

Impact Assessment

Impact Assessment of Arrangements to Maintain and/or Reinststate Gas Interconnector Import Capability Supported by GB Gas Consumers

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Associated Documents:	1. Consultation: Proposed modifications to National Gas Transmission plc Gas Transporter Licence, Special Conditions (System operator pass-through items) and Price Control Financial Instruments (Consumer funding for maintaining and/or reinstating gas interconnector import capability) – Published 22 October 2026 (“statutory consultation”) 2. Approval of the Import Capacity Availability Agreement under Standard Condition 3 of Interconnector Limited’s Gas Interconnector Licence – published 22 October 2026 3. Consent to allow National Gas Transmission plc (Licensee) to investigate, negotiate, enter into and perform arrangements pursuant to Standard Special Condition A36 – published 22 October 2026
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Type of IA:	Section 5

Summary

This Impact Assessment supports the Ofgem statutory consultation¹ that is published alongside this document and should be read in conjunction with it.

What is the problem under consideration? Why is Ofgem intervention necessary?

Great Britain's gas supply position is undergoing significant change. Domestic gas production from the UK Continental Shelf continues to decline, while reductions in continental European interconnector import capability have reduced the supply capability available to GB. Our analysis shows that in the vast majority of anticipated circumstances the GB gas system will continue to deliver the gas needed to meet demand. However, without intervention, GB could potentially face a negative supply margin under very rare stress conditions involving extremely high gas demand and the loss of the single largest element of GB gas infrastructure. Together, these changes are reducing GB's resilience during periods of system stress.

As set out in the statutory consultation, maintaining continental European interconnector import capability is the only currently available intervention identified that both addresses the immediate security of supply position for winter 2026/27 and provides continuing security of supply benefits over the following four winters. The proposed INT arrangement would prevent the planned further reduction in import capability but does not guarantee that gas will flow, which will continue to depend on market conditions. It also does not remove the need for further measures to support security of supply and wider gas-system resilience over the medium and longer term. This Impact Assessment assesses the impacts on GB consumers of that arrangement.

Statutory gas security of supply standard

Under the UK's gas security of supply framework, the UK Secretary of State is responsible for ensuring that the necessary measures are taken to meet the statutory infrastructure

¹ Consultation: Proposed modifications to National Gas Transmission plc Gas Transporter Licence, Special Conditions (System operator pass-through items) and Price Control Financial Instruments (Consumer funding for maintaining and/or reinstating gas interconnector import capability) – Published 22 October 2026

standard set out in UK legislation. The standard is that sufficient gas supply capability (technical capacity) is available to meet demand during a severe winter event, even in the event of the disruption of the largest single item of gas infrastructure. Known as the “1-in-20/N-1” infrastructure standard, this is designed to protect consumers by ensuring there is sufficient redundancy within the gas system during low-probability but high-impact stress events ².

What are the policy objectives?

Policy objectives are to:

- Maintain sufficient gas interconnector import capability to support GB gas security of supply during periods of peak demand and system stress.
- Improve the resilience of GB’s gas supply position and reduce the likelihood and potential severity of a gas supply shortfall.
- Ensure that appropriate infrastructure capability remains available to the market where commercial incentives alone may not deliver the level of resilience required for wider GB security of supply.
- Provide an appropriate regulatory mechanism through which National Gas (NG) can recover incurred costs associated with the bilateral arrangements.
- Deliver an intervention that addresses the immediate security of supply position for winter 2026/27 and provides continuing security of supply benefits over the following four winters, while medium and longer-term measures continue to be developed.

This Impact Assessment assesses the consumer impacts of the proposed INT arrangement. Any future arrangement with BBL is outside its scope.

What are the policy options that have been considered, including any alternatives to regulation?

Since December 2024, Ofgem has worked with DESNZ, National Gas and NESO to assess GB’s changing gas supply and demand position and identify potential mitigations. This work identified that existing measures were insufficient to fully mitigate the supply/demand risks

² <https://www.legislation.gov.uk/eur/2017/1938/contents>

presented above. Measures considered included maintaining or reinstating interconnector capability, gas network charging reform, gas-quality regulatory reform, network upgrades, gas storage, LNG import facilities and demand-side response. These interventions span the short, medium and longer term and have potential to strengthen the resilience and deliverability of the GB gas system as market and supply conditions evolve.

Of these measures, maintaining interconnector import capability was the only currently available intervention identified as capable of both materially addressing the immediate security of supply position in time for winter 2026/27 and providing continuing security of supply benefits over the following four winters. Other potential interventions continued to be considered by government alongside the interconnector work, but were not progressed for winter 2026/27. These measures remain relevant to GB's medium and longer-term security of supply needs.

Preferred option - Monetised Impacts (£m)

Net Benefit to GB Consumer	If modelled stress scenarios occur, Option 1 is estimated to avoid, compared to baseline, under the central estimate, over the assessment period, wholesale gas price costs of up to: - £396 million in the case under 1-in-20 peak demand scenario, - £5.5 billion under the scenario where GB's largest element of GB's supply infrastructure is no longer available (N-1 scenario) and, - £5.7 billion under the combined 1-in-20 and N-1 scenario. Under the combined 1-in-20/N-1 scenario, Option 1 additionally avoids: - £66 million of power station curtailment costs, - £8 million of gas supply disruption costs (Value of Lost Load) costs. The annual bill impact of the intervention to maintain INT capability is estimated at approximately £1.19 per domestic gas meter account.
Wider Benefits/Costs for Society	Wider societal impacts that arise only under the combined 1-in-20/N-1 scenario comprise reduced economic output losses, measured through GVA of around £198 million, offset by increased carbon emissions of around £74 million and air-quality damage of around £2 million.
Explain how was the Net Benefit monetised, NPV or other.	NPV and BCR are not reported because intervention expenditure is incurred if the option is implemented, whereas the estimated avoided costs arise only if the relevant, low-probability stress events occur. In the absence of sufficiently robust event probabilities, comparing the full conditional avoided costs directly with intervention expenditure would implicitly treat each stress event as certain and could overstate the economic case for intervention.

Preferred option - Hard to Monetise Impacts

Describe any hard to monetise impacts, including mid-term strategic and long-term sustainability factors following Ofgem IA guidance.

- Some potential impacts have not been monetised. These include wider effects on the electricity system, such as potentially higher balancing costs and electricity prices if gas-fired generation is constrained. Their scale would depend on the timing, severity and duration of any gas-system stress event.
- Cold-related mortality impacts have also not been quantified and are considered qualitatively in this assessment because the relationship between gas-system stress events, retail energy prices, household heating behaviour and cold-related mortality is subject to considerable uncertainty.

