THE IRISH ACADEMY OF ENGINEERING

ENGINEERING & TECHNOLOGY

THOUGHT LEADERSHIP IN A TIME OF GREAT CHANGE

Rebalancing Ireland's Energy Policy

The Energy Trilemma — Project Delivery – Authority & Accountability

November 2025
Ref. No. 01/11/11.25

THE IRISH ACADEMY OF ENGINEERING

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ISBN: 978-1-7395317-7-5

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PREAMBLE

This report has been prepared by the Energy & Climate Action Committee of the Irish Academy of Engineering to provide an overview of the multiple facets of the energy transition challenge Ireland is facing over the next 25 years.

These challenges range in nature and include policy, technology, project delivery, economic effects and environmental impacts.

The report is intended to provide the framework for a future series of issue-specific papers addressing particular challenges in greater detail.

The objective of all of this work is to increase the influence of engineering considerations in energy policy and to promote the greater participation of engineers working in the energy sector in its development and delivery.

EXECUTIVE SUMMARY

Energy policy is dominated by a legal requirement for Ireland to be carbon neutral by 2050. Although carbon neutrality is not defined in legislation, the explicit target in policy is to have zero net GHG emissions by 2050. Based on this requirement, a framework of carbon budgets and Government policies has been created. These are failing to deliver their objectives.

This is most evident in the undermining of Government's 2030 targets for renewables by the absence of any sense of urgency in the delivery of the policy required to deliver these targets. It is certain now that the targets will be very substantially missed and, as a result, Ireland could be exposed to large financial liabilities.

Energy-related sectors account for 55% of Ireland's GHG emissions and the means to achieve zero net emissions do not exist. For this reason alone - and whatever about the other 45% - the legal obligation, carbon budget targets and policy objectives for 2050 will not be met. In the meantime, Irish energy prices are uncompetitively high and the country's energy security is parlous.

Certainty is required that the energy infrastructure needed to meet increasing demand due to growth in the economy - more people and increasing industrial demand - and due to the electrification of transport and heating will be delivered. This infrastructure includes renewables, transmission, distribution, conventional fossil fuel generation, interconnectors and an LNG facility.

National energy policy needs to be rebalanced, and far greater emphasis given to the price of energy, to energy security and to project delivery:

Energy Prices

1. Require CRU to publish an annual analysis of the cost build up in the price of electricity and gas inclusive of the aggregate gross margins of energy retailers.
2. Require CRU to periodically publish an objective critique of the electricity and gas retail sectors to determine whether the aggregate cost of multiple energy retailers is delivering a price reduction benefit for consumers or not.
3. Protect consumers by preventing the development of an excessive level of renewables (such as the 54,000 MW targeted in existing policies) by a combination of increased reliance on private sector power purchase agreements (PPAs) to fund new developments and by finding an appropriate mechanism to put a limit on RESS and ORESS support in future auctions.
4. Create a path to this endpoint for new RESS and ORESS schemes by, firstly, requiring CRU to assess the impact on electricity prices of each new support scheme before auctions take place and, secondly, evaluating the outcomes ex post.
5. Recognise the growing potential of interconnectors to reduce the requirement for renewables.

Energy Security

6. Deliver a substantially larger and longer-lived LNG facility than is currently proposed to provide increased diversity of supply and gas storage capacity to 2050 and beyond.
7. Commence preparations for the introduction of nuclear power - in line with IAEA's milestone approach for countries to develop a nuclear generation capacity - to ensure that, if SMRs become widespread worldwide over the next decade or so, Ireland is ready to consider their introduction without the level of delays experienced with offshore wind over the past decade and more.

8. Continue to assess the potential of hydrogen, hydrogen derived fuels and other efuels to, again, be prepared to introduce them into Ireland's energy mix if it would be beneficial but recognising that they are not options that can be relied on to be available between now and 2050.

Project Delivery

9. Develop a masterplan - with Strategic Environmental Assessment - for the delivery of transmission and back-up generation infrastructure over the next 25 years and integrate it into all levels of the national planning hierarchy - National Planning Framework; Regional Spatial and Economic Strategies; local authority development plans – to give increased certainty to critical electricity infrastructure projects at the planning stage, particularly in An Coimisiún Pleanála.
10. Give responsibility for the preparation of this masterplan to EirGrid / ESB Networks along with the accountability to deliver projects from it.
11. Review the four State-owned energy companies - EirGrid, ESB, GNI and NORA - to ensure that their respective roles and responsibilities - and how these have evolved in recent years - are appropriate for the challenges of the next 25 years.

The rebalancing of Ireland's energy policy would represent a fundamental, but essential, change to the current failing policy approach and, importantly, would have no negative effect on Ireland's climate.

Ireland's GHG emissions are so small (58 Mt CO_2eq in 2024) compared to global emissions (53,817 Mt CO_2eq in 2023) that there will be no difference in the impact on Ireland's climate whether we were to somehow achieve the unachievable goal of net-zero by 2050 or, more realistically, if we achieve a lower, but still substantial and eminently possible reduction. While Ireland's emissions are decreasing (6 Mt CO_2eq between 2018 and 2023), worldwide emissions are increasing (1,397 Mt CO_2eq).

Future energy policy needs to be pragmatic and informed by a balanced consideration of inescapable engineering and economic realities.

SECTION A LAW, POLICIES AND ENGINEERING REALITIES

1. INTRODUCTION

Ireland has a mandatory objective, set in national law, to be *climate neutral* by 2050.[1]

This requires, among other things, the elimination of greenhouse gas (GHG) emissions from the combustion of fossil fuels in four energy-related areas over the next 25 years:

1. Electricity generation
2. Transport
3. Heating
4. Industrial processes

However, rather than declining, the global consumption of fossil fuels has increased over the past 25 years (**Figure 1**) and renewables have yet to reverse this trend let alone make a significant contribution to reducing the absolute level of energy consumption.

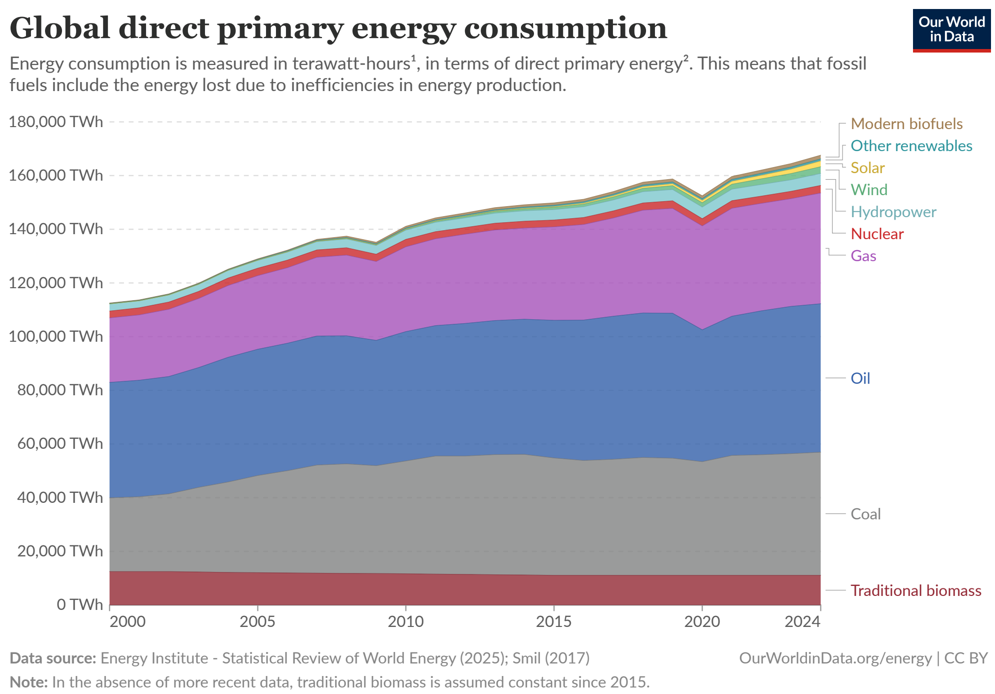


Figure1: Trends in global primary energy requirement, 200 to 2024
Source: *Our World in Data*

Regardless of what Ireland might achieve in reducing GHG emissions, it will have no impact on the country's climate. Climate impacts due to gases such as CO_2, CH_4 and N_2O are the result of global emissions, and these are not reducing to the extent required by the Paris Agreement.[2,3]

1 *Climate Action and Low Carbon Development Act 2015* and *Climate Action and Low Carbon Development (Amendment) Act 2021.*

2 CO_2 (carbon dioxide), CH_4 (methane or natural gas) and N_2O (nitrous oxide) are the three main greenhouse gases emitted as a result of combustion and industrial processes. Each gas makes a different contribution to global warming. The impacts of each are expressed in terms of CO_2 equivalent (CO_2eq) as explained in the Glossary.

3 Ireland is one of 195 countries that have signed up to the Paris Agreement, which aims to limit global warming to well below 2°C and try to limit the increase to 1.5°C. These countries include some of the largest emitters (notably China and India) with the US currently in the process of withdrawing from the agreement for the second time.

Whereas Ireland has significantly reduced fossil fuels in the country's Primary Energy Requirement (PER) since 2000 (-19.3%), fossil fuel consumption globally has considerably increased (+50.8%) as shown in **Table 1** (and **Appendix 1**).

TWh	Global			Ireland		
	2000	**2024**	**Change**	**2000**	**2024**	**Change**
Primary Energy Requirement	112,545	167,584	48.9%	168.3	163.8	-2.7%
Fossil fuels in PER	94,467	142,421	50.8%	165.5	134.0	-19.3%
Fossil fuel %	83.9%	85.0%	1.0%	98.3%	81.5%	-16.8%

Table 1: Changes in Primary Energy requirement globally and in Ireland from 2000 to 2024
Source: Our World in Data and SEAI

Notwithstanding the progress that has been made in Ireland, fossil fuels still account for 81.5% of the country's Primary Energy Requirement compared to 85.0% globally.

While it is feasible to significantly reduce GHG emissions in Ireland in all four of the areas listed above, the limitations of currently available engineering solutions make it all but certain that they cannot be entirely eliminated by 2050.

The reduction of GHG emissions is primarily an engineering challenge and, as is the case with all engineering challenges, is subject to constraints of different types.

On the energy supply side, there are six main constraints:

1. Availability of proven technologies to enable the design and delivery of the required solutions.
2. The need for the engineering solutions to meet energy demand to be both adequate and reliable.
3. The need to ensure security of supply from disruptions as a result of risks outside of Ireland's control.
4. Financial viability of projects to deliver the engineering solutions.
5. Public acceptance and planning approval for many large energy infrastructure projects.
6. Price of energy for consumers, both households and businesses.

The policy path to eliminate GHG emissions is set in five year carbon budgets devised by and recommended to Government by the Climate Change Advisory Council (CCAC).

EPA projections suggest that Ireland will miss the targets for both the first (2021 to 2025) and second (2026 to 2030) carbon budgets by between 16% and 23%.[4] By missing EU targets for 2030, Ireland will be exposed to potentially large financial liabilities.[5] The Irish Fiscal Advisory Council's best case estimate of these liabilities is between €2.9 billion and €10.2 billion.[6]

4 See **Section 1.3**

5 The EU targets Ireland that Ireland is obliged to achieve are set out in two pieces of legislation:

- The *Effort Sharing Regulation* sets binding national targets for reducing greenhouse gas emissions. It covers domestic transport (excluding aviation transport), buildings, small industry, waste and agriculture emissions out to 2030. Ireland has annual limits to reduce emissions in these sectors with a target to reduce emissions by 42% by 2030, compared to 2005 levels.
- The *Renewable Energy Directive* establishes renewable energy targets for final energy consumption, including sub-targets for heating & cooling, and transport. Ireland is required to maintain a baseline renewable energy share of 16% of final energy consumption and achieve a 43% renewable energy share by 2030.

6 Irish Fiscal Advisory Council (in collaboration with the Climate Change Advisory Council), *A colossal missed opportunity - Ireland's climate action and the potential costs of missing targets, March 2025*

Moreover, where the EU has set a target date of 2050 to achieve climate neutrality, the largest GHG emitters are working to longer timescales. China has a target date of 2060 to achieve carbon neutrality and India has a date of 2070 to achieve net-zero emissions. In the US, the Government has begun to fundamentally question the impacts of GHG emissions.[7]

Against this background, Ireland needs to rebalance its energy policy to better meet the needs of the country. The path towards climate neutrality is technically challenging and will be costly. It is essential, therefore, that the economy performs well so that the engineering solutions required to achieve climate neutrality can be afforded – both on the supply side and on the demand side.

This report focuses on the energy supply side challenges that future policy needs to better address. The central implication of addressing these challenges is that the elimination of Ireland's GHG emissions needs to be reframed as a desirable objective - treated in policy as a constraint - rather than as an unfeasible mandatory requirement by 2050.

For the avoidance of doubt, this report does **not** suggest that efforts to reduce GHG emissions - including by the deployment of renewables and by the electrification of energy services in transport and heating – should be abandoned. Rather, the report suggests that a more appropriate balance – informed by engineering and technological realities – be struck between energy sustainability, energy security and the cost of energy, the three legs of the well-understood but largely overlooked energy trilemma (**Section 3**).

The ultimate objective of energy policy has to be to meet the needs of society. These needs are simply stated as the requirement for supplies of energy for households and businesses which are adequate, reliable, secure and economic.

This requires there to a coherent and consistent link between societal needs and the policy and legal framework of energy policy (**Figure 2**).

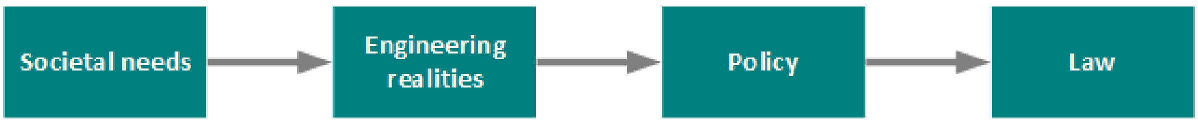


Figure 2: The flow of logic required in the framing of a coherent national energy policy

Ireland's current energy policies are framed by policy objectives and legal obligations which are increasingly divorced from engineering realities both in terms of the capabilities of available technologies and in terms of the management and delivery of a complex programme of large energy infrastructure projects.

Current energy solutions - largely based on fossil fuels - have been developed over the past 150 years. Climate policy seeks to replace fossil fuels by renewables in just 25 years. This is not feasible but significant progress towards the objective is possible.

7 The US Department of Energy published *A Critical Review of Impacts of Greenhouse Gas Emissions on the U.S. Climate* on 23rd July 2025. The EPA in the US subsequently announced its intention to rescind its endangerment finding of 2009 which found that GHG emissions pose risks to public health and welfare. More recently, the National Academies *launched a review* of the latest evidence for whether GHG emissions endanger public health and welfare focusing on evidence gathered by the scientific community since the EPA's endangerment finding in 2009.

1.1 Ireland's GHG emissions

Ireland's GHG emissions are split 55% / 45% between energy-related activities and other activities (**Table 2**).

kt CO_2eq	2018	2024	% change	% in 2024
Transport	12,308	11,652	-5.3%	20.2%
Energy Industries	10,559	7,157	-32.2%	12.4%
Public electricity and heat production	*10,012*	*6,846*	*-31.6%*	*11.9%*
Residential	7,000	5,615	-19.8%	9.7%
Manufacturing Combustion	4,662	4,130	-11.4%	7.2%
Industrial Processes	2,292	1,880	-18.0%	3.3%
Commercial Services	868	771	-11.2%	1.3%
Public Services	678	721	6.3%	1.3%
Mainly energy-related emissions	***38,367***	***31,926***	***-16.8%***	***55.4%***
Agriculture	21,400	20,408	-4.6%	35.4%
Land use, land-use change and forestry	3,996	3,895	-2.5%	6.8%
Waste	934	837	-10.4%	1.5%
F-Gases	788	581	-26.3%	1.0%
Other emissions	***27,118***	***25,721***	***-5.2%***	***44.6%***
National Total with LULUCF	**65,487**	**57,646**	**-12.0%**	**100.0%**

Table 2: GHG emissions 2018 and 2024, kt CO_2eq
Source: EPA

The base year used in Irish policy for reductions in GHG emissions is 2018 and, in that year, total emissions were 66 Mt CO_2eq.

By 2024, total emissions had fallen by 8 Mt CO_2eq to 58 Mt CO_2eq.

The objective of reducing GHG emissions by 2050 in order to achieve, what is termed in national law, climate neutrality, is set in a framework of legislative, institutional and policy measures.

1.2 Legislative framework

The legal and institutional framework to achieve climate neutrality in Ireland was set by the *Climate Action and Low Carbon Development Act 2015*. This legislation created the concept of carbon budgets to be devised and recommended to Government by a new agency established under the Act, the Climate Change Advisory Council (CCAC).

Section 15 of the Act required public bodies (including planning authorities and State-owned energy companies) **to have regard to**:

(a) the most recent approved national mitigation plan,

(b) the most recent approved national adaptation framework and approved sectoral adaptation plans,

- **(c)** the furtherance of the national transition objective, and
- **(d)** the objective of mitigating greenhouse gas emissions and adapting to the effects of climate change in the State.

The Act was amended in 2021 and Section 17 of the *Climate Action and Low Carbon Development (Amendment) Act 2021* now requires public bodies to **in so far as practicable, perform** [their] **functions in a manner consistent with**:

- **(a)** the most recent approved climate action plan,
- **(b)** the most recent approved national long term climate action strategy,
- **(c)** the most recent approved national adaptation framework and approved sectoral adaptation plans,
- **(d)** the furtherance of the national climate objective, and
- **(e)** the objective of mitigating greenhouse gas emissions and adapting to the effects of climate change in the State.

The legislation sets the objective to achieve climate neutrality by 2050 and puts obligations on State bodies (including energy companies and planning authorities) without defining what the objective means.

However, the intention that the objective of the legislation and of policy is to entirely eliminate GHG emissions is confirmed in *Ireland's Long-term Strategy on Greenhouse Gas Emissions Reduction 2024* (**Figure 3**).

This implies that the overall GHG emissions of 58 Mt CO_2eq in 2024 and, within that total the 32 Mt CO_2eq of energy-related emissions – should reduce to zero over the next 25 years.

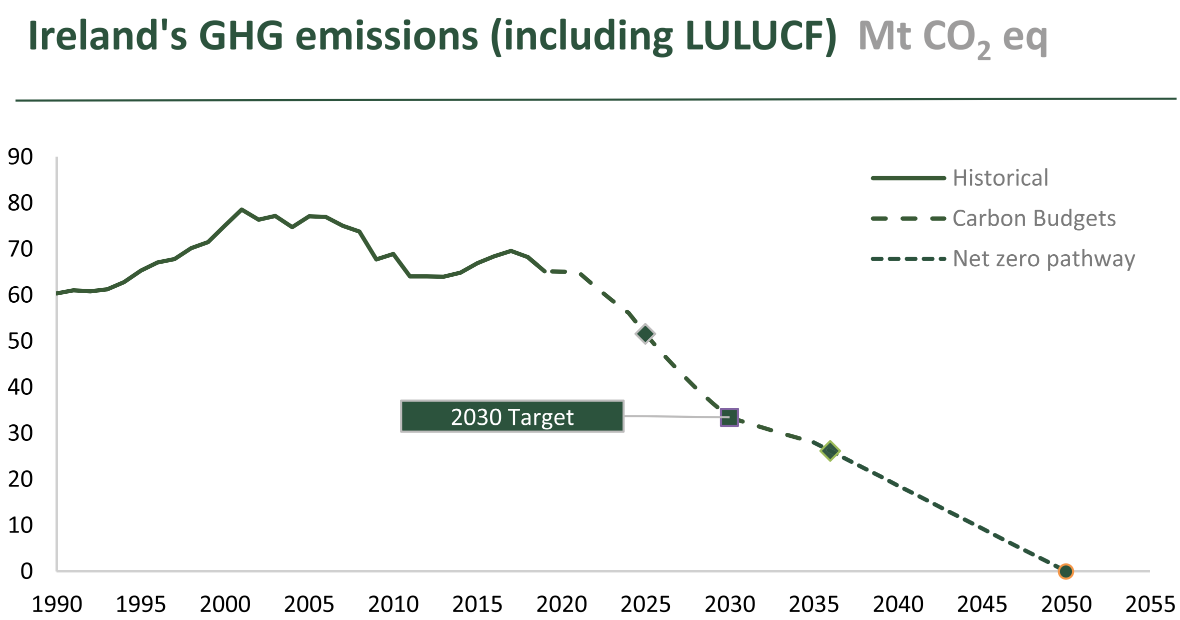


Figure 3: Ireland's required GHG emissions trajectory
Source: *Ireland's Long-term Strategy on Greenhouse Gas Emissions Reduction 2024*, Page 17, Figure 3.3

The lack of clarity in the legislation is addressed in the following terms in a footnote in a 2023 report by the EPA:[8]

> *There are different interpretations of the term climate neutrality. The EU Climate Law aligns it with achieving net zero greenhouse gas emissions by 2050. The Climate Action and Low Carbon Amendment Act 2021 interprets a "climate neutral economy" as a "sustainable economy and society where greenhouse gas emissions are balanced or exceeded by the removal of greenhouse gases".*

In this report, climate neutrality is taken to imply the complete elimination of GHG emissions from energy-related sectors including electricity generation, transport and heating, however unlikely it is that this can actually be achieved.[9]

It is extraordinary that the foundation stone of Ireland's energy policy is the achievement of a climate neutrality objective, the meaning of which is open to interpretation. This is not just an academic issue as it gives rise to poor policy and creates opportunities for legal challenges of planning decisions on important energy infrastructure projects. It also provides the basis for the setting of successive unrealistic five-year carbon budgets to progressively reduce average annual GHG emissions to 24 Mt CO_2eq by 2040 and, it is presumed, to zero by 2050 (**Table 3**).

1.3 Carbon budgets and sectoral emission ceilings

The first two carbon budgets envisaged in the 2015 legislation have been accepted by Government and cover the ten years from 2021 to 2030. In addition, the CCAC has recommended a third budget for the five years to 2035 and has published a provisional budget to 2040 (**Table 3**).[10]

Mt CO_2eq	Period	Five year total emissions	Average annual emissions
1	2021-2025	295	59
2	2026-2030	200	40
3	2031-2035	160	32
4	2036-2040	120	24

Table 3: Carbon budgets (including LULUCF) from 2021 to 2040, Mt CO_2eq
Source: Climate Change Advisory Council

The EPA has projected that Carbon Budget 1 (295 Mt CO_2eq) will be exceeded by between 8 Mt CO_2eq and 12 Mt CO_2eq and Carbon Budget 2 of (Mt CO_2eq) will be exceeded by between 77 Mt CO_2eq and 114 Mt CO_2eq (inclusive of carryover from Carbon Budget 1).[11]

The scale of the projected shortfalls to 2030 suggests that the first two budgets were unrealistically optimistic. Because shortfalls in a given carbon budget carry over into subsequent budgets, the scale of the challenge to achieve climate neutrality by 2050 will increase year by year and the achievement of zero net emissions by 2050 will become ever more unfeasible.

