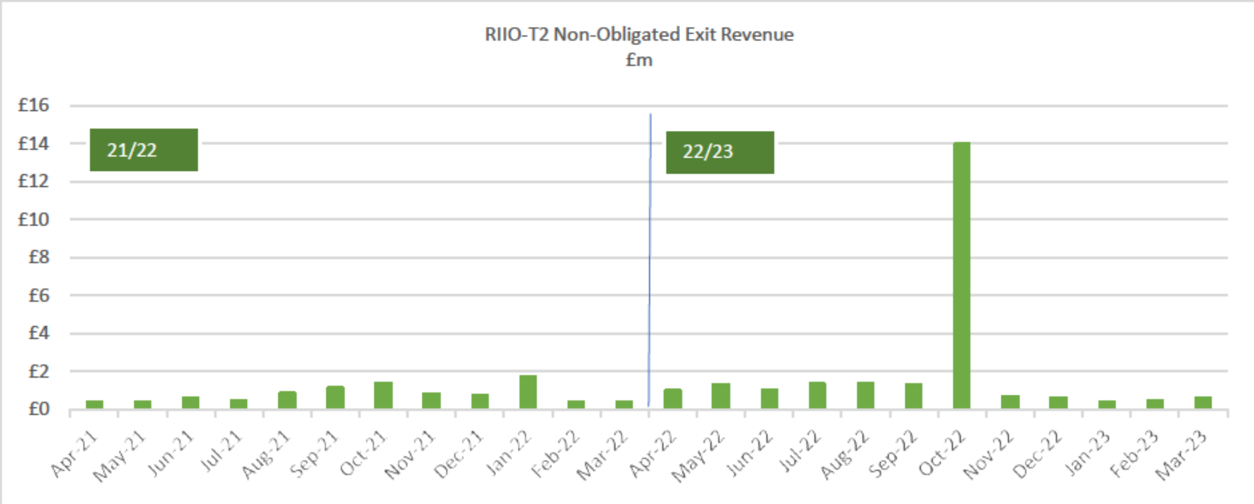
4.2.4 Factors Impacting Performance

In RIIO-T2, we experienced challenging network conditions due to global events which had a direct impact on the CCM performance. The most significant of these are outlined below.

In 2021/22, we managed an Entry constraint at [redacted] due to a congested period of LNG deliveries following sustained high winds which had delayed LNG ships docking. We utilised locational actions to maintain safe operating pressures which generated a revenue of £3.6m across 2 days (pre sharing factor). This resulted in a performance outturn which exceeded the £5.2m cap. Without these actions, the year's incentive performance would have been ~£4.0m.

In 2022/23, the war in Ukraine led to us releasing unprecedented levels of non-obligated capacity to support high export flows to the EU through the [redacted] interconnectors. The increased volumes and revenues through the summer months were compounded by shippers electing to pay a premium over the reserve prices in October, which generated £13.5m in that month alone, as shown in Chart 2 below. This resulted in a performance outturn of £4.8m. Without the inflated October revenue, the year's incentive performance would have been ~£4.1m.

Capacity Constraint Management Chart 2 - RIIO-T2 - Non-obligated Revenue (pre sharing factor) 2018/19 prices



When no commercial actions are undertaken, the activities we carry out to proactively and reactively manage constraints are intrinsically difficult to capture and quantify due to the breadth and scope of effort required across our business and throu ghout our supply chain. We continue to develop our approach to capturing information in this area, which will support our proposal for greater transparency through RIIO-GT3 (see later section). In addition to the many examples cited in our stakeholder engagement we have detailed some recent examples where we needed to assess and manage emerging constraints on the network.

Teesside - June 2024. A customer requested an earlier return to operation from an agreed outage window at short notice to complete performance testing at their Above Ground Installation (AGI). Our project works were still inflight therefore we were not in a position to re-commission the site. The shipper held Firm capacity rights which presented a risk of needing to buy back their capacity if we could not facilitate their request. We worked with our internal teams and supply chain to provide an accelerated work programme, which achieved an earlier return to operation meeting their requirement.

Tirley – June 2024. Maintenance requiring full pipeline isolation and depressurisation was scheduled to replace 3 valve filters over a 2-week period and, as such, the work was aligned to customer maintenance. Once on site it became evident that the work was more complex than anticipated/planned. Even with extensive optioneering a 4-week outage period was needed. This heightened the risk of a constraint so further engineering solutions and commercial options (e.g., contracts) were explored, though none were considered feasible in the time available. A commercial strategy was confirmed to Gas Network Control teams and additional challenges encountered during the works (including plug valve issues and valve removal space) were all overcome within the allocated time.

4.2.5 Consumer Benefit

All the customers we've engaged with agreed that the scheme delivers value in principle. Some customers noted that if there is no incentive 'we might see more conservative attitude and associated risk aversion in capacity release which may have a great impact on market flexibility'.

The consumer benefit from the CCM scheme is realised from.

1. effective constraint management strategies leading to efficient mitigation and/or management of constraints, and
2. releasing capacity over and above our baseline obligations, supporting market flexibility and delivering value to shippers and consumers.

These then reduce the operational impact, the overall costs, and the risks to our customers. Whilst we recognise that the benefits are hard to quantify, at a principal level, the key benefits of the CCM scheme are:

To try and quantify the customer value created by the CCM incentive, we have estimated the value of the non-obligated capacity released as well as the impact constraints could have on NBP prices.

Impact of non-obligated capacity release

<u>Release of non-obligated capacity at the [redacted] Exit Interconnection Point</u>

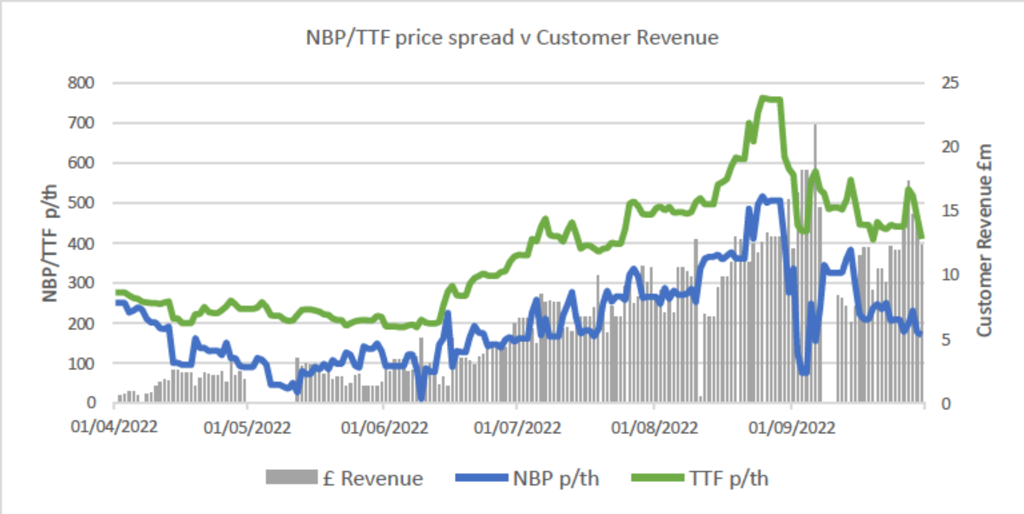
Through Summer 2022, we regularly increased the level of available capacity for customers at the [redacted] Exit point from ~660GWh/d to ~825GWh/d, to support replenishing EU storage stock for winter. To quantify the financial value this created, we used the following approach:

- We considered the Argus NBP and TTF day-ahead and weekend price spreads[20] for the period 1st Apr to 31st Oct 2022.
- We assumed 100% of allocated non-obligated capacity was utilised (e.g., gas flowed to the level of Exit capacity sold).
- We calculated the commodity value by multiplying the volume of allocated non-obligated capacity released by the relevant daily NBP/TTF price spread.

Capacity Constraint Management Chart 3 illustrates the NBP and TTF gas price spread for summer 2022 alongside the calculated customer revenue from additional gas flows, using the approach detailed above.

[20] Argus Media Ltd is the source of the data, on which National Gas has produced the graph above. National Gas obtains data from Argus Media under licence, from which data National Gas conduct and publishes its own calculations. Argus makes no warranties, express or implied, as to accuracy, adequacy, timelines, or completeness of its data or National Gas's calculations, or fitness or fitness for any particular purpose. Argus should not be liable for any loss or damage arising from any party's reliance on Argus' data or National Gas's calculations and disclaims all liability related to or arising out of use of the data and/or calculations to the full extent permissible by law.

Capacity Constraint Management Chart 3 – NBP/TTF price spread v Customer Revenue



Customer revenue from gas flows supported by non-obligated capacity was calculated to be £1.1bn for the summer 2022 period, with an average daily revenue of £6.4m (ranging from £0.5m to £21.7m). In this period, we utilised all available resources to support the release of non-obligated capacity on 99% of days, allocating an additional 17,154 GWh and generating £4.3m in revenue. Retained revenue was £233k after the sharing factors were applied.

Although many factors influence gas prices (such as level of storage stock, availability of alternative supply, level of demand), and we have not accounted for additional transportation charges, the price spread between the two hubs indicates the order of magnitude of value to customers. There could be additional value we have not accounted for, as we have not attempted to quantify the value derived from facilitated efficient trade between the two markets.

To further support the EU in securing gas for winter 2022/23 we engaged with customers in relation to network capability and non-obligated release. We developed and published a tool to indicate the likelihood of non-obligated capacity release, improving transparency and aiding customer decision-making. Customer feedback at the time praised our assessments and transparency.

The average [redacted] Exit customer value, based on FY2021-FY2023 and the annual average Argus day-ahead/weekend NBP and TTF price spread, is ~£274m, recognising that the 2022 outcomes were driven by extreme market conditions. It is worth noting that while the FY2022 figure captures 12 months, the estimated value is lower than that captured in the previous analysis (estimated customer value of £1.1bn for summer 2022). The earlier analysis used the applicable day ahead/weekend price spread, whilst this analysis uses an annual average price spread (the NBP TTF average summer price spread was 5.6p/kWh compared to the annual spread 3.51p/kWh).

Release of non-obligated capacity at other Entry and Exit points.

To estimate the customer value of Entry and Exit non-obligated capacity release since the start of RIIO-T2, we've used the following approach:

- For each financial year we have extracted the volume of non-obligated capacity released at all Entry and Exit points.
- We have assumed a utilisation rate for non-obligated capacity allocated based on FY23/24 behaviours (54.9% for Entry and 64.1% for Exit).

For Entry, to estimate the customer value we have considered 2 hypothetical scenarios which could have occurred if the non-obligated capacity had not been allocated.

- **Scenario 1** considers the SAP and SMP Buy price spread. SAP represents the average market price and SMP Buy represents a customer having bought the gas but being unable to trade at the NBP due to the absence of non-obligated capacity. In this scenario, we have assumed customers would need to source the gas at a different location (presumably at a higher price) or be cashed out for their imbalance at SMP Buy.
- **Scenario 2** considers the SMP Sell and SMP Buy spread. SMP Sell represents a customer having brought gas in advance at a lower price than SAP. SMP Buy representation is as per Scenario 1.

For Exit, to estimate the customer value we have considered IP and GB Exit points separately (excluding GDNs due to their 1 in 20 obligations). For GB Exit points, as per entry calculations, we have considered 2 hypothetical scenarios.

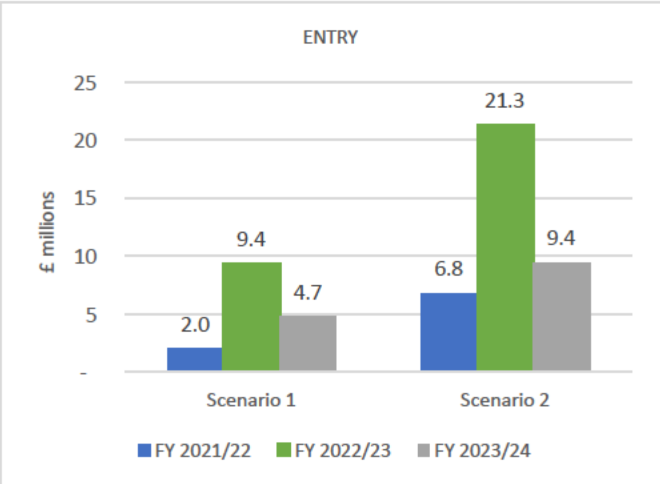
- **Scenario 1** considers the SAP/SMP Sell price spread. SAP represents the average market price and SMP Sell represents a customer having bought the gas but being unable to flow it due to non-obligated capacity not being available. In this scenario, we have assumed it is likely customers would incur additional costs either to re-route the gas to a different location; sell it to another Shipper; inject into storage (at a loss due to stressed conditions) or get cashed out for the imbalance at SMP Sell.

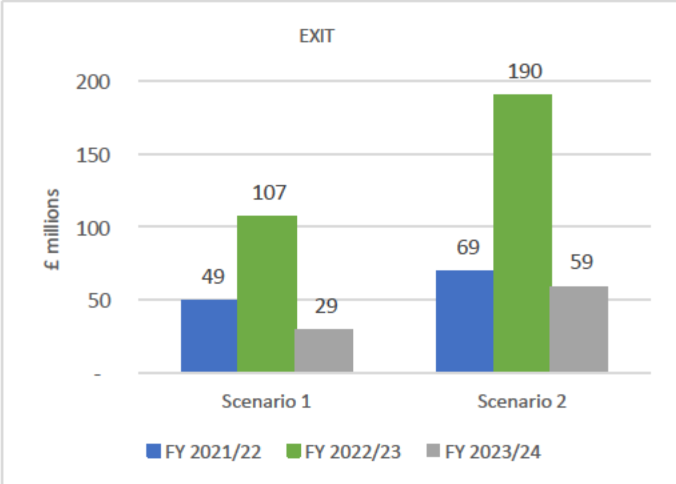
- **Scenario 2** considers the SMP Sell and SMP Buy spread, using a reverse logic to the Scenario 2 Entry calculation.

Capacity Constraint Management Charts 4 & 5 show the calculated estimates for each of the scenarios described above. In summary, the 3-year average annual customer value:

- For Entry, ranges from ~£5m (Scenario 1) to ~£13m (Scenario 2).
- For Exit, ranges from ~£62m (Scenario 1) to ~£106m (Scenario 2).

Capacity Constraint Management Charts 4 & 5 – scenario estimates





Impact of capacity constraints on the market

To assess the customer benefit of the CCM scheme beyond non-obligated capacity release, we have estimated the impact constraints might have on the wholesale gas price. Several studies have been published attempting to estimate the impact of constraints on energy prices. One recent study by The Conversation estimated the impact on LNG carriers of not being able to berth when the energy crises evolved in the EU in 2022. The analysts used econometrics to estimate that '~10% of the energy inflation in the EU was the result of port congestion'. They concluded that a 10% increase in the time that LNG vessels were delayed in berthing at EU ports increased gas prices by 1%.

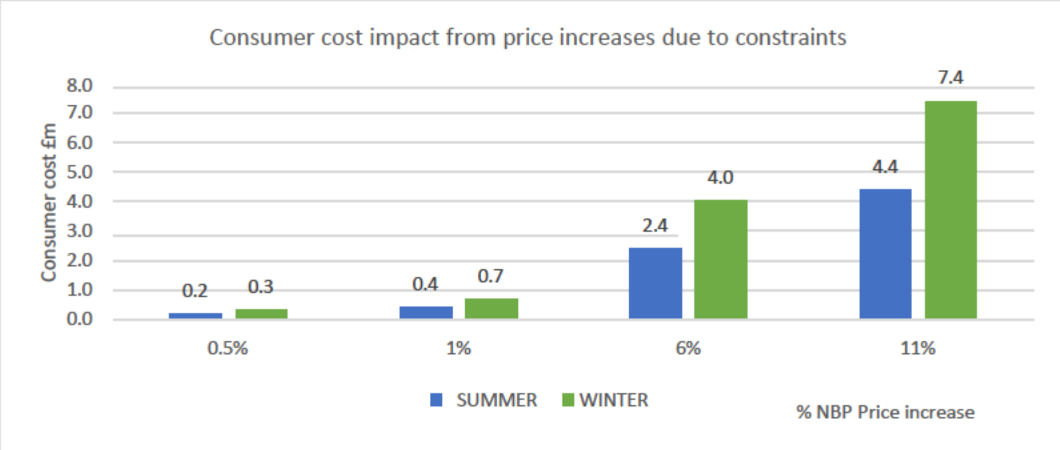
Other studies estimate that the impact of limited capacity on energy prices could be significantly higher (6-11%) and we believe the complexity of market interactions makes it difficult to favour any one assumption over another. The constraint management costs will ultimately depend on multiple factors including the geographic location of the constraint, local and national/international demand, constraint duration, the constrained volume and severity of impact.

We have used the following assumptions to estimate the impact of Entry constraints on market prices:

- an average summer (April – September) SAP of 2.86p/kWh, and average winter (October -March) SAP of 2.90p/kWh (based on FY2023/24).
- a constraint duration of 24 hours.
- an average summer/winter demand of 121mcm/d and 212mcm/d respectively (based on FY2023/24).
- a potential 0.5%, 1% and 6% and 11% impact of a constraint on the NBP price (SAP).

Capacity Constraint Management Chart 6 shows the estimated additional cost to customers (and potentially end consumers) of between £0.2 – £7.4m due to the impact of a constraint on NBP prices per day. We appreciate that not all the impact would materialise on the day (e.g., repercussions could impact long-term contracts) but feel this estimation serves as a reasonable proxy. The CCM incentive drives us to actively mitigate and manage constraints which we believe directly leads to more stable prices, thus shielding customers from price spikes such as those presented in the chart below.

Capacity Constraint Management Chart 6 – Consumer cost impact from price increases due to constraints.



We've shared examples of proactive actions undertaken to avoid constraint in an industry webinar. This was positively received with expressions of a need for further transparency in this area, which we addressed as a part of our proposal later in this document.

When asked whether our analysis reflect the value the incentive brings to the market, two participants agreed, two disagreed and fourteen were unsure, some commenting that it's a complex area which would take time to be fully understand or that with many assumptions there is a risk that the benefit is overestimated.

4.2.6 Process Improvements.

During RIIO-T2, we improved our processes and increased the breadth and depth of collaboration across our business to better mitigate the CCM risks and be better placed to meet customers' requirements. Annual seasonal preparedness sessions, along with monthly, weekly, and within-week reviews, allowed us to identify and reassess specific network challenges to support proactive constraint management strategies as required. These are kept under review and as such have proven effective in managing the inherent risk that exists across the network. We have also evidenced our ability to reactively manage constraints and maximise the use of assets/the NTS - adapting and tailoring our processes to manage the challenges faced during RIIO-T2. Examples of improvements driven by the CCM scheme principles include:

- Challenging ourselves to consider a greater level of risk when assessing non-obligated capacity release.
- Using real experiences to inform decision-making.
- Applying a more innovative approach to maintenance by trialling new asset configurations which support flow levels during physical works.
- Collaborating with supply chains for creative engineering solutions, reducing outage periods (planned and unplanned), minimising capability reductions, and lessening customer impact.
- Conducting detailed analysis for customers requiring capacity beyond obligated levels and substituting capacity from underutilised areas, in place of triggering network reinforcements.
- Realigning and reducing outages at cost, using key contractual levers like 24-hour shift working as needed.
- Presenting combined physical, operational, and commercial viewpoints to customers, explaining challenges and decisions.

4.2.7 Proposal for RIIO-GT3

There are no changes to baseline arrangements being considered for implementation during the RIIO-GT3 period, and as such the inherent risk described above will continue to need to be actively managed.

Although potential constraints arise throughout each year, use of commercial tools has to date been infrequent due to us proactively managing the network and deploying bespoke strategies. Our proactive strategies have involved us moving maintenance, using contracts pertaining to specific sites and equipment, assessing the risk/reward of alternative engineering solutions, and having operational staff on site to ensure asset availability. Our reactive strategies may be triggered by events such as third-party damage, asset losses and unforeseen changes to customer requirements. These have also proven highly effective in maintaining safe operations whilst minimising the need to use commercial constraint management tools.

The CCM incentive also drives us to meet customer requirements for gas delivery and offtake, encouraging the introduction of better tools and processes for assessing the risk of releasing additional non-obligated capacity. Customer engagement has confirmed that releasing non-obligated capacity is crucial for their businesses, with some considering it the most important aspect of the incentive.

Incentive Structure

We believe that the CCM scheme should be retained broadly in its current form, though some changes are required to the incentive metrics to ensure that the right behaviours are appropriately encouraged. The basis of our proposal is founded on customer feedback and our assessment of the current scheme parameters and future challenges. Table 2 contains the details of our proposal and how it compares with the current scheme.