Key Assumptions/sensitivities/risks

- The results are conditional on the modelled stress events occurring. No event probabilities are assigned, so the analysis does not calculate an NPV or BCR.
- The low, central and high estimates reflect different event durations. The 1-in-20 event lasts 1, 5 or 6 days, while the N-1 disruption lasts 7, 180 or 365 days.
- Wholesale price impacts use an indicative historical relationship between gas demand and NBP prices. Results are sensitive to this relationship and to the assumption that additional gas can be attracted until peak supply capability is exhausted.
- Physical unmet demand arises only where demand exceeds peak supply capability. Of this shortfall, 75% is allocated to power-station curtailment and 25% to non-domestic consumers for the VoLL calculation.
- GVA estimates use an average relationship between gas availability and economic output. Actual losses may differ where businesses can adjust production, use inventories or substitute fuels, and some overlap with other disruption impacts is possible.
- Option 2 assumes, for modelling purposes, that capability is reinstated in 2030/31. Reinstatement timing and costs are uncertain, and actual costs could exceed the high-level estimate.

Will the policy be reviewed?

No separate formal review is proposed; Ofgem will monitor costs through the proposed regulatory oversight and annual reconciliation arrangements.

1. Problem under consideration

Section summary

This section describes the changes in GB gas demand and supply capability that have created the emerging security of supply risk, which necessitates the proposed licence change and an impact assessment of that change.

GB gas demand and supply

GB gas demand

1.1. Overall gas demand has generally declined in recent years. However, most winters feature at least some high gas demand days driven by particularly cold weather. While annual gas demand has declined, peak daily demand has remained broadly stable in recent years and continues to drive the level of supply capability needed for periods of system stress.

Key changes to elements of GB gas supply

1.2. UK Continental Shelf (UKCS) continues to be an important component of GB's gas supply capability. However, its maximum production rate has been in structural decline since 2000 when production from the basin peaked.

1.3. GB is connected to continental Europe through two bi-directional gas interconnectors: INT, connecting GB and Belgium, and BBL, connecting GB and The Netherlands. The import capability of both interconnectors is driven by three electrically-driven gas compressors, (with an additional backup compressor) on the European side, which are the equipment used to drive gas imports through the interconnector pipelines to GB.

1.4. Historically, these interconnectors have both imported gas to GB and exported gas to continental Europe. Following the significant reduction in Russian gas supplies to Europe from 2022, Europe became more reliant on gas exported from GB, while imports from Europe to GB reduced significantly. This has reduced the revenues available to interconnector operators from GB import capacity and weakened the commercial case for

maintaining that capability. In response to these changing market conditions, both BBL and INT reduced the level of GB import capability available to the market as further detailed in the statutory consultation. Taken together, without intervention, the reductions by INT and BBL will have removed around 60 mcm/d of GB import capability. Combined with declining UKCS production, this has materially reduced the supply capability available to GB during periods of peak demand or system stress.

1.5. We have concluded that maintaining continental European interconnector import capability is the only currently available intervention identified that both materially addresses the immediate security of supply position for winter 2026/27 and provides continuing security of supply benefits over the following four winters. Ofgem therefore provided National Gas with consent under Standard Special Condition A36 of its licence to investigate, negotiate and enter into arrangements with one or both continental European interconnector operators. National Gas will enter into an agreement with INT, which Ofgem has separately assessed and approved under Standard Licence Condition 3 of INT's Interconnector Licence. Those decisions do not themselves enable the costs of the INT agreement to be passed on to consumers. The agreement is structured so that liabilities for National Gas arise only following modifications to National Gas's licence. If we decide not to make those modifications, payments cannot be made under the INT agreement and the parties are ultimately entitled to terminate it. Neither the agreement nor the consents and approvals already given therefore prejudice our decision on the proposed licence modifications. We will consider all relevant consultation responses before reaching our final decision.

1.6. An arrangement with BBL is not currently available because constraints on BBL's access to electricity in the Netherlands limit its ability to reinstate GB import capability. The options and analysis in this Impact Assessment therefore relate only to the INT arrangement. A future arrangement with BBL would be assessed separately

1.7. Ofgem has published a statutory consultation on proposed modifications to National Gas's Gas Transporter Licence and Price Control Financial Instruments that would establish a mechanism for National Gas to recover eligible costs associated with qualifying Interconnector Capacity Availability Agreements

2. Policy objective

Section summary

Ofgem's policy objective is to strengthen GB gas security of supply by maintaining continental European interconnector import capability from winter 2026/27 and over the following four winters, while medium and longer-term measures continue to be developed. This Impact Assessment assesses the consumer impacts of the proposed INT arrangement.

Ofgem's Principal Objective

2.1. Ofgem's Principal Objective is to protect the interests of existing and future energy consumers. In carrying out this objective, Ofgem has specific statutory duties which require that it must also have regard to a number of factors, including consumer interests in security of supply.

Ofgem's Policy Objective

2.2. Ofgem's overarching policy objective is to maintain a secure and resilient GB gas system by ensuring sufficient gas supply capability remains available during periods of peak demand and system stress in line with its principal objective.

2.3. Given the timing and nature of the emerging risk³, potential measures were assessed over the course of 2025, against three principal considerations:

³ NESO's 2025 Gas Supply Security Assessment highlighted the risk to future gas security of supply. The statutory consultation identifies that this risk materialises as early as winter 2026/27.

- Deliverability: could the intervention materially strengthen the security of supply position from Winter 2026/27 and beyond
- Capability: could the intervention mitigate the identified security of supply risk
- Costs: costs that consumers would face for the proposed intervention

2.4. This document assesses the impact on GB consumers of such an arrangement. Our policy objectives are to:

- Maintain sufficient gas interconnector import capability to support GB gas security of supply during periods of peak demand and system stress
- Improve the resilience of GB's gas supply position and reduce the likelihood and potential severity of a gas supply shortfall
- Ensure that appropriate infrastructure capability remains available to the market where commercial incentives alone may not deliver the level of resilience required for wider GB security of supply.
- Provide an appropriate regulatory mechanism through which NG can recover incurred costs associated with the bilateral arrangements.
- Deliver a short-term mitigation to the emerging security of supply risk while longer-term options continue to be developed and assessed.

Intended Effects

2.5. The principal intended effect is to maintain the gas import capability available to GB compared with the position in which the planned reductions in interconnector capability proceed from October 2026. Maintaining appropriate gas import capability would strengthen GB's supply resilience during periods of peak demand or disruption to other sources of supply. NESO's 2025 Gas Security of Supply Assessment confirms that Europe maintains sufficient gas transmission infrastructure to provide sufficient flows as the market requires. The intervention would not guarantee that gas will flow through the interconnectors, as actual flows will continue to depend on market conditions and the

availability of gas. The intervention instead ensures that the relevant infrastructure capability remains available to the market when required.

Effect on Ofgem's strategic outcomes

Protecting consumers

2.6. This intervention would support security of supply by maintaining gas import capability available to the market during periods of peak demand. This would protect domestic and industrial consumers from the potential impacts of a gas supply shortfall, including higher wholesale prices and reducing the risk of demand restrictions during a Gas Deficit Emergency.

Security of supply

2.7. Security of supply is the central objective of the intervention. Maintaining appropriate continental European interconnector capability would strengthen GB's resilience during periods of peak demand and system stress and provide additional capability where other sources of supply are constrained or unavailable.