Based on the first two carbon budgets, Government has set sectoral emissions ceilings for the ten years to 2030 as shown in **Table 4**.[12]

8 *Ireland's Climate Change Assessment Volume 2: Achieving Climate Neutrality by 2050,* Page 2

9 Given the early stage of their technological development and limited deployments to date, technologies such as Carbon Capture Utilisation and Storage (CCUS) and Direct Air Capture (DAC) are not considered as realistic options to reduce GHG emissions in Ireland in the period to 2050.

10 *Carbon Budget Proposal Report 2024* and the *Letter to the Minister*.

11 *Ireland's Greenhouse Gas Emissions Projections 2024-2055,* Page 2, EPA, May 2025

12 *Sectoral Emissions Ceilings,* September 2022

Mt CO_2eq	2018	2021-2025	2026-2030
Electricity	10	40	20
Transport	12	54	37
Built Environment – Residential	7	29	23
Built Environment – Commercial	2	7	5
Industry	7	30	24
Electricity, transport built environment and industry	***38***	***160***	***109***
Agriculture	23	106	96
Other (F-Gases, Waste & Petroleum refining)	2	9	8
LULUCF	5	???	???
Other sectors	***30***	***???***	***???***
Total	**68**	**275**	**213**

Table 4: Sectoral Emissions Ceilings, September 2022, Mt CO_2eq

In the case of non-energy-related sectors, ceilings for Land Use, Land Use Change and Forestry (LULUCF) have yet to be set.

Both the carbon budgets and the sectoral emissions ceilings (where they have been finalised) have been set without adequate regard to engineering realities. Achieving the budgets and working within the ceilings depends entirely on technology and the delivery of many large energy infrastructure projects.

1.4 Projections of Ireland's GHG emissions in 2050

Notwithstanding that there is a policy objective to achieve climate neutrality by 2050, EPA has published projections of GHG emissions which indicate that considerable emissions will remain in 2050 (**Table 5**) based on the policy options currently in place or currently being considered by Government departments and State agencies.

EPA's projections are based on two sets of assumptions out to 2030 titled With Existing Measures (WEM) and With Additional Measures (WAM). These terms are explained by the EPA in the following terms:[13]

- The WEM scenario is a projection of future emissions based on the measures currently implemented and actions committed to by Government. To become part of the WEM scenario a policy or measure must be in place by the end of 2023 (the latest inventory year) and, in parallel, the resources and/or legislation must be in place or committed to by Government Departments or Agencies
- The WAM scenario is a projection of future emissions based on implemented measures included in the WEM scenario plus additional planned measures that are under discussion (as per plans, programmes or other policy documents) and have a realistic chance of implementation in the future (e.g. by 2030). The WAM scenario is based on the measures in the latest Government plans (such as the Climate Action Plan 2024) which have a realistic pathway in place for implementation.

The WEM and WAM scenarios EPA considers possible are not based on any large scale infrastructure delivery masterplan for the simple reason that no such plan exists. The projections based on these two scenarios are, therefore, both subjective and aspirational.

13 *Ireland's Greenhouse Gas Emissions Projections 2024-2055*, Page 6, EPA, May 2025

kt CO_2eq	2018	2050 WEM	2050 WAM
Transport	12,308	4,988	4,810
Energy Industries	10,559	1,936	1,663
Public electricity and heat production	*10,012*	*1,580*	*1,322*
Residential	7,000	4,603	1,232
Manufacturing Combustion	4,662	3,601	2,262
Industrial Processes	2,292	2,578	2,578
Commercial / Public Services	1,546	660	169
Mainly energy-related emissions	***38,367***	***18,366***	***12,714***
Agriculture	21,400	21,965	17,390
Land use, land use change and forestry	3,996	7,593	6,966
Waste	934	478	478
F-Gases	788	991	1,121
Other emissions	***27,118***	***31,027***	***25,955***
National Total	**61,491**	**41,798**	**31,702**
National Total including LULUCF	**65,487**	**49,391**	**38,668**

Table 5: Greenhouse Gas Emissions Projections to 2050, kt CO_2eq
Source: EPA[14]

The projections indicate that current policies might be sufficient to reduce overall GHG emissions to between 39 Mt CO_2eq and 49 Mt CO_2eq, and energy-related emissions to between 13 Mt CO_2eq and 18 Mt CO_2eq.

Given,

- that the first two carbon budgets will be missed by a significant extent,
- the lack of clarity on the contribution of LULUCF to overall GHG emissions, and
- given the imperative in national law that carbon neutrality be achieved by 2050,

it is evident that existing climate policy is unrealistic in its expectations of future outcomes.

In particular, there is an excessive and unrealistic reliance on what the energy sector can deliver (in terms of reducing its emissions to zero) by 2050.

Most significantly, there is a concerning lack of a clear energy policy to 2050 with realistic targets of what can be achieved not only to contribute to the objectives of climate policy but also to meet the requirements of a growing economy within which there is an inexorable trend towards the electrification of energy services.

14 *Ireland's Greenhouse Gas Emissions Projections 2024-2055*, EPA, May 2025

Notwithstanding this, in its Annual Review 2025 – Electricity, CCAC's Key Recommendations included the following:

> *The Government should immediately align the legal mandate and strategy for all public bodies to act in conformity with the Climate Act 2021, particularly those operating in the energy sphere, such as An Bord Pleanála, the Maritime Area Regulatory Authority, the Commission for Regulation of Utilities (CRU), EirGrid, ESB Networks and Gas Networks Ireland, and ensure full depreciation of fossil fuel regulatory assets by 2050 as an integral part of the energy transition plan.*[15]

On the face of it, this recommendation suggests that Ireland can achieve zero emissions from the energy sector by 2050 by which stage the size of the country's electricity requirement will have risen from 34 TWh to, as suggested in previous reports by the Academy, perhaps 80 TWh.[16]

If this interpretation is correct, the means by which Ireland might conceivably reduce EPA's projected energy-related emissions of 13 Mt CO_2eq (EPA's 2050 WAM projection) to zero by 2050 need to be explained. Based on any reasonable view of the technologies available today that are capable of being deployed in a period of just 25 years, a transition to a net-zero energy sector is not achievable.

When taken together with the requirements of the 2021 Act, and however the meaning of these requirements might be interpreted by the Superior Courts, it is clear that existing climate change policy is unrealistic in its objectives and, as a consequence of this, Ireland's energy policy cannot, as currently constituted, meet the needs of the country or provide for the welfare of the people of Ireland.

This reality is particularly evident in Ireland's GHG emissions covered by the Emissions Trading Scheme (ETS).

1.5 Ireland's ETS emissions

Ireland's performance within the EU's Emissions Trading System (ETS), launched in 2005, provides a useful focus on the lack of reality in the policy target to eliminate GHG emissions from energy-related sectors by 2050. The ETS puts a price on the CO_2 emissions in specified sectors based on a cap and trade principle. Annual emissions allowances and surplus allowances can be traded to enable operators with a deficit acquire the allowances they need to cover their emissions.

The number of allowances diminishes year by year in order to put upward pressure on the carbon price with the intention of incentivising operators to find zero carbon alternatives for their energy requirements. In the case of electricity generation, no allowances are available.

15 *Annual Review 2025 – Electricity*, Page viii, Climate Change Advisory Council

16 *Small Modular Reactors*, IAE, June 2024 and *The Energy Transition*, IAE, April 2025

There are 136 operators in Ireland covered by the ETS (**Table 6**).

kt CO_2eq	# operators	Verified emissions 2024	Allocation 2024	Surplus of allocations over emissions	Cost of emissions at €65 per tonne CO_2
Power station fuel combustion	23	6,311	-	-6,311	€ 410.2m
Cement production	4	2,281	2,405	124	- € 8.1m
Other fuel combustion	80	1,197	566	-631	€41.0m
Bauxite refinery	1	1,126	518	-608	€ 39.5m
Oil refinery	1	210	206	-4	€ 0.3m
Lime and magnesite production	3	132	167	36	- € 2.3m
Gypsum and plasterboard production	1	33	10	-23	€ 1.5m
Data centres fuel combustion	22	5	-	-5	€ 0.3m
Ceramics production	1	4	3	-1	€ 0.1m
Totals	**136**	**11,297**	**3,875**	**-7,422**	**€ 482.4m**

Table 6: Ireland's ETS emissions 2024, kt CO_2eq
Source: IAE analysis of data from DG CLIMA

The largest sector is electricity generation, and, in 2024, generators had to purchase allowances to cover 6.3 Mt CO_2 at an estimated cost of €410.2 million. Averaged over the total electricity requirement of 34.3 TWh in 2024, this is equivalent to €12 per MWh.[17]

In two other major emitting sectors – cement production and bauxite refining – the options to decarbonise are limited.

In the case of cement production, 40% of emissions arise from combustion and 60% from the chemical process of calcination.[18] In 2024, cement plants had more allowances than they needed (2.4 Mt CO_2 versus 2.3 Mt CO_2) but as emissions reduce over time, this will change. Allowances are gradually reducing and by 2024 had fallen by 38% from their level in 2008.

In the case of bauxite refining, the consumption of approaching 7 TWh of natural gas in 2024 (about 15% of total national consumption) generated emissions of 1.1 Mt CO_2 in the production of heat and the generation of electricity. The cost of the excess emissions was in the order of €40m.

Looking out to 2050, the prospects for any of the above three sectors achieving net-zero emissions are low:

- Renewables cannot meet all of the electricity requirement and back-up generation is required. There is no alternative for this currently other than fossil fuels, notably natural gas. If 95% of the electricity requirement in 2050 could be met by renewables / interconnection and if the remaining 5% were met from natural gas, then it is conceivable that emissions from power generation could fall by 90% (compared to their 2023 levels) to in the order of 0.8 Mt CO_2eq.[19]

17 The total electricity requirement of 34.3 TWh in 2024 was met by renewables (13.7 TWh), non-renewables (15.5 TWh) and imports (5.1 MWh)

18 Calcination changes calcium carbonate ($CaCO_3$) into lime (CaO) and carbon dioxide (CO_2).

19 The Energy Transition, Page 30, Table 20, IAE, April 2025

- Whereas there are low carbon alternatives for the production of cement (notably granulated blast furnace slag), these alternatives do not have the capacity to meet total market demand. In addition, even if an alternative zero-carbon energy source for the production of cement could be found, emissions from calcination would remain.
- In the case of bauxite refining, there are opportunities to use electric heating to raise steam and, in 2024, Aughinish Alumina, installed a 25 MW electric boiler. However, this would reduce overall natural gas by only a small amount, and it is hard to envisage that the entire consumption of 7 TWh of natural gas could be replaced by electric or zero-carbon alternatives by 2050.

In summary, in the case of the three sectors which accounted for 9.7 Mt CO_2eq (30%) of Ireland's energy-related GHG emissions in 2024, it is highly unlikely that these can be entirely eliminated by 2050 even if the financial incentives to do so continue to increase under the ETS.

The scope of the ETS is due to expand in 2027 with the introduction of ETS2 to cover CO_2 emissions from fuel combustion in buildings, road transport and small industry sectors not covered by the existing ETS.

As in the case of the existing ETS, the success of ETS2 in helping to reduce emissions to zero by 2050 will depend on the availability of zero carbon alternatives, particularly electrification. Electrification is not yet an option in some sectors, most notably in the road freight sector which generated in the order of 2.4 Mt CO_2eq in 2023.

1.6 Government plans and policies for the energy sector

Starting from the legislative objective of climate neutrality, there is a burgeoning welter of top down Government strategies, policies and plans which provide the framework within which State-owned energy companies and private sector energy companies operate:

- *Climate Action and Low Carbon Development (Amendment) Act 2021*. This mandated the preparation of an annual Climate Action Plan, the most recent version of which is *Climate Action Plan 2025*.
- The Act also mandated the preparation of a national long term climate action strategy every five years. The most recent version of this is *Ireland's Long-term Strategy on Greenhouse Gas Emissions Reduction 2024* (as referenced in **Figure 3**).
- The *National Adaptation Framework Planning for a Climate Resilient Ireland, 2024*.
- The *Electricity & Gas Networks Sector Climate Change Adaptation Plan*, 2019. This is currently under review.

What is strikingly absent in all of these strategies, policies and plans is any reference to any national infrastructure masterplans guided by a realistic view of what Ireland's energy mix and requirements will be in 2050 and set out in terms of the major energy projects that will need to be delivered to meet these requirements.

1.7 Ireland's GHG emissions in context

Energy policy in Ireland is dominated by climate policy and by the objective of eliminating GHG emissions. However, Ireland's efforts to reduce GHG emissions are territorial and the impact of GHG emissions on climate is global.

Between 2018 and 2023, global GHG emissions increased by 1,397 Mt CO_2eq (**Table 7**). Ireland's emissions in 2023 were 0.1% of global emissions and only 4.2% of the increase of 1,397 Mt CO_2eq in the five years from 2018 to 2023.

Mt CO_2eq	2018	2023	Change	% change	% in 2023
World	52,420	53,817	1,397	2.7%	100.0%
China	12,280	13,969	1,689	13.8%	26.0%
United States	6,305	5,895	- 411	- 6.5%	11.0%
India	3,682	4,196	514	14.0%	7.8%
EU 27	**3,709**	**3,105**	**- 604**	**- 16.3%**	**5.8%**
Germany	845	671	- 175	- 20.7%	1.2%
United Kingdom	475	392	- 82	- 17.4%	0.7%
Sweden	74	70	- 4	- 5.3%	0.1%
Ireland	64	58	- 6	- 9.6%	0.1%

Table 7: Analysis of GHG emissions in selected regions and countries, 2018 to 2023, Mt CO_2eq

Source: *Our World in Data*[20]

Whether Ireland achieves a substantial level of reductions in its 2018 emissions by 2050 (which is feasible) or eliminates them entirely (which is implausible) will make no difference to Ireland's climate.

That being the case, Ireland's climate and energy policies should be realistic in terms of what can be achieved, responsible in terms of their impact on the welfare of the Irish people and proportionate by reference to the negligible impact Ireland can have on global climate.

The policy objective needs to move from attempting to do what is not possible to achieving an appropriate balance between sustainability, energy security and energy cost.

1.8 Conclusions

Among the conclusions in its April 2025 report (*Ireland's Future Power System and Economic Resilience*), the National Economic and Social Council said:

> *Overall, the Council's extensive consultations and analysis suggest that, essentially, much of Ireland's policy action for transition in the power sector is headed 'into fog', where visibility and certainty are low. Key actors in the necessary transition are not 'on the same page' from a strategic standpoint.*

The fog referred to by NESC is a product of the development of a labyrinthine bureaucracy created to oversee the attainment of unrealistic and unclear climate objectives and to control the strategies and plans of the State-owned energy companies accountable for delivering the critical infrastructure needed to meet the country's long-term energy needs.

20 Jones et al. (2024) – with major processing by Our World in Data. "Annual greenhouse gas emissions including land use" [dataset]. Jones et al., "National contributions to climate change 2024.2" [original data].

2. GEOGRAPHY, POLITICAL CHOICES AND ENERGY SERVICES

Ireland's Primary Energy Requirements are predominantly met by fossil fuels, 83% in 2023 (**Table 8**).

TWh	Coal / peat	Oil	Natural Gas	Renewables	Non-Renewable Waste	Electricity[21]	Total
Primary Energy	7.2	80.1	48.3	23.0[22]	2.0	3.3	**163.8**
	4.4%	48.9%	29.5%	14.1%	1.2%	2.0%	100%

Table 8: Primary Energy Requirement, 2023
Source: SEAI

This share has been declining slowly but steadily since 2003 (**Figure 4**) .

At the current rate of decline, fossil fuels would still account for two-thirds of PER by 2050.

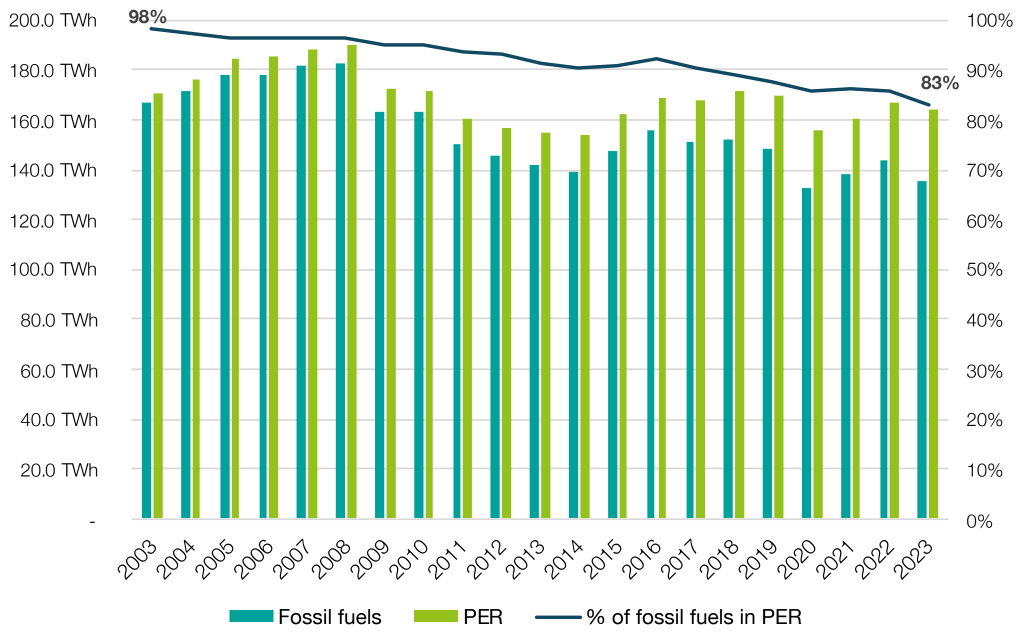


Figure 4: Share of fossil fuels in Primary Energy requirement from 2003 to 2023
Source: SEAI

Achieving carbon neutrality requires the elimination of all fossil fuels from Ireland's energy mix over the next 25 years. Whereas it is foreseeable that the amount of fossil fuels will decline significantly, it is not conceivable that they will disappear entirely.

A continuing dependence on fossil fuels is not only a function of the availability of alternative renewable energy options, it is also a function of geography and political choices.

21 Electricity at the level of Primary Energy comprises imports of electricity via interconnectors.

22 The 23.0 TWh of Renewables at the level of Primary Energy includes wind energy of 11.7 TWh.

2.1 How geography and political choices shape Primary Energy

Table 9 and **Appendix 2** show the dependency on fossil fuels among the 27 countries in the EU and Norway.

Country	Fossil fuels in PER	Renewables	Nuclear	Other	Total	Fossil fuel dependency Rank *1 is the highest*
Belgium	74.3%	9.8%	14.1%	1.8%	100.0%	10
Denmark	52.9%	43.0%	0.0%	4.1%	100.0%	24
Finland	34.7%	39.6%	23.9%	1.8%	100.0%	28
France	47.1%	14.9%	39.1%	-1.2%	100.0%	26
Ireland	83.2%	13.7%	0.0%	3.1%	100.0%	5
Netherlands	85.7%	12.4%	1.2%	0.7%	100.0%	3
Portugal	64.0%	31.4%	0.0%	4.6%	100.0%	16
Sweden	28.5%	50.2%	24.7%	-3.3%	100.0%	28
EU 27	**67.6%**	**19.5%**	**11.8%**	**1.1%**	**100.0%**	**n/a**
Norway	48.4%	55.3%	0.0%	-3.7%	100.0%	25

Table 9: Sources of Primary Energy in selected EU countries and in Norway, 2023
Source: IAE analysis of *Eurostat data*

Ireland has the fifth highest dependency among the 28 countries:

- As in the case of the Netherlands, Ireland has no significant hydro power resources or nuclear power and the shares of fossil fuels in each country's Primary Energy Requirement (PER) is similarly high at 85.7% and 83.2% respectively.
- Belgium, which also has no hydro power, does have nuclear power, and fossil fuels share in PER is lower than Ireland's at 74.2%.
- Portugal has no nuclear power but does have significant hydro resources which boost renewables to 31.4% and leave fossil fuels at 64.0%.
- France, with its large nuclear capacity, depends on fossil fuels for 47.1% of its PER.
- In countries with both nuclear and a lot of hydro power, the shares of fossil fuels in PER is much lower than in Ireland. In Finland, fossil fuels' share of PER is 34.7% and in Sweden it is only 28.5%.
- By comparison with Sweden, Finland and France, more than half of Norway's energy comes from renewables and almost half from the country's abundant indigenous fossil fuel resources.
- Among the 27 EU countries and Norway, Sweden has the lowest dependency on fossil fuels (28.5%) and Ireland has the fifth highest.

Geography determines that Ireland will never have significant hydro resources and political choices have determined that nuclear power does not feature in the country's energy mix.

Ireland has wind and solar resources similar to other north European countries and has significant scope to increase the level of renewables, including wind and biomethane.

However, Ireland is starting from a very high level of dependence on fossil fuels with no possibility to reduce this by increasing hydro power. Nor is it possible to reduce this dependence by using nuclear power until national laws and energy policies are changed.

2.2 The impact of geography and political choices on GHG emissions from electricity generation

The impact of geography and political choices on PER follows directly into the level of emissions from electricity generation (**Table 10** and **Appendix 3**).

Sweden and France have the lowest specific emissions in the EU as a result of their similarly high availability of electricity from nuclear and hydro.

	kg CO_2eq per MWh	Nuclear / hydro share of electricity requirement %	Wind / solar share of electricity requirement %	Specific emissions rank *1 is the lowest*
Belgium	118	42%	31%	7
Denmark	143	0%	69%	11
Finland	72	56%	26%	3
France	44	80%	12%	2
Ireland	280	2%	40%	19
Netherlands	253	3%	45%	17
Portugal	112	30%	46%	6
Sweden	36	67%	26%	1
Total EU in 2024	**213**	**37%**	**29%**	
UK	216	16%	35%	

Table 10: Specific emissions from electricity generation in selected EU countries and in the UK, 2024
Source: Ember

Ireland, on the other hand has specific emissions six times higher than those in France and eight times higher than in Sweden.

In the case of Denmark – frequently cited as an exemplar which Ireland should emulate in terms of the penetration of wind in its energy mix – it benefits enormously from the geographical proximity of its eastern grid area to the Nordic Synchronous Area (Finland, Sweden and Norway) and, via Germany, of its western grid area to the Central Europe Synchronous Area. This proximity allows for Denmark's surplus renewable power to be sold into adjacent markets and for imports from these adjacent markets into Denmark when the output from renewables is not sufficient to meet demand. In 2024, for example, Denmark had net imports of 3.7 TWh equivalent to 11% of its electricity requirement.

Ireland's island location does not allow for similar synchronous connection of the SEM with Britain or France or with any other grid area. This has important consequences for determining the amount of renewables Ireland should deploy. It also creates a different dynamic (by comparison to Denmark) for the interplay between renewables and interconnectors which, in Ireland's case, must be DC rather than synchronous AC (**Section 5**).

2.3 Energy Services

The ultimate objective in energy policy is to provide the energy services the country needs (transport, heating and industry) with the optimum balance between efficiency, sustainably, cost and security of supply.

In the order of two-thirds of primary energy is lost as waste heat. The energy flow diagram published annually by the Lawrence Livermore National Laboratory illustrates well how 66% of the primary energy in the US is wasted as heat and only 34% delivers energy services (**Appendix 4**). The same pattern of loss occurs in Ireland.

Renewables offer the possibility of increased energy efficiency by eliminating the losses inherent in the generation of electricity by the combustion of fossil fuels. These losses are inevitable because of the laws of physics and explain most of the 23.0 TWh difference between Primary Energy (163.8 TWh in 2023) and Final Energy Consumption (140.8 TWh) as shown in **Table 11**.

