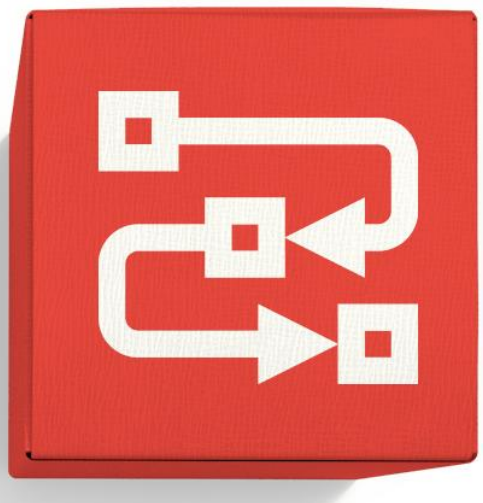
# Security of Energy Supply Study Update

## Department of the Environment, Climate and Communications (DECC)

16 May 2025



**FINAL REPORT**

# Important notice

This document was prepared by CEPA LLP (trading as CEPA) for the exclusive use of the recipient(s) named herein on the terms agreed in our contract with the recipient(s).

CEPA does not accept or assume any responsibility or liability in respect of the document to any readers of it (third parties), other than the recipient(s) named in the document. Should any third parties choose to rely on the document, then they do so at their own risk.

The information contained in this document has been compiled by CEPA and may include material from third parties which is believed to be reliable but has not been verified or audited by CEPA. No representation or warranty, express or implied, is given and no responsibility or liability is or will be accepted by or on behalf of CEPA or by any of its directors, members, employees, agents or any other person as to the accuracy, completeness or correctness of the material from third parties contained in this document and any such liability is expressly excluded.

The findings enclosed in this document may contain predictions based on current data and historical trends. Any such predictions are subject to inherent risks and uncertainties.

The opinions expressed in this document are valid only for the purpose stated herein and as of the date stated. No obligation is assumed to revise this document to reflect changes, events, or conditions, which occur subsequent to the date hereof.

The content contained within this document is the copyright of the recipient(s) named herein, or CEPA has licensed its copyright to recipient(s) named herein. The recipient(s) or any third parties may not reproduce or pass on this document, directly or indirectly, to any other person in whole or in part, for any other purpose than stated herein, without our prior approval.

# Contents


EXECUTIVE SUMMARY ..... 4

1. INTRODUCTION ..... 7
   - 1.1. Scope of the analysis ..... 7
   - 1.2. Report structure ..... 7

2. OVERVIEW OF PREVIOUS CEPA ANALYSIS ..... 8

3. APPROACH AND SCENARIOS ..... 10
   - 3.1. Modelling framework ..... 10
   - 3.2. Risk scenarios and mitigation options modelled ..... 10
   - 3.3. Input assumptions ..... 11
   - 3.4. Further notes on modelling framework ..... 15

4. N-1 INFRASTRUCTURE STANDARD ANALYSIS ..... 17
   - 4.1. Context ..... 17
   - 4.2. 1-in-50 peak-day demand projections ..... 17
   - 4.3. Results of N-1 infrastructure standard analysis ..... 18
   - 4.4. Alternative N-1 mitigation options ..... 19

5. SECURITY OF SUPPLY DISRUPTION SCENARIO ANALYSIS ..... 23
   - 5.1. Estimated security of supply impacts: 2035 ..... 23
   - 5.2. Estimated security of supply impacts: 2040 ..... 27
   - 5.3. Assessment of potential mitigation options against disruption scenarios ..... 30

6. CONCLUSION ..... 36

# EXECUTIVE SUMMARY

CEPA has been commissioned by Department of the Environment, Climate and Communications (DECC) to carry out an updated analysis of security of energy supply in Ireland covering the period beyond 2030 and up to 2040. This study builds on CEPA's technical analysis of the security of supply of Ireland's electricity and natural gas systems up to 2030, published in September 2022[1], that helped inform DECC's review and consultation on Ireland's security of energy supply.

The aim of this study is to update CEPA's 2022 analysis using the latest available data, to assess if the key risks and mitigation actions identified in the 2022 analysis of security of energy supply are still relevant and appropriate in the period up to 2040. Given the shorter timeline and narrower focus of the requirements for this piece of work, we use a simplified modelling framework to deliver the requirements of this work, as described in more detail in Section 3 of this report.

The scope of this study includes:

- Conducting an **assessment of Ireland's ability to meet the N-1 infrastructure standard**[2] for gas in 2035 and 2040 without additional mitigation.
- Testing the **impact of gas import disruption scenarios** (partial and full disruption of gas supplies from GB).
- Identifying the **shortfall in supply** in 2035 and 2040 for gas and power systems under the disruption scenarios modelled. The supply shortfall is measured in terms of unserved energy demand during the disruption period in both the gas and electricity sectors.
- Assessing the **ability of potential mitigation options** to address the identified shortfall in energy supplies. The mitigation options included in the scope of this study are the addition of a Strategic Gas Emergency Reserve in the form of a Floating Storage Regasification Unit (FSRU); additional electricity interconnection, offshore wind, and long-term electricity storage.

The primary focus of this assessment is on physical electricity and gas security of supply – e.g., on the ability of the Irish energy system to meet physical demand of electricity and gas consumers – rather than price impacts.

## Ireland's ability to meet the N-1 infrastructure standard

We find that Ireland would not meet the N-1 infrastructure standard for gas during the 2030s, in the way defined in EU regulations and based on the assumptions around the evolution of gas demand and supply. With the addition of an FSRU, having an assumed daily supply capacity of 161 GWh/d, we estimate that Ireland would meet this standard.

Electricity interconnection could potentially also help meet the N-1 standard by reducing power sector gas demand. However, the level of additional interconnection required could be as high as 2.2 GW (or a 75% increase in capacity relative to existing and planned interconnection), depending on the future evolution of peak gas demand. Crucially, the availability of electricity imports during severe peak gas demand days is uncertain, especially if the interconnected markets experience the same demand and weather patterns driving peak demand in Ireland.

We find that very high levels of additional electricity storage and offshore wind capacity would be required to meet the N-1 standard. This would be both challenging to deliver and costly. The availability of these technologies during

[1] CEPA (September 2022), Technical Analysis of the Security of Energy Supply of Ireland's Electricity and Natural Gas Systems

[2] The N-1 infrastructure standard, as defined in EU Regulation 2017/1938, refers to the ability to meet a 1-in-20 peak demand day in the event of the loss of the largest single piece of gas infrastructure.

severe peak demand days is also uncertain. A 1-in-50 peak gas demand[3] day is likely to reflect low temperature and low wind conditions which means that the availability of offshore wind generation and also the ability to charge storage may be limited.

## Gas import disruption scenario analysis

Under a scenario assuming the outage of the largest piece of gas infrastructure (the IC2 interconnector), we find that Ireland could meet all non-power sector gas demand by importing gas from GB through the IC1 gas interconnector and domestic production. However, there would be disruption to electricity consumers in both 2035 and 2040. Impacts on electricity consumers would be particularly significant if the IC2 outage coincided with a period of extreme cold weather and low wind availability.

The impact of an IC2 outage on electricity consumers could be mitigated by the addition of an FSRU. The alternative mitigation options modelled would reduce but not fully eliminate these impacts.

A full disruption to gas supplies from GB (i.e. an outage of both IC1 and IC2 interconnectors) would result in widespread unmet gas demand in the non-power sector, with virtually all non-protected Industrial & Commercial (I&C) demand[4] being cut off during the disruption period. We also estimate significant disruption to protected consumer[5] demand in both 2035 and 2040.

The impacts of a full Moffat outage on the electricity sector, assuming normal weather conditions, would also be notable, with up to 6% of overall electricity demand during the disruption period being unmet if Ireland cannot import electricity at full capacity during the disruption period. We estimate that an FSRU, based on the assumed sizing of 161 GWh/d, could mitigate a significant portion but not all of these impacts.

## Comparison against CEPA's 2022 security of supply review

The findings of CEPA's 2022 analysis of the security of supply can be summarised as follows:

- Under IC2 outage (and cold weather), there was no unmet gas and electricity demand in either 2025 or 2030. However, in 2025 in particular, unmet demand was avoided only by fully drawing on available linepack and use of secondary fuel switching in the power sector.
- Under a 30-day full Moffat outage, we found that up to 74% of all non-power sector gas demand is unserved during the disruption, including up to 58% of protected consumer demand. There were also impacts on the electricity sector, with 389 GWh of unserved electricity demand in 2025, and between 1-3 GWh in 2030

In comparison, our current assessment finds:

- There is unserved electricity demand in the case of an IC2 outage with cold weather in both 2035 and 2040, though still no unserved demand in the gas sector. The different finding regarding unserved electricity demand is largely due to the fact that use of secondary fuel was key to avoiding electricity demand impacts in the 2022 study, whereas we do not assume any secondary fuel switching in our current analysis, following guidance from DECC that the ability of plants to switch to secondary fuel on a large scale is untested, and represents a risk around plant and fuel availability in a security of supply situation.

---

[3] We assess the N-1 test in this report against 1-in-50 peak gas demand projections based on GNI guidance that 1-in-20 and 1-in-50 peak demand conditions for Ireland are similar based on analysis undertaken for the National Risk Assessment 2022.

[4] Non-protected I&C demand refers to Daily Metered (DM) and Large Daily Metered (LDM) customers which includes large gas consumers in sectors such as pharma, food & drink and dairy.

[5] Protected Customers are defined as all Non-daily metered consumers (including domestic customers) as well as priority customers in the Daily Metered sector (hospitals and nursing homes, including retirement homes; high security prisons). Gas Networks Ireland will prioritise gas supply to Protected Customers above other categories, however this does not guarantee continuity of supply in all circumstances.

- There are very significant impacts on power sector and non-power sector gas consumers, including protected consumers in both 2035 and 2040 under a full disruption to gas imports from GB. The percentage of protected consumer demand affected during 1-month full disruption is 51% in 2035 and 47% in 2040. This is in line with results estimated for 2030 under Baseline 1 (lower gas demand) in the 2022 study.

A further CEPA study, commissioned by DECC and published in November 2023 as part of DECC's Energy Security Package[6], presented analysis on Ireland's ability to meet the N-1 infrastructure standard. The study estimated that Ireland would be able to meet 69% of peak day gas demand in 2029/30 in the case of an N-1 outage. This report finds that Ireland would be able to meet 73% and 77% of peak day gas demand in 2035 and 2040, respectively. The increase in the proportion of peak day gas demand that can be met in the case of an N-1 outage, as we move closer to 2040, is primarily due to projected reductions in peak day gas demand from residential and I&C consumers.

[6] CEPA (April 2023), Review of the Security of Energy Supply of Ireland's Electricity and Natural Gas Systems

# 1. INTRODUCTION

CEPA's technical analysis of the security of supply of Ireland's electricity and natural gas systems, published in September 2022[7], helped inform the Department of the Environment, Climate and Communications' (DECC) review and consultation on Ireland's security of energy supply ("Security of Supply Review"). That analysis covered the period up to 2030.

DECC has now commissioned CEPA to conduct an update of the analysis of security of energy supply in Ireland that CEPA carried out for DECC in 2022, but looking over the period into the 2030s.

The aim of this study is to update CEPA's 2022 analysis using the latest available data, to assess if the key risks and mitigation actions identified in the 2022 analysis of security of energy supply are still relevant and appropriate in the period up to 2040.

## 1.1. SCOPE OF THE ANALYSIS

This analysis is undertaken in the context of concerns raised in the Security of Supply Review regarding Ireland's dependency on pipeline imports of natural gas from GB, with the majority of natural gas supplies being imported via two gas interconnector pipelines from GB - IC1 and IC2. Ireland currently fails the EU N-1 infrastructure standard which requires that EU Member States be able to serve exceptionally high gas demand in the event of a loss of the largest single piece of gas infrastructure.

The scope of this study, as agreed with DECC, includes:

- Conducting an **assessment of Ireland's ability to meet the N-1 infrastructure standard** for gas in 2035 and 2040 without additional mitigation.
- Testing the **impact of gas import disruption scenarios** (partial and full disruption of gas imports from GB).
- Identifying the **shortfall in supply** in 2035 and 2040 for gas and power systems under the disruption scenarios modelled. The supply shortfall is measured in terms of unserved energy demand during the disruption period in both the gas and electricity sectors.
- Assessing the **ability of potential mitigation options** to address the identified shortfall in energy supplies.

The primary focus of this assessment is on physical electricity and gas security of supply – e.g., on the ability of the Irish energy system to meet physical demand of electricity and gas consumers

The study does not seek to update the findings of the previous analysis for 2025 and 2030, given that the proposed mitigation measures are not likely to be implemented before the 2030s.