Efficient regulation

2.8. Commercial incentives alone have not provided the level of interconnector capability required to support wider GB security of supply⁴. The proposed regulatory framework would allow NG to recover incurred costs associated with securing the required capability, while providing appropriate regulatory oversight of those costs.

Net Zero transition

2.9. Although overall gas demand may decline as the energy system decarbonises, gas continues to play an important role in meeting peak demand and supporting electricity generation. Maintaining sufficient gas supply resilience for five years from winter 2026/27

⁴ <https://www.fluxys.com/-/media/project/fluxys/public/corporate/fluxyscom/documents/iuk/market-announcement---close-of-open-season-and-review-of-int-be-to-uk-capacity-offering.pdf>

therefore supports a secure and orderly transition to Net Zero while longer-term alternatives continue to be developed.

Public Sector Equality Duty

2.10. Under the Equality Act 2010, Ofgem, as a public authority, is required to have due regard to factors set out in the act in respect of persons who share relevant characteristics. We have not identified any evidence that the proposal would result in any direct adverse impact on persons who share the protected characteristics.

2.11. The intervention is expected to have a small impact on consumer bills under the preferred option. In contrast, severe gas-system stress events could disproportionately affect some vulnerable consumers, including older people and disabled people, through higher energy costs or disruption to energy supplies. By supporting security of supply, the proposal may help reduce these risks. This has been discussed further in paragraph 9.4 in relation to cold mortality impacts.

Growth Duty

2.12. In accordance with Ofgem's growth duty, we have considered the potential impacts of the proposal on economic growth. The assessment estimates that, under severe stress scenarios, maintaining interconnector import capability could reduce economic output losses measured through Gross Value Added (GVA) impacts.

3. Description of options considered (including baseline)

Section summary

This section sets out the options considered in relation to INT and the baseline against which the proposed INT arrangement, to mitigate the emerging gas security of supply risk, is assessed.

Options considered for impact analysis

3.1. As an arrangement with BBL is not currently available, the options and analysis described here relate only to the INT arrangement. The regulatory arrangements do allow for a subsequent agreement with BBL to be developed, which would be assessed separately.

Table 1: Options considered for impact analysis

Option 0	Do-nothing: Planned INT capacity reduction proceeds. INT capacity based on 1 compressor capability
Option 1	Maintain INT import capability: The planned reduction of INT capacity does not proceed. INT capacity based on 2 compressor capability
Option 2	Delayed Reinstatement of INT import capability: The planned reduction of INT capacity proceeds (ie 1 compressor) and capability is restored (to equivalent capacity of 2 compressors) later.

Option 0: Do nothing: INT capacity based on 1 compressor capability

3.2. INT's planned reduction of capability in October 2026 proceeds from 2 compressors to 1 compressor capability. No further reduction of capability is assumed in the baseline. This is the baseline without intervention, consistent with currently publicly available information.

3.3. Moving from two compressors to one means reduced system resilience and under the stress conditions considered in this assessment, increases the risk of not being able to meet peak demand in a combined 1-in-20/n-1 stress scenario in winter 26/27.

3.4. **Additional Risk:** Without intervention, there is a risk of further capability reductions over and above what has been publicly announced by INT. This has been assessed separately as a downside sensitivity and does not form the part of the baseline.

Option 1 (preferred option): Maintain INT import Capability: INT capacity based on 2 compressor capability

3.5. The proposed INT arrangement is implemented and INT's planned October 2026 capability reduction does not proceed. Two-compressor import capability is maintained over the appraisal period, supported by GB consumers through the proposed cost-recovery arrangements. No further capability reductions are assumed for the period in question.

Option 2: Delayed Reinstatement of INT import capability: INT capacity based on delayed 2 compressor capability

3.6. INT's planned reduction of capability in October 2026 proceeds but the issue is mitigated later by reinstating this capability after winter 2026/2027. As an assumption for modelling purposes, we assume that this capability would be reinstated in 2030/31. This is an illustrative assumption informed by discussions with INT and should not be interpreted as a forecast of the actual reinstatement date. Actual delivery could occur later depending on the extent of decommissioning, asset condition, procurement requirements and other project-specific dependencies⁵.

3.7. Reinstating equipment later once it has been mothballed for some time, or even removed completely, would cost more than upgrading and maintaining existing equipment.

⁵ Through informal discussions with INT, they have stated that the reinstatement of capability in such a situation would take at least 4 to 6 years.

4. Scenarios considered

Section summary

This section sets out the scenarios used to assess the impact of changes in continental European gas interconnector import capability. The analysis considers four scenarios: normal demand conditions, a 1-in-20 peak-demand event, a major supply disruption involving the loss of the largest element of GB gas supply infrastructure (referred to as an N-1 event), and a combined scenario where GB experiences peak demand and loss of the largest element of GB gas supply infrastructure simultaneously.

Scenarios

Table 2: Different scenarios considered in the analysis

Scenario	Description
Scenario A: Normal demand	Normal gas demand with no additional supply disruption.
Scenario B: 1-in-20 peak demand	Gas demand increases to the level associated with a 1-in-20 peak-demand event, with no additional loss of supply.
Scenario C: N-1 supply disruption	Normal gas demand occurs at the same time as the loss of the largest element of GB supply infrastructure (an N-1 event).
Scenario D: Combined 1-in-20 and N-1 event	A 1-in-20 peak-demand event occurs at the same time as the N-1 supply disruption.

Scenario D reflects the combined conditions considered under the statutory Infrastructure Standard. Scenarios B and C are separate analytical sensitivities used to assess the effects of high demand and infrastructure disruption individually.

Scenario A: Normal Demand

4.1. In this scenario, demand remains at normal levels throughout the appraisal period with no extreme demand event.

4.2. There is no further loss of gas supply infrastructure.

Scenario B: 1-in-20 peak demand

4.3. In this scenario, gas demand increases to the level associated with a 1-in-20 peak-demand event, representing a period of exceptionally cold weather that occurs, on average, once every twenty years.

4.4. There is no further loss of gas supply infrastructure.

Scenario C: N-1 supply disruption

4.5. In this scenario, demand remains at normal levels throughout the appraisal period.

4.6. However, the largest element of GB supply infrastructure is assumed to be unavailable which is referred to as an 'N-1' supply disruption.

4.7. The loss of this gas supply infrastructure reduces available gas supply and tests the resilience of the gas system to a significant supply-side shock.

Scenario D: Combined 1-in-20 and N-1 event

4.8. In this scenario, gas demand increases to the level associated with a 1-in-20 peak-demand event.

4.9. At the same time, the largest element of GB supply infrastructure becomes unavailable.

4.10. This combines a severe demand-side shock with a significant supply-side disruption, resulting in the most challenging conditions considered in the assessment.

Low, central and high estimates

4.11. The low, central and high estimates are illustrative sensitivity assumptions reflecting uncertainty about the duration of the modelled stress events. They do not represent probabilities or confidence intervals. Given the limited evidence available on the potential duration of such rare events, the specific durations of events are used to test how the

results vary under different event durations,⁶ rather than estimates of the likely duration of such events.