TWh	Coal / peat	Oil	Natural Gas	Renewables	Non-Renewable Waste	Electricity	Total
Industry	0.6	3.9	9.9	2.0	0.9	6.7	24.0
Transport		57.1	0.2	3.5		0.3	61.1
Residential	2.8	12.1	5.4	1.3		8.1	29.6
Commercial Services		1.1	2.0	0.4		13.0	16.5
Public Services		1.2	1.8	0.2		2.9	6.1
Agricultural		2.6				0.5	3.2
Fisheries		0.2					0.2
Final Energy Consumption	**3.4**	**78.3**	**19.3**	**7.4**	**0.9**	**31.6**	**140.8**
	2.4%	55.6%	13.7%	5.2%	0.6%	22.4%	100%

Table 11: Final Energy Consumption by sector, 2023
Source: SEAI

Beyond that, there is the possibility to greatly reduce fossil fuel consumption by the electrification of heating and transport in three areas which, combined, account for 88.4 TWh or 63% of FEC (**Table 12**).

Sector	TWh	% of FEC
Oil in transport	57.1 TWh	40.6%
Oil and gas in residential	17.5 TWh	12.4%
Oil and gas in industry	13.8 TWh	9.8%
Total	**88.4 TWh**	**62.8%**

Table 12: Main target areas to decarbonise Final Energy Consumption

The efficiency opportunities in heating and transport come from heat pumps and EVs:

- An efficient condensing gas boiler achieving 90% efficiency could be replaced by a heat pump with a coefficient of performance of 3.5 to provide the same heat for about one-quarter of the energy input.
- Electric vehicles have substantially higher battery-to-wheel efficiencies compared to the tank-to-wheel efficiencies of internal combustion engines, and, for the same level of transport activity that could be powered by oil, only 44% as much electrical energy would be required.

When combined with the potential to greatly increase renewables in electricity generation, the electrification of heating and transport could, conceivably, reduce Primary Energy Requirement by about 35% or 60 TWh based on 2023 levels (**Figure 5**).[23]

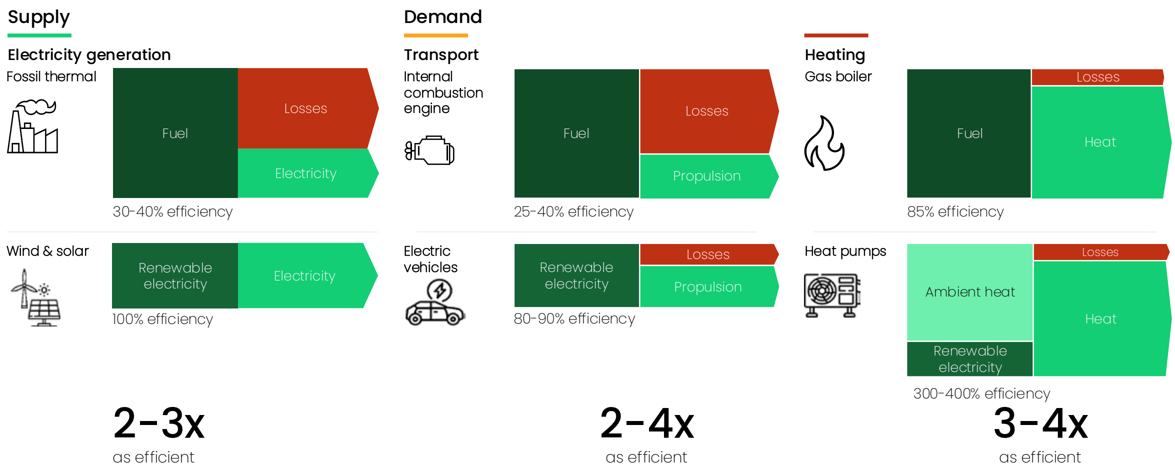


Figure 5: Illustration of the possibilities for energy efficiency gains from renewables and from electrification
Source: *The Electrotech Revolution - The shape of things to come*, Ember, September 2025

Whereas this would considerably reduce Ireland's GHG emissions from energy-related activities, it would not entirely remove them because of,

- the residual dependence on natural gas for back-up power generation
- ongoing emissions from non-renewable waste, and
- continued dependence on fossil fuels in difficult to abate industries and for HGVs.

Rather than an ill-defined and mandatory target of achieving climate neutrality by 2050, energy policy needs to be based on:

- Realistic estimates of national energy demand in 2050 both from electricity and from liquid and gas fuels.
- The identification - in an electricity infrastructure masterplan – of critical overhead transmission line and back-up generation projects that would be needed to meet this demand.
- A conservatively high estimate for the electricity requirement in 2050 such that if actual demand is less than planned for, projects can be deferred.

23 Whereas this report focuses on the supply side challenges of the energy transition, it is important to recognise that there are considerable demand side challenges if energy services are to be electrified, particularly in rural areas where the utility of diesel for transport will be difficult to replicate and also where the experiences of major outages following Storm Éowyn in January 2025 exposed vulnerabilities in the country's distribution system.

The masterplan required to plan Ireland's critical electricity infrastructure over the next 25 years needs to be prepared by those responsible for delivering the plan and needs to be informed by engineering expertise and project delivery experience (**Section 8**).

2.4 Conclusions

If it is not feasible to eliminate GHG emissions from energy – and it has nowhere been explained in policy or elsewhere how this might be possible – then it needs to be accepted that some level of GHG emissions will continue until 2050.

The energy transition needs to be understood as a gradual process by which GHG emissions will be reduced over time. Today, fossil fuels account for 83% of Ireland's primary energy requirement and there will remain a large and long fossil fuel tail for many years to come.

Energy policy should facilitate this while not constraining economic development or imposing excessive costs on consumers. A balance needs to be found between the competing constraints of the energy trilemma, and this needs to be recognised in policy and in national climate law. It also needs to inform Ireland's contribution to European laws and policies.

It is extraordinary that Ireland has become exposed to large financial liabilities for not meeting EU climate and renewable energy targets for 2030. This has arisen as a result of poor national policies and by the naïve acceptance of unrealistic targets conceived by the European Commission.

In the following sections of this report, when the term ***energy transition*** is used, it should be taken to mean the electrification of energy services – with a concomitant reduction in GHG emissions – and the increased penetration of renewables into the country's energy mix – also contributing to a reduction in GHG emissions – but not to the implausible extent of eliminating GHG emissions entirely in energy-related activities by 2050.

SECTION B THE ENERGY TRILEMMA, PROJECT DELIVERY, AUTHORITY & ACCOUNTABILITY

3. THE ENERGY TRILEMMA

In the 1970s and 1980s, Ireland's energy policy was dominated by the two challenges of energy security and energy prices. The oil shocks of 1973 and 1979 were caused by geopolitical events in the Middle East that threatened the supply of oil. At that time, Ireland depended on imported oil not only for transport but also for electricity generation.

In the wake of the 1973 oil shock, the International Energy Agency was established to ensure the security of oil supplies.

In Ireland, the exposure to an oil security of supply risk brought nuclear power onto the policy agenda. The need for a diversity of power sources had, at that point, already been recognised by *legislation* in 1971 to establish the Nuclear Energy Board (NEB). The NEB was set up in 1973 and the option of building a nuclear power plant was considered but ultimately rejected due, primarily, to the large scale of a nuclear plant (500 MW) compared to a maximum demand of 2,000 MW at the time.

Instead, a decade later, Moneypoint was commissioned with three units each with a capacity of 300 MW.

The energy security of supply threats in Ireland were largely addressed by the establishment of NORA and by the reliance on coal and peat for power generation, both of which could be stored in large quantities.

The challenge of energy policy up to the 1990s was one of balancing energy security with the cost of energy.

This dilemma became a trilemma in the 1990s when the impact of GHG emissions on climate began to be recognised in energy policy (**Figure 6**). The concept of the energy trilemma is, today, well understood and provides a useful conceptual framework for considering the balance between three competing policy drivers.

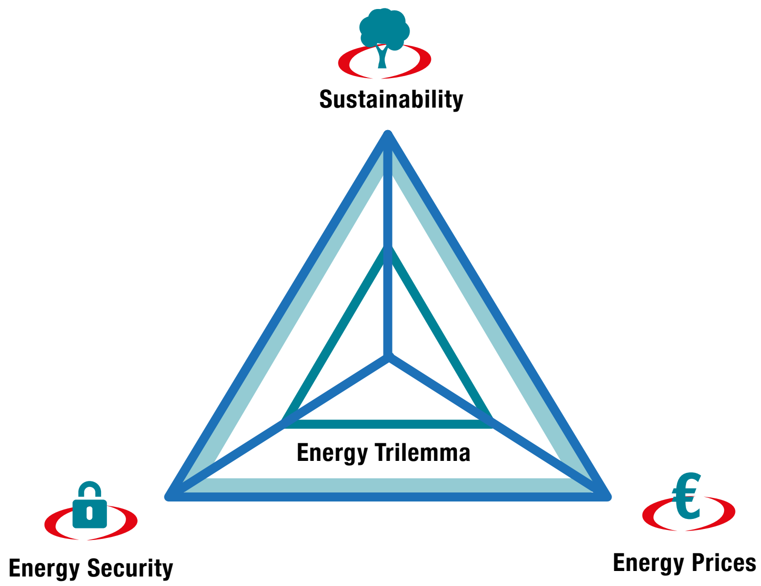


Figure 6: The energy trilemma

The emphasis on the sustainability driver has increased greatly and Irish energy policy has come to be dominated by UNFCC agreements and by EU policy and law.

In recent years, geopolitics has re-emerged as a factor in energy policy and there has been a returned focus to the challenges of energy security and affordability.

Ireland has committed to achieving the sustainability objective of carbon neutrality by 2050 with little regard to energy security and energy prices. In the case of prices, policy responses have been short-term by way of direct subsidies in recent years to electricity consumers.

In the case of energy security, there has been a belated decision (2024) to develop a small LNG facility by docking a leased floating storage and regasification unit (FSRU) in a west or south coast port. The thinking behind this is dominated by the policy objective of reducing GHG emissions and the natural gas from the LNG facility is seen as a necessary short-term risk mitigant to be reluctantly tolerated.

Beyond the energy trilemma, there is the challenge in Irish energy policy to deliver an unprecedently large programme of electricity infrastructure projects.

Bringing these two facets together, the challenge of Irish energy policy can be summarised as one of rebalancing the three legs of the energy trilemma and delivering a large programme of electricity infrastructure projects.

Just as environmental concerns created a singular focus on the sustainability leg of the energy trilemma, so also environmental concerns have created a delivery challenge for large infrastructure projects.

In the former case, climate policy has set an impossible outcome target in terms of the elimination of national GHG emissions.

In the latter case, there has been a lack of urgency in translating environmental obligations into law and policy in a manner which gives project developers clarity and certainty on what they need to do to deliver essential national energy infrastructure projects, both for electricity and for natural gas.

4. THE ABSENCE OF URGENCY IN POLICY DELIVERY

A clear and unambiguous policy framework is essential if large energy infrastructure projects are to be delivered reliably and on time. It is the responsibility of Government to deliver this policy framework. Unfortunately, there has been an evident lack of urgency in doing this with the result that there have been long delays and impediments to the delivery of renewables and other energy projects, notably for LNG.

4.1 Environmental designations

Ireland has benefitted greatly by EU laws which protect the environment. Although these laws result in significant constraints for large infrastructure projects of all types, if project developers comprehensively evaluate environmental impacts – including on Natura 2000 sites – and if planning authorities complete their Environmental Impact Assessments (EIAs) and Appropriate Assessments (AAs) thoroughly, then large infrastructure projects in Ireland can, and have, received grants of planning permission.

There are notable examples of projects with significant potential for environmental impacts successfully and efficiently navigating the correctly demanding planning consent process in Ireland, including:

- The original Shannon LNG project from 2008[24]
- Dublin Port's ABR Project and MP2 Project[25]

However, because Ireland has generally been slow in designating Natura 2000 sites, projects under development can be impacted by the belated creation of new designated areas and there are two examples of this in recent times:

- The Oriel wind farm project has been under development for many years, and a foreshore lease was granted in 2010. It took over a decade for the ORESS1 auction process to be established in June 2022, provisional results for which were announced in May 2023. Two months later, in July 2023, the North-west Irish Sea SPA – overlapping the area of the proposed wind farm development – was announced.
- Iarnród Éireann commenced pre-application consultation with An Bord Pleanála in May 2024 for a project to develop a facility in Rosslare Harbour for offshore wind farm construction. In July 2025, the Seas of Wexford SPA – covering the area of the proposed expansion of Rosslare Harbour – was created.

Whereas the development of projects in Natura 2000 sites is possible, belated Natura 2000 designations, such as those above, can lead to projects having to be significantly redesigned to accommodate the requirements of the new designations. This is potentially costly both monetarily and in terms of wasted time.

If climate policy and energy policy require, as they do, a large programme of infrastructure projects, then certainty of environmental designations is a prerequisite. Ireland lags the EU in having 13.6% of land and 7.7% of the seas covered by Natura 2000 designations compared to EU averages of 18.6% and 9% respectively.[26] Both Ireland and the EU as a whole compare poorly with the objectives of the EU Biodiversity Strategy to achieve legal protection for 30% of the land area and 30% of the marine area.

If the extent of legal protections is to increase considerably, it is essential for the developers of energy projects that the NPWS completes its work to designate SPAs and SACs around the country to complete Ireland's Natura 2000 network and to give certainty as to where renewables projects and other large energy infrastructure projects should be contemplated.

This requirement extends beyond Natura 2000 sites and includes Marine Protected Areas (MPAs).[27]

24 An Bord Pleanála *PA08B.PA0002*

25 An Bord Pleanála *PA29N.PA0034* and An Bord Pleanála *PA29N.304888*

26 *European Environment Agency*

27 Communication From the Commission to the European Parliament, The Council, The European Economic and Social Committee and the Committee of the Regions, EU Biodiversity Strategy for 2030 Bringing nature back into our lives, *COM/2020/380 final.*

4.2 MPAs and DMAPs

In 2019, the Department of Climate, Energy and the Environment commenced a process to expand Ireland's Marine Protected Areas (MPA) network beyond what was covered by Natura 2000 sites.[28]

Two years later, in May 2021, the National Marine Planning Framework was established.[29]

A general scheme for a new Marine Protected Areas Bill was published in 2022. No bill has yet been published and consideration is now being given to revising the Maritime Area Planning Act 2021 to deliver the legal basis for MPAs. It is unclear when the decision on one or other legislative avenue will be decided and, subsequent to this, when the legislative basis to create and manage MPAs will be created.

In the meantime, the South Coast Designated Maritime Area Plan (DMAP) for Offshore Renewable Energy was *published* in October 2024 and a proposal to establish a National DMAP with a target date of December 2027 has been announced.

The position of marine planning within the wider national planning frameworks is shown in **Figure 7**.

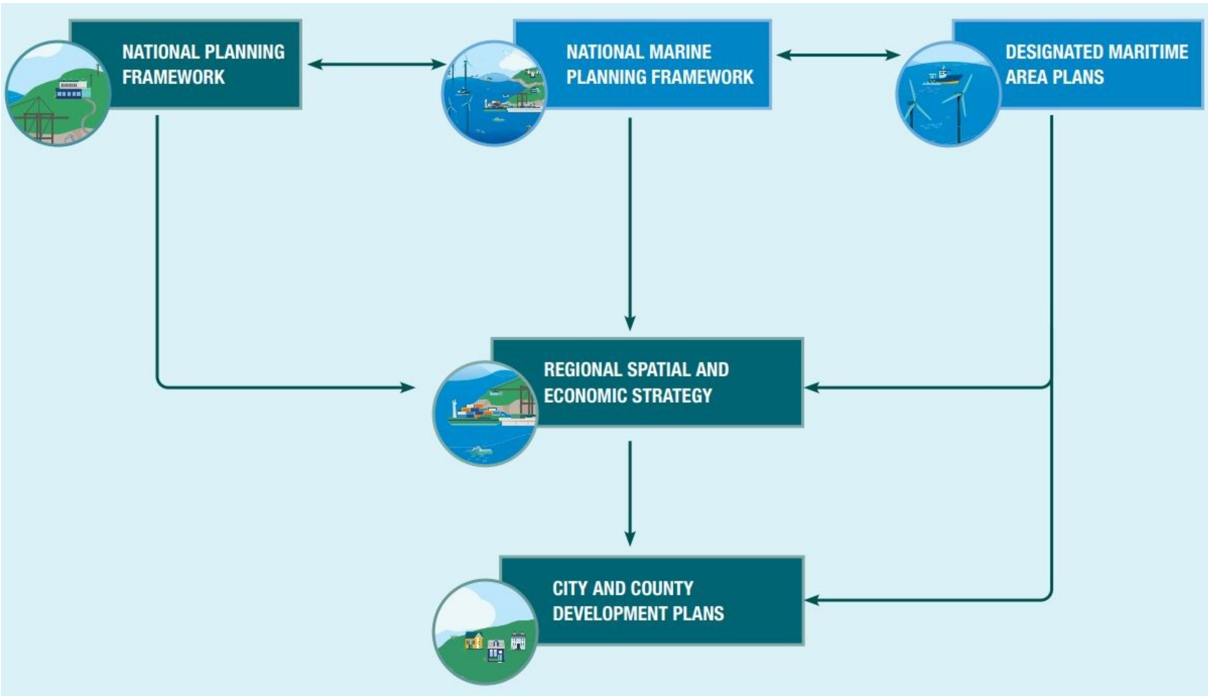


Figure 7: Position of Designated Marine Area Plans within Ireland's national planning framework
Source: *South Coast Designated Maritime Area Plan for Offshore Renewable Energy* presentation

From the perspective of a developer of an ORE project, the introduction of new environmental protection legislation while projects are under development creates uncertainty and potentially opens avenues for legal challenges of grants of planning permission.

No responsible project developer wants or sets out to degrade the environment. Where there are environmental protection areas, projects can, and are, routinely designed to avoid negative impacts.

The slowness of the State in creating certainty for ORE project developers in terms of designated environmental protections creates a major risk for the delivery of ORE projects.

28 Marine Protected Areas *announcement,* Department of Climate, Energy and the Environment, December 2019

29 *National Marine Planning Framework*

The practical impact of the tardiness in developing the administrative and environmental protection framework within which renewable and other energy infrastructure projects have to be delivered is well exemplified by the ORESS1 process:

- In April 2021, Government set a policy target to deliver 5,000 MW of offshore wind power by 2030 with a further 2,000 MW to be under development to provide power for the production of green hydrogen.
- What *under development* meant was not defined and it is not conceivable that any meaningful progress to achieve this objective will be made by 2030.
- Maritime Area Consents (MACs) - to allow already established projects to compete in the ORESS1 auction - were issued in December 2022, eight months in advance of the launch of the Maritime Regulatory Area Authority (MARA), the body designated to consider applications for MACs, in July 2023.
- The ORESS1 auction results were announced in May 2023 and four projects (3,074 MW) had bids accepted and two did not (1,175 MW).
- All six projects submitted planning applications to An Bord Pleanála between 12 and 20 months later.
- One of the six projects has been abandoned and four of the remaining projects have requests for further information (FI) with receipt deadlines in 2026 (**Table 13**).
- The earliest that An Coimisiún Pleanála can be expected to issue decisions (grant or refusal) is in the second half of 2026.
- There is a distinct possibility of judicial reviews being lodged based on the sequence and timings of the issuing of MACs, the preparation of DMAPs and the creation of marine protected areas. Some NGOs have already highlighted their intentions and approaches.

Rather than meeting the target of 5,000 MW of offshore wind by 2030, the best that can be hoped for is 3,799 MW, but the likelihood is that far less than this will be achieved. It is even possible that no offshore wind farm will be operation by 2030.

	Planning application lodged	Capacity	Route to market	Further Information Request	FI due date
Oriel Wind Farm	May-2024	375 MW	PPA	Apr-2025	Jan-2026
Arklow Bank Phase 2 Wind Farm	Jun-2024	800 MW	PPA	Apr-2025	Jan-2026
North Irish Sea Array	Jun-2024	500 MW	ORESS1	Apr-2025	Jan-2026
Codling Wind Park	Sep-2024	1,300 MW	ORESS1	Aug-2025	May-2026
Sceirde Rocks Windfarm	Jan-2025	450 MW	Cancelled		
Dublin Array Wind Farm	Feb-2025	824 MW	ORESS1		
		4,249 MW			

Table 13: Status of the six offshore wind projects which submitted bids in ORESS1

Thirteen years ago, Government published Harnessing Our Oceans Wealth in which the potential for offshore renewable energy was identified and the need for marine spatial planning and the reform of planning and foreshore consent regimes was highlighted.[30] It took until 2021 for the Maritime Area Planning Act to be passed and a further two years for the establishment of MARA in July 2023. With a fixed date in law of 2050 for Ireland to be climate neutral, the time that has been lost cannot be made up.

The slowness in creating the environmental and regulatory framework for offshore wind is not confined to the maritime area.

On the landside, and notwithstanding the 2030 targets for onshore wind (9,000 MW) and solar (8,000 MW), there are still no appropriate planning guidelines which project developers can work from or to guide planning authorities in their assessment of applications for planning permission:

- Wind energy development guidelines were published in 2006 and a review of these guidelines commenced in 2013. Twelve years later, the review is still ongoing.
- There are no specific planning guidelines for the development of solar projects.

Also, in the case of ORE, there is the requirement for port facilities from which the five remaining projects that participated in the ORESS1 auction, and any projects that could emerge from the planned ORESS2 auction in late 2025, might be built. Here, also, policy has failed to deliver.

4.3 Port infrastructure for ORE projects

Building fixed-bottom offshore wind farm projects requires access to a port facility where wind turbine components (blades, nacelles and towers), monopiles, transition pieces and undersea cables can be marshalled and despatched on specialist ships to offshore construction sites.

Ireland has one ORE port facility nearing completion in Port of Cork. This facility is actually the second phase of a project to develop Ringaskiddy Container Terminal which was brought forward and constructed within an extant planning permission. It was financed by a combination of debt and EU grant.

Elsewhere in Port of Cork, a private sector project to redevelop the former Verolme Dockyard as an ORE facility was abandoned in 2024 due to the uncertainty of future revenues.

Irish Rail is planning to submit a planning application for a large development at Rosslare Harbour to provide facilities for ORE project construction and, in the long-term, provide additional cargo handling capacity.

Allowing for winter weather, a 760 MW offshore wind farm would occupy a port facility for up to two years including mobilisation and demobilisation time.[31]

If Ireland were to build, say, 20,000 MW of ORE projects, each of an average size of 760 MW, this could be done from a single port facility in the country but only over a period of more than 50 years.

The development of a large number of fixed-bottom ORE projects requires some combination of:

30 *Harnessing Our Oceans Wealth*, An Integrated Marine Plan for Ireland, July 2012

31 The five remaining projects that participated in the ORESS1 auction have an average capacity of 760 MW based on their aggregate capacity of 3,799 MW.

- Use of the new Port of Cork facility
- Use of facilities in other jurisdictions
- The construction of new ORE facilities in other Irish ports

Financing the construction of a new ORE port facility with project finance would be, and has already proven to be, impossible because of the uncertainty of future revenues and cash flow.