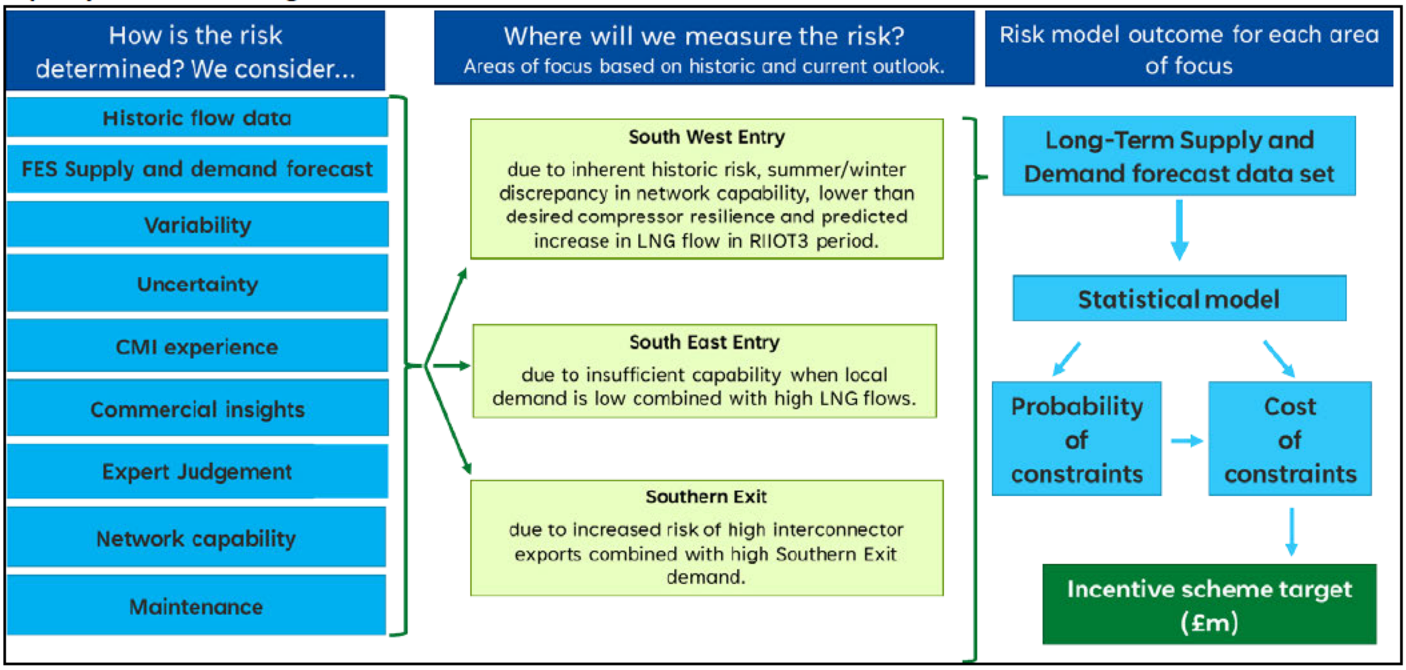
Capacity Constraint Management Table 2 – RIIO-T2 v RIIO-GT3 scheme

RIIO-T2 scheme (2018/19 prices)	Proposed RIIO-GT3 scheme (2023/24 prices)
• Cap: +£5.2m • Collar: -£5.2m • Performance Target: £8.5m	• Cap: +£7.2m • Collar: -£7.2m • Performance Target: £10.5m
Performance measure, subject to TIM, is established by summing up revenue and costs components and comparing the value to the target. **Revenue components** o Locational Sells and PRI charges o Sales of Non-obligated Entry and Exit capacity (14% of revenue subject to TIM sharing factor) **Cost components** o Locational Buys o Capacity Buybacks o Other constraint costs (e.g., turn up/down contracts)	Performance measure, subject to TIM, is established by summing up revenue and costs components and comparing the value to the target. **Revenue components** o Locational Sells and PRI charges o Sales of Non-obligated Entry and Exit capacity (14% of revenue retained, not subject to TIM) **Cost components** o Locational Buys o Capacity Buybacks o Other constraint costs (e.g., turn up/down contracts) o Commodity value associated with locational sell actions
• Incremental capacity buy back and Accelerated release mechanism.	• Incremental capacity buy back and Accelerated release mechanism (retain as is).
• Re-opener – triggered if we cap out under the scheme two years in a raw or collar out in any single year	• Re-opener – triggered if we cap out under the scheme two years in a raw or collar out in any single year (retain as is)
	• Transparency proposal

Assessment of Performance Parameters – Risk Modelling

The network capability model simulates the risk probability of different factors impacting the network on any given day, with the greatest risk occurring where several different factors impact at the same time. Long Term Forecast databases[21] are a collection of all the possible Supply and Demand patterns for a given year (980 possible scenarios for each day in that year) and provide both the nodal[22] Supply and Demands and the likelihood of certain flow patterns happening. The chart below illustrates how we have forecast the level of constraint risk (probability and cost) on the network in the RIIO-GT3 period. Chart 7 lists the model inputs which, once put through the statistical model, return an estimated probability and cost of constraints.

Capacity Constraint Management Chart 7



[21] Previously known as TobySpace
[22] Refers to individual points on the network rather than a "site type" level.

The key risk model inputs, included in the first column of Chart 7 include:

- Historic flow data – as per National Gas data portal
- FES data - forecasts created within the National Energy System Operator i.e. Future Energy Scenarios (FES) generate Supply forecasts (non-Storage Supply) and Demand curves based on an industry-consulted process. Our analysis is based on the Falling Short scenario.
- Variability - collection of all the possible Supply and Demand patterns for a given year - 980 possible scenarios for each day in that year, ranging from possible minimums to maximums.
- Uncertainty – uncertainty vectors are used to mirror the atypical flow patterns (i.e., where there is no correlation between the level of flow and demand) observed at NTS entry points. A different uncertainty vector is associated with each entry subterminal, for instance UKCS supply sites have a reasonably linear relationship with demand, more predictable behaviours and therefore a lower uncertainty vector (typically 10%). Conversely, LNG sites generally have little to no linear demand relationship, multiple drivers for changes to their flow patterns and are therefore given a higher uncertainty vector (40%).
- Constraint Management Incentive (CMI) experience – prices used to calculate costs reflecting SAP deviation and constraint resolution method and volumes seen historically.
- Commercial insights – captures insights the FES team might have not included in the future prediction of demand and supply e.g., incremental capacity requests and long-term obligated capacity bookings, impacts of the latest market developments e.g., geopolitical events or emerging investment plans.
- Expert judgement – as a system operator we continuously gain experience on how our assets react to different market and flow conditions which are not necessarily captured in the FES scenarios.
- Network capability – The network capability lines determine the capability of a geographic area and its ability to cope with a set of localised and network-wide conditions. Capability lines are derived using network analysis carried out using the modelling tool SIMONE to simulate the behaviour of the NTS under set conditions.

  Our network capability equations incorporate compressor reliability data. Compressor data was taken for each individual unit and based on operational reality, aggregated into combinations of compressors that would be used to manage pressures and flows on the NTS. Our approach to compressor availability and capability equations is explained in detail in our ANCAR 2023 publication. For modelling purposes, these variables were added to determine the number of days we will have some level of compressor unavailability. The remaining scenarios were intact (all compressors are assumed available), therefore when running the model, an intact or non-intact was selected for analysis.

  In RIIO-T1 we measured compressor reliability regionally/in silos while our current approach considers interactions between different parts of the network. We now understand the interdependencies much better and can therefore assess different capabilities based on assets available and the conditions we have on the network more comprehensively.
- Maintenance – When interventions such as isolations and pressure restrictions are required on the network to deliver maintenance and investments, these typically reduce system capability, flexibility, and resilience, thereby resulting in significant addition constraint risk, which should be reflected in the scheme target. We mitigate much of this risk by collaborating with the users of our network to schedule these activities in such a way as to minimise their impact. There may, however, be substantial interventions for which this is not possible, especially when the duration is long and/or the impact on capability is high. Detailed planning and scheduling of our Asset Management Plan (NGT_A1_Asset Management Plan (AMP)_RIIO_GT3) over the next few months may identify additional constraint risks which need to be added to our proposed incentive target.

Assessment of Performance Parameters – Constraint Cost Calculation

For each year we generate an estimation of constraint events, volumes, and associated costs.

- **Event Calculation**. To identify a constraint on any given day the analysis looks at whether the net of the supply and demand exceeds network capability to determine a potential constraint (e.g., net supply > entry capability = an entry constraint event, and net demand > exit capability = an exit constraint event).
- **Constraint volume**. The constraint volume is the difference between boundary curve (capability) and net supply (on entry) and boundary curve and net demand (on exit).
- **The buy back volume** is reflective of half of the capability impact of losing a key compressor. Constraints experienced in RIIO-T2 have been predominately due to a combination of high flows and asset failure, so we believe this is reflective of reality (for all areas in Summer 5mcm/d assumed, in Winter for SW and SE Entry 10 mcm/d and for SO Exit 5mcm/d assumed).
- **Forward prices.** Gas prices used are based on the DESNZ Annex M values and range from 101p/th in October 2026 to 73p/th in October 2031 (Reference tab wholesale gas prices). We have adjusted DESNZ prices to apply these to financial years.
- **Price deviation**. To make the prices reflective of those experienced when constraints have materialised on the network, we have:

- For locational actions: adjusted the DESNZ prices by applying historically experienced average price deviation from SAP to the costs/revenues from locational actions. On Entry, locational sell deviation equates to 76% of SAP, locational buy to 137%. On Exit, the average locational buy action equates to 145% of SAP, and the corresponding sell action to 71% of SAP.
- For buybacks: assumed 150% SAP.

Costs of constraints. The price deviations are applied to the constraint volumes to generate the event cost. Each event cost is calculated by applying a resolution method assumption (see below) and associated probability (see above: event calculation)/price deviations to the volume specific to that constraint day. The costs for each day are then aggregated.

Resolution method. We have applied a specific resolution method to each location to better reflect recent experiences, where these are available. Through RIIO-T2, locational actions have proven effective in resolving entry constraints at Milford Haven, though elsewhere this has not been the case (e.g., [redacted] in May 2023). We believe buy backs need to remain as a potential resolution method when valuing the cost of constraint management events. Our breadth of experience in using commercial tools is limited, but it is important to recognise that when executing locational actions and buy backs, we are entirely reliant on the market responding.

We believe that by making changes to the resolution method approach, and other risk inputs, we have improved the accuracy of our cost estimation outcomes and made them more reflective of operational reality. Capacity Constraint Management Table 3 summarises the key changes we have introduced:

Capacity Constraint Management Table 3 – RIIO-T2 v RIIO-GT3 Risk Modelling

Risk modelling	RIIO-T2	RIIO-GT3
Network capability	Capability was measured in zonal isolation.	Zonal interactions incorporated in modelling.
Calculation of constraint volume	The buyback constraint volume was calculated as the difference between baseline and network capability.	The buyback constraint volume reflects operational reality and RIIO-T2 experiences (half of the actual capability lost when a compressor unit fails).
Constraint resolution method	Used 50/50 resolution method for all locations.	Approach tailored to reflect RIIO-T2 experiences, albeit these have been limited in frequency/location. Southwest 75/25 applied i.e., the model will assume 75% of constraints will be resolved via locational actions and 25% via buy back. Other locations 50/50 applied.
Maintenance	Approximate work categories and numbers considered.	Capabilities required to deliver the vast majority of Asset Management Plan used to generate the constraint risk associated with maintenance works

Customer feedback confirmed that risk modelling is a complex area; with five out of fifteen webinar participants confirming that we had clearly articulated our approach (ten were unsure). Four out of ten agreed that we have made relevant improvements to the way we model the risk, however six were unsure.

Assessment of Performance Parameters – measured risk areas

UKCS decline will lead to changing supply and demand patterns on the NTS both generally over time, between days and within day – all of which provides a challenge when operating the system. According to predictions (see DESNZ analysis) LNG is expected to provide an increasing proportion of GB's gas supply and therefore there will be potential for more 'unseasonal' behaviour and high winter flows at both [redacted] and [redacted].

South West Entry: This part of the network is where we have experienced the highest volume of constraints materialising in RIIO-T2. Physical capability varies significantly across the year in this part of the network due to it being reliant on a single feeder and, critically, local demand.

At the time of undertaking our analysis, and included in the underlying FES23 forecasts, was an assumption that the in-flight PARCA (the "Western Gas Network Upgrade" project) would be completed by January 2026, providing higher [redacted] Entry capability. The PARCA has since been terminated therefore our asset investment proposal for RIIO-GT3 now includes some physical works in the South West which would provide some reinforcement in this area. The analysis when based upon FES24 data shows no changes to investment options.

The aggregate [redacted] Entry flow data shows an increase over the last 10 years (see Capacity Constraint Management Chart 8) adding to our concerns regarding capability and resilience in that part of the network.

Capacity Constraint Management Chart 8

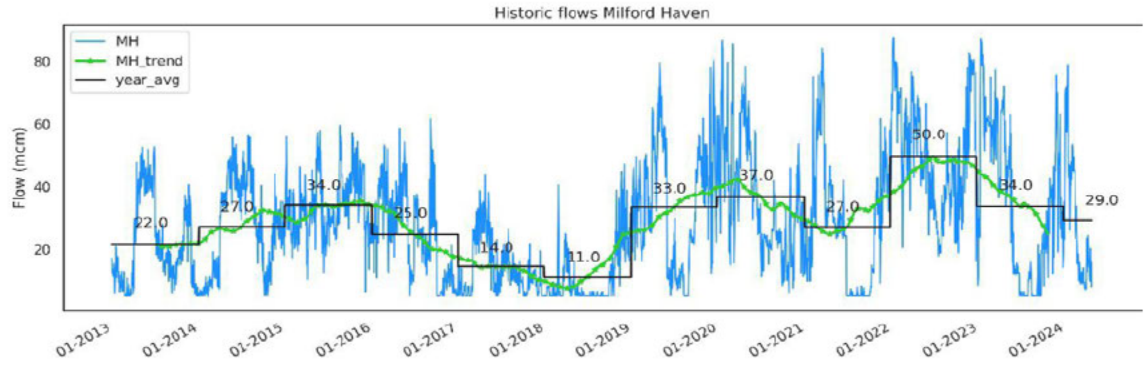
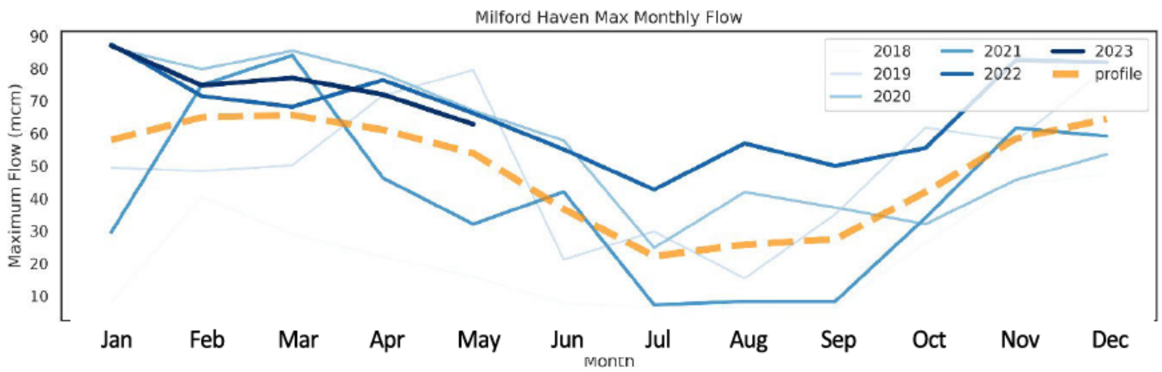


Chart 9 shows a trend of high flows materialising towards the end of winter and beginning of summer when entry capability is significantly reduced primarily due to local demand reducing.

Capacity Constraint Management Chart 9



South East Entry: Our network analysis indicates (see ANCAR report) that the risk of constraints at [redacted] starts increasing when there is lower NTS demand but when there is also an increase in LNG flows which we expect in the RIIO-GT3 period.

Southern Exit: The ANCAR report also states that the South East Exit region does not have sufficient intact network capability to meet exit requirements either now or in the next 10 years, when there are minimum feasible supplies from [redacted] and [redacted]. This is evidenced by the 1 in 20 demand level being above the intact network capability.

We included Scotland Exit risk in our initial analysis, however we have discounted this from outputs as the inherent risk is less than 1 day.

Treatment of commodity value associated with locational sell actions.

In our analysis (and in events seen through RIIO-T2), resolving constraints through the use of locational sell actions can result in a net revenue feeding into the CCM performance measure. Ofgem have asked us to consider amending this approach for RIIO-GT3 such that any commodity value of locational sell volume is included in performance measure and target calculation as a cost and offset against the locational sell revenue. The driver for this is to further encourage us to mitigate constraints on the network.

By accepting locational sell offers we effectively reduce the volume of gas entering the NTS. To replenish this gas, the future calculation will incorporate that volume into the formula at a market value i.e. End of Day ISAP, ultimately making the outturn of the equation a net cost. When applying formulae to gauge the magnitude of impact of this proposal, we considered a scenario when only locational sell actions are taken to resolve the constraint, as well as a scenario when locational buy actions are required as a secondary action to maintain the overall system balance.

- For Entry: ((Locational Sell volume – Locational Buy volume) * EOD SAP)
- For Exit: ((Locational Buy volume – Locational Sell Volume) * EOD SAP)

To include this element in our RIIO-GT3 constraint risk analysis we have:
- taken the average daily constraint volume for 2026 for each location and for simplicity, applied this to each year in the RIIO-GT3 period.
- applied resolution methods and SAP deviations as per the assumptions in our risk modelling.

- assumed that the volume of any secondary action taken will be half of the primary action.

In an industry webinar on our proposed scheme outline we have asked participants whether they agree with the inclusion of cost of gas related to locational sell actions in the scheme performance measure. Ten out of fourteen respondents agreed, while four were unsure.

Assessment of Performance Parameters – RIIO-GT3 Constraints

RIIO-GT3 Constraint Results. Below is a summary table of the RIIO-GT3 constraint forecast results based on the FES23 Falling Short data and utilising the methodology explained previously. The "Events" data represents the number of constraint days forecast to occur in each year, and alongside this is the associated cost forecast to resolve those constraints based on the resolution method applied to each location. We have added locational sell commodity cost as a separate cost at each location.

Capacity Constraint Management Table 4 - Inherent risk forecast analysis and cost of gas associated with locational sell actions - results.

Location >	South West Entry			South East Entry			South East Exit			
Resolution Method >	75/25			50/50			50/50			
	Constraint Days	Inherent Risk	L/Sell cost of gas	Constraint Days	Inherent Risk (£m)	L/Sell cost of gas	Constraint Days	Inherent Risk	L/Sell cost of gas	Annual Cost
26/27	6	-£3.1m	-£3.3m	3	-£3.8m	-£1.1m	0.3	-£0.3m	-£0.1m	-£11.7m
27/28	3	-£1.8m	-£1.6m	3	-£4.2m	-£1.5m	0.1	-£0.1m	£0.0m	-£9.2m
28/29	4	-£1.9m	-£2.0m	4	-£5.0m	-£2.0m	0	£0.0m	£0.0m	-£10.9m
29/30	4	-£1.7m	-£2.1m	5	-£4.8m	-£2.2m	0	£0.0m	£0.0m	-£10.8m
30/31	4	-£1.5m	-£2.0m	4	-£4.2m	-£2.0m	0	£0.0m	£0.0m	-£9.7m
Total	21	-£10.0m	-£11.0m	19	-£22.0m	-£8.8m	0.4	-£0.4m	-£0.1m	-£52.3m

Assessment of Scheme Parameters

In summary, based on the risk analysis undertaken (FES23 basis) we propose the following CCM scheme parameters, and explain our rationale in more detail below:

- An annual CCM cost target of £10.5m (noting that this excludes the risk associated with maintenance activities)
- A symmetrical Cap and Collar of £7.2m subject to the Totex Incentive Mechanism (TIM) sharing factor.
- Exclusion of the non-obligated capacity revenue from TIM
- Commodity value associated with locational sell actions to be added to the performance measure and ultimately, the scheme target.
- Greater transparency for customers to explain constraint management activities (reactive and proactive)
- Retention of the current re-opener and accelerated risk, i.e.
    - a scheme target reopener is triggered if we reach the cap two years in a row or reach the collar in any single year.
    - no changes to the incremental buyback (100% downside) and accelerated release (100% upside) elements to the scheme.

<u>CCM Cost Target</u>

Our RIIO-GT3 risk forecasts indicate a mean average annual cost of managing constraints of £10.5m (based on the increase in gas price since 2021 this equates to ~£11.5m target) across the 3 locations defined, and we propose for the new incentive target to reflect this. We believe this target to be challenging as it assumes that a proportion of our inherent risk forecast will be managed using the existing commercial tools available and operational strategies. In addition, we have excluded all risk related to delivering maintenance from the scheme cost target. This principle was supported by our stakeholders in RIIO-T2 engagement, but this would mean that the cost target becomes less reflective of the risk we expect to manage in RIIO-GT3.

Using an average mean annual constraint cost, which the above numbers are based on, could ultimately be perceived as a conservative view of risk (i.e., it excludes the lower probability high-cost events including maintenance risks) by averaging the entire risk for all probabilities. We believe using an average is a reasonable and sensible approximation of the RIIO-GT3 inherent constraint risk and will strive to provide customers with the level of system use flexibility that they currently benefit from. The scale of maintenance work to be delivered, and extent of granularity we have yet to define will undoubtedly create an additional challenge for us. We believe we are well-placed to manage this given our ambitious approach to continual improvement.

<u>Constraint Management Cap and Collar</u>

We believe the scheme cap should be high enough to mean capping is considered unlikely but should also be set low enough to ensure windfall gains don't occur. Given that gas prices used in our risk analysis increased by 37% on average in comparison to these used in our RIIO-T2 submission, we propose to increase the cap and collar by an equivalent to +/- £7.2m.

Given complexities related to risk modelling and target setting, the industry webinar participants did not express a clear view on our proposed scheme parameters; two agreed with these, one didn't, and eight were unsure.

Non-obligated revenue

The customers we directly engaged with described the release of non-obligated capacity as of 'extreme importance' and 'crucial to their business'. No views regarding a specific scaling percentage to be applied to non-obligated capacity were expressed – they perceive this to be an Ofgem decision. Several customers suggested they would not raise objections, should a reasonable increase be proposed and justified. One customer stated that 'non-obligated release is definitely better than reinforcement investment', another thought that an increase share from sales 'seems reasonable because there is risk related to non-obligated capacity release in terms of stretching the system'. Lastly, it was mentioned that 'value should be proportionate to the effort going into achieving the good performance'.

Considering the customer value, the release of non-obligated capacity delivers, and the customer feedback above, it is our view that the non-obligated revenue should not be subject to the Totex Incentive Mechanism in the RIIO-GT3 period, but that the 14% sharing factor should be applied.

Incremental Capacity Buy back scheme and Accelerated release of incremental obligated capacity scheme

To date in RIIO-T2 we have not allocated any incremental entry or exit capacity and hence have no data available to analyse our performance under the scheme. We are currently in discussions with a customer regarding the potential application for Incremental Entry capacity that cannot be met through capacity substitution and are aware that unsold capacity available for substitution in certain parts of the network is either not available or of limited availability (meaning future requests for incremental capacity are less likely to be delivered via substitution). For that reason, we think that the accelerated capacity release scheme should be retained for RIIO-GT3 in its existing format.

Re-opener

Under the RIIO-T2 scheme a target reopener can be triggered if we cap out under the scheme two years in a row or collar out in any single year. We propose to retain this element of the scheme. In such scenario, especially if impacted by market volatility or geopolitical events, we should be prepared to review the scheme parameters at pace.