Table 3: Low, central and high illustrative estimates used in the analysis

Event	Low estimate	Central estimate	High estimate
1-in-20 peak-demand event	One event lasting 1 day	One event lasting 5 days	Two events lasting 3 days each
N-1 supply disruption	One event lasting 7 days	One event lasting 180 days	One event lasting 365 days

4.12. The 1-in-20 demand is assumed to happen in 2030/31 in low and central estimate. In the high estimate, the peak demand is assumed to happen for 3 days each in 2030/31 and 2031/32 in order to show some benefit of option 2 (delayed mitigation).

4.13. The N-1 event is assumed to occur once during the appraisal period, in 2030/31. Under Scenario D, the 1-in-20 event and the N-1 disruption are assumed to happen during the same year and overlap.

4.14. Impacts associated with physical unmet demand are calculated only during the period in which the two events overlap. The overlap periods are therefore 1, 5, and 6 days under the low, central and high estimates respectively⁷.

4.15. Once the 1-in-20 event ends, demand returns to normal levels. The N-1 disruption may continue, but where normal demand can be met, no further physical unmet-demand impacts are calculated. Wholesale gas price impacts may nevertheless continue for the remaining duration of the N-1 disruption because the reduction in available supply may still require higher prices to attract sufficient gas into GB.

⁶ As a comparison, NESO's Gas Security of Supply Assessment identified the possibility of up to five days of negative supply margins in 2030/31 under an 1-in-20/N-1 scenario and three days in 2035/36.

⁷ Under the high estimate, the 1-in-20 peak demand event is assumed to occur for three days in each of two years, giving a total of six days over the appraisal period. For the combined-event scenario, we assume that all six days occur in the same year so that they coincide with the N-1 event.

Treatment of the option and scenario results

4.16. The results show the illustrative costs that could arise or be avoided if each scenario occurred. **Due to the speculative nature of the scenarios, the results of the analysis should be treated as illustrative rather than exact.** No probabilities are assigned to the scenarios because the available evidence does not provide a sufficiently robust basis for estimating their likelihood.

4.17. Each option is assessed incrementally against Option 0. For Options 1 and 2, reductions in adverse impacts are reported as the costs that are avoided if the relevant scenario occurs.

4.18. The risk of a further deterioration from the baseline is discussed as additional costs that arise relative to Option 0.

5. Appraisal framework

Section summary

This section sets out the analytical framework used in the assessment. Impacts are evaluated over an appraisal period from gas year 2026/27 comprising a five year commercial arrangement with INT and NG cost recovery one year in arrears. Impacts are presented in present-value terms. All monetised values are expressed in a common 2026 price base and discounted in accordance with HM Treasury Green Book guidance. Since these scenarios are low-probability events and there is insufficient evidence to estimate robust event probabilities, the assessment does not calculate Net Present Values (NPVs) or Benefit-Cost Ratios (BCRs). Instead, results are presented as the costs that would arise, or be avoided, if the modelled scenarios were to occur.

Appraisal period

5.1. The appraisal assesses costs and benefits over a period comprising a five year commercial arrangement with INT and NG, with cost recovery one year in arrears, beginning in gas year 2026/27. A gas year runs from 1 October to 30 September. Impacts are estimated for each gas year in the appraisal period and converted to present values.

Price base year

5.2. All monetised impacts are expressed in 2026 prices. Where source data are reported in prices from another year, monetary values are converted to the common 2026 price base using HM Treasury GDP deflators before discounting.

Discounting

5.3. Future costs and benefits are discounted to present values in accordance with HM Treasury Green Book principles. A real discount rate of 3.5%⁸ is applied to intervention

⁸ Green Book guidance will be updated to 3%. This would not affect our assessment in this case.

costs, wholesale gas price impacts, gas supply disruption costs (VoLL), economic output impacts, carbon impacts and power station curtailment costs.

5.4. A lower discount rate of 1.5% is applied to air-quality impacts because these are treated as health-related effects.

Baseline and incremental analysis

5.5. Option 0 is used as the do-nothing baseline. Impacts of Options 1 and 2 are calculated incrementally by comparing the outcome under Option 0 with the outcome under each intervention option.

Net present value (NPV) /Benefit Cost Ratio (BCR)

5.6. NPV and BCR are not reported because intervention expenditure is incurred if the option is implemented, whereas the estimated avoided costs arise only if the relevant, low-probability stress event occurs. In the absence of sufficiently robust event probabilities, comparing the full conditional avoided costs directly with intervention expenditure would implicitly treat each stress event as certain and could overstate the economic case for intervention.

6. Data

Section summary

This section lists all the relevant data used for the analysis and their sources.

Wholesale gas prices

6.1. Wholesale gas price projections were taken from the Department for Energy Security and Net Zero's Fossil Fuel Price Assumptions 2025. The DESNZ central series provides the underlying wholesale gas price projection used in the appraisal. Prices were converted from pence per therm to pounds per million cubic metres and rebased to 2026 prices using HM Treasury GDP deflators.

6.2. Historical National Balancing Point (NBP) gas prices and gas demand data for 2021/22 to 2023/24 were compared with 2024/25 as the reference year. These observations provide the evidence used to quantify the historical relationship between changes in gas demand and wholesale gas prices. The resulting central scaling factor indicates that a 1% increase in demand was associated with an average 3.32% increase in wholesale gas prices over the period examined.⁹

Value of Lost Load (VoLL)

6.3. The gas VoLL estimate was sourced from the Ofgem-commissioned London Economics¹⁰ study on gas supply interruptions. The analysis uses the SME willingness-to-accept estimate for a one-day winter interruption occurring once in twenty years as a proxy for non-domestic gas consumers. The SME estimate was selected because it provides a

⁹ During the Russia-Ukraine crises, for example, between 22 and 26 August 2022, NBP prices reached approximately 410 to 516 p/therm, compared with an average of around 97 p/therm in 2024/25. This represents an increase of approximately 320% to 430% relative to the 2024/25 average. These observations indicate that wholesale gas prices can respond disproportionately to relatively small changes in supply-demand balance when the market is under stress. The 3.32 scaling factor is therefore intended to provide an indicative estimate of the potential scale of wholesale gas price impacts under tighter market conditions rather than a precise prediction of future prices.

¹⁰ Source: [london-economics,-estimating-value-of-lost-load---final-report-to-ofgem.pdf](#)

non-domestic customer valuation derived from stated-preference survey evidence. Industrial and commercial values reported in the same study are based on sector-specific production-loss methodologies and may overlap with the separate Gross Value Added (GVA) assessment included elsewhere in this appraisal. The SME value is therefore used to represent the disruption experienced by non-domestic gas users, while wider economic output impacts are estimated separately through the GVA methodology.

Power station curtailment

6.4. Historical System Average Price data were obtained from the National Gas Transmission Data Portal. This assessment uses the average 30-day rolling System Average Price during gas year 2021/22, as the unit value informing the assessment of emergency power station curtailment costs. The period was selected because 2021/22 is the period of exceptional gas-market stress due to Russia-Ukraine crises.