An alternative approach would be to have the construction of new ORE port facilities financed by Government. However, national port policy precludes this.

There is a clear policy target conflict between ORE policy and National Ports Policy.

A recent report suggested that Ireland needs four ORE marshalling ports at an investment cost of €2 billion to €3 billion.[32] It further suggests that it would take four to five years to prepare an existing port for ORE.

The reality is that large port infrastructure projects have a much longer lead time than four to five years and, absent an unlikely allocation of unprecedentedly large exchequer funding to port infrastructure projects, offshore wind construction projects will only have one port in the State from which to construct ORE projects in Irish waters.

If Irish ORE projects had to rely on port facilities in other countries, it would complicate project construction logistics and increase project costs. However, it is likely that ORE port facilities might not be available elsewhere for Irish ORE projects because most other countries in northwest Europe are implementing their own ORE programmes at the same time.

Aside from any other challenges ORE projects may face, it is clear that the critical path to build out the remaining five projects from ORESS1 will be determined by access to suitable port facilities.

These realities suggest that it is not just quite possible that no offshore wind farm will be operation in 2030, it is far more likely than not that this will be the case.

Looking beyond fixed-bottom offshore wind, there are similar challenges to constructing port facilities in the Shannon Estuary for any floating offshore projects that might be envisaged.

The full economic cost of building offshore wind in Irish waters has been ignored.

In Britain, there are many suitable old port facilities with good depth of water, adequate quay wall length and sufficient back-up space which could be repurposed at low cost and these have facilitated the development of 14,000 MW of ORE capacity since Ireland's first and only 25 MW ORE project was constructed 23 years ago in Arklow.[33]

Ireland has no such facilities and the availability of port facilities for ORE projects is a constraint that has been all but ignored in policy.

32 *Missing the Boat: Port Infrastructure as a Critical Barrier to Offshore Wind Energy Development in Ireland*, October 2025, Dr James G. Carton, Bill Duggan, John Doody

33 For example, the 3,600 MW (277 x 13 MW wind turbines) Dogger Bank Windfarm is being constructed from the Able Seaton port facility in Hartlepool.

4.4 Conclusions

There has been, and remains, a lack of coherence in the framework of policies, guidelines and laws within which renewables projects and, more generally, large energy projects can be developed and delivered.

This lack of coherence recently became manifest in the refusal by An Coimisiún Pleanála for an onshore wind farm project[34] which the project developer then appealed to the High Court[35] whose decision to return the project to An Coimisiún Pleanála for reconsideration was subsequently appealed to the Supreme Court by An Coimisiún Pleanála.

An Coimisiún Pleanála (formerly An Bord Pleanála) is frequently cited as being an obstacle to the delivery of large energy infrastructure projects. While there have been instances (confirmed by judicial reviews) of shortcomings in the process of EIA and AA, by far the biggest obstacles large energy infrastructure projects face in securing grants of planning permission come from conflicts between different policy targets, from a lack of policy clarity and from a tardiness in policy delivery.

Given the unrealistic and over-riding mandatory obligation to progress towards climate neutrality by 2050, there is an obvious and major risk that Ireland's energy policy will not meet the country's requirements over the next 25 years.

Given the extreme slowness in delivering renewable energy in sufficient quantity to power the growing electrification of energy services, the dependence on fossil fuels for transport, heating and industry will continue at a greater scale and for far longer than it otherwise might have.

Renewables will always require back-up from some source of dispatchable generation and – based on the technologies available in the foreseeable future – this requires fossil fuels. There are important choices to be made in national energy policy as to what the priorities should be.

It is clear that prioritising renewables over all other considerations is the wrong option. The correct option requires a balance between the three legs of the energy trilemma based on the realities of what is required to deliver large energy infrastructure projects.

34 An Coimisiún Pleanála decision *PA11.317809*, August 2024

35 High Court *judgement*, January 2025

5. FUTURE RENEWABLES CAPACITY

In previous reports – and in the absence of a clear planning target in policy for the development of Ireland's electricity sector over the next 25 years - the Academy has assumed an electricity requirement of 80 TWh and a maximum demand of 12,000 MW by 2050. These are conservatively high estimates on the basis that if we plan to provide the infrastructure required to meet these targets, and if demand does not grow to that level, then projects that have been planned can be deferred.

This approach is deliberately intended to avoid the recurring failure in Ireland not to deliver essential infrastructure on time and, instead, the incurring of costs and other impacts due to infrastructure capacity constraints as has occurred in sectors including water, wastewater and housing.

Even against these putative levels, current policy targets for renewables are unrealistic (**Table 14)**.

	Power capacity	Government target date	Assumed capacity Factor	Electricity capacity
Offshore wind	37,000 MW	2050	45%	145.9 TWh
Onshore wind	9,000 MW	2030	28%	22.1 TWh
Solar	8,000 MW	2030	11%	7.7 TWh
Totals	**54,000 MW**			**175.7 TWh**

Table 14: Government targets for renewable generation capacity in Ireland by 2050

This raises the obvious question as to what the targets for renewables should be?

The need for renewables and the impact on the cost of electricity is being volubly challenged in some countries, even with the suggestion of a return to an almost complete reliance on fossil fuels.

Irish energy policy is at the opposite end of the spectrum with an unquestioned commitment in law, policy, regulation and strategy to attain the undefined goal of climate neutrality with no limit on the volume of renewables that might be deployed. In pursuing its policy objective, Government explicitly advocates, and identifies, opportunities for Ireland to become a major electricity exporter or a producer of green hydrogen. The target levels in **Table 14** are only understandable on this basis.

Energy policy needs to find an appropriate middle ground between these two extremes to ensure that the electricity sector is expanded to provide the increase in supply needed for electrification while not overburdening consumers with excessive electricity prices or allowing the current exposure to energy supply risks to continue.

This requires consideration of a number of inter-related factors including the impact of intermittency, interconnection and the cost of too much renewables.

5.1 Intermittency

There is no relationship between the level of power demand and the speed of the wind. At times, high power demand will coincide with high wind speeds. At other times, the opposite will be the case.

During 2024, the power output from a fleet of wind turbines with an aggregate capacity of 4,730 MW was less than 500 MW (equivalent to 10.6% of the aggregate capacity) for 2,127 hours (24% of the time).[36]

EirGrid plans power generation capacity, with a particular focus on the winter, when demand is highest, to ensure that a specified Loss of Load Expectation (LOLE) standard is met. The LOLE is the number of hours in the year during which the available generation could likely be inadequate to meet demand. The annual standard in Ireland is three hours. Over the past five years, the LOLE has, in some years, been exceptionally high but, more recently, has significantly improved (**Table 15**).

Winter	LOLE
2021 / 2022	17.4 hours
2022 / 2023	51.0 hours
2023 / 2024	21.0 hours
2024 / 2025	3.6 hours
2025 / 2026	1.1 hours

Table 15: Winter Loss of Load Expectations from 2021/2022 to 2025/2026
Source: EirGrid

A starting point to think about how much wind power Ireland should have for a maximum demand in 2050 of 12,000 MW is to imagine trying to achieve the LOLE standard by wind alone. This is not such an unrealistic thought given how great a dependence on wind national energy policy currently envisages.

If we could depend on wind power to generate not less than 500 MW, then we would need 114,000 MW of wind power to guarantee 12,000 MW at all times.

However, this would be a significant underestimate of the level of renewables that would be needed because, for a large number of hours during 2024, power output from the 4,730 MW of wind turbines was much less than 500 MW (**Table 16**).

During 2024, wind power output was less than 100 MW for 357 hours. This is two orders of magnitude higher than the LOLE standard.

36 The pattern in 2024 of power from wind is discussed in more detail in the Academy report *The Energy Transition* , April 2025 in Section 3.2 on Page 15.

from	to	% rated capacity	hours
0 MW	100 MW	2.1%	357
100 MW	200 MW	4.2%	829
200 MW	300 MW	6.3%	1,263
300 MW	400 MW	8.5%	1,688
400 MW	500 MW	10.6%	2,127

Table 16: Analysis of low power output levels for wind in 2024
Source: IAE analysis of EirGrid data

A policy of oversupplying renewables in order to offset the disadvantage of their intermittency must, inevitably, lead to an increase in their curtailment (because supply exceeds demand) or in their constraint (because the transmission system cannot cater for their power output).

Table 17 shows the levels of curtailment and constraint for wind and for solar in 2024.[37]

	Wind			Solar		
	Constrained	**Curtailed**	**Despatch down**	**Constrained**	**Curtailed**	**Despatch down**
%	5.1%	5.0%	10.1%	1.0%	4.3%	5.3%
GWh	639 GWh	627 GWh	1,266 GWh	7 GWh	32 GWh	39 GWh
Available	12,478 GWh	12,478 GWh	12,478 GWh	738 GWh	738 GWh	738 GWh
% impact	5.1%	5.0%	10.1%	1.0%	4.3%	5.3%
% of TER [38]	1.9%	1.9%	3.8%	0.0%	0.1%	0.1%

Table 17: Despatch down of wind and solar, 2024
Source: EirGrid

37 The combination of Curtailment and Constraint is referred to as Despatch Down. See Glossary.

38 The Total Electricity requirement (TER) in 2024 was 33,719 GWh

5.2 Closing the gap in winter

When the combination of renewables, storage, interconnectors and demand side units are added together, there remains an overwhelming requirement for there to be dispatchable fossil fuel based plant. In the Winter of 2024 / 2025, this dependency reached 76% as shown in **Table 18** and as illustrated in **Figure 8**.

	Total Generation Capacity	De-rated Generation Capacity	Derating factor
Renewables	5,973	606	10%
CCGT	3,396	2,944	87%
Thermal	1,218	878	72%
Storage	1,018	449	44%
Interconnector	900	400	44%
Peaker	788	709	90%
Demand Side	703	138	20%
Temp Emergency Generation	505	455	90%
Totals	**14,501**	**6,579**	**45%**
Fossil fuel	5,907	4,986	84%
% fossil fuel	41%	76%	

Table 18: Total generation capacity and derated generation capacity, Winter 2024 / 2025
Source: *Winter Outlook 2024/25*, EirGrid

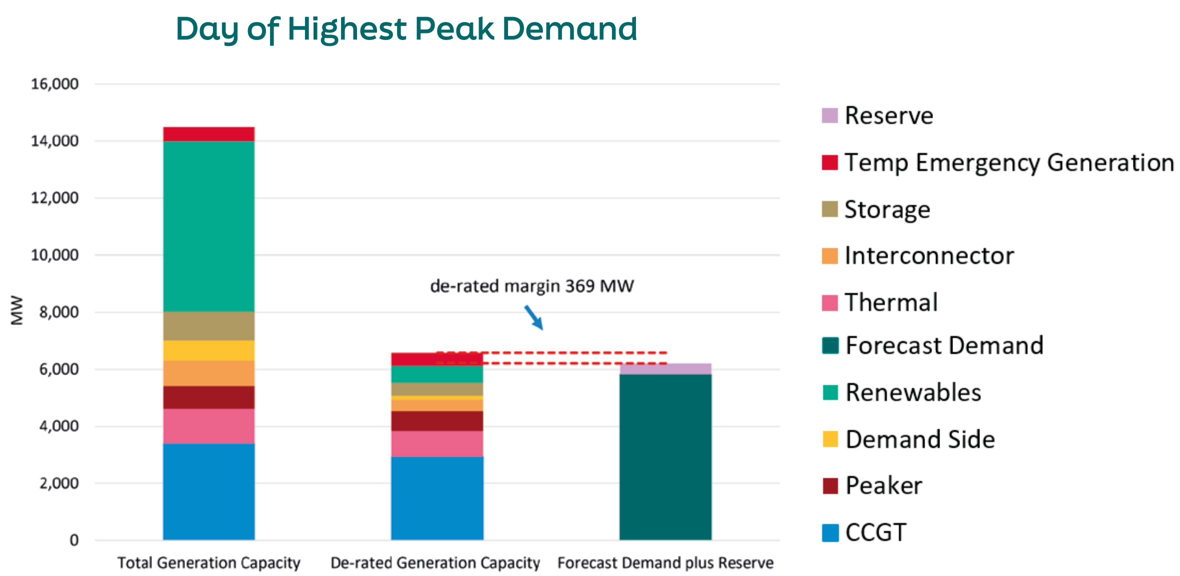


Figure 8: Generation capacity versus forecast demand for the day of highest peak demand/lowest capacity margin
Source: *Winter Outlook 2024/25*, EirGrid

The derating of the capacity of renewables to only 10% of their rated capacity - as shown in **Table 18** - highlights the impact of intermittency and demonstrates the need for a fleet of dispatchable fossil fuel plant capable of meeting a very high proportion of maximum demand. The size of this fleet depends on the level of maximum demand. As maximum demand is set to double over the next 25 years, the capacity of back-up fossil fuel generation plant will also have to double.

The amount of time that this plant will need to operate will be a function of the level of oversupply of renewables.

The greater the oversupply, the fewer the hours the fossil fuel plant will have to run and the lower GHG emissions will be.

Because there is no conceivable level of renewables that can guarantee the adequacy of supply, there is a trade-off to be made between the level of GHG emissions from electricity generation and the price paid for it by consumers in their bills. There needs to be some mechanism - beyond an adherence to the impossible target of zero emissions - to find this balance.

5.3 How much renewables should be deployed by 2050?

The Academy has previously suggested that it could be feasible to develop renewables with a capacity of up to 37,149 MW by 2050 (**Table 19**).

	MW	Contribution to electricity requirement
Onshore wind	9,000 MW	22.1 TWh
Fixed bottom offshore wind	20,149 MW	79.3 TWh
Solar	8,000 MW	7.7 TWh
Totals	**37,149 MW**	**109.1 TWh**

Table 19: Breakdown of the contribution of different renewable technologies to total renewables in 2050
Source: *The Energy Transition – What is the 2050 Action Plan and Timeline?*, IAE, April 2025

This 37,149 MW is not a suggested value for what should be built. When limitations on how much renewable power can be accommodated on the transmission system are considered, the quantity that the country should plan on delivering would be significantly less than 37,149 MW.

Ireland already has a large wind capacity compared to maximum demand. In 2024 aggregate wind capacity had reached 87% of maximum demand. By 2050, what is feasible could take this to 310%. As more wind projects are delivered it is likely that wind capacity will outstrip maximum demand before 2030. **Figure 9** shows the possible trend in wind capacity and maximum demand out to 2050 based on a growth of renewables to 37,149 MW.

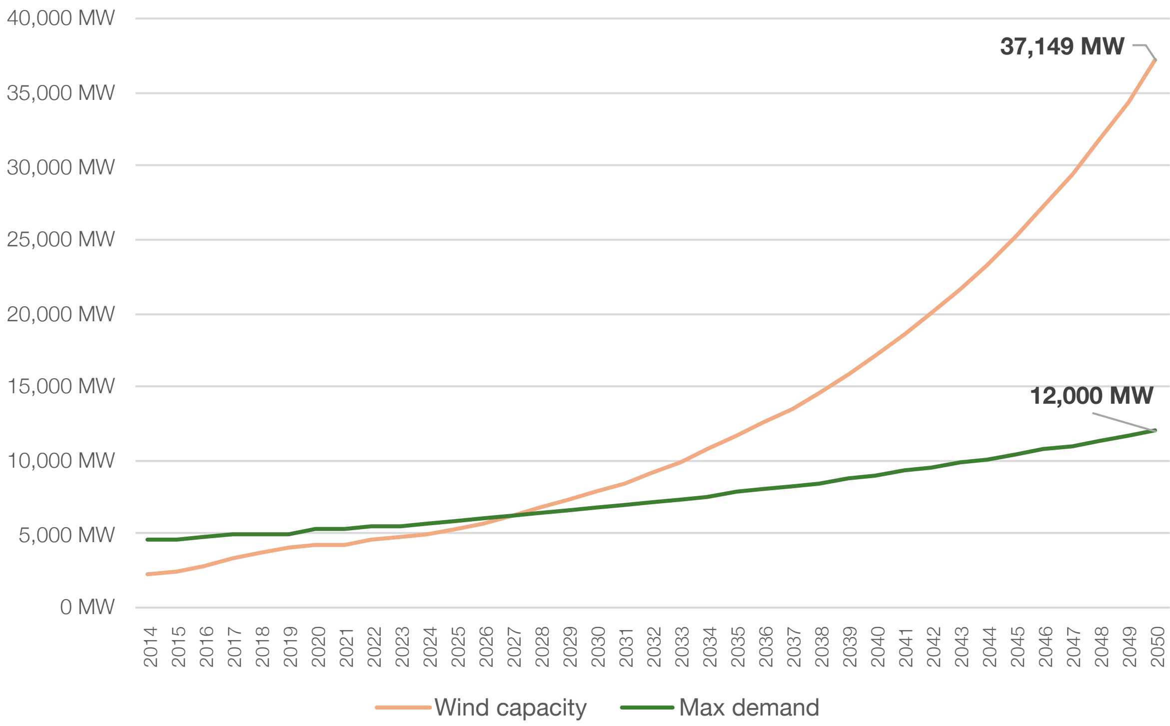


Figure 9: Indicative growth in wind capacity in Ireland compared to maximum demand

In current RESS and ORESS contracts, renewables receive compensation payments - not for when they are constrained but for when they are curtailed - through a mechanism termed *Unrealised Available Energy Compensation* (UAEC). The cost of this is met by consumers by way of the PSO charge in their bills.

In addition, the continuous challenge to balance the grid requires real-time decisions on what type of generation plant should operate, what particular units should run and at what power output levels they should generate.

This process of balancing causes increased costs to be incurred by the system operator beyond the costs that had been committed to in the wholesale market. In Ireland, these costs are appropriately termed *imperfections costs* and they occur when economic market theory meets electrical engineering realities.[39]

Renewables have grown in Ireland based on a series of price support schemes which enabled project developers make a decision to invest. In essence, the market risk of selling into the wholesale market was transferred to consumers.

As the capacity of renewables overtakes maximum demand and increases exponentially after that (as current policy would make happen), there should come a point where these risks are taken away from consumers and given back to generators. However, it is difficult to see how a merchant wholesale market can ever work where the market operators bidding into the market have zero marginal costs. This conundrum, while well understood, has yet to be addressed.

In the absence of a simple answer as to when it would be appropriate to stop supporting new renewables projects in RESS and ORESS auctions, finding a balance between GHG emissions and consumer prices could be facilitated by requiring CRU to evaluate the likely impact of a new RESS or ORESS scheme on the price paid by consumers:

39 Imperfections charges are discussed in **Section 6.6**.

- If this analysis showed the scheme would have a beneficial downward impact on prices, then it would be appropriate for it to go ahead.
- If the analysis showed that prices would increase, then any decision to proceed would need to explicitly recognise this fact and be justified to consumers.

The liberalisation of the electricity market was intended to introduce competitive forces. Where there are no competitive forces - notably in transmission and distribution – regulation serves as a proxy to control investment and prices. The support of renewables by RESS and ORESS and the previous generations of schemes has allowed the renewables sector to mature. Looking to the future, the trade-off between prices and GHG emissions needs to be recognised and embedded in energy policy.

In considering the level at which the capacity of renewables might plateau, there is an additional factor which needs to be considered. The proportion of Ireland's electricity requirement met by imports has increased substantially in recent years and with new interconnectors coming into service, imports could, conceivably, provide a portion of the country's emissions-free electricity thereby lowering the aggregate quantity of renewables that might be needed.

Reducing GHG emissions by a huge oversupply of renewables - premised on surplus electricity being used to produce green hydrogen, or as the basis for Ireland to become the *Saudi Arabia of wind* - is a dangerously aspirational policy objective as it risks exposing consumers to the cost of excessive revenue supports for the developers of renewables projects.

5.4 The substitution of renewables by interconnectors

The island of Ireland will, by 2026, have interconnection with Britain and France with a total capacity of 2,200 MW.

By the end of the decade, this will increase to 3,650 MW assuming the LirIC and MaresConnect projects proceed as planned (**Table 20**).

Interconnector	Capacity	Description	Status
Moyle	500 MW	Scotland to Northern Ireland	Operational
EWIC	500 MW	Wales to Ireland	Operational
Greenlink	500 MW	Wales to Ireland	Operational
Celtic	700 MW	France to Ireland	Due to enter service 2026
Existing	**2,200 MW**		
MaresConnect	750 MW	Wales to Ireland	Target date 2029
LirIC	700 MW	Scotland to Northern Ireland	Target date 2030
Planned	**1,450 MW**		
Total	**3,650 MW**		

Table 20: Summary of existing and planned interconnectors

In 2023, interconnectors met 10% of the country's electricity requirement. In 2024, this increased to 15% and, for the first six months of 2025, further increased to 17%.[40]

40 *Mid-Year Review of Ireland's Energy and Related Emissions in 2025*, SEAI

This trend raises the possibility that renewables and interconnectors could be treated as competing sources of zero carbon electricity rather than as complementary asset classes:

- The availability of power from both renewables and interconnectors is similar in that neither can be guaranteed in the way power availability can be guaranteed from fossil fuel back-up plant.
- There is a particular risk of very low power availability from wind for long periods (weeks rather than days) due to settled high pressure weather systems. When this might happen in Ireland, it is likely to also happen in Britain and power availability from renewables and through interconnectors could be simultaneously low.
- Both renewables and interconnectors are non-synchronous power sources and the combined contribution they can make to the power system is limited by the system operator's maximum allowable System Non-Synchronous Penetration (SNSP).
- It can already happen that interconnectors displace renewables in Ireland. When this happens, each MWh could be paid for twice and this would be reflected in imperfections charges.

Given that the market is already operating with a high penetration of imports and given that the capacity of interconnection is set to increase considerably, there is a policy option to regard interconnectors primarily as a source of power to meet the country's electricity requirement rather than as a conduit for exports of green electricity.

Whatever the concern of power not being available from interconnectors might be, the risk is no different to the risk that the output of renewables might be very low. Both risks are beyond Ireland's control. The wind risk has already been implicitly accepted and that is how the electricity system has operated for many years already.

Because GHG accountancy rules regard imported electricity as having zero emissions, displacing some renewables by interconnectors has no impact on the country's net emissions.

However, the introduction of the EU Carbon Border Adjustment Mechanism (CBAM) in 2026 will recognise the carbon content of electricity imports by increasing the cost of electricity imports through the addition of the ETS cost of carbon. At the average 2024 carbon price of €65 per tonne, and at Britain's specific emissions of 124 kg CO_2 per MWh (**Table 21**), this would suggest an increase in the cost of imported electricity in the order of €8 per MWh.

kg CO_2 per MWh	2014	2024	Change
Ireland	461	256	-44%
Britain	419	124	-70%

Table 21: Comparison of trends in specific emissions of GHG emissions from electricity generation in Ireland and Britain, 2014 to 2024

Over the 34 months from January 2023 to October 2025, the monthly average wholesale electricity price in Ireland was €20 per MWh higher in Ireland than in Britain (**Figure 10**).