## 1.2. REPORT STRUCTURE

The rest of this report is structured as follows:

- **Section 2** provides a brief overview of the findings of our 2022 study.
- **Section 3** presents our methodology and the key assumptions for carrying out the assessment.
- **Section 4** presents our findings on the analysis of the N-1 infrastructure standard.
- **Section 5** summarises our assessment of the security of supply shocks modelled and the impact of selected mitigation options.

[7] CEPA (September 2022), Technical Analysis of the Security of Energy Supply of Ireland's Electricity and Natural Gas Systems

# 2. OVERVIEW OF PREVIOUS CEPA ANALYSIS

CEPA's technical analysis of the security of supply of Ireland's electricity and natural gas systems, published in September 2022, helped inform DECC's review and consultation on Ireland's security of energy supply.

The scope of CEPA's analysis was as follows:

- Identify and examine the key shocks to physical security of supply in Ireland's electricity and natural gas systems by 2030.
- Identify and appraise options which could mitigate the impact of these shocks.

The analysis carried out by CEPA in 2022 was run using a modelling framework that consisted of a set of gas and electricity market models that captured interactions between the gas and electricity sectors as well as between Irish and global/European energy markets.

CEPA's analysis identified a full disruption to Ireland's gas import capability through the two pipeline interconnectors to GB (IC1 and IC2) as the main risk to physical gas security of supply in Ireland. Two scenarios involving a full disruption of the two pipelines were tested and the following findings were reached:

- A seven-day outage of both pipelines (**Shock Scenario 4**) would lead to a disruption of supplies to customers, including some protected gas customers.
- A similar shock lasting 30 days (**Shock Scenario 5**) would lead to a disruption of gas customers, including more protected customers and over a longer period.

The analysis was carried out for the 2025 and 2030 spot years with two separate baseline scenarios being tested in 2030: Baseline 1 assuming that that the Climate Action Plan (CAP) 2021 targets are met; and Baseline 2 which represented a lower level of climate ambition, set out in the previous CAP 2019.

The main findings from CEPA's previous security of supply study were:

- Under IC2 outage (and cold weather), there was no unmet gas and electricity demand in either 2025 or 2030.
- However, in 2025 in particular, unmet demand was avoided only by fully drawing on available linepack and use of secondary fuel switching in the power sector.
- Under a 30-day full Moffat outage, we found that up to 74% of non-power sector gas demand is unserved during the disruption, including up to 58% of protected consumer demand, as summarised in Table 2.1 below.
- There were also impacts on the electricity sector, with 389 GWh of unserved electricity demand in 2025, and between 1-3 GWh in 2030.

*Table 2.1.Impact of the full disruption to pipeline gas imports on unserved gas demand within the chosen shock period (14th Jan to 12th Feb)*

| Impact of the disruption on the value of unserved gas demand | | 2025 | Baseline 1 | Baseline 2 |
|---|---|---|---|---|
| Unserved demand (GWh) | Protected | 736.3 GWh | 732.9 GWh | 1,092.6 GWh |
| | I&C | 1,177.0 GWh | 998.8 GWh | 1,178.7 GWh |
| | Power Sector (to meet unserved electricity) | 713.9 GWh | 5.6 GWh | 2.2 GWh |
| Unserved demand (%) | Protected | 37% | 48% | 58% |
| | I&C | 100% | 100% | 100% |
| | Power Sector (to meet unserved electricity) | 100% | 100% | 100% |

*Source: CEPA study September 2022*

The analysis also assessed the ability of a range of potential options to mitigate the observed security of supply impacts of the shocks mentioned above. The gas sector mitigation options included a strategic FSRU, a strategic gas storage facility, and a package of options including strategic gas storage, renewable gas, gas DSR and hydrogen injection. The mitigation options were assessed for 2025 and 2030 but only against Baseline 1 (which were consistent with the Government climate targets at the time of the analysis).

The Minister of the Environment, Climate and Communications requested Gas Networks Ireland (GNI), as a final part of the review of Ireland's energy security, to complete a detailed examination of the optimal approach to deliver the emergency gas reserve. A floating storage and regassification unit was considered the optimal technology approach to deliver a Strategic Gas Emergency Reserve.

# 3. APPROACH AND SCENARIOS

In this section, we describe the approach used in this study to assess security of supply impacts and the key inputs and data sources that were used in our analysis.

## 3.1. MODELLING FRAMEWORK

Given the shorter timeline and narrower focus of the requirements for this piece of work relative to the 2022 study, we agreed with DECC a simplified modelling framework to deliver the requirements of this work, as described below.

To determine **gas sector** impacts, we carried out quantitative modelling that assessed the extent to which the Irish gas system can meet gas demand under the security of supply scenarios modelled (described below) and what the impact of the mitigation options would be. Our model compares the available supply capacity under all shock/mitigation scenarios against daily gas demand during the entire disruption period. The outputs of this modelling are:

- Unserved non-power sector gas demand, including volume of unserved protected consumer gas demand.
- Gas supply available to the power sector, if any, on each day of the disruption.

For the **electricity sector**, there are more complex interactions including interconnection to various markets, increasing levels of electricity storage and the need to balance demand and supply on an hourly basis.

To assess these impacts, we developed a modelling tool which enables us to estimate the ability of the Irish power system to meet electricity demand, given assumptions about the availability of gas in the power sector and ability to import electricity from neighbouring markets. We model the Single Electricity Market (SEM) as a whole, but we focus the analysis and calculate the unserved demand for Ireland only.

We first determine the hourly electricity demand that needs to be met in every hour, net of available renewable generation. We then assess the extent to which demand can be met based on available dispatchable generation capacity in the SEM. We constrain the availability of gas-fired power plants to generate electricity based on the level of available gas supplies determined in our gas sector modelling.

Electricity storage is modelled based on a simplified approach which does not fully optimise storage use based on price, but where storage charges during periods of excess generation and discharges in periods of excess demand, subject to the limits on the storage capacity.

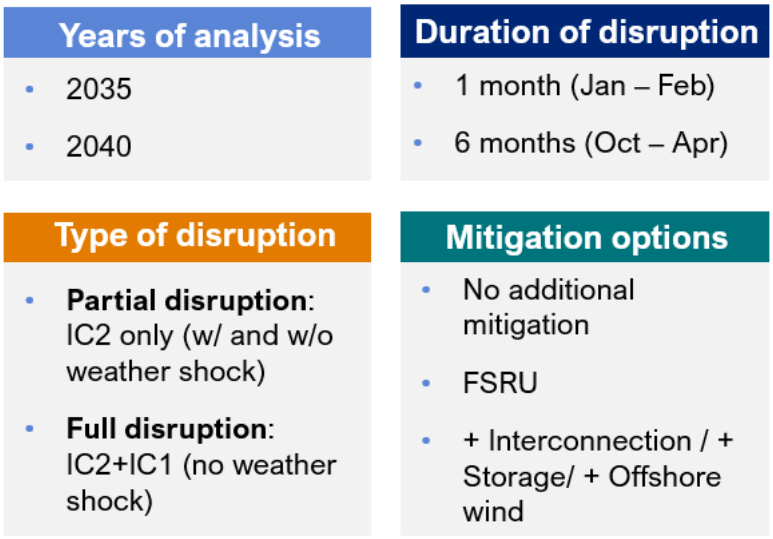
The simplified approach does not simulate electricity cross-border flows. Instead, we make assumptions about the availability of these imports. For this reason, our results for the electricity sector in this report are provided as a range based on assumptions about the availability of electricity imports during the disruption period.

The output of this modelling is unserved power sector electricity demand.

## 3.2. RISK SCENARIOS AND MITIGATION OPTIONS MODELLED

The scenarios set out in the scope of this study, including type of disruption and mitigation options analysed, are summarized in Figure 3.1.

*Figure 3.1. Scenarios included in the study*




We assessed the potential security of supply impacts and benefit of mitigation options in the years **2035** and **2040** in the context of the following disruption scenarios:

- **Risk Scenario A:** A disruption to pipeline imports of natural gas from GB through the largest single piece of gas infrastructure (IC2). This disruption is simulated under two cases:
  - **A1:** Normal seasonal weather conditions, including typical availability of solar and wind generation.
  - **A2:** Cold weather conditions, based on 1-in-20 temperature conditions, resulting in high gas demand, coupled with a period of low wind and low solar generation.
- **Risk Scenario B:** A disruption to all pipeline imports of natural gas from GB (both IC1 and IC2).

**All risk scenarios were modelled assuming a period of 30-day disruption and a period of 6 months disruption for a total of six risk scenarios per year.**

We assessed the following **mitigation options**:

- **Status quo**: no additional mitigation
- Addition of a **Strategic Gas Emergency Reserve - FSRU**
- Additional **electricity interconnection, offshore wind,** and **long-term electricity storage**.

Our assessment focuses on physical security of supply impacts within the disruption scenarios outlined above, rather than price impacts. This approach is in line with the previous analysis undertaken by CEPA for DECC.

## 3.3. Input assumptions

An important part of the analysis involved developing the input assumptions and scenarios underpinning the modelling. Given the modelling horizon involved, there is uncertainty regarding demand and supply forecasts. **The input assumption gathering exercise aimed to develop a view of Ireland's gas and electricity supply and demand balance in 2035 and 2040, including evolution of annual, peak, and average demand, given the best available information at the moment.**

Table 3.1 summarizes the main assumptions required for our input scenarios.

*Table 3.1. Key assumptions used in our modelling scenarios*

| Gas sector assumptions | Electricity sector assumptions |
|---|---|
| • Evolution of annual and peak-day non-power gas demand broken down by consumer type (protected vs non-protected consumers)<br>• Future indigenous natural gas supplies (e.g. evolution of Corrib supplies)<br>• Future supply of biomethane or hydrogen blending in Ireland | • Evolution of annual and peak electricity demand<br>• Future generation capacity mix, including plant additions and retirements of existing plants<br>• Future interconnection and electricity storage levels |

### 3.3.1. Gas sector assumptions

As part of the overall goal to conduct our study based on the most recently available projections, we developed our assumptions by drawing on GNI's Network Development Plan 2024, which provides gas demand and supply projections for the 2024-2033 period, and the National Energy Projections (NEP) 2024, published by the Sustainable Energy Authority of Ireland (SEAI)[8], which provides gas demand projections for 2030 and 2040. The SEAI projections include two scenarios:

- **'With Existing Measures' (WEM) scenario** – based on the estimated impact of policies and measures currently implemented and actions committed to by Government. It considers the 2023 Climate Action Plan (CAP23), but not the 2024 Climate Action Plan (CAP24). The targets set in the CAP23 are not automatically assumed to be met - e.g., EV uptake target is not fully met under this scenario. Similarly, the heat pump uptake in the WEM reaches 240,000 heat pumps in existing dwellings by 2030, compared to the 400,000 target in CAP23 and CAP24.
- **'With Additional Measures' (WAM) scenario** – based on the estimated impact of measures outlined in the latest Government plans at the time of the National Energy Projections. This includes all policies and measures included in the WEM scenario, plus those included in the latest Government plans but not yet fully implemented. The WAM scenario takes into account the CAP24 and assumes that the CAP targets will be either fully achieved or will be much closer to being achieved, compared to the WEM scenario. For example, this scenario predicts 362,000 heat pumps in existing dwelling by 2030.

As power sector gas demand needs are determined within our electricity market modelling, we only need to derive assumptions about the evolution of residential and industrial and commercial (I&C) gas demand in Ireland.

Based on discussions with DECC, we identified GNI's **NDP 2024 Best Estimate** projections as the best option to consider in terms of the evolution of residential gas demand. The Best Estimate residential demand scenario assumes 75% heat pump and district heating adoption target being met by 2030 and the adoption trajectory continues beyond 2030. It also corresponds largely to the mid-point between the two SEAI scenarios. As the NDP 2024 projections only cover the period to 2032/33, we extended GNI's forecast to 2035 and 2040 based on recent growth trajectories and considering a pathway consistent with Net Zero by 2050.

