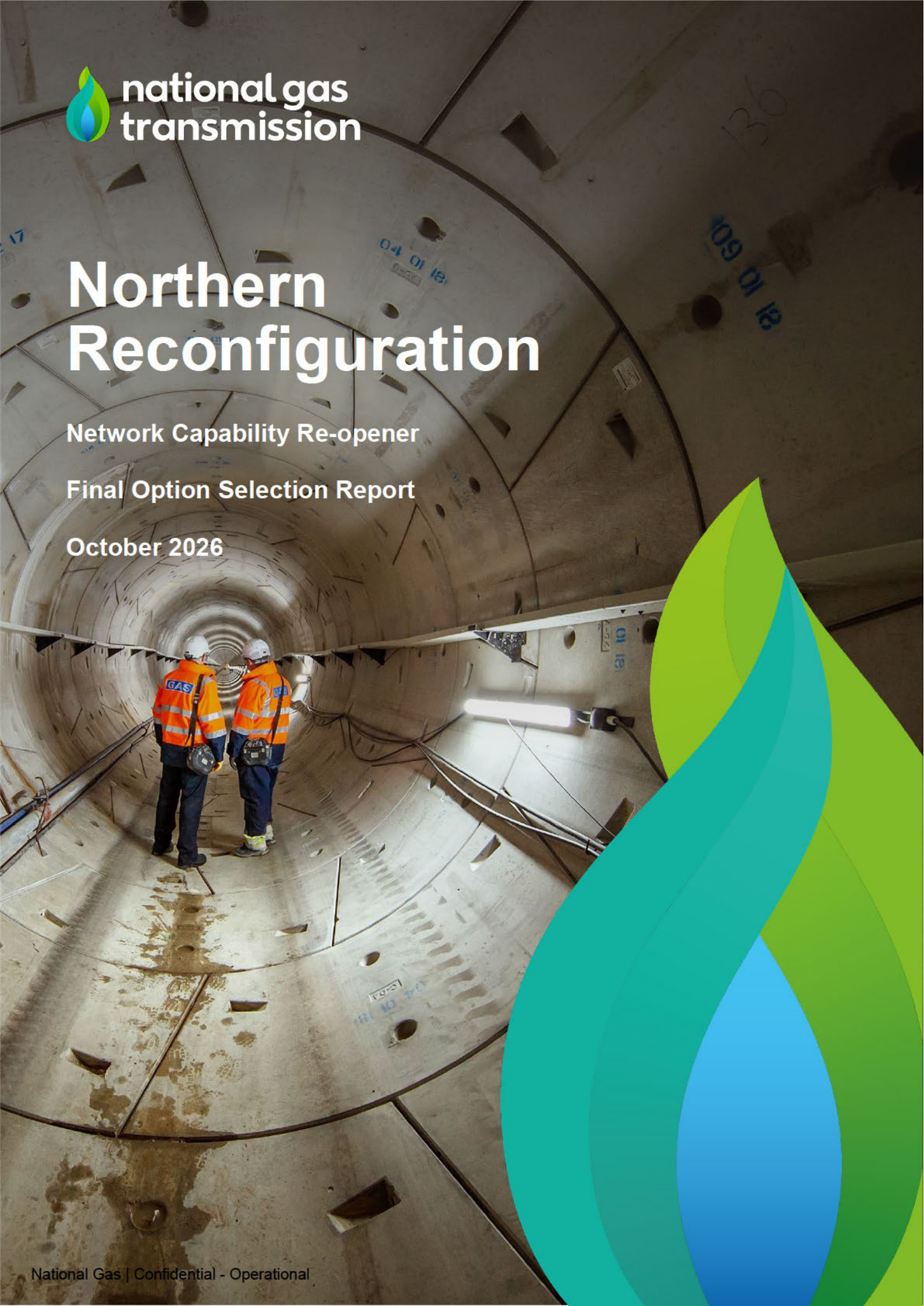
national gas transmission

Northern Reconfiguration

Network Capability Re-opener

Final Option Selection Report

October 2026



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1 Summary table

Name of Project	Northern Reconfiguration	
Scheme Reference/ Mechanism Category	[redacted]	
Primary Investment Driver	Network Capability and Resilience	
Project Initiation Year	[redacted]	
Project Close Out Year	[redacted]	
Total Installed Cost Estimate £m, 2023/24)	[redacted]	
Cost Estimate Accuracy (%)	-20%/+30%	
Project Spend to date as of 30 October 2026 (£m, in 2023/24 prices)	[redacted]	
Price Base	2023/24	
Current Project Stage Gate	ND500 (4.2) Option Selection	
Reporting Table Ref	RRP Table 6.2 (Projects) and Table 6.1 (CAPEX Summary)	
Spend Apportionment for EAC (£m, in 2023/24 prices)	RIIO-GT3	RIIO-GT4
	[redacted]	[redacted]

Table 1: Summary Table

2 Executive Summary

2.1.1 National Gas (referred to in this regulatory submission as 'NGT', 'we', 'us' and 'our') is submitting this Final Option Selection Report (FOSR) to seek Ofgem's approval of the preferred option to address the identified network capability and resilience requirements in the Northern Area (Scotland and the North of England) of the National Transmission System (NTS).

2.1.2 As the owner and operator of the NTS, we are responsible for transporting gas safely and reliably across Great Britain and meeting our licence obligations and customer requirements in relation to network pressures, flows and security of supply. [redacted]

2.1.3 Additionally, Future Energy Scenario (FES) forecasts show supplies entering the NTS at St Fergus, Teesside and Barrow declining significantly over the coming decade. Although demand in Scotland is also forecast to decline, it is not expected to reduce at the same rate as supply, resulting in an increasing supply deficit within the Northern Area, manifesting especially at peak demand conditions.

2.1.4 The capability and resilience requirements for this investment are intrinsically linked. While sufficient northbound transportation capability is required to meet demand as northern supplies decline, it is equally important that this capability remain available during credible supply disruptions, maintenance, outages and asset unavailability. Accordingly, the requirement is not simply to provide sufficient northbound capability under normal conditions, but to ensure that an appropriate and reliable level of capability is maintained across a range of credible supply, demand and asset availability conditions.

2.1.5 This FOSR provides a summary of all the work performed to date to evaluate, cost and analyse the full suite of feasible options available. It seeks approval for the preferred option to mitigate the capability [redacted] while maintaining our ability to meet exit flow and pressure obligations by enabling transportation of gas from more southerly supply sources into the Northern Area.

2.1.6 [redacted]

2.1.7 We undertook a structured optioneering process to identify the most economic and efficient solution to address the future network resilience and capability requirement. The viable options progressed through conceptual design, high-level cost estimating, network modelling and economic assessment.

2.1.8 The preferred option is the reconfiguration of the Bishop Auckland and Nether Kellet[2] compressor stations, with targeted asset health intervention to key suction and discharge isolation valves at Carnforth Multijunction to maintain the availability and resilience of Nether Kellet compression. This option provides the most cost-effective means of providing the required resilience and increasing south-to-north transportation capability using existing assets, delivering value as well as security of supply for consumers.

2.1.9 The preferred option will ensure the network continues to deliver gas where and when it is needed as supply patterns evolve, future demand remains uncertain and domestic production declines. Table 2 shows the cost estimate for the preferred option.

[redacted]

Option	Cost Estimate 2023/24 price base (£)
Reverse flow at Bishop Auckland Compressor Station	[redacted]
Reverse Flow at Nether Kellet Compressor Station	[redacted]
Nether Kellet Suction and Discharge Valves	[redacted]
Total	[redacted]

Table 2: Northern Reconfiguration cost estimate -20%/ +30%

2.1.10 The costs throughout the document are in 2023/24 price base unless otherwise stated.

3 Introduction

3.1.1 The Northern Area has historically been supported by significant supplies entering the NTS at St Fergus and Teesside[3], together with supplies entering at Barrow and Easington. These supply sources have supported demand within the Northern Area while also enabling gas to be transported through the NTS to meet demand across Great Britain, but apart from St Fergus they are not directly able to support demand in Scotland. In addition to meeting demand across the Northern Area, the NTS in this region facilitates gas transportation to the Moffat Interconnector, providing supplies to the Island of Ireland.

3.1.2 Within this supply portfolio, St Fergus is one of the most significant entry points to the NTS and is critical to both Scottish and wider Great Britain security of supply. The terminal receives gas from the UK Continental Shelf (UKCS) and Norway and regularly facilitates between 25% and 50% of Great Britain's natural gas supply, meaning its importance extends significantly beyond its crucial role of meeting demand within Scotland and the North of England.

3.1.3 Bishop Auckland and Nether Kellet compressor stations, shown in Figure 1, are key transmission assets within the Scotland and Northern Area of the NTS. Both sites can only operate in a north-to-south configuration, transporting gas from northern supply sources, including St Fergus, towards demand centres further south. Together they play a critical role in maintaining network pressures and enabling gas transportation from and across the northern transmission system.

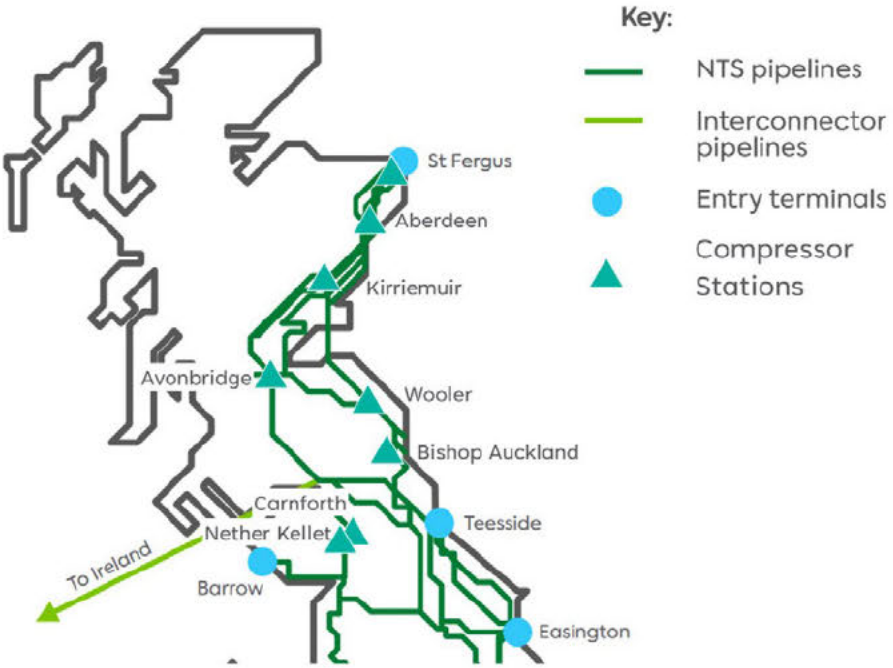


Figure 1: Scotland and North Area Transmission map with key compressor stations

3.1.4 Successive FES publications have consistently forecast a gradual decline in northern gas supplies from the UKCS. Figure 2 illustrates forecast flows from St Fergus and Teesside reduce over time towards 2050. This continues to change the balance of supply and demand across the north of the network and creates reliance on gas transported from supply sources further south.

[redacted]

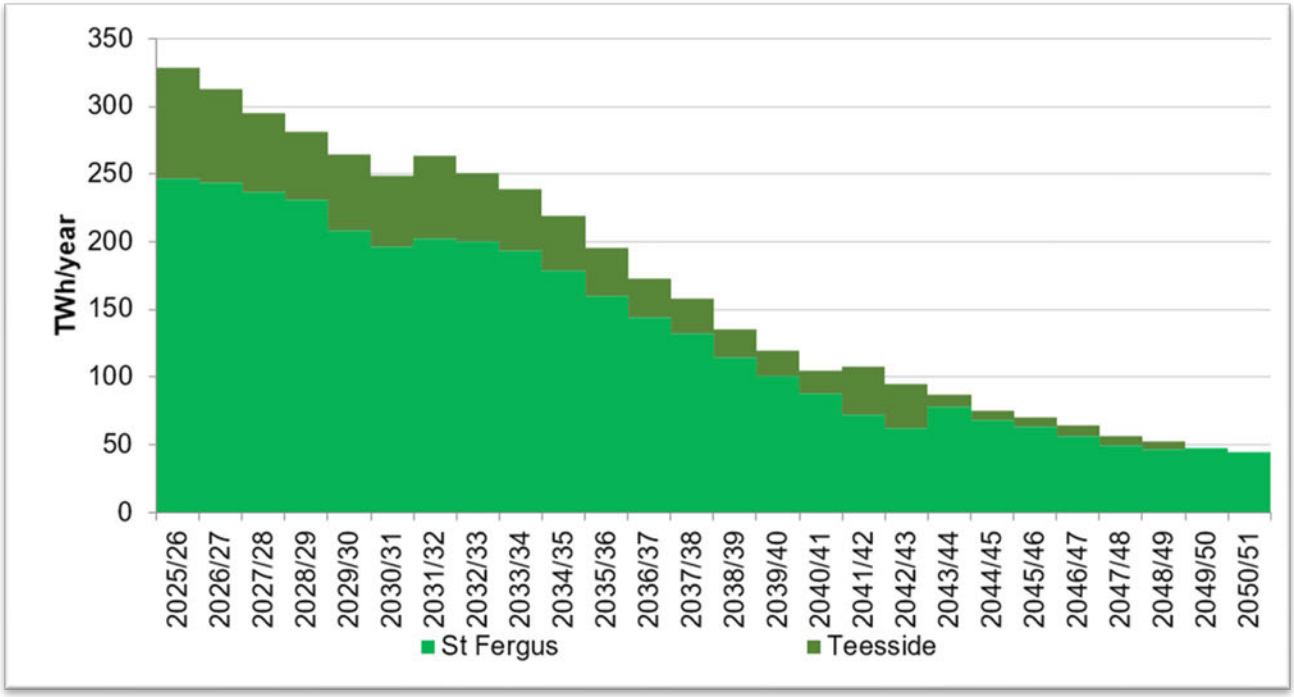


Figure 2: Annual Supply by Terminal. Falling Behind Low Continent/High LNG Case

3.1.5 As these supply patterns change, the network is required to transport gas northwards into Scotland. However, the existing assets on the network are not able to support south-to-north operation under the current configuration. Intervention is therefore required to provide the capability and operational flexibility needed to maintain pressure and flow obligations under future supply and demand scenarios.

4 Project Status and Request Summary

4.1 Project Overview

4.1.1 In our RIIO-GT3 Business Plan (NGT_EJP13_Compressor Fleet - Network Investments and Zone 1 (Scotland)_RIIO-GT3) we identified site reconfiguration at Nether Kellet and Bishop Auckland as potential network capability interventions to provide south-to-north gas transportation into Scotland under declining St Fergus supply scenarios. At that stage, we requested the option to proceed with this intervention under the Network Capability Uncertainty Mechanism, pending further assessment of future supply and demand pathways and detailed network analysis. That analysis is provided in this submission and confirms the need for intervention.

4.1.2 We have since considered a range of options, including compressor station flow reversals, new compressor stations, pipeline solutions, operational interventions and commercial measures. We assessed each option against capability, technical viability, resilience, deliverability and cost, and progressed the viable options[4] to detailed network modelling and Cost Benefit Analysis (CBA). Our optioneering process identified reconfiguration of the existing compressor assets at Bishop Auckland and Nether Kellet with asset health work as the preferred option. It provides the required network capability and resilience while delivering the best value for consumers.

4.2 Project Status

4.2.1 The project was sanctioned through the Gas Transmission Investment Committee (GTIC) regional governance process in December 2025 and was subsequently re-sanctioned through the Regional Delivery Process (RDP). The submission has also been subject to the appropriate internal governance and assurance processes, including review by the Uncertainty Mechanism Oversight Committee, chaired by the Director of Uncertainty Mechanisms. The project will be at the ND500 Stage 4.2 after the F2 sanction planned in November 2026.

4.2.2 We have completed conceptual design for both reconfigurations, confirming that the proposed modifications are technically feasible and can be accommodated within the existing sites. The conceptual designs define the principal valve, pipework, pressure equalisation, civil, electrical and control modifications required to enable south-to-north operation and have provided the engineering basis for the current cost estimates.

4.2.3 Following Ofgem's final determination on this proposal, the project will progress from Option Selection towards the next stage of development, front end engineering design (FEED), where we will further develop the preferred technical solutions, site and outage requirements, delivery strategy and cost certainty ahead of the cost submission.

4.3 Request Summary

4.3.1 This submission is in line with Appendix 1 of Special condition 3.21 Network Capability Re-opener

Project	Output	Delivery Date	Re-opener application window	Total Cost Estimate (all years) ([redacted])
Site Reconfiguration	Final Option Selection Report	30 October 2026	1-7 April 2028 or 1-7 April 2029	[redacted]

Table 3: Special Condition 3.21 Appendix 1 - Network Capability Re-opener - Site reconfiguration

4.3.2 To ensure that we continue to meet exit flow and pressure obligations whilst also providing the required level of network resilience and flexibility under varying supply and demand patterns, our final preferred option is to reconfigure Bishop Auckland and Nether Kellet compressor stations.

4.3.3 The total cost for the project is estimated at [redacted] and has been prepared as an indicative cost confidence range of -20% to +30%.

[4] With an exclusion of one option – see Chapter 7 for justification and further detail

4.3.4 Ofgem are invited to assess and approve our proposed final preferred option in line with Special Condition 3.21, Part C. Our view is that the Price Control Deliverable (PCD) should be viewed as fully delivered once we have submitted our Re-opener application at which point the PCD will be revised to reflect the outputs and allowances related to the delivery of our preferred option. We are reporting on our progress and spend as part of the annual Regulatory Reporting Pack (RRP).

4.3.5 Following Ofgem's decision on the final preferred option, we will develop the approved option further and submit a Re-opener application in line with Special Condition 3.21, part C2 for Ofgem's consideration in April 2028. We welcome engagement with Ofgem at appropriate stages of project development to maintain regulatory visibility and support the successful delivery of a solution that provides the required network capability and resilience.

5 Problem / Opportunity Statement

5.1 Why are we doing this work and what happens if we do nothing?

5.1.1 Our RIIO-GT3 Business Plan identified an increasing risk to our ability to meet demand obligations for consumers in Scotland and the Northern Area. Following the submission, the circumstances evolved, strengthening the need for intervention.

5.1.2 [redacted]

5.1.3 [redacted] Chapter 6 provides further detail [redacted]

5.1.4 [redacted] Historically, the NTS was designed to transport large volumes of gas southwards from Scottish supply sources. However, declining UKCS production and reducing gas supplies mean Scotland is likely to become dependent on gas transported northwards from supply sources elsewhere on the NTS.

5.1.5 Existing compression capability is unable to transport the required volumes of gas northward from key supply sources (Figure 3) at Teesside in the North East, North West storage and Milford Haven into Scotland during periods of high demand and reduced northern supplies. Consequently, the network has no capability to replace lost St Fergus supplies from Teesside and the wider NTS should a significant supply disruption occur.