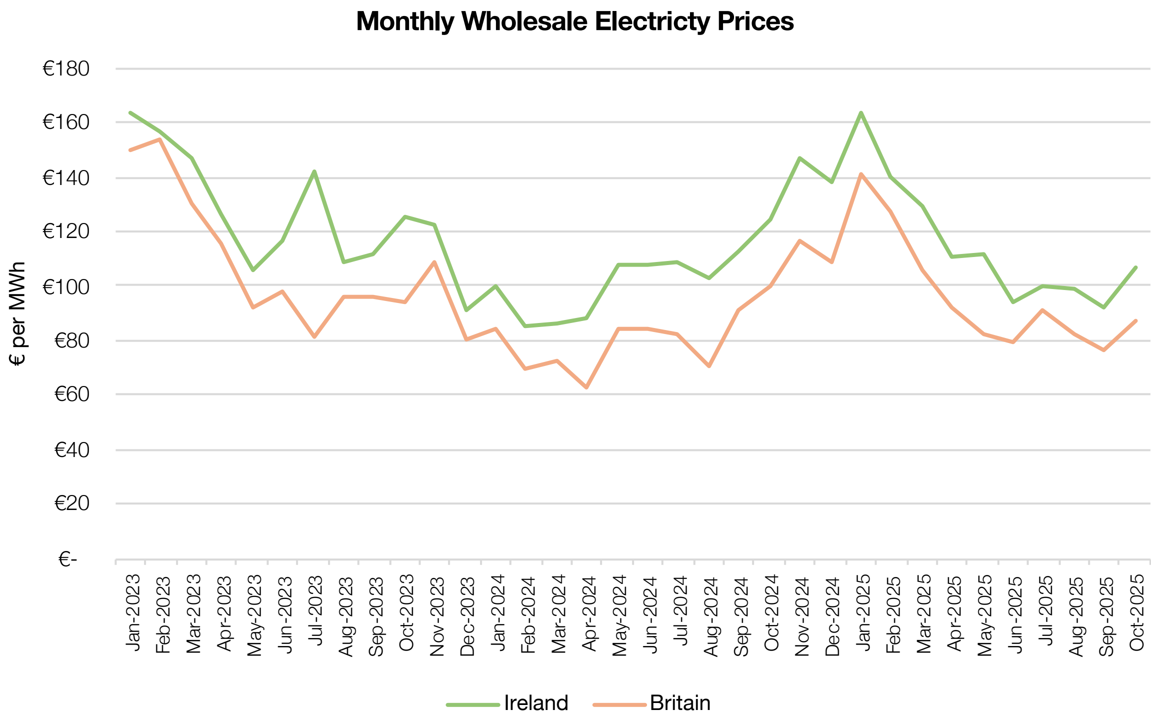


Figure 10: Trends in monthly wholesale electricity prices in Ireland and Britain, January 2023 to October 2025
Source: Ember

Against the above background, it is quite possible that imports from Britain could continue to provide a high proportion of Ireland's electricity requirement even after the CBAM is introduced.

Beyond the cost competitiveness of imported electricity from Britain, interconnectors have very low visual impact and new interconnector projects have been able to secure planning consents with less difficulty than many wind farms. All large infrastructure projects have an environmental impact. All else being equal, projects with lower environmental impact should be favoured over those with higher environmental impact.

This principle is already embedded in the process of EIA where project developers must consider alternatives and demonstrate that their proposed scheme is the most appropriate - and, by extension, the least environmentally impactful - way of meeting its objective.

Finally, the support schemes necessary to derisk interconnector projects, are potentially less impactful on consumers. Where renewables get guarantees of revenues in RESS and ORESS schemes for whatever they produce or could produce, the more recent interconnector projects get support from system operators based on a cap and floor scheme. If power flows are below a lower agreed limit, then the system operators guarantee a minimum revenue. If flows are above a higher agreed limit, the system operators share in the upside.

The capacity factor of the interconnectors into the island of Ireland is high. In 2024, 5.1 TWh was imported into the SEM implying an aggregate capacity factor for the Moyle and East-West interconnectors of 58%. At such a high capacity factor, it would be unlikely that consumers would be exposed to the cost of price supports for interconnector projects.

5.5 Developing the capacity for an electricity export sector

If a significant proportion of the country's electricity requirement continues to be met by imports, the possibility of Ireland becoming a significant exporter of green electricity disappears.

The key determinant of the direction of the net flow of electricity between Ireland and Britain will be the differential in wholesale prices between the two markets. Whatever impact the CBAM might have on closing this differential, starting in 2026, the introduction by Britain of its own CBAM, one year later in 2027, will more than offset this effect.

If the idea that Ireland could become the *Saudi Arabia of wind* due to the country's large wind resource were to remain an objective – either in policy or in the business plans of renewables companies – the best way to facilitate this would be to allow market forces to operate and not to offer State support contracts. This would prove – or disprove – the concept while protecting consumers from the cost of excess revenue support schemes in future RESS or ORESS contracts which would act as a subsidy from consumers to electricity exporters.

It would be a wonderful outcome if Ireland were to become a large exporter of green electricity because it would mean that Irish wholesale electricity prices would have fallen to below the level of wholesale prices in Britain, or maybe even in France, to the great benefit of Irish consumers.

5.6 The more likely continuation of Ireland as an electricity importer

While the argument that Ireland could continue to be a net importer of electricity is at variance with the objectives of policy to date, it is important to recognise that there would be nothing particularly noteworthy if this trend were to continue.

EU single market policy is premised on establishing a level playing field between member states. In the electricity sector in 2024, 16 countries were net importers and 10 were net exporters (**Appendix 5**).

By EU standards, there is nothing unusual in the penetration of imports in Ireland's electricity market. The same pattern seen previously - whereby a combination of nuclear and hydro gives some countries an advantage in terms of their comparative emissions levels - recurs in the international electricity market in Europe with Sweden and France being major exporters (**Table 22**).

Denmark, even with its high renewables capacity, depended on imports to meet 11.4% of its electricity requirement.

	%
Belgium	+13.3%
Denmark	+11.4%
Finland	+4.1%
France	-21.8%
Ireland	+15.4%
Netherlands	-3.8%
Portugal	+20.4%
Sweden	-26.7%
Norway	-14.4%

Table 22: Net electricity imports in selected EU countries and Norway, 2024. "+" for importers and "-" for exporters
Source: Eurostat

Finally, when the Celtic Interconnector enters service, France's comparatively low wholesale market prices would suggest that its 700 MW capacity could further increase import flows (**Table 23**).

Country	€ per MWh
Ireland	€116.86
Britain	€96.82
France	€73.02

Table 23: Average monthly wholesale prices in Ireland, Britain and France, January 2023 to October 2025
Source: Ember

As France is already a large electricity exporter (89 TWh in 2024), the Celtic Interconnector could become an important contributor to Ireland's electricity requirement. At a capacity factor of 58%, it would provide 3.6 TWh per annum equivalent to 10% of current demand.

5.7 Conclusions

There has to be some reasonable limit on the amount of renewables that might be deployed to meet Ireland's electricity requirement over the next 25 years.

Rather than having a fixed target, such as the 54,000 MW in policy currently, the combination of three factors would protect consumers from the possibility of excessive costs being imposed on them due to an excess of renewables over and above what Ireland might reasonably require:

- The application of cost benefit analysis to future renewables auctions
- Acceptance that interconnection could meet a considerable proportion of the country's electricity requirement, and
- A decision to leave it to market forces to develop a green electricity export sector.

The key point in policy is, again, to recognise the need to achieve a balance between the level of GHG emissions we might hope to achieve in the electricity sector and the level of costs that would be imposed on consumers.

6. ELECTRICITY PRICES

Electricity demand in Ireland is split across three main categories of customers (**Table 24**) and all categories need access to electricity at reasonable and competitive prices.

Category	%
Residential	28%
Business	40%
LEUs	31%
Other	1%
Total	**100%**

Table 24: Electricity demand by customer category, 2024
Source: *CSO*

The success of the energy transition depends, ultimately, on decisions by consumers - both in households and in businesses - to electrify heating and transport. The decarbonisation of electricity generation, although important to reducing GHG emissions, is of secondary importance. Even a grid with a large dependency on fossil fuels can deliver substantial decarbonisation because of the very high efficiencies of electric vehicles and heat pumps.

The extent to which consumers will opt for electric alternatives for energy services will be influenced, to a considerable degree, by the price of electricity.

The price of electricity is a function of a number of factors including:

- Cost base of the providers of electricity infrastructure (ESB Networks)
- System operator costs (EirGrid)
- Strength of competitive forces in retail electricity markets
- Strength of competitive forces in auctions (including RESS, ORESS, capacity and future system services auctions)
- Effectiveness of Power Purchase Agreements (PPAs) in giving revenue certainty to make renewables projects – which do not have access to RESS or ORESS supports – financially viable.
- Effectiveness of market regulation by the CRU
- Levels of taxes and levies imposed by Government

The electricity market is a highly contrived market and, notwithstanding liberalisation, is inescapably dominated by factors which prevent it operating like an archetypal market where there are substitution possibilities for consumers and where supply can be allowed to fall below demand. The dominant characteristics of the electricity market are:

- Monopoly suppliers of infrastructure (transmission and distribution) which account for a large proportion of the cost base which determines prices.
- An overarching requirement by TSOs and regulators to ensure the adequacy and reliability of supply even, in extreme circumstances, without regard to cost.
- The need for price guarantees to generators to make investment in power generation projects financially viable including for both renewables and fossil fuel projects.
- Government policies to force consumers to move away from fossil fuels for the energy services they need and, instead, invest in options powered by electricity (EVs and heat pumps).

6.1 Electricity prices in Ireland in 2024

Electricity prices for households vary greatly across the EU's 27 member states both before and after taxes and levies are applied.

Electricity in Ireland is expensive and, in the second half of 2024, was the most expensive for households (across all consumption bands) among the 27 EU member states both before taxes and levies - such as VAT and the PSO - and after (**Figure 11**).

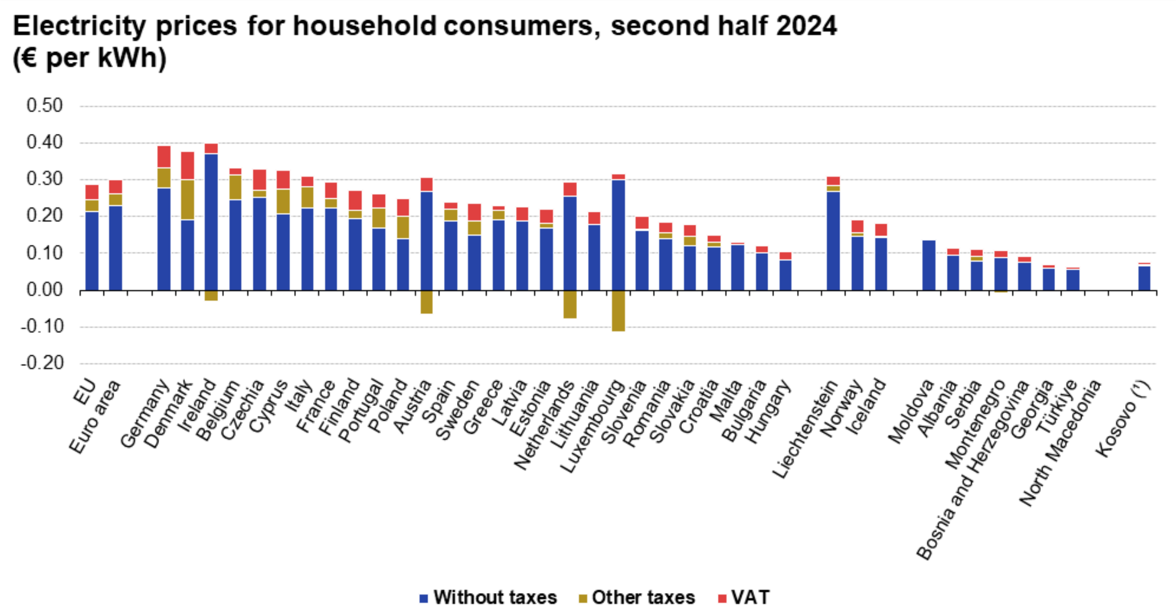


Figure 11: Electricity prices for household consumers, second half 2024, € per kWh
Source: *Eurostat*

It is notable that the price in Ireland in the second half of 2024 was so high notwithstanding the contribution of three months of the negative PSO levy from July to September 2024 (**Table 25**).

PSO year	Value of PSO
2025 / 2026	€162.4m
2024 / 2025	€251.8m
2023 / 2024	- €67.1m
2022 / 2023	- €491.3m

Table 25: Value of the PSO in recent years. PSO year runs from 1st October to 30th September.
Source: CRU

The impact of taxes and levies on household electricity prices in Ireland is lower than it is in other EU member states (**Table 26**) suggesting that underlying costs and / or retailer margins are significantly higher in Ireland.

	EU	Ireland
Including taxes and levies	€ 0.2881	€ 0.3590
Excluding taxes and levies	€ 0.2465	€ 0.3294
Difference	€ 0.0416	€ 0.0296
% difference	17%	9%

Table 26: Difference in electricity prices for Band DC households in the second half of 2024

The high cost of electricity for Irish households is mirrored in non-households, and, in 2024, businesses in Ireland had the highest price in the EU (**Table 27**).

	€ per kWh	Rank *1 is the highest*	% difference from EU average
Belgium	0.1269	20	-17%
Denmark	0.1173	22	-23%
Finland	0.0817	25	-46%
France	0.1520	13	0%
Germany	0.1767	5	16%
Ireland	0.2288	1	50%
Netherlands	0.1590	10	4%
Portugal	0.1149	23	-25%
Sweden	0.0832	24	-45%
EU average	**0.1525**		

Table 27: Average electricity prices for businesses in Ireland and in selected other EU member states in 2024 (excluding recoverable taxes)

Source: *Eurostat*

6.2 Trends in electricity prices for households, 2007 to 2024

The high prices for electricity in 2024 are a continuation of a consistent trend since 2007.

Whereas Ireland consistently has among the highest prices for households, Irish prices are not always the very highest. Over the 18 years from 2007 to 2024, Denmark had the highest prices in 13 of the 18 years and Germany had the highest in the remaining five years.[41]

At the opposite end of the spectrum, the cheapest countries were Finland and France (six years each), Netherlands (four years), Portugal and Sweden (one year each).

41 This analysis is based on data for Band DC households which had an annual consumption in the range 2,500 kWh to 5,000 kWh. The prices per kWh paid by households (including taxes) and businesses (excluding VAT) across different consumption bands in the period January to June 2024, as reported by SEAI, are shown in **Appendix 6**.

Figure 12 shows how prices in Ireland compared over the 18 years with *Dear Countries* (Denmark and Germany) and with *Cheap Countries* (Finland, France, Netherlands, Portugal and Sweden) and with the EU average. With the exception of the Netherlands, all four of the other *Cheap Countries* have a high proportion of nuclear and hydro in their energy mixes.

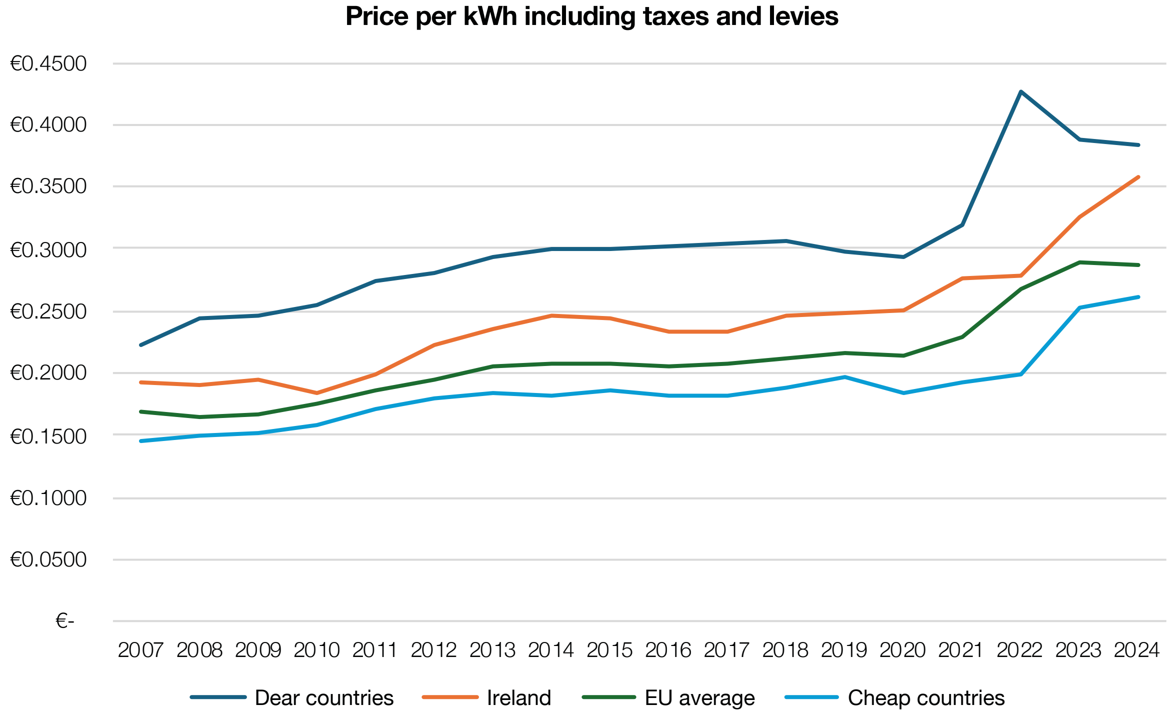


Figure 12: Electricity price per kWh for Band DC households including VAT and levies, 2007 to 2024

Ireland, although higher than the EU average, was below the *Dear Countries*. The main explanation for this is the low level of taxes and levies in Ireland (**Table 26**). Before taxes and levies, Ireland is much closer to the *Dear Countries* and, in 2024, surpassed them (**Figure 13**).

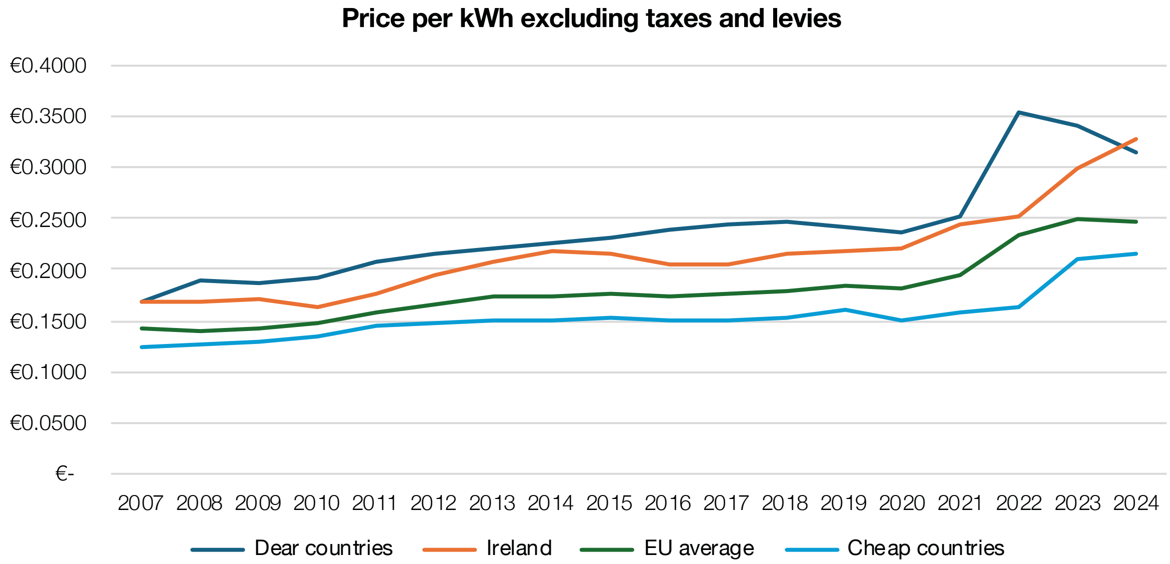


Figure 13: Electricity price per kWh for Band DC households excluding VAT and levies, 2007 to 2024

6.3 Future prospects for electricity prices in Ireland

Irish electricity prices are high by comparison to average prices in the EU and have been on an upward trend for the past 17 years. The price paid by consumers comprises the costs incurred by retailers plus their gross margins.

ESB has estimated that the cost (before gross margins) paid by electricity retailers in 2025 is €8 billion, made up of six elements as summarised in **Table 28**.[42]

Cost heading	%
Wholesale electricity market	55%
Distribution	14%
Transmission	15%
Imperfections charges	7%
Capacity payments	6%
PSO levy	3%
Total	**100%**

Table 28: Breakdown of the costs of electricity (before retailer gross margins), 2025
Source: ESB

The prospect for future electricity prices is that the upward trend in prices will continue for a number of reasons:

- The impact of the very large programme of investment in transmission and distribution assets (which currently account for 29% of retailer operating costs)
- Guaranteed price escalation in contracts for difference in new RESS and ORESS schemes
- Increasing imperfections charges
- Capacity payments for increased back-up generation as both the electricity requirement and maximum demand rise

42 *Electricity costs in Ireland – drivers and outlook,* ESB, August 2025

6.4 Investment in transmission and distribution

The CRU has approved a 35% increase in EirGrid / ESB Network's operating costs over the five years to 2030 (**Table 29**). In addition, capital expenditure by ESB Networks and EirGrid of almost €10 billion has been approved, an 88% increase compared to the five years from 2021 to 2025.

Role	Company	PR5 2021-2025	PR6 2026-2030	% increase
		Out-turn	Draft determination	From PR5 to PR6
TSO	EirGrid	€348m	€660m	89.7%
TAO	ESB Networks	€1,185m	€4,017m	239.0%
DSO	ESB Networks	€3,716m	€5,195m	39.8%
CAPEX		**€5,249m**	**€9,872m**	**88.1%**
TSO	EirGrid	€386m	€771m	100.0%
TAO	ESB Networks	€207m	€193m	-6.5%
DSO	ESB Networks	€1,679m	€2,093m	24.6%
OPEX		**€2,271m**	**€3,057m**	**34.6%**

Table 29: Comparison of capital expenditure (CAPEX) and operating expenditure (OPEX) in PR5 and PR6
Source: *CRU*

The scale of the investment in the next five years will need be replicated in subsequent five year price review periods. Most of the €10 billion to be invested in transmission and distribution assets will be invested by ESB Networks. The investment over the course of PR6 will substantially increase ESB's fixed assets base (€13 billion at end 2024) and will require a large increase in the company's net debt (€7 billion at end 2024). Investment in subsequent price review periods will increase the asset base and debt still further.

It is important for national energy policy to be informed by long-term considerations notably as regards the level of capital investment in transmission and distribution infrastructure over the next 25 years and by an understanding of the impact this will have on electricity prices.

This requires a focus in policy on the future cost of electricity rather than solely on the level of GHG emissions.

6.5 Market forces and renewables

Renewables projects require revenue certainty for periods long enough to give project developers sufficient certainty to make investment decisions.

For most renewables projects, but not all, this revenue certainty is provided in contracts with the State. Recent RESS and ORESS auctions include guaranteed prices - irrespective of wholesale market prices - plus annual escalation of the strike price accepted in the auctions (**Table 30**).

43 EirGrid is the Transmission System Operator (TSO) while ESB Networks is the Transmission Asset Owned (TAO). ESB Networks is both the asset owner and operator of the Distribution System (DSO).

Scheme	Duration	Average strike price per MWh	Strike price base year	Capacity supported
ORESS1	20 years	€86.05	2023	2,624 MW
RESS4	16 ½ years	€96.85	2024	1,334 MW
RESS5	16 ½ years	€98.81	2025	1,079 MW

Table 30: Summary of recent RESS and ORESS schemes

RESS / ORESS contracts will continue to enable project developers to proceed with renewables projects for the foreseeable future.