Carbon emissions

6.5. The natural gas combustion emissions factor was sourced from the DESNZ Greenhouse Gas Conversion Factors 2026. Carbon values were obtained from the Green Book supplementary guidance on the valuation of energy use and greenhouse gas emissions. The carbon values were converted to 2026 prices using HM Treasury GDP deflators

Air quality/damage

6.6. Air-quality/damage costs relate to health issues arising due to air quality deterioration due to carbon emissions. Valuation data were obtained from the DESNZ and Defra Green Book supplementary appraisal data tables. The analysis uses the national average air-quality activity cost associated with natural gas consumption, expressed in pence per kWh. This value captures monetised damage associated with emissions from natural gas combustion and was converted to 2026 prices.

Domestic gas meters

6.7. The number of domestic gas meters was obtained from DESNZ's Regional and Local Authority Gas Consumption Statistics. The assessment uses the reported 24.7 million domestic gas meters in Great Britain when estimating intervention-related bill impacts per meter.

Intervention costs

6.8. Information on the costs of maintaining or reinstating interconnector capability was provided by National Gas and INT. The data include indicative monthly payments associated with maintaining operational capability and capital expenditure associated with reinstating compressor assets. These inputs were used to estimate the costs assigned to each intervention option.

6.9. The costs of maintaining interconnector capability are assumed to be recovered from consumers over a five-year period but the envisaged cost recovery is one year in arrears.

6.10. The analysis also includes the estimated costs incurred by National Gas in establishing and managing the commercial arrangement with INT. These costs are allocated over the same period and in the same proportions as the costs of maintaining INT import capability.

6.11. In addition to the costs of maintaining interconnector capability and the costs incurred by National Gas to manage the commercial arrangement in Option 1, there are additional costs of reinstating compressors after a delay that are included separately for the Option 2. The additional costs to NGT of compressor reinstatement are currently an approximate estimated amount received from National Gas.

Key assumptions and caveats

6.12. Carbon values are published on a calendar-year basis. Gas-year impacts are valued using the carbon value for the first calendar year of the relevant gas year.

6.13. To avoid double counting the same physical supply shortfall, unmet gas demand is allocated between power station curtailment costs and gas supply disruption costs (gas VoLL). In the absence of evidence on how any shortfall would be distributed across different user groups during a gas emergency, 75% of unmet gas demand is assumed to be managed through curtailment of gas-fired power stations and 25% is assumed to affect non-domestic gas consumers and is used for calculations of gas supply disruptions (gas VoLL). This assumption reflects the ability of curtailing a relatively small number of large gas-fired power stations to release substantial volumes of gas to the network.

6.14. Where peak supply capability is sufficient to meet demand, wholesale gas prices are assumed to rise and attract the additional gas required to restore market balance. Physical unmet demand arises only where peak supply capability is exhausted.

6.15. Where demand exceeds peak supply capability, the wholesale price response is calculated only for the quantity that can physically be supplied. The remaining quantity is classified as unmet demand and valued separately through the gas supply disruption calculations. This prevents the same physical shortfall from being represented both as additional market-supplied gas and as unmet demand.

6.16. The wholesale price estimates represent an indicative response to gas-market tightness. They do not model the detailed supply response of individual sources, contractual arrangements, demand-side response or interactions with European gas markets. The results are therefore sensitive to the historical price-demand relationship used and to the assumption that additional gas can be attracted up to the limit imposed by peak supply capability.

6.17. The low estimate assumes 1-in-20 peak-demand event lasting one day in 2030/31. The central estimate assumes one event lasting five days in 2030/31. The high estimate assumes two separate three-day events, with one occurring in 2030/31 and the other in 2031/32, giving six event days in total. Due to the speculative nature of the scenarios, the results of the analysis using these figures should be treated as illustrative rather than exact.

6.18. The N-1 disruption is assumed to happen once in 2030/31 and is assumed to last 7 days, 180 days and 365 days under the low, central and high estimates, respectively. Due to the speculative nature of the scenarios, the results of the analysis using these figures should be treated as illustrative rather than exact.

6.19. The estimated GVA impact provides an indication of potential economic disruption arising from constrained gas supply. However, the analysis applies an average relationship between gas availability and economic output and does not explicitly model short-run behavioural responses by firms. Actual impacts could be lower if businesses are able to reschedule production, draw on inventories, substitute fuels or temporarily reduce activity. In addition, some of the disruption reflected in the GVA estimate may also be captured indirectly through the non-domestic Value of Lost Load and power-station curtailment estimates so there could be some overlap between the impacts.

6.20. The compressor reinstatement costs used in the analysis are a high level approximation of what it would cost to reinstate a compressor. The actual costs could be greater if there are any additional costs associated with the reinstatement.

6.21. In Option 2, the reinstatement of capability is assumed to happen in 2030/31. Through informal discussion with INT, the reinstatement of capability in such a situation would take at least 4 to 6 years. For the purpose of the analysis it is assumed that Ofgem intervenes before 2027/28 as a result of which the capability is reinstated in 2030/31. Actual delivery times could be longer, depending on the scope of decommissioning, the complexity of the reinstatement process, and other project-specific factors and external dependencies.

6.22. For modelling purposes, the ongoing costs of maintaining INT capability under Option 2 are assumed to be the same as under Option 1, in addition to the costs of reinstatement. These costs could be higher depending on the complexity of the reinstatement process.

6.23. The gas VoLL estimates are based on the Ofgem-commissioned study. A limitation of this approach is that the study was undertaken more than a decade ago and patterns of energy consumption may have changed since then as the energy mix has evolved. As a result, current consumer preferences and willingness to pay to avoid gas supply interruptions may differ from those captured in the original research.

7. Methodology

Section summary

This section sets out the methods used to estimate a range of impacts associated with changes in interconnector capability . These include monetised impacts like wholesale gas price costs, wider economic impacts measured through Gross Value Added (GVA), electricity market impacts, power station curtailment costs, carbon emissions, and air quality impacts. The section also discusses the non-monetised impacts like fuel-poverty, impact on balancing costs and cold-weather mortality impacts.

Wholesale gas price impacts

7.1. Wholesale gas price impacts are estimated using the historical association between changes in gas demand and NBP prices. Percentage changes in demand and wholesale gas prices between 2021/22 and 2023/24 are compared with 2024/25 as the reference year. Across the period examined, average wholesale gas prices increased by around 3.32% for each 1% increase in demand relative to the 2024/25 reference year.

7.2. For each option and scenario, the additional gas required to restore market balance is expressed as a proportion of overall supply. This proportion is multiplied by the 3.32 scaling factor and applied to the DESNZ central wholesale gas price projection to estimate a stressed wholesale price.

7.3. Where demand exceeds peak supply capability, the wholesale price calculation includes only demand that can physically be supplied. Any residual shortfall is classified as unmet demand and valued separately. This avoids treating the same quantity as both market-supplied gas and physical unmet demand.

7.4. The difference between the stressed and central prices is then applied to the relevant gas demand and event duration to calculate the additional wholesale gas cost.