Transparency of reporting

Feedback received from our customer engagement indicated a need to provide more transparency around the actions we take when constraints materialise, or when we proactively manage the network to avoid constraints. As a result, we commit to provide the industry with the following:

- Constraint management activities– following each constraint incident where commercial actions are enacted we will share the event context in the Gas Operational Forum, including operational details on decisions made as well as financial impacts materialised.
- Constraint management actions – bi-yearly to present in the Gas Operational Forum detailing examples of where we have undertaken non-commercial actions to prevent constraints through the preceding Summer or Winter period.

Five out of eleven webinar participants agreed that our transparency proposal meets their requirements, while four were unsure and one disagreed.

4.2.8 Options Considered

We have considered and discounted the following options alongside our proposal.

Capacity Constraint Management Table 5 - Other options considered and discounted.

Discounted option	Further detail	Why discounted?
Inclusion of maintenance risk in the scheme target	Inherent risk of maintenance not included within the scheme parameters.	Discounted due to the uncertainty regarding the details of the plan, the impact on the scheme target relating to a low likelihood high impact event.
Revenues from selling non-obligated capacity	Considered higher percentage revenue feeding into the scheme because of customer feedback received throughout the RIIO-T2 and RIIO-GT3 engagement and importance of non-obligated capacity to customers' operations.	Discounted as we believe our current proposal provides the right balance between risk and reward. We also considered maintaining the same structure as RIIO-T2, but this does not reflect the customer value / benefit or risk.
Revenues from selling non-obligated capacity	Considered reward based on volume of non-obligated release (i.e., ratchet structure).	Discounted as this would add unnecessary complexity which would be at odds with customer feedback and Ofgem discussions through the consultation period.
Introduction of re-opener based on fluctuations of gas price (performance target linked to gas price).		Discounted as we believe our current proposal provides the right mechanism to reopen the scheme based on actual performance.
Introduction of re-opener related to major market changes/ policy developments like CCUS/hydrogen.		Discounted as we believe our current proposal provides the right mechanism to reopen the scheme based on actual performance.

4.3 Residual Balancing

4.3.1 Residual Balancing Purpose

In our role as the residual balancer of the GB gas market, we can take market actions to encourage Shippers to balance their individual portfolios and improve the national balance.

4.3.2 Residual Balancing Incentive

The Residual Balancing incentive aims to minimise our impact on the market while performing our residual balancer role. This is achieved through two elements:

1. Minimising the change in the end-of-day stock (linepack) level within the NTS. This is known as the 'Linepack Performance Measure' (LPM).
2. Minimising the price impact of our residual balancing on the market. This is known as the 'Price Performance Measure' (PPM).

4.3.3 Incentive Background

The residual balancing incentive has been in place with broadly the same structure since 2002 and was first introduced to minimise the costs of residual balancing and to target balancing costs to the appropriate Shippers. It continues to be an integral element to our residual balancer role. Residual Balancing Table 1 – shows how the scheme has changed since 2002 and shows that the scheme targets and size have broadly reduced over time.

Residual Balancing Table 1 – Changing scheme parameters. (Nominal prices)

Component	2002	2004	2009	2010	2011	2013	2021
PPM Target	20%	10%	5%	2.50%	1.5%	1.5%	1.5%
PPM Daily Cap	0% / £5k	0% / £5k	0% / £5k	0% / £2.5k	0% / £1.5k	0% / £1.5k	0% / £1.2k
PPM Daily Collar	85% / £30k	85% / £30k	85% / £30k	78% / £30k	76% / £30k	76% / £30k	76% / £24k
LPM Target	2.4 mcm	2.4 mcm	2.8 mcm	2.8 mcm	2.8 mcm	2.8 mcm	2.8 mcm
LPM Daily Cap	0 mcm / £5k	0 mcm / £5k	1.5 mcm / £4k	1.5 mcm / £4k	1.5 mcm / £4k	1.5 mcm / £4k	1.5 mcm / £3.2k
LPM Daily Collar	20.4 mcm/ £30k	20.4 mcm/ £30k	15 mcm / £30k	15 mcm / £30k	15 mcm / £30k	15 mcm / £30k	15 mcm / £24k
Annual Cap	£3.5m	£3.5m	£3.5m	£2m	£2m	£2m	£1.6m
Annual Collar	£3.5m	£3.5m	£3.5m	£3.5m	£3.5m	£3.5m	£2.8m

- 2002 - The PPM target was 10% but price spread was divided by 2 times System Average price (SAP), effectively meaning the PPM target was 20% for comparison purposes
- 2021 - The LPM Shoulder month allowance was introduced, as part of RIIO-T2

4.3.4 Performance to date

In response to the incentive being in place, we continue to work closely with industry through targeted sessions to help us understand their own balancing drivers and market views. We build this intelligence into our residual balancing strategies to help ensure our actions evolve and keep pace with the market we operate within. Furthermore, we produce weekly reports, visuals, and commentary to help GNCC make informed residual balancing decisions, share lessons learnt and embed a culture of consistency and continuous improvement across National Gas. We have specifically looked at the timing of our actions and how the market has responded to them and adapted the magnitude and timing of our trading strategy accordingly. Residual Balancing Table 2 – shows our Residual Balancing incentive performance over the RIIO periods, split by PPM and LPM elements.

Residual Balancing Table 2 - Residual Balancing incentive performance over the RIIO periods.

Incentive Year	Incentive Target (daily)		Performance (average, all days in year)		Incentive performance (£m) in 23/24 prices
	Price	Linepack	Price	Linepack	
2013/14	1.5%	2.8 mcm	0.70%	1.90 mcm	£1.3m
2014/15	1.5%	2.8 mcm	0.96%	1.61 mcm	£1.5m
2015/16	1.5%	2.8 mcm	0.64%	1.62 mcm	£1.6m
2016/17	1.5%	2.8 mcm	0.95%	1.74 mcm	£1.4m
2017/18	1.5%	2.8 mcm	1.77%	1.99 mcm	£0.8m
2018/19	1.5%	2.8 mcm	0.73%	1.90 mcm	£1.2m
2019/20	1.5%	2.8mcm	1.12%	1.73mcm	£1.1m
2020/21	1.5%	2.8mcm	0.77%	1.51mcm	£1.5m
2021/22	1.5%	2.8mcm	1.84%	2.00mcm	£0.7m
2022/23	1.5%	2.8mcm	3.96%	2.48mcm	-£0.5m
2023/24	1.5%	2.8mcm	0.90%	1.76mcm	£1.0m

"Average performance" is determined by averaging the daily performance for each component for each day of the formula year.

4.3.5 Factors Impacting Performance

Our RIIO-T2 performance has been challenging in a market that has seen unprecedented day to day price and linepack volatility (Residual Balancing Chart 1). This increased volatility means it becomes more challenging to take residual balancing actions within a narrow price spread and supply and demand balance becomes less certain as it reflects the more volatile market conditions.

An example of those challenging market conditions can be seen in 2022/23 which was dominated by the Russia / Ukraine crisis and created a complex and difficult year to balance with high energy prices and market nervousness, factors which continue to influence the market today. This resulted in a loss under the incentive with the price element being the most impacted component due to within day and across day market price volatility.

Despite this backdrop, our performance has been broadly positive and within the schemes annual cap and collar. This has generated customer and consumer value by minimising market price movement whilst maintaining a balanced NTS.

4.3.6 Consumer Benefit

Our role as the residual balancer is crucial for the functioning of the GB market. Fulfilling this responsibility ensures system security and a balanced gas market, providing stakeholders with confidence in decision making and providing reliable and cost-effective gas supply to consumers. In 2022/23, the absolute value of our residual balancing trades totalled approximately £450m, with a net revenue position of £67m returned to customers via Energy Balancing Neutrality.

The financial incentive is important to ensure that we enter the market in a measured way, to avoid incurring unnecessary costs for consumers by minimising our actions and allowing the market time to resolve imbalances where possible. Our strategy has evolved to maximise opportunities for the market to resolve imbalances ahead of us entering the market in our role as residual balancer.

The incentive has been integral to residual balancing for over 20 years, so there is no recent data to compare with its absence. However, in the absence of the residual balancing incentive, it becomes more likely that our residual balancing actions become more reactive and frequent, or imbalances persist longer, leading to larger actions later.

To quantify the consumer benefit of the scheme, we have considered the occasions in 2023/24 that we set a System Marginal Price (SMP) over and above the fixed differential, which, on average impacted the cashout price for that day by 0.1 p/kWh. If we assume that in the absence of an incentive we take more actions, our residual balancing actions could increase the daily gas price by 0.1 p/kWh. If we apply this to the average daily demand in 2023 (approximately 1,900 GWh), this equates to £2m for each residual balancing day, or £700m per annum if we took residual balancing actions every day.

Most stakeholders we have engaged with recognised the value of the incentive and importance it brings to the market. Some expressed that without the incentive there would be a risk that we would buy or sell more frequently and therefore moving the gas price due to risk aversion.

4.3.7 Proposal for RIIO-GT3

Our analysis, stakeholder feedback and the challenging market has led us to conclude that we should retain the financial incentive structure with the only exception being an increase to the scheme's caps and collars to reflect the increased impact our residual balancing actions have had because of the increase in energy prices seen since 2019/20.

Incentive Structure

We propose that the Residual Balancing scheme should be retained broadly in its current form, though some changes are required to the incentive metrics. The basis of our proposal is founded on customer feedback and our assessment of the current scheme parameters and future challenges. We propose the following structure:

Price Performance Measure (PPM)

- Daily target of 1.5%
- Daily Cap of £2,300 / Daily Collar of -£46,300

Linepack Measure (LPM)

- Daily target of 2.8 mcm/d
- Shoulder months: 2.8 to 5.6 mcm/d dead band for Oct, Nov, Feb, Mar.
- Daily Cap of £6,200 / Daily Collar of -£46,300

Overall Scheme

- Annual Cap of £3,088,000m Annual Collar of £5,404,000m

Assessment of PPM and LPM Targets

We believe the current scheme targets for both the PPM and LPM components of the scheme are set at an appropriate level that remain sufficiently challenging in an environment where we have seen unprecedented levels of market volatility. For example, in 2022/23 there were 222 days where at least the PPM or the LPM targets were not met.

We have traded more often in RIIO-T2 than we did in RIIO-T1, for example in 2019 we traded on 200 days and for the first three years of RIIO-T2 we traded on average 255 days per year, an increase of 28%. Whilst we have seen some stability return to the markets; we do not believe it's possible to conclude that we won't see similar or increased levels of volatility and challenge within the RIIO-GT3 period given geopolitical events and their links to global energy markets.

We consider that reducing the target levels from their current levels (2.8 mcm/d LPM and 1.5% PPM) would mean the incentive risks becoming too marginal. What we mean by that is that the targets would be at such a low level that reasonable margins of information uncertainty become a predominant factor in determining whether we achieve a target or not. We consider any incentive scheme should have targets set at level where reasonable information uncertainty doesn't become a key factor in whether the incentive target is met.

To put these current targets in perspective, the PPM target of 1.5% is below the fixed SMP default differential. For example, the default SMP differential from October 2024 is 0.0533 pence/kWh and if we assume an SAP of around 3p/kWh (~90p/therm), the default SMP price is 1.8% away from SAP, meaning if we want to set a SMP price through our residual balancing actions above the default, it becomes likely we will not meet the PPM target. From an LPM perspective in 2023 the average daily gas demand was ~174 mcm/d, meaning the LPM target of 2.8 mcm/d is around 1.6% of average daily demand.

Assessment of Shoulder Months

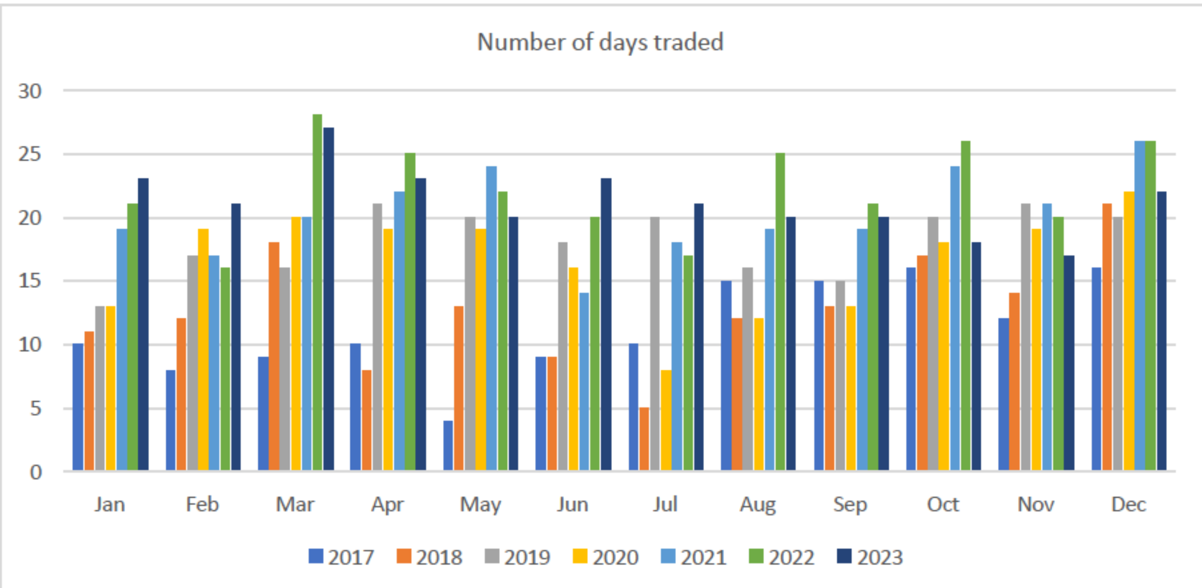
In their SSMD, Ofgem asked us to "to consider ways in which the shoulder month arrangements could be improved", asserting that "the current arrangements mean there are significant periods during which National Gas is not incentivised to respond to linepack variations".

The arrangement referred to is a performance deadband on the Linepack Performance Measure for the months of October, November, February and March, introduced at the start of RIIO-T2, to reflect the operational reality that it is more efficient to operate the network at higher pressures in the winter and lower pressures in the summer, that "preserves the focus on the PPM but avoids any potential distortions to the LPM measure that might arise as a result of seasonal adjustments to linepack volumes or the operational realities of the NTS."

We do not believe that the performance data supports Ofgem's assertion that we are not incentivised to balance the network in the shoulder months. Since the current shoulder month arrangements were introduced, there has been no difference in the proportion of days on which we have traded between shoulder months (70% of days) and non-shoulder months (69%)[23].

Residual Balancing Chart 1 shows that during the RIIO-T2 period (up to and including financial year 2023/24), the percentage of days with residual balancing actions is similar in both shoulder and non-shoulder months, at 70% and 69% respectively. This demonstrates that the new arrangement has had the desired effect, in normalising balancing actions between the two periods.

Residual Balancing Chart 1 – Residual Balancing actions



[23] Financial years 2012/22 to 2023/24 inclusive

Seasonal linepack levels are a fundamental element of operational strategy and any incentive regarding the linepack parameters should consider optimal physical performance to generate efficiencies that would in turn bring down the cost to the consumer whilst continuing to ensure the safe operation of the network. By optimising the system through ensuring adequate linepack for demand levels, we can optimise the NTS to increase the amount of time for GNCC to proactively manage and react to changes in supply or demand. High linepack with high demand helps enable us to manage pressures at higher demand levels, reducing costs passed through to the consumer. Similarly, low linepack with low demand helps us to manage pressures at lower demand levels therefore better enabling us to meet customer's flow requirements.

The months where summer becomes winter and vice versa creates supply and demand uncertainty depending on cold/warm weather snaps.

When we try to move the linepack levels for operational reasons as we move into winter and summer, shippers may be out of balance and as a result could be moving the linepack in the same direction as the strategy. In such a scenario it is efficient to be able to hold the new linepack position without having to revert to within 2.8mcm/d of opening. For example, if shippers were imbalanced by +5mcm/d at a time where we had a strategy to increase the linepack by 5mcm/d over the coming days, it would be economical to be able to hold this position rather than trading back to within 2.8mcm/d of opening, aligning to the incentive principle of minimal market intervention.

We believe that the current shoulder month concept strikes the right balance between simplicity and ensuring the incentive compliments the operational need to move linepack seasonally.

We considered alternative linepack incentive options ahead of RIIO-T1 (such as a dynamic LPM, creation of a linepack provider role and suspension of the LPM during the shoulder months) but we concluded that these were unduly complex and potentially counterproductive to what they are trying to achieve. For RIIO-GT3 we have considered flexible shoulder months. While this change could have a small benefit in better aligning the arrangement with near time operational reality, it would also increase complexity and uncertainty to the market, and therefore on balance we concluded it would not be appropriate to implement.

Assessment of Scheme Parameters

We believe an incentive scheme should reflect the changing impact and value of the actions it supports. Therefore, we have reviewed the residual balancing scheme's caps and collars, recognising that energy prices and the value of residual balancing actions passed to customers have materially increased during the RIIO-T2 period.

Residual Balancing Table 3 shows how the SAP, the value of our residual balancing actions and unit cost of our residual balancing trades have changed from 2019/20 through to 2023/24. Furthermore, we can see how the increase in gas prices has impacted the absolute value (buys and sells) of our residual balancing actions, peaking at ~£453m in 2022/23, an increase of nearly 800% from 2019/20 levels (the year in which the RIIO-T2 scheme was set) and consequently the increased amounts being passed through balancing neutrality to our customers.

Therefore, the consequences of poor performance and the benefits of good performance to end consumers also scale accordingly. The table also compares the current daily (£52.4k) and annual (£4.4m) cap and collar range to the average daily and annual value of our residual balancing actions from 2019/20 to 2023/24, illustrating how the scheme's financial size has effectively decreased relative to the market value since 2019.

Residual Balancing Table 3 – shows since 2019/20 the size of the scheme has effectively decreased when compared to the value of the residual balancing actions required.

Formula Year	A	B	C	£52.4k / C	£4.4m / A
	Abs Value of RB Trades (£m)	No. of trade Days	B/A avg daily Trade Value (£m)	Daily CAP and Collar Range %	Annual Cap and Collar Range %
2019/20	£57.4m	220	0.3	20%	8%
2020/21	£67.8m	200	0.3	15%	6%
2021/22	£396.3m	252	1.6	3%	1%
2022/23	£452.8m	273	1.7	3%	1%
2023/24	£184.9m	241	0.8	7%	2%

We therefore consider it is appropriate to increase the scheme's caps and collars. In recognition that the value of our residual balancing actions broadly tracks SAP, we are proposing to increase the scheme's daily and annual caps and collars by the change in SAP, using 2019/20 as the year in which the RIIO-T2 scheme was calibrated and comparing this to 2023/24 as the most recent complete formula year, as shown in Residual Balancing Table 4. This therefore implies increasing the scheme's caps and collars by a factor of 2.9.

Residual Balancing Table 4 - Average SAP values from 2019/20 to 2023/23.

Incentive Year	Average SAP p/kWh	Average SAP p/therm	Inflation Factor
2019/20	1.00	29.31	-
2020/21	1.07	31.36	1.07
2021/22	5.40	158.26	5.44
2022/23	6.34	185.81	6.34
2023/24	2.93	85.87	2.93

The majority of stakeholders supported updating the cap and collar in line with SAP inflation. We note a significant rise in the gas price, nearly tripling. Although we haven't matched the increase, we felt the proposed adjustments better reflect the current market conditions. However, some stakeholders suggested it would be more appropriate to incorporate a mechanism to review these parameters annually due to SAP's variability.

Considering stakeholder feedback and the unpredictable nature of gas prices during the RIIO-GT3 period, we propose an automatic adjustment to the scheme's financial caps and collars. To avoid yearly changes due to minor SAP fluctuations, we suggest using a three-year rolling average. If this average increases by 30% from the current SAP value (e.g., 2.93 p/kWh from 2023), the caps and collars will be adjusted accordingly from year 2 of RIIO-T2 onwards. For decreases the same principles / calculation would be applied but with a bottom stop of the current RIIO-T2 cap/collar.

We believe incentive schemes should reflect the changing value of activities, which is incorporated into our RIIO-GT3 Residual Balancing scheme proposal with suggested parameters in Table 5.

Residual Balancing Table 5 – shows the proposed RIIO-GT3 parameters and RIIO-T2 comparison.

RIIO-T2 Scheme Parameters	Cap in 18/19 prices	Collar
Daily LPM	1.5mcm / £3,200	15mcm / £24,000
Daily PPM	0% / £1,200	76% / £24,000
Annual	£1,600,000	£2,800,000

RIIO-GT3 Scheme Parameters	Cap in 23/24 prices	Collar
Daily LPM	1.5 mcm / £6,200	15mcm / £46,300
Daily PPM	0% / £2,300	76% / £46,300
Annual	£3,088,000	£5,404,000

4.3.8 Options Considered

We have considered and discounted the following options alongside our proposal.

Residual Balancing Table 6 – Options considered.

Discounted option	Further detail	Why discounted?
Inflate schemes caps and collars by SAP inflation.	SAP from 2019 to 2023 has inflated by around 3 times.	The original scheme was calibrated to gas price and whilst this would maintain the relationship between gas price and the schemes value, we consider using % increase better reflects the relationship between gas price and the consumer impact of residual balancing actions.
Inflate schemes caps and collars by RPI.	Use RPI to increase the size of the scheme	Energy prices have not tracked RPI and hence don't reflect the changed consumer impact of residual balancing actions.
Increase PPM target.	Increasing the PPM target would protect from market price swings seen in RIIO-T2	Whilst this would protect from those days where the market price naturally swings, we recognise this also doesn't occur every day and although remaining sensitive to market changes the gas price has reduced over the last 18 months.
Reduce PPM and LPM target measures.	Schemes targets have regularly reduced since the scheme's inception	Lowering the current targets any further would mean increased risk that information uncertainty becomes the influencing factor on whether targets are met or not.
Flexible shoulder months.	Shoulder months are no longer "fixed"	No strong case that the complexity of flexible shoulder months would be more beneficial.
Different shoulder months.	Redefine the shoulder months.	No strong case that redefining the shoulder months would be more beneficial.
Dynamic shoulder months.	Near time definition of shoulder months	Unduly complex and potentially counterproductive.
Symmetrical scheme.	Remove asymmetry from the scheme	Whilst we do believe symmetrical incentive schemes provide a better balance between reward and penalty; we also recognise the scheme has been asymmetrical since its inception in 2002.