However, because interest rates and construction costs have significantly increased from their levels in the decade from 2013 to 2022, future strike prices will be higher than they had been.

The marginal cost of electricity generated by renewables is zero. By contrast, the marginal cost for traditional fossil fuel plant is a function of fuel costs and thermal efficiency. The price received by generators in the wholesale electricity market is based on the marginal price that needs to be accepted to secure the last tranche of supply required to meet demand at a point in time. All generators whose bids have been accepted to get to that point are paid the same price.

If renewables have bid into the market at low prices, they still receive the price of the highest bid. Typically, this price would be set by a gas-fired plant.

The more recent RESS and ORESS contracts protect consumers from having to pay electricity prices determined by high gas prices by setting the price the renewable generator receives and returning the surplus earned by the renewables generator back to consumers through the PSO levy. Older schemes protected renewables from low wholesale market prices but allowed them to benefit from high wholesale market prices.

The growth in renewables supported by RESS and ORESS contracts - and by the schemes that preceded them - raises a number of issues:

- How will existing renewables projects secure their earnings in the future when RESS, ORESS and other older support schemes expire?
- Will there be a merchant market where renewables operators take the market risk day to day or will operators be able to mitigate this market risk by power purchase agreements (PPAs) not only with large energy users but also with the electricity retailers that consumers buy their electricity from?
- How will Government determine when to stop launching new RESS and ORESS schemes and allow market forces to work to set the balance between supply and demand?
- In the absence of RESS and ORESS schemes, can PPAs provide sufficient revenue certainty to allow developers make final investment decisions to proceed with new projects?

The logic behind the EU's liberalisation of electricity markets was to break up vertically integrated State-owned monopolies, such as ESB, and, instead, rely on market competition and market forces to bring increased efficiencies and lower prices.

Unless the wholesale electricity market can get to a position where there are no more State support contracts (underwritten by consumers) then it is difficult to see how the objectives of liberalisation can be achieved.[44]

44 The economist, Dieter Helm, has written extensively on this challenge over the past decade and published a concise and incisive commentary in respect of the electricity market in Britain in September 2025.

The questions posed above are open questions and are intended to prompt consideration as to how energy policy in Ireland needs to develop to protect consumers from excessively high electricity prices.

To date, energy policy has been dominated by the objective of reducing GHG emissions with little evident concern for the level of electricity prices.

Language in CAP25 and the consistent repetition in publications from EirGrid, SEMO and Government departments of the need to reach carbon budgets as part of the national effort towards climate neutrality far outweighs considerations of the future price of electricity for consumers, both household and non-household:

> *Beyond the legally binding targets set in our climate legislation, there is an existential imperative to deliver on Irish climate neutrality by no later than 2050. The mobilisation of society in achieving this will require continued urgency, ambition, and action by all sectors of society.*[45]

In this environment, there is a concerning absence of adequate consideration as to what capacity of renewables might ultimately be deployed and what impact an excess amount might have on electricity prices. With a policy target for 54,000 MW of renewables by 2050 and the continuing availability of State support RESS and ORESS schemes, it is unlikely that there will ever be any shortage of project developers willing to invest in renewables projects in Ireland. So long as the guaranteed strike price is high enough, any renewables project will be financeable.

6.6 Imperfections charges

Since the establishment of the ESB, the Irish electricity grid has been well managed and, considering, the small scale of the grid with no synchronous connections to other larger grids (as, for example, in Denmark), the Irish grid has been subject to very few, if any, losses of supply for system management reasons.

More recently, as the penetration of renewables has increased, the ceiling on non-synchronous sources of electricity has been carefully managed and increased gradually over time (**Table 31**).[46]

from	to	Duration	SNSP ceiling
Jan-2014	Sep-2015	20 months	50%
Oct-2015	Feb-2016	4 months	55% trial
Mar-2016	Oct-2016	7 months	55%
Nov-2016	Feb-2017	3 months	60% trial
Mar-2017	Oct-2017	7 months	60%
Nov-2017	Mar-2018	4 months	65% trial
Apr-2018	Dec-2020	32 months	65%
Jan-2021	Mar-2021	2 months	70% trial
Apr-2021	Mar-2022	11 months	70% permanent and 75% trial
Apr-2022	Nov-2025	43 months	75%

Table 31: Development of the SNSP limit for renewables and other inverter based resources since 2014

45 *Climate Action Plan 2025*, Page 6.

46 Wind farms, solar farms, batteries and interconnectors all supply electricity as DC converted to AC by inverters. These are collectively termed inverter based resources (IBRs) and the proportion of power that can be delivered by them is limited by system operators to ensure that the grid can be operated stably and that system voltage can be controlled within acceptable limits. The limit on IBRs is referred to as System Non-Synchronous Penetration (SNSP). A fully renewables grid would require an SNSP of 100%. Synchronous machines (either generators or synchronous condensers) will continue to be required on the grid even as the SNSP limit increases from 75% towards 100%. This will, necessarily, be a slow and carefully managed process.

The maintenance of grid stability and the continuity of supply as renewables increase is becoming more challenging for system operators as evidenced by the Iberian black out in April 2025.

The management of the grid to ensure a balance between supply and demand - while simultaneously maintaining system frequency and voltage levels - becomes more difficult as traditional synchronous generators are replaced by renewables. In addition, as the proportion of renewables (and other non-synchronous sources) increases, the cost of keeping the system stable and balanced increases. These costs are termed *imperfections costs*, and they are recouped from electricity retailers and, ultimately, paid by consumers. Imperfections charges account for 7% of the total cost of electricity (**Table 28)** before retailer gross margins.

Imperfections costs arise, for example, when financial agreements with generators to supply power at an agreed price at a specified time have to be reneged on in order to maintain balance between supply and demand. When this happens, the system operator has to make compensation payments to the generator.

The SEM Committee has set the imperfections charges to be recovered from retailers over the period October 2025 to September 2026 at €790.2 million. Based on an estimated electricity requirement of 39,650 GWh, this is equivalent to €19.93 per MWh. There has been an upward trend to imperfections charges in recent years (**Table 32**).

	Cost per MWh	% of electricity requirement from renewables and imports[47]
2017 / 2018	€ 5.00	33.0%
2018 / 2019	€ 5.22	39.7%
2019 / 2020	€ 10.40	41.8%
2020 / 2021	€ 8.51	39.8%
2021 / 2022	€ 9.19	39.4%
2022 / 2023	€ 21.85	50.2%
2023 / 2024	€ 11.52	54.8%
2024 / 2025	€ 14.62	
2025 / 2026	€ 19.93	

Table 32: Trend in average imperfections charges from 2017 to 2026
Source: SEM Committee *Consultation Paper SEM-25-028* and *Decision Paper SEM-25-053*

47 Calendar years 2018 to 2024

The SEM Committee commented on this trend as follows, noting that the trend is not confined to Ireland and is associated with an increase in the penetration of renewables:

> *The SEM Committee notes the increasing trend in Network Imperfections Charges is not just unique to SEM, it is observed across Europe. These costs, which arise from the need to balance supply and demand in real-time, have been driven by several factors, including the integration of renewable energy sources and the variability they introduce. For instance, in Great Britain, balancing costs continue to trend upwards, with costs in Financial Year (FY) 2024/25 more than doubling (108% increase) since FY2021/22. Similarly, in Germany, the costs associated with balancing the grid have also risen. In 2023 the total costs for redispatch measures had increased by more than two and a half times when compared with 2021 costs.*[48]

The SEM Committee additionally identifies a number of actions that will mitigate / control these costs in the future including completion of the north-south interconnector and greater investment in the transmission network. Both of these actions will require capital investment which will be recovered from consumers. What might be saved by reducing imperfections charges will be offset, to some extent, by increases in transmission costs.

There is no possibility for competitive forces to impact on the level of imperfections charges, and their minimisation is down to the skill of the system operator in managing supply and demand. No matter how good the system operator is at this task, imperfections costs will always arise and the established trend suggests that they will increase as the penetration of renewables increases.

This is one of the hidden costs associated with renewables. Another is the cost of maintaining a back-up dispatchable generation fleet.

6.7 The capacity market

The generation capacity required to ensure that the electricity system can reliably meet demand is secured, for the most part, through capacity auctions. These guarantee payments for power availability (€ per MW per annum) which can be called on when needed. Capacity auctions are intended to ensure capacity is available for a year into the future (T-1 auctions) or will be available four years into the future (T-4 auctions).

48 *Network Imperfections Charges Decision Paper*, SEM Committee, Page 9, September 2025,

The results of the most recent such auctions are summarised in **Table 33**.

	T-4 Capacity Auction in respect of the Capacity Year 2028/2029 49			T-1 Capacity Auction in respect of the Capacity Year 2025/2026 50		
	Existing	New	Total	Existing	New	Total
Autoproducer	111 MW		111 MW			0 MW
Demand side unit	182 MW	195 MW	377 MW	20 MW	6 MW	27 MW
Gas turbine	4,129 MW	267 MW	4,396 MW	191 MW	17 MW	209 MW
Hydro	190 MW		190 MW			0 MW
Interconnector	506 MW	12 MW	517 MW	77 MW		77 MW
Battery storage	15 MW	132 MW	147 MW			0 MW
Pumped hydro storage	124 MW		124 MW			0 MW
Steam turbine	46 MW		46 MW	462 MW		462 MW
Wind	34 MW	1 MW	35 MW		1 MW	1 MW
Other storage				3 MW	7 MW	10 MW
Total	**5,336 MW**	**606 MW**	**5,942 MW**	**753 MW**	**32 MW**	**785 MW**

Table 33: Summary of results for recent All-Island SEM T-1 and T-4 capacity auctions
Source: SEMO

The capacity market approach in Ireland is similar to that in other countries and is a logical way to try to harness competitive market forces to ensure adequacy of generation capacity at the lowest cost.

However, three issues cast doubt on whether the current capacity market approach is suitable for Ireland's future needs:

- The electricity generation shortfall crisis of 2022
- Gas turbine delivery lead times
- Ageing fleet of base-load fossil fuel generation plant

Firstly, the capacity market has already proven itself not to be wholly reliable and a shortage of capacity arose in 2022 due, in part, to not all projects to deliver 710 MW of new capacity secured in the T-4 Capacity Market of 2022 / 2023 proceeding.

49 *SEM Capacity Market 2028/2029 T-4 Capacity Auction Final Capacity Auction Results,* January 2024

50 *SEM Capacity Market 2025/2026 T-1 Capacity Auction Provisional Capacity Auction Results*, June 2025

As a consequence of the generation crisis that was declared, a series of emergency steps were taken:

- In November 2021, Government published a policy statement - Policy Statement on Security of Electricity Supply - which, among other things, confirmed:
  - The future need for new fossil fuel powered generation plant,
  - That it would be appropriate to retain existing coal, heavy fuel oil and biomass fired generation capacity
  - That it would be appropriate to develop additional natural gas transmission and distribution infrastructure to support security of the electricity supply
- In July 2022, CRU directed EirGrid to deliver temporary emergency generation capacity for the period of winter 2023-2024 to winter 2025-2026 and, if needed, to the end of winter 2026-2027.
- Also in July 2022, legislation was passed to allow EirGrid to procure this emergency generation capacity.[51]
- EirGrid incorporated a special purpose vehicle subsidiary company (EirGrid SPV 2022 DAC) to procure the required plant.
- Government gave this SPV a grant of €151 million to fund the procurement of 412 MW of generation plant.
- Arrangements were put in place for EirGrid to recoup the costs it was incurring from electricity retailers via TUOS charges.[52]

These were extraordinary events and required the TSO (EirGrid) to directly procure generation capacity in contravention of the logic behind the splitting up of ESB's vertically integrated businesses in 2006.

Secondly, lead times for the delivery of new gas turbines from a small number of manufacturers - whose order books are full - is increasing. If lead times for new gas turbines are five years and more, a T-4 auction will struggle to reliably deliver new capacity when it is needed. As the electricity requirement increases, it is certain that a lot of new capacity will be required.

Finally, there is the risk that older base-load generation plant (both steam and CCGT) may become uneconomic and be peremptorily retired - either by State-owned companies or by private sector companies – without enough time for capacity market auctions to secure guaranteed replacement capacity. The Grid Code requires generators to give the CRU three years' notice of their intention to take plant out of service.

In the past, the type and capacity of future generation plant was reliably determined and delivered by ESB. In introducing a capacity market, the mechanism to secure future capacity has passed to an auction process operated by EirGrid and overseen by CRU.

With the notable exception of the Government statement of November 2021, there is insufficient regard in energy policy of the need for a growing fleet of fossil fuel plant to back-up renewables and imports.

While the grid of the future will be different from the grid of the past, when renewables aren't available, grid operation will revert to the practice of operating base-load plant supplemented by load-following plant, both fossil fuel. This reality needs to be recognised not only when a crisis arises but as a central part of national energy policy.

The conclusion of the analysis into the events which led to the generation capacity shortfall crisis of 2022 identified the need to learn from what had happened:

51 *EirGrid, Electricity and Turf (Amendment) Act 2022*

52 TUOS: Transmission Use of System charges

> *The risks entailed in the pace of transition were, in my opinion, underestimated. The appropriate learning from that experience need to be applied over the remainder of this decade if the transition to even more ambitious goals is to be achieved on a more secure basis.*[53]

It would be prudent for Government to critically evaluate the effectiveness of the capacity market and consider reverting to an engineering-led approach operated by a State-owned company with both the authority and the accountability to deliver back-up generation capacity. This possibility is discussed further in **Section 8.4**.

Such an approach could comprise a combination of capacity auctions and concession contracts under EU procurement law to procure long-term generation assets.[54] This would ensure the continued participation of private sector generators and allow the continued use and redevelopment of existing brownfield sites with grid connections. It would also maintain an opportunity for new private sector entrants to enter the market.

It has already been proven that the Capacity Market process may not be adequately reliable and there are readily apparent risk factors which could lead to a shortage of back-up generation capacity.

The over-arching principle is that responsibility for the availability of the generation capacity of last resort should be entrusted to a single organisation which has both the authority to deliver this capacity and the accountability for doing so. The central lesson from the events of 2022 is that when responsibility is split, accountability is lost.

6.8 From one set of assets to four sets of assets

Prior to the advent of renewables, a single set of assets - synchronous generators driven by steam, gas and water turbines - met Ireland's electricity requirement. These generators inherently maintained frequency, provided mechanical inertia to dampen changes in supply / demand elsewhere on the grid and, with an N-1 management philosophy (where there was always sufficient generating capacity online to cater for an event which caused the loss of the largest single unit), did not require back-up.

The grid, today, requires four sets of assets to do the same job:

- There remains a need for a set of fossil fuel generators to fill in the gaps in supply caused by intermittency.
- A second set of assets (synchronous condensers and batteries) is required to provide what are termed *system services* to perform the tasks which traditional generators do inherently.
- There is the set of renewable assets – primarily wind but increasingly also solar - which consume no fuel and have no GHG emissions – but which are characterised by intermittency.
- Fourthly, there is an increasing capacity of storage, primarily batteries, which can better match the output from renewables to demand with low round-trip losses.

All of these assets have capital and operating costs and these costs must be recovered in the price paid by consumers.

Renewables cannot meet Ireland's electricity requirement on their own. The introduction of renewables causes substantial additional transmission, back-up generation and imperfections costs.

Electricity is a commodity but, unlike other commodities, it cannot be stored in volume and at low cost. Moreover, supply cannot be allowed to fall below demand and there are no alternative substitutes which consumers can switch to.

53 *Independent Review on the Security of Electricity Supply*, Dermot McCarthy, January 2023, Page 71

54 *European Union (Award of Concession Contracts) Regulations*, S.I. No. 203/2017

Commodity markets work best when there is price and cost transparency. This does not exist in the electricity retail market and the expectation that has been built up of low prices from renewables has not and will not be met.

6.9 Price transparency and the effectiveness of retail competition

The success of the energy transition will depend on the willingness of consumers (households and businesses) to make decisions to move away from fossil fuels. Whether they do this out of choice or mandatorily (because, for example, of a ban on the future sale of internal combustion engines and gas / oil boilers), it is important that consumers have an informed expectation of the level of future prices.

Unfortunately, there is no reliable source offering guidance on the prospects for future prices. Given the contrast between consumers' actual experiences and the frequently cited downward impact increased renewables have on electricity prices, there is a risk that public support for the energy transition could diminish.

There is a level of complexity in the oversight and decision making of the CRU and the SEM Operator and in their interactions with commercial operators – both private sector and State-owned – which makes the operation of the electricity market all but invisible to consumers.

Most of the costs which determine the ultimate price of electricity paid by consumers are not subject to competitive forces. Transmission and distribution costs are regulated by CRU, wholesale market prices are significantly determined by the terms of State contracts and imperfections costs are what they are, and end up being what they have to be.

The Commission for the Regulation of Utilities (CRU) is charged with protecting energy consumers – both electricity and gas – and part of this mandate involves oversight of the regulated asset bases of State-owned utilities (ESB, EirGrid and GNI). The CRU additionally regulates the Single Electricity Market (in collaboration with the Utility Regulator in Northern Ireland) and audits RESS and ORESS auctions.

In the absence of information on the make-up of current electricity prices and their projected future levels, it would be beneficial if the CRU was required to publish data and produce an annual report showing the make-up of electricity prices in Ireland including not only the cost inputs identified in **Table 28** but also the aggregate gross margin (inclusive of administration costs, overheads and profit contribution).

In addition to reporting on actual costs, the CRU should also be required to indicate the likely trend of prices for future years based on its decisions.

There are, today, 11 electricity retailers offering consumers a choice of approaching 100 different tariffs. Given the importance of electricity prices for economic welfare and for national competitiveness, it would be appropriate now, 25 years into the era of a liberalised electricity market, to assess the effectiveness of retail competition to see if competition actually contributes to lower prices for consumers or not. It is possible that the aggregate gross margin of multiple retailers, whose input costs - wholesale electricity prices; transmission and distribution charges - are largely fixed, offsets the intended benefit of competition for consumers.

6.10 Conclusions

Electricity prices are driven by a set of input costs most of which are not subject to competitive forces or, where there are competitive forces, their strength is lessened by price support mechanisms in State contracts for renewables.

The liberalisation of the market and the growth of renewables have introduced additional costs into the system. It is questionable whether these cost increases have been offset elsewhere in the set of costs which make-up electricity prices.

Achieving a balance between the three legs of the energy trilemma to best meet the needs of the country requires consideration of the price consumers and industry have to pay to meet their energy needs. To date, the impact of energy policy on the retail price of electricity has been largely ignored and the promise of reduced prices from renewables has not been met.

7. ENERGY SECURITY

Ireland's approach to energy security has been negligent for many years and, today, the country runs an unacceptably high risk of a disruption to supplies of natural gas for any reason.

In recent years, there has been a complacency based on the assumption in policy that Ireland's requirement for natural gas will diminish to zero by 2050 as a result of climate change policy.

The more recent identification of the need for an LNG facility to increase diversity of supply and to provide a strategic energy store is welcomed albeit that what is envisaged by Government is inadequate and still appears to be informed by a belief that Ireland will have no dependency on natural gas by 2050. This is a naïve assumption, and a more robust approach is required, informed by the continued dependence the country will have on natural gas until 2050 and beyond.

7.1 Background

In 2023, the main energy vectors were oil and natural gas, and, between them, they accounted for 78% of primary energy (**Table 34**)

	Primary Energy Requirement		Final Energy Consumption	
Oil	80.1 TWh	48.9%	78.3 TWh	55.6%
Natural gas	48.3 TWh	29.5%	19.3 TWh	13.7%
Electricity	3.3 TWh	2.0%	31.6 TWh	22.4%
Renewables	23.0 TWh	14.1%	7.4 TWh	5.2%
Other	9.2 TWh	5.6%	4.3 TWh	3.0%
Totals	**163.8 TWh**	**100.0%**	**140.8 TWh**	**100%**

Table 34: Fuel mix in the Energy Balance, 2023
Source: SEAI Energy Balance

After transformations (of natural gas and renewables into electricity), oil accounted for 56% of Final Energy Consumption, electricity delivered 22% and natural gas 14%.

As the energy transition progresses – notably as EVs predominate and as heating is electrified –Ireland's energy mix will be transformed and the country's energy-related GHG emissions will substantially decline.

However, in the absence of a robust and deliverable plan for the transformation, the already parlous state of Ireland's energy security will continue.

7.2 Trends in Ireland's energy security

The only significant energy storage available is the 1.7 million tonnes of product (gasoil, kerosene and crude oil) stored by NORA in Ireland[55], Northern Ireland[56] and overseas[57]. The energy content of these strategic stores is 20 TWh, sufficient to provide supply to meet the country's needs for 90 days.

55 Galway; Dublin Port, Ringsend & Poolbeg; Shannon; Tarbert; Foynes; Whitegate Refinery & Aghada; Whiddy Island

56 Cloghan Point; Derry

57 Aalborg & Fredericia, Denmark; Amsterdam & Flushing, Netherlands; Madrid, Spain; Oskarshamn & Gävle, Sweden.

Where Ireland had considerable energy security for electricity generation a decade ago, this has been entirely lost with no efforts made to replace it.

In 2014, there was significant security of supply for 1,810 MW of power generation capacity – sufficient to meet 39% of a maximum demand of 4,613 MW - from stores of natural gas, peat and coal as shown in **Table 35**. Beyond this, the Kinsale gas field was still producing and provided yet more security of supply to the country.

	Natural Gas	Peat	Coal	Totals
Contribution to the electricity requirement of 28.0 TWh	12.6 TWh	2.5 TWh	4.0 TWh	**19.1 TWh**
% of demand	45%	9%	14%	**68%**
Power capacity	540 MW	370 MW	900 MW	**1,810 MW**
Electricity generation capacity of stored fuels [58]	1 TWh	5 TWh	2 TWh	**8 TWh**
# days at full capacity	83 days	507 days	90 days	

Table 35: Security of supply for electricity generation in 2014
Source: IAE analysis

Since 2014, all 8 TWh of the secured electricity output shown in **Table 35** has been lost:

- The Kinsale gas field store ceased operations in 2017 and, since then, all of the gas field infrastructure has been decommissioned and removed.
- The decommissioning of Kinsale coincided with the run-down of the peat stations.
- Coal burning at Moneypoint has ceased and the station is due to close in 2029. In the interim, Moneypoint will operate on oil but with a very much smaller storage capacity.

The only fuel storage available for power plants are small volumes of distillate in tanks adjacent to gas fired power stations with the capacity for between three and five days in the event that gas were to be unavailable.

A 100 MW OCGT running at full capacity would require more than 30 road tanker deliveries daily to keep the plant in operation. These small, localised storage reserves would not be capable of being replenished in order to allow gas fired power stations operate for any significant period beyond three to five days in the event of a local or national disruption to the supply of natural gas.

At this stage, almost all non-renewable electricity generation is fuelled by natural gas (91% in 2024). Production from Corrib is diminishing and the country is exposed to a risk that gas supplies in the two pipelines from Scotland could be disrupted.