7.5. The 3.32 factor is used as a historical scaling relationship rather than a causal price elasticity. The results therefore provide an indicative estimate of the potential effect of market tightness on wholesale gas prices.

7.6. Under Scenario D, the combined 1-in-20 and N-1 price impact is applied during the overlap between the two events. Once the peak-demand event ends, demand returns to normal, but the N-1 disruption continues. The N-1-only wholesale price impact is therefore applied for the remainder of the disruption.

7.7. Wholesale gas price impacts are the largest quantified impact in the analysis, particularly where the modelled supply disruption is assumed to persist for a prolonged period.

Gas supply disruption costs

7.8. Where demand exceeds available peak supply capability on a particular day, the resulting physical shortfall is divided between non-domestic gas consumers and gas-fired power stations. For modelling purposes, the analysis assumes that 25% of unmet gas demand affects non-domestic consumers, with the remaining 75% managed through power-station curtailment. This allocation ensures that each unit of unmet demand is valued once. This 25% volume is multiplied by the number of days for which the stress event occurs and then valued using the gas VoLL.

7.9. The gas VoLL represents the estimated welfare value that non-domestic consumers place on preventing disruption to their gas supply. It is applied only where a physical supply shortfall remains after all available peak supply has been taken into account.

7.10. Under Scenario D, physical unmet demand occurs only during the overlap between the 1-in-20 peak-demand event and the N-1 disruption. Gas VoLL is therefore applied over 1, 5 and 6 days under the low, central and high estimates respectively. No gas VoLL is applied during the remaining N-1 period where normal demand can be met.

Economic output impacts

7.11. The wider economic effect of physical unmet gas demand is measured using Gross Value Added (GVA). This is included to inform Ofgem's consideration of its growth duty. For each relevant option and scenario, the volume of unmet demand is multiplied by the applicable stressed wholesale gas price to estimate the value of gas demand affected.

7.12. An internally derived multiplier of 0.734 is then applied to estimate the associated economy-wide GVA impact. The multiplier is based on the 2023 ONS Input-Output

Analytical Tables and combines the direct and indirect production associated with final demand for gas with sector-level GVA-to-output ratios.

7.13. GVA impacts are calculated over the period of physical unmet demand. Under Scenario D, this is the 1, 5 or 6-day overlap period under the low, central and high estimates respectively.

Power station curtailment costs

7.14. During a Network Gas Supply Emergency, curtailing gas-fired power stations could release substantial gas volumes and help maintain safe pressure on the gas transmission system. Since the emergency procedures do not specify a fixed allocation of curtailed volumes between power stations and other gas users, the analysis assumes that 75% of physical unmet gas demand is managed through curtailment of gas-fired power stations.

7.15. In the absence of a published forward emergency curtailment price for the stress events considered in this appraisal, the average 30-day System Average Price (SAP) observed during gas year 2021/22, a period of significant gas market disruption linked to the Russia-Ukraine crisis, is used as a proxy¹¹. This value is converted to a cost per unit of gas and multiplied by the estimated volume curtailed under each option and scenario and then multiplied by the number of stress event days. The resulting estimate represents the potential compensation associated with involuntary power station curtailment. This cost is calculated only during the period of physical unmet demand.

Carbon impacts

7.16. Carbon impacts are estimated by applying the DESNZ natural gas combustion emissions factor to the volume of gas that cannot be supplied. This represents emissions that do not arise because the unavailable gas is not combusted.

¹¹ This is based on information from National Gas that compensation payable to industrial sites during a Stage 2 Gas Deficit Emergency is based on the 30-day SAP.

7.17. The resulting tonnes of carbon dioxide equivalent are valued using the DESNZ central carbon value for the relevant year, expressed in 2026 prices. Gas-year impacts are valued using the carbon value corresponding to the first calendar year of the gas year.

7.18. When an intervention enables more gas demand to be met than under Option 0, the reduction in emissions foregone is presented in the analysis as an increase in carbon emissions damage. Carbon impacts are calculated only during the period of physical unmet demand in Scenario D.

Air-quality/damage impacts

7.19. Air-quality/damage impacts are estimated by converting the volume of gas that cannot be supplied into kilowatt-hours and applying the national average air-quality activity cost for natural gas. The activity cost captures the monetised damage associated with nitrogen oxides, fine particulate matter and sulphur dioxide emissions from gas combustion. This is then multiplied by the number of days of the stress event where applicable.

7.20. The resulting value represents air-quality damage that does not arise because the unavailable gas is not combusted. Where an intervention enables more gas demand to be met than under Option 0, this difference is presented as an increase in air-quality damage in the incremental appraisal.

7.21. Air-quality impacts are calculated only during the period of physical unmet demand and are discounted using the health-related discount rate specified in the appraisal framework of 1.5%.

Consumer bill impacts

7.22. The associated consumer bill impact is calculated by spreading the total intervention cost of the option evenly across five years, from 2027/28 to 2031/32, and dividing the annual amount by the number of domestic gas meter accounts. The bill impact represents the recovery of intervention expenditure from consumers.

Wider electricity-system impacts

7.23. Wider electricity-system impacts are assessed by comparing electricity prices and balancing costs during 2021/22, a period of severe energy-market stress, with those

observed under more typical market conditions. These historical comparisons provide contextual evidence of the potential scale of wider electricity-system effects during periods of severe energy-system stress. These impacts are treated as indicative wider effects and are not monetised.

Cold-related mortality impacts

7.24. A severe gas-system stress event could contribute to higher household energy costs and may increase the risk of adverse health outcomes during periods of cold weather, particularly for vulnerable households. The scale of this effect would depend on several factors, including the duration of any price increase, the extent to which wholesale prices are passed through to consumers, weather conditions, household resilience and any mitigating policy measures in place at the time.

7.25. Cold-related mortality is not quantified or monetised in this analysis. The available data does not provide a sufficiently robust basis to estimate the number of additional deaths that might arise from the short-duration gas-system stress events considered in the assessment. Any mortality impact is therefore treated qualitatively.

8. Results

This section presents the conditional impacts estimated under the baseline Option 0 and compares Options 1 and 2 against it. They show the impacts that could arise, if the modelled stress scenarios occur.

Estimated impacts under baseline (Option 0)

8.1. Option 0 represents the baseline against which the intervention options are assessed, with the impacts quantified in Tables 4 to 7. Under this option, the planned October 2026 reduction in the INT import capability proceeds, leaving import capability based on a single compressor. The results show the impacts if each of the modelled stress scenarios occur. As probabilities have not been assigned to the stress scenarios, the results should be interpreted as conditional impacts rather than expected costs.