4.4 National Transmission System Shrinkage

4.4.1 National Transmission System Shrinkage Purpose

The UNC designates us, National Gas Transmission as the NTS Shrinkage Provider. In this role we are responsible for managing the end-to-end service of forecasting, accounting for, and procuring energy to satisfy the daily NTS Shrinkage components requirements.

The components of NTS Shrinkage fall into three categories:

1. Compressor Fuel Use (CFU): The energy used to run compressors to transport gas through the NTS. This can either be gas or electricity, depending on the power source for the specific compressor.
2. Calorific Value (CV) Shrinkage (CVS): The energy which cannot be billed due to the provisions of the Gas (Calculation of Thermal Energy) Regulations 1996 (amended in 1997); this is a calculated value.
3. Unaccounted for Gas (UAG): The quantity of gas which remains after considering all measured inputs and outputs from the system, Own Use Gas (OUG) consumption, CVS, and the daily change in NTS linepack. UAG can be both Meter error and Data error.

Therefore, if you take Shrinkage, deduct OUG & CVS, you are left with UAG.

Overall Shrinkage costs also include emissions costs for compliance with the UK Emissions Trading System, this relates only to the OUG component of Shrinkage.

Our ability to procure shrinkage energy by trading is limited by our Licence. We cannot speculate (buy and sell based on market price movements) and we only trade to a forecast requirement. We publish our NTS Shrinkage Methodology Statement annually on the National Gas website.

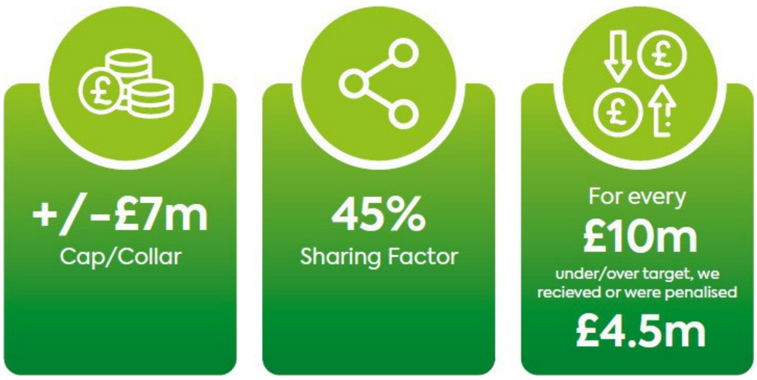
4.4.2 NTS Shrinkage Incentive

The NTS Shrinkage incentive aims to minimise the overall cost of shrinkage incurred in operating the network in our role as NTS Shrinkage Provider through efficient energy procurement.

4.4.3 Performance to date

The Shrinkage Incentive for the **RIIO-T1 period** was a financial incentive based upon an overall cost minimisation scheme.

Within that scheme the cost target that was based on a derived market reference price and compared to the actual costs based on pre-defined volume targets incurred by National Grid Gas (now National Gas Transmission) to determine incentive performance. It is also worth noting that the scheme included a winter Triad avoidance element which incentivised us to minimise the running of electric compressors during such periods.



During the RIIO-T1 period the incentive was seen as driving the right behaviours in terms of minimising consumer costs across the elements of the scheme. The incentive purchasing strategy was also effective in reducing Shipper exposure to energy price fluctuations and limiting the impact of significant spikes in market prices. Please note that the annual total shrinkage costs in RIIO-T1 were between £60-£90m.

An example of this was seen on 1 March 2018 (Beast from the East) when the cost of Shrinkage would have been £540k if the shrinkage allocation for that day was cashed out with those costs ultimately passed on to consumers. The management activities and purchasing strategy as part of the RIIO-T1 NTS Shrinkage incentive actual cost was ~£70k, saving Shippers, and ultimately consumers, £470k in one day alone. NTS Shrinkage Table 1 provides RIIO-T1 incentive cost and performance details.

NTS Shrinkage Table 1 – Incentive Performance

Incentive Year	Incentive Target (£m) in 23/24 prices	Performance (£m) in 23/24 prices	Out-Performance (£m) in 23/24 prices	Incentive Performance (£m) in 23/24 prices
2013/14	£157.9m	£141.9m	£16.0m	£7.2m
2014/15	£120.9m	£106.1m	£14.8m	£6.6m
2015/16	£118.6m	£99.6m	£19.0m	£8.6m
2016/17	£101.4m	£93.9m	£7.5m	£3.4m
2017/18	£106.8m	£91.3m	£15.5m	£7.0m
2018/19	£118.0m	£96.1m	£21.9m	£8.7m
2019/20	£118.2m	£97.2m	£20.9m	£8.5m
2020/21	£91.6m	£81.2m	£10.4m	£4.7m

The Shrinkage Incentive for the **RIIO-T2 period** is reputational, where performance is based on a calculation of benchmark costs set out in the Gas Volumes Methodology. These benchmarks compare our procurement to a best-case scenario, worst case and average (2022/23 onwards). Benchmarks are based on forecast and actual volumes, and market prices. Due to the timing of the publication of Final Determinations for RIIO-T2 (in December 2020), and the subsequent Licence consultation, it was not possible to put in place a Gas Volumes Methodology for 2021/22, so there are no benchmark costs for 2021/22.

For RIIO-T2, the best, worst, and average benchmarks are calculated using forecast volumes for forward procurement for seasons and quarters, and daily differences between shrinkage allocation and the net forward volumes. When we buy the best benchmark is calculated by costing these volumes and the lowest market prices seen for the front season, front quarter and within day trades. The worst benchmark uses the highest market prices. The average benchmark uses the volume weighted average prices of all market trades.

During RIIO-T2, energy prices significantly increased due to geopolitical factors, with annual gas procurement costs ranging from £136m to £630m. Our incentive purchasing strategy effectively reduced uncertainty and limited Shipper exposure to price fluctuations. As part of this process, we continuously reviewed our trading strategy to manage price risks for consumers, especially during the winter months of 2022/23 and 2023/24, by procuring a high proportion of forecast volume in advance. For detailed gas procurement costs, refer to NTS Shrinkage Table 2. Actual gas procurement costs for 2022/23 were comparable to (2.5% higher than) the average cost benchmark for the year. This was achieved in the context of a highly volatile gas market.

For 2023/24, actual gas procurement costs, were substantially lower than the average cost benchmark for the year, although this was driven by differences between initial forecast volumes used for the benchmarks and later adjusted forecasts feeding into procurement. Total shrinkage costs were lower mainly because of a meter reconciliation revenue.

NTS Shrinkage Table 2 - Total Shrinkage Costs, actual gas procurement cost, and benchmarks. (nominal values)

Incentive Year	Total Shrinkage costs (£m)	Actual gas procurement costs	Best case gas procurement costs	Worst case gas procurement costs	Average gas procurement costs
21/22	£205.72m	£151.26m	-	-	-
22/23	£681.70m	£629.88m	£463.91m	£914.91m	£614.65m
23/24	£133.34m	£136.70m	£94.38m	£265.63m	£166.44m

For RIIO-GT3 we are proposing a new incentive with a different performance measure that is based on actual traded volumes, comparing the prices we trade at against shorter-term market average prices.

4.4.4 Factors Impacting Performance

NTS Shrinkage Table 1 (including RIIO-T1 costs) and NTS Shrinkage Table 2 (including gas procurement costs) show the cost of procuring Shrinkage Gas throughout the RIIO periods to date. The wholesale gas market has been impacted by several global events since 2020/21 and created a level of volatility not previously witnessed in the gas market, these have included:

- COVID reduced demand and gas prices in 2020/21,
- The recovery from COVID and Supplier/Shipper failures increased prices in 2021/22,
- The gas market changed significantly in 2021/22 in the build-up to the Russia / Ukraine conflict. Changes in demand / supply patterns as a result also had an impact on UAG levels (from 2022).

By the start of 2024/25 gas prices had reduced from their peak but have yet to return to pre-2020/21 levels.

4.4.5 Consumer Benefit

Our history of being incentivised and our obligations to be economic and efficient mean we already take a proactive approach to trading to deliver value for consumers. This makes it challenging to quantify the additional value of a new incentive.

We believe that an incentive focused on procurement activities under NGT control should be considered. This would sharpen our focus on delivering value to consumers by giving us 'skin in the game.' Without a financial shrinkage incentive, we would likely take a more conservative approach to shrinkage cost management. The focus would, over time, most likely change from outperforming the agreed target costs to one of trying to meet the target as well as signalling to NGT that this is not a high priority activity.

Stakeholder engagement supports our proposed approach, with the following feedback received, 'The fact that we should be risk exposed should give the market confidence that we won't buy when we want but try to do it in the most cost-effective way possible' and 'As we are spending industry money, NG should have skin in the game' and 'We are a supporter of Shrinkage being a financial incentive to encourage proper purchasing behaviour'.

A new financial incentive would enhance our focus on market and purchasing strategies, balancing risk, and certainty in managing energy procurement costs that pass through to users. It would also support continued investment in system and reporting changes to help improve performance. Stakeholders also said, 'Having an incentive on trading/pricing seems reasonable as we should operate at best price possible'.

Without an incentive, we would likely perform around the average. The incentive encourages us to be proactive and add value for customers while maintaining financial risk for underperformance.

Our Stakeholder engagement supported this with some saying, 'We support your view there should be a financial incentive around your Shrinkage performance and agreed that unidentified gas volumes is a separate problem due to NG not being the owner of the metering equipment'.

We acknowledge the feedback and the SSMD requirements related to shrinkage volumes, and we look forward to supporting Ofgem-led industry discussions on Shrinkage forecasting and NTS Shrinkage cost recovery in 2025. These discussions may lead us to seek innovation funding for specific projects related to this topic.

To further help support our net zero 2050 commitment we are currently exploring the use of Power Purchase agreements which has been identified as a potential way to decarbonise our business carbon footprint.

4.4.6 Proposal for RIIO-GT3

Although market forces drive gas prices, we are well-positioned to manage costs across all three components of shrinkage energy: CFU, UAG, and CVS. While we cannot control UAG and CVS volumes—since CVS is driven by user supply and demand patterns, and UAG is driven by metering equipment errors linked to metering tolerances and data errors—we excel in managing additional cost drivers and risks for NTS users and consumers due to our comprehensive view of shrinkage and our trading activity.

We have direct control over the energy price paid via the timing of our market trades. Stakeholders support this approach, noting 'Having an incentive on trading/pricing seems reasonable as we should operate at best price possible'.

We propose a financial incentive for RIIO-GT3 focused on purchasing NTS Gas Shrinkage. We recognise and believe that using a mix of forward and prompt trading is a prudent risk management strategy.

We acknowledge Ofgem's request for greater transparency and will collaborate on providing Ofgem with a suite of reporting components for a full performance assessment. However, we cannot share commercially sensitive information in real time or retrospectively to the market, as it could give other shippers and traders a commercial advantage and hinder our ability to deliver value to consumers. Other market participants are not required to publish their trading data for similar reasons.

By using forward and prompt trading, we spread risk and smooth costs as the market fluctuates. A financial incentive enhances our focus on adapting to market changes, balancing risk and reward, and ultimately minimising Shrinkage costs for NTS users and consumers.

We believe a financial incentive provides a greater focus on market and purchasing strategies as it changes the balance between risk and certainty. Any outperformance will provide a direct benefit to NTS users and consumers via reduced charges.

The principles of the scheme are based on our market participation, and having: -

- A limited role as a shipper i.e., we cannot speculate we are only able to trade to a forecast requirement.
- A broadly flat procurement profile (irrespective of strategy).
- We cannot predict global event impacts on the market – price and throughput.
    - Hence, we cannot control volume changes.
    - Hence, we cannot control market prices.

Therefore, the incentive proposal principle is efficient procurement within the market to provide cost benefit to customers and the end consumer via reduced charges. Our Stakeholder engagement supported this with some saying, 'As a reputational only activity we are currently potentially subject to criticism, which re-introduction of financial incentive should remove'.

We are not proposing that the incentive includes reductions to or targets for volumes of UAG and/or CV shrinkage. UAG is already at low levels, please see link to Unaccounted for Gas & Calorific Value Shrinkage Report (UAGCVS Report), and the causes of historic UAG have been predominantly out of our control as previously detailed above and in our consultation engagement. In line with Ofgem's SSMD document we recognise that supporting both industry engagement regarding this topic and reviewing potential innovation projects will be required in the RIIO-GT3 period.

Incentive Structure

Given the price volatility seen over recent years a fixed cap/collar that is between 1% and 8% of gas shrinkage costs in our view strikes the best balance between providing certainty of the parameters, risk and reward related to the overall gas shrinkage cost. Whilst recognising that the T1 scheme structure/calculations were different the cap/collar was ~10% of the average gas cost in that period.

Our Stakeholder engagement supported this with some saying, 'setting the benchmark against periods when we trade seems reasonable'. 'Agreed that setting the cap/collar around 4% of the Shrinkage costs seems reasonable'. Although one customer commented saying 'A cap/collar of £5m seem high considering the level of spend and the fact that market doesn't react when you buy, therefore +/-2% seems more reasonable'.

We propose to introduce a new incentive with the following structure:

- Cap/Collar +/-£5m. Sharing Factor @ TIM. (in 23/24 prices).

We propose two elements to the scheme. Each element will have a performance weighting measure, see NTS Table 3 Weighted metrics.

1. **Trading Performance:** Performance will be assessed against a target based upon all gas volumes traded by National Gas. This approach balances forward and prompt trading products. Forward trades are trades done ahead of the month, including seasons, quarters, and months. Prompt trades are shorter term products including week ahead, weekend, day ahead and within day. Our actual trading cost will be compared to this target to determine rewards or penalties.

For example, we are comparing the cost of a seasonal trade today against the market average for seasonal trades today and for this week to ascertain if that trade was "good value" – this principle is applied to each trade for each product (the prompt products comparison is different, but the principle is the same).

2. **Forward Clip Deferral:** The second element is applicable for Forward trading only. The incentive would drive us to consider deferring clips to capitalise on near term market movements. Performance would be assessed by comparing the outturn cost of deferred clips against the market average price for that product in the week it was deferred from to determine rewards or penalties.

Forward trades are actioned based on a schedule of weekly volumes for each product. We hedge purchases over a period of months, with the schedule for each product typically being one or two trades per week, rather than daily volumes, so the timing of the trades scheduled for the week is the key decision for trading performance. Hence, we propose to compare the traded price with the (volume weighted) average market price for that product for that week, with a 60% weighting, as well as the daily market average price, with a 40% weighting.

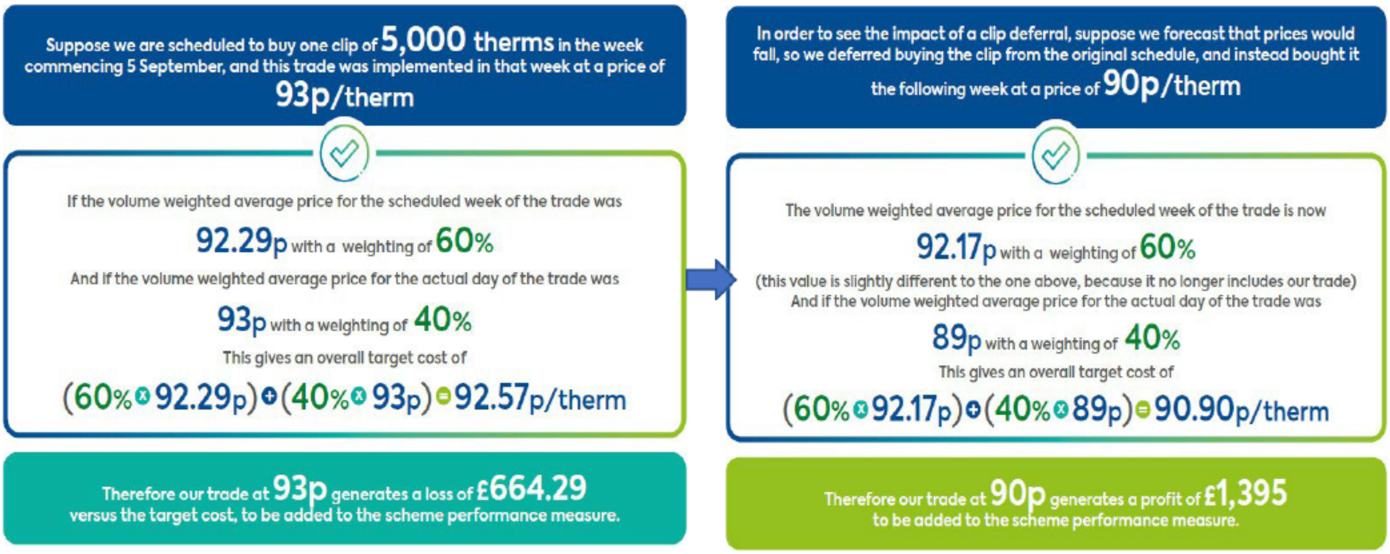
For Prompt trades, we believe there are two important aspects of assessing trading performance. One is to compare the traded price to the market average for that product, for example a day ahead trade done on a Monday for delivery on Tuesday. The market average does not include "out of hours" trades and is calculated over normal working hours and days covered by our shrinkage traders. The other aspect is to compare the traded price to the System Marginal Price on the delivery day, on which costs would be based if no trades were completed. We propose both aspects are weighted equally at 50%.

NTS Shrinkage Table 3 – Weighted metrics

Forward Trades	Weighting
NG Trades valued at Weekly Market Volume Weighted average Price (VWAP)	60%
NG Trades valued at Daily Market Volume Weighted average Price (VWAP)	40%

Prompt Trades	Weighting
NG Trades valued at Daily Market (VWAP)	50%
NG Trades valued at System Marginal Buy or Sell (SMPB/S)	50%

The following worked example illustrates how the scheme would be applied to forward trades:



The overall performance measure for the forwards element of the scheme would be calculated from the sum of this calculation repeated for every forward trade taken throughout the year, applied to the relevant product and schedule week.

4.4.7 Options Considered

We have considered and discounted the following options alongside our proposal.

NTS Shrinkage Table 4 - Options considered.

Discounted option	Further detail	Why discounted?
Retain incentive as reputational	Continue with RIIO-T2 performance parameters	Discounted due to strong customer agreement from Stakeholder consultations that the incentive should be financial. Customers agreed that the incentive should ensure value for money based on the elements of Shrinkage we control through an efficient procurement strategy.
Financial incentive with scalable performance %	Cap / Collar as a % of annual Shrinkage costs	Discounted as this unknown value will lead to uncertain risk/reward exposure

4.5 Maintenance

4.5.1 Maintenance Purpose

We are required to carry out maintenance on NTS assets to ensure the safety and security of the network so it can be operated economically and efficiently. The Uniform Network Code (UNC) sets out the process and notification periods which enables us to inform our customers where our maintenance work may impact their pressures or steady flow.

This process involves issuing notifications in advance to provide customers with an opportunity to discuss the timing and impact of these maintenance activities. These notifications are called 'Maintenance Days'. The number of Maintenance Days we can call and notice periods vary as they are dependent on the Network Exit Agreement (NExA) or legacy agreement for each site.

The UNC requires us to publish our maintenance programme twice each year; by 1 April to cover the following 24 months, with a specific focus on the 7-month period between April and October and by 1 October to cover the following 24 months with specific focus on the 6-month period between October and March. The planned maintenance period and key maintenance activities typically take place in the summer, between April and October, to minimise the impacts on customers.

4.5.2 Maintenance Incentive

The scheme incentivises us to schedule maintenance during periods that don't impact customer contractual rights, calling these "advice notice days" when maintenance aligns with customer plans. If alignment isn't possible, we designate "Maintenance Days," requiring customer outages or reduced flexibility. The incentive sets a target for the number of Maintenance Days, rewarding us for better alignment and penalising for exceeding the target.

The scheme also encourages us to minimise changes to the maintenance plans once they have been published to further minimise disruption. The Maintenance incentive covers the period between 1 April and 31 October for our exit or offtake customers and has three scheme elements, as follows:

1. **Remote Valve Operations** (RVOs): We have a policy to maintain key valves on an annual basis as they control the flow of gas on the network. Under this element of the scheme, we are incentivised to align activities with customers and work under 'Advice Notices'.
2. **Non-Remote Valve Operations:** Include activities like asset replacement and reinforcements, In-Line Inspections (ILIs) and metering/telemetry/analyser works. These legislatively driven works often have long durations and require detailed planning to minimise impact to the customer. Our ability to carry out these activities via actively managing a pressure restriction is limited in most areas of the NTS due to network limitations. In most cases, we isolate pipelines at a lower pressure, or even recompress and vent them to atmospheric pressure. We are incentivised to align activities with customers and conduct work under 'Advice Notices'.
3. **Change Scheme:** Once our maintenance plans are published, we are incentivised not to make amendments to the activities detailed above.

The incentive parameters for each scheme can be seen in the Incentive Structure Section.

4.5.3 Performance to date

The scheme was introduced at the start of RIIO-T1 with two of the three elements detailed above forming part of that scheme, Remote Valve Operations and Change Scheme. The scheme was recalibrated based on consultations in 2016/17 and 2018/19, with new activities being added the scheme.

In RIIO-T2, RVO and other maintenance activities were split into two elements, creating a Remote and Non-Remote Valve Operations with a total incentive reward of +£0.5m and a collar of -£1.5m. Maintenance table 1 details the combined incentive schemes and performance.