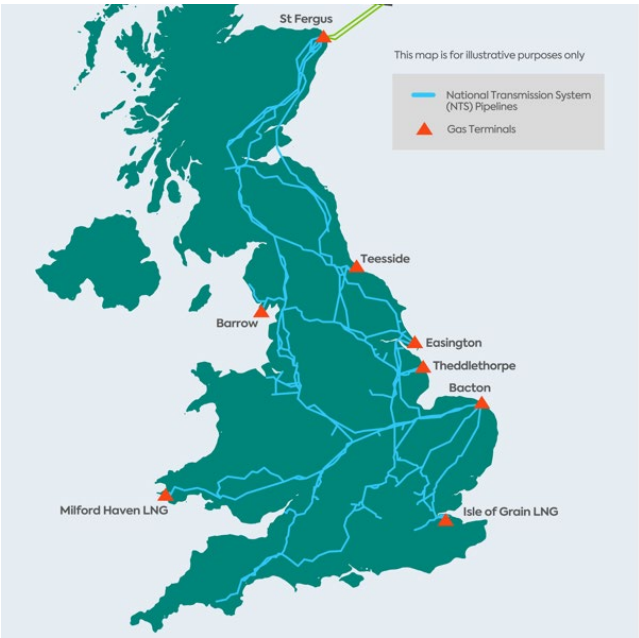


Figure 3: Map of NTS showing Teesside, Milford Haven and St Fergus

5.1.6 A significant loss of St Fergus supply could leave insufficient network capability to meet customer demand. The consequence would be an increased risk of pressure shortfalls in Scotland, constraints on gas supplied to power generation and industrial users, reduced supply flexibility for deliveries through the Moffat Interconnector into Northern Ireland, and the need for emergency operational actions to maintain security of supply.

5.1.7 We currently manage low supply and/or pressure conditions in the short term through operational interventions including looping arrangements at Aberdeen, Kirriemuir and Avonbridge Compressor Stations. These arrangements help maintain Scottish pressures by retaining gas within the region and slowing southbound flows. Looping configurations can reduce the rate of transmission through Scotland by approximately [redacted] during periods of low demand. However, the FES forecasts shown in Table 7 indicate that in most future peak scenarios the forecast supply deficit exceeds this capability, meaning looping arrangements alone will be insufficient.

5.1.8 Additionally, these interventions do not increase the quantity of gas available within Scotland and do not provide a means of transporting additional gas northwards from alternative supply sources. Furthermore, the ability to establish these looping arrangements cannot always be relied upon, as the assets required to facilitate them may be unavailable.

5.1.9 Looping arrangements therefore provide only a partial and temporary mitigation and are not a sustainable long-term resilience solution. They do not increase the quantity of gas available and can only be used to redistribute existing gas, that is already within the Northern Area, under favourable network conditions. In addition, they require compressor units to operate for extended periods maintaining local pressures in addition to their primary transportation duty, increasing operating hours, compressor fuel consumption and operating costs, which are ultimately borne by consumers.

5.1.10 Increased reliance on these operating modes can lead to higher energy consumption, accelerated asset degradation, operational inefficiencies and reduced flexibility. More importantly, they cannot address the underlying risk associated with the loss of gas supplies entering the NTS at St Fergus.

5.1.11 Network modelling confirms that, under declining northern supply and high Scottish demand conditions, existing network capability becomes insufficient to reliably meet Scottish demand. This creates the requirement for northbound transportation capability from alternative supply sources. Chapter 6 sets out the supporting network analysis and future supply and demand forecasts.

5.1.12 [redacted]

5.1.13 In addition to addressing the identified capability and resilience requirements, delivery of a reliable northbound transportation route will require targeted asset health interventions to address existing asset condition risks. This includes isolation valves at the Carnforth Multi-Junction (associated with the Nether Kellet compressor station), where identified defects could affect the availability of the proposed route. We have included further detail on this in Chapters 7 and 10.

5.1.14 Timely investment is required to address this capability gap and mitigate the identified resilience risk, limiting the period during which the network remains exposed to conditions that could adversely affect consumers and our ability to meet our obligations.

5.1.15 The investment creates an opportunity to establish a northbound transportation capability, allowing the NTS to access a wider range of supply sources and respond flexibly to changing supply patterns. By enabling gas from southern, east and west coast sources to support Scotland, it reduces reliance on St Fergus and creates a more resilient network that can adapt to future changes and availability of supply.

5.2 Under what circumstances would the need or option change for this project?

Government Policy

5.2.1 Rosebank is the UK's largest undeveloped oil field, located approximately 80 miles (129 km) north-west of Shetland, while Jackdaw is a gas field located around 150 miles (241 km) east of Aberdeen. Together, they represent significant potential new sources of domestic oil and gas production from the UKCS.

5.2.2 Rosebank is currently awaiting a renewed UK Government approval decision following a court ruling that the original consents did not fully assess the climate impacts associated with the combustion of the produced oil and gas. Updated environmental assessments have since been completed and are under review.

5.2.3 In October 2026, the UK Government approved the Jackdaw gas field development, enabling production to commence. Industry forecasts indicate that Jackdaw could provide approximately 4-7 mcm/d of gas production[5], delivered via the Shearwater hub and St Fergus, thereby increasing future domestic gas supplies available to the NTS.

5.2.4 The additional gas supply from Jackdaw has the potential to reduce the forecast supply deficit identified within some FES pathways and may partially offset the decline in UKCS production over the coming decade. However, the contribution remains modest relative to the long-term reduction in northern gas supplies forecast across the assessment period and does not remove the need for sufficient northbound transportation capability under future network conditions.

5.2.5 Should the UK Government approve Rosebank development, it would also represent an additional source of domestic gas supply. Should this additional supply be sufficient to offset the gas deficit volumes projected within future FES pathways for Scotland, the identified capability concern and associated needs case would require reassessment. We would also need to give consideration to the timing of production commencement, as any benefit would be dependent on when the fields become operational relative to the forecast capability shortfall.

5.2.6 While the additional supply from Rosebank and Jackdaw could reduce or potentially eliminate the forecast capability shortfall, [redacted]

Uncertainty of Future Supply Infrastructure

5.2.7 [redacted]

5.2.8 [redacted]

5.2.9 [redacted]

5.2.10 [redacted]

Speed of Decarbonisation

5.2.11 The pace of decarbonisation remains uncertain. A slower-than-anticipated transition could result in higher gas demand persisting for longer, increasing reliance on northbound gas transportation and exacerbating the identified capability and resilience requirements. This could accelerate the capability need for the proposed investment, [redacted]

[5] Jackdaw field consent is correct for UK climate targets and the economy, Wood Mackenzie analysis shows | Wood Mackenzie

5.3 What are we going to do with this project?

5.3.1 To address the identified network capability and resilience requirements, our final preferred option is to reconfigure the Bishop Auckland and Nether Kellet compressor stations and undertake targeted asset health interventions to key suction and discharge isolation valves at Carnforth Multi-Junction. We have demonstrated through network modelling that this option maximises the use of existing assets and provides the most cost-effective solution for increasing south-to-north transportation capability while maintaining network resilience.

5.3.2 Given the evolving supply mix, declining domestic production[6] and uncertainty in future demand requirements, these interventions are required as soon as reasonably practicable to ensure the network can continue to operate safely, reliably and efficiently.

5.3.3 The preferred option will ensure the network continues to deliver gas securely and reliably as supply sources change, domestic production declines and future demand requirements remain uncertain.

5.3.4 We included further detail on our final preferred option in Chapter 10 Preferred Option Scope and Project Plan.

5.4 What makes this project difficult?

5.4.1 The project is being developed in the context of significant uncertainty regarding future gas supply patterns and the timing and scale of energy transition impacts, [redacted] the frequency and severity of future constraints are dependent on a range of external factors, including supply availability, flow patterns [redacted]

5.4.2 Delivery of the project also presents engineering and operational challenges. The proposed modifications are required at operational compressor station sites and must be carefully coordinated with outage availability to minimise impacts on system operation. Construction activities will involve work within constrained and congested site environments, requiring careful planning to safely integrate new assets and pipework modifications with existing infrastructure while maintaining ongoing site operations. Section 10.13 identifies high level and site-specific risk which capture further potential difficulties and scenarios the delivery of the project may entail.

5.5 What are the key milestone dates for project delivery?

5.5.1 The project aims to deliver the reconfiguration of the Bishop Auckland and Nether Kellet compressor stations, together with targeted asset health interventions at Carnforth Multijunction, as soon as reasonably practicable.

5.5.2 We informed milestone dates by project development requirements, outage constraints and coordination with other planned investment activities. We identified that the opportune time to begin the design and build phase is in [redacted] with project delivery activities commencing in [redacted] and operational acceptance by [redacted] Final project closure is anticipated in [redacted][7]. Chapter 10 provides further details on the Delivery Programme.

5.5.3 Our delivery programme assumes a six-month decision period following submission of the FOSR to Ofgem before progressing to FEED. [redacted]

5.6 How will we understand if the project has been successful?

5.6.1 [redacted]

[6] Whilst developments such as Rosebank have the potential to increase future UKCS gas production, their timing, scale and long-term contribution remain uncertain. Accordingly, our assessment is based on the current supply outlook, under which domestic gas production is expected to continue to decline over time.

[7] Subject to further planning and FEED studies confirming feasibility of works to be delivered and interactions with other projects planned on sites.

5.6.2 The project will also be considered successful if it provides sufficient south-to-north transportation capability to meet forecast demand under the assessed FES pathways.

5.6.3 For this Option Selection stage, the project will be deemed a success if the Final Option Selection Report is delivered by 30 October 2026 as per the requirements of Special Condition 3.21 Network capability Re-opener (NCt).

5.7 Related Projects

5.7.1 The project will interface with a number of significant network investments that are currently planned for delivery. The principal related investments are listed below.

5.7.2 **Bishop Auckland Capability Re-wheel**. Our RIIO-GT3 Compressor Fleet programme includes capability re-wheels for Bishop Auckland Units A and B. As this investment changes the compressor operating envelope, there is a potential interaction with the Northern Reconfiguration project, which alters the flow paths and future operating duties. Where practicable, the re-wheel should be undertaken prior to the reconfiguration, allowing the final re-wheel design and compressor operating envelope to reflect the revised station configuration and anticipated operating duties.

5.7.3 **Carnforth B Disconnection**. Our RIIO-GT3 Compressor Fleet programme includes the planned disconnection of Carnforth Unit B following assessment that it is no longer required for long-term network capability requirements. The timing of this activity will require coordination with the Northern Reconfiguration project to ensure outage requirements and site access arrangements are aligned. The proposed Nether Kellet reconfiguration is not dependent on continued operation of Carnforth Unit B and has been developed based on the long-term compressor fleet strategy for the area.

5.7.4 **Control System replacement**. The RIIO-T2/GT3 Control Systems programme includes planned control system replacement works at Nether Kellet, Bishop Auckland and Hatton compressor stations, together with wider control system investments at St Fergus. Simultaneous outages at Hatton and Bishop Auckland could reduce operational resilience and limit flexibility to manage network flows during periods of high system demand. The Northern Reconfiguration project will therefore be coordinated with the Control Systems programme to optimise outage planning, maintain security of supply and minimise disruption to network operations.

5.7.5 **St Fergus MCPD Compressor Emissions Re-openers**. We continue development of the RIIO-T2 Compressor Emissions Re-opener to replace the existing Avon compressor units at berths 1C, 2C and 2D with three new SGT-400 compressor units, whilst retaining Unit 1A and decommissioning Units 1B, 1D and 2B following commissioning. The re-opener maintains compression capability and resilience at St Fergus. Furthermore, we are also progressing the RIIO-GT2 asset health investment to maintain the availability and operational capability of the retained Avon Unit 1A at St Fergus. The investment supports continued compression capability and resilience at the terminal alongside the new compressor unit programme.

5.7.6 **Kirriemuir Re-wheel.** We have a baseline RIIO-GT3 Network Capability investment to re-wheel the Kirriemuir E variable speed drive compressor, enabling operation across a wider range of flow conditions and supporting Scottish exit flows more frequently. The investment will enhance resilience across Scotland by increasing operational flexibility and is complementary to the Northern Reconfiguration project.

5.7.7 **Avonbridge Re-wheel.** Similarly to Kirriemuir, we have baseline funding to re-wheel Avonbridge Units 1A and 2A. Performance testing has been undertaken, and the output is being analysed to determine what process duty specification changes are required. The re-wheel should improve efficiency and operation of the compressor at periods of lower flow ranges which, without intervention, could result in compressor surge, vibrations and effectively shortening the asset life whilst increasing maintenance frequency. This intervention does not improve or effect the scope of Nether Kellet or Bishop Auckland reversal as it does not assist with increasing gas supplies into Scotland. The investment is intended to improve performance under lower flow conditions expected as Scottish supply patterns evolve and forms part of the wider programme of network capability investments being developed across Scotland.

5.7.8 **Avonbridge Unit Decommissioning.** We plan to submit a RIIO-GT3 re-opener submission to decommission Avonbridge Units 1B and 2B. These units were disconnected during RIIO-GT2 following assessment that they are no longer required to meet future network needs. The intervention forms part of the wider optimisation of the Scottish compressor fleet alongside other network capability investments considered in response to changing supply patterns.

5.7.9 **RIIO-GT3 Asset Health.** In addition to the related projects described above, we plan a number of baseline asset health investments across the affected sites during RIIO-GT3. At Bishop Auckland, we will undertake flood resilience activities, including studies to identify permanent mitigation measures and the implementation of temporary flood protection interventions. At Nether Kellet, we will refurbish critical valve actuators, replace fire suppression equipment and deliver targeted infrastructure renewals. At Carnforth, we will carry out significant asset health investment, including turbine overhauls, valve refurbishment and replacement programmes, pressure systems compliance works, cathodic protection upgrades, and replacement of critical electrical resilience systems. Whilst we will deliver these activities through separate investment programmes, we will coordinate outages, site access arrangements and construction interfaces with the Northern Reconfiguration project to ensure efficient delivery across all works.

5.7.10 **Asset Health Re-opener - Valves.** As part of the asset health re-opener development, we are preparing a proposal for additional valve replacement works within the RIIO-GT3 price control. To avoid duplication, we have ensured that the valves included within this FOSR submission are excluded from the April 2027 asset health re-opener submission.

5.7.11 **Hydrogen and Carbon Capture, Utilisation and Storage.** Wider opportunities to repurpose the network for hydrogen transportation or CCUS continue to be monitored as part of broader strategic network planning. However, these developments do not form part of the needs case for this project, and any interventions required to facilitate future network repurposing are outside the scope of this assessment.

5.8 Project Boundaries

5.8.1 The spend relates primarily to infrastructure and equipment needed to enable the network to manage flows from south to north. This includes the purchase, refurbishment or modification of assets directly required to deliver the selected network reconfiguration option and achieve the resilience capability identified in the needs case.

5.8.2 For Options 2a and 4a, the scope also includes associated asset health works on nearby valves that are essential for the isolation of Carnforth Compressor Station, and which present an efficient opportunity to be delivered alongside the reconfiguration works.

5.8.3 As detailed within section 5.7 Related Projects, investments which are already funded as part of our RIIO-GT3 business plan are not included within this submission. These include asset health, station and unit control system replacements and decommissioning of redundant assets.

6 Project Definition

6.1.1 This chapter defines the capability and resilience requirements that underpin this proposal. It describes the security of supply risks associated with changing supply patterns and reduced processing diversity, together with the supply and demand forecasts and network analysis that demonstrate the need for intervention.

6.2 Security of Supply and Network Resilience

6.2.1 The St Fergus complex comprises the National Gas terminal and three adjacent sub-terminals, which receive and process gas delivered from offshore before transferring treated gas into the National Gas facilities for entry to the NTS. The three sub-terminals are currently owned by [redacted] as shown in [redacted] Collectively, these facilities provide access to multiple offshore supply routes and fields, meaning that the resilience of St Fergus is dependent not only on the availability of National Gas infrastructure, but also on the availability of the upstream pipeline systems, processing facilities and sub-terminals through which these supplies are delivered.

[redacted]

6.2.2 [redacted]

6.2.3 Based on the future FES pathways, approximately 60-70% of the gas supply to St Fergus originates from the UKCS[8]. [redacted]

6.2.4 [redacted]

[8] Based on 2031, 2036 and 2041 2025 FES Pathways. See Table 4 for further detail.
[9] Associated gas is gas linked to offshore oil production

6.2.5 [redacted]

6.2.6 [redacted]

6.2.7 [redacted]

6.2.8 [redacted]

6.2.9 [redacted]

6.2.10 [redacted]

Security of Supply Capability Assessment

6.2.11 Figure 5 shows a probabilistic assessment of Scottish demand against Norwegian supply flows into St Fergus for 2030/31, [redacted] according to FES 2025 Falling Behind and Holistic Transition scenarios. Each blue mark represents a possible combination of demand and supply conditions, while the areas of highest concentration are shown in green and red.

6.2.12 The yellow line represents the intact network capability, i.e. the maximum combination of Scottish demand and available supply that the NTS can accommodate while operating in its normal configuration with all required assets available. Scenarios above this line exceed the capability of the existing network and indicate conditions where Scottish demand and pressure obligations could not be fully met without additional transportation capability.

[redacted] Protection Agency

6.2.13 The figure shows that periods of high Scottish demand can coincide with lower supply flows from St Fergus, resulting in operating conditions that exceed the capability of the existing network. In these scenarios, the NTS would be unable to fully meet Scottish demand.

6.2.14 Network analysis confirmed that, in a no investment scenario, demand cannot be met on 21 days during a typical winter.

6.2.15 The pink and green lines show how the network capability improves with investment i.e. Nether Kellett and Bishop Auckland reconfigurations. The number of instances where flows exceed the capability limits reduces significantly following either reconfiguration option when compared with the intact network configuration.

[redacted]

6.2.16 [redacted] As one of the largest Aggregate System Entry Points (ASEPs) on the NTS, a material reduction in supplies entering at St Fergus would increase the requirement for gas to be transported northwards from alternative sources to maintain security of supply in Scotland.

6.2.17 As regional supply margins continue to reduce, the network's ability to absorb and recover from such events is diminishing, increasing the risk of pressure shortfalls, supply interruptions and wider system impacts.

6.2.18 [redacted]

6.2.19 [redacted] The next two sections focus on FES 2025 forecasts and indicate that supplies available within Scotland are expected to reduce, therefore creating sufficient northbound transportation capability will become increasingly important to meeting Scottish demand.

[13] Subject to UK Government decision about future gas production, see section 5.2 for details

6.3 Supply and Demand Scenarios

6.3.1 We conduct network capability calculations and the flame chart development in line with the Transmission Planning Code, with both activities closely aligned with NESO's current Gas Network Capability Needs Report (GNCNR).

6.3.2 We predominantly use the Falling Behind and Holistic Transition FES pathways to provide a credible range of future gas supply and demand conditions against which we can assess network requirements. Falling Behind represents a slower transition away from natural gas and therefore generally maintains higher gas demand for longer. Holistic Transition represents a faster, coordinated transition to net zero, resulting in a more rapid reduction in natural gas demand and changes in the location and composition of gas supplies.

6.3.3 Figures 6 to 10 show the exit capability marked in yellow which assumes full asset availability "intact", whilst a more conservative capability view of "high resilience" is marked in pink. Intact capability represents the physical capability of the NTS under normal operating conditions with all required assets available. High resilience capability represents the capability of the NTS following the loss of a key network asset, demonstrating the level of capability that can be maintained while continuing to meet demand and network security requirements under credible outage conditions.