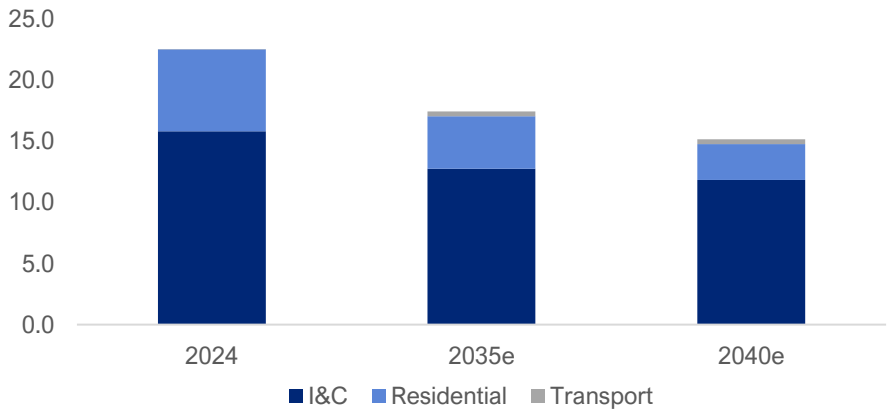
In the case of industrial and commercial gas demand, we adopted the **NEP 2024 WEM** scenario projections (i.e. the higher of the two SEAI demand projections). All GNI's NDP 2024 I&C demand scenarios are above the SEAI demand projections for 2030, and, except for the NDP Low demand scenario, they predict higher I&C gas demand in 2032/33 compared to the present. We considered that the SEAI WEM projections provide a better representation of the potential reductions in I&C gas demand that can be achieved by 2040. Another consideration was the fact that a key driver of higher I&C gas demand in the GNI projections is increased gas demand from Large Energy Users (LEUs). As our analysis also accounts for increasing demand from LEUs through the electricity sector

[8] SEAI, National Energy Projections 2024, available online

assumptions (which can then translate into increased power sector gas demand), we considered that there is a risk of double counting if we used GNI's I&C gas demand projections.

These assumptions result in a 23% decline in non-power sector gas demand by 2035 and 33% by 2040 (compared to 2024 values). The graph below shows current non-power sector gas demand and the forecast for the years of the analysis.

*Figure 3.2. Gas demand projections (excluding power sector) in Ireland – TWh*




*Source: CEPA based on GNI and SEAI. 2024 figures and breakdown by category are exclusively from GNI's NDP 2024.*

For gas supply, we assume that:

- Moffat import capacity remains at current levels, as predicted by GNI's NDP 2024 forecast.
- Biomethane production reaches 2.85 TWh/yr in 2035 and 5.7 TWh/yr in 2040, reflecting a delay in meeting the 2030 CAP target.
- There is no hydrogen injection in the gas grid by 2040.
- Corrib continues production in 2035 but at a declining rate, based on extending the GNI NDP 2024 forecast. We assume that Corrib production is depleted by 2040.

### 3.3.2. Electricity sector assumptions

To derive electricity demand and generation assumptions, we reviewed a draft version of EirGrid's 2024 All Island Resource Adequacy Assessment (AIRAA), which provides EirGrid's most recent forecast of electricity demand, covering a 10-year horizon (until 2034).

The AIRAA projections, however, do not assume any further deployment of dispatchable generation, storage, demand side response or interconnection beyond what is already contracted in the capacity market[9] (i.e. it does not make projections about what level of capacity might be contracted in future capacity auctions for delivery by 2035 and 2040). Therefore, we considered alternative data sources for the purpose of this modelling exercise.

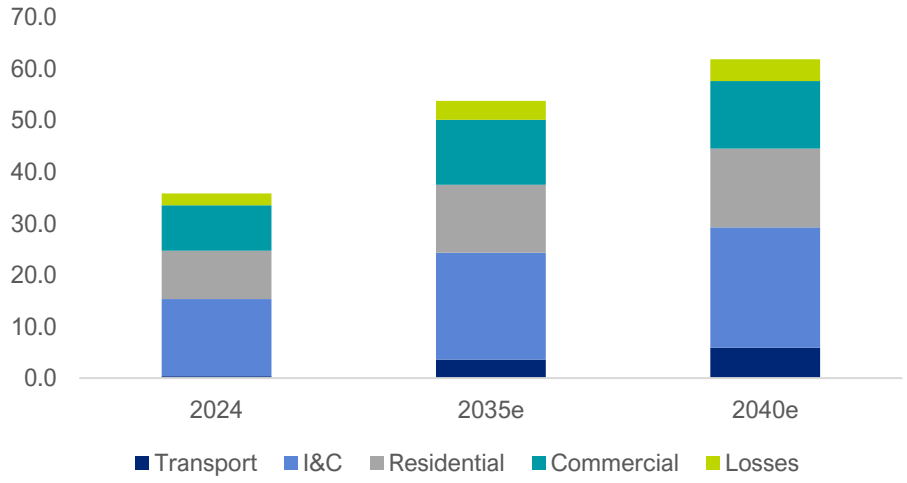
We decided to further explore the 2023 Tomorrow Energy Scenarios (TES) published by EirGrid, which provides different pathways for Ireland's clean energy transition and forecast electricity demand and generation for the years 2035, 2040, 2045 and 2050. The TES do not represent a forecast of the future, but rather they illustrate different potential states of the world for the electricity system. They are a useful data source for our analysis because they provide a complete, internally consistent set of assumptions for demand and generation capacity, for both 2035 and 2040.

[9] This does not include capacity procured through the T-4 2028/29 Capacity Auction.

We selected the Constrained Growth scenario from the TES because it is the pathway that most closely aligns with the AIRAA 2024 forecast for electricity demand in Ireland.[10]

Figure 3.3 below shows current electricity demand and the corresponding projections for 2035 and 2040. The projections show a 50% increase in demand by 2035, and a 73% increase by 2040, compared to 2024.

*Figure 3.3. Electricity demand projections in Ireland (TWh)*




*Source: CEPA based on TES 2023 and AIRAA 2024.*

In the case of Northern Ireland, we adjusted the electricity demand projections from the TES Constrained Growth scenario to bring in line with the AIRAA 2024 Median demand projection (extended to the years of the analysis), given that Northern Ireland demand projections in the TES CG scenario were much higher than the latest AIRAA.

Our assumptions on the level of installed capacity for 2035 and 2040 are mostly in line with assumptions in the TES 2023 Constrained Growth (CG) scenario with some adjustments, described below.

The TES CG scenario assumes significant deployment of onshore wind (over 9 GW) and solar PV (7 GW) by 2035, but assumes very low expansion of offshore wind. To reflect the potential and ambition for offshore wind in Ireland, we have adjusted upwards the assumed offshore wind capacity, relative to the TES CG assumptions, to 3.75 GW by 2035 and 7 GW by 2040. This is below the current targets for offshore wind deployment of 5 GW by 2030 and 20 GW by 2040, however the 2035 capacity values are aligned with the level of offshore wind capacity projected at the end of the AIRAA 2024 horizon. In addition, we have intentionally taken a conservative approach to assumptions regarding offshore wind deployment given that we are assessing higher levels of deployment as part of the mitigation options assessed for this study, as specified in Table 3.2.

We assumed interconnection capacities in 2035 and 2040 equal to 2.95 GW of SEM-GB interconnection and 700 MW to France. This reflects the development of known interconnection projects including Celtic, MaresConnect and LirIC. We assume no further interconnection projects are developed as part of our baseline scenario assumptions; however, we test the impact of additional interconnection as part of the mitigation options.

Table 3.2 summarises the generation capacities assumed for Ireland for the baseline scenario and the additional capacities assumed for the mitigation options assessed in Section 5.3.

[10] We extended the AIRAA demand projections from 2034 out to 2035 and 2040.

*Table 3.2. Electricity installed capacity assumptions in Ireland under baseline and mitigation options*

| | Baseline | | Mitigation (increase from baseline) | |
|---|---|---|---|---|
| | 2035 | 2040 | 2035 | 2040 |
| **Generation capacity (GW)** | | | | |
| Solar | 7.0 | 9.1 | - | - |
| Onshore wind | 9.1 | 10.8 | - | - |
| Offshore wind | 3.8 | 7.0 | 3.0 | 7.0 |
| Gas | 5.9 | 5.9 | - | - |
| Hydro | 0.2 | 0.2 | - | - |
| **Demand side response (GW)** | 1.2 | 1.2 | - | - |
| **Storage capacity (GWh)** | 18.6 | 25.2 | 5.0 | 10.0 |
| **SEM interconnection capacity (GW)** | 3.7 | 3.7 | 1.0 | 1.0 |

Finally, we do not model the ability of gas-fired plants to operate on secondary fuel, based on current obligations[11]. This is based on advice from DECC and reflects the fact that secondary fuel operations are not generally considered as part of N-1 assessments. Furthermore, the capability of plants to switch to secondary fuel on a large scale is untested, potentially resulting in generators tripping when switching or operating on secondary fuel, and there are challenges around resupplying generators operating on secondary fuel beyond their 3–5-day storage obligations. Therefore, this represents a risk around plant and fuel availability in a security of supply situation.

## 3.4. FURTHER NOTES ON MODELLING FRAMEWORK

The analysis presented in this report should be interpreted in the context of the following assumptions and modelling limitations present in our analysis:

- We do not take into account the ability of gas-fired plants to switch to secondary fuel generation or the ability to draw on available linepack in the gas sector.[12] Secondary fuel operation in particular can provide a significant degree of mitigation for electricity sector impacts; however, it comes with associated risks around the ability to switch to secondary fuel generation in a sudden security of supply event. Use of gas stored in linepack can also provide very short-term relief in the case of a gas supply shortage; however, linepack depletion presents operational risks for the network and would only be used as a last resort measure.
- Our simplified modelling framework does not fully optimise the use of storage, including the interaction between storage and interconnection – with full optimisation, these sources could be better used to mitigate more unmet demand.

[11] The current secondary fuel obligations require gas fired generators in Ireland to be able to run on secondary fuel at full capacity for 3 days (OCGT) and 5 days (CCGT). In Northern Ireland, the obligation is to be able to run for 5 days for all gas fired plants.

[12] The availability of linepack is highly dependent on the timing and duration of the supply shock. A one-day event would give the system the opportunity to recoup linepack once the event has passed and/or demand has dropped. There is limited/no ability to recoup linepack during an extended and severe disruption i.e. longer than one day.

- We assume no voluntary demand response from energy consumers - voluntary demand reductions, in response to higher prices or to public appeals to reduce consumption, can help mitigate some of the impacts observed.[13]
- Our analysis only considers the ability of the system to balance supply and demand. It does not consider the need for additional system services, including the need for local generation to deal with network constraints. A full disruption to gas supplies that limits the availability of gas fired generation over a prolonged period of time may affect the ability of the System Operators to procure the system services required for a safe operation of the network.

[13] Although we note that the N-1 infrastructure standard requires all demand to be met without taking account of demand-side measures.

# 4. N-1 INFRASTRUCTURE STANDARD ANALYSIS

In this section, we present results from our assessment of the ability of the Irish gas system to meet the N-1 infrastructure standard in 2035 and 2040.

## 4.1. CONTEXT

The **N-1 standard**, as defined in EU Regulation 2017/1938[14], refers to the ability to meet demand, on a day of exceptionally high gas demand, in the event of the loss of the largest single piece of gas infrastructure. For Ireland, this would be a disruption of supply from the IC2 interconnector with GB. The purpose of the N-1 standard is to oblige Member States to maintain a minimum level of infrastructure such to ensure a degree of redundancy in the system in the event of a disruption of the single largest gas infrastructure.

Ireland does not currently meet the N-1 infrastructure standard. In 2022, GNI carried out an assessment that determined that, on its own, Ireland could cover 65% of peak-day demand in the event of a disruption to its largest infrastructure.[15] The EU Regulation allows for the infrastructure standard to be met on a regional basis together with another Member State, however, following UK's exit from the EU, Ireland no longer meets the infrastructure standard on that basis.

According to Regulation (EU) 2017/1938, the N-1 standard is assessed in the context of a 1-in-20 peak demand day – i.e., a daily gas demand expected to occur with a statistical probability of once in 20 years. We assess the N-1 test in this report against 1-in-50 peak gas demand projections[16], which theoretically represents a higher level of demand than 1-in-20. This is based on GNI guidance that 1-in-20 and 1-in-50 peak demand conditions for Ireland are similar.[17]

The formula for calculating the N-1 standard (set out in Annex II of Regulation 2017/1938) does not include the contribution of potential mitigation that could be provided by the use of linepack for gas or secondary fuel switching by gas-fired electricity generators in Ireland.

Finally, we note that the N-1 analysis presented in this report is just an indicative analysis based on possible peak demand projections, and **it is not meant to represent a formal assessment of Ireland's compliance with the N-1 standard**.

## 4.2. 1-IN-50 PEAK-DAY DEMAND PROJECTIONS

GNI's 1-in-50 peak demand forecasts reflect very low ambient temperature (driving up both gas and electricity demand) and low wind conditions - which GNI finds tend to be correlated with very cold temperatures and therefore increases dependency on gas-fired generation.

To project 1-in-50 peak-day gas demand beyond the end of the GNI NDP 2024 horizon (2032/33), we apply the following assumptions:

- We take residential 1-in-50 peak gas demand from the NDP Best Estimate scenario and assume it declines from 2032/33 onwards at the same rate as annual residential gas demand, as assumed in our input

[14] The N-1 Infrastructure Standard is set out in Regulation (EU) 2017/1938 of the European Parliament and the Council of 25 October 2017 concerning measures to safeguard the security of gas supply and repealing Regulation (EU) No 994/2010and is available on europa.eu

[15] CRU, *Annual Report on Gas Security of Supply 2024*

[16] Representing a severe winter peak day that is statistically likely to occur once every 50 years.