Table 4: Illustrative costs and impacts under the baseline (Option 0), Scenario A: Normal Demand (£ million, present value, 2026 prices)

Impact	Low	Central	High
All quantified impacts	0	0	0

Table 5: Illustrative costs and impacts under the baseline (Option 0), Scenario B: 1-in-20 peak demand (£ million, present value, 2026 prices)

Impact	Low	Central	High
Wholesale gas price impacts	368	1840	2255

Table 6: Illustrative costs and impacts under the baseline (Option 0), Scenario C: N-1 supply disruption (£ million, present value, 2026 prices)

Impact	Low	Central	High
Wholesale gas price impacts	322	8287	16805

Table 7: Illustrative costs and impacts under the baseline (Option 0), Scenario D: Combined 1-in-20 and N-1 event (£ million, present value, 2026 prices)

Impact	Low	Central	High
Wholesale gas price impacts	927	11309	20431
GVA losses	58	288	3147.2
Power station curtailment costs	21	104	125
Gas VoLL costs	3	13	16
Air-quality/damage costs avoided	1	4	5
Carbon costs avoided	23	117	141

8.2. Under normal demand conditions (Scenario A), demand can be met without additional market stress and no impacts are identified. Under the 1-in-20 peak-demand scenario (Scenario B) and the N-1 supply disruption scenario (Scenario C), available peak supply capability remains sufficient to meet demand, but the tighter supply-demand balance results in estimated wholesale gas price impacts. These impacts are materially larger and more sensitive to event duration under the N-1 scenario.

8.3. The most significant impacts arise under the combined 1-in-20 and N-1 scenario (Scenario D). Under this scenario, available supply capability is insufficient to meet all demand. In addition to wholesale gas price impacts, this results in physical unmet demand and associated GVA losses, power-station curtailment costs and gas VoLL costs. Under the central estimate, the modelled impacts are approximately £11.3 billion of wholesale gas price impacts, £288 million of GVA losses, £104 million of power-station curtailment costs and £13 million of gas VoLL costs.

8.4. Under Scenario D, physical unmet demand also reduces gas consumption and therefore results in avoided carbon and air-quality damage relative to a position in which that demand is met. These environmental effects are small relative to the modelled wholesale price and wider economic impacts

Downside sensitivity: further reduction in the INT import capability.

8.5. Option 0 assumes that no further reduction in INT import capability occurs after the planned October 2026 reduction. There is, however, a risk of further decommissioning and a corresponding additional loss of import capability. To test the potential significance of this risk, we have undertaken a downside sensitivity in which INT capability reduces further in 2027/28. This is not part of the Option 0 baseline.

Table 8: Illustrative additional costs associated with a further reduction in INT import capability, Scenario B: 1-in-20 peak demand (£ million, present value, 2026 prices)

Impact (£m, PV, 2026 prices)	Low	Central	High
Wholesale price impacts	160	801	990

Table 9: Illustrative additional costs associated with a further reduction in INT import capability, Scenario C: N-1 supply disruption (£ million, present value, 2026 prices)

Impact (£m, PV, 2026 prices)	Low	Central	High
Wholesale price impacts	548	14097	28585

Table 10: Illustrative additional costs associated with a further reduction in INT import capability, Scenario D: Combined 1-in-20 and N-1 event (£ million, present value, 2026 prices)

Impact (£m, PV, 2026 prices)	Low	Central	High
Wholesale price impacts	669	14700	29308
GVA losses	97	483	580
Power station curtailment costs	19	96	115
Gas VoLL costs	2	12	15
Additional Air-quality/damage costs in option 0	1	4	4
Additional Carbon costs in option 0	22	109	130

8.6. The sensitivity indicates that a further reduction in INT capability could materially increase the consequences of the modelled stress scenarios. The effect is greatest under the N-1 and combined scenarios, where reduced import capability increases both market tightness and, under the combined scenario, physical unmet demand. Under the central combined scenario, the model estimates approximately £14.7 billion of additional wholesale gas price impacts relative to Option 0, alongside additional GVA losses, power-station curtailment costs and gas VoLL costs.

8.7. These results should be interpreted as a downside sensitivity rather than an expected outcome. They show the potential consequences if INT capability deteriorates beyond the planned October 2026 reduction and the specified stress events subsequently occur.

Option 1: Maintain INT capability compared with the baseline

8.8. Option 1 represents the proposed INT arrangement. It prevents the planned October 2026 reduction in INT import capability and maintains two compressors throughout the five-year period. Tables 11 to 13 show the costs that could be avoided, relative to Option 0, if modelled stress scenarios occur.

Table 11: Illustrative additional costs avoided under Option 1 relative to Option 0, Scenario B: 1-in-20 peak demand (£ million, present value, 2026 prices)

Impact (£m PV, 2026 prices)	Low	Central	High
Wholesale price impacts avoided	79	396	485

Table 12: Illustrative additional costs avoided under Option 1 relative to Option 0, Scenario C: N-1 supply disruption (£ million, present value, 2026 prices)

Impact (£m PV, 2026 prices)	Low	Central	High
Wholesale price impacts avoided	214	5498	11148

Table 13: Illustrative additional costs avoided under Option 1 relative to Option 0, Scenario D: Combined 1-in-20 and N-1 event (£ million, present value, 2026 prices)

Impact (£m PV, 2026 prices)	Low	Central	High
Wholesale price impacts avoided	261	5733	11430
GVA losses avoided	40	198	238
Power station curtailment costs avoided	13	66	79
Gas VoLL costs avoided	2	8	10
Additional air-quality costs in option 1	0	2	3
Additional carbon costs in option 1	15	74	89

8.9. Under normal demand conditions (Scenario A), there are no material differences between Options 0 and 1, as demand can be met in full and there are no differences in wholesale gas prices. Under the 1-in-20 peak-demand scenario (Scenario B) and the N-1 supply disruption scenario (Scenario C), maintaining additional INT import capability reduces the estimated wholesale gas price impacts, although available peak supply capability remains sufficient to meet demand under both scenarios. The central estimates of wholesale gas price impacts avoided are approximately £396 million under Scenario B and £5.5 billion under Scenario C.

8.10. The greatest differences arise under the combined 1-in-20 and N-1 scenario (Scenario D), where Option 0 results in physical unmet demand. Under the central

estimate, maintaining INT capability avoids approximately £5.7 billion of wholesale gas price impacts, £198 million of GVA losses, £66 million of power-station curtailment costs and £8 million of gas VoLL costs.

8.11. Most of the quantified avoided costs arise through the estimated wholesale gas price effect. Retaining the additional import capability increases the volume of gas that can be imported during periods of system stress, reducing market tightness and limiting the increase in wholesale gas prices required to attract gas into Great Britain.

8.12. Maintaining capability also enables more gas demand to be met under Scenario D. This results in higher carbon and air-quality damage relative to Option 0 because less gas demand is curtailed.

Delayed reinstatement compared with the baseline

8.13. Under Option 2, INT's planned October 2026 reduction proceeds and the lost capability is subsequently reinstated. For modelling purposes, the analysis assumes that this capability is restored in 2030/31. Tables 14 to 16 show the costs that could be avoided relative to Option 0 if the modelled stress scenarios occur after reinstatement.