6.3.4 Figure 6 and Figure 7 illustrate the Scottish and the North zone capability at the start (2025/26) and end of RIIO-GT3 (2030/31) against the combined four FES 2025 scenarios. They assume the current levels of capability and resilience remain at current levels, as other planned RIIO-GT3 investments do not increase this capability.

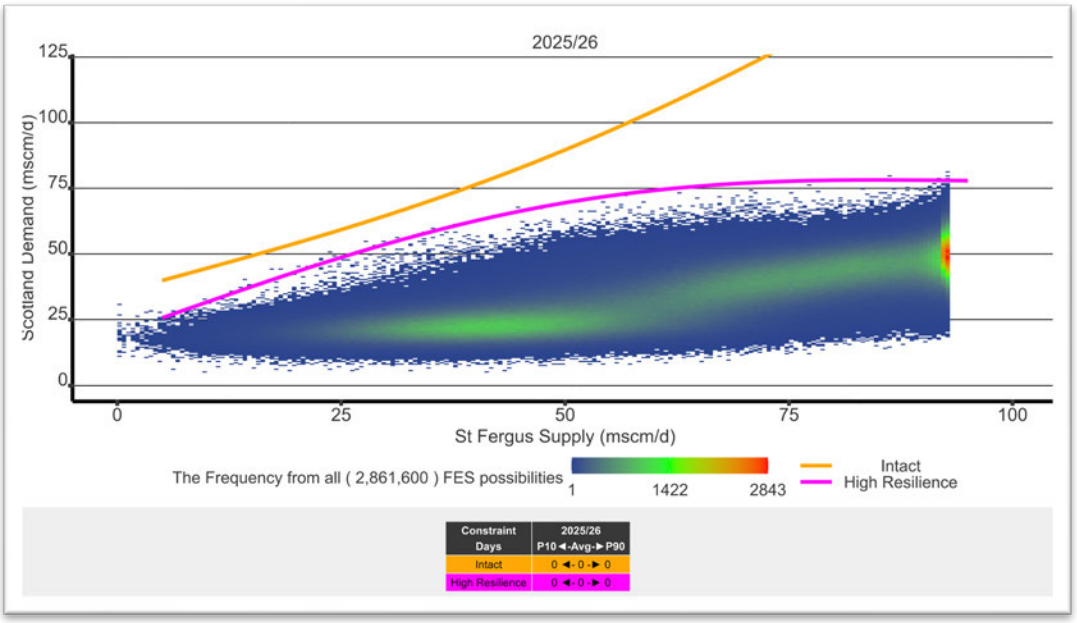


Figure 6: Scotland and the North flame chart at the start of RIIO-GT3

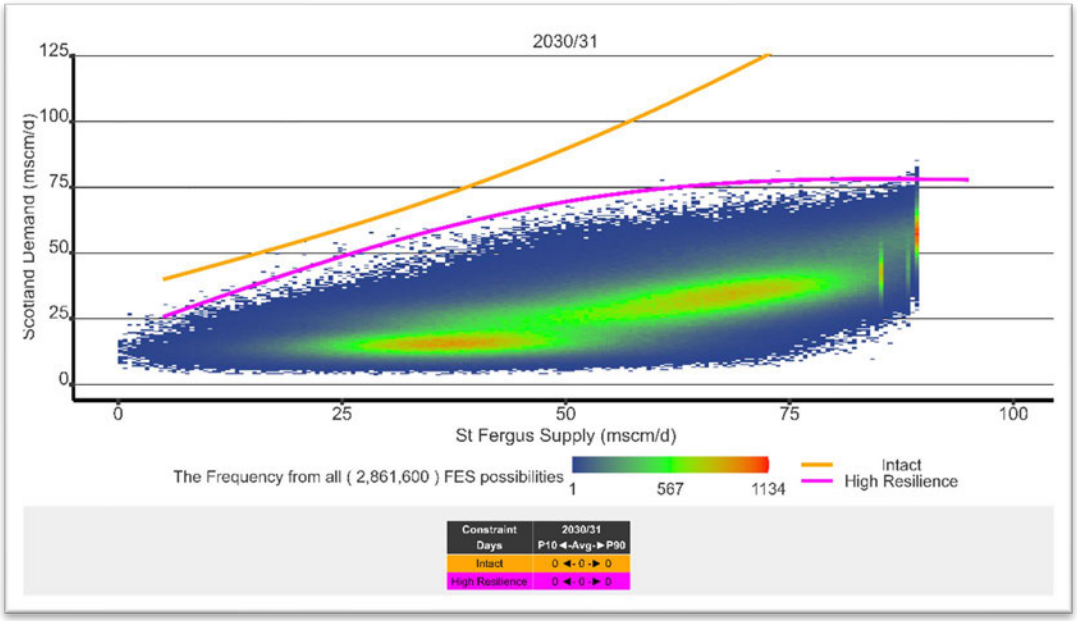


Figure 7: Scotland and the North flame chart at the end of RIIO-GT3

6.3.5 The future reduction in entry flows at St Fergus will make it increasingly challenging to meet exit commitments in Scotland. To understand the capability required, we carry out an annual assessment comparing supplies at the St Fergus terminal with demand across Scotland.

6.3.6 The network currently lacks compression capability to transfer gas supplies from Teesside, the North East and the North West into high-demand areas of Scotland. This challenge is being exacerbated by the continuing decline in supplies, with flows from Barrow having reduced significantly over the past decade and forecast to fall to zero by 2031 under FES pathways.

6.3.7 As illustrated in Figure 6, the maximum flows through St Fergus in 2030/31 are still expected to be comparable to current levels; however, there is a growing number of scenarios with very low or zero flows, coupled with the upstream risk on liquid processing facilities which could significantly affect these projections. Several of these scenarios exceed current network capability, creating situations where demand cannot be met without intervention. The red areas indicate that from 2025/2026 to 2030/2031 we can expect an increased number of scenarios where St Fergus supplies have decreased from in the region of 90mscm down to 37mscm as well as in the region of 65 mcm.

6.3.8 By 2035/36 (figure 7), supplies from both St Fergus and Teesside are forecast to decrease significantly (the red/orange shade reflecting supply shifts towards lower supply level on the chart), leading to a substantial increase in the number of scenarios that fall outside high-resilience thresholds and overall network capability. Whilst Teesside supplies are forecast to decline, they remain an important source of gas and could continue to support Scotland through a number of the options assessed.

6.3.9 Figure 9 shows that by 2040/41 there is an increase in the number of instances where flows are outside of high resilience capability. This means it is likely there will be more circumstances in which available network capability may be insufficient.

6.3.10 While St Fergus supplies are expected to continue to decline as UKCS production reduces, the rate of consumer demand decline is less certain and dependent on a range of market and consumer factors. The network is already subject to capability constraints, managed through looping arrangements. If demand declines slower than forecast, or available supply declines more rapidly, the capability shortfall would increase, further constraining the network's ability to meet demand.

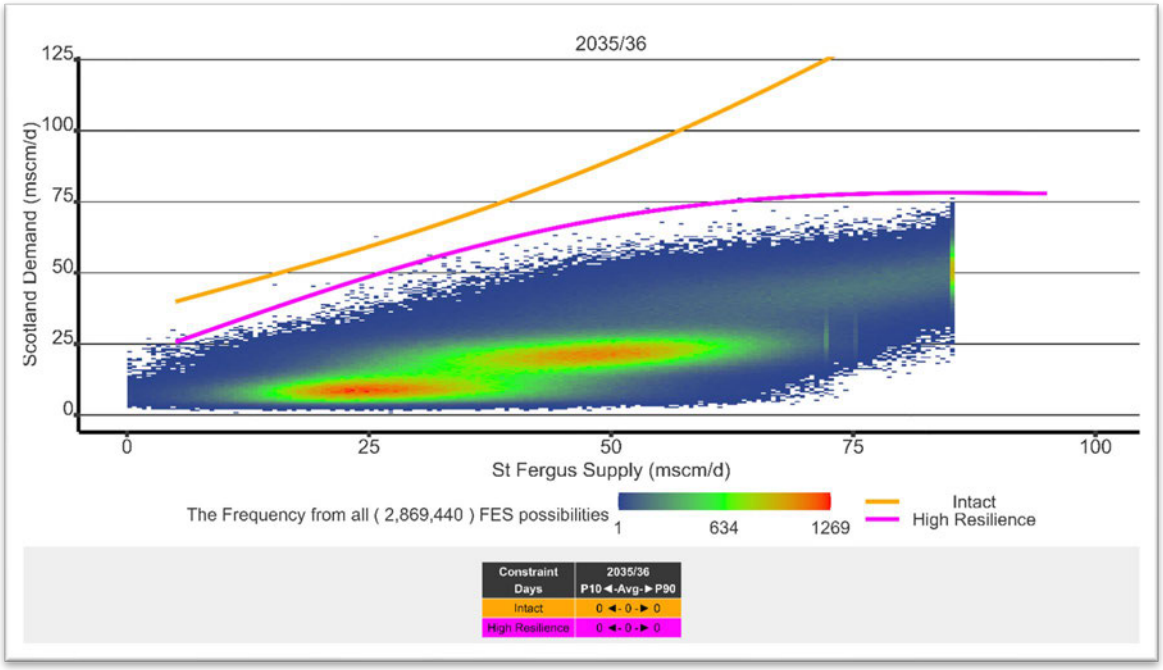


Figure 8: Scotland and North Flame Charts 2035/36

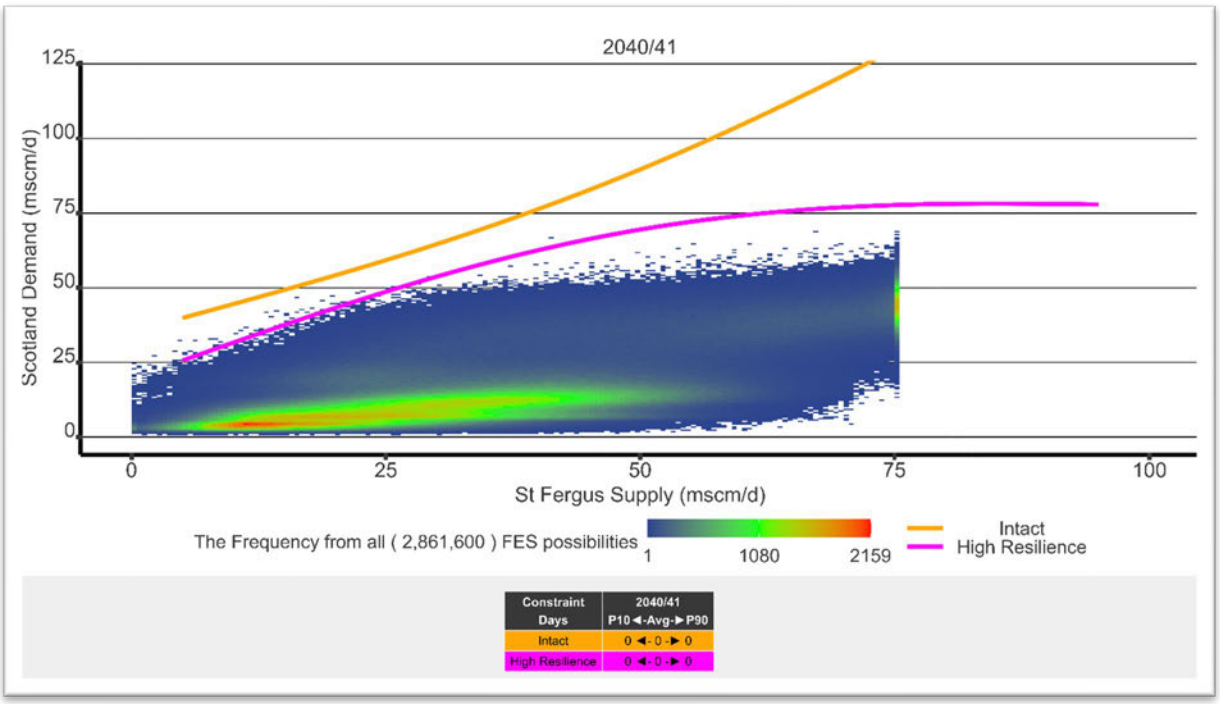


Figure 9: Scotland and North Flame Chart 2040/41

6.3.11 The analysis indicates the network capability requirement will be above the High Resilience capability threshold but remain within the intact network capability. However, the dataset considered represents a specific supply position and indicates St Fergus flows of approximately 70 mcm/d, whereas actual St Fergus flows can vary materially depending on the prevailing supply conditions. Figure 10 shows 1in20 position based on FES Falling Behind and Holistic Transition.

6.3.12 While we have an obligation to develop and operate the network to facilitate 1in20 demand, we do not control how or where gas is supplied onto the network, with supply patterns largely determined by market participants. Consequently, should St Fergus flows reduce to below approximately 50 mcm/d, the network could experience constraints. Therefore, the apparent capability within the dataset should not be interpreted as demonstrating resilience across the full range of credible St Fergus supply conditions.

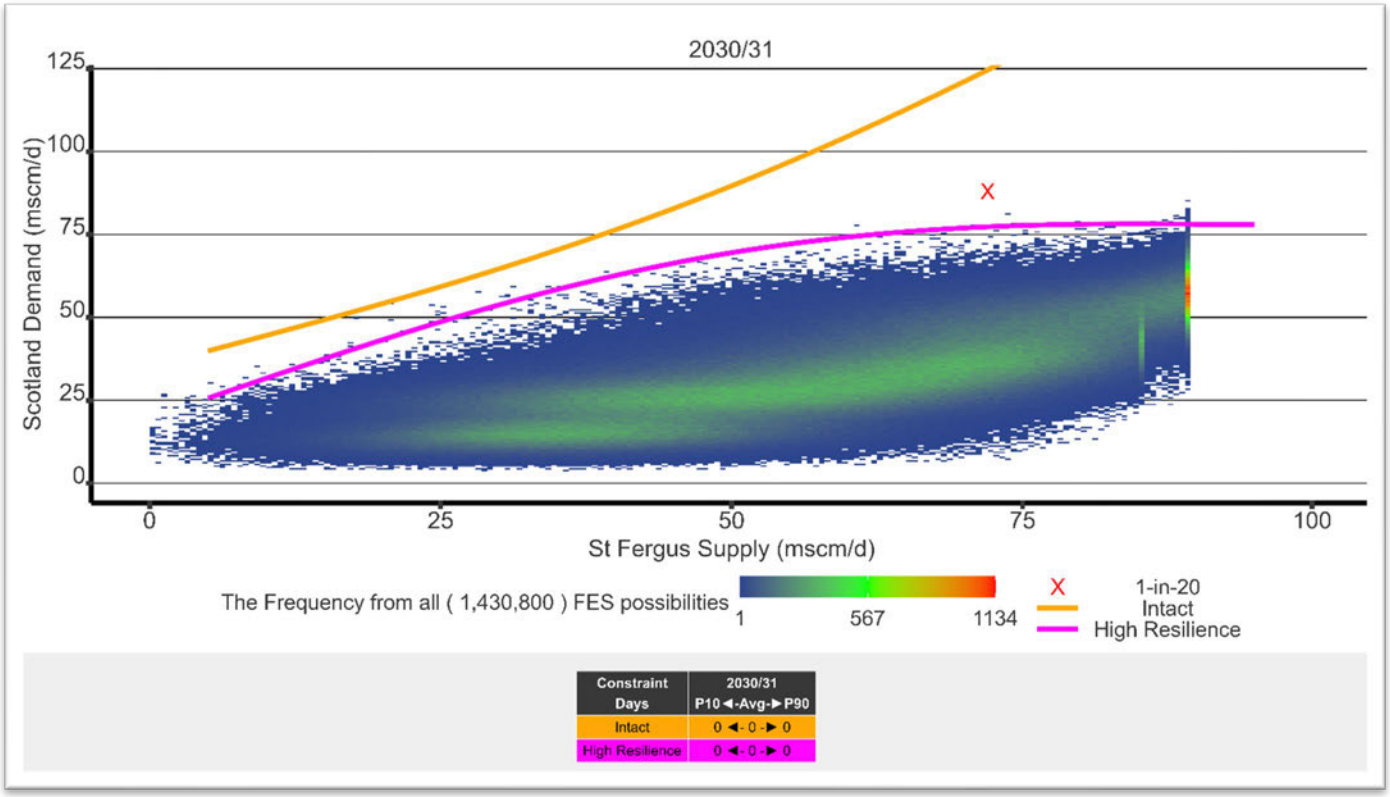


Figure 10: Flame chart for Falling Behind and Holistic Transition showing 1in20 positions

6.4 FES Pathways

6.4.1 FES pathways are presented using a load duration curve, which ranks national demand for an average year from highest to lowest. Day 1 represents the highest national demand (approximately 430 mcm/d), typically expected on a cold winter day in January or February. Day 365 represents the lowest national demand (approximately 100 mcm/d), typically expected during the summer months, such as July or August.

6.4.2 A 1in20 peak day forecast is also provided for each year representing an extreme cold weather event in line with NGT's Pipeline Security Standard obligation for planning the NTS, approximately 480 mcm/d.

6.4.3 Table 4 below shows the breakdown of the supply forecasts for St Fergus terminal in the 2025 FES pathway Falling Behind under a range of demand conditions. In all scenarios, a significant proportion of the gas supply is from the UKCS.

6.4.4 Network analysis indicates that the NTS does not have sufficient northbound transportation capability to fully replace these volumes from alternative supply sources, resulting in an increased risk to Scottish security of supply, supplies delivered via the Moffat Interconnector to Northern Ireland, network resilience and compliance with exit pressure demand requirements.

Supply	Source/Company Name	2031			2036			2041		
		Peak	D1	D46	Peak	D1	D46	Peak	D1	D46
Norway	Vesterled	22.0	22.0	14.3	16.2	16.2	10.4	17.1	16.0	7.5
	Norway Total	22.0	22.0	14.3	16.2	16.2	10.4	17.1	16.0	7.5
Continental Shelf	[redacted]	3.5	3.5	3.5	6.4	6.4	6.4	1.4	1.4	1.4
		8.0	8.0	8.0	4.6	4.6	4.6	1.3	1.3	1.3
		12.2	12.2	12.2	7.1	7.1	7.1	5.2	5.2	5.2
	[redacted]	26.4	26.4	24.2	21.2	21.2	17.3	16.7	16.2	10.7
	UKCS Total	50.1	50.1	47.9	39.3	39.3	35.4	24.5	24.1	18.5
	St Fergus TOTAL	72.1	72.1	62.2	55.4	55.4	45.8	41.6	40.0	26.0

Table 4: 2025 FES Falling Behind data for St Fergus Supplies

6.4.5 FES pathways indicate that under low St Fergus supply scenarios, further compounded by declining Teeside supply, the network does not have the capability to support exit flows due to significant change in gas supply patterns over the next 20 years.

6.4.6 Successive FES publications have consistently shown a reduction in gas supplies available in Scotland, driven primarily by UKCS decline. Whilst the absolute volumes vary between scenario iterations, the direction of travel has remained consistent. Table 5 shows the latest FES 2025 pathways and confirms continuation of this trend.