Government has recognised that the lack of a diversity of supply sources and the lack of any storage capacity for natural gas is a risk and has accepted that these risks need to be mitigated.[59]

58 The storage capacity shown for natural gas is the capacity that was available in the Southwest Kinsale field when it was used for seasonal storage over the period from 2001 to 2017. Storage capacity was in the order of 2.2 TWh of natural gas (LHV) which, at an average generation efficiency of 50% (across a range of OCGT and CCGT plants) would be equivalent to about 1 TWh of electricity output. However, the reservoir had a limited send-out rate of 26 GWh per day (LHV), sufficient to power 540 MW of power generation capacity. In addition to this, production from the wider Kinsale field would have provided additional security of supply. The Corrib gas field was not yet in production in 2014.

59 *National Risk Assessment 2024*, Section 5.2, Page 31

One option to increase the diversity of supply for back-up generation capacity would be to increase the use of distillate stored in NORA facilities for power generation as the requirement to maintain stocks of gasoil diminishes with the electrification of transport.

A more immediate means to increase the diversity of energy supply is the development of gas storage capacity by either or both of the construction of an LNG facility and the development of geological stores.

7.3 Diversity of natural gas sources of supply

Among a number of energy security of supply risks identified in the National Risk Assessment 2024 was the lack of a diversity of supply for natural gas and the lack of any storage capacity in either geological stores or in LNG tanks.

The lack of diversity in Ireland's natural gas supply chain contrasts starkly with that of Great Britain **(Figure 14)**.

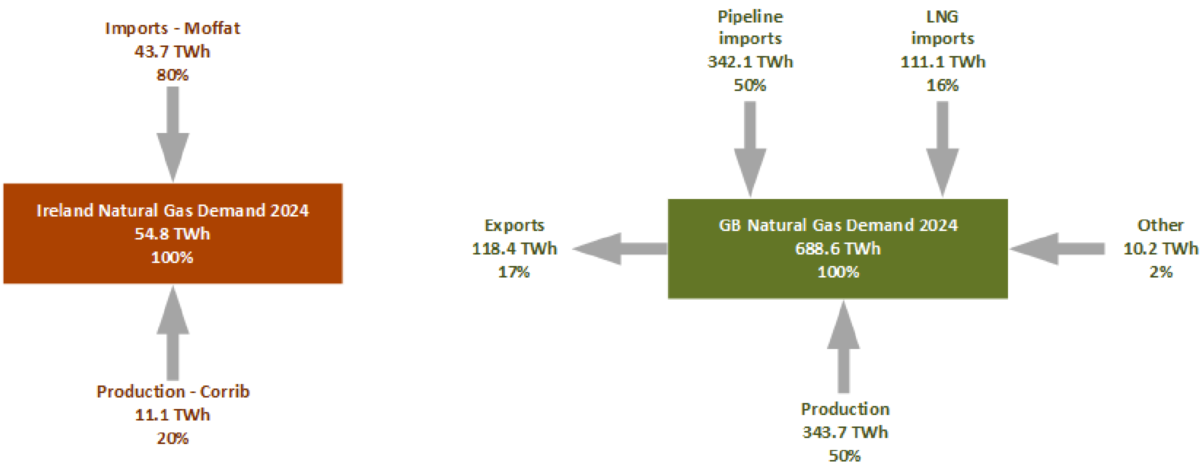


Figure 14: Comparison of the sources of natural gas supply in Ireland and Great Britain, 2024
Source: *GNI* and *DUKES*

The only indigenous production of natural gas is from the Corrib gas field and its output is steadily declining (**Table 36**).

	Output	% of national supply
2018	31.9 TWh	55%
2019	25.1 TWh	43%
2020	20.2 TWh	34%
2021	16.0 TWh	28%
2022	14.8 TWh	26%
2023	11.8 TWh	22%
2024	11.1 TWh	20%

Table 36: Trend in Corrib share of national supply,2018 to 2024
Source: GNI

In the absence of the discovery, proving and development of a new indigenous supply of natural gas, Ireland will, within less than ten years, be almost entirely dependent on imports from Britain for the country's supply of natural gas via the Moffat to Gormanstown and Loughshinny undersea pipelines . The only additional supply will be from biomethane which, today, accounts for 0.1% of total gas supply.

While the overall demand for natural gas has marginally declined by just over 5% from 56.8 TWh in 2018 to 53.6 TWh in 2024, the peak daily demand from the electricity generation sector has increased by 18% from 150 GWh per day to 176 GWh per day. (**Figure 15**).

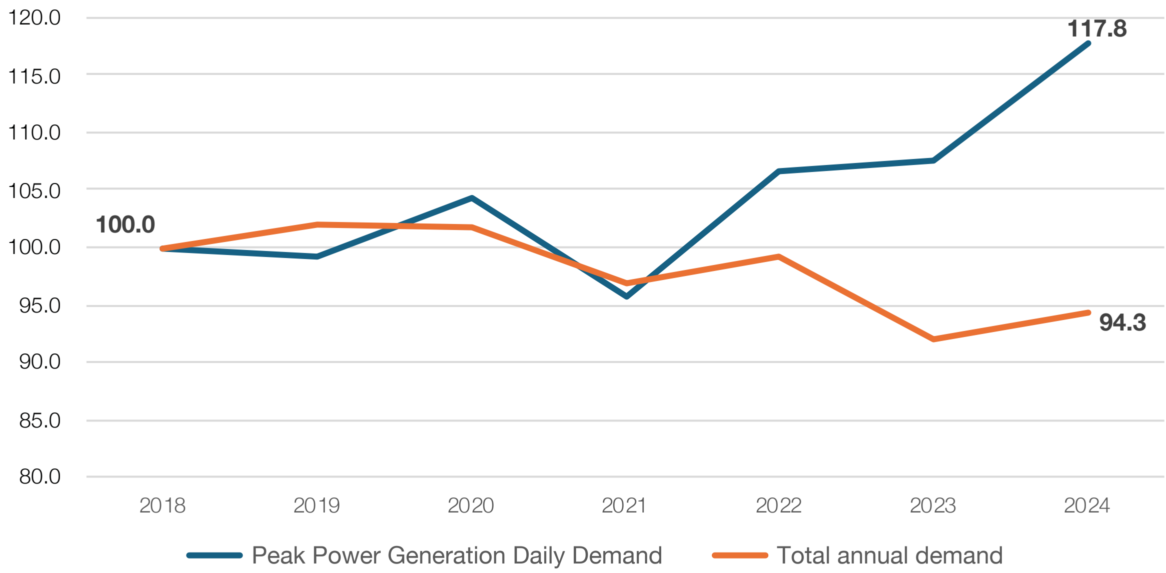


Figure 15: Trends in peak daily gas demand for power generation and annual demand for natural gas, 2018 to 2024
Source: IAE analysis of *GNI Open Data*

As the maximum demand for electricity increases from 6,000 MW today to in the order of 12,000 MW by 2050, the peak demand for natural gas for back-up power generation will also increase even as the overall annual demand reduces.

7.4 Proposed FSRU

In March 2025, Government approved the development of a floating storage regasification unit (FSRU) as a State-led project to address the known risk to the country's natural gas supplies. The FSRU was specified to have a storage capacity of 170,000 m^3 of LNG equivalent to 1.0 TWh. This was stated to be sufficient to supply 200,000 average domestic gas customer demand for 6 months or, alternatively, sufficient to supply the entire gas demand for Ireland for seven days and would be refilled to continue to supply the national gas network.

Previous analysis by the Academy suggests that Ireland could need a 13.2 TWh back-up store of natural gas capable of delivering gas at 440 GWh per day just to meet the requirement to provide security of supply for back-up generation necessary to ensure a reliable and adequate electricity supply in 2050.[60]

If, as is likely to be the case, there are other requirements for natural gas remaining in 2050, then the capacity required in a natural gas store could be higher than these estimates.

What is clear is that the limited LNG facility currently proposed by Government will be far short of what the country requires today, or what it will require in the future, if the identified risks are to be adequately mitigated.

60 *The Energy Transition*, Page 30, Table 20, IAE, April 2025

The key point is that the planned capacity of a strategic store of natural gas needs to look at future requirements in 2050. There is a paradox that as the energy transition progresses, the scale of a strategic store (in terms of energy storage capacity and power output) will need to be greater than is required today even as the consumption of natural gas declines as renewables come to meet the majority of the country's electricity requirement.

Where this was recognised in the 1970s for petroleum products, it has yet to be recognised for natural gas.

7.5 Option of a large onshore LNG facility

There have been two proposals to build onshore LNG facilities in the Shannon Estuary

- In 2008, planning permission was granted for an LNG facility with a storage capacity of 800,000 m^3 of LNG in four tanks (4.9 TWh) and a peak regasification rate of 314 GWh per day.[61] The project did not proceed due to viability concerns arising from regulatory impositions.
- In 2023, planning permission was refused for an FSRU with a capacity of 180,000 m^3 (1.1 TWh) and a send-out capacity of up to 250 GWh per day. This planning permission was the subject of ongoing legal review and has returned to An Coimisiún Pleanála for assessment.[62]

Elsewhere within the Shannon Estuary - and notwithstanding that there are different plans for Moneypoint - it is conceivable that an onshore LNG facility could be developed there utilising the now redundant coal unloading jetty with the potential to reduce the capital development costs of an LNG facility by in the order of €150 million compared to the projects proposed elsewhere.

The capacity of the LNG facility the country might require to significantly reduce the natural gas security of supply risk can be gauged by comparison with the natural gas storage capacities that other countries maintain to mitigate the same risk. Ireland is an outlier among comparable countries in Europe – as shown in **Table 37** – in having no storage capacity, either geological or LNG.

	Demand 2023	Total storage capacity	# days storage
Netherlands	283 TWh	154 TWh	199 days
Denmark	21 TWh	10 TWh	181 days
Portugal	47 TWh	9 TWh	71 days
Greece	53 TWh	5 TWh	37 days
UK	681 TWh	40 TWh	21 days
Ireland	53 TWh	0 TWh	0 days

Table 37: Comparison of Natural gas demand and storage capacity (geological plus LNG) for selected countries.
Source: IAE analysis of ENTSOG *data* (**Appendix 7**)

Whereas Government has proposed a solution which it says can be implemented quickly, the solution it is progressing is too small and is subject to unnecessary and potentially limiting constraints including that it,

- *does not inadvertently increase gas demand by increasing the supply available on the market,*
- *is a cost-effective proposal at the appropriate scale,*
- *provides sufficient resilience if a disruption to gas supply occurs, and*
- *is compatible with the Climate Act 2021.*

61 An Bord Pleanála *PA08B.PA0002*

62 An Bord Pleanála *311233*

Because of the intermittency of renewables, Ireland will have a requirement for natural gas for electricity generation until at least 2050 and also for other sectors which are hard to abate. It is important that policy recognises the scale of the storage and send-out capacities that will be needed between now and 2050 and, likely, beyond. The current approach will not be sufficient and an alternative that better meets the requirements of the country needs to be found as a matter of urgency.

The establishment of a national strategic store of oil by NORA in the 1970s provides a benchmark for what is required now to address the same risk to the national supply of natural gas.

7.6 Potential of the former Ballycotton gas field for storage of natural gas

Investigations by ESN, BGE and dCarbonX as part of the Kestrel project have identified the potential for the Ballycotton Gas Field (**Appendix 8**) to be developed as a natural gas store with an indicative capacity of 10 TWh (and a requirement for 5 TWh of cushion gas) with the possibility of transitioning to become a hydrogen store with a capacity of 3 TWh.

If a 10 TWh storage capacity could be achieved at Ballycotton, it would potentially be sufficient to meet 70 days of demand.

7.7 Conclusions

With the exception of NORA's 20 TWh of petroleum storage stocks (some of which is not in Ireland), Ireland has virtually no other stores of fuels to protect the country from a sudden energy supply shock. The country is particularly exposed to a shortage of fuel for power generation following the cessation of coal burning in Moneypoint where coal stocks had been sufficient to generate 2 TWh of electricity at a power level of 900 MW.

Today, Ireland has small volumes of oil stored at a number of power stations with the capacity to maintain generation for between three and five days in the event of a loss of supply of natural gas for any reason.

Given that there will be an inevitable dependence on natural gas for power generation for the next 25 years – albeit at a reduced volume but with a higher peak demand – the delivery of a much higher storage capacity and send-out rate than is currently envisaged in Government's limited plan for a floating LNG facility is essential to provide a reasonable level of protection for the electricity generation and other sectors which will continue to have a significant continuing dependence on natural gas in the years ahead.

Based on Ireland's current consumption levels, achieving the same security of supply for natural gas which either Denmark or the Netherlands have would suggest a storage capacity in excess of 25 TWh. To achieve Great Britain's capacity of 21 days would require a store of 3 TWh. In both cases, the requirement would be multiples of what Government's FSRU proposal would deliver.

The engineering options to substantially address Ireland's natural gas security of supply risk exist by way of a larger LNG facility than is currently being planned and / or by the development of Ballycotton gas field (if this ultimately proves to be feasible / viable).

8. THE NEED FOR A NATIONAL ELECTRICITY INFRASTRUCTURE MASTERPLAN

The energy transition will require the construction of many large electricity infrastructure projects. The Academy previously estimated that 352 such projects might be needed by 2050 (**Table 38**).[63]

Category	Assumptions	# projects
Onshore wind	4,270 MW at 60 MW per windfarm	71
Fixed bottom offshore wind	20,149 MW at 700 MW per windfarm	29
Solar	5,452 MW at 40 MW per project	136
Interconnectors	6,113 MW at 600 MW per project	10
Back-up generation	6,000 MW at 300 MW per project	20
Transmission lines	1,150 km of transmission lines at 25 km per line	46
Storage	2,000 MW / 50 GWh at 50 MW per project	40
Total		**352**

Table 38: Indicative scale of the programme of projects needed in the electricity sector
Source: *The Energy Transition*, Page 43, April 2025, IAE

Given their scale, renewable and transmission infrastructure projects will, inevitably, have a high visual impact and other significant potential environmental impacts, including on Natura 2000 sites: [64]

- At least 1,150 km of new high voltage transmission lines would require 3,000 towers, each 40 metre high.
- 71 onshore wind projects would require 850 individual wind turbines, each 150 metres high.
- 29 offshore wind farm projects would require 1,200 wind turbines, each 300 metres high.
- 136 solar utility scale projects would cover a land area of 100 km^2.

All of the generation projects (onshore wind, fixed-bottom offshore wind and solar) and all of the interconnector projects will require grid connections, planning permissions and routes to market before a final investment decision (FID) can be made by project developers.

After that, the projects would move to final design, procurement and construction. Offshore wind projects, additionally, require a Maritime Area Consent (MAC).

Wind Energy Ireland (WEI) estimates that it takes from six to 11 years to take an onshore windfarm project from concept to completion (**Figure 16)**. WEI further estimates that there is 3,000 MW of onshore wind currently with consent - but not yet gone to construction – and a further 2,000 MW awaiting a planning decision. In addition, WEI indicates that a further 2,000 MW will go into planning in the next 12 months.

63 *The Energy Transition*, Page 43, April 2025, IAE

64 Natura 2000 is a network of areas in which birds are protected on Special Protection Areas (SPAs) and natural habitats, wild fauna and flora are protected in Special Areas of Conservation (SACs). SPAs and SACs are designated and monitored in Ireland by the NPWS under the *Birds Directive* of 1979 and the *Habitats Directives* of 1992.

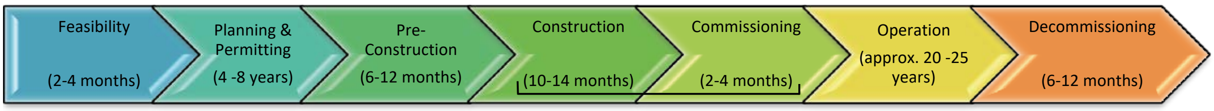


Figure 16: Onshore wind farm timeline estimates
Source: *Life-cycle of an Onshore Wind Farm*, Wind Energy Ireland, March 2019

In addition to the projects summarised above, a doubling of the capacity of back-up generation by the addition of in the order of 6,000 MW of new gas-fired / oil-fired power plant will be required from an appropriate mix of OCGT, CCGT and reciprocating engine generator sets.

There is a paradox that as more gas and oil-fired power capacity is needed, the electricity it will produce, the energy it will consume, and the greenhouse gases it will emit will all decline as the penetration of renewables increases. While more fossil fuel ***power*** will be needed, less fossil fuel ***energy*** will be consumed.

Fossil fuel plant will remain the backbone of the Irish electricity sector to ensure adequacy and reliability and will provide the basis for addressing the country's energy security of supply exposure.

However imperfect the processes are to facilitate renewable energy projects, the basic framework – with notable exceptions in terms of planning guidelines for onshore wind and solar - exists to guide their progress through the consenting, planning and renewables support scheme auctions.

Since 2020, 235 renewables projects (with a power capacity of 6,282 MW) have had bids accepted in RESS auctions (**Table 39)**.

Scheme	Date	Onshore wind		Solar	
		# projects	MW	# projects	MW
RESS1	Sep-2020	19	479 MW	63	796 MW
RESS2	Jun-2020	14	414 MW	66	1,534 MW
RESS3	Oct-2023	3	148 MW	20	498 MW
RESS4	Sep-2024	4	374 MW	23	960 MW
RESS 5	Sept-2025	5	219 MW	18	860 MW
Totals		**45**	**1,634 MW**	**190**	**4,648 MW**

Table 39: Summary of RESS auction results for onshore renewables, wind and solar

The challenges to facilitate all such projects to secure planning permissions are well understood. How long it will take Government to provide a coherent policy and legal framework which allows projects to progress is unclear as is the potential for delays from judicial reviews due to the legacy of the slow delivery of facilitatory policies over the past decade and more (**Section 4**).

In the meantime, there is an urgent need to ensure the timely delivery of the estimated 46 overhead transmission line projects and 20 back-up generation projects that will be needed to meet the projected electricity requirement of 80 TWh and maximum demand of 12,000 MW in 2050.

The more challenging of these two sets of projects is the set of projects to deliver new high voltage overhead transmission lines.

Since the publication in 2008 of Grid25[65], there has been an evident reluctance in policy and in regulatory development plans to identify the overhead transmission line projects that will need to be built to deliver national energy policy. The failure to plan for and to progress new projects contrasts with past experience (**Table 40**) and suggests that a major delivery problem has been created which could significantly impact the energy transition in the future.

Period / plan	New overhead lines	Increase in max demand
1966 to 1990	1,570 km of 220 kV line	1,128 MW to 2,466 MW (1970 to 1990)
In <10 years up to 1986	438 km of 400 kV line	1,971 MW to 2,466 MW (1980 to 1990)
2000 to 2025	103 km of 220 kV line	3,200 MW to 5,857 MW (2000 to 2025)
TDP 2024[66]	137 km North-South interconnector	6,000 MW in 2025

Table 40: Trends in the construction of new overhead transmission lines from the mid-1960s

In the case of back-up generating plant, there are clear and proven risks that the existing approach may not be fit for purpose (**Section 6.7**).

Delivering programmes of infrastructure projects with long delivery lead times requires a masterplan with a longer time horizon than plans overseen by the CRU have.

8.1 The need for an engineering-led masterplan for electricity infrastructure

There are two examples where long-term master-planning has allowed large infrastructure - with the combined characteristics of national importance and significant potential environmental impact – to be successfully delivered:

- The *National Road Needs Study* of 1998 - prepared for the *National Roads Authority* - projected road needs over the 20 years to 2019, identified the projects necessary to meet these needs and estimated the capital cost in 1999 prices. The understanding this gave of the inadequacy of the Irish road network prompted the subsequent political decision to develop the national motorway network. Based on the experience of delivering multiple projects from this programmed approach, major roads projects can, today, be routinely delivered on time and on budget.
- Dublin Port's Masterplan 2040 projected the volumes the port should plan to cater for over a 30 year period to 2040 and identified the engineering projects that would be required to deliver the required capacity. Two SID projects[67] have received planning permission - one with a 15 year duration grant - and a planning application for a third project - which would allow the development of the port to its ultimate capacity by 2040 - was lodged with An Bord Pleanála in July 2024.

The scale of the transmission and back-up electricity infrastructure projects - and their evident potential for significant environmental impact (both visual and in terms of GHG emissions) - suggest the need for an overarching large electricity infrastructure masterplan similar in concept to the above exemplars.

The need for such a plan is also evident from the complex framework of the national planning hierarchy (**Figure 17**) which comprises:

- The National Planning Framework
- Regional Spatial and Economic Strategies
- Local Authority Development Plans

65 *Grid25,* EirGrid, 2008

66 EirGrid Ten Year *Transmission Development Plan 2024*

67 Planning permission for the *ABR Project* was granted in July 2015 and planning permission for the *MP2 Project* was granted in July 2020.

Each of these levels is informed by EU and national law and by national policies.

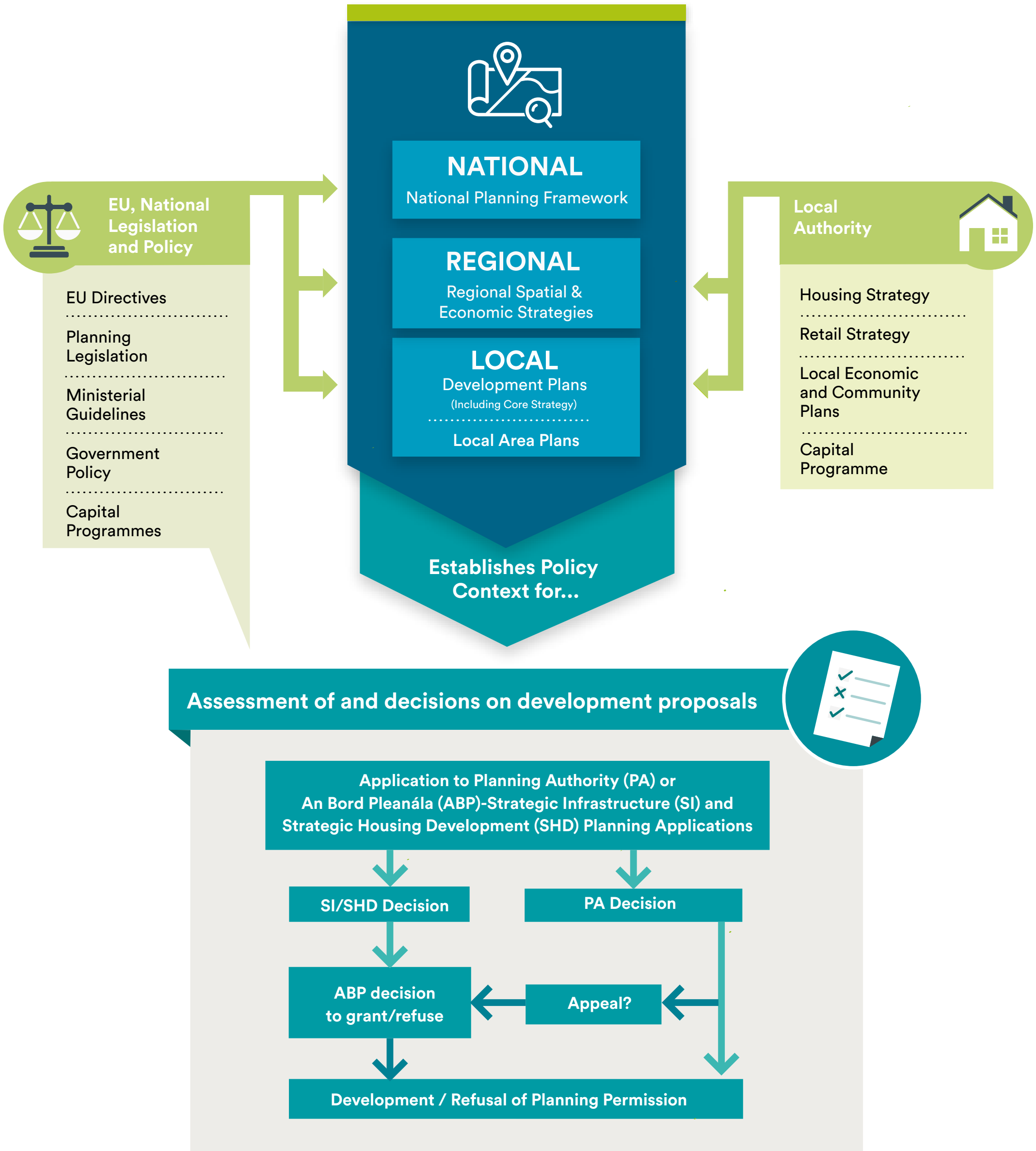


Figure 17: Overview of the national planning system
Source: National Planning Framework, 2018

An important feature of masterplans is that they are supported by Strategic Environment Assessment.[68] The nature and scale of the programme of transmission line projects and back-up generation plant fits the criteria set in EU law for programmes requiring strategic environment assessment.