[17] Based on previous analysis undertaken for the National Risk Assessment 2022.

scenarios described in section 3.3.1. This results in a 12% reduction by 2035 and 40% reduction by 2040 relative to 2032/33 levels.

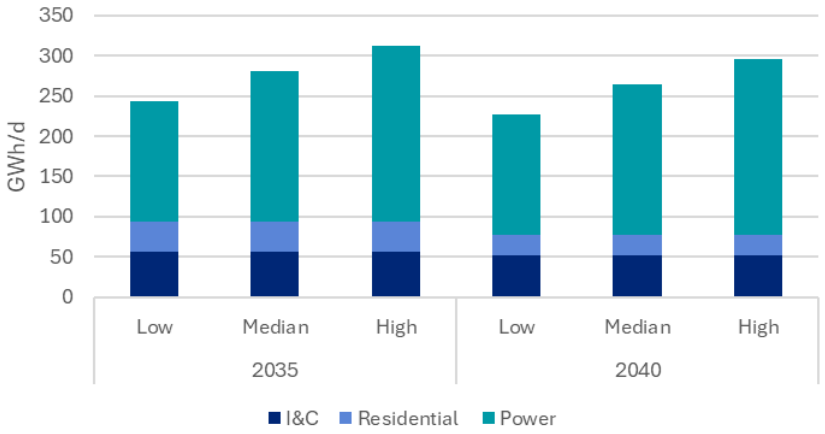
- We take I&C 1-in-50 peak gas demand from the NDP Low demand scenario and assume it declines from 2032/33 onwards at the same rate as annual I&C gas demand in our input scenarios. This results in a 15% reduction by 2035 and 21% reduction by 2040 relative to 2032/33 levels.

There is greater uncertainty around the evolution of 1-in-50 peak day gas demand from the power sector. The evolution of peak-day demand in the power sector can be expected to be decoupled from the evolution of annual demand. While annual power sector gas demand is expected to decline as renewable penetration increases, the peak day power sector gas demand, especially under 1-in-50 conditions with low wind generation, may remain high.

To deal with this uncertainty, we take the Low, Best Estimate and High GNI NDP 1-in-50 peak-day power sector demand projections for 2032/33 and we keep these projections constant in both 2035 and 2040. Given the relatively large gap between Low and High projections, this gives us a broad range of potential peak-day gas demand projections to use in our analysis.

Figure 4.1 below shows the level and make-up of the 1-in-50 peak day gas demand used in our analysis for 2035 and 2040. Power sector gas demand accounts by far for the greatest proportion of demand on a severe peak demand day.

*Figure 4.1.: 1-in-50 peak day gas demand projections for 2035 and 2040*




## 4.3. RESULTS OF N-1 INFRASTRUCTURE STANDARD ANALYSIS

Figure 4.2 shows the results of our analysis of Ireland's ability to meet the N-1 standard in 2035 and 2040. We find that Ireland would fail to meet the requirements set out under the N-1 infrastructure standard, under our baseline assumptions, when assessed on a national level.

We estimate that, in the case of a N-1 outage, Ireland may be able to meet, depending on the peak day gas demand scenario assumed, between:

- 66% and 84% of 1-in-50 peak-day demand in 2035 (with a central estimate of 73%); and
- 68% and 89% of 1-in-50 peak-day gas demand in 2040 (with a central estimate of 77%).

As shown in Table 4.1, this is equivalent to a gas supply shortfall of between:

- 38 – 108 GWh/d in 2035; and
- 25 – 94 GWh/d in 2040.

Most of the gas demand on a 1-in-50 peak demand day comes from the power sector. Assuming that power sector gas demand would be interrupted before non-power sector gas demand in the case of a gas supply shortage, the shortfall identified in our N-1 analysis would translate into disruptions to gas supplies to the power sector but not to residential or I&C gas consumers.

*Figure 4.2. Ability to meet N-1 standard in 2035 and 2040*

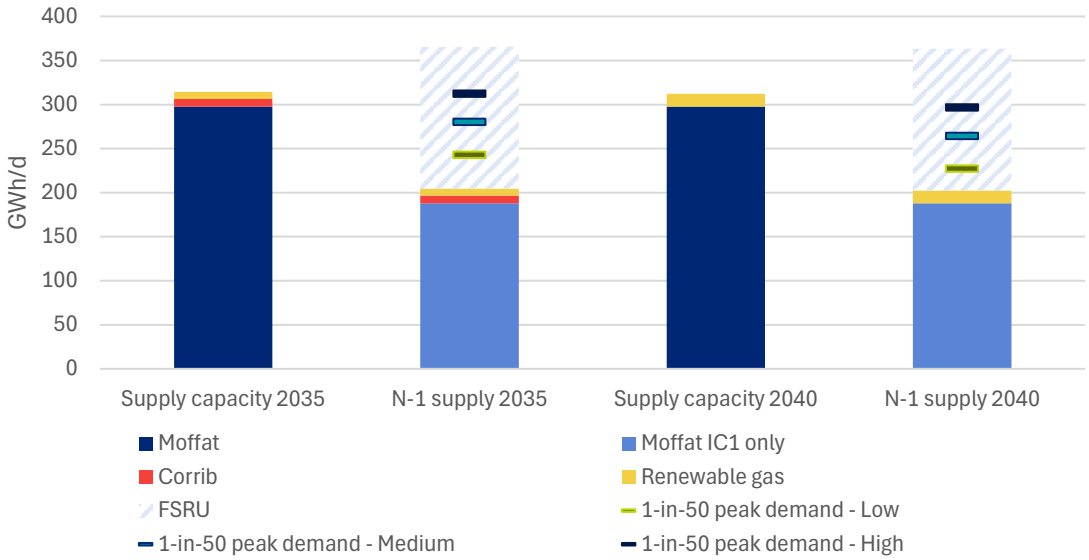



*Table 4.1. Estimated gas supply gap on 1-in-50 peak gas day (GWh/d)*

| | 2035 | 2040 |
|---|---|---|
| 1-in-50 peak demand: Low | 38.2 | 24.5 |
| 1-in-50 peak demand: Medium | 75.4 | 61.7 |
| 1-in-50 peak demand: High | 107.6 | 93.9 |

Figure 4.2 also shows the impact of adding an FSRU with assumed daily supply capacity of 161 GWh/d. In this case, we estimate that Ireland would be able to meet the entire 1-in-50 peak day gas demand in the event of an IC2 outage.

## 4.4. ALTERNATIVE N-1 MITIGATION OPTIONS

We have also estimated the capacity required from alternative mitigation options, other than an FSRU, to help Ireland meet the N-1 standard. As specified by DECC, we have focused our analysis on electricity sector mitigation options. The rationale for this is that power sector gas demand accounts for most of the gas demand on a 1-in-50 peak demand day. Therefore, electricity sector mitigation options could help Ireland meet the N-1 standard for gas by reducing power sector gas demand.

The alternative options that we have been asked by DECC to consider in this study are:

- Additional electricity interconnection.
- Additional electricity storage.
- Additional offshore wind capacity.

To determine the additional electricity capacity required to meet this gap under the different mitigation options, we assume that the gas supply gap identified in our N-1 analysis affects power sector gas demand (i.e., the shortfall in

gas supply translates into a shortfall in electricity generation). We then calculate the **power supply gap**[18] resulting from the gas N-1 event for each year and each peak day demand scenario, as shown in Table 4.2.

*Table 4.2. Estimated total electricity supply gap on a 1-in-50 peak gas day (GWh)*

| | 2035 | 2040 |
|---|---|---|
| 1-in-50 peak demand: Low | 19.1 | 12.2 |
| 1-in-50 peak demand: Medium | 37.7 | 30.8 |
| 1-in-50 peak demand: High | 53.8 | 46.9 |

The main challenge that these mitigation options face is the uncertainty around the contribution that they can provide during peak demand periods. In the following sections, we provide an indication of the level of capacity required from each of these technologies to mitigate N-1 impacts based on assumptions regarding their availability. In Section 4.4.4 we also provide a high-level indicative estimate of the cost associated with the required additional capacity under each mitigation option.

### 4.4.1. Impact of additional electricity interconnection

Table 4.3 below shows the estimated additional electricity interconnection capacity required to meet the electricity shortfall on a 1-in-50 peak gas demand day under N-1 conditions. This is in addition to the 2.95 GW of SEM-GB interconnection and 700 MW of interconnection to France already assumed in our baseline scenario.

Consistent with the rest of our analysis, we assume an import availability factor of between 70% and 100%. We note that GNI assumes that electricity imports are capped at 70% of capacity for the purpose of calculating the 1-in-50 peak gas demand therefore this assumption is most consistent with the basis on which 1-in-50 peak day gas demand estimates are determined.[19] Under this assumption, we estimate that over 2.2 GW of additional electricity interconnection would be required in 2035 to meet the supply shortfall in a gas N-1 event, under a medium 1-in-50 peak day demand projection. Under a high peak day demand projection, the additional interconnection required would rise to 3.2 GW.

*Table 4.3. Additional interconnector capacity (MW) needed to cover the electricity supply gap on a 1-in-50 peak gas demand day*

| Peak-demand scenario | 2035 | 2040 |
|---|---|---|
| With 100% import availability | | |
| Low | 796 | 510 |
| Medium | 1,571 | 1,285 |
| High | 2,242 | 1,956 |
| With 70% import availability | | |
| Low | 1,138 | 729 |
| Medium | 2,245 | 1,836 |
| High | 3,203 | 2,794 |

Arguably, on a 1-in-50 peak gas demand day, the availability of imports may be reduced below the 70% assumed in our analysis - for example, if regional correlation of weather patterns means the interconnected markets experience similar high-demand and low-renewable generation conditions. This has been illustrated through recent events

[18] The electricity supply gap is calculated by multiplying the gas supply gap in Table 4.1 by a 50% efficiency rate for a gas fired power plant.

[19] EirGrid also assumes 70% interconnector capacity availability as part of the 2024 AIRAA Secure scenario.

such as the cold weather spell in early January 2025 when both Ireland and GB experienced very low renewable generation and high demand due to the cold weather. During the peak period in the evening on the 8th January, SEM electricity imports from GB dropped to as little as 188 MW, just below 20% of the total interconnection capacity (excluding Greenlink which began full operation at the end of January 2025).[20] At the same time, over the entire day on the 8th January, the interconnector utilisation was over 80%, which is within the availability range used in our analysis.

If the existing electricity interconnection capacity is not fully utilised on this peak gas demand day because of a lack of available generation in the neighbouring market, this calls into question whether any additional interconnection capacity to the same market would bring any additional benefit. For example, if the 2.95 GW of SEM-GB interconnection assumed in our analysis for 2035 and 2040 is not fully utilised in peak demand periods, then adding more interconnection to GB seems unlikely to deliver more electricity imports (except where the lack of imports was due to interconnector outage or local network constraints).

### 4.4.2. Impact of additional electricity storage

Table 4.4 shows the estimated additional electricity storage capacity required to meet the electricity shortfall on a 1-in-50 peak gas demand day under N-1 conditions.

The availability of storage units on high peak demand days is uncertain. We can assume that, given conditions on the day (high demand, low wind), storage facilities would not be able to charge during this day. Therefore, as a best-case scenario, we assume that storage units will be fully charged at the start of the day and can fully discharge the energy stored. Under these assumptions, the additional storage capacity needed to mitigate the supply gap must be exactly equal to the estimated shortfall. We note that this is potentially an overly optimistic assumption given that, under a prolonged weather spell, storage facilities may be unable to recharge, partially or fully, and therefore may be less than fully charged at the start of a 1-in-50 peak gas demand day.

Mitigating the N-1 impacts, even under the assumptions of storage availability on the day, would require a very significant level of additional storage volume – e.g., in the Low 1-in-50 peak demand scenario, the equivalent of at least an additional 10 GW of 2-hour battery storage or 5 GW of 4-hour battery storage would be required.

*Table 4.4. Additional storage capacity (GWh) needed to cover the electricity supply gap on a 1-in-50 peak gas demand day*

| Peak-demand scenario | 2035 | 2040 |
|---|---|---|
| Low | 19.1 | 12.2 |
| Medium | 37.7 | 30.8 |
| High | 53.8 | 46.9 |

### 4.4.3. Impact of additional offshore wind

Table 4.5 shows the estimated additional offshore wind capacity required to meet the electricity shortfall on a 1-in-50 peak gas demand day under N-1 conditions. A 1-in-50 peak gas demand day is likely to reflect low temperature and low wind conditions. Therefore, the benefit of additional offshore wind capacity in terms of meeting the electricity shortfall in these periods may be limited.