Year	St Fergus Peak	Teesside Peak	St Fergus Day 1	Teesside Day 1	St Fergus Day 46	Teesside Day 46
2031	72.1	16.3	72.1	16.3	62.2	16.3
2036	55.4	7.5	55.4	7.5	45.8	7.5
2041	41.6	9.5	40.0	9.5	26.0	9.5

Table 5: 2025 FES forecast (Falling Behind Scenario - aligning to 2022 FES Falling Short scenario)

6.4.7 Table 6 shows the forecast national demand, St Fergus supply and Scottish demand over a similar period. Whilst demand is predicted to fall, supplies are expected to reduce at a faster rate, resulting in an increasing supply deficit in Scotland and the North of England.

	Year 2031			Year 2036			Year 2041		
	Peak	Day 1	Day 46	Peak	Day 1	Day 46	Peak	Day 1	Day 46
National Demand	500.2	428.1	299.9	471.9	392.9	273.8	453.9	373.2	262.5
St Fergus Supply	72.1	72.1	62.2	55.4	55.4	45.8	41.6	40.0	26.0
Scotland Demand	88.5	68.0	51.5	84.6	64.3	47.7	74.1	55.0	42.1
Deficit	-16.4	-4.1	-10.7	-29.2	-8.9	-1.9	-32.5	-15.0	-16.1

Table 6: 2025 FES Falling Behind forecast National and Scottish Demand

[redacted]

6.4.8 Table 6 above shows that, under Falling Behind peak demand conditions, gas supplies available to Scotland are expected to be unable to meet demand by up to 32mscm by 2041. This gap in supply cannot be addressed through existing configurations and operational measures alone. Existing looping arrangements can retain approximately [redacted] of additional gas in Scotland under optimal conditions; this is significantly below the forecast deficit and therefore does not provide a sustainable solution. As a result, investment is required to enable the transportation of gas from southerly supply sources to meet future demand in Scotland and the North of England.

6.5 Project Scope Summary

6.5.1 Our final preferred option solution proposes to undertake site reconfigurations at Nether Kellet and Bishop Auckland Compressor Stations and undertake suction and discharge valves asset health works at Carnforth Multi-Junction. This will ensure that we have the required network resilience and are able to meet our exit demand obligations. Table 7 provides the project scope summary.

Final preferred option	Reverse Flow at Nether Kellet and Bishop Auckland Compressor Stations and undertake Carnforth Compressor Station Suction and Discharge Valve Asset Health Works	
Location	Nether Kellet - Carnforth Multi Junction	Bishop Auckland
Investment Action	Reconfiguration and Valve Asset Health	Reconfiguration
Year of Commission	[redacted]	[redacted]
High Level Scope	Enable south-to-north gas transportation through reconfiguration of the Carnforth Multi-Junction 4 x Ball Valves 80m of 1050DN Pipe Requiring completion of associated valve asset health works. 4 x Replacement Valves	Enable south-to-north gas transportation through reconfiguration of the Bishop Auckland Multi-Junction. 6 x Ball valves 230m of 1050DN Pipe

Table 7: Northern Reconfiguration Project Summary

7 Options Considered

7.1 Strategic Optioneering

7.1.1 A variety of commercial and contractual arrangements, alongside asset-based solutions, can be deployed individually or in combination to address the challenges identified in the problem statement. Building on previous Northern Reconfiguration network analysis and RIIO-GT3 planning activities, we worked with subject matter experts to develop a comprehensive range of strategic options and establish a long list of possible solutions to address the identified risks.

7.1.2 We assessed each option against a defined and consistent set of assessment criteria to determine whether it met the project's key strategic requirements and should progress to the next stage of development. Table 9 describes the assessment criteria used.

7.1.3 Not all assessment criteria carry equal weight in determining whether an option is viable and can progress to the short-list. The primary objective of the project is to safely and reliably enable the required gas flows from south to north as quickly as practicable to address the identified network need. Consequently, the key decision-making criteria are Capability, Technology, Deliverability, Resilience, and Cost. An option must be capable of meeting the required flow requirements, be technically viable, deliverable within the required timeframe, and provide a resilient and cost-effective solution.

Assessment Criteria	Description
Capability	Can the option provide sufficient south-to-north transportation capability to address the identified network need and meet customer need.
Technology	Does the option rely on proven and deployable technology, with acceptable levels of technical risk.
Resilience	Does the option reduce the risk of customer impacts arising from supply disruptions, asset outages or changing network conditions.
Cost	Is the scale of investment associated with the option proportionate to the benefits delivered, and does it avoid clearly disproportionate or speculative cost exposure prior to detailed evaluation through the CBA.
Deliverability	Can the option be delivered reasonably quickly (next 2-5years) to reduce the risk of [redacted] and to improve network resilience.
	Secondary Criteria
Brownfield	Can the solution be constructed within the existing plant boundary, avoiding the need to purchase additional land.
Enhanced benefits	Does the option provide benefits beyond the identified need, such as improved operability and/or flexibility

Table 8: Assessment Criteria Description

7.1.4 Other criteria (listed as Secondary in Table 9) while important, are considered secondary and are assessed in the context of their impact on the primary project needs case i.e. support the requirement to fulfil those needs but are not essential. For example, a brownfield solution may offer certain advantages but could introduce additional complexity, consents, or construction constraints that extend delivery timescales and therefore fail to address the identified need in time and increase the cost to consumers.

7.1.5 We considered enhanced benefits where options provided additional value beyond the identified need, such as improvements to network operability or flexibility. Whilst these benefits may strengthen the overall case for an option, they were not considered a substitute for delivery of the required northbound capability and resilience outcomes. Consequently, options were not progressed solely on the basis of wider network benefits where there was limited contribution towards addressing the identified need.

7.1.6 We assessed resilience based on the extent to which an option improved network security and maintained the ability to meet customer demand during supply or asset outages. Options that provided only limited or partial resilience benefits were generally not progressed unless they offered sufficient overall benefit to warrant further assessment, for example where they could contribute to addressing part of the identified need or form part of a wider solution.

7.1.7 Where detailed cost estimates have not been developed, a qualitative assessment of relative cost has been undertaken to inform the options assessment. For those options progressed to CBA, more detailed cost estimates have been developed to support the assessment and comparison of shortlisted solutions. We provide further information on cost derivation, assumptions and estimating methodology in the Chapter 8 Cost Definition.

7.1.8 As a result, options were primarily evaluated against their ability to meet the essential requirements, with secondary criteria used to differentiate between options that performed similarly against the key decision factors.

7.2 Option Summary

7.2.1 When considering how the additional capability can be achieved, we have focused on four categories of interventions. We provide further details of the technical aspects of these categories and summarise the indicative delivery timescales considered when assessing the suitability of each option in the context of the urgency of implementing a solution.

Site Reversals

7.2.2 We have considered options that utilise existing compressor station sites. This requires reconfiguring existing pipework and valve arrangements to enable compressor stations to operate in a south-to-north flow direction, increasing transportation capability whilst making use of existing assets and infrastructure. As these solutions rely on existing operational assets, condition assessments may identify associated asset health interventions necessary to maintain the availability and resilience of the proposed transportation route and carry additional costs. Where such interventions provide benefits beyond delivery of the identified need, such as improvements in asset condition, availability or network resilience, these have been considered under the Enhanced Benefit criterion.

7.2.3 These types of site reconfiguration works are typically multi-year interventions, reflecting the time required to undertake detailed design, procurement, consenting and outage planning before construction can commence. Delivery must also be carefully integrated with planned network outages and ongoing compressor station operations, particularly where modifications are required to existing high-pressure pipework, valves, control systems and multi-junction arrangements. As a result, we would generally expect implementation to take two to three years from project start through to commissioning, with the programme influenced by site complexity, constructability and the availability of suitable network outages.

Investment in a new compressor site or units

7.2.4 These options involve construction of new compression facilities or installation of additional compressor units. Such interventions provide additional compression capability but require significant new infrastructure, longer delivery timescales and higher capital expenditure than modifications to existing assets.

7.2.5 We would typically expect the development and delivery of new compression infrastructure to take several years, potentially around five to ten years from initial design and consenting through procurement, construction, commissioning and entry into operation, depending on the scale and complexity of the works.

Pipeline solutions

7.2.6 These options involve constructing new pipelines. A new feeder would provide an additional high-pressure transmission route, increasing physical transportation capacity and linepack between the relevant parts of the NTS. This represents a significant infrastructure intervention requiring route development, land rights and consenting, detailed design, procurement, construction, testing and commissioning, and would therefore typically require around five to ten years to develop and deliver, depending on its length, complexity and consenting requirements. Major transmission reinforcement can involve both upgrades and additions to the existing network and associated land acquisition processes.

Commercial options

7.2.7 Commercial options use market-based arrangements, including contracting with network users, to alter supply or demand patterns or incentivise the development and use of new gas storage, to manage the identified constraint. We discuss these two options in detail in section 7.3.

7.2.8 Short-term commercial tools, including flow swaps, capacity buybacks and locational buy-and-sell trades, are used to manage operational network constraints on a temporary basis. Whilst these measures provide flexibility in response to changing network conditions, they do not provide an enduring solution to the identified long-term need and have therefore been screened out of further consideration.

Options Comparison

7.2.9 Table 10 below summarises a long-list of strategic options considered and their performance against each assessment criterion. We also provide narrative describing each option, together with their respective advantages and disadvantages and reasons for submission or exclusion from the CBA, in the subsequent sections.

7.2.10 An "X" indicates that the option materially satisfies the criterion. Some options provide partial resilience or enhanced benefits but were not considered to fully satisfy the criterion.

7.2.11 The Counterfactual (Do Nothing) option is retained as the baseline within the CBA but is not considered a viable solution to the identified network need as it does not address the identified network resilience and capability need. Without intervention, the NTS would be unable to consistently transport sufficient gas from southern supply sources into Scotland and the North during periods of high demand. [redacted]

7.2.12 A delayed implementation scenario has not been assessed separately, as it would materially resemble the counterfactual. [redacted] as future network conditions evolve, meaning that any postponement of investment would defer, rather than avoid, the associated impacts.

Options			Criteria						Decision
Option	Option Title/Category	Capability	Technology	Resilience	Cost	Deliverability	Brownfield	Enhanced Benefits	Decision and main reason(s) for exclusion from CBA if applicable
0	Do Nothing				X		X		Exclude – Capability
Compressor Reversals									
1	Bishop Auckland Reverse	X	X		X	X	X		Progress to Full CBA
2	Nether Kellet Reverse	X	X		X	X	X		Progress to Full CBA
2a	Nether Kellet Reverse Plus Asset Health	X	X		X	X	X	X	Progress to Full CBA
3	Carnforth Reverse		X				X		Exclude – Cost and Deliverability
4	Bishop Auckland Reverse and Nether Kellet Reverse	X	X	X	X	X	X	X	Progress to Full CBA
4a	Bishop Auckland Reverse and Nether Kellet Reverse Plus Asset Health	X	X	X	X	X	X	X	Progress to Full CBA
New Units and Stations									
5	New Units		X				X		Exclude – Cost and Capability
6	New Compressor Station (Assembly)	X	X					X	Exclude – Costs
7	Recommission Moffat						X		Exclude – Capability and Cost
Pipelines									
8	New Pipeline		X						Exclude – Cost and Capability
Commercial									
9	Commercial Contracts		X			X	n/a		Exclude – Cost and Capability
10	Reduced Assured Operating Pressure	X	X						Exclude - Cost
11	New build LNG Storage Facility in Scotland		X					X	Exclude – Cost and Capability

Table 9: Strategic Options Assessment

7.3 Compressor Reversals

Option 1 – Reverse flow at Bishop Auckland Compressor Station Only

7.3.1 The Bishop Auckland compressor station comprises [redacted] with an operating flow range of [redacted]

7.3.2 Future south-to-north flows are forecast to range from [redacted] This option changes the site configuration to allow south to north compressor flow at Bishop Auckland Compressor Station. It improves network capability by enabling Bishop Auckland to increase flows into the Scotland and the North in high east coast supply scenarios (for example when supplies are high from Teesside and /or Easington).

7.3.3 **Capability.** Site reconfiguration would enable the station to provide the required south-to-north transportation capability. Separately, re-wheeling of the existing compressor units is planned within RIIO-GT3 to broaden their operating envelope in response to changing network flow requirements.

7.3.4 The re-wheel scope is anticipated to take the proposed reconfiguration into account to ensure the compressor units can provide increased operational flexibility across the range of anticipated future flow conditions, including lower-flow operating scenarios. Whilst the reconfiguration and re-wheel projects address different aspects of station capability, they are complementary interventions that together support the long-term operability of the station. In addition, the re-wheels are expected to improve compressor operability across the anticipated future operating range with reconfiguration, supporting safe, reliable and efficient operation of the units under evolving network flow conditions

7.3.5 Future south-to-north flows are forecast to range from [redacted] where the lower flows would primarily be expected in the peak of summer months when south to north compression is less likely to be required due to lower demand levels.

7.3.6 We will undertake further assessment of compressor performance during FEED and detailed design, including engagement with the compressor OEM where required, to confirm that the units can safely and reliably operate under the anticipated operating conditions and to identify any modifications required to support their operation.

7.3.7 **Technology.** The option utilises established gas transmission infrastructure and proven engineering solutions. The option predominantly comprises modifications to existing assets and operational arrangements, including changes to valve and station configurations, rather than the introduction of novel technologies or new applications.

7.3.8 The required equipment is readily available from established suppliers and can be designed, constructed, operated and maintained using our existing standards, specifications and engineering competencies.

7.3.9 **Resilience**. While the site reconfiguration would provide the required network capability under normal operating conditions, implementation at a single site would not provide full resilience. Continued reliance on that site would create a single point of dependency, meaning that any planned or unplanned outage, maintenance activity or other loss of availability could result in the additional capability being unavailable and put the associated gas flows at risk.

7.3.10 **Cost.** The proposed site reconfiguration represents a materially lower-cost solution than options requiring significant new infrastructure, such as a new pipeline, compressor station or additional compressor units, as it maximises the use of existing NTS assets and avoids the substantial capital expenditure associated with constructing new assets.

7.3.11 **Deliverability.** The relatively limited scope of the modifications enables the solution to be delivered within a short timescale. We will need to coordinate the delivery to ensure work is completed in designated outages without impacting operations on the remainder of the NTS. As the option relies on mature and well-understood technology, there is a high degree of confidence in its deliverability, performance and long-term operability.

7.3.12 **Brownfield**. The reconfiguration works would be undertaken within the existing operational site boundary and would modify existing infrastructure rather than require development of a new site. The works are therefore considered brownfield in nature.

7.3.13 **Enhanced Benefit.** We have not identified any additional benefits for this option**.**

7.3.14 Consequently, this option meets the needs case capability requirement while being cost effective and deliverable. We have therefore progressed it to full CBA.

Option 2 – Reverse Flow at Nether Kellet Compressor Station Only

7.3.15 The two [redacted] at Nether Kellet are smaller than those at Bishop Auckland, and each can flow up to [redacted] This option modifies the site configuration at Carnforth/Nether Kellet multijunction to allow south-to-north compressor flow at Nether Kellet Compressor Station.

7.3.16 This configuration would complement the existing south-to-north transfer capability at Alrewas, allowing gas from Milford Haven and north-west storage facilities to be transported further northwards. Reversing the flow at Nether Kellet would provide additional capability to supply Scotland via Feeders 11 and 15 during periods of high gas availability on the West coast.

7.3.17 **Capability.** The current operating envelopes are suitable for the current flow on the network and the reversed flow range which is forecasted to be required. Therefore, reversal can be achieved with multijunction modifications (at the adjacent Carnforth/Nether Kellet AGI).

7.3.18 Considerations given to **technology, resilience, cost, deliverability, brownfield and enhanced benefits** led to the same conclusions as per Option 1, and therefore this option has been progressed to full CBA.

Option 2a Reverse Flow at Nether Kellet Compressor Station and Asset Health Works

7.3.19 As part of the development, we reviewed potential asset health requirements associated with the proposed northbound transportation route. This assessment identified the Carnforth suction and discharge isolation valves as an intervention required to support the long-term availability and operability of the route.

7.3.20 [redacted]

7.3.21 **Cost.** The added valve scope will make this option between [redacted][16] more expensive than option 2, depending on the valve solution taken forward. We present further details on valve options considered, justification for inclusion and related costs in section 10.8.

7.3.22 **Deliverability.** Option 1 describes deliverability from the reversal perspective. The additional valve replacement scope is considered deliverable using established engineering and construction approaches and can be progressed alongside the reconfiguration. We will develop detailed sequencing and assess any impact of the valve works on the overall delivery programme through FEED, including consideration of the isolation and outage requirements necessary to undertake the works safely while maintaining network operation. It is likely the work could be delivered in the same outage window as the reconfiguration, therefore not extending the delivery period of the project.

7.3.23 **Enhanced Benefit**. The valve replacement does not directly provide additional transportation capability. However, the condition of the existing valves means that future maintenance or intervention at Carnforth could require a wider isolation of the Carnforth/Nether Kellet Multijunction. This could temporarily constrain or remove the south-to-north flow path enabled by the proposed reconfiguration under Option 2.

7.3.24 Under option 2a, the resilience capability is delivered through a single reconfigured site. Consequently, maintaining operational availability at that location is critical to the delivery of the option's benefits. The additional suction and discharge valves enhance operational flexibility, facilitate maintenance activities and reduce the impact of asset outages by providing greater isolation capability. Given the reliance on a single site, the need for these valves is stronger under option 2a than under options where resilience is distributed across multiple reconfigured installations (option 4a).

7.3.25 Furthermore, incorporating the valve works within the wider project scope is expected to provide delivery and cost efficiencies through the consolidation of activities such as site mobilisation and establishment, project management, design and engineering, construction supervision and contractor overheads.

7.3.26 Given the close proximity of the valves and the similar nature of the works, there is potential for the scope to be delivered by a single contractor, subject to the final contracting and procurement strategy. At this stage, we estimate that combining the works could deliver approximately [redacted] compared with delivering the scopes separately. We will further develop the extent of these efficiencies and validated them through FEED and subsequent procurement activities.

7.3.27 On this basis, the combined option provides a more robust means of delivering and maintaining the required capability, plus efficiencies of progressing valve asset health works at the same time and has therefore been progressed to the CBA.

Option 3 – Reverse Flow at Carnforth Compressor Station only

7.3.28 Carnforth Compressor Station has two operational units. Unit B is currently derogated under Large Combustion Plant Directive (LCPD) and is scheduled for disconnection during RIIO-GT3. Unit C is a large compressor unit not currently suited to the required south-to-north operating range.

7.3.29 This option modifies the Carnforth/Nether Kellet multijunction configuration and undertakes necessary works on the Carnforth units to enable south-to-north compressor flow at Carnforth Compressor Station.

[16] Based on pre-feasibility study and RIIO-GT3 unit costs. FEED study and cost submission will determine more accurate cost of works.

7.3.30 **Capability.** Neither of the two Carnforth units are currently capable of providing the capability required without significant investment. To meet the required operating range for south-to-north flows, Unit C would require a re-wheel at a minimum. Unit B would require a re-wheel in addition to replacement of its unit control system and potentially further asset health work since it is currently planned for decommissioning in RIIO-GT4.