Table 14: Illustrative additional costs avoided under Option 2 relative to Option 0, Scenario B: 1-in-20 peak demand (£ million, present value, 2026 prices))

Impact (£m PV, 2026 prices)	Low	Central	High
Wholesale price impacts avoided	79	396	485

Table 15: Illustrative additional costs avoided under Option 2 relative to Option 0, Scenario C: N-1 supply disruption (£ million, present value, 2026 prices)

Impact (£m PV, 2026 prices)	Low	Central	High
Wholesale price impacts avoided	214	5498	11148

Table 16: Illustrative additional costs avoided under Option 2 relative to Option 0, Scenario D: Combined 1-in-20 and N-1 event (£ million, present value, 2026 prices)

Impact (£m PV, 2026 prices)	Low	Central	High
Wholesale price impacts avoided	261	5733	11430
GVA losses avoided	40	198	238
Power station curtailment costs avoided	13	66	79
Gas VoLL costs avoided	2	8	10
Additional air-quality damage in option 2	0	2	3
Additional carbon costs in option 2	15	74	89

8.14. The modelled avoided impacts are the same as under Option 1 because, once reinstatement has occurred, both options provide the same level of INT import capability. Before reinstatement, however, Option 2 provides the same capability as Option 0. If a stress event occurred during this period, the avoided impacts shown in Tables 14 to 16 would not be realised.

8.15. Option 2 also incurs higher costs because additional capital expenditure is required to reinstate capability after the planned reduction has occurred. The timing and cost of reinstatement are uncertain. The assumption that capability is restored in 2030/31 is used for modelling purposes and is informed by discussions with INT. Actual reinstatement timelines and costs may differ from those assumed in the analysis.

Consumer Bill Impact

8.16. Table 17 presents the estimated undiscounted annual impact per domestic gas meter account. Intervention costs are assumed to be recovered evenly over five years from 2027/28 to 2031/32. The figures are expressed as the estimated annual impact per domestic gas meter account.

Table 17: Indicative annual consumer bill impact by option (£ per domestic gas meter account per year, undiscounted)

Option	Central estimate	High estimate
Option 0: do nothing, based on one-compressor capability (baseline)	0.00	0.00
Option 1: Maintain INT import capability, based on two-compressor capability	1.19	1.19
Option 2: Delayed reinstatement of INT import capability, based on two-compressor capability	1.43	1.44

8.17. Option 0 does not involve intervention expenditure and therefore does not result in any additional consumer bill impact.

8.18. Under Option 1, the estimated annual bill impact is approximately £1.19 per domestic gas meter account, under both the central and high estimates. Under Option 2, the estimated annual bill impact is approximately £1.43 per domestic gas meter account. The higher bill impact under Option 2 reflects the additional expenditure required to reinstate compressor capability after the planned reduction has occurred. The timing and cost of reinstatement are uncertain, and actual reinstatement could occur later than the assumed 2030/31 date.

9. Non-Monetised Impacts

Section summary

This section discusses the hard to monetise impacts of the appraisal. The intervention options are not expected to have a material impact on fuel poverty. Maintaining INT capability may reduce wider electricity-system impacts, such as higher electricity prices and balancing costs during periods of severe gas-system stress, and may also reduce exposure to cold-related health/mortality impacts arising from higher energy costs.

Fuel Poverty Impact

9.1. The fuel poverty assessment indicates that the small increases in consumer bills under Options 1 and 2 do not result in any additional households meeting the fuel poverty criteria. Therefore, while the interventions marginally increase bills, there is no estimated impact on the number of households in fuel poverty under any of the intervention options.

Wider Electricity Market Effects

9.2. Periods of severe energy-system stress have historically been associated with higher electricity prices and balancing costs. For example, average balancing costs increased from £9.81 per customer during 2019/20 to 2021/22 to £37.32 during 2022/23 to 2025/26, while electricity prices averaged £226.68/MWh during the 2021/22 energy crisis compared with £89.33/MWh in 2024/25. These comparisons provide contextual evidence of the potential scale of wider electricity-system effects during periods of severe energy-system stress, but do not provide a robust basis for attributing or monetising an impact specifically from changes in INT capability.

9.3. Gas supply constraints could also have wider effects on the electricity system through the curtailment of gas-fired generation during periods of severe gas-system stress. Whilst the direct costs paid by NGT to enable this curtailment have been monetised, potential wider effects on electricity prices and balancing costs have not been monetised and are considered qualitatively.

Cold-related mortality impacts

9.4. Severe gas-system stress events could lead to higher energy costs for households and increase exposure to cold indoor temperatures, particularly among vulnerable households. Evidence published by the UK Health Security Agency¹² and the Office for National Statistics¹³ identifies an association between cold conditions and higher mortality during winter periods. By reducing the severity of gas-system stress events and associated wholesale gas price increases, the intervention options may reduce these risks. However, the relationship between gas-system stress, household energy costs, heating behaviour and cold-related mortality is subject to considerable uncertainty. Cold-related mortality impacts have therefore not been quantified and are considered qualitatively in this assessment.

9.5. Overall, the assessment has not identified material non-monetised impacts that change the comparison between the options. Maintaining INT capability could reduce exposure to wider electricity-system and health impacts associated with severe gas-system stress, but there is insufficient evidence to quantify these effects robustly.

¹² [Cold mortality monitoring report: winter 2024 to 2025 - GOV.UK](#)

¹³ [Excess winter mortality in England and Wales - Office for National Statistics](#)

10. Overall comparison and preferred option

Section summary

Option 1 is the preferred option because it maintains INT import capability throughout the period, avoiding the period of reduced capability under Options 0 and 2. It is also estimated to cost less than restoring capability later under Option 2. The scenario analysis indicates that maintaining this capability could materially reduce the consequences of severe gas-system stress.

10.1. The analysis compares three options for addressing the emerging gas security of supply risk associated with reductions in interconnector import capability. As the appraisal does not assign probabilities to the stress scenarios, the results should be interpreted as the costs that could arise if those scenarios occur, rather than as expected outcomes.

10.2. Under normal conditions, the analysis identifies no material benefit from maintaining additional INT capability. The value of Option 1 arises under periods of system stress, when maintaining capability can reduce market tightness and, under the combined 1-in-20 and N-1 scenario, physical unmet demand and its associated impacts. These estimated benefits are conditional on the stress scenarios occurring and are particularly sensitive to the assumptions underpinning wholesale gas prices and event duration.

10.3. Option 2 could provide the same capability and modelled benefits once reinstatement has occurred, but leaves an intervening period in which capability is the same as under Option 0 and incurs additional reinstatement costs. On the assumptions used in the assessment, Option 1 has an estimated annual bill impact of around £1.19 per domestic gas meter account, compared with around £1.43 for Option 2.

10.4. Our overall assessment is that the analysis demonstrates that the proposed intervention (Option 1) strengthens GB's resilience under conditions of the type considered under the N-1 Infrastructure Standard, and in doing so provides material additional protection against a risk that would have significant adverse effects on consumers. The analysis indicates that reduced supply capability could increase the risk of supply interruptions and result in economic costs through higher wholesale gas prices during periods of system stress. On balance, we consider that the additional resilience provided by Option 1 justifies the associated cost to consumers.