To estimate the availability of offshore wind during such periods, we rely on the de-rating factor for wind technologies as calculated by EirGrid for the SEM Capacity Market Auctions. Based on the latest Auction Information Pack published by EirGrid[21], the de-rating factor for wind is 0.065.

[20] Based on EirGrid system data available at https://www.eirgrid.ie/grid/real-time-system-information

[21] 2025/2026 T-1 Capacity Auction Initial Auction Information Pack

Based on this availability factor, we estimate that at least 12.25 GW of additional offshore wind would be needed by 2035 to cover the N-1 shortfall, rising to 34.5 GW in the high peak demand scenario.

*Table 4.5. Additional offshore wind capacity (GW) needed to cover the electricity supply gap on a 1-in-50 peak gas demand day*

| Peak-demand scenario | 2035 | 2040 |
|---|---|---|
| Low | 12.3 | 7.9 |
| Medium | 24.2 | 19.8 |
| High | 34.5 | 30.1 |

### 4.4.4. Cost implications of different mitigation options

In addition to the analysis of the capacity required from each option to potentially address the N-1 gap, we also drew on publicly available sources to develop an assessment of the potential cost implications of each option.

**Note:** We provide high-level indicative costs associated with the additional capacity based on published information. We have not independently verified the cost information provided in these sources.

It is important to note that these estimates simply capture the cost of developing these projects and do not consider the potential benefits/additional costs that different projects will bring, in terms of impacts on the energy markets, emissions, etc, (i.e., this does not provide a full cost benefit analysis estimate for the different technologies). Therefore, these estimates do not provide a comparison of the economic case for different security of supply mitigation options and will need to be interpreted with care.

Table 4.6 shows the estimated cost of the additional capacity required to cover the supply gap under an N-1 gas infrastructure outage, under different mitigation options, including an FSRU. We note that the costs shown for 2035 and 2040 are both relative to baseline - i.e., if the costs associated with mitigating impacts in 2035 are incurred then, assuming the additional capacity remains available in 2040, no further costs would be incurred for mitigating impacts in 2040.

*Table 4.6. Estimated cost (EUR billion) of the additional capacity needed to cover the supply gap under different mitigation options*

| | FSRU[22] | Additional IC[23] (100% import availability) | | Additional IC (70% import availability) | | Additional storage[24] | | Additional offshore wind[25] | |
|---|---|---|---|---|---|---|---|---|---|
| Peak-demand scenario | | 2035 | 2040 | 2035 | 2040 | 2035 | 2040 | 2035 | 2040 |
| Low | 0.9 | 1.3 | 0.9 | 1.9 | 1.2 | 12.1 | 7.8 | 79.8 | 51.2 |
| Medium | | 2.6 | 2.1 | 3.8 | 3.1 | 23.9 | 19.6 | 157.5 | 128.8 |
| High | | 3.7 | 3.3 | 5.4 | 4.7 | 34.2 | 29.8 | 224.8 | 196.1 |

[22] For FSRU, we used a base cost estimate provided by DECC of approximately [✂] for capex and [✂]/year for annual lease and operating costs over a 10-year period.

[23] For interconnectors, the estimated costs reflect the total project cost (capex and opex) of interconnection capacity to GB and are derived based on the Greenlink project costs submitted to the CRU and published in: Greenlink Electricity Interconnector "Cap and Floor Regulatory Framework."

[24] For electricity storage, the estimated costs reflect the capex and opex for a Li-ion battery and are derived based on cost estimates referenced in a GB study on the benefits of Long Duration Storage.

[25] For offshore wind, the cost estimates are based on total offshore wind costs (capex and opex) projected for projects operational in 2035 from the DESNZ Electricity Generation Costs 2023 dataset.

# 5. SECURITY OF SUPPLY DISRUPTION SCENARIO ANALYSIS

In this section, we present results from our modelling of scenarios assuming disruption to gas supplies from GB. We consider:

- Partial disruption assuming loss of the IC2 gas interconnector – this is modelled both under average winter conditions and under a weather shock event.
- Full disruption assuming loss of all gas imports to Ireland from GB – this is modelled against average winter conditions.

The disruptions have been modelled over a one-month (Jan-Feb) and a six-month (Oct –Apr) period.

The weather shock event modelled together with the IC2 outage is assumed to be a two-week cold spell occurring in the second half of January (overlapping with the period of IC2 outage), based on 1-in-20 temperature conditions, coupled with a period of low wind and low solar generation. We assume these weather conditions affect the whole island of Ireland.

## 5.1. ESTIMATED SECURITY OF SUPPLY IMPACTS: 2035

### 5.1.1. Gas market impacts

The maximum daily gas supply capacity (including imports through IC1, gas from Corrib and biomethane injections) under an **IC2 outage** scenario in 2035 is estimated at 205 GWh/d, relative to a peak non-power sector gas demand of 82 GWh/d (under normal conditions) or 92 GWh/d (under cold weather conditions).

This means that the available gas supply capacity is sufficient to avoid any unmet non-power sector gas demand and leaves at least 113 GWh/d of gas supply capacity available to the power sector each day. This is however not sufficient to avoid all instances of unmet electricity demand, as explained in the electricity sector impacts section.

Under a **full Moffat outage scenario**:

- The maximum daily gas supply capacity available from Corrib and biomethane is only 17 GWh/d.
- Gas consumers experience disruption to supplies every day during the outage period. Overall, around 75% of total non-power sector gas demand is unmet during the disruption period with no gas available for power generation or for the I&C gas sector (i.e. all power stations and all I&C gas consumers are almost completely cut off during the 1-month or 6-month disruption period[26]).
- In addition, there is also widespread disruption to gas supplies to protected consumers with 51% of overall protected consumer demand unserved during the 1-month disruption, or 42% in the 6-month disruption.

[26] Under the 6-month full Moffat disruption, 1.2 GWh of gas demand from the I&C sector can be met on a single day in April when protected consumer demand is low.

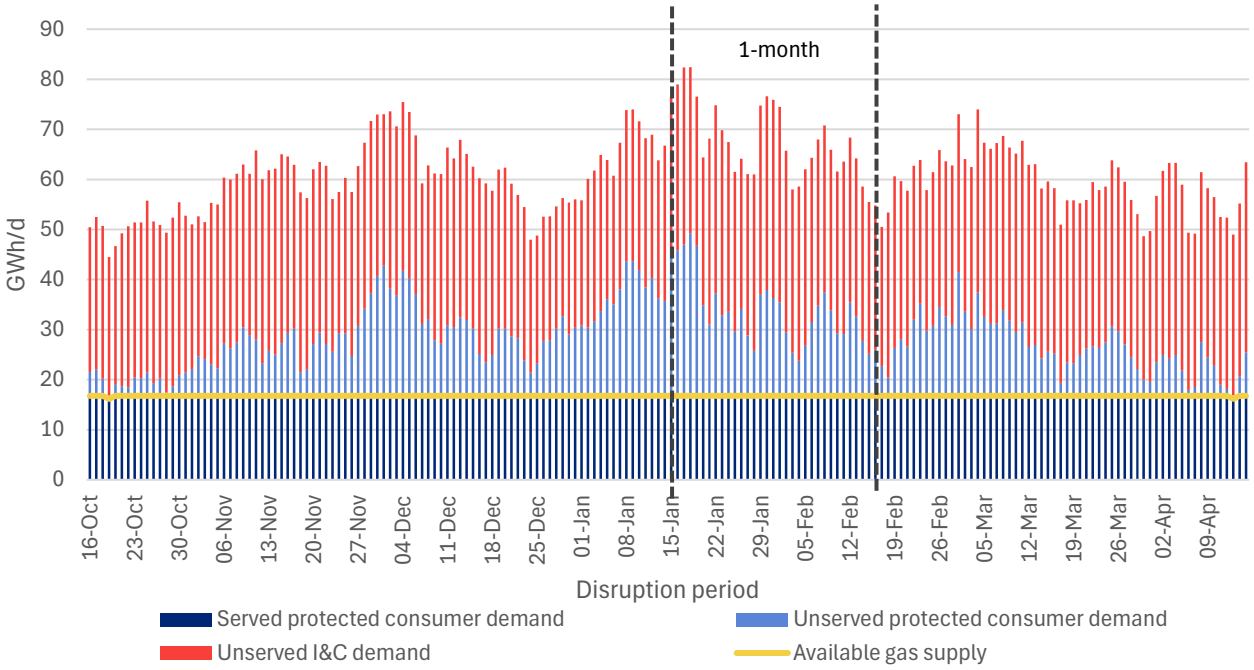
*Table 5.1. Summary of impact in the gas market by disruption scenario (2035)*

| | IC2 outage – normal weather 1m | IC2 outage – normal weather 6m | IC2 outage – cold weather 1m | IC2 outage – cold weather 6m | Full import outage 1m | Full import outage 6m |
|---|---|---|---|---|---|---|
| Disruption period | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) |
| # days with unserved non-PS gas demand | - | - | - | - | 31 | 182 |
| Total unserved non-PS gas demand (GWh) | - | - | - | - | 1,600 | 8,097 |
| (% of total demand) | *0%* | *0%* | 0% | 0% | *75%* | *73%* |
| Unserved protected consumer demand (GWh) | - | - | - | - | 546 | 2,213 |
| (% of demand) | *0%* | *0%* | 0% | 0% | *51%* | *42%* |
| Max daily protected consumer unserved demand (GWh) | - | - | - | - | 32 | 32 |
| Unserved DM I&C gas demand (GWh) | - | - | - | - | 1,054 | 5,884 |
| (% of DM I&C demand) | *0%* | *0%* | 0% | 0% | *100%* | *100%* |
| Unserved power sector gas demand (GWh)[27] | 10-32 | 36-98 | 290-528 | 316-596 | 330-610 | 1,710-3,250 |

Figure 5.1 shows the daily non-power sector gas demand during the disruption period broken down by served protected consumer demand and unserved consumer demand (protected and I&C). We only present this graph for the full Moffat outage scenario since there is no unserved non-power sector gas demand in the IC2 outage scenarios. In the worst day of the disruption, around 32 GWh/d, or approx. 66% of protected consumer demand is unmet.

[27] We estimate power sector unmet gas demand as the volume of gas required for gas fired generation to meet any unserved electricity demand. Range is calculated assuming either 100% or 70% of the interconnection capacity can be used for imports during the disruption period.

*Figure 5.1. Daily served and unserved non-power gas demand under full outage of gas imports from GB in 2035*




### 5.1.2. Electricity market impacts

The electricity sector can meet almost all demand under an IC2 outage under normal weather patterns with only 0.2% to 0.3% of overall demand unmet during the disruption period. This is through a combination of:

- renewable generation, which, given the assumed deployment levels in our scenario, could be expected to meet close to 80% of demand in a typical year;
- gas-fired generation using gas supplied through IC1 (including power stations in Northern Ireland);
- electricity imports; and
- electricity storage and DSR.

However, the level of unmet demand is much higher in periods of extreme weather primarily due to the low availability of renewable generation. In this case, we estimate that up to 5.3% of overall electricity demand is unmet during a 1-month IC2 outage that overlaps with a two-week period of cold weather and low renewable generation.

In the case of a complete disruption to gas imports, renewable generation, electricity imports and domestic flexibility sources make an important contribution to meeting demand. However, between 3% and 6% of demand during the disruption period is unmet under the full outage scenario.