7.3.31 **Cost.** The requirement to re-wheel both units, in addition to unit control system replacement and possibly asset health work at one site and the reconfiguration work, makes this option more costly than reconfigurations at other sites where the units are already suitable or have re-wheels planned. Based upon our RIIO-GT3 submission, the unit cost for replacing the unit control system (Se-6) is [redacted]

7.3.32 **Deliverability**. The additional work described above would also extend the timeframe required to deliver this option along with increased scope and delivery complexity. It is estimated this would increase the deliver programme by three years compared to alternative sites.

7.3.33 **Resilience**. As noted above, this option would require both Carnforth Units B and C to remain available and capable of meeting future forecast flow requirements. However, while the site reconfiguration would provide the required network capability under normal operating conditions, implementation at a single compressor site would not provide sufficient operational resilience. The additional capability would remain wholly reliant on the continued availability of Carnforth, reducing the network's ability to withstand planned maintenance activities, unplanned compressor outages, or other site-level availability constraints. Consequently, any such event could temporarily remove the additional capability and place the associated northbound gas flows at risk.

7.3.34 While this option is **technically** feasible and utilises proven compressor reversal **technology**, it requires significant additional investment to both Carnforth compressor units, including re-wheels, control system replacement and potentially further asset health interventions. These works substantially increase both the cost and delivery duration of the option relative to alternative site reconfigurations, whilst providing no material increase in network capability. We therefore discounted this option from further consideration as it does not represent an efficient or economic solution compared with the other reversal options assessed.

Option 4 – Reverse Flow at Nether Kellet and Bishop Auckland Compressor Stations

7.3.35 Combining Options 1 and 2, this option considers reversals at both Bishop Auckland and Nether Kellet.

7.3.36 **Capability.** By implementing reverse flow capability at both sites, this option provides the required south-to-north transportation capability across a wider range of network operating conditions than either reconfiguration individually. Whilst each site is capable of facilitating the identified transportation requirement in its own right, the two locations complement one another under different supply, demand and network operating scenarios, providing greater flexibility in how the required capability is delivered. With both stations reversed, the required capability can be delivered by either site, increasing intact availability.

7.3.37 The configuration allows pressures to be maintained across the region under varying supply patterns, with Nether Kellet supporting northbound transmission when west coast supplies are high and Bishop Auckland supporting northbound transmission when east coast supplies are high. The availability of two reverse flow locations therefore increases confidence that the required northbound capability can be maintained across a broader range of future network conditions and asset availability scenarios.

7.3.38 **Technology.** The option uses the same established technologies and equipment considered under Options 1 and 2, with no additional fundamental technological challenges arising from implementation at both sites.

7.3.39 **Resilience.** The option provides greater resilience than a single-site reconfiguration by reducing dependency on any one compressor station. Where one site is unavailable due to planned maintenance, an unplanned outage or other loss of availability, south-to-north capability may continue to be provided through the alternative site, subject to prevailing network conditions. This reduces the risk of the required capability being wholly unavailable and improves network flexibility under a range of asset availability and supply-demand scenarios.

7.3.40 **Cost.** The option requires reconfiguration works at two sites and therefore has a higher capital cost than either Option 1 or Option 2 individually but is materially cheaper than new infrastructure.

7.3.41 **Deliverability**. Delivery across two sites would increase the overall scope and require coordination of design, construction and network outages at both locations. The works would not be able to be delivered in parallel due to criticality of either of the site being available to support prevailing network conditions, meaning that the overall programme would increase in comparison to single site solution. However, completion of the first site would provide the capability required to support northbound gas flows, resulting in only a potential one-year period before the full resilience benefit is realised.

7.3.42 **Brownfield.** Both reconfigurations would be undertaken at existing operational sites and principally involve modification of existing infrastructure. The works are therefore brownfield in nature and avoid the additional land, planning and infrastructure requirements associated with developing new compressor stations or pipelines.

7.3.43 **Enhanced benefit.** Option 4 would also provide enhanced operational flexibility by increasing optionality in the use of the compressor fleet. As supply patterns change, different transportation routes can be utilised to support northbound flows. For example, east coast Norwegian supplies can be supported via the Bishop Auckland route, while Milford Haven and storage facilities can utilise the Carnforth/Nether Kellet route. This additional flexibility would improve network operability and resilience to changing supply conditions.

7.3.44 Overall, this option provides the required south-to-north capability while offering greater resilience than either reconfiguration individually. Although it requires investment at two sites, meeting the resilience criteria warrants further economic assessment and the option has therefore been progressed to the full CBA.

Option 4a – Reverse Flow at Nether Kellet and Bishop Auckland Compressor Stations and undertake Asset Health Works

7.3.45 [redacted]

7.3.46 **Cost.** As per option 2a, the added valve scope will make this option more expensive (see paragraph 7.3.14)

7.3.47 **Resilience.** Whilst the resilience dependency on Carnforth/Nether Kellet is lower under Option 4a due to the availability of Bishop Auckland as an alternative route, replacement of the valves remains beneficial as it maximises availability of one of the two preferred northbound transportation routes.

7.3.48 The assessment against the criteria led to the same conclusion that the option meets the **capability** criteria, is **deliverable** in relatively short period of time with available **technology** as a **brownfield** solution. As two sites would be reconfigured, the option meets the **resilience** requirement and provides the added **benefit** of valve replacement described in option 2a.

7.4 New Units

Option 5: New Unit at Bishop Auckland, Nether Kellet or Carnforth

7.4.1 This option is to construct an additional compressor unit at an existing compressor station. The sites we considered were Bishop Auckland, Nether Kellet or Carnforth. These locations were chosen as they are situated on key transportation routes into Scotland and already contain existing compression infrastructure.

7.4.2 **Capability**. Installing a new compressor unit would not remove the need to reconfigure the existing station and multi-junction arrangements to enable sustained south-to-north flows. This option would therefore require the reconfiguration works identified under Options 1, 2 and 4, in addition to the installation of a new compressor unit.

7.4.3 A new compressor unit could provide additional compression capability and operational flexibility. However, our assessment demonstrated that the required network capability can be delivered through reconfiguration of the existing assets, with a new unit providing only limited incremental benefit.

7.4.4 The technology required to install a new compressor unit is established and proven within the gas transmission industry and is therefore considered technically deliverable.

7.4.5 **Technology**. The technology required to install a new compressor unit is established and proven within the gas transmission industry and is therefore considered technically deliverable.

7.4.6 **Resilience.** A new compressor unit would not provide resilience in an instance where more northbound network capability is required in the changing demand supply scenarios.

7.4.7 **Cost.** The cost of delivering a new compressor unit would be significant compared with the site reconfiguration options considered. We have recently completed FEED studies for new compressor units elsewhere on the NTS, with cost estimates exceeding [redacted]

7.4.8 **Deliverability**. Delivering a new compressor unit would also require FEED, consenting, procurement, construction, testing and commissioning activities. The longer delivery programme would delay the required capability becoming available, increasing the period of exposure to potential network constraints and reduced resilience.

7.4.9 **Brownfield.** We assumed that the new units could be delivered as brownfield solution within the existing sites boundaries.

7.4.10 **Enhanced Benefit.** Installation of a new compressor unit could provide some additional operational benefits through increased asset availability, improved reliability and reduced reliance on existing compressor units at the selected site.

7.4.11 As this option doesn't provide sufficient required capability (while it can be delivered through the reconfiguration of existing assets), this option would not provide sufficient benefit to justify the additional cost of installing a new compressor unit. Furthermore, a new unit could not be delivered within the required timescales. On this basis, the option was discounted from further consideration.

Option 6: New Compression Station - Asselby

7.4.12 This option involves the conversion of Asselby AGI into a new compressor station to facilitate gas compression north along feeders 7 and 13, towards Bishop Auckland, facilitating increased entry capability at Bacton.

7.4.13 Following Nether Kellet and Bishop Auckland compression stations, Asselby represents the next logical location along the network at which additional compression site could be provided.

7.4.14 **Capability.** A new compressor station at Asselby would provide the required capability.

7.4.15 **Technology.** The compressor technology required is established and proven within the gas transmission industry, with no fundamental technological barriers identified. However, its application at Asselby would require site-specific design and integration to establish compression at a new location.

7.4.16 **Resilience.** This option would not provide adequate resilience being the only station able to support more northbound capability.

7.4.17 **Cost**. Development of a new compressor station would be significantly more costly than installing an additional unit or reconfiguring an existing site, as it would require extensive new civil, mechanical, electrical and control infrastructure, whereas the alternative options make greater use of existing assets and facilities.

7.4.18 In practice, a new compressor station would be expected to include at least two compressor units to provide an appropriate level of operational resilience and maintainability, further increasing the required investment. Recent compressor station developments indicate that the cost of the compressor units alone would be substantial[17], before allowing for the wider station infrastructure and associated development costs.

7.4.19 The scale of investment required to establish a new compressor station was considered materially greater than that of all shortlisted options and was therefore judged unlikely to represent an economically efficient solution. On this basis, a detailed cost estimate was not developed, as the option was considered prohibitively expensive relative to the alternative solutions capable of meeting the identified network need.

7.4.20 **Deliverability.** Delivery would require construction of a new compressor station and its integration with the existing NTS, including associated pipework, electrical, control and civil infrastructure. Similarly to construction of the new unit, the scale of these works would result in a longer programme and greater delivery risk than options utilising existing compressor stations.

7.4.21 **Technology.** The compressor technology required is established and proven within the gas transmission industry, with no fundamental technological barriers identified.

[17] Ofgem's Final Determination on Peterborough MCPD Compressor Emissions re-opener awards £137m for the installation of a new compressor unit

7.4.22 **Brownfield**. Conversion of the existing multijunction at Asselby into a compressor station would present complex land and planning challenges as the existing site footprint is unlikely to be sufficient to accommodate the infrastructure required for the compressor station.

7.4.23 **Enhanced benefit.** A new compressor station could provide an additional source of compression capability on the NTS and reduce reliance on existing compressor stations operating further north. This may provide some operational flexibility in responding to changing network conditions and asset outages. However, the benefit extends beyond the requirements of the current needs case and are not required to meet the identified network need.

7.4.24 While Asselby could provide the required capability, it does not provide a materially greater capability or resilience benefit than reconfiguration of existing compressor stations. Due to the complexity, it would take longer to deliver and overall require significantly greater investment. On that basis, we have discounted this option.

Option 7: New Unit at Moffat

7.4.25 This option involves investment in a new compressor unit at a decommissioned site. We considered Moffat which ceased operation in 2018 and was subsequently decommissioned. Re-establishing compression at the site would enable flows along Feeders 11 and 12 to enable gas compression and transportation northwards and westwards.

7.4.26 **Capability**. At Moffat, insufficient gas is available on the suction side of the network to support the required northbound flows. Consequently, this option does not provide the capability required to address the identified network need.

7.4.27 Our assessment of **technology, resilience, cost, deliverability** and **enhanced benefit** criteria led to the same conclusions as Option 5.

7.4.28 **Brownfield**. The option would utilise the existing Moffat site; however, as the compressor station has been decommissioned, significant new infrastructure would be required to reinstate compression capability. It therefore offers fewer brownfield benefits (no existing operational infrastructure available for reuse) than options that modify operational compressor assets.

7.4.29 The option has been discounted from further consideration because it does not provide the capability required to address the identified network need. Reinstating compression at a decommissioned site would also introduce significant cost, complexity and delivery risk compared with options utilising existing operational compressor stations.

Option 8: New Pipelines

7.4.30 As part of the options development process, we assessed the feasibility of installing new pipeline infrastructure to support the required northbound gas flows.

7.4.31 **Capability**. Installing a new feeder would increase linepack and provide greater operational flexibility. However, while this could help manage short-term fluctuations in demand, it would not address the underlying long-term supply deficit within the region or provide sufficient additional transportation capability to meet the identified network need. Compression capability would still be required to move gas from southern supply sources into Scotland during periods of high demand and low St Fergus supply.

7.4.32 **Technology.** Construction of new high-pressure gas transmission pipelines is an established and proven technology.

7.4.33 **Resilience.** The solution would provide limited resilience benefit. Although a new pipeline would introduce an additional asset to the network, it would not address the underlying transportation constraint caused by insufficient compression capability to move gas northwards during periods of low St Fergus supply. Furthermore, the asset would remain subject to planned and unplanned outages, meaning the option would not provide a sufficiently resilient solution to the identified need.

7.4.34 **Cost.** Analysis indicates that hundreds of kilometres of new pipeline would be required to provide sufficient additional linepack [redacted]

7.4.35 **Deliverability.** Delivery of a new feeder of this scale would represent a significant infrastructure programme. It would require route development and optioneering, land acquisition and access, environmental assessment and consenting, detailed design, procurement and construction, followed by connection and commissioning into the existing NTS.

7.4.36 **Brownfield.** Construction of a new pipeline represents a predominantly greenfield solution. It would require substantial new land corridors and introduce associated consenting, environmental and construction requirements, together with brownfield works where the new pipeline connects into the existing NTS.

7.4.37 **Brownfield.** Construction of a new pipeline represents a predominantly greenfield solution. It would require substantial new land corridors and introduce associated consenting, environmental and construction requirements, together with brownfield works where the new pipeline connects into the existing NTS.

7.4.38 **Enhanced benefit.** As mentioned earlier, the new feeder could provide wider benefits through increased linepack, additional network capacity and greater operational flexibility.

7.4.39 Given that a new pipeline alone would primarily provide additional linepack and would not provide the compression required to deliver sustained northbound flows, it would not meet the identified network need as a standalone solution. Additional compression or associated network reconfiguration would still be required. The option has therefore been discounted mainly on capability and cost, but also deliverability grounds.

7.5 Commercial Options

Option 9: Commercial Contracts

7.5.1 This option considers the use of commercial turn-up and turn-down contracts with network users to provide additional flexibility during periods of constraint. Turn-down arrangements would reduce gas demand at specified locations, while turn-up arrangements would increase gas supply where capability exists. The contracts would be activated during predicted periods of supply shortfall to manage the identified capability gaps.

7.5.2 The availability, cost and duration of such contracts are dependent on market interest and tender outcomes, and there is no guarantee that we will receive sufficient commercial responses or that we will be able to secure agreements on acceptable terms.

7.5.3 [redacted] Hence there is a lack of confidence in securing a contract for the required duration the needs case identified.

7.5.4 The number of potential counterparties in the affected area is limited, significantly reducing confidence that sufficient contractual responses could be secured. [redacted]

7.5.5 **Capability.** A turn-down contract can only be equal to or less than the counterparty's flow on the day and is therefore difficult to predict with any certainty for the duration requirement. There is also a risk that the turndown volume will be less than what is required to provide the additional volumes to Scotland and the Northern Area.

7.5.6 **Resilience.** This option remains dependent on the continued availability and participation of third parties. As the capability cannot be assured under all network conditions and may not be available when required, the option does not provide the level of resilience necessary to address the identified supply loss risk.

7.5.7 **Cost.** We undertook analysis to determine the cost estimate of enabling commercial contracts. The option considered a period of 12 months and volume of 5 mcm on a turn down Power Station contact, but the methodology and calculation could be applied to any desired duration or volume during which the contacts are to remain active. The analysis concluded that the annual cost of the contract would come to [redacted]

7.5.8 **Deliverability.** Delivery of turn up and turn down arrangements would require a competitive tender process to identify and secure suitable counterparties. Based on experience from previous procurements, the development of the commercial framework, tender process, evaluation, negotiations and contract execution could take approximately 12 months to complete. Deliverability would also remain dependent on receiving sufficient market interest and securing contractual arrangements on acceptable terms.

7.5.9 **Technology** and **Brownfield** criteria are not applicable to this option.

7.5.10 This option does not provide a sufficiently reliable (on ongoing basis or in the instance of network emergency), controllable or sustainable means of addressing the long-term need. Reliance on market participation means that the required capability cannot be assured when needed and therefore does not provide an equivalent level of resilience to a network solution. Given the enduring nature of the identified capability need, commercial interventions would need to be procured repeatedly over an extended period, resulting in materially higher cumulative costs than the preferred network solution without providing the same certainty of capability. We have therefore discounted this option on capability, resilience and cost grounds.

Option 10: Reduced assured operating pressure.

7.5.11 This option considers reducing the minimum pressure that the NTS is required to maintain at relevant offtakes. Delivery of such an option would require agreement with affected Gas Distribution Networks (GDNs) and other connected users regarding revised operating arrangements and the management of any consequential impacts. The process would have to be repeated on annual basis and GDNs would have a right to agree or disagree with the proposed rates.

7.5.12 In practice, pressure reduction could require downstream network modifications, changes to operational procedures, or alternative arrangements to maintain customer security of supply.

7.5.13 **Capability.** This option could reduce the network capability requirement by lowering the pressure obligations that the NTS is required to maintain.

7.5.14 **Resilience.** Reducing Assured Operating Pressure may reduce the likelihood of pressure-driven constraints on the NTS, but this is achieved by accepting a lower level of network performance rather than improving the resilience of the transmission system. [redacted]

7.5.15 **Technology.** The option does not require the deployment of new technology and is technically feasible from a transmission system perspective.

7.5.16 **Cost.** Whilst the option could reduce the need for investment, we expect it would result in significant consequential costs elsewhere in the gas network. These costs could be substantial, potentially requiring extensive reinforcement or operational changes within distribution networks. Our estimates from 2019 suggest an estimated cost of circa [redacted]

7.5.17 **Deliverability.** Implementation would require extensive industry engagement, regulatory assessment and agreement across multiple parties. The scale of stakeholder involvement and the potential impact on downstream network users would make delivery complex and unlikely to be achievable within the required timeframe.

7.5.18 Through the annual Exit Capacity Planning Group (ECPG) and Exit process, we engage with GDNs to review required offtake volumes and pressures. In practice, GDNs typically seek to maintain or increase offtake pressures to support security of supply to consumers and are under no obligation to reduce them. As a result, there is limited certainty that the required pressure reductions could be secured and maintained over the long term.

7.5.19 **Brownfield.** We have not assessed this criterion as it would require direct engagement with the GDN, while we decided not to pursue it on other grounds.

7.5.20 **Enhanced benefit.** We have not identified any enhanced benefit in relation to this option.

7.5.21 Given the uncertainty over securing and maintaining the required reductions in Assured Offtake Pressures, the associated consumer supply risk and potential cost, we have discounted this option. We consider the compressor station reconfiguration options to provide a more reliable, controllable and enduring solution to the identified need.

Option 11: New LNG Storage facility

7.5.22 This option considers the development of a new Liquefied Natural Gas (LNG) storage facility in Scotland. However, under the terms of our licence, NGT cannot own or operate LNG storage assets and would therefore be reliant on third-party investment to develop and operate such a facility.

7.5.23 **Capability**. No suitable third-party developer has currently been identified within the region. Even if a private LNG storage opportunity were to emerge, the option would remain subject to significant delivery and commercial risks. We would be reliant on contractual availability and third-party performance, limiting operational control over the asset. Furthermore, the resilience of such arrangements during peak winter demand periods cannot be guaranteed. Consequently, this option is not considered capable of reliably addressing the identified network need.

7.5.24 **Resilience.** Due to ownership and operational arrangements, the facility could not be relied upon to provide assured capability when required.

7.5.25 **Technology**. LNG storage is an established technology and is technically capable of providing additional gas supply.

7.5.26 **Cost**. Development of a new facility would require significant new infrastructure and associated investment. The overall capital and ongoing commercial costs are therefore expected to be significant and would be outside our direct control. This compares unfavourably with options that make more efficient use of existing NTS infrastructure.