Maintenance Table 1 – Combined incentive schemes and performance

Incentive Year	Days used	Days used	Days used	Incentive performance (£m) in 23/24 prices
2013/14	31	0	0	£1.60m
2014/15	4	0	0	£1.19m
2015/16	2	0	0	£0.50m
2016/17	1	0	0	£0.92m
2017/18	1	0	0	£0.89m
2018/19	0	0	0	£0.89m
2019/20	0	0	6	£0.57m
2020/21	0	0	0	£0.57m
*2021/22	1	6	0	£0.62m
*2022/23	1	8	0	£0.62m
*2023/24	1	0	0	£0.62m

**Split scheme into two for RVO and other maintenance activities called Non-Remote Valve Operations*

4.5.4 Consumer Benefit

Throughout the consultation all the customers we have spoken to support continuation of the incentive as they see it delivering real value, with some highlighting the improved communications and alignment process. An example of the customer benefits can be seen below:

The average daily Power Station revenue depends on many factors including type of plant, installed capacity (and therefore varying ability to generate) and operating costs (including fuel costs, maintenance, labour, insurance, capital costs etc). To estimate the customer benefit of the maintenance incentive we have approximated the value of the lost opportunity for a Power Station to generate in a scenario where it is unable to offtake gas due to our maintenance activities (and where, in effect, we have issued a Maintenance Day notice). We've based our calculation on the following formula:

Lost opportunity = Power Income - (Gas Cost + CO_2 Cost + CO_2 floor tax + Operational Costs)

The results indicated a range of outcomes depending on the assumptions made regarding gas and electricity prices i.e., when they were purchased and sold. The estimated lost opportunity (therefore the value we deliver via the Maintenance incentive to the market) ranged between £250k to £3.8m a day per power station.

All customers we have engaged with have confirmed that the incentive creates consumer value and should be retained within RIIO-GT3. Two customers mentioned that some changes to the scheme might need to be considered in the RIIO-T4 period as the Power sector may require a more flexible and agile approach to our maintenance schedule, due to increased renewable penetration.

The investment related to asset health (maintenance), which we see as necessary to continue delivery of a safe and reliable network, is planned to increase in the next price control period. An increase in customer impacting activity, or rather its alignment, means that the customer value the incentive carries will increase proportionally.

In the absence of an incentive there is the potential for us to extend the duration of Advice Notices to cover any unexpected changes to the maintenance schedule. We may also decide to plan work to fit best with our operational requirements rather than planning around our customers and their outages. Either of these outcomes would have a negative consequence on our customers as such behaviour would impact their operations.

4.5.5 Process Improvements

We re-evaluated our outage program, carefully considering and accommodating customer requirements while planning and executing our work. Since summer 2022, we've focused on moving gas from LNG imports at Milford Haven to Bacton for export to Europe due to the Russia/Ukraine conflict. This increased the use of our compressor fleet along the west/east corridor, complicating previously scheduled planned outages.

We have improved our maintenance scheduling in the following areas: -.

Communication and publications: We have been increasingly using power stations REMIT[24] notices when planning shorter duration outages, rather than rely on the information power stations provide us with twice a year as per their UNC requirement. This has led to fewer customer driven change requests.

In RIIO-T2 we implemented an early planning process which allows us to indicate maintenance to customers up to 3 years in advance of any long duration works. To help improve this process we have:

- improved the clarity of our notices by giving customers more detail, particularly regarding providing steady flow rates and timings during ILI runs, or maximum flow rates when conducting RVOs.
- started providing maps within our published maintenance plans to give better visibility of the outage areas.

Innovation: We have explored novel ways of working to allow customers to continue to operate as normal while the maintenance is conducted. This included undertaking live works with a managed pressure restriction as an alternative to isolating pipelin es. Our ILI run strategies have been optimised to limit the impact on our customers and allow them to continue to take gas whilst the run is occurring. The incentive changed our approach; maintenance days are used as a last resort after all other options of conducting or aligning the works have been explored.

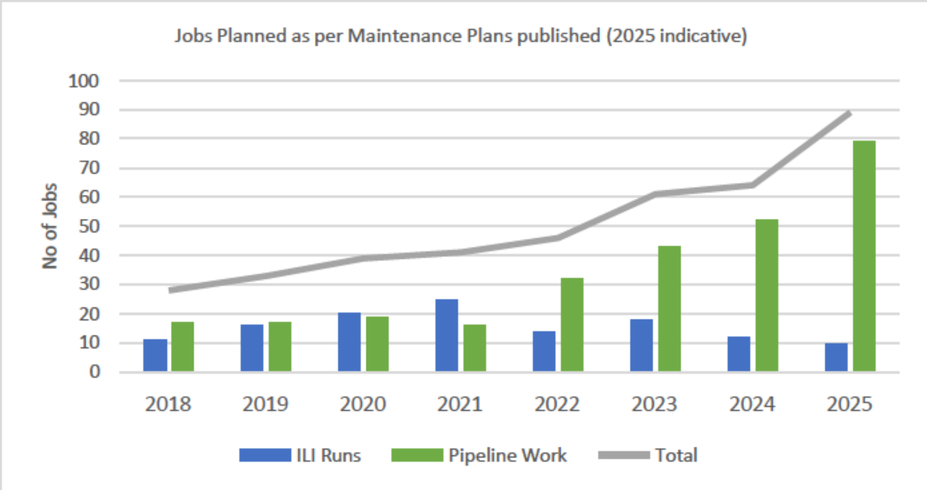
Beyond BAU: We work closely with both interconnector companies to ensure they have good visibility of our maintenance program, so they are clear on our ability to provide any additional capability (or pressures) for exports from the GB market.

[24] EU Regulation on Wholesale Energy Market Integrity and Transparency

4.5.6 Proposal for RIIO-GT3

We propose a financial incentive for RIIO-GT3 focused on the activities that most impact the customer. The maintenance requirement has been increasing gradually over the last 5 years. Although our performance in the first 3 years of RIIO-T2 period has been successful, we are encountering more challenges in alignment for all the works required. Maintenance Chart 1 shows our overall maintenance activity (including works not impacting customers) has been increasing gradually and shows the split by asset health investment by sub themes. We expect ~20% increase in maintenance activity in RIIO-GT3.

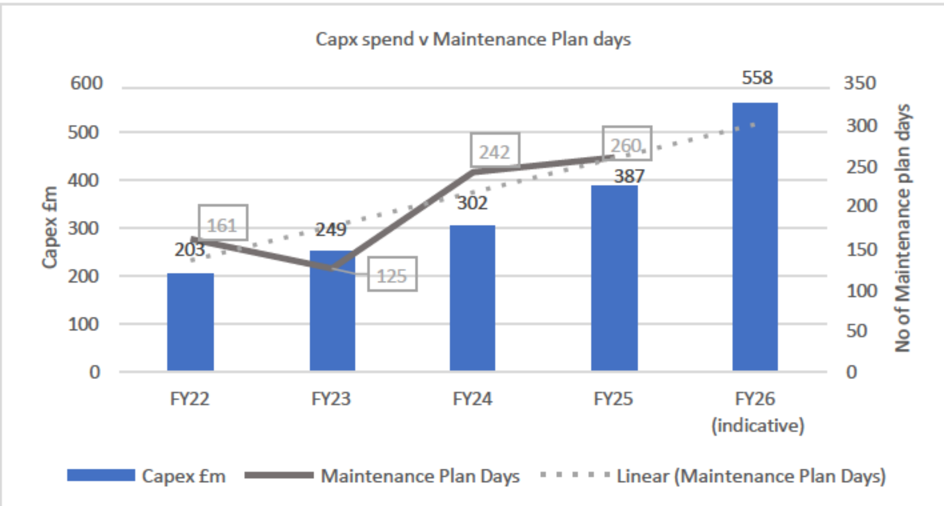
Maintenance Chart 1 - Maintenance activity.



There is a strong correlation between our RIIO-T2 Capex spend and the number of Maintenance Days impacting customers, as shown in Maintenance Chart 2. Based on the correlation it is evident that there will be more customer impacting work and other work impacting the customer work in the future and therefore more effort will be required to sustain a similar level of performance. FY23 is below the trend, however this is due to deferral of an in-line-inspection and the cancellation of two customer-impacting asset replacement jobs before the start of the maintenance year.

We propose that the increase in risk and effort required to manage the work and associated schemes results justify the change to the cap and collar. Our RIIO-GT3 Asset Maintenance Plan will increase due to the requirement to maintain our assets and associated legislation which will continue to ensure the safe operation of the NTS.

Maintenance Chart 2 - Correlation between our RIIO-T2 Capex spend and the number of Maintenance Plan Days



SSMD suggests spreading the existing cap across the three elements of the incentive. It is our view that the Change and non-RVO elements will pose a greater challenge in the future (therefore increase or applicability of cap is justified), this will not be the case for RVOs. The number of RVO jobs we need to deliver from one year to another is unlikely to change, therefore our existing processes are sufficient to maintain the performance. For that reason, we think that a zero cap should be applicable to RVOs.

Incentive Structure

We propose to introduce the following structure:

- **Maintenance table 2a - Minimisation of the use of Maintenance Days to perform Remote Valve Operations (RVO)**

RIIO-T2 (2018/19 prices)	RIIO-GT3 (2023/24 prices)
Cap / Collar +£0.0m /-£0.5m (downside only)	Cap / Collar +£0.0m /-£0.5m (downside only)
Target: 11 days (penalty applied for exceeding 11 Maintenance Days issued)	Target: 5 days
Reward/penalty of £20,000 per each change day above the target	Penalty of £20,000 per day up to £0.5m (for 25 days or more above target).

- **Maintenance table 2b - Minimisation of the use of Maintenance Days to perform non-Remote Valve Operations (non-RVO)**

RIIO-T2 (2018/19 prices)	RIIO-GT3 (2023/24 prices)
Cap / Collar +£0.5m /-£0.5m	Cap / Collar +£0.75m /-£1.0m
Target: 75% (penalty applies for each day less aligned)	Target: 85% alignment
Penalty/reward of £50,000 per day up to cap/collar	Penalty of £125,000 /reward £95,000 per each 0.5% change below/above the target of 85%.

- **Maintenance table 2c - Minimisation of changes to the agreed maintenance plan (Change Scheme)**

RIIO-T2 (2018/19 prices)	RIIO-GT3 (2023/24 prices)
Cap / Collar +£0.0m /-£0.5m (downslide only)	Cap / Collar +£0.75m /-£1.0m
Target: 7.25% of total days in the year (penalty per change day exceeding the target)	Target: 7.25% of total days in the year Propose deadband: 4% -7.25%.
Penalty of £50,000 per day more than the target up to -£0.5m (10 changes or more)	Penalty of £125,000 /reward £95,000 per each 0.5% change outside of the deadband

- **Extension of maintenance period (subject to UNC change) for all elements**

RIIO-T2	RIIO-GT3
1 April – 31 October	1 March – 30 November

Assessment of new performance parameters

Minimisation of the use of Maintenance Days (MD) to perform Remote Valve Operations (RVO)

Target: The current target for this element of the incentive is 11 days. We have used one maintenance day in each incentive year for the last three years and are on track to use zero in 2024. We agree within Ofgem's SSMD view to tighten the target to five days. In the context of the predicted increase in maintenance activity, this will impose a more challenging target.

Daily penalty calculation: The number of RVO jobs is consistent year on year (except for 2023/24 where multiple valves required multiple days to complete) and is expected to remain, therefore do not propose to switch to a percentage-based penalty for this element of the scheme.

Cap and collar: We propose for these to remain as is.

Minimisation of the use of Maintenance Days (MD) to perform non-Remote Valve Operations (RVO)

Target: To reflect our higher level of business-as-usual performance, driven by this incentive, we are proposing to set the RVO target to 85% (currently 75%) to further stimulate our performance. We recognise Ofgem's suggested target; our proposal takes account of recent performance, as well as the higher level of customer impacting activity planned for the RIIO-GT3 period. Additionally, more effort will need to be put into managing this element based on the proposed extension of the maintenance window.

Non-RVO jobs for asset replacement can be lengthy and therefore greater than the duration of customer outages. If just one job is misaligned (see Maintenance Chart 3), it could prevent us from meeting our targets and result in a maximum penalty for underperformance.

Daily penalty calculation: Currently the daily reward and penalty is fixed at 10 days. Moving to a percentage misalignment-based penalty will be consistent with the target methodology and better reflect any changes in the number of maintenance days delivered. Similarly, as per the Change scheme, we propose a continuous reward for each 0.5% alignment above the proposed target of 85% (up to a cap of £0.75m) or penalised for each 0.5% below it (up to a collar of -£1m).

Cap and collar: As the customer benefit of this incentive is directly linked with energy prices and because of the increased risks a more congested maintenance plan will bring in the future, we propose to increase the cap to £0.75m and collar of -£1m.

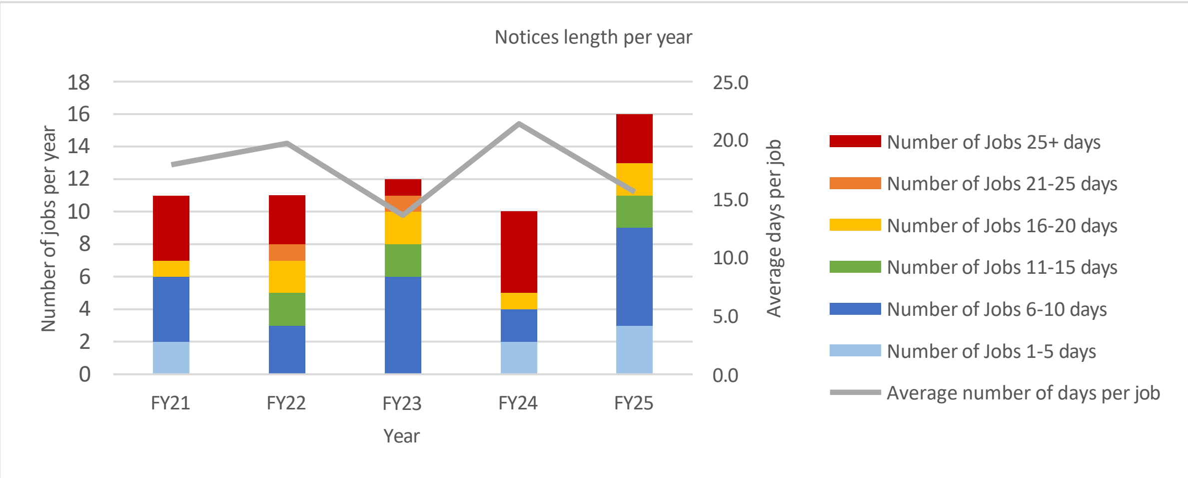
Minimisation of changes to the agreed maintenance plan (Change Scheme)

Target: We recognise Ofgem's view expressed in SSMD regarding tightening the target for this element of the incentive. Although we have not made changes to published maintenance plans for the first three years of RIIO-T2, we believe there is a strong justification for retaining the current target due to the increased risk related to the long duration non-RVO jobs. We are proposing a new performance deadband, see below.

This can be demonstrated in Maintenance Chart 3 below; it shows the average number of days per job. In 2022 the average job was over 13 days and in 2023 the number increased to circa 22 days. If we consider these numbers in relation to the target (7.25% translates into 17.5 days in 2023 and 9.1 in 2022), it is possible for a scenario where one delayed or cancelled job could lead to a maximum incentive penalty. Between 2021 and 2024, 21 out of 49 customer impacting jobs were longer than 16 days. ~ 40% of our jobs hold this risk. Incurring a maximum penalty for one job change would devalue the intended incentive purpose.

With the forecast increase in maintenance days being delivered in RIIO-GT3 the target will increase in absolute terms, however it will not eliminate that risk. Furthermore, the proposed introduction of the extension to the maintenance window to address th e volume of work will further expose us to risk as even more of our planned activity will form part of the incentive. The existing target already acts as a strong factor when considering moving a non-RVO piece of maintenance.

Maintenance Chart 3 - shows the average number of days per job.



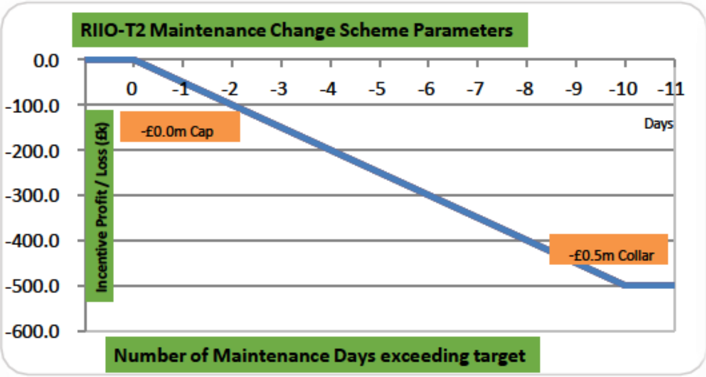
Our most recent activities have seen 6 days of change due to long lead item delays for a capital project in 2024. With an increase in the volume of asset replacement work planned for the RIIO-GT3 period, it is likely that delays due to external factors will be more prevalent, thereby increasing the number of changes.

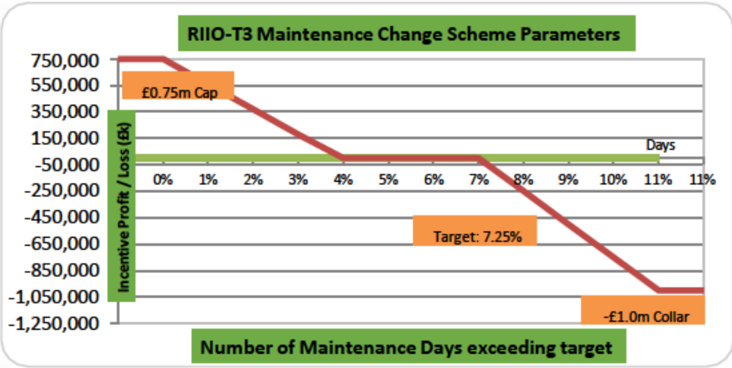
We have also seen a greater number of customer-initiated changes this year with similar causes, e.g., a seven-day delay to a project starting due to the customer's works on site overrunning. As the customer can initiate these changes without penalty, we must adapt our own works to facilitate this, often at cost and with potential impacts on other maintenance activities. We therefore believe it is reasonable to propose the introduction of an upside to this scheme, while increasing the potential penalty in the event we deviate from our published plan.

Introduce a dead band: (4% -7.25%). We recognise that we should only reach an incentive cap when we make no changes to published maintenance plans. As mentioned above, we believe it is unlikely that no plan changes will be seen in future years. We propose an introduction of a dead band for performance between 4% and 7.25%. Most of our maintenance jobs are between 6-10 days in duration (see chart 3) which translates into 4-7% of the incentive target, we will therefore need to make less change than one average job before being rewarded.

The dead band will ensure we don't benefit from performance just below target but encourages us to improve performance further than would otherwise be the case.

Maintenance Chart 4 – proposed new deadband.





Daily Reward and penalty: Since the start of the incentive the daily penalty has been set as a fixed figure regardless of the amount of maintenance work we needed to deliver. We propose to change this to a percentage to ensure alignment with the overall target for this element of the scheme and to ensure the number is reflective to the amount of work we need to complete. We propose that we should be rewarded for each 0.5% alignment below the dead band of 4% (up to a cap of £0.75m) or penalised for each 0.5% change above the dead band (up to a collar of £1.0m). This is further shown in Maintenance Chart 4.

One of our customers thought that switching to a percentage based daily reward/penalty 'seems sensible as the number of maintenance days fluctuates from year to year in a price control period, but we seek assurance that the overall number of maintenance days will not increase to manage this parameter'.

Cap and collar: We propose to introduce a financial upside element with a cap of +£0.75m and deepen the collar to -£1m respectively, based on the increase in maintenance activity to be undertaken and associated risk and effort for delivery in RIIO-GT3.

This incentive scheme element commands most of our effort as we have control over avoiding changes (subject to customer changes) to the published plans. Adjusting the performance parameters will incentivise us to realise all solutions (use of innovation, working extra hours) before any rearrangement of works.

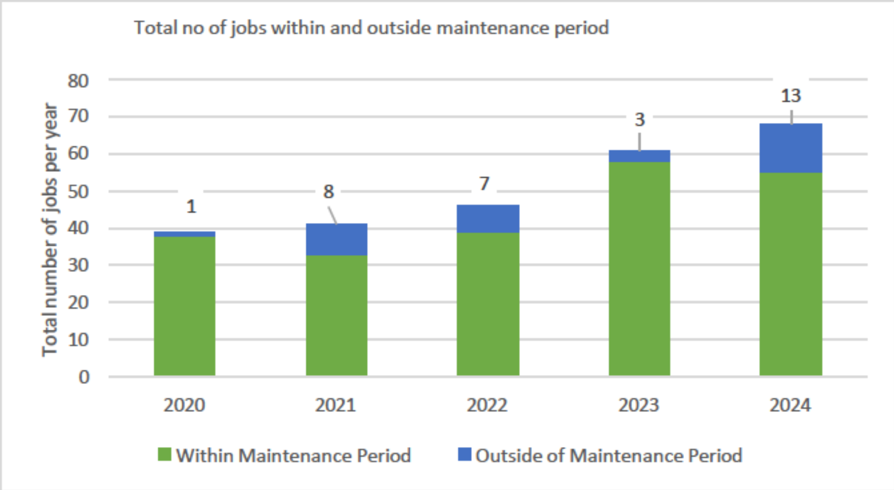
Several customers said that 'the overall value of the incentive is small' and that we 'should be financially rewarded for keeping the impact of maintenance activities to minimum as our customers don't have a choice but to accept the consequences of maintenance and they cannot re-route flows, our actions might have a direct impact on your business and may lead to loss of revenue'. One customer mentioned that 'a £1m increase in cap/collar is justifiable in the context of the customer benefit this incentive delivers'.

Two customers struggled to express view on a specific level of reward/penalty and thought that this is for Ofgem to judge and decide upon. It is worth putting the proposed parameters into the context of the customer value estimate this incentive delivers; the new parameters proposed are equivalent of a 0.5 to 1-day revenue loss in a scenario where we force a power station to come offline.

Assessment of extension to maintenance period

An increase in maintenance has required an increase in activities to be completed outside of the core maintenance window of April to October. Maintenance Chart 5 shows the number of jobs completed/planned outside of the window, this equates to 20% in 2021, 15% in 2022 and 5% in 2023 and 19% in 2024.

Maintenance Chart 5 - activities completed/planned outside of the core maintenance window.



This is set to further increase in RIIO-GT3; therefore, we are proposing to extend the maintenance window from 1 March to 30 November to reflect the new operational reality.

This will require our maintenance publications to be adjusted to the new timeframe i.e., we will be required to publish our plans one month earlier to ensure our customers continue receiving sufficient notice of any works being planned.