*Table 5.2. Summary of impact in the electricity market 2035 per scenario (range showing interconnector availability factor of 100% and 70% respectively).*

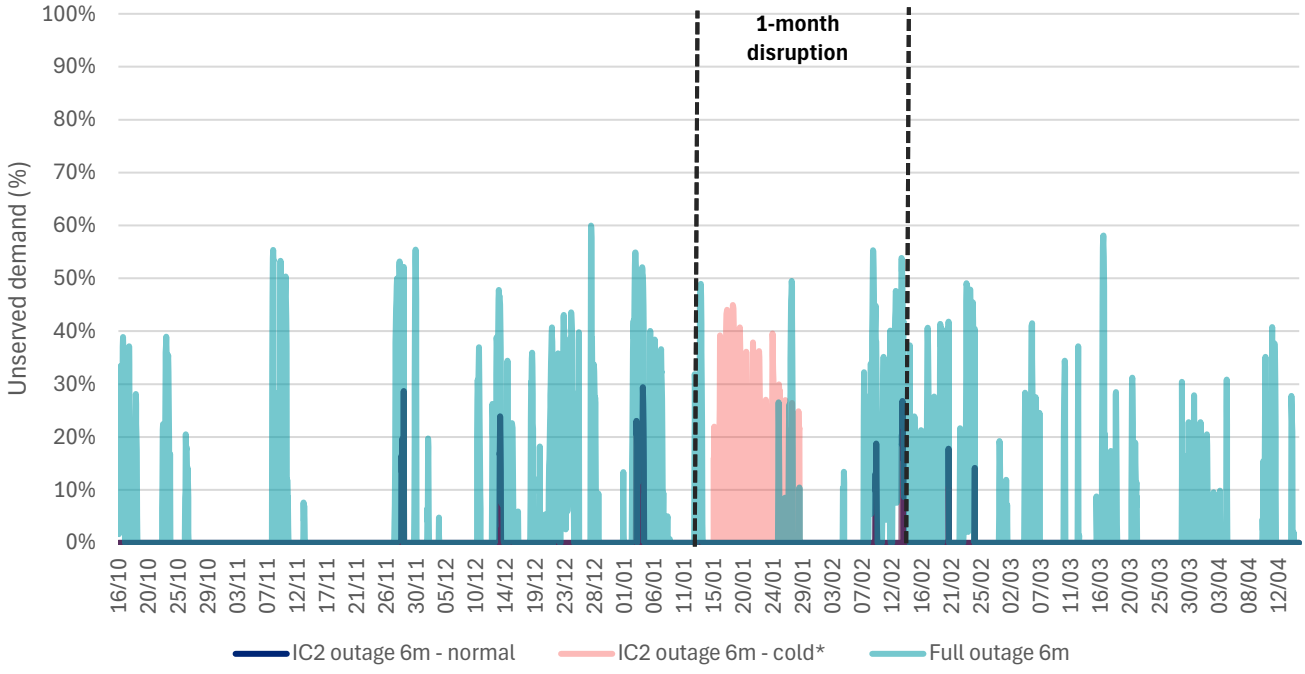
| | IC2 outage – normal weather 1m | IC2 outage – normal weather 6m | IC2 outage – cold weather 1m | IC2 outage – cold weather 6m | Full import outage 1m | Full import outage 6m |
|---|---|---|---|---|---|---|
| Disruption period | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) |
| # hours with unserved demand | 9-13 | 30-36 | 120-135 | 141-158 | 134-174 | 691-1014 |
| Total unserved demand GWh | 5-16 | 18-49 | 145-264 | 158-298 | 165-305 | 855-1625 |
| (% of total demand) | *0.1%-0.3%* | *0.1%-0.2%* | *2.9%-5.3%* | *0.6%-1.0%* | *3.3%-6.1%* | *3.0%-5.7%* |
| Max hourly unserved demand (GWh) | 1.2-2.1 | 1.4-2.3 | 2.8-3.8 | 2.8-3.8 | 3.3-4.2 | 3.9-4.9 |

The extent of the disruption experienced by electricity consumers appears worse when considering hourly impacts.

The analysis reveals that the unserved demand is relatively concentrated, with most unserved demand occurring in a relatively small number of hours.

Maximum hourly unserved demand is 5 GWh in the worst scenario (import availability factor of 70% and full gas outage for 6 months), representing around 60% of demand in that period. Assuming full import availability, the maximum hourly unserved demand in the 6-month full outage scenario in 2035 is 3.9 GWh, representing almost 40% of total electricity demand in that hour. Even in the less severe scenarios, hourly unserved demand can be in excess of 1 GWh over a number of periods. This means that even if the disruption relative to overall electricity demand during the outage period is relatively limited, there would still be a significant number of hours when consumers would experience widespread disruption to electricity supplies.

*Figure 5.2. Daily unserved electricity demand under different scenarios in 2035 (% of total IE demand, assuming IC availability factor of 70%)*




**Outside the two-week cold weather period, the impacts under the IC2 outage scenarios with cold and normal weather overlap (dark blue and pink lines)*

## 5.2. ESTIMATED SECURITY OF SUPPLY IMPACTS: 2040

### 5.2.1. Gas market impacts

In 2040, we project that Ireland's reliance on gas imports from GB remains similar to 2035, due to a combination of lower domestic gas supply (as increased biomethane supply compensates for some but not all the loss of production due to the depletion of the Corrib gas field) and lower gas demand. Therefore, we find similar impacts on the gas sector of a disruption to gas imports from GB in 2040 as in 2035.

Under an **IC2 outage scenario**, we estimate that:

- The maximum daily gas supply capacity available (through IC1 and biomethane) is 203 GWh/d, relative to a peak non-power sector gas demand of 70 GWh/d (under normal conditions) or 78 GWh/d (under cold weather conditions).
- We continue to find no disruption to non-power sector gas demand given that the available gas supply capacity remains above the level of protected and I&C gas demand, but we find that there is unmet gas demand in the power sector resulting in unmet electricity demand.

Under a **full Moffat outage scenario**, we find that:

- There is large-scale disruption to gas demand, similar to 2035 levels.
- Overall, around 72-75% of total non-power sector gas demand is unmet during the disruption period with no gas available for power generation or next to no gas supplies for the I&C gas sector.[28]
- The impacts on protected gas consumers are slightly lower than in 2035, due to lower gas demand, but are still significant with up to 47% of protected consumer gas demand unserved during the 1-month disruption.

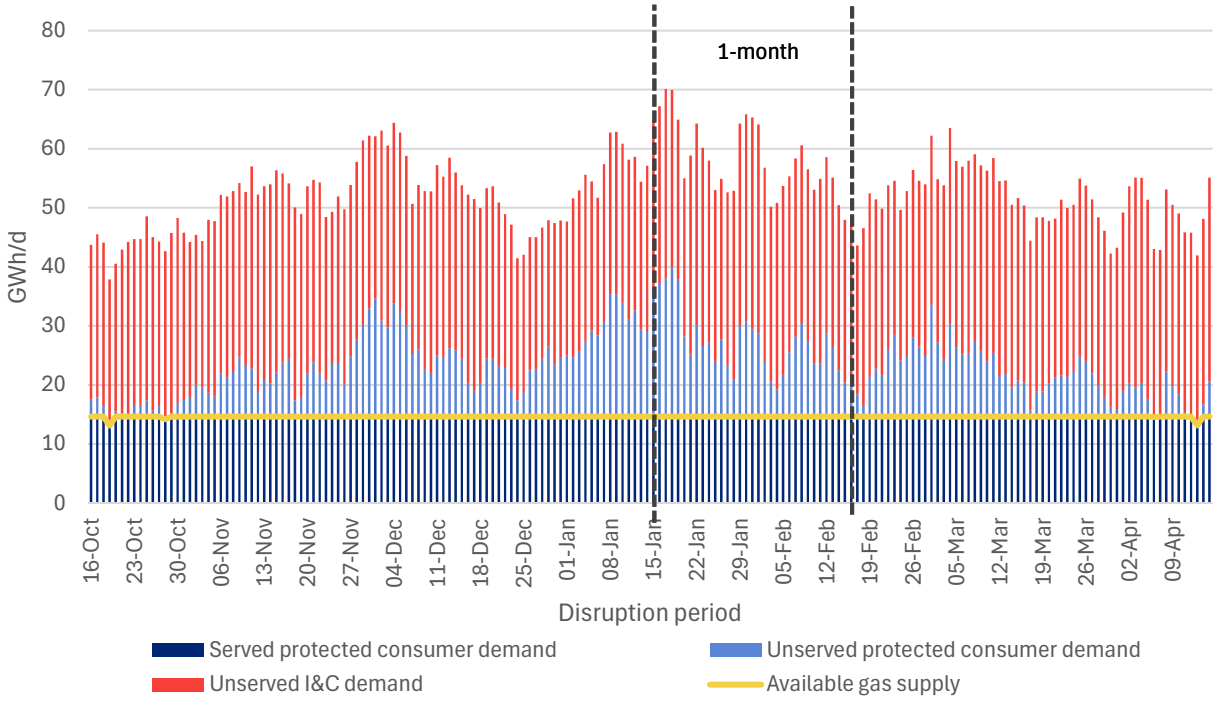
[28] A total of 3.6 GWh/d of gas supply is available to the I&C sector spread across four days during the 6-month full outage period.

*Table 5.3. Summary of impact in the gas market by disruption scenario (2040)*

| | IC2 outage – normal weather 1m | IC2 outage – normal weather 6m | IC2 outage – cold weather 1m | IC2 outage – cold weather 6m | Full import outage 1m | Full import outage 6m |
|---|---|---|---|---|---|---|
| Disruption period | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) |
| # days with unserved non-PS gas demand | - | - | - | - | 31 | 182 |
| Total unserved non-PS gas demand (GWh) | - | - | - | - | 1,367 | 6,945 |
| (% of total demand) | *0%* | *0%* | 0% | 0% | *75%* | *72%* |
| Unserved protected consumer demand (GWh) | - | - | - | - | 409 | 1,604 |
| (% of demand) | *0%* | *0%* | 0% | 0% | *47%* | *38%* |
| Max daily protected consumer unserved demand (GWh) | - | - | - | - | 25 | 25 |
| Unserved DM I&C gas demand (GWh) | - | - | - | - | 958 | 5,340 |
| (% of DM I&C demand) | *0%* | *0%* | 0% | 0% | *100%* | *99.9%* |
| Unserved power sector gas demand (GWh) | 40-68 | 116-200 | 570-836 | 646-968 | 418-660 | 1,896-3,160 |

Figure 5.3 shows the daily non-power sector gas demand during the disruption period broken down by served protected consumer demand and unserved consumer demand (protected and I&C) for 2040. The profile of the observed impacts is similar to 2035, however overall levels of unserved demand are lower due to reduction in demand between 2035 and 2040. In the worst day of the disruption, around 25 GWh/d of protected consumer demand is unmet.

*Figure 5.3. Daily unserved non-power gas demand under full outage of gas imports from GB in 2040*




### 5.2.2. Electricity market impacts

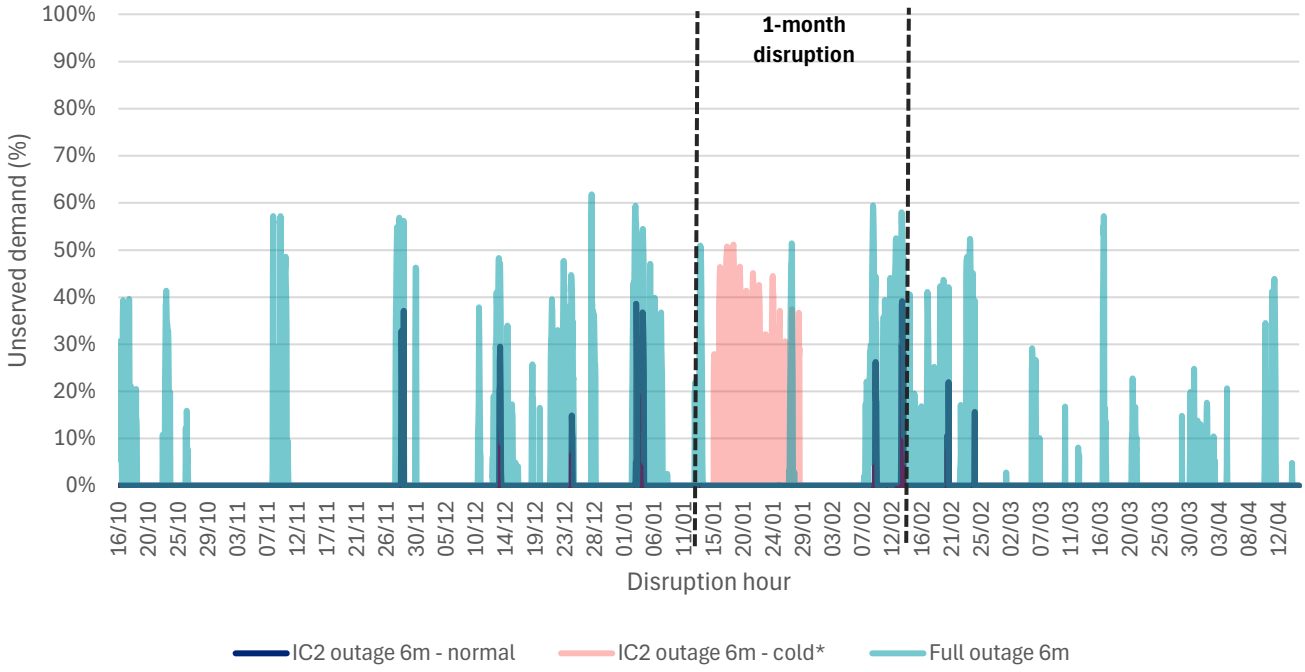
We find similar electricity sector impacts in 2040 compared to 2035, but with some differences:

- Under the **IC2 outage scenarios**, the impacts in 2040 are slightly worse than in 2035. Despite more gas generation being available during the disruption period as a whole (as non-power sector gas demand declines), electricity demand growth means that gas-fired plants meet a lower share of demand during the disruption period.
- Under the **full outage scenario**, the impacts are lower in 2040 in terms of total unserved electricity demand during the disruption period and total number of periods with unserved demand, compared to 2035. This is primarily due to higher renewables penetration in 2040. However, the highest level of hourly unserved demand (likely to occur during periods of low renewables availability) goes up relative to 2035 due to electricity demand growth.