7.5.27 **Deliverability**. Development of a new LNG storage facility would require site selection, environmental assessment, planning and regulatory consents, commercial arrangements, detailed engineering, procurement, construction and commissioning activities. Based on the scale and complexity of comparable infrastructure projects, delivery is likely to require at least seven to ten years from project inception to operation.

7.5.28 **Brownfield.** A new LNG storage facility would also require the development of new assets and associated infrastructure at a new or substantially developed site and would therefore not meet the brownfield criterion applied to options that can be delivered predominantly through modification or reconfiguration of existing NGT assets within existing operational sites.

7.5.29 **Enhanced Benefit.** A new LNG storage facility could provide wider system benefits by increasing gas supply diversity and creating additional flexibility to respond to future changes in supply and demand patterns. It may also support broader energy security objectives by providing a source of stored gas during periods of market stress.

7.5.30 Whilst a new LNG storage facility could provide wider system benefits, it is not considered a credible solution to the identified network need due to the absence of an identified developer, reliance on third-party delivery and an anticipated development timescale of at least seven to ten years. On this basis, the option has been discounted from further consideration.

7.5.31 Although this assessment focused on LNG storage due to the flexibility provided by LNG cargo imports, a similar conclusion would apply to conventional gas storage. The key difference is that LNG facilities can receive and regasify additional gas supplies from imported cargoes, whereas conventional storage relies on gas that has previously been injected and stored from the NTS. LNG facilities would therefore provide greater operational flexibility, as additional supplies can be brought into the network in response to changing market conditions and system requirements, rather than relying solely on gas stored in advance.

Alternative combinations of option

7.5.32 While combinations of options, such as a single-site reconfiguration supported by commercial arrangements or multiple physical interventions across the network, could potentially provide additional benefits, these were not progressed for detailed assessment. The options appraisal focused on identifying efficient solutions capable of meeting the needs case requirements. Combined solutions would introduce additional complexity and cost. As a result, we have not considered them as more economic or deliverable solution than the options progressed to detailed assessment.

7.6 Options Short-listing

7.6.1 Options 1, 2, 2a, 4 and 4a were the only solutions assessed as capable of materially addressing the identified need using proven technology within the required timeframe and at proportionate cost. We progressed these options to detailed cost estimation and CBA to enable evaluation against the counterfactual.

7.6.2 We provide the cost of these options in Table 10. We included the basis for the estimate as well as estimation methodology in the next chapter.

Ref	Option	Cost £m
1	Bishop Auckland Reverse	[redacted]
2	Nether Kellet Reverse	
2a	Nether Kellet Reverse Plus Valve Asset Health	
4	Bishop Auckland Reverse and Nether Kellet Reverse	
4a	Bishop Auckland Reverse and Nether Kellet Reverse plus Valve Asset Health	

Table 10: Investment options progressed to CBA

8 Cost Definition

8.1 Cost Estimate Introduction

8.1.1 We developed cost estimates for each progressed option using an approach that ensures the estimates and associated confidence levels are transparent, auditable, and capable of supporting the review process. We aligned the estimating approach with Infrastructure and Projects Authority (IPA) guidance.

8.1.2 The original estimate of [redacted] per site, included in our RIIO-GT3 business plan, was based on a high-level concept which assumed four 42-inch actuated valves and approximately 20m of 42-inch connecting pipework. There was limited engineering, constructability or site-specific information available at the time.

8.1.3 The revised cost estimate included in this FOSR reflects the continued development of the project scope and increased design maturity, providing greater certainty and accuracy in the forecast cost.

8.1.4 We have applied a range of estimating techniques to develop the cost estimate, selecting the approach most appropriate to the level of definition and design maturity of each scope element. These techniques include:

- Bottom-up and first-principles estimating for defined and measurable activities.
- Analogous estimating for less-developed scope.
- Parametric estimating using relevant cost drivers.
- Supplier and subcontractor quotations, where available.
- Provisional allowances for undefined scope.

8.1.5 We assessed estimate uncertainty, project risk and contingency using our estimating tools and governance processes. We applied the Estimate Uncertainty (EU) methodology and the 3Cs assessment (Criticality, Complexity and Cost) to quantify uncertainty and determine an appropriate contingency allowance for the maturity of the project.

8.2 Basis of Estimate

8.2.1 The updated option estimates reflect the project's current early stage (Development/Optioneering) which equates to ND500 Phase 4.2 to early Phase 4.3. They have been prepared with an indicative cost confidence of -20% to +30%.

8.2.2 The estimate confidence range reflects the current maturity of the design. As the project remains at the optioneering stage, elements of scope, quantities and delivery requirements are subject to further development and refinement, resulting in a greater degree of cost uncertainty than would be expected at later project stages.

8.2.3 We applied a bottom-up estimating method using available engineering drawings and Material Take Off (MTOs) provided by [redacted], first-principles build-ups, current cost data for asset health Frameworks, and recent supplier quotations from OEM/Direct vendors. The estimate incorporates a Design and Build delivery model, with management and time-related costs aligned to the high-level project programme. It assumes brownfield site conditions.

8.2.4 The estimated scope includes site establishment, site clearance, excavation, pipe handling and shop fabrication activities, temporary works, foundations, mechanical installation, electrical and instrumentation works, tie-ins, testing, commissioning and reinstatement.

8.2.5 The scope has evolved through reviews of the available engineering information, preliminary layouts, equipment requirements, site constraints and input from [redacted] Project Delivery, Engineering and Estimating teams. Where scope information remains incomplete, reasonable assumptions and allowances have been included and recorded in the Basis of Estimate.

8.3 Estimate Methodology

8.3.1 We developed the estimate using a structured and Ofgem accepted Cost Breakdown Structure (CBS), providing traceability between the project scope, quantities, resource requirements, rates and estimated cost. Nether Kellett and Bishop Auckland estimates are included as Appendix B and Appendix C.

8.3.2 The estimate includes direct labour, plant and materials, permanent equipment, subcontract and specialist services, temporary works and construction consumables, site establishment and temporary facilities, engineering, project management and construction management, testing, commissioning and handover, defined allowances and provisional risks, contingency and uncertainties.

8.3.3 We estimated the durations of measurable quantities from our productivity rates and assumed based on experience or related activity where the quantity cannot be directly measured. We predominantly assumed the high-level estimate duration for the Design and Build stages based on size and complexity of activities in each project and will likely change at a more defined project stage.

8.3.4 We derived quantities from the available drawings, layouts, equipment lists, preliminary material take-offs, desktop studies, site information and construction sequencing assumptions.

8.3.5 As detailed design information was unavailable, we applied reasonable assumptions and allowances using preliminary engineering information, historical data, comparable projects and estimating judgement. Our cost estimation files include a list of assumption and exclusions we have considered.

8.3.6 We have excluded Electrical, Control and Instrumentation (EC&I) modifications, pipeline isolation arrangements (including any stopple or bypass requirements) and associated recompression activities from the current estimate because we cannot yet define these elements with sufficient confidence at the current stage of engineering maturity. We will determine the extent of these requirements through FEED and subsequent detailed design activities. Depending on the final design solution and operational constraints, these elements could add significant cost to the project. We have therefore identified them as key estimating uncertainties and incorporated them into the project's assumptions, exclusions, risk assessment and estimate confidence range. We will update the cost estimate as we further develop the scope and increase design certainty.

8.4 Cost Accuracy and Confidence

8.4.1 The estimate has been prepared in accordance with the AACE Cost Estimate Classification System and the estimating principles set out within Infrastructure and Projects Authority guidance.

8.4.2 The AACE framework classifies estimates from Class 5, representing early conceptual estimates, through to Class 1, which is supported by substantially developed engineering information. Based on the level of project definition currently available, the Northern Reconfiguration Project estimate is considered broadly aligned with a Class 3 Estimate.

8.4.3 This assessment reflects the varying maturity of the underlying information. While some scope elements have been developed using preliminary quantities and first-principles estimating techniques, other elements remain less defined and are based on historical costs, benchmark rates, analogous project data and estimating allowances.

8.4.4 In line with OFGEM requirements for the FOSR submission, the estimate is presented as a Class 3 Estimate. However, we consider some elements of the estimate more closely aligned with a Class 4 Estimate due to the current stage of project development.

8.4.5 Several key scope elements remain at a conceptual stage and the estimate therefore relies on a number of assumptions, engineering judgements, allowances and exclusions. As a result, the level of engineering definition available is lower than would typically be expected to support a fully developed Class 3 Estimate.

8.4.6 Notwithstanding this, we developed the estimate using the best information available and is considered sufficiently robust to support the option assessment and investment decision required at this stage. Given the relative cost differences between the options under consideration, further design development is not expected to materially alter the preferred option or the overall decision outcome.

8.4.7 Achieving a higher-confidence estimate would require additional engineering definition, surveys, investigations and design development that cannot be completed within the current programme timescales. Consequently, we reflected the associated uncertainty through the assumptions, exclusions and contingency allowances applied, consistent with an estimate of Class 4 maturity.

8.5 Risk, Uncertainty and Contingency Assessment

8.5.1 Risk and contingency are assessed separately from the base estimate to provide transparency and avoid duplication. Contingency is intended to cover identified and quantified uncertainty[18]. It does not cover scope changes, escalation or items specifically excluded from the estimate. A Project Criticality, Complexity and Cost (3Cs) Assessment was undertaken to determine the appropriate risk uplift for both the Contractor's and NGT risk. The assessment considers the project's criticality, technical complexity, and baseline cost to evaluate overall exposure to delivery and cost uncertainty.

8.5.2 The combined assessment generates an overall project rating, which is used to establish the risk allowance applied to the estimate. This structured methodology provides a consistent and auditable basis for quantifying project risk.

8.5.3 Based on the outcome of the 3Cs assessment, we applied [redacted] risk allowance to both the Nether Kellet and Bishop Auckland Main Works Contractor estimates, while NGT risk allowance has been estimated at [redacted]

8.5.4 We undertook an Estimating Uncertainty (EU) Assessment to quantify the inherent variability within the estimate resulting from the maturity of the project scope, estimating methodology, and available cost data. Unlike project risks, estimating uncertainty applies to all estimate outcomes and reflects the expected range of cost variation as the design develops.

8.5.5 We assessed the level of uncertainty based on level of scope definition, quantity confidence, pricing assumptions, and the quality of supporting estimate information for each major activity project. The assessment produced uncertainty range of +30%/--20% for both Nether Kellet and Bishop Auckland into the final total project cost. This approach provides a transparent and auditable basis for assessing estimate accuracy and was applied separately from identified project risks to avoid double counting.

[18] Including all cost except NGT Overheads and Project Management

9 Option Evaluation

9.1 Cost Benefit Analysis

9.1.1 As mentioned in conclusion of Chapter 7, the shortlisted options progressed to CBA represent the solutions identified through the strategic optioneering process as being capable of materially addressing the identified need using established technology, within the required timeframe and at proportionate cost.

9.1.2 We completed the CBA using the Ofgem RIIO-GT3 CBA template and assessed each option against the counterfactual case of continuing to operate the network without further investment. The assessment includes CAPEX, network constraint costs and asset risk costs. As these inputs are all costs, the benefits of investment are captured through reductions in these costs and risks therefore any improvement in NPV relative to the counterfactual represents the benefit delivered by the options.

9.1.3 We have incorporated all source data into the CBA workbooks, with relevant calculations and formulae referencing the source data directly to provide a clear and transparent audit trail throughout the analysis.

9.1.4 Capability and resilience are closely linked. As northern supplies decline, greater northbound transportation capability is required, while resilience ensures that sufficient capability remains available during supply disruptions, maintenance and asset outages.

9.1.5 The CBA is based [redacted] This provides the basis for assessing the economic benefit of investment in maintaining supply to Scotland and the North [redacted]

9.1.6 The CBA could alternatively be based on the forecast supply deficit related to the lack of capability to transport gas north. However, quantifying the economic value of gas that could not be supplied to exit customers is inherently uncertain, as the impact would vary depending on prevailing market conditions, the duration and scale of the deficit, and the customers affected.

9.1.7 Whilst economic efficiency is a key consideration, option selection has not been based solely on net present value. Consideration has also been given to resilience, operational flexibility, deliverability and the robustness of the solution under future network conditions. Consequently, options with marginally better economic performance may not necessarily represent the preferred overall solution.

9.1.8 The CBA considers five options that are all feasible and forecast to mitigate the potential constraints, as well as the counterfactual. Table 10 provided a summary of the CBA options. We present the detailed CBA results and the completed Ofgem RIIO-GT3 CBA workbook in Appendix D.

9.2 CBA Rates and Assumptions

9.2.1 Key rates and assumptions used for the CBA are set out below in Table 11.

Category	Input	Base Assumption (RIIO-GT3)
Ofgem Template	All inputs, formulas and rates	[redacted]
Financial Parameters	WACC	
	Social Time Preference	
	Regulated Asset Life	
	Assessment Period	
	Depreciation	
	Capitalisation (Ofgem Template)	
Constraints and Fuel	Gas Price (Reference Price)	
	Constraint Management Pricing	
	Constraint Management Method	
Emissions	CO2 Cost	
	Nox Price	

Table 11 Key Rates and Assumptions

9.3 Network Constraints

9.3.1 [redacted]

9.3.2 We calculated the cost of exit constraints for each progressed option based upon a [redacted] cost split of locational actions and buybacks.

9.3.3 We use locational actions to encourage the market to either reduce their supply or increase their demand in the area and these are associated with the purchase of volumes of gas that is necessary to resolve the constraint. A buyback is a commercial solution to buyback an amount of capacity to the level of capability the network can deliver. The buyback actions are considered more costly than locational actions.

9.3.4 We calculated constraints using the 2025 FES Falling Behind (FB) and Holistic Transition (HT) pathways and with a balanced sensitivity (High Continental and High LNG). We have also included a consideration for how the outcomes might change considering the High Price (HP) or Reference Price (RP) scenarios.

9.3.5 The calculated constraint volumes represent exit constraints. In practice, there is a risk that the required level of demand reduction may not be achievable by instigating locational actions or buybacks, in which case the network may be unable to maintain required pressure levels, increasing the likelihood of a network emergency in the absence of investment.

9.4 CBA Results

9.4.1 Absolute and relative Net Present Values (NPV) provide two different views of the economic assessment. Absolute NPV represents the total discounted costs and benefits attributable to an option over the appraisal period. Relative NPV compares each investment option against the Counterfactual baseline and therefore shows the incremental economic value of intervening. An option may consequently have a negative absolute NPV while still having a positive relative NPV where the cost of intervention is lower than the economic impact associated with the Counterfactual.

9.4.2 The table below sets out the absolute NPV of all options across HT and FB 2025 FES pathways, and for both gas prices in £m.

Option	Description	HT			FB		
		RP	HP	Rank	RP	HP	Rank
Option 0	Counterfactual	[redacted]					
Option 1	Bishop Auckland Reverse						
Option 2	Nether Kellet Reverse						
Option 2a	Nether Kellet Reverse & Valve Asset Health						
Option 4	Bishop Auckland & Nether Kellet Reverse						
Option 4a	Bishop Auckland & Nether Kellet Reverse, plus Valves Asset Health						

Table 12 Absolute NPVs

9.4.3 These results demonstrate that the capital costs of the investments are the significant driver of the NPVs under the Holistic Transition scenario.

9.4.4 Under Falling Behind the constraint costs associated with the Counterfactual option are substantially higher and the investment options provide material savings over the assessment period. Table 13 shows that all options have a positive NPV compared to the Counterfactual.

Option	Description	HT			FB		
		RP	HP	Rank	RP	HP	Rank
Option 1	Bishop Auckland Reverse	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 2	Nether Kellet Reverse	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 2a	Nether Kellet Reverse & Valve Asset Health	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 4	Bishop Auckland & Nether Kellet Reverse	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Option 4a	Bishop Auckland & Nether Kellet Reverse, plus Valves Asset Health	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 13: Relative NPVs

9.4.5 [redacted] Delivering reversals at both locations provides greater operational flexibility and network resilience than a single-site intervention. In addition, replacement of the Carnforth valves addresses known asset health requirements and ensures the long-term operability and reliability of the associated reversal capability, reducing the risk of future constraints while avoiding the need for standalone future interventions and minimising whole-life costs for consumers.

9.4.6 [redacted]

9.4.7 Option 4a represents the preferred option as it delivers a range of potentially significant wider societal and system-level benefits that are inherently difficult to quantify and are not captured in the CBA. As recognised by Ofgem in its assessment of arrangements to maintain gas import capability[19], these may include wider consumer welfare impacts arising during loss of supply incidents

9.4.8 The scale and likelihood of such impacts are uncertain and therefore not readily monetised; however, they reinforce the value of investing in resilient gas transmission infrastructure capable of maintaining security of supply under a range of future scenarios. In this context, Option 4a provides additional strategic value beyond its quantified benefits by enhancing network resilience, operational flexibility and the ability to manage credible low-probability, high-impact gas supply disruption events.

[19] Impact Assessment of Arrangements to Maintain and/or Reinstate Gas Interconnector Import Capability Supported by GB Gas Consumers

10 Preferred Option Scope and Project Plan

10.1 Introduction

10.1.1 The option evaluation identified a number of technically feasible solutions capable of addressing the identified need. We selected the preferred option based on its ability to deliver the required northbound capability and resilience outcomes for customers and end consumers whilst providing the best overall balance of economic efficiency, deliverability and long-term network value. The assessment considered both quantified and qualitative factors, recognising that economic performance alone was not sufficient to differentiate options where material differences in resilience and asset availability existed.

10.1.2 We identified Option 4a, comprising the reconfiguration of both Nether Kellet Compressor Station and Bishop Auckland Compressor Station together with replacement of the associated suction and discharge valves at Carnforth, as the preferred option. Whilst alternative options demonstrated strengths against individual assessment criteria, Option 4a provides the most robust overall solution by combining the required northbound capability with enhanced resilience through two geographically distinct transportation routes, whilst also addressing an identified asset health risk on a critical transportation route.

10.1.3 Both the Nether Kellet and Bishop Auckland compressor station reversal options address the identified risk in relation to the need to increase gas transportation into Scotland from the south during periods of low St Fergus supply and high Scottish demand [redacted]

10.1.4 Reversal of flow at either site is technically challenging due to the congested layout and complexity of the existing multi-junction arrangements. High-level design studies have been completed to confirm technical feasibility and support robust cost estimation.

10.1.5 As supply patterns continue to change, the NTS will increasingly transition from its historic north-to-south operating mode towards routine south-to-north transportation of gas. This represents a fundamental and long-term change in network operation, requiring sufficient resilience and operational flexibility to maintain security of supply under a range of supply and demand conditions.

10.1.6 Under normal winter operating conditions, compressor stations such as Hatton, Peterborough and Huntingdon are routinely used to transport gas from northern and eastern supply sources to demand centres further south. If one of these compressor stations becomes unavailable, either through planned maintenance or an unplanned outage, alternative compressor stations can be brought into service to maintain network capability, albeit less efficiently. [redacted] enabling required network capability to be maintained until the primary asset is returned to service.

10.1.7 The same resilience principle should also be applied to northbound transportation capability. While the network may be capable of meeting demand under normal operating conditions, resilience requires sufficient capability to be maintained under a range of credible supply and asset outage conditions.