This new maintenance period will require a change to the UNC, and we are committing to raising a Modification proposal should our incentive proposal be accepted. We are committed to work on the UNC proposal ahead of Ofgem's RIIO-GT3 Final Determination to ensure prompt workgroup development and implementation ahead of the start of the next price control. We believe that by extending the incentive period, we are adding value for our customers who will have access to published maintenance plans earlier than is currently the case (which will enable timely operational planning) and will also cover the larger period in which maintenance is being delivered. Should the UNC proposal not be implemented, we will fall on the current Maintenance Window arrangements.

We realise that an extension to the maintenance period might concern some customers who might not want to be issued with Maintenance Days in March or November, while demand on the network might be high, and any disruption to flows costly. However, more work will be captured as a part of the incentive monitoring, and we therefore will ensure that we will work closely with our customers throughout the new Maintenance Window. Furthermore, for some customers working outside the period may be advantageous i.e., an ILI run may be better planned in early spring or late autumn/early winter as they are more easily able to provide steady flows. We will continue avoiding delivery of longer or more complex work in March or November and, as incentivised now, deliver these when we know the impact on customers will be minimised.

We have received mixed feedback regarding the extension to the Maintenance Window. One customer said: 'being sent a Maintenance Day notice in March or November might not be an issue for a long time until 1 day it might make a significant difference to a party and therefore, I don't support this'. Three customers agreed that the extension is needed, with one stating it is inevitable considering the work we will need to deliver on our aging assets.

4.5.7 Options Considered

We have considered and discounted the following options alongside our proposal.

Maintenance Table 3 - Options considered.

Discounted options	Further detail	Why discounted?
Retain incentive with RIIO-T2 performance parameters. Or retain incentive as reputational.	Customers agreed that the incentive creates value and should be retained.	Bothr option discounted due to strong customer agreement from Stakeholder Engagement sessions that the incentive should be retained and have a financial element to reward improved performance.

4.6 Greenhouse Gas Emissions

4.6.1 Greenhouse Gas Emission Purpose

The aim of the Greenhouse Gas (GHG) emissions incentive schemes is to incentivise us to reduce the amount of natural gas (primarily methane) released to atmosphere from our compressors, pipeline maintenance and fugitive leakage identified via our detection programme and therefore reduce the impact of our operational activities on the environment.

This section details our proposals for:

- Greenhouse Gas Compressors (GHGC) Emissions (existing incentive)
- Greenhouse Gas Pipeline (GHGP) Emissions (new incentive) (Likely 2027)
- Greenhouse Gas Fugitive (GHGF) Emissions (new incentive) (Likely 2027)

4.6.2 Greenhouse Gas Emissions Incentives

GHGC is an existing incentive scheme that we propose remains in place, with updated performance targets and parameters. GHGP and GHGF are new schemes in our ambitious environmental incentive package as supported in our Stakeholder engagement.

- GHGP aims to optimise the planning, availability, and deployment of mobile recompression and additional capability units to maximise gas reinjection and reduce venting during pipeline maintenance.
- GHGF focuses on reducing emissions by using data from an expanded fugitive methane detection and analytics program to implement a more efficient repair program.

This annex outlines our analysis of the new proposed GHGC performance measures and the principles for establishing these new incentives. Agreement on these principles will allow time to design, build, and commission the necessary units and establish a robust fugitive methane emissions baseline, specific proposals to be designed, and incentives activated during the RIIO-GT3 period.

4.6.3 Journey To Net Zero

These incentives encourage us to exceed business-as-usual activities. For GHGC, our aim is to continue to reduce emissions as we work towards virtually eliminating operational venting by 2050. The proposed GHGP and GHGF incentives will drive the optimisation of process to support the reduction and of greenhouse gas venting from our operations.

Government focus on methane emissions, including the natural gas supply chain, led to the Global Methane Pledge at COP26 in Glasgow (November 2021). The UK and 121 other countries committed to reducing global methane emissions to limit temperature rises to 1.5°C, mitigating climate change impacts.

By committing to this pledge, the UK has agreed to cut its methane emissions by 30% by 2030 from a 2020 baseline. These commitments align with, and contribute to, our target to reach net zero from scope 1 direct and scope 2 indirect greenhouse gas emissions by 2050.

Following this pledge, we accelerated our innovation programmes to advance emissions reductions projects under the Net Zero Pre-construction Work and Small Net Zero projects reopener (NZASP) project. The funding consultation decision in March 2024 supported these projects. These projects would not impact GHGC performance as they are targeting other types of emissions therefore the proposed incentives aim to ensure we innovate beyond the consultation outcomes to reduce emissions further.

4.6.4 GHGC Incentive Background (existing incentive)

Compressors move gas from supply sources to demand areas by increasing pressure in the NTS. We use the Best Available Technology (BAT) per the Industrial Emissions Directive (IED) for both gas and electrically driven compressors under the GHGC incentive.

NTS assets are designed to release gas during their commissioning, operation, maintenance, and decommissioning lifecycle phases. Gas leakage also occurs through compressor shaft seals during compressor operation or pressurized standby.

The scheme incentivises us to choose between depressurising compressor units (venting gas) or keeping them on standby. Standby incurs costs from ancillary equipment and emissions through shaft seals. As such we continually assess the likely customer flow requirements and the costs of both approaches to determine the best approach.

For RIIO-T2, the incentive scheme was changed from the RIIO-T1 unlimited downside-only scheme to a symmetrical financial scheme, capped at +/-£1.5m per annum. This encourages further proactive performance improvements beyond those seen in RIIO-T1.

Government policy determines a cost for methane emissions using the HM Treasury Green Book, (non-traded carbon price). Methane emissions costs rose from £1,302/tonne in Year 1 of RIIO-T1 to nearly £2,500 in Year 3 of RIIO-T2, a 92% increase over 14 years. This is expected to rise to ~£8,000/tonne in the RIIO-GT3 period assuming utilisation of the new central traded carbon price.

The new central traded carbon price is about three times higher than the current value used in the incentive scheme, reflecting the UK's ambitious climate goals. Previous values were based on an 80% emissions reduction target, while the new values align with Net Zero and Paris 1.5°C policy aims. The government now values traded and non-traded carbon equally to ensure a balanced decarbonisation strategy.

4.6.5 Performance To Date

During the 8-year RIIO-T1 period, we incurred a total penalty of ~£3.5m (in 13/14 price base), mainly in the first 5 years. To improve our venting performance, under a Director Sponsored project called the 1,000-tonne reduction challenge we were successful in identifying and reducing some of our controllable emissions and avoiding a penalty in the final 3 years of RIIO-T1.

In the RIIO-T2 consultation, we discussed the benefits of a symmetrical incentive scheme with Ofgem and stakeholders, which encourages proactive innovation and investment. This approach, supported by Ofgem and stakeholders, included an upside in the RIIO-T2 GHGC scheme.

GHGC Table 1 shows our target allowance against financial incentive performance. Over the last 11 years, the average venting emissions through compressors were 2,815 tonnes, with the highest year being 3,893 tonnes (2017/18) and the lowest year being 2,061 tonnes (2021/22).

GHGC Table 1 - Financial Incentive Performance

Regulatory Period	Incentive Year	Incentive Target	Incentive Performance	Incentive performance (£m) in 23/24 prices
RIIO-T1	2013/14	2,917 tonnes	3,332 tonnes	-£0.78m
RIIO-T1	2014/15	2,829 tonnes	2,857 tonnes	-£0.23m
RIIO-T1	2015/16	2,744 tonnes	2,882 tonnes	-£0.26m
RIIO-T1	2016/17	2,897 tonnes	3,590 tonnes	-£1.34m
RIIO-T1	2017/18	2,897 tonnes	3,893 tonnes	-£1.81m
RIIO-T1	2018/19	2,897 tonnes	2,871 tonnes	*£0.00m
RIIO-T1	2019/20	2,897 tonnes	2,500 tonnes	*£0.00m
RIIO-T1	2020/21	2,897 tonnes	2,371 tonnes	*£0.00m
RIIO-T2	2021/22	2,897 tonnes	2,061 tonnes	**£1.72m
RIIO-T2	2022/23	2,897 tonnes	2,287 tonnes	£1.35m
RIIO-T2	2023/24	2,897 tonnes	2,325 tonnes	£1.46m

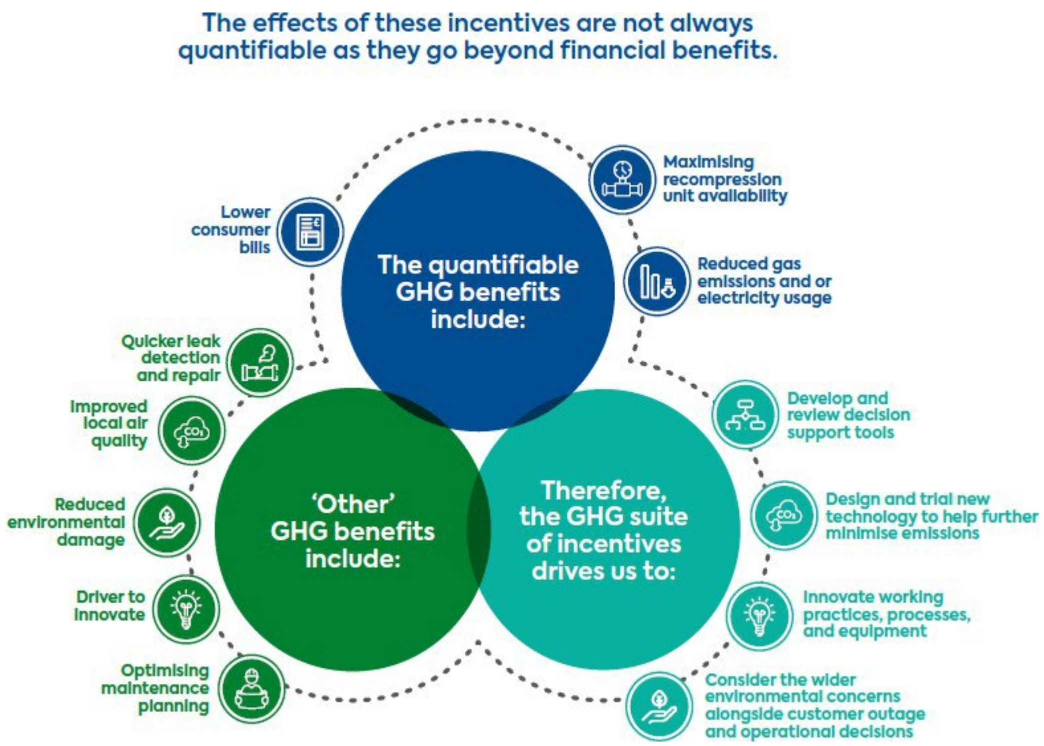
*Venting emissions improvements following improvement projects, RIIO-T1 parameters

** Capped vented performance. Coronavirus impact on Demand in 2021/22 with various lockdowns between England, Wales and Scotland and new hybrid ways of working, coupled with increasing gas prices supressed demand and subsequent emissions.

4.6.6 Consumer Benefit

Minimising emissions from all venting is important as methane has 28 times the global warming potential of carbon dioxide. The value of the gas saved can be measured in the form of:

1. Wholesale Cost - value of natural gas (supporting a reduction in Shrinkage OUG and UAG costs) for each 1,000 tonnes of gas reinjected saves ~£429k. @80p/th.
2. Environmental Cost - value of carbon emissions avoided. Based on the Governments Treasury Green Book for each 100 tonnes of gas not vented equates to ~£800k. @Y1 RIIO-GT3 estimated price. (£8,000 per tonne).



We have demonstrated value to Stakeholders via the GHGC incentive scheme over the RIIO periods, where we have been successful in reducing compressor vented emissions. We have continued to test this position with Stakeholders through our engagement on the development of RIIO-GT3 proposals.

All stakeholders we have engaged with recognised the continued value of the GHGC incentive to minimising our impact on the environment through emission reductions, recognising this needs to be done in a sustainable way. They also supported our proposals for the two new emissions incentive schemes and are keen for further engagement once we have data regarding mobile compression and established a fugitive emission baseline level of performance.

4.6.7 Process Improvements

The RIIO-T2 symmetrical financial scheme has incentivised us to proactively review our procedures and innovate our processes to reduce compressor venting.

This has led us to create a 'toolbox' of options (below) to reduce compressor venting, the use of which will depend on supply and demand, flow patterns and maintenance outages. Therefore, the selection of options we can potentially utilise based on the specific set of circumstances being experienced. Below are some activities that form the 'toolbox' and projects driven by the incentive scheme to investigate and reduce emissions:

Behavioural changes: We introduced clear ownership of pressurising and venting decisions in part by ensuring sites have a 'think emissions' mindset alongside asset health and reliability to reduce emissions. This is supported by National Control Centre (NCC) decision making, and the Breakeven tool detailed below.

Procedural changes: To ensure compressors operate on demand, they undergo a 28-day test run after being inactive, which includes pressurisation and venting. To reduce these emissions, three initiatives have been implemented. These initiatives maintain testing and operational integrity while reducing test venting. Site engineers and NCC can use these options based on the specific scenario, unit type, future flow requirements, and maintenance procedures.

- **Unit Inhibition:** During summer, non-critical units can be preserved, eliminating the need for 28-day test runs.

- **Dry Cranking:** For engines that can't be inhibited, rotating the units off their current position protects the bearing, avoiding full test runs every 28 days.
- **Entry Visual Inspections**: From 2010 to 2022, we increased monthly inspections to reflect asset age and ensure safety procedures for unit isolation which led to more venting. To mitigate this, visual inspections are completed for units that ru n less than 500 hours per annum, reducing venting.

Additionally, we have implemented other initiatives to reduce compressor pressurisation and venting.

- **Winter Assurance Readiness Testing**: We have improved our process to focus on critical units only, reducing venting while ensuring operational integrity.
- **System Control Panel Improvements**: Although when carrying out the work/testing there is a short-term increase in emissions once the testing is completed the upgrades to control panels have reduced emergency shutdowns and venting.
- **Breakeven Calculation Support Tool:** This tool helps the NCC, and site operatives compare vented tonnes to ancillary equipment costs, enabling informed decisions to optimise venting reductions.
- **Early Depressurisation:** The NCC conducts daily analysis to assess if recently used sites can be depressurised, reducing static seal emissions.
- **Aligned Maintenance:** Compressor maintenance activities are aligned where possible to reduce emissions during testing.

These initiatives have reduced emissions by approximately 300 tonnes. We have incorporated this reduction into our proposed incentive target to recognise that these initiatives are now business as usual.

4.6.8 Proposal for Greenhouse Gas Compressor Emissions Incentive (GHGC) for RIIO-GT3

We propose to retain the financial incentive scheme in RIIO-GT3 with a recalibrated performance measure to continue to reduce our operational methane emissions.

We propose retaining the symmetrical incentive structure with a revised Cap and Collar of +/-£2.5m per year, using government carbon cost calculations and established GHG methodologies for setting and measuring performance. A continued symmetrical incentive supports proactive and innovative efforts, as endorsed by stakeholders who support steps to exceed emission reduction goals.

We propose to lower our GHGC allowance target from 2897 tonnes to 2600 tonnes, reflecting the RIIO-T2 initiatives described above that have reduced compressor emissions by 300 tonnes. This reduction is now considered business as usual (BAU) and part of our management control. We will continue these activities, recognising annual fluctuations, and seek further innovations to continue to reduce emissions.

The new target is challenging, requiring the use of existing initiatives to maintain performance and new opportunities to realise potential incentive financial benefits. This proposed target reduction exceeds the previous 110-tonne reduction seen over the last 12-years (2012-2023). Our Stakeholder engagement supported this with some saying, 'we would support any steps which will lead us to going above and beyond to limit our emissions'.

We also propose to retain the annual external verification statement (independent audit) and timelines.

GHGC Table 2 – Proposed scheme parameters

Target allowance for RIIO-T2: 2,897 tonnes	Target allowance for RIIO-GT3: 2,600 tonnes
Cap / Collar +/-£1.5m - (2018/19 prices)	Cap / Collar +/-£2.5m - (2023/24 prices)
Reference Price (CPt £/tCO2e) (non-traded carbon reference price)	Reference Price (CPt £/tCO2e) (central traded carbon reference price)
Venting Factor (VFt) 25 (Global Warming Potential)	Venting Factor (VFt) 28 (Global Warming Potential)
Venting incentive Reference Price (VIRPt) = (NTCPt £/tCO2e) * (VFt)	Venting incentive Reference Price (VIRPt) = (NTCPt £/tCO2e) * (VFt)
Annual external verification statement	Annual external verification statement

Assessment of RIIO-GT3 GHGC incentive scheme and future focus

The need to operate an individual compressor on any given day is dependent upon several variables, including the sources of supply and demand, the prevailing network conditions, and the need to accommodate maintenance outages and construction plans. Our compressor emissions are impacted by NTS flows (higher flows generally means more potential compression and associated emissions), the location of flows, our compressor maintenance activity and safety obligations.

As we accelerate towards net zero by 2050 our customer requirements are likely to become even more variable, diverse, and flexible meaning that the NTS needs to be able to meet these customer requirements. Flexibility and volatility of supplies may see a return to the increased summer flows, this will provide some challenges to maintenance outages and potentially limit our ability to utilise all our compressor venting reduction toolbox options. Throughout the changing and dynamic operating environment, we will need to continue to ensure compliance with all safety regulations.

The Industrial Emissions Directive (IED) is a major change in environmental legislation, consolidating several European emissions directives. It significantly impacts the NTS compressor fleet, requiring us to replace, remove, or limit the use of some compressors. As a result, some assets are becoming non-compliant with emissions legislation as they age beyond their original design life.

Compliance with these directives and assessing our ability to meet customer needs are part of our uncertainty mechanisms within the RIIO-T2/RIIO-GT3 price control. Upgrading units to comply with the IED will affect our compressor emissions as old units are decommissioned and new units are commissioned (likely to increase in the short term and decrease in the longer term).

During the RIIO-GT3 period, we plan to upgrade and commission five compressors: one each at Wormington and Peterborough, and three at St Fergus. Our experience shows that upgrading, commissioning, and mapping the operation of new units may result in approximately 50 tonnes of additional venting per unit over the first ~12 months.

Assessment of GHG Reference Price

To calculate each year's non-traded carbon reference price (NTCPt in the NGT Licence), we refer to the "Valuation of Energy Use and Greenhouse Gas" guidance from HM Treasury's Green Book, and RPI inflation to determine the financial penalty/reward for the GHGC incentive.

In October 2021, the guidance was updated, replacing non-traded carbon prices with a combined traded and non-traded carbon value. From October 2021 to the end of RIIO-T2, we agreed with Ofgem to continue using the non-traded carbon values to maintain consistency with the RIIO-T2 consultation principles and maintain incentive integrity for the remainder of the RIIO-T2 period.

For RIIO-GT3, the reference price will increase due to two updates:

1. Using the new central carbon value from the Green Book.
2. Updating the NTS special conditions to use the latest methane CO2 conversion from 1:25 to 1:28, aligning with European standards.

This will increase the reference price by approximately 230% to around £8000 per tonne for the first year of RIIO-GT3. Should we align our incentive cap/collar range with this increase they would increase to approximately +/-£5.0m. Although we haven't matched our proposal to this increase, we felt the proposed adjustments better reflect the current government emissions evaluation and maintains the strength and integrity of the incentive purpose.

4.6.9 Options Considered

We have considered and discounted the following options alongside our proposal.

GHGC Table 3 - Options considered.

Discounted option	Further detail	Why discounted?
Do nothing.	Continue with RIIO-T2 performance parameters.	Discounted due the majority of customers agreeing that the incentive should be recalibrated to include current performance.
Increase cap/collar in line with reference price.	Cap/collar of +/-£5.0m.	Discounted in order to strike the right balance of incentive to consumer value.
Track value of carbon and set a % range.	Sets changeable annual target.	Discounted as more challenging to cost projects and innovation against. Also adds additional complexity to the scheme.
Annual target reduction.		Discounted as new technology and improvements do not align with year-on-year reductions.

4.7 Proposal for Greenhouse Gas Pipeline Emissions Incentive (GHGP) for RIIO-GT3

4.7.1 Pipeline Maintenance Background

Pipeline maintenance is essential to keep the high-pressure gas NTS safe, efficient, and economical. Maintenance sometimes leads to network outages or reduced ability to meet pressures over and above contractual requirements. Sections of the pipeline must be depressurised for safe working; we do this by using mobile recompression units to reinject gas back into live section s of the pipework and venting the remaining gas to the atmosphere.

Mobile recompression units have a pressure limit to ~7barg, so any remaining gas is currently vented. We received RIIO-T2 funding to replace our 30-year-old (end of life) recompression units to compress gas to ~7barg and used Net Zero funding to procure additional capability units to deliver an enhanced recompression capability to ~1 barg.

The first of these sets is scheduled to be delivered in August 2025, the second in Summer 2026. As such we propose to start this incentive following successful commissioning and delivery of both sets, allowing an appropriate incentive target to be calculated following real life experience of operation.

4.7.2 Pipeline Maintenance Emissions Assessment

GHGP Table 1 details the number of pipeline maintenance jobs completed within each calendar year, gas recompressed to live sections of pipe and gas vented to atmosphere and the total gas (recompressed gas plus vented gas). The increased recompression values seen in 2023 are due to the size of sections of pipe being maintained and therefore the associated amount of gas recompressed / vented is greater.

GHGP Table 1 - pipeline maintenance jobs and vented gas

Number of jobs completed	Calendar Year	Gas volumes Recompressed (Tonnes)	Gas Vented (Tonnes)	Total Gas (Tonnes)
10	2019	4461	532	4993
9	2020	3068	458	3526
10	2021	6762	606	7368
9	2022	4371	319	4690
10	2023	8936	1001	9937

Optimising the planning of the Pipeline Maintenance program and availability / deployment of the mobile recompression and additional capability units as a set would support recompression to ~1barg. This would save~80% of the Gas Vented (Tonnes) column.

The GHGP incentive would drive us to minimise venting by maximising the usage of the combined units and innovate alternative options to reduce venting below 1barg.

Once both new sets of pipeline recompression machines have been successfully commissioned the existing machines would be retired from service as they are outside of their original life expectancy.