*Table 5.4. Summary of impact in the electricity market 2040 per scenario (range showing interconnector availability factor of 100% and 70% respectively).*

| | IC2 outage – normal weather 1m | IC2 outage – normal weather 6m | IC2 outage – cold weather 1m | IC2 outage – cold weather 6m | Full import outage 1m | Full import outage 6m |
|---|---|---|---|---|---|---|
| Disruption period | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) | 15 Jan – 14 Feb (31 days) | 15 Oct – 14 Apr (182 days) |
| # hours with unserved demand | 14-16 | 42-50 | 142-148 | 170-182 | 120-148 | 593-800 |
| Total unserved demand GWh | 20-34 | 58-100 | 285-418 | 323-484 | 209-330 | 948-1580 |
| (% of total demand) | *0.3%-0.6%* | *0.2%-0.3%* | 4.9%-7.2% | 1.0%-1.5% | *3.6%-5.7%* | *2.9%-4.8%* |
| Max hourly unserved demand (GWh) | 3-4 | 3-3.9 | 4-5 | 4.2-5.1 | 4.6-5.5 | 4.6-5.5 |

*Figure 5.4. Daily unserved electricity demand under different scenarios in 2040 (% of total IE demand, assuming IC availability factor of 70%)*




## 5.3. ASSESSMENT OF POTENTIAL MITIGATION OPTIONS AGAINST DISRUPTION SCENARIOS

For this analysis, we have assessed the ability of various options to mitigate the security of supply impacts observed in the modelled disruption scenarios. In line with the N-1 assessment, we have modelled the addition of a Strategic Gas Emergency Reserve, in the form of an FSRU, and additional electricity interconnection, offshore wind and storage capacity relative to the baseline assumptions in our modelling. Our analysis focuses on the scenarios with the highest levels of unserved demand (i.e., assuming 70% electricity import availability).

In contrast to the analysis of mitigation options in the context of the N-1 assessment (Section 4.4), which looks at a single peak demand day in isolation, the aim of the assessment in this section is to assess the ability of the different mitigation options to address security of supply impacts over a wider range of disruption scenarios (both in terms of length and extent of the disruption) under dynamic conditions.

For this analysis, we are also not determining the level of capacity required to mitigate all impacts under all scenarios as is the case for the N-1 assessment. Instead, we are testing the impact of adding 'feasible' levels of additional capacity.

### 5.3.1. Impact of FSRU facility

We assessed the impact of adding an FSRU that could provide 161 GWh of gas supply per day[29]. This sizing is based on preliminary scoping work undertaken to date, with the final specification to be determined as part of the detailed design process.

In line with our findings in the N-1 assessment, we estimate that an FSRU of this size would mitigate virtually all impacts in the gas and electricity sector under an IC2 outage scenario, including when a cold weather event is assumed to overlap with the gas disruption period, by increasing the volume of gas available for electricity generation. In the IC2 outage with cold weather scenario in 2040, we find that there is a remaining 2 GWh of

[29] We assume that new LNG cargos will arrive in Ireland to sustain this level of gas supply throughout the disruption period

unserved electricity demand (assuming 70% electricity import availability), spread over 8 hours during the disruption period, which the FSRU cannot mitigate. The largest impact during these 8 hours is equivalent to 5% of electricity demand.

In the case of a full disruption to pipeline imports from GB, the FSRU capacity would replace just over half of the 297.6 GWh/d import capacity from GB lost during the disruption period. In the gas market, an FSRU of this size would be enough to cover all gas demand from residential and I&C gas consumers both in 2035 and 2040 under the full Moffat outage scenario.

While electricity sector impacts are reduced with the addition of an FSRU, we find that there would still be around 2-3% of electricity demand unserved during the disruption period. This suggests that a FSRU with a larger send out capacity would be required to mitigate all impacts under a full disruption to pipeline imports from GB. We would expect that the optimal size of the FSRU will be determined as part of the detailed design process.

*Table 5.5. Impact of an FSRU on unserved demand in the gas market*

| Scenario | Unserved non-PS gas demand (%) 2035 | | Unserved non-PS gas demand (%) 2040 | |
|---|---|---|---|---|
| | Without FSRU | With FSRU | Without FSRU | With FSRU |
| IC2 outage 1m (normal) | - | - | - | - |
| IC2 outage 6m (normal) | - | - | - | - |
| IC2 outage 1m (cold) | - | - | - | - |
| IC2 outage 6m (cold) | - | - | - | - |
| Full outage 1m | 75.5% | - | 75.1% | - |
| Full outage 6m | 72.6% | - | 72.3% | - |

*Table 5.6. Impact of an FSRU on unserved demand in the electricity market (range showing interconnector availability factor of 100% and 70% respectively)*

| Scenario | Unserved gas demand (%) 2035 | | Unserved gas demand (%) 2040 | |
|---|---|---|---|---|
| | Without FSRU | With FSRU | Without FSRU | With FSRU |
| IC2 outage 1m (normal) | 0.1%-0.3% | - | 0.3%-0.6% | - |
| IC2 outage 6m (normal) | 0.1%-0.2% | - | 0.2%-0.3% | - |
| IC2 outage 1m (cold) | 2.9%-5.3% | - | 4.9%-7.1% | 0.0%-0.0% |
| IC2 outage 6m (cold) | 0.5%-1.0% | - | 1.0%-1.5% | 0.0%-0.0% |
| Full outage 1m | 3.3%-6.1% | 2.0%-3.2% | 3.6%-5.7% | 1.9%-2.8% |
| Full outage 6m | 3.0%-5.7% | 1.3%-2.2% | 2.9%-4.8% | 1.2%-1.8% |

### 5.3.2. Impact of alternative mitigation options

We also modelled the impact of alternative mitigation options based on the assumed additional capacities summarised in Table 5.7.

We assume:

- An additional 1 GW of electricity interconnection in both 2035 and 2040 relative to our baseline assumptions.
- An additional 3 GW in 2035 and 7 GW in 2040 of offshore wind capacity relative to our baseline assumptions.
- An additional 5 GWh in 2035 and 10 GWh in 2040 of battery storage capacity relative to our baseline assumptions.

*Table 5.7. Assumed additional capacity under alternative mitigation options*

| Mitigation | 2035 | 2040 |
|---|---|---|
| Electricity interconnection | 1 GW | 1 GW |
| Offshore wind | 3 GW | 7 GW |
| Electricity storage | 5 GWh | 10 GWh |

In the rest of this section, we present the estimated impact of each of these mitigation options across the disruption scenarios modelled. We focus our analysis on electricity sector unserved demand since:

- We found no unserved demand for non-power sector gas consumers except in the full disruption scenario.
- These electricity sector mitigation options can only address unserved demand in the electricity sector and cannot mitigate unserved demand for non-power sector gas consumers in the full disruption scenario.

## IC2 outage and normal weather

As shown in Figure 5.5 and Figure 5.6, we find that, under an IC2 outage with normal weather conditions:

- None of the alternative mitigation options fully mitigate all unserved demand in either 2035 or 2040. Both increasing interconnection and offshore wind capacity could contribute to reducing the gap, but none of them can fully mitigate periods when unmet demand is high.
- In 2035, the 1 GW of additional interconnection and the 3 GW of offshore wind capacity provide similar levels of mitigation. In 2040, we assume more additional offshore wind capacity (+ 7 GW relative to baseline) which helps to mitigate more of the unserved demand.
- We find that increasing storage capacity under IC2 outage would have very little mitigation effect. The additional storage can help meet demand in some hours but typically when imports would also have been available (i.e., storage can reduce the reliance on imports during these security of supply events but not necessarily reduce the level of unserved demand). The security of supply benefits of additional storage depend on the ability to fill up storages. The periods with high unserved demand are likely to be periods when storage is already depleted. In addition, the simplified modelling approach does not fully optimise the use of storage.

*Figure 5.5. IC2 outage + normal weather: unserved electricity demand (%) under various mitigation options – 2035, 70% interconnector availability*

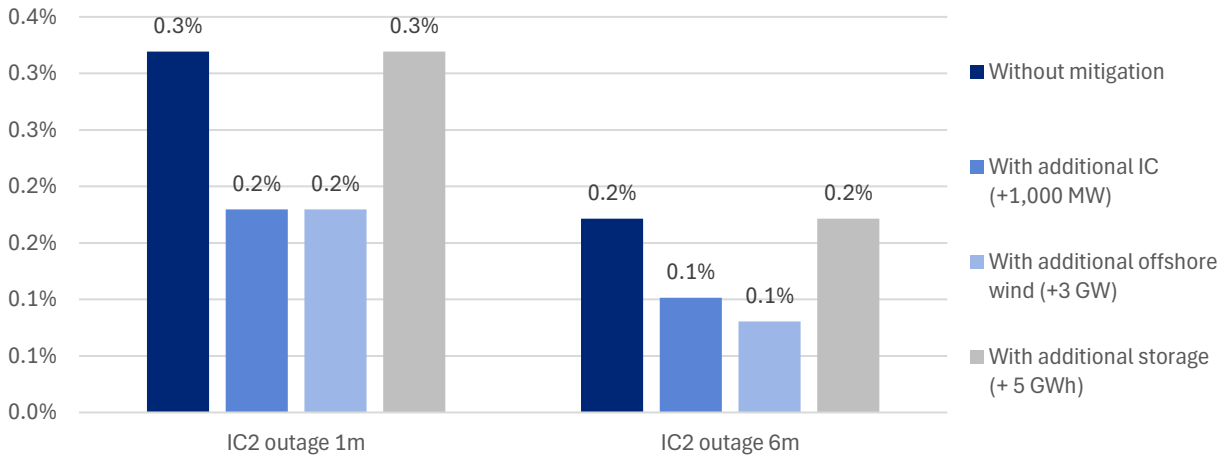
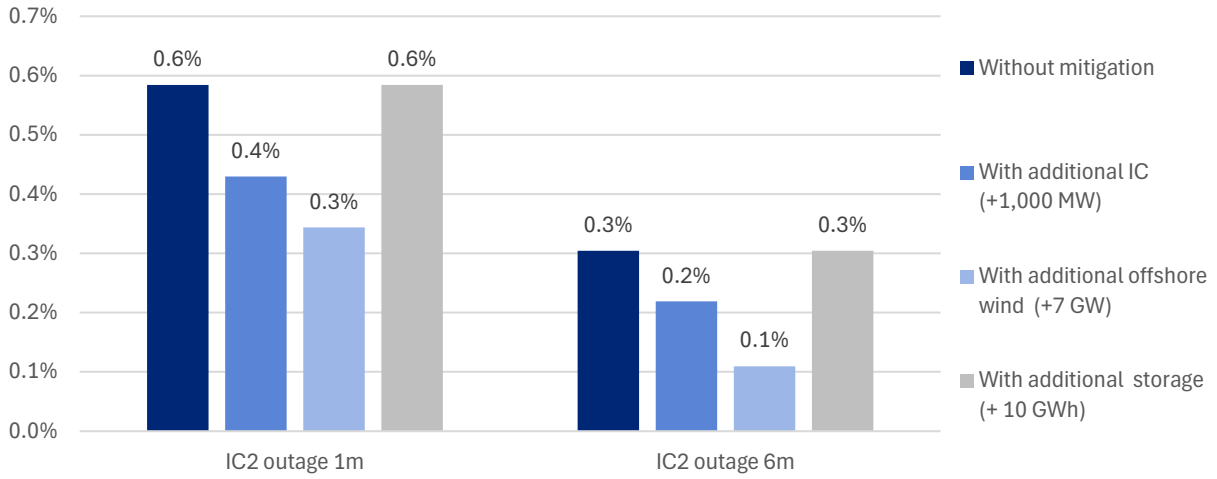


*Figure 5.6. IC2 outage + normal weather: unserved electricity demand (%) under various mitigation options – 2040, 70% interconnector availability*




## IC2 outage and cold weather

As shown in Figure 5.7 and Figure 5.8, we find that, under an IC2 outage with cold weather conditions:

- The relative impact of adding offshore wind capacity under the cold weather scenario is lower, as the capacity factors of wind generation are much lower during the two weeks of the cold weather event compared to the typical weather scenario. However, the additional offshore wind capacity assumed for 2040 can still mitigate more unserved demand compared to the additional interconnection or storage.
- The additional interconnection (assuming 70% import availability) mitigates around 30% of the unserved demand in 2035 and around 17% of unserved demand in 2040. This is a significantly lower level of mitigation compared to an FSRU.