10.1.8 Historic operational experience demonstrates that unplanned compressor outages are a credible operational risk. Bishop Auckland Unit A experienced unplanned outages of 297 hours in September 2025, while Nether Kellet Unit A experienced an unplanned outage of 144 hours in May 2026. Although infrequent, these events demonstrate that compressor unit failures can occur and should be considered when assessing resilience requirements. If such outages were to occur during a period of high winter demand, [redacted] Reconfiguring only one site would leave the network exposed to this risk.

10.1.9 [redacted]

10.1.10 Future gas supply patterns are expected to become increasingly variable and are outside our control. On days when East Coast supplies are relatively high, Bishop Auckland would typically provide the most effective compression capability to transport gas into Scotland. In contrast, during periods of higher West Coast supplies, Nether Kellet would generally provide the preferred operating configuration. The availability of both sites therefore provides the operational flexibility required to respond efficiently to changing system conditions.

10.1.11 Consequently, reversal of both Nether Kellet and Bishop Auckland compressor stations, with replacement of the associated suction and discharge valves at Carnforth, is the preferred strategic solution. Delivering both projects provides the resilience, flexibility and network capability required to support future south-to-north gas transportation, ensuring security of supply for Scotland and the North of England.

10.1.12 Delivering both reversals provides resilience, operational flexibility and access to multiple supply sources, enabling the NTS to respond efficiently to changing supply patterns while maintaining security of supply. By reducing the risk of customer interruptions, emergency operational actions and future reinforcement requirements, the dual-site solution delivers the greatest long-term value for UK gas consumers.

10.2 Feasibility Assessment

10.2.1 To support development of the preferred option, we engaged Premtech to undertake a high-level engineering assessment of the proposed Nether Kellet and Bishop Auckland reconfigurations and the asset health work. We commissioned the studies included in Bishop Auckland Engineering Report (Appendix E) and Nether Kellet Engineering Report (Appendix F) to validate the technical feasibility of the option and provide an engineering basis for the Final Option Selection Report.

10.2.2 [redacted] developed a conceptual design for the Carnforth/Nether Kellet Multi Junction and Bishop Auckland modifications, including proposed valve arrangements, pressure equalisation systems and associated civil, electrical and control requirements. The assessment considered constructability, outage requirements and integration with existing assets.

10.2.3 The proposed engineering arrangements demonstrate that the reconfigurations are achievable and can deliver the required reverse flow capability using established engineering solutions. Whilst further design development will be required during subsequent project phases, the study provides confidence that the preferred option is technically viable and deliverable.

10.3 Delivery Strategy and Programme Assumptions

10.3.1 The construction strategy will seek to maximise enabling, fabrication, testing and other activities that can be completed while the network remains operational, limiting outage-dependent works to intrusive tie-ins, isolation-dependent modifications, testing and commissioning. Construction and commissioning programmes will be developed around phased isolation strategies that maintain the required network capability throughout delivery and will be refined through continued engagement with Outage Planning team, Operations and the design team.

10.3.2 Indicative delivery programmes have been developed based on [redacted] engineering assessment, the maturity of the preferred configuration, anticipated engineering and procurement activities, and the requirement to deliver the intervention ahead of the forecast network constraint. Subject to the relevant regulatory and investment approvals, the project will progress through FEED, detailed design and procurement. Further engineering development activities are summarised Appendix F: Nether Kellet Engineering Report and Appendix E: Bishop Auckland Engineering Report.

10.3.3 Early engagement with the outage planning function has confirmed that the requirement to maintain network capability during implementation will be a key consideration in developing the final delivery strategy and programme. We will continue to work closely with Operations, the outage planning function and the design team to optimise outage requirements and delivery sequencing as the design matures.

10.3.4 Delivery dates presented within this chapter represent preferred implementation windows based on current engineering, construction and outage planning assumptions. These programmes will continue to be refined through subsequent project phases as the delivery strategy and network access requirements mature.

10.3.5 [redacted] we are actively investigating opportunities to bring forward delivery of the proposed works. This could include bundling the project with other planned interventions and deferring lower-priority activities where appropriate.

10.4 Bishop Auckland Reconfiguration

10.4.1 Bishop Auckland Compressor Station is a key NTS asset located in County Durham and forms the interface between Feeders 7, 12 and 13. The proposed reconfiguration is located within the station's multi-junction area, where the feeder and compressor station pipework connect, rather than within the compressor units themselves. Figure 11 shows the location of the proposed works within the wider Bishop Auckland Compressor Station and highlights the area that will be modified to support future south-to-north transportation capability.



10.4.2 Figure 12 illustrates [redacted] proposed conceptual reconfiguration arrangement for the Bishop Auckland Multi Junction. The design introduces six new remotely operated ball valves, comprising a combination of 1050mm, 900mm and 750mm Nominal Bore (NB) valves together with associated cross-connection pipework, pressure equalisation facilities and a temporary pigging provision. This arrangement enables the existing feeder connections and compressor station interfaces to be reconfigured, allowing gas flow paths to be altered and facilitating future operational flexibility across the interconnected feeder network without requiring fundamental modifications to the existing station infrastructure.



10.4.3 The proposed arrangement incorporates new connections between Feeders 7, 12 and 13, together with tie-ins to the existing infrastructure. The configuration includes approximately 230m of new above and below ground pipework ranging from 50mm to 1050mm nominal bore, six new isolation valves, associated actuators, pressure equalisation pipework and a dedicated electrical instrumentation to support valve operation and control.

10.4.4 The layout has been developed to suit the constraints of the existing Bishop Auckland installation, taking account of the existing pipework corridors, roadways, structures, buried services and available working areas. [redacted] assessment considered constructability, access and egress requirements, excavation works, pigging operations, lifting activities, civil modifications and system outage constraints. The assessment concluded that the proposed reconfiguration can be accommodated within the existing site boundary whilst maintaining safe operational and maintenance access to existing and new assets. The conceptual design therefore demonstrates a practical and deliverable solution for enhancing network flexibility and accommodating future operational requirements at Bishop Auckland.

10.5 Bishop Auckland Delivery Programme

10.5.1 Early engagement with Outage Planning team identified that feeder interfaces and the requirement to maintain transmission capability throughout construction will significantly influence outage planning and implementation sequencing. On this basis, delivery during [redacted] may be feasible, however, considering the re-wheel requirement it is more likely to stretch into [redacted]

10.5.2 We expect to undertake a wider programme of work at Bishop Auckland over the RIIO-GT3 timeframe. During FEED, we will assess project interfaces, delivery requirements and site constraints to determine the most appropriate implementation strategy. We will use this assessment to optimise the delivery programme where practicable whilst supporting timely delivery of the Northern Reconfiguration project.

10.5.3 Table 14 summarises the anticipated principal programme milestones assuming delivery will be feasible in [redacted]

Milestone	Indicative Timing (FY)	Delivery Basis / Key Activity
FOSR / UM Submission	October 2026	Submission of preferred option and supporting investment case
FOSR Decision	March 2027	Funding / Governance decision to progress the preferred option into project development
FEED, Surveys and Isolation Strategy Development	[redacted]	[redacted]
Cost Submission Development	October 2027- April 2028	Development of the regulatory cost submission using FEED outputs, updated estimate, risk and delivery strategy
Cost Submission	April 2028	Regulatory cost submission to Ofgem
Detailed Design, Procurement and Construction Readiness	[redacted]	[redacted]
Bishop Auckland Outage-Dependent Implementation	[redacted]	[redacted]
Testing, Commissioning and Operational Acceptance	[redacted]	[redacted]
Programme Contingency	[redacted]	[redacted]

Table 14: Bishop Auckland Indicative Programme

10.6 Bishop Auckland Cost Estimate

10.6.1 Table 15 shows a breakdown of the Total Installed Cost for Bishop Auckland.

Item	Description	% of Total Installed Cost
Engineering Design	Detail costs for studies/FEED/Detailed design as appropriate.	[redacted]
Project management	Element of project costs attributed to project management, not direct or indirect company costs.	[redacted]
Materials	Bulk materials, breakdown preferred	[redacted]
Main Works Contractor	Project construction contractor costs.	[redacted]
Specialist Services	Costs for any additional services used to support the project i.e. surveys, data procurement etc.	[redacted]
Vendor Package costs	Costs of packages purchased for project	[redacted]
Direct Company Costs	Refer to Regulatory Instructions and Guidance for definition of direct company costs.	[redacted]
Indirect Company Costs	Refer to Regulatory Instructions and Guidance for definition of indirect company costs.	[redacted]
Contingency	Contingency included in base cost estimate	[redacted]
Total Installed Cost	Forecast total project cost including contingency. Sum of all elements noted above.	[redacted]

Cost Estimate Accuracy	This is an important element to give confidence that the engineering is mature and the costs can be relied upon.	[redacted]

Table 15: Bishop Auckland Cost Estimate Breakdown

10.7 Nether Kellet Reconfiguration - Carnforth Multi Junction

10.7.1 Carnforth Compressor Station and Nether Kellet Compressor Station are adjacent NTS assets located within the same operational area. Carnforth Compressor Station forms the interface between Feeders 15 and 21 and the adjacent Nether Kellet Compressor Station, with the proposed reconfiguration located within the Carnforth Multi Junction that connects the two sites. Figure 13 illustrates the physical relationship between the Carnforth Multi Junction and Nether Kellet Compressor Station. Throughout this report, the project is referred to as the Nether Kellet reconfiguration, although the physical modifications are undertaken within the Carnforth Multi Junction.



10.7.2 Figure 14: Isometric view of proposed reconfiguration at Nether Kellet (Appendix F Figure 4) and illustrates proposed conceptual reconfiguration arrangement for the Carnforth/Nether Kellet Multi Junction. The design introduces four new 1050mm NB remotely operated ball valves (Valves A-D) together with associated pressure equalisation pipework, enabling the existing suction and discharge streams to be switched and allowing gas flow to be reversed without fundamental changes to compressor station operation. Under normal operation, one pair of valves remains open while the alternative pair remains closed, with the arrangement designed to facilitate both north-to-south and south-to-north gas transportation.



10.7.3 The proposed layout has been developed around the constraints of the existing station infrastructure and available workspace. [redacted] assessment considered constructability, access, excavation requirements, lifting operations and outage constraints, concluding that the arrangement can be accommodated within the existing site while maintaining operational and maintenance access. The conceptual design demonstrates a practical and achievable solution for providing the required reverse-flow capability at Nether Kellet.

10.8 Carnforth Compressor Station Suction and Discharge Valves

10.8.1 During RIIO-T2, we identified a requirement to replace elements of the Carnforth Compressor Station Suction and Discharge valve arrangements, with only a limited element of the scope retained within the RIIO-GT3 asset health plan due to investment prioritisation decisions. Subsequently we considered the replacement of the station suction and discharge arrangements, associated valves and insulation joints as a part of this proposal.

10.8.2 Figure 15 shows the location of the reconfiguration proposal with the proposed layout as the red line and the suction and discharge valves for this option on the right.



10.8.3 During the RIIO-GT3 Business Plan option development process, a review of historical valve condition assessments identified four critical valves within the Carnforth Compressor Station suction and discharge arrangements. The review confirmed that valves [redacted] are passing at the rates shown in Table 16.

Valve	Direction	Passing	Isolation
[redacted]	Suction	[redacted]	
[redacted]	Suction	[redacted]	[redacted]
[redacted]	Discharge	[redacted]	
[redacted]	Discharge	[redacted]	[redacted]

Table 16: Suction and Discharge Valve Conditions

10.8.4 [redacted] isolation valves on the suction and discharge pipework associated with Carnforth Compressor Station. Current condition assessments indicate that both valves are passing [redacted]

10.8.5 Where a valve is unable to achieve an effective seal, gas may continue to pass across the closed valve, preventing the intended isolation boundary from being achieved. In these circumstances, additional upstream and downstream valves may be required to isolate a larger section of the multi-junction, increasing operational constraints and reducing network flexibility.

10.8.6 Following implementation of the Northern Reconfiguration project, the Carnforth/Nether Kellet route will become increasingly important in supporting northbound transportation capability. Replacement of [redacted] therefore reduces the risk that future maintenance activities, fault conditions or emergency shutdown events could affect availability of this strategic transportation route.

10.8.7 The identified valve condition provides an asset health driver for intervention at Carnforth Multi Junction. While only one individual valve replacement [redacted] was retained for intervention within the RIIO-GT3 asset health plan, the proposed Northern Reconfiguration project makes it necessary to address the wider identified valve condition issues as part of a coordinated intervention.

10.8.8 This alignment is particularly relevant because the reconfiguration works and the asset health scope affect the same area of the station and require many of the same enabling and construction activities. Both scopes would require a station outage, site establishment and welfare facilities, temporary works, excavations, buried services investigations, lifting operations and subsequent testing and commissioning.

10.8.9 Coordinating the asset health scope with the proposed reconfiguration therefore provides an opportunity to deliver material cost and delivery efficiencies. It would also reduce the need for separate future interventions at the site and the associated operational disruption.

10.8.10 This approach would maximise the value of the planned intervention, reduce whole-life delivery costs and provide a clear consumer benefit compared with progressing the scopes independently. We estimate that a coordinated delivery approach could [redacted] This should be considered a broad planning assumption, as validation would require separate and combined contractor quotations which we have not obtained at this stage.

10.9 Suction and Discharge Valves - Optioneering and Cost

10.9.1 During development of the Suction and Discharge asset health pre-feasibility, we considered a range of options each delivering an increasing level of asset intervention. Table 17 shows the list of options considered and their ability to resolve the risk.

Options	Intervention	Scope of work	Engineering Assessment Outcome	Total Unit Cost
Option 1	Do Nothing	N/A	Does not address identified Asset Health risks	[redacted]
Option 2	Lite refurbishment	Painting, NRV overhauls and minor remediation	Does not address [redacted]	[redacted]
Option 3	Selective Replacement	Replacement of valves [redacted] plus associated pit wall transition remediation	Targeted intervention addressing [redacted]	[redacted]
Option 4	Full Replacement	Full station pit replacement excluding insulation joints (IJ's)	Full isolation and addresses additional defects. Replaces all valves and brings pit above ground.	[redacted]
Option 5	Full Replacement with IJ's	Full station pit replacement including (IJ's)	Full isolation and addresses additional defects. Replaces all valves and brings pit above ground as well as addresses insulation joints.	[redacted]

Table 17: List of Suction and Discharge valve Asset Health Options

10.9.2 We have considered Option 1, Do Nothing. Under this option, [redacted]

10.9.3 Option 2 includes NRV overhauls and minor refurbishment works [redacted]

10.9.4 Option 3 comprises replacement of the two main passing suction and discharge valves [redacted] (volume agreed in the baseline RIIO-GT3 business plan) and [redacted] with associated supporting infrastructure identified through the asset health assessment. [redacted]

10.9.5 This option retains the existing pit structure and other station valves. As a result, there remains a risk that additional asset health intervention may be required on the retained assets in future regulatory periods.

10.9.6 Option 4 and 5 includes replacement of the complete valve pit arrangement, including all station valves, associated pipe supports and pit infrastructure with the exclusion of insulation joints in option 4. In addition to addressing the identified valve defects, this option would remove the existing below-ground valve pit and replace ageing infrastructure with modern above-ground installations.

10.9.7 This would address the valve defects and brings all station valves to the same condition and above ground. This aligns with our wider asset health approach described in NGT_EJP023_Valves: Valves_RIIO-GT3, which identifies valve pits as presenting maintainability and access challenges and supports pit breakout and installation of replacement assets above ground where practicable.

10.9.8 Appendix I: Suction and Discharge Valves Cost Estimate, includes a table summarising the scope and estimated costs of key options. The costs have been developed using RIIO-GT3 Business Plan Unit costs and should be considered indicative at this stage of project development.

10.9.9 [redacted] It represents the minimum intervention required to address the identified defects whilst avoiding replacement of assets that do not prevent isolation.

10.9.10 The estimated cost of Option 3 is [redacted] for full replacement. With one valve volume agreed as a part of the Business Plan, the total funding request is [redacted]

10.9.11 Costs are based on InvID unit rates from the RIIO-GT3 Business Plan and will be refined through subsequent design development and FEED activities. As these rates have not been tailored to the specific project requirements, the current estimate may be subject to material change as the design matures and the consequences of reconfiguration on the suction and discharge valve arrangement is fully developed.

10.10 Nether Kellet Delivery Programme

10.10.1 Early engagement with the outage planning function has identified several operational constraints that will influence the final construction strategy. For the purpose of this assessment, we have assumed that delivery at Carnforth and Nether Kellet can be undertaken within similar timeframes. In practice, however, at least one of the two stations would need to remain available to maintain north-south transmission capability throughout delivery. We are actively developing the outage and delivery strategy to determine the feasibility and sequencing of the works, including whether one station should be progressed ahead of the other to enable mitigation of the identified resilience risk at the earliest practicable opportunity.

10.10.2 Table 18 included the principal programme milestones.

Milestone	Indicative Timing	Delivery Basis / Key Activity
FOSR / UM Submission	October 2026	Submission of preferred option and supporting investment case
FOSR Decision	March 2027	Funding / Governance decision to progress the preferred option into project development
FEED, Surveys and Isolation Strategy Development	[redacted]	[redacted]
Cost Submission Development	October 2027- April 2028	Development of the regulatory cost submission using FEED outputs, updated estimate, risk and delivery strategy
Cost Submission	April 2028	Regulatory cost submission to Ofgem
Detailed Design, Procurement and Construction Readiness	[redacted]	[redacted]
Nether Kellet Outage-Dependent Implementation	[redacted]	[redacted]
Testing, Commissioning and Operational Acceptance	[redacted]	[redacted]
Programme Contingency	[redacted]	[redacted]

Table 18: Nether Kellet Indicative Programme

10.11 Nether Kellet Cost Estimate

Table 19 shows a breakdown of the Total Installed Cost for Bishop Auckland.

Item	Description	% of Total Installed Cost
Engineering Design	Detail costs for studies/FEED/Detailed design as appropriate.	[redacted]
Project management	Element of project costs attributed to project management, not direct or indirect company costs.	[redacted]
Materials	Bulk materials, breakdown preferred	[redacted]
Main Works Contractor	Project construction contractor costs.	[redacted]

Specialist Services	Costs for any additional services used to support the project i.e. surveys, data procurement etc.	[redacted]
Vendor Package costs	Costs of packages purchased for project	[redacted]
Direct Company Costs	Refer to Regulatory Instructions and Guidance for definition of direct company costs.	[redacted]
Indirect Company Costs	Refer to Regulatory Instructions and Guidance for definition of indirect company costs.	[redacted]
Contingency	Contingency included in base cost estimate	[redacted]
Total Installed Cost	Forecast total project cost including contingency. Sum of all elements noted above.	[redacted]
Cost Estimate Accuracy	This is an important element to give confidence that the engineering is mature and the costs can be relied upon.	[redacted]

Table 19: Total Installed Cost Estimate for Bishop Auckland

10.12 Project Spend Profile

10.12.1 We have determined approximate spend profile for the preferred option. Table 20 breaks down the spend into financial years.