4.7.3 Proposal For GHGP for RIIO-GT3

We are proposing a new symmetrical financial incentive scheme within the RIIO-GT3 period. This will ensure that we make the appropriate maintenance planning decisions to optimise the availability of the mobile recompression units to run concurrently with the additional capability units and reinject gas back into the live sections of the system. This gas would otherwise have been vented in RIIO-T2; the incentive then encourages us to further innovate to reduce the gas vented under 1barg.

We are proposing an incentive that rewards us for going beyond our ambitious investment assumption of recompression to 1barg. Under our proposal we will be rewarded via an outperformance payment based on the central carbon price and where we fail to achieve 1barg we are subject to a cost penalty based on the central carbon price.

The under/out performance will be subject to a narrow deadband, which will be proposed based on the field trial data. Our Stakeholder engagement supported this with some saying, *'Support the ideas/content of proposals in principle as anything reducing the environmental impact and shrinkage is a positive'.*

GHGP Table 2 – Proposed Scheme Parameters

>1barg recompression
Cap +£1.5m, (2023/24 prices)
Collar -£1.5m, (2023/24 prices)
Reference Price (CPt £/tCO2e) - Global Warming Potential (GWP) of methane 100-year time horizon
Venting Factor (VFt) 28 - IPCC Fifth Assessment Report (AR5); now standard in Defra Green Book and OFGEM CBA templates
Venting incentive Reference Price (VIRPt) = (NTCPt £/tCO2e) * (VFt)
• The venting incentive performance measure (in tonnes of natural gas) is calculated as the aggregate amount of natural gas reinjected from planned pipeline maintenance. • Potential Deadband - 1.2barg – 1.0barg. • Incentive upside at 1barg or less, incentive downside at more than 1.2 barg venting. • Latest venting factor of 28. • Use central traded carbon price as published periodically using latest green book guidance. • Potential need to design methodology calculation if metering unavailable. • Forms part of independent 3rd party audit to the annual ISAE 3410 limited assurance of the entire scope 1 and 2 business carbon footprint.

4.7.4 Options Considered

We have considered and discounted the following options alongside our proposal.

GHGP Table 3 – Options considered.

Discounted option	Further detail	Why discounted?
Do nothing.	Continue with RIIO-T2 performance parameters.	Discounted due to strong customer agreement from Stakeholder Engagements sessions that we should look at ways to reduce emissions from our activities.

4.8 Proposal for Greenhouse Gas Fugitive Emissions Incentive (GHGF) for RIIO-GT3

4.8.1 Fugitive Emissions Background

The current NTS methane emission volumes are calculated based on a periodic fugitive survey programme which consists of a four-yearly site survey of compressor stations and terminals. This approach meets the current Environmental Agency standards. In addition to the fugitive survey programme, we have another 509 Above Ground Installations (AGIs) on the NTS that are not regularly surveyed, therefore, this provides a gap in our visibility and understanding of the whole fugitive methane detection and quantification of emissions performance.

In October 2022, we submitted the Methane emissions reduction and monitoring projects: Net Zero Pre-Construction Work and Small projects Re-opener (NZASP) to request funding to close the gap between the current periodic fugitive survey programme that covers compressors and terminals and the unknown fugitive methane emission performance at the other Above Ground Installations (AGIs) on the NTS. Our NZASP request increases the survey frequency at compressor stations and terminals to annually. The remaining AGIs will be surveyed once every three years as part of the expanded survey programme.

Through this funding we are seeking to deliver a measurement based above ground network methane emission performance baseline by the end of the RIIO-T2 period as well as carrying out detection, monitoring and repair work as this fugitive survey programme expands. Due to the longer than expected consultation decision process resulting in Ofgem's minded to decision to not fund the monitoring and repair aspects of this submission, we will not be able to provide a base level of emissions in 2026 (Y1) and would expect this baseline to be established in 2027 (Y2).

Our Stakeholder engagement supported this with some saying, 'Our approach makes sense in terms of setting the benchmark once we have experience how the new equipment functions. Similarly, setting the benchmark once we have the funded level of fugitives defined makes sense.'

Fugitive surveys undertaken to date show that, on average across all surveys conducted, 14% of all fugitive emission sources identified are responsible for 50% of emissions. Therefore, by undertaking more frequent surveys, we can iden tify these high fugitive emission sources faster and intervene sooner, thereby improving emissions performance.

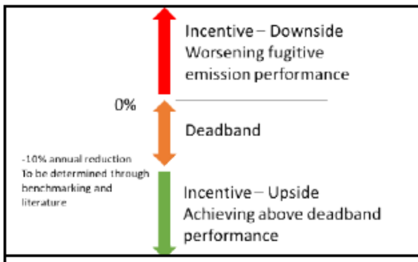
4.8.2 Proposal For GHGF for RIIO-GT3

We propose a new symmetrical financial incentive scheme to go beyond our investment funding triggered once a fugitive emissions baseline is established, expected to be in Y2 of RIIO-GT3. This incentive is designed to support rapid repair and emission reductions of small high-volume defects identified from the expanded fugitive methane detection and analytics programme.

We propose an incentive that encourages us to outperform the >10% (year on year) reduction of baseline emissions funding, with performance valued at the central traded carbon price, to align with GHGC and GHGP.

We propose a 10% deadband allowance that takes account of current defect repair funding.

GHGF Table 1 – Proposed scheme parameters

<table>
<tr><td>
</td><td>>10% reduction in baseline = outperformance, underperformance = increased volume vs baseline.
Cap +£1.5m Collar -£1.5m, (2023/24 prices)
Reference Price (CPt £/tCO2e)
Venting Factor (VFt) 28
Venting incentive Reference Price (VIRPt) = (NTCPt £/tCO2e) * (VFt)</td></tr>
<tr><td colspan="2">• A measurement-based above ground network methane emission performance baseline, combining understanding from periodic and continuous fugitive detection.
• An annual periodic monitoring campaign covering a proportion of its above ground assets, to revalidate baseline and measurements.
• Use the current methodology for periodic fugitive gas escape detection following BS EN 15446 for screening, followed by gas escape rate quantification using ground-based measurement techniques for accessible gas escapes and optical gas imaging (OGI) techniques for elevated sources obtained.
• These techniques were demonstrated in our investigation into the use of optical gas imaging cameras for elevated fugitive emission sources in the Monitoring of Realtime Fugitive Emissions (MoRFE) Network Innovation Allowance project.
• Using these techniques will provide a measurement-based methane emission baseline for the NTS by the end of Y2 RIIO-GT3 period to deliver:
• Reference price calculation using the central traded carbon price as published periodically by the relevant government department for penalty and reward and Retail Inflation Index.
• Forms part of independent 3rd party audit to the annual ISAE 3410 limited assurance of the entire scope 1 and 2 business carbon footprint.
• This holds equal opportunity and risk.</td></tr>
</table>

See link for details of our monitor and repair costs that the incentive performance would cover as detailed in the consultation.

4.8.3 Options Considered

We have considered and discounted the following options alongside our proposal.

GHGF Table 2 – Options considered.

Discounted option	Further detail	Why discounted?
Do nothing.		Discounted due to strong customer agreement from Stakeholder Engagements sessions that we should look at ways to reduce emissions from our activities.

4.9 Demand Forecasting Incentive

4.9.1 Demand Forecasting Purpose

Our NTS GT licence and the Uniform Network Code (UNC) require us to provide national demand forecasts to help the industry make efficient decisions regarding supply and demand. We publish daily national demand forecasts for:

1. day ahead (D-1) (This is a financial incentive in RIIO-T2) and,
2. two to five days ahead (D-2 to D-5) (This is a reputational incentive in RIIO-T2).

4.9.2 Demand Forecasting Incentive

These forecasts are available on our website "Data and Operations" page and support our customers in commercial decision-making processes for the following day (D-1) as well as giving them a longer-term view of how demand may evolve (D-2 to D-5).

The day ahead (D-1) incentive has a breakeven target of 8.35mcm/day based on an annual weighted average absolute forecast error. There is an adjustment to this target for the level of short-cycle storage injection capability that is designed to consider the unpredictability of demand from short-cycle storage sites. The Demand Forecast Adjustment (DFAt) is capped at an additional 1mcm/day and therefore has the potential to revise the D-1 demand forecasting target to 9.35mcm.

If the published error is below the breakeven target, an incentive payment will be received, conversely, if the forecast error for any day exceeds the target an incentive penalty will be applied.

- Cap: +£1.5m, Collar: -£1.5m, Target: 8.35mcm (weighted), DFAt: max 1mcm (storage)
- The maximum reward = if the weighted average error is ≤ 4.5mcm + DFAt.
- The maximum penalty = if the weighted average error is >=12.2mcm + DFAt.

Under the two to five days ahead (D-2 to D-5) we publish demand forecasts each day from two to five days ahead of the gas day. The scheme is reputational only in RIIO-T2. It has an annual average absolute error target of 13.7 mcm/d; but there is no short cycle storage adjustment applied.

- Cap/Collar: Reputational, Target: 13.7mcm (weighted)

4.9.3 Performance to date

The Demand forecasting Table 1 summarises our performance against the target for D-1 (including the DFAt) and D-2 to D-5.

Demand Forecasting Table 1 - Demand forecasting performance for D-1 to D-5

	D-1			D-2 to D-5			
Year	Target (mcm)	Actual (mcm)	£ (m) Incentive performance (£m) in 23/24 prices	Target (mcm)	Actual (mcm)	£ (m) Incentive performance (£m) in 23/24 prices	Total £(m) Incentive performance (£m) in 23/24 prices
2013/14	9.40	8.69	£1.24m	16.00	13.10	£2.25m	£3.49m
2014/15	8.95	8.07	£2.11m	16.00	12.55	£2.96m	£5.07m
2015/16	9.00	7.75	£2.66m	13.70	12.09	£1.60m	£4.26m
2016/17	9.39	8.53	£2.02m	13.70	12.39	£1.27m	£3.29m
2017/18	9.03	8.24	£1.79m	13.70	12.06	£1.53m	£3.32m
2018/19	8.41	8.90	-£1.07m	13.70	13.44	£0.24m	£-0.84m
2019/20	9.12	8.56	£1.20m	13.70	12.91	£0.70m	£1.90m
2020/21	8.83	8.20	£1.33m	13.70	13.52	£0.16m	£1.49m
2021/22	8.97	8.52	£0.22m	13.70	12.37	ODI-R	£0.22m
2022/23	8.48	8.97	£-0.24m	13.70	13.95	ODI-R	£-0.24m
2023/24	8.52	7.86	£0.32m	13.70	12.89	ODI-R	£0.32m

4.9.4 Factors Impacting Performance

- Due to Covid and the Russia-Ukraine war we have seen a reduction in Industrial load and domestic consumption since 2020. The Russia-Ukraine war also impacted exports to Europe. These events created challenges and led to continuing upwards pressure on the level of volatility in gas demand. This translated into performance challenges (see Demand Forecasting Table 1 2022/23) and intensified efforts in seeking performance improvements detailed below.
- Our ability to create an accurate forecast is directly dependent on the accuracy of the input data (e.g. CWV and Wind forecasts) we receive from third parties.

RIIO-T2 Process and System Improvements: Our customers told us that our incentive reward should be proportional to the efforts we put into improving performance. This section summarises the improvements we have instigated as part of our forecasting process during RIIO-T2.

Supply forecasting

- **Terminals**: Since 2020, we regularly contact terminals to better understand their operations and forecasts, ensure we track new fields coming online, or have awareness of changes to existing field/terminal operations.
- **Liquified Natural Gas (LNG) deliveries:** LNG supply has grown in the last 3 years. We now focus more on and monitor multiple data sources to predict LNG deliveries, stock levels and FRU (Floating regasification units) developments to support forecasting cargo destinations and flows.
- **Norwegian Gas Supply (Gassco):** Since June 2021 we have further developed our knowledge on Gassco operational activities and forecasting processes for their entire grid to support our forecasts for deliveries to the GB market.

Electricity Demand Forecasting

- **Total Electricity Demand (TED) model:** The previous access database model (created in 2012) was limited in the areas it considered and as a result its performance gradually declined, and we stopped using it in January 2021. We have implemented the TED model which is more comprehensive and takes new elements of market dynamics into account, therefore producing more accurate picture of the total electricity demand for the coming days.
- **Power Station model (Metamodel):** We progressed the internal development of an improved demand forecasting power station model. The investment is ongoing and estimated at ~£70K annually since 2022. The metamodel combines the forecasts of 6 models into one weighted output. It enables efficiency by providing a combined outcome with the aim of minimising errors. We estimate that when fully operational, it will save 1-1.5 hours/day currently spent on forecasting power station demand.
- **Generation per fuel:** We have broken down the power generation forecast into fuels to enable us to identify the areas of forecast where we were underperforming. From this we have amended our processes to review the data relating to the separate elements and how they interact as part of our daily processes including learning from the commercial links, e.g., price triggers between gas and coal, to better understand different sources of demand.
- **Electricity Interconnectors:** The granularity of our analysis in relation to electricity interconnectors has significantly increased since the start of RIIO-T2. We now use within-day nominations from ENTSOG, available data on live transmission, within-day and day ahead wind gust and temperature forecasts. The forecast weather allows us to predict potential price spread between TTF and NBP and therefore the likelihood and volumes of electricity interconnector imports or exports.
- **LDZ model:** The LDZ gas demand forecast is derived from a model which was introduced at the start of 2022 to provide more agility to changing market conditions.

It is not possible to quantify how much each of the above contributed to performance improvement as forecasting comprises of a number of closely interlinked moving components. All the above inputs and improvements are consistently checked and balanced ensuring any changes to one fuel are considered against another, e.g., high winds would put downward pressure on biomass in comparison to the original forecast. Following that the forecast is adjusted to allow for ‘probable’ scenarios and therefore produces more accurate forecast outcome.

4.9.5 Consumer Benefit

(D-1 scheme)

Additional cost of under or over-delivery of gas. Shippers are incentivised to ensure that they balance i.e. their daily inputs equal outputs, otherwise they are exposed to charges via cash-out prices. By providing an accurate demand forecast we enable Shippers to better balance their portfolio and therefore we can make more timely / informed balancing decisions which result in lower wholesale prices, ultimately providing a benefit to end consumers.

We believe that inaccurate demand forecasting could potentially lead to additional costs for Shippers (and by default end consumers, assuming that any costs are passed on), in scenarios where Shippers are either:

a) forced to procure additional gas to meet the unanticipated demand at a higher cost.
b) sell excess gas at a lower cost than purchased if forecast was higher than the actual demand.
c) or are subject to cash-out price exposure.

To support these hypotheses, we have conducted analysis based on a set of assumptions focussed on where demand is higher than anticipated:

This scenario considers circumstances when Shippers need to buy gas at short notice due to demand being under forecast. In such circumstances it is likely that shippers may be required to purchase gas from more costly sources. *(N.B., we accept that there will be circumstances when some market participants can procure (or deliver) gas last minute without any additional cost e.g., some will have entered option contracts. However, we expect the on the day price will ultimately feed through to the prices paid for those contracts, therefore it is still included in this analysis).* To conduct the analysis, we have taken the following steps and assumptions:

1. We have calculated the average demand D-1 forecast error since the start of RIIO-T2 period up to 31 March 2024 as 8.2mcm/day, with a standard deviation of ~10.5mcm (approximately 68% of the population should be within a standard deviation of the mean).
2. We have then categorised our performance in the first 3 years of RIIO-T2 as
    - Correctly anticipated: where the forecast error was within a standard deviation of the mean error.
    - Higher than anticipated: where the forecast error was greater than a standard deviation above the mean error.
    - Lower than anticipated: where the forecast error was greater than a standard deviation below the mean error.
3. We have summed the number of days on which the forecast was lower than/correctly/ or higher than anticipated in the first three years of RIIO-T2, as can be seen from the table below when demand was higher than anticipated this accounted to ~15% of the population which is in line with what you would expect.

Demand Forecasting Table 2 – Actual vs forecasting.

The actual gas demand v NGT demand forecast 2021-2023			
	Lower than anticipated	Correctly anticipated	Higher than anticipated
Number of days	166	767	162
Percentage of Total	15%	70%	15%

4. We have then looked at the average Argus volume weighted day ahead price versus the within day mid-point between SAP and SMP Buy price, for the same period where we categorised demand as higher than anticipated, in this period on average this equated to ~0.23p/kWh.
5. For those days where demand was higher than anticipated, the average absolute error was 15.8mcm.

As shown above, in the first three years of RIIO-T2 we have had 162 days when the actual demand was higher than our forecast D-1 demand by more than a standard deviation above the mean error. On those days the average change in gas prices between day ahead and on the day was 0.23p/kWh higher, which supports the hypothesis that some cheaper gas sources may not be available at short notice and, as a result, if demand is higher than anticipated, then on-the-day gas prices would increase by a larger amount relative to the day-ahead price than if demand had been correctly forecast.

From this data we have sought to value the incentive to consumers by considering the impact on the market if we didn't have an incentive to forecast D-1 demand accurately. We consider that in the absence of an incentive it is likely that over time there becomes a greater number of days where demand is higher than anticipated, i.e., greater than a standard deviation from the mean and in those days the level of error also increases. The table below summarises what would be the additional annual customer cost based on a 10, 20 and 30 percentage increase in days when the forecast is higher than anticipated and the error increases on the same basis, as a result of declining performance (compared to where we are now). As shown in Demand Forecasting Table 3 below, the additional cost might vary between £4m and £15m annually on the assumption that the differential between the volume weighted Day ahead price and the mid-point between SAP and SMP holds as a proxy for the value from the scheme.

Demand Forecasting Table 3 - Additional cost to customers if there is no incentive.

% Increase in days when demand is higher than anticipated	No of days when demand is higher than anticipated	Sum of additional average demand forecasting error when demand higher than anticipated (mcm)	Sum of additional average demand forecasting error when demand higher than anticipated (GWh)	Sum of average error at 0.23p/kWh in £m per annum
10	60	182	2,003	£4.6m
20	66	382	4,197	£9.5m
30	71	598	6,582	£15.0m

Our analysis focuses on the case where demand is higher than anticipated and does not consider days where demand was lower than expected. When that's the case it is likely there would be greater supply than needed to meet demand, so the supply curv e would not be expected to shift i.e., prices would be likely lower than forecast due to lower than expected demand but there would not be any additional price adjustment to reflect a lack of supply availability. We have only analysed the value of the D-1 forecast being lower than actual demand but theoretically if the D-1 forecast was higher than actual this could drive costs onto the Shipper and ultimately the end consumer also.

Our demand forecast also **aids competition by providing access to a free demand forecast.** Our demand forecasts reduce barriers to entry for small shippers that may not otherwise be able to procure forecasts at a reasonable cost and therefore may also help to 'level the playing field' (facilitate smaller shippers competing effectively with larger shippers), leading to more effective competition in the market. Our forecasts also provide a useful cross-check for larger firms who produce their own internal forecasts.

Stakeholder engagement feedback. Nine customers fed back that our D-1 forecast was valuable in correctly anticipating supply and demand, some describing it as a critical to their business. Two of these customers confirmed that they are using our forecast as a validation of own forecasts delivered internally.

One customer said that 'D-1 forecast is being looked at in addition to factors like price and temperature. It is valuable and it would be questioned if it wasn't provided. Review of parameters is sensible as market changes will be accelerated in the future'. Another customer stressed that 'it is particularly useful in the cold spells to check if any supply issues can be anticipated'.

4.9.6 Proposal for RIIO-GT3

We propose the following RIIO-GT3 scheme:

D-1 Demand Forecasts – Retain financial incentive at £1.5m as the existing principles, and objectives remain without significant alteration, the scheme ensures consistency in its benefits to provide an accurate demand forecast to enable Shippers to better balance their portfolios and remove the Demand Forecasting Storage Adjuster and propose a Demand Forecasting Wind Adjuster.

D-2-D-5 Demand Forecasts – Retain as Reputational Incentive.

Demand Forecasting Table 4 – RIIO-GT3 proposal.

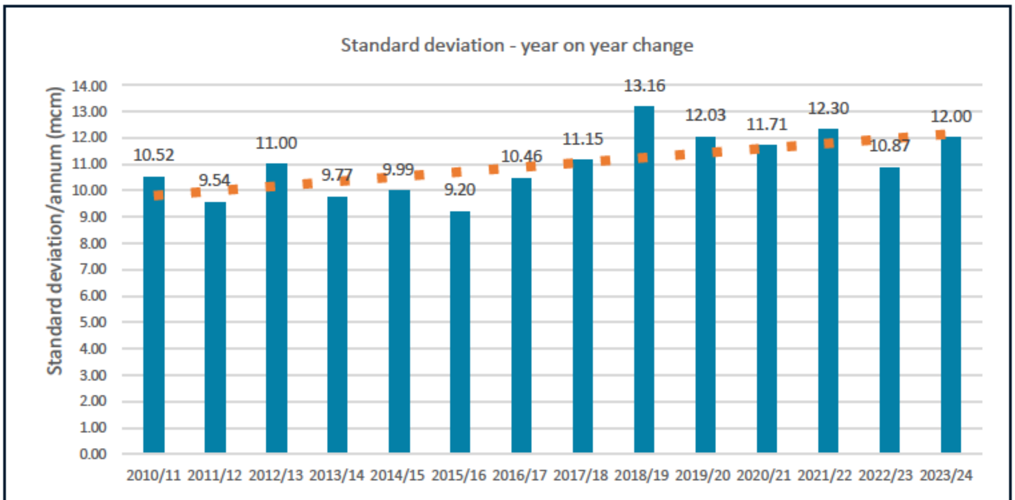
Scheme	RIIO-T2 (2018/19 prices)	RIIO-GT3 (2023/24 prices)
D-1	Cap / Collar +/-£1.5m	Cap / Collar +/-£1.5m
	Target: 8.35mcm (weighted), DFAt: max 1mcm (Demand Forecasting Storage Adjuster)	Target: 8.83mcm (absolute), DFAt: max 2mcm (Demand Forecasting Wind Adjuster)
	RIIO-T2	**RIIO-GT3**
D-2 to D-5	Target: 13.7mcm (weighted)	Target: 14.48mcm (absolute)

Assessment of scheme parameters

Parameters for the D-1 demand forecasts and D-2-D-5 schemes.