*Figure 5.7. IC2 outage + cold weather: unserved electricity demand (%) under various mitigation options – 2035, 70% interconnector availability*

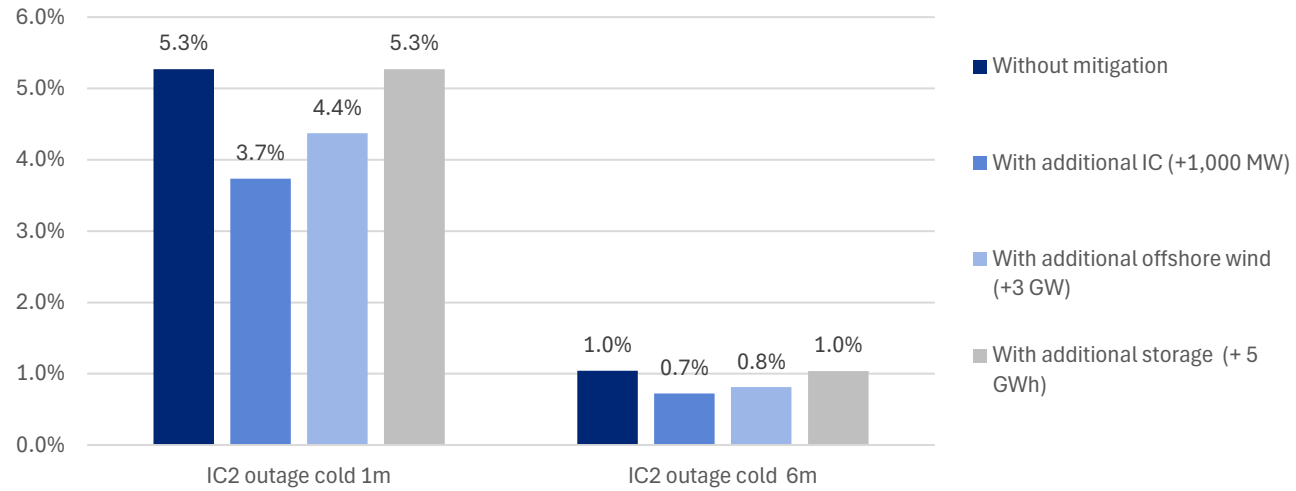
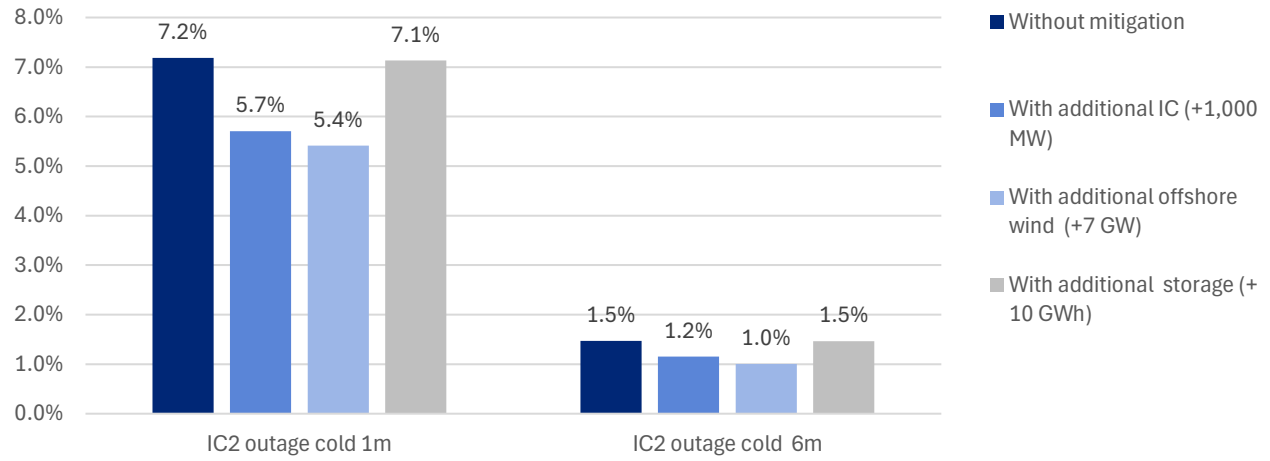


*Figure 5.8. IC2 outage + cold weather: unserved electricity demand (%) under various mitigation options – 2040, 70% interconnector availability*




## Full GB gas import disruption

As shown in Figure 5.9 and Figure 5.10, we find that, under a full disruption to gas imports from GB:

- Increasing interconnection would be the most effective mitigation tool in 2035 with the exception of an FSRU. Adding 1,000 MW of additional interconnection reduces unmet demand in every period but it cannot fully mitigate periods when unmet demand is high.
- Increasing offshore wind capacity by 3 GW in 2035 would have a slightly smaller impact on results, but adding 7 GW in 2040 provides more mitigation compared to 1 GW additional interconnection . Offshore wind generation contributes directly to mitigating unserved demand and also indirectly, helping to fill up storage in periods of high wind generation. Note that this scenario is based on a normal weather profile and does not account for prolonged or unusually low wind periods.
- Increasing storage has a limited effect on unmet demand.

*Figure 5.9. Full GB gas import outage: unserved electricity demand (%) under various mitigation options – 2035, 70% interconnector availability*

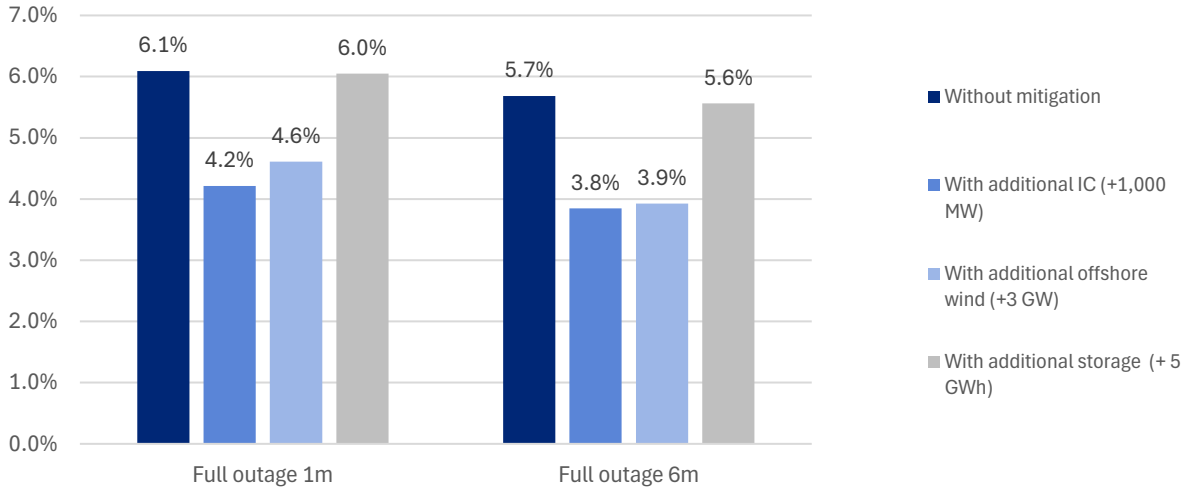
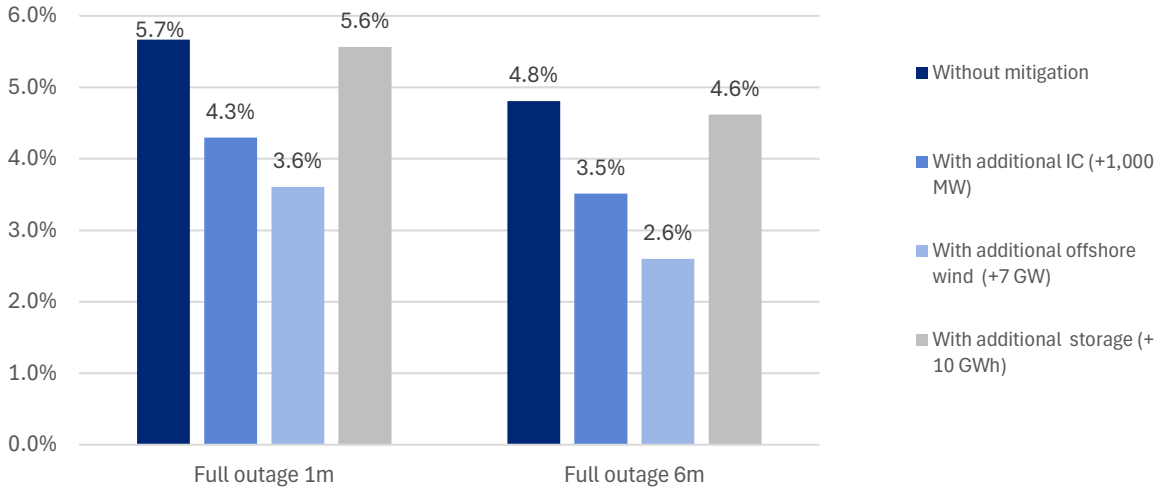


*Figure 5.10. Full GB gas import outage: unserved electricity demand (%) under various mitigation options – 2040, 70% interconnector availability*



# 6. CONCLUSION

The aim of this study was to update CEPA's 2022 analysis using the latest available data, to assess if the key risks and mitigation actions identified in the 2022 analysis of security of energy supply are still relevant and appropriate in the period up to 2040.

As part of this study, we have carried out the following analysis:

- Conducting an **assessment of Ireland's ability to meet the N-1 infrastructure standard** for gas in 2035 and 2040 without additional mitigation.
- Testing the **impact of gas import disruption scenarios** (partial and full disruption of gas supplies from GB).
- Identifying the **shortfall in supply** in 2035 and 2040 for gas and power systems under the disruption scenarios modelled. The supply shortfall is measured in terms of unserved energy demand during the disruption period in both the gas and electricity sectors.
- Assessing the **ability of potential mitigation options** to address the identified shortfall in energy supplies. The mitigation options included in the scope of this study are the addition of a Strategic Gas Emergency Reserve in the form of a Floating Storage Regasification Unit (FSRU); additional electricity interconnection, offshore wind, and long-term electricity storage.
- We also present high-level cost estimates associated with the additional capacity required to cover the supply gap under an N-1 gas infrastructure outage, under each mitigation option (see Section 4.4.4). These indicative cost estimates only capture the cost of developing and operating these projects. A full cost-benefit analysis (not included in the scope of our study) would be required to assess the wider benefits/costs and to compare the economic case of different mitigation options.

## Ireland's ability to meet the N-1 infrastructure standard

Our analysis finds that Ireland would not meet the N-1 infrastructure standard for gas during the 2030s, based on the assumptions around the evolution of gas demand and supply made in this study.

With the addition of an FSRU with assumed daily supply capacity of 161 GWh/d, we estimate that Ireland would meet this standard.

We also assessed the ability of alternative mitigation sources, focused on the electricity sector, to mitigate the N-1 impacts.

Electricity interconnection could potentially help meet the N-1 standard by reducing power sector gas demand, however the level of additional interconnection required may be high depending on the future evolution of peak gas demand. Crucially, the availability of electricity imports during severe peak demand days is uncertain, especially if the interconnected markets experience the same demand and weather patterns driving the severe peak in Ireland.

We find that very high levels of additional electricity storage and offshore wind capacity would be required to meet the N-1 standard. This would be both challenging to deliver and costly. The availability of these technologies during severe peak demand days is also uncertain. A 1-in-50 peak gas demand day is likely to reflect low temperature and low wind conditions which means that the availability of offshore wind generation and also the ability to charge storage may be limited.

## Security of supply disruption scenario analysis

Under a scenario assuming the outage of the largest piece of gas infrastructure (the IC2 interconnector), we find that Ireland could meet all non-power sector gas demand by importing gas from GB through the IC1 gas interconnector and domestic production. However, there would be disruption to electricity consumers in both 2035

and 2040. Impacts on electricity consumers would be particularly significant if the IC2 outage coincided with a period of extreme cold weather and low wind availability.

The impact of an IC2 outage on electricity consumers could be mitigated by the addition of an FSRU. The alternative mitigation options modelled would reduce but not fully eliminate these impacts.

A full disruption to gas supplies from GB would result in widespread unmet gas demand in the non-power sector, with virtually all non-protected I&C demand being cut off during the disruption period. We also estimate significant disruption to protected consumer demand in both 2035 and 2040.

The impacts of a full Moffat outage on the electricity sector, assuming normal weather conditions, would also be notable, with up to c. 6% of overall electricity demand during the disruption period being unmet if Ireland cannot import electricity at full capacity during disruption periods. We estimate that an FSRU, with an assumed supply capacity of 161 GWh/d, could mitigate a significant portion but not all of these impacts.

**UK**

Queens House

55-56 Lincoln's Inn Fields

London WC2A 3LJ

T. **+44 (0)20 7269 0210**

E. **info@cepa.co.uk**

**www.cepa.co.uk**

**Australia**

Level 20, Tower 2 Darling Park

201 Sussex Street

Sydney NSW 2000

T. **+61 2 9006 1308**

E. **info@cepa.net.au**

**www.cepa.net.au**