Scope	FY27	FY28	FY29	FY30[20]	FY31	Total
Nether Kellet Site Reconfiguration	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Nether Kellet Valves Asset Health	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Bishop Auckland Site Reconfiguration	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Total Installed Cost Estimate	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

Table 20: Project Spend Profile

10.13 Key Business Risks and Opportunities

10.13.1 We undertook high-level risk identification and assessment during concept development for the preferred reconfiguration option at Bishop Auckland and Nether Kellet. We held facilitated risk workshops with key stakeholders and subject matter experts from the North, East and West regions, with representation across asset and pipeline engineering, project delivery, operations, integrity and network analysis disciplines. This multidisciplinary approach was used to identify and assess the principal risks and uncertainties associated with delivery of the preferred option.

10.13.2 We assessed risks on a pre-mitigation basis, reflecting the inherent level of exposure before consideration of planned mitigation or additional controls. The assessment considered the key risk drivers and areas of uncertainty associated with the developing scope, including design maturity, technical and constructability complexity, asset condition, operational and outage requirements, and delivery interfaces, together with their potential impact on project cost and programme.

10.13.3 Given the maturity of the project, we assessed risks qualitatively using the 5x5 risk matrix. Likelihood and impact were each scored on a scale of 1 to 5, with the resulting scores used to determine an overall risk rating of High, Medium or Low. The assessment provides a point-in-time view of the risk profile based on the information and assumptions available at concept stage and will require further development as the scope and design mature. Further detail on the risk assessment methodology and the supporting risk registers is provided in Appendix G- Nether Kellet Risk Register and Appendix H- Bishop Auckland Risk Register.

10.13.4 The resulting risk profile comprises project-wide risks and dependencies, together with site-specific risks reflecting the technical, operational and constructability conditions and constraints at Bishop Auckland and Nether Kellet. At the current stage of development, the principal risk areas relate to outage availability and coordination, project commencement, specialist resource availability, constructability and interfaces with other planned works. These risks have the potential to affect cost, programme, operational requirements and overall delivery confidence.

[20] It is unlikely we will be able to deliver the reconfigurations at both sites simultaneously, but our cost assumptions assume so

[21] Valve Asset Health works cost is derived from the RIIO-GT3 unit cost. If Ofgem approved option including Asset Health, further design studies will determine detailed scope of work, including feasibility of delivery in the same outage as Nether Kellet reconfiguration.

10.14 Key Programme Risks

10.14.1 Table 21 summarises common risks for both projects.

Risk Title	Risk Description	Risk Score	Risk Level
Network Outage Scheduling and Coordination and Interface with Other Projects	Availability of network outages and access windows required to undertake phased construction, tie-ins and commissioning activities. Interface and dependency risks associated with other National Gas projects competing for outage windows, operational support and delivery resources.	[redacted]	[redacted]
Delay in Project Start	Prolonged waiting period for regulatory approval and funding results in project costs escalating, business proceeding at risk and inability to secure 2031 network outage.	[redacted]	
Inadequate Design Buildability and Asset Constructability	Detailed engineering design fails to fully account for practical site constraints, geotechnical conditions, spatial congestion, specialised material tolerances, or sequential installation requirements.	[redacted]	

Table 21: Common Option Risks

10.14.2 We have identified significant risks impacting both sites which could leading to cost increases and schedule delays. Network outage availability is a critical hazard because shutting down a compressor station or restricting sections of a live high-pressure pipeline to tie in new assets (valves and actuator) threatens overall resiliency of the network and security of supply from south-to-north and may trigger regulatory penalties, financial and safety liabilities.

10.14.3 The risk will be mitigated through early planning of works during lower-demand summer periods, close coordination with operational requirements and, where practicable, alignment with outages planned for other projects to minimise additional network disruption.

10.14.4 At this early stage of project development, design and scope uncertainty remains a key project risk, with potential implications for cost and programme. This includes potential scope growth associated with asset health works, such as valve system replacement, and the risk that further stress analysis could require redesign or deviations from existing policy. These uncertainties are expected to reduce as design assumptions are validated, data quality improves and the scope is further defined through detailed design.

10.15 Bishop Auckland Reconfiguration Risks

10.15.1 Table 22 summarises the key risks identified for the Bishop Auckland reconfiguration project.

Risk Title	Risk Description	Risk Score	Risk Level
Inadequate Design Buildability and Asset Constructability	Various buildability issues and layout constraints known for working area of existing installation. Removal and ground support required for ~60-80m retaining wall, elevated to 2.5m, near critical valve 55.	[redacted]	[redacted]
Site Establishment	Sharing of a small welfare and laydown area with other projects poses significant operational challenges (congestion), safety hazards and logistical friction.	[redacted]	
Interface with Other Projects	Known risk of conflict or adverse interface issues with other projects including Hatton Compressor Station Replacement Programme and Feeder 7 and 13 In-line Inspections, competing for outage windows, operational support and delivery resources.	[redacted]	

Table 22: Bishop Auckland Site-Specific Risks

10.15.2 Constructability represents a key site-specific risk at Bishop Auckland, driven by the constrained site layout, complexity of the existing multi-junction arrangement and proximity of the proposed works to operational high-pressure assets. The proposed works, including removal of the existing retaining wall, introduce significant structural, geotechnical and construction challenges, with potential for ground or slope instability, temporary works complexity and inadvertent damage to existing pipeline and valve infrastructure during construction. Particular consideration will be required to manage potential instability associated with retaining wall removal and to protect adjacent valve and pipeline assets during construction activities.

10.15.3 Should these risks occur, they could affect the integrity of existing high-pressure assets, resulting in impacts on cost, programme, safety and security of supply. We will further assess and refined the constructability risk as the design, construction methodology and temporary works requirements are developed.

10.15.4 Risk reduction will focus on the development and validation of the construction methodology, including temporary works, ground stability, asset protection and construction sequencing. Delivery is expected to require a phased construction approach coordinated with outage requirements and other planned works to maintain network capability throughout implementation.

10.15.5 Site establishment and logistics represents a further key site-specific risk at Bishop Auckland, driven by the limited space available for welfare, laydown and construction activities and the potential requirement to share these areas with other projects. Competing demands for available space and access could result in congestion and logistical constraints, with potential impacts on construction productivity, programme and the safe delivery of the works.

10.15.6 Risk reduction will focus on early development and coordination of the site establishment and logistics strategy, including confirmation of laydown, welfare and access requirements and alignment with other projects operating within or adjacent to the site. These requirements will be further developed as the construction methodology and delivery programme mature.

10.16 Nether Kellet Reconfiguration Risks

10.16.1 Table 23 summarises the key risks identified for the Nether Kellet reconfiguration project.

Risk Title	Risk Description	Risk Score	Risk Level
Sequential Outage Constraint	Reconfiguration at Nether Kellet is critically dependent on the access and outage schedule of Carnforth AGI; it cannot proceed independently.	[redacted]	[redacted]
Interface with Other Projects	Known risk of conflicts or interface issues arising from concurrent projects, including the Control System Replacement works and other emerging interventions, creating competing demands for outage windows, operational support, and delivery resources.	[redacted]	
Valve Asset Health Work	At Carnforth Multi-Junction Required Asset Health work may impact reconfiguration outages and programme sequences	[redacted]	

Table 23: Nether Kellet Site-Specific Risks

10.16.2 Outage availability and sequencing represent a key site-specific delivery risk at Nether Kellet. Delivery of the reconfiguration requires access to suitably timed and sequenced network outages, including coordination with the Carnforth AGI outage programme. With potential delivery in [redacted] dependency on the Carnforth outage schedule remains a significant constraint. A concurrent outage affecting both Feeder 15 and Feeder 21 could place network capability at risk, as isolation of the North West transmission corridor would restrict the movement of gas from northern supply terminals towards major southern and western demand centres. If the required outage windows cannot be secured or sequenced as planned, construction, tie-in and commissioning activities may be delayed or require changes to the delivery strategy, with potential impacts on programme and security of supply.

10.16.3 Interfaces with other planned projects represent a further key site-specific delivery risk at Nether Kellet. The Control System Replacement projects at Carnforth and Nether Kellet, together with other emerging interventions, may create competing requirements for outage windows, operational support and delivery resources. Changes to the timing, scope or delivery requirements of these projects could affect the planned sequencing of the Nether Kellet works, with potential impacts on cost and programme.

10.16.4 Risk reduction will focus on early and ongoing coordination with interfacing projects to understand their respective delivery requirements, key milestones and resource and outage demand. Interfaces will require active management as the respective programmes develop to identify potential conflicts and enable coordinated planning of outage, operational and delivery requirements.

10.17 Key Opportunities and Benefits

10.17.1 The risk assessment also identified a number of potential opportunities associated with delivery of the preferred option. These principally relate to coordinated delivery, alignment with other planned network interventions, optimisation of outage and procurement requirements, and potential longer-term operational and whole-life benefits.

10.17.2 We have identified a number of opportunities at the concept stage that require further development and validation. We will undertake additional assessment to confirm their feasibility, potential value, dependencies, and any associated risks or trade-offs before considering the benefits achievable. We will develop and manage these opportunities alongside the project risk profile as the design and delivery strategy mature, assigning clear ownership and actions to support their evaluation and, where appropriate, realisation.

10.17.3 Table 24 summarises the key opportunities and benefits of the reconfigurations.

Opportunity	Benefit
Coordinated delivery of the Bishop Auckland and Nether Kellet reconfigurations.	Potential programme efficiencies through coordinated delivery and procurement.
Alignment with other planned and emerging network interventions and investment projects: Control System Replacement works; Inline inspection dig programmes and filter inspection works.	Potential to reduce mobilisation requirements, optimise outage utilisation and improve overall delivery efficiency.
Improved operational flexibility through access to both east coast and west coast gas supply sources	Potential to enhance operational flexibility and network resilience under changing future supply scenarios.
Delivery of both reversals as a single strategic solution	Potential to reduce reliance on individual flow paths and enhance overall network resilience.
Integration with future asset health interventions.	Potential to reduce future intervention and outage requirements and deliver whole-life cost efficiencies.

Table 24: Key Opportunities

10.18 Efficient cost

10.18.1 We will adopt a procurement strategy that supports the safe, efficient and economic delivery of the Northern Reconfiguration project. The strategy will build upon lessons learned from previous project.

10.18.2 We will also consider addressing issues experienced on previous projects, such as high vibration and noise levels associated with compressor and pipework installations. The procurement approach will therefore ensure that specialist engineering capability, including pipework pulsation modelling and vibration analysis, is engaged at the appropriate stages to identify and mitigate potential risks early in the design process.

10.18.3 We will refine the strategy as the project progresses through FEED and detailed design stages, enabling the delivery of the required capability and resilience outcomes while securing best value for consumers.

10.18.4 The preferred option comprises the reconfiguration of existing infrastructure at Bishop Auckland and Nether Kellet Compressor sites plus Valve Asset Health. As both interventions are brownfield modifications to operational assets, we will undertake early contractor and supplier engagement to inform delivery strategy, validate assumptions and improve cost certainty before construction activities commence.

10.18.5 We will assess the most appropriate route to market for the engineering, procurement and construction activities. Where appropriate, our existing frameworks and competitively tendered agreements will be utilised to reduce procurement timescales, leverage established supplier relationships and ensure costs remain competitive.

10.18.6 We will procure long lead items, including specialist valves, actuators and associated electrical and control equipment using established procurement processes where applicable. We will assess whether direct procurement and free issue of critical equipment offers greater value than inclusion within a main contractor scope. This assessment will consider cost, programme, quality assurance and risk allocation to ensure the most efficient overall outcome.

10.18.7 We will use competition wherever practical to support efficient cost delivery. Our tender evaluation will consider not only cost, but also technical capability, relevant experience, programme certainty, safety performance and ability to deliver within the operational constraints of the NTS. This approach will help ensure that the selected suppliers provide an optimal balance between cost, quality and delivery confidence.

10.18.8 Throughout project development, we will continue to review opportunities to coordinate the reconfiguration works with other planned asset health, such as the preferred option for the Carnforth suction and discharge valves. Aligning outages, site mobilisation and other construction activities has the potential to reduce overall project costs, minimise disruption to network operations and deliver additional value for consumers.

11 Conclusion

11.1.1 This FOSR identifies a network [redacted] in Scotland and the North of England. [redacted] At the same time, declining gas supplies and evolving supply and demand patterns are increasing the requirement for gas to be transported northwards from alternative supply sources to meet future demand. Together, these factors create both an immediate resilience concern and a longer-term network capability requirement.

11.1.2 Our assessment considered a wide range of infrastructure and commercial interventions and concluded that reconfiguration of both Bishop Auckland and Nether Kellet Compressor Stations, together with targeted asset health replacement of the Carnforth Multi-Junction suction and discharge isolation valves, provides the most appropriate solution. The preferred option delivers the required south-to-north transportation capability while also providing resilience through access to both east coast and west coast supply routes and reducing dependence on a single compression location.

11.1.3 The asset health intervention forms an integral part of the preferred option. Replacing the passing isolation valves improves the long-term availability of the Carnforth/Nether Kellet route, reduces future operational constraints and enables delivery efficiencies through coordinated construction and outage activities. The combined solution therefore provides a more robust and enduring outcome for consumers than delivering the scopes separately.

11.1.4 The preferred option provides a materially higher level of resilience than a single-site solution. As a result, it increases network availability and provides greater flexibility to respond to changing network conditions and supply disruptions while supporting continued compliance with our licence obligations.

11.1.5 Whilst the Cost Benefit Analysis provides an important measure of consumer value, it does not capture the resilience benefits associated with maintaining security of supply during supply disruption and compressor outage scenarios. As resilience is the primary driver for this investment, we selected the preferred option not only on the basis of its economic performance, but also its ability to provide geographically diverse northbound transportation capability, reducing reliance on any single compression location and strengthening overall network resilience.

11.1.6 The preferred option avoids the significantly higher costs and delivery timescales associated with new-build alternatives and provides the best balance of capability, resilience, deliverability and consumer value. Importantly, [redacted] We are continuing to explore opportunities to accelerate delivery where practicable, reducing the period over which the network remains exposed while ensuring sufficient capability is available as future supply patterns evolve.

11.1.7 We invite Ofgem to assess the preferred option presented in this FOSR and welcome continued engagement as we progress the project through the next stages of development.

11.1.8 Following Ofgem's assessment of this submission, we intend to develop the preferred option further and submit a funding application through the applicable Network Capability Re-opener window. An early decision from Ofgem would support efficient project development [redacted] at St Fergus.

12 Appendix

Appendix A: [redacted]
Appendix B: Nether Kellet Cost Estimate
Appendix C: Bishop Auckland Cost Estimate
Appendix D: Cost Benefit Analysis
Appendix E: Bishop Auckland Engineering Report_Redacted
Appendix F: Nether Kellet Engineering Report_Redacted
Appendix G: Nether Kellet Risk Register
Appendix H: Bishop Auckland Risk Register
Appendix I: Suction and Discharge Valves Cost Estimate
Appendix J: NGT Northern Reconfiguration Mapping to Ofgem Requirements
Appendix K: Assurance Letter

13 Glossary

Glossary	
AGI	**Above Ground Installation**: Above ground gas assets (including, but not limited to; pipework, valves, pig traps, meters and regulators) located within a fence line for the safe operation and maintenance of the National Transmission System.
AH	Asset Health
ASEP	Aggregate System Entry Point
CAPEX	Capital Expenditure
CBA	**Cost Benefit Analysis:** A mathematical decision support tool to quantify the relative benefits of each site option.
CCUS	Carbon Capture, Utilisation and Storage
CEPOt	Funding request category within licence mechanism
CEPREt	Compressor Emissions Re-opener term
CEPt	Price Control Deliverable term (licence term used in the document)
DESNZ	Department for Energy Security and Net Zero
EAC	**Estimate at Completion** The total cost of the project at completion.
EJP	Engineering Justification Paper
FEASIBILITY	**Front End Engineering Design:** The FEASIBILITY is basic engineering which comes before the Detailed Engineering stage. The FEASIBILITY design process focusses on the technical requirements as well as an approximate budget investment cost for the project.
FEED	Front End Engineering Design
FES	**Future Energy Scenarios:** An annual industry-wide consultation process encompassing questionnaires, workshops, meetings and seminars to seek Feasibility back on latest scenarios and shape future scenario work. The Future Energy Scenarios document is produced annually by National Grid ESO and contains their latest scenarios.
[redacted]	[redacted]
[redacted]	[redacted]
FOSR	Final Option Selection Report
GDN	Gas Distribution Network
IPA	Infrastructure and Projects Authority
LCPD	**Large Combustion Plant Directive:** An EU directive to reduce emissions from combustion plants with a thermal output of 50 MW or more. Combustion plant must meet the emission limit values (ELVs) given in the LCP directive for NOx, CO, SO2, and particles
LNG	Liquified Natural Gas, Natural gas that has been cooled to a liquid state (around -162°C) and either stored and/or transported in this liquid form.
MCPD	**Medium Combustion Plant Directive**: A directive to reduce emissions from combustion plants with a net thermal input between 1-50 MW.

Glossary	
NESO	National Energy System Operator
NGL	Natural Gas Liquids
NGT	National Gas Transmission
[redacted]	[redacted]
NTS	**National Transmission System:** The high-pressure system consisting of Terminals, compressor stations, pipeline systems and offtakes. Designed to operate at pressures up to 94 barg. NTS pipelines transport gas from Terminals to NTS offtakes.
OEM	Original Equipment Manufacturer
Ofgem	**Office of Gas and Electricity Markets:** The regulatory agency responsible for regulating Great Britain's gas and electricity markets.
PCD	Price Control Deliverable
Re-opener	Re-openers are a type of RIIO uncertainty mechanism. Depending on their design, they allow Ofgem to adjust a licensee's allowances (in some cases up and in some cases down), outputs and delivery dates in response to changing circumstances during the price control period.
RIIO	**Revenue = Incentives + Innovation + Outputs**: RIIO-T2 is the second transmission price control review to reflect the framework; it sets out what the transmission network companies are expected to deliver and details of the regulatory framework that supports both effective and efficient delivery for energy consumers.
RRP	**Regulatory Reporting Pack**: Annual submission to Ofgem on 31 July as per RIIO-T2 reporting requirements Standard Special Condition A40: Regulatory Instructions and Guidance
[redacted]	[redacted]
SEPA	**Scottish Environment Protection Agency** Scotland's environment regulator and flood warning authority
NTS	**National Transmission System:** The high-pressure system consisting of Terminals, compressor stations, pipeline systems and offtakes. Designed to operate at pressures up to 94 barg. NTS pipelines transport gas from Terminals to NTS offtakes.
Uncertainty Mechanism	Uncertainty mechanisms exist to allow price control arrangements to respond to change. They protect both end consumers and licensees from unforecastable risk or changes in circumstances.
UKCS	**United Kingdom Continental Shelf:** The UK Continental Shelf (UKCS) is the region of waters surrounding the United Kingdom, in which the country has mineral rights. The UK continental shelf includes parts of the North Sea, the North Atlantic, the Irish Sea and the English Channel; the area includes large resources of oil and gas.
RDP	Regional Delivery Process
MW	Megawatt
mcm	Million cubic metres
mcm/d	Million cubic metres per day
ND500	National Gas project stage gate
WIP	Work in Progress

Glossary	
AACE	Association for the Advancement of Cost Engineering
PARCA	Planning and Advanced Reservation of Capacity Agreement
SGT-400	Siemens gas turbine model