Target: We propose to update our performance target based on the observed increase in the standard deviation of day-to-day gas demand volatility between 2019-2023 (since the parameters of RIIO-T2 incentive have been established). We have defined volatility as a standard deviation of outturn demand across the regulatory year. The Demand Forecasting Chart 1 shows the gradual increase in observed year on year market volatility between 2010 and 2024.

Demand Forecasting Chart 1 – Standard deviation



Due to the 2050 net zero target and related governmental policies (i.e., potential introduction of hydrogen blending, more reliance on LNG as opposed to shale gas) as well as the changing geopolitical landscape, it is anticipated that the increase in market volatility shown above is likely to continue and increase as we progress through RIIO-GT3.

Between 2015-2019 the observed average daily gas demand volatility was 10.99mcm. Between 2019-2023 the average volatility has increased to 11.78mcm (7.2% increase). We propose that this increase should be included in target setting for RIIO-GT3 as this would reflect a like for like level of performance. This would increase our current D-1 error target from 8.35mcm to 8.95mcm, and the D-2-D-5 error from 13.70mcm to 14.67mcm.

However, to reflect that our processes, tools and people develop and contribute to our forecasting performance we propose to introduce a 20% improvement factor to the increase in standard deviation and apply this to our revised performance target for RIIO-GT3. The final proposed target figures are reflected in the Demand Forecasting Table 5.

Demand Forecasting Table 5 - RIIO-GT3 scheme parameters

Scheme	Current target (mcm)	Updated target (mcm) based on increased volatility 2015-2019 (7.2%)	Proposed target (mcm) (updated target – 20% improvement factor = 5.76% increase)
D-1	8.35	8.95	8.83
D-5	13.7	14.67	14.48

Four customers we engaged with remarked that growing renewable generation will make forecasting more difficult and one remarked specifically that *'tightening the target might not be appropriate as there is no point to financially punish for elements of the forecast National Gas has no control over'*. One customer specifically mentioned that the new target should reflect the increasing volatility we have witnessed in the market, while another was unsure about the increase in the target but supported removing the weighting if supported by analysis.

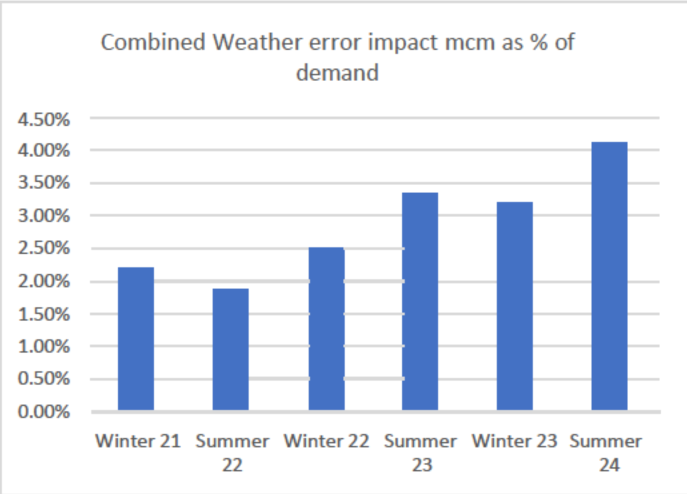
D-1 performance calculation. The current calculation of error is weighted (WMAE = weighted mean average error) by the daily gas demand rather than being mean absolute error (MAE). WMAE is more versatile as it accounts for varying levels of importance through the introduction of weights. This makes it well-suited for situations where some forecasts carry greater significance than others. When introducing WMAE, Ofgem's assumption was that the higher the demand, the more challenging the accuracy of the forecast or the value to the market. Based on this, it was thought that WMAE calculation will present more reflective output for the current price control period.

MAE is suitable for scenarios where all forecasts are considered equally important, regardless of the differences in actual values or impact. We propose to remove the weighting effect from the error calculation and replace with arithmetic absolute mean. Historically any error in weather, specifically temperature, was more directly linked to domestic demand in the distribution networks, however currently even in summer (when overall demand is lower) any error in the weather between day ahead and within day impacts on the accuracy of the forecast and has a greater impact than during RIIO-T1. This is due to the growth of renewables and the greater reliance on gas generation to react to changes in renewable generation. We believe that each mcm of error now is equally relevant and should be feeding into performance calculation directly, rather than being weighted as that weather error has a similar effect on each day of the year. This change aligns with Ofgem's goal of increased simplicity in the incentive scheme.

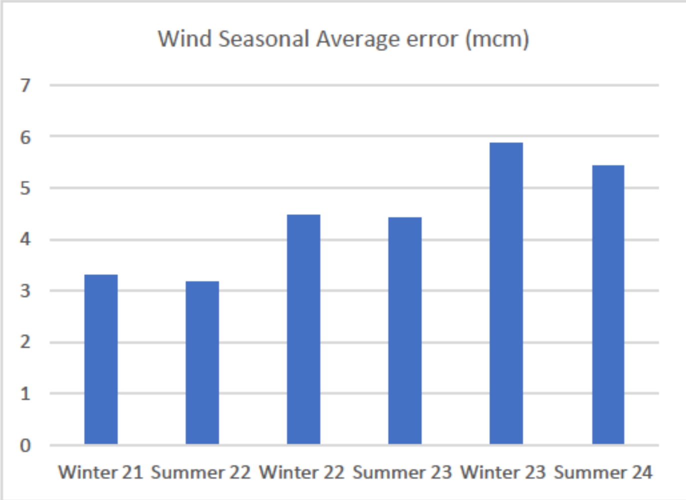
To support the view that weather error has a similar impact on forecasting at all levels of demand, we have looked at weather related errors by season. Demand Forecasting Chart 2 shows the combined weather error as a percentage of average demand by season. Over the last three years this impact continued to grow as a proportion of demand, with the last two summers showing higher percentage than the winters.

Demand Forecasting Chart 3 shows wind error by season and demonstrates the increasing impact of electricity generation error on gas demand forecasting on a volume basis and demonstrates a reduced seasonality effect, supporting the removal of weightings from the incentive calculation.

Demand Forecasting Chart 2



Demand Forecasting Chart 3



D-1 Adjuster Clarification:

The current Demand Forecasting Storage Adjuster (DFSA) accounts for the impact of storage sites withdrawing and injecting gas on the same day, affecting demand forecasting. As the volume of short-cycle storage has stabilised, we now consider wind volatility from renewables to be the primary factor influencing demand forecasting volatility.

Key Points:

Storage Impact: While storage still affects demand forecasting, it is no longer the main source of volatility. Future short-cycle storage capacity growth during RIIO-GT3 is not expected to be substantial.

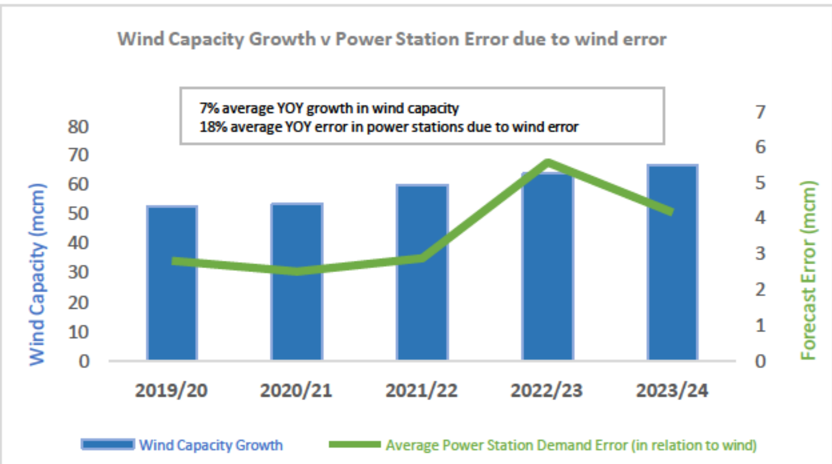
Wind Adjuster Proposal: We propose replacing the storage demand forecast adjuster with a wind adjuster. Wind energy's share of total renewable electricity generation has increased from 55% in 2012/13 to 67% in 2022/23.

Renewable Energy and Gas Demand: Due to the variability of renewable energy, gas is used as a balancing fuel, leading to increased volatility in gas demand forecasts. According to NESO's Future Energy Scenarios (Falling Short scenario), wind capacity will increase by 83% from current level by the end of RIIO-GT3.

Correlation Between Wind Capacity and Forecast Error: Over the last five years (see Demand Forecasting Chart 4), we've observed a growing correlation between wind capacity growth and errors in power station gas consumption forecasts. From 2019 to 2023, wind capacity grew by an average of 7% annually, while power forecasting errors increased by an average of 18% annually.

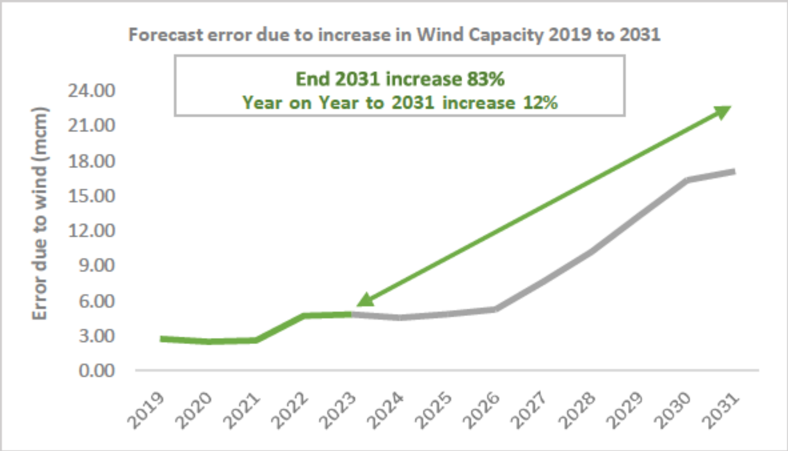
Therefore, although storage remains a factor in demand forecasting volatility, our analysis shows that increases in wind generation volatility have a significant impact our ability to forecast gas demand accurately. We therefore propose to remove the storage demand forecast adjuster and replace it with a wind adjuster calculation.

Demand Forecasting Chart 4



Wind capacity is expected to grow to approximately 53 GWh by the end of RIIO-GT3, increasing by 12% annually as predicted by the FES Falling Short scenario. We forecast that power station demand forecast error will rise from 4.16mcm in 2023/24 to approximately 17mcm (see Demand Forecast Chart 5), assuming no improvements in wind forecasting. This projection is based on a linear correlation observed between wind forecast errors and the increase in wind capacity from 2019 to 2023, converted to gas equivalent using an efficiency factor.

Demand Forecasting Chart 5



D-1 Wind Adjuster Proposal:

We propose implementing a D-1 wind adjuster based on observed errors in wind forecasts provided by NESO. This approach adjusts for the growing impact of wind volatility on gas demand forecasting. To determine the level of error the NESO forecast contains, we have collated the NESO historical incentivised forecast published on their website and compared it with the actual wind which materialised on a day.

Process:

Data Conversion:

1. Convert NESO wind data from electricity day (48 settlement periods) to gas day (5am to 4:30am next day).
2. Convert values from MW to GW.
3. Apply a daily efficiency factor to convert the gas heat energy to electrical energy.

The error calculation figure was calculated by deducting the forecast wind from the actual wind figure experienced on the day and divided by the efficiency factor. The outturn was then converted into mcm to calculate the error impact on gas demand , or expressed as:

Wind Error formula = (NESO wind forecast in Gas Day less Actual wind)/Efficiency factor) – result is converted to mcm.

Adjuster Calculation:

1. 50% of the previous year's observed year-on-year error change (reflecting its ongoing impact, and same principle as DFSA calculation).
2. Current year-on-year error difference. If negative (i.e. forecasting improves), only half of the previous year's error is considered, unless both years are negative, then the adjuster is 0.

Adjuster Boundaries:

1. Adjuster will be between 0mcm and 2mcm.

This method ensures that the wind adjuster more accurately reflects the variable impact of wind energy on gas demand forecasting.

Customers generally agreed that *'uncertainty in wind generation and hence gas demand to support wind intermittency could become more significant as the installed capacity of wind generation increases'*. Four customers concluded that switching from a storage to a wind-based adjuster is sensible. Two suggested that other sources of renewables, like solar, should be considered in the calculation.

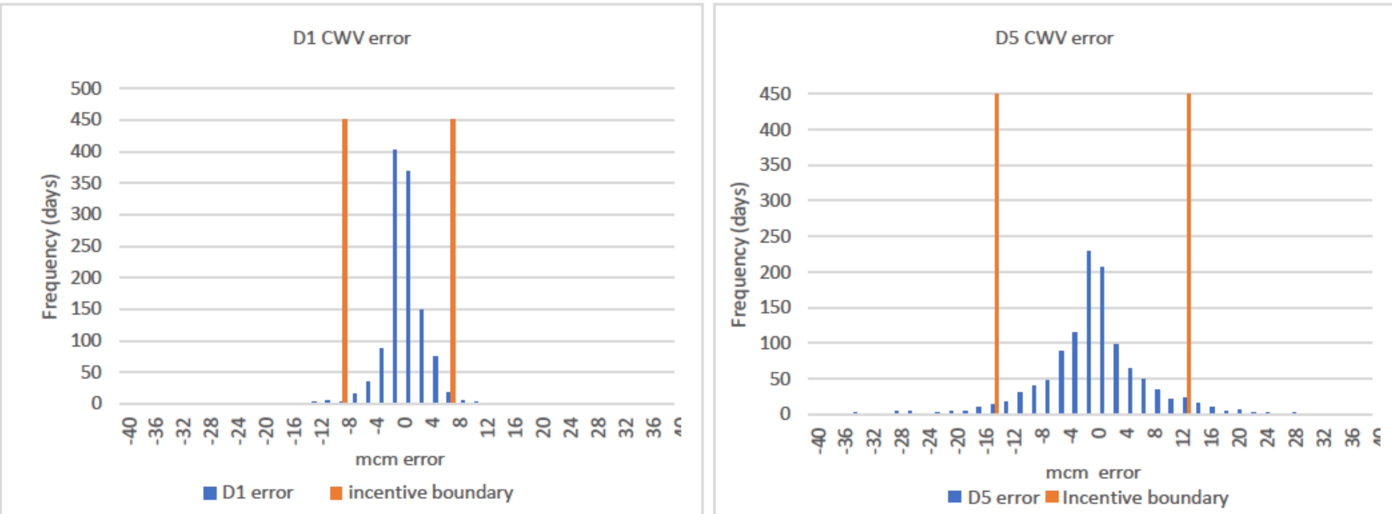
4.9.7 Proposal for D2-D5 Demand Forecasting Scheme

In SSMD Ofgem stated that they are minded introducing a financial incentive for D-2 to D5. Through our engagement activities there was no stakeholder support in favour of re-introducing a D2-5 financial incentive from those we engaged with, and the overriding feedback was that *'longer terms forecasting was not being considered in commercial decisions'* and *that 'no one is looking that far ahead therefore the incentive should be kept reputational'*. Only two customers suggested that the D2 forecast is considered to see how demand is shaping up, but it is not crucial as looking any further ahead than D1 is not reliable. Regarding the link with DSR, one customer mentioned that *'the scheme is not a driver for growing the DSR market'*, one more added that *'attention to it (D2-D5 scheme) might be paid by DSR parties if we expect frequent gas deficiency, which is not the case'*.

Our reasoning for supporting the continuation of a reputational scheme is based on both the stakeholder feedback and that the data uncertainty increases at any timescale greater than the day ahead stage. The following charts show how the uncertainty in weather increases the further ahead of the gas day and demonstrate that wind and CWV pose similar impact on gas demand forecasting. However, we have developed a project plan to investigate alternative methods which could lead to performance improvement and deem the project-based strategy for RIIO-GT3 a more appropriate approach considering the factors detailed in this paragraph.

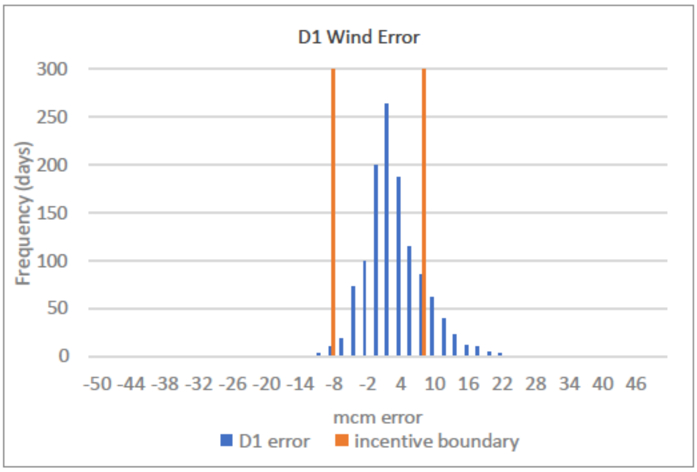
Composite weather variable error. Demand Forecasting Chart 6 shows the frequency of the approximate mcm error from weather change from forecast to the actual outturn between May 2021 and July 2024. The average CWV error at D1 across this period is ~1.8mcm/day whereas for D5 the average error is almost treble at 5.25mcm/day. However, it is the range of uncertainty that really stands out. For D1 the range was between 19mcm under forecast to 17mcm over forecast, whereas for D5 this extends to a 37mcm under forecast to 36mcm over forecast. The earlier the CWV forecast, the wider and flatter the distribution of errors becomes, therefore demonstrating the challenge in significantly improving the demand forecast, especially in the D2 to D5 timescale. We believe that in the absence of an improved weather forecast, significant improvement to the demand forecast for the temperature related load is unlikely.

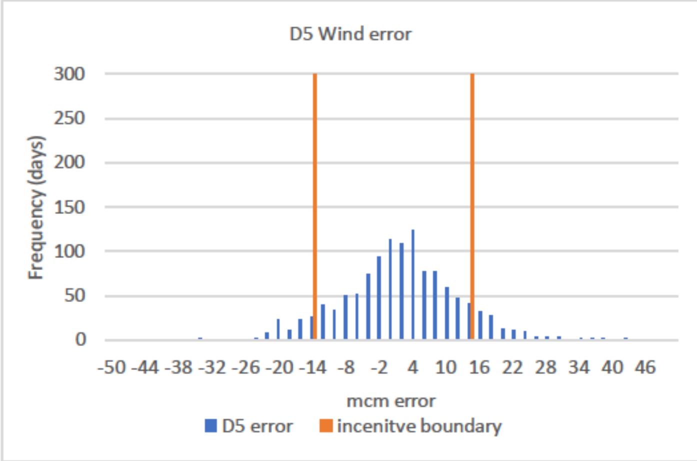
Demand Forecasting Chart 6 - D1 CWV error and D5 CWV error captured in daily forecasting process from DTN



Wind generation error. In generating Demand Forecasting Chart 7 we have assumed that any error in the wind forecast is covered by a change in gas fired generation and therefore no other forms of generation reacted within the power market (prices may drive other forms of generation to respond to a change in wind, but gas is likely to be the majority). Again, the range of error attributable to wind based on the above assumptions significantly varies between D1 and D5 i.e., for D1 the average error attributable to wind error is 4mcm/day, whereas at D5 it is ~8mcm/day.

Demand Forecasting Chart 7 - D1 Wind error and D5 Wind error Wind generation forecast/actuals captured in daily process





Whilst there have been market developments, such as D-5 DSR, which places a greater reliance on the D-5 forecast, we believe that a reputational incentive remains appropriate. As stated above we have developed a project plan to investigate alternative methods which could lead to performance improvement and deem the project-based strategy for RIIO-GT3 more appropriate considering the uncertainty in longer term forecasting.

We have shared details of our project plan with Ofgem ahead of the Business Plan submission; in summary, the project will initially be 12 months in duration to consider quantification of the realistic forecasting performance potential in the D-2 to D-5 timescales, and therefore whether an incentive mechanism is appropriate and if so, how it could be designed. This project forms a component of the following IT investment:

Demand Forecasting Table 6 – IT investment

Ref#	IT Investment Title	Investment Description
IT 016[25]	Predictive Forecasting and Network Simulation	Build on work delivered in RIIO-T2 to develop advanced predictive forecasting and network simulation capability that provides a visual representation of both historical and near real-time data for enhanced & automated decision making

Alongside the work to understand the level of error "achievable" we will also consider other information available that could be procured to enhance our forecasting models. The project will utilise skills from data scientists with backgrounds in meteorology, electrical system modelling, and uncertainty quantification to understand what is achievable and enhance our forecasting models. The power supply mix in the UK is changing rapidly and will continue to do so as we move through the next price control. A lack of timely, reliable information on causes of volatility can influence shifts in prices as market participants might be forced to base their trading decisions on speculation rather than reliable market intelligence and fundamentals. We expect to continue investing in our processes and people to maintain our forecasting performance, given the expected increases in volatility in the market.

[25] NGT_IJP03_Enabling Energy Security_RIIO-GT3

4.9.8 Options Considered

We have considered and discounted the following options alongside our proposal.

Demand Forecasting Table 7 – Options Considered

Discounted option	Further detail	Why discounted?
Solar growth	Having received customer feedback that the adjuster calculation should consider other forms of renewable generation including solar energy, we have looked at the predicted solar capacity in RIIO-GT3.	We concluded that whilst solar growth may result in an increasing challenge, wind growth will likely be the dominant factor and therefore will act as a suitable renewable adjuster to reflect the increasing challenge, whilst minimising complexity in the scheme. This will be an area we will continue to monitor throughout RIIO-GT3 to inform future price controls.
Solar capacity and generation growth	Having received customer feedback that the adjuster calculation should consider other forms of renewable generation including solar energy, we have looked at the predicted solar capacity and generation growth in RIIO-GT3	We considered growth in wind capacity within the calculation of the adjuster and combining it with the error calculation. For simplicity and data availability reasons related to receiving up to date wind capacity growth data (produced quarterly by DESNZ Renewable Electricity Capacity and Generation report), we have decided to go ahead with the option to base the calculation purely on wind forecast error as this should encompass any capacity growth.
Seasonal and/or shoulder month target		We considered development of a seasonal and/or shoulder month target and providing a breakdown of demand forecast by demand type (i.e., LDZ, Power etc) but dismissed due to limited customer feedback in support.