A large electricity infrastructure masterplan embedded at all levels of the national planning hierarchy and explicitly supported by national policies and in line with EU and national law would provide an essential base to establish need and context in planning permission applications for individual projects brought forward from the masterplan to An Coimisiún Pleanála.

68 EU Directive 2001/42/EC on the assessment of the effects of certain plans and programmes on the environment, 2001

8.2 Relationship of the proposed masterplan to existing plans

EirGrid meets its regulatory obligations to plan the delivery of the transmission and generation system through a series of publications and actions including:

- Ten-year All-Island Resource Adequacy Assessments
- Ten-year Transmission Development Plan
- Annual Winter Outlook
- T-1 and T-4 capacity auctions
- RESS and ORESS auctions

In addition, EirGrid provides a longer range view of future requirements by way of scenario analysis, most recently in Tomorrow's Energy Scenarios 2023 (TES 2023) which projected Ireland's electricity requirement and maximum demand out to 2050 under four scenarios.

There are fundamental problems with the currently mandated approach to meeting the country's future generation and transmission requirements:

- The timescales are too short given the lead times to plan and deliver transmission line projects and also the long delivery lead times for high voltage transformers.
- Ireland will need significantly more gas turbine capacity in the coming years and, as demand for such plant has increased greatly in recent years, there is a risk that the current T-4 auctions will not be capable of delivering the required capacity when it is needed (**Section 6.7**).
- A large proportion of the generation assets required will be fossil fuel based up to and beyond 2050 in contravention of both national law and national policy.

The delivery problems described above have already arisen, notably with the North-South interconnector project and in the electricity supply crisis of 2022. In the case of the North-South Interconnector, construction has yet to commence 25 years since the project commenced.

The proposed electricity infrastructure masterplan is not intended to supplant EirGrid's ten year ***Resource Adequacy Assessment*** or its ***Ten Year Transmission Development Plan***. Rather, it is intended to provide an overarching framework for these plans and facilitate decisions to proceed with projects with lead times greater than their relatively short ten year time horizons.

8.3 Contents of the masterplan

In this, and in previous reports, the Academy has based its analysis on putative figures for the two key parameters that will drive supply side electricity infrastructure plans. These parameters are based on an average of EirGrid's four scenarios in TES 2023 (**Table 41)**.

	2024	2050
Electricity requirement	34 TWh	80 TWh
Peak demand	5,691 MW	12,000 MW

Table 41: Assumed electricity requirement and peak demand in 2050 compared to the actual out-turn in 2024

The masterplan to 2050 needs to be based on a conservatively high estimate of the future electricity requirement and maximum demand.

Where this report assumes parameters of 80 TWh and 12,000 MW, the starting point for the masterplan would be more robust estimates of these figures by EirGrid. This would require EirGrid taking its TES 2023 analysis to the next stage and identifying the most realistic future scenario over the next 25 years, unencumbered by,

- loose policy objectives regarding hydrogen,
- the economic unfeasibility of Ireland becoming a major exporter of green electricity, and
- the unrealistic objective of entirely eliminating GHG emissions from electricity generation by 2050.

It is impossible to envisage this being done in the current policy environment because it would amount to a recognition by a State-owned company of the failure of national energy policy.

The suggestion that the future projections be conservatively high is to ensure that there is no shortage of projects in preparation at any time over the next 25 years. To the extent that future demand might be lower than the projections in the masterplan, the construction of future projects - which could already have gone past the consent phase and secured grants of planning permission of not less than 15 years duration – could be deferred.

If the projected levels of electricity requirement and of maximum demand in the masterplan are too low, then there would be a risk that the delivery of essential infrastructure would be late. This is already happening with renewables projects, and this eventuality must be avoided for transmission line and back-up generation projects.

The cost of bringing a large infrastructure project through the planning system is a small fraction of its ultimate cost (perhaps 2% to 3%).

Having a masterplan in place would allow projects to be brought forward for consent early. An Coimisiún Pleanála has demonstrated an acceptance of the need to plan ahead and a willingness to grant consents of long duration to provide flexibility in determining when construction should commence. Such flexibility would allow, for instance, consented projects to be constructed during a downturn in the economic cycle when construction costs might be depressed.

The next question to be addressed is who would be responsible for preparing the large electricity infrastructure masterplan and who would have the authority and accountability for delivering it?

8.4 Authority and accountability

One of the downsides of the liberalisation of the electricity market has been the division of authority and accountability among a range of different organisations.

Where, in the past, ESB had a clear mandate to plan and deliver the national electricity system to meet the country's requirements - and, demonstrably, succeeded in fulfilling this mandate - the situation today is less clear.

The movement of authority from the vertically integrated monopoly that was the ESB up to 2000 to a combination of EirGrid, ESB, CRU, Government departments and private sector companies has created proven delivery problems for critical infrastructure and, when things go wrong - as they did in the electricity supply crisis of 2022 - the division between authority and accountability ensures that nobody is to blame. This is particularly evident in the conclusions of the *Independent Review on the Security of Electricity Supply* of January 2023.

It is important to learn from past failures and, given the criticality of the proposed national electricity infrastructure masterplan, it is recommended that the responsibility both for its preparation and its delivery be given jointly to EirGrid and ESB Networks.

This raises the issue as to whether the separation of functions between ESB and EirGrid and, more widely, among all State-owned energy companies is appropriate for the challenges of the energy transition.

8.5 Roles and responsibilities of State-owned energy companies

The three State-owned energy companies - ESB, EirGrid and GNI - have very different scales and face contrasting challenges over the next 25 years (**Table 42**).

	ESB	EirGrid	GNI
Revenue	€7,259m	€1,106m	€600m
EBITDA	€1,934m	-€94	€323m
PAT	€706m	€10m	€138m
Net debt	€6,674m	-€198	€699m
Dividend	€89m	€4m	€44m
Capex	€1,640m	€161m	€188m
Employees	9,600	482	800
Fixed assets	€13,203m	€655m	€2,512m

Table 42: Summary of State-owned energy companies' financial performance, 2024
Source: Annual accounts

In addition to these three energy companies, there is NORA which has an important responsibility to manage the only significant national energy security stocks, namely, 1.7 million tonnes of oil (mostly gasoil) with an energy content of 20 TWh and a value of €943 million.

Over the past 25 years, a number of anomalies have developed, and, over the next 25 years, there will be a growing overlap and interaction between the plans and operations of all four organisations:

- In the case of ESB, its regulated asset base of transmission and distribution assets will grow considerably under PR6 and in subsequent price review periods and the financial size of the already large company will increase substantially.
- While this is happening, EirGrid – which, by comparison to ESB, is a small company - will develop its own offshore transmission asset base from the transfer of substations built by ORESS1 project developers to EirGrid and also by EirGrid itself developing new offshore substations (as currently being planned for ORESS2).
- The overlap in transmission asset ownership extends into the generation sector because of the obligation placed on EirGrid to develop a generation business following the electricity generation shortfall crisis of 2022 (**Section 6.7**).
- As EirGrid oversees the development of an expanded electricity sector over the next 25 years, GNI's business will decline as gas consumption reduces. The *EU Hydrogen and Gas Package*[69] requires gas distribution operators to prepare decommissioning plans in their Network Development Plans[70] should a reduction in gas demand be forecast. GNI has indicated that it will do this in future plans. The future decline in GNI's business will come as a result of increased electrification. This suggests the need to co-ordinate the growth plans for the electricity sector with the retrenchment plans for the gas sector while ensuring that the gas sector develops capacity to cater for a higher peak demand for back-up electricity generation.

69 The EU hydrogen and gas decarbonisation package of May 2024 comprises *Directive (EU) 2024/1788* and *Regulation (EU) 2024/1789* and was adopted in May 2024.

70 *Network Development Plan 2024,* GNI

- The co-ordination of GNI's *Network Development Plan*, 2024 (published in February 2025) with EirGrid's plans is being overseen by the CRU. In August 2025, CRU indicated its intention to continue its review of GNI's plan to ensure alignment with EirGrid's plans.[71]
- As the demand for oil declines, the level of stock NORA is required to hold will decline. This will create opportunities to use existing NORA facilities to supply nearby back-up electricity generation plant, thereby increasing national energy security.
- ESB and GNI have interlinked hydrogen development plans. ESB has a *hydrogen strategy* and GNI has a vision to move from natural gas to a combination of biomethane (32%) and hydrogen (68%) by 2045.[72] Whether these approaches prove to be feasible or not, it would be logical for the two inter-dependent hydrogen plans to be closely co-ordinated, possibly in the one organisation.
- Where GNI has been tasked by Government to deliver an LNG facility to provide natural gas storage and diversity of supply, ESB is investigating the possibility of developing the former Ballycotton gas field, initially, for storage of natural gas and, ultimately, hydrogen.

There is considerable overlap between ESB, EirGrid, GNI and NORA and it is questionable whether the existing divisions of roles and responsibilities between the four organisations is suitable for the challenges of the energy transition.

Just as it is appropriate, now, for the CRU to review the effectiveness of the retail energy market in meeting consumers' needs, so also would it be appropriate for Government to review how the four State-owned energy operators might be re-structured to meet the challenges of the next 25 years.

8.6 Conclusions

The key risks identified in this report to the delivery of the energy transition are,

- failure to deliver high voltage overhead transmission lines, and
- failure to expand the fleet of back-up generation plant that Ireland will need as the electricity source of last resort.

The scale of the challenge to deliver the energy transition and the rapid pace of technological development creates a formidable challenge for planning and delivering future energy solutions over many different timeframes.

An electricity infrastructure masterplan with a 25 year time horizon, but also with an eye to supply side options that might transcend 2050, is needed to provide an essential roadmap for future energy policy. Current time horizons are too short and legal mandates for carbon neutrality and unrealistic targets for renewables are no substitute for proper engineering-led planning.

There are anomalies and overlaps between the assigned roles and functions of the country's four State-owned energy operations - ESB, EirGrid, GNI and NORA – which warrant critical analysis by Government to determine the most effective structure to achieve the best balance between energy prices for consumers, security of the national energy supply and realistic levels of GHG emissions reduction.

71 CRU *Decision Notice,* CRU/2025121

72 *Pathway to a Net Zero Carbon Network*, GNI, 2024

9. KEEPING OTHER OPTIONS OPEN OVER THE NEXT 25 YEARS

The analysis and recommendations in this report are structured around the simple proposition that the delivery of large energy infrastructure requires a long-term plan and that such a plan can only be based on technologies that provide certain options over its term.

However, there have been extraordinary technological developments over the last 25 years (including in battery technologies, solar panels, the power capacity of wind turbines and the development of offshore wind) and it is likely that there will be more developments in the coming 25 years which could change any long-term plans that might be made today. This creates a temptation to wait and see and to continue with the existing unachievable mandate to eliminate GHG emissions by 2050.

This would be a serious mistake, as would ignoring the potential that new viable technologies might become available over the course of the masterplan. These technologies could include small modular nuclear reactors (SMRs) and new zero-carbon fuels as alternatives to natural gas and oil.

In the particular case of SMRs, much preparatory work is required to create a legislative and regulatory framework that would allow their deployment if they prove to be viable.

9.1 Nuclear power

Traditional generation plant is long lived. Ardnacrusha is 95 years old and, by the time Moneypoint prematurely ceases operation in 2029, it will have been in operation for 46 years.

By contrast, onshore wind farms typically have a lifetime of 25 years and offshore wind farms may have a lifetime of 35 years. These are short lifespans by comparison to traditional generating plant.

Energy policy needs to be planned with a very long time horizon in mind and the possible emergence of SMRs to provide a long-term option for Ireland transcending the 2050 target date for carbon neutrality should be considered. Many existing nuclear plants have operating lives of 50 years and more. The four Barakah nuclear power plant units in Abu Dhabi - which commenced operation between 2020 and 2024 and which have a combined power output of 5,348 MW – have a design life of 60 years

It Is possible to envisage a scenario where Ireland could begin to deploy SMRs in the 2030s to reduce the amount of fossil fuel generation plant in the country's mix and also to reduce the amount of renewables particularly as older wind farms come to the ends of their operating lives. Already, some onshore wind farms are approaching this point and will need to be redeveloped if they are to continue to contribute to the national electricity requirement.

In June 2024, the Academy recommended that Ireland should make the basic preparations for the introduction of nuclear power as a contingency in case a decision was made in the future to go this route.[73] The approach suggested is similar to the approach taken in the 1970s following the second oil shock when ESB acquired the skills necessary to undertake a nuclear power project and the Nuclear Energy Board was established to provide the regulatory functions that would be needed.

This recommendation is similar to what has been happening in Estonia in recent years. Estonia does not have nuclear power but has been working in conjunction with the IAEA in accordance with its milestone approach (**Figure 18**) to develop the institutional framework - including enabling legislation - that would be required to facilitate the introduction of SMRs.

73 *Small Modular Reactors,* IAE, June 2024

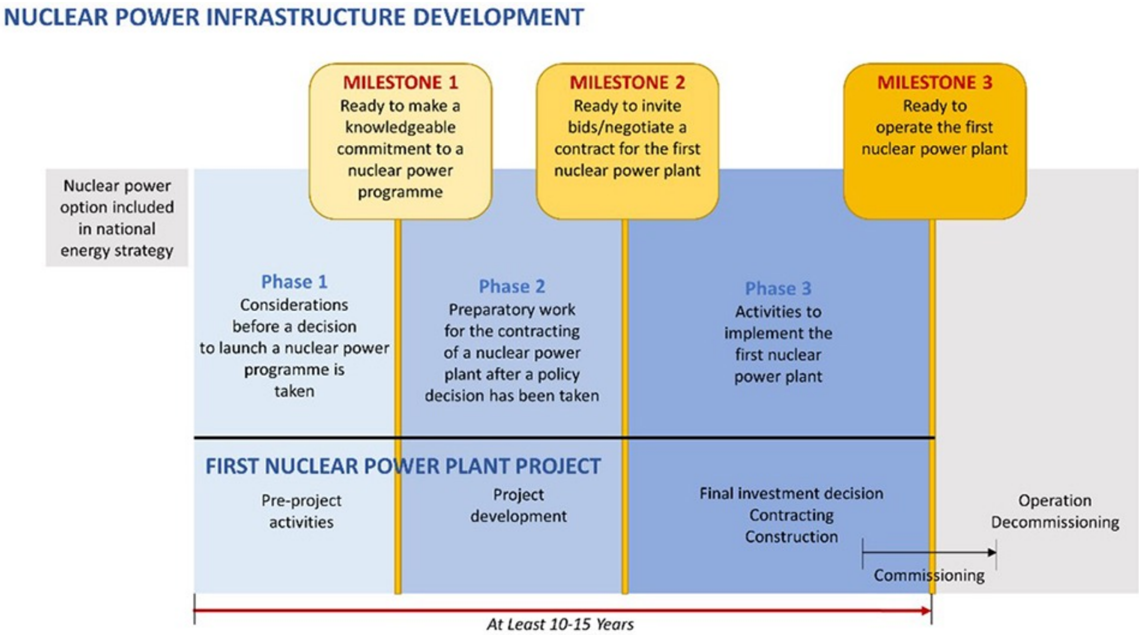


Figure 18: IAEA's milestone approach for countries to develop a nuclear generation capacity, IAEA

Insufficient attention is being paid to the potential of SMRs because of the twin legislative bans on nuclear power in Irish law.

For example, while ESB's *Emerging Technology Insights* 2024 describes SMR technology, it does so tentatively noting that:

> *ESB has no direct involvement in SMR. The production of electricity for the Irish national grid by nuclear fission is prohibited in the Republic of Ireland by the Electricity Regulation Act, 1999 (Section 18).*

Separately, but more encouragingly, EirGrid noted in its Annual Report 2024 that:

> *… serious consideration should be given on how to increase the range of options available to Ireland, and even though some of the options may not be popular (for example, use of nuclear energy), it is important that they are given serious consideration.* [74]

Whatever objections or concerns there might be today about nuclear power in Ireland, there is a growing, albeit a small, dependency on nuclear power from Britain and France through interconnectors.

Moreover, there is already considerable opposition to the development of electricity infrastructure (not only overhead transmission lines but also wind turbines, both onshore and offshore). Nuclear power could, in the future, reduce or even reverse the latter impact.

By the time Ireland might have reached the first milestone of IAEA's approach, there would be the possibility of a meaningful national dialogue on the option of nuclear power informed by the experience of SMRs developed in other countries such as Canada and Britain.

74 *Annual Report 2024*, Eirgrid

IAEA's Phase 1 approach in **Figure 18** is explicitly designed to take a country to the decision point of saying either *Yes* or *No* to a nuclear power programme. Ireland has the option of taking this approach even while the legislative bans on nuclear power remain in place. An informed national discussion could, at that point, endorse the removal of the legislative barriers to nuclear energy and allow the commencement of a nuclear programme. We should not be closing off options in this generation which the next generation might need to depend on.

The Academy has previously suggested that it might be possible to deploy a fleet of SMRs in Ireland with an aggregate capacity equal to the minimum demand with the balance of the country's electricity provided by renewables. Based on a peak demand of 12,000 MW by 2050 and a minimum demand of 5,500 MW and, assuming a capacity factor of 80%, a 5,500 MW fleet of SMRs could provide 38.5 TWh of electricity equivalent to 48% of Ireland's 2050 electricity requirement of 80 TWh.[75]

It would be irresponsible if Government did not remove the block on State-owned energy companies - ESB and EirGrid – and on State bodies - CRU and EPA - to actively participate in a milestone process with the IAEA similar to Estonia.

9.2 New fuels

It is frequently said that there is no ***silver bullet*** solution to decarbonising energy. This gives an incentive and motivation for research and pilot projects – often funded by EU grants or other support schemes – to develop and commercialise green alternatives for natural gas and for traditional liquid petroleum fuels. These options include:

- Hydrogen
- eMethanol
- Green ammonia
- Other net-zero fuels

The development of a National Hydrogen Strategy and the inclusion of hydrogen in many policy documents and in the plans and strategies of ESB and GNI in recent years was premature as it gave a baseless optimism that hydrogen will definitely contribute to Ireland's energy mix. It is equally likely that hydrogen will turn out to be neither feasible nor viable at any significant scale that will make an impact on Ireland's energy needs.

Notwithstanding this, research and pilot work should continue on the same contingency basis that preparations should be made for SMRs to ensure that, if new options do become available over the next 25 years - as they have over the past 25 years - they can be planned for and deployed in the country's energy mix.

75 *The Energy Transition*, Page 57, IAE, 2025

10. SUMMARY AND CONCLUSIONS

1. Irish law requires that the country must be carbon neutral by 2050 and energy policy confirms that this means reducing net GHG emissions from their 2024 level of 58 Mt CO_2eq to zero over the next 25 years.
2. Energy-related emissions account for 55% of total emissions and, therefore, GHG emissions from heating, transport, electricity generation and industry must be eliminated. This is not possible using the technologies that are available today.
3. There will, therefore, be a long tail dependency on fossil fuels up to and beyond 2050. The size of this tail will diminish over time as progress is made to decarbonise generation, and to electrify heating, transport and industrial processes.
4. Energy policy is dominated by the unachievable target of carbon neutrality by 2050 and needs to be rebalanced to ensure that the two challenges of high electricity prices and energy security - which have been largely ignored to date - are addressed.
5. Other countries which have a significantly lower dependence on fossil fuels in their energy balances and lower specific GHG emissions in electricity generation benefit from a combination of large hydro power resources and nuclear power. Ireland can never have the former and has outlawed the latter.
6. The main focus in energy policy on reducing energy-related GHG emissions is the replacement of fossil fuels in electricity generation by renewables. This requires a large expansion in the capacity of onshore wind, fixed-bottom offshore wind and solar. The development of policy to facilitate this expansion has been slow and characterised by an absence of urgency.
7. Most notably, the target to have 5,000 MW of fixed bottom offshore wind by 2030 will not be met and it is possible that none of the 3,799 MW in five projects currently being considered by An Coimisiún Pleanála will be completed by 2030.
8. Delays have arisen because of a slowness in reforming the consenting regime in the foreshore and putting in place marine planning and environmental protection measures.
9. The construction of fixed-bottom offshore wind farms will also be constrained by insufficient port infrastructure. Delivering, say, 20,000 MW of fixed-bottom offshore wind could take more than 50 years if projects have to depend on the only ORE facility in the State (Port of Cork).
10. Government has set targets for 54,000 MW of renewables by 2050. There is no basis for this target and no estimate of what a realistic target should be.
11. In recent years, Ireland has developed a large dependence on interconnectors and, in the first half of 2025, imports met 17% of the electricity requirement. This reliance raises the possibility that Ireland might need less renewables than it otherwise might.
12. Beyond this possibility, there is a need for some mechanism to put a limit on the amount of renewables that might be supported by RESS and ORESS schemes. This is needed to protect consumers.
13. Current policy foresees the development of a large green electricity export sector. If there is real potential for this to happen, additional renewables capacity to supply an export sector should be left to the private sector without the benefit of State support schemes.
14. There are four recommendations for an enhanced role for the CRU to protect consumers from excessively high electricity prices:
    i. Firstly, CRU should be required to publish an annual analysis of the costs - including the aggregate gross margin of electricity and gas retailers - which set the price of energy so that consumers can understand why electricity and gas prices are at the level they are at.

ii. Secondly, based on this cost and price analysis, CRU should produce a critique on the effectiveness of retail competition in the electricity and gas markets to determine whether the aggregate gross margin of multiple retailers results in any economic benefit for consumers. This critique should be repeated periodically.

iii. Thirdly, in order to introduce a mechanism which will lead to an optimum level of renewables in the electricity system, CRU should be required to complete an assessment of the impact on consumer prices of future RESS and ORESS auctions before they are launched as an input to determining whether they should proceed or not. A similar ex post analysis should be done to determine whether or not the supports granted in State contracts after the auction provided value for consumers.

iv. Fourthly, given the extent of its control - including through direct regulation of costs and price recovery on regulated asset bases - CRU should be required to prepare periodic projections of future energy prices to provide an indication of their likely trends.

15. The CRU has a key role in protecting the interests of consumers and it is important that it holds itself accountable by completing the above exercises.

16. The increasingly long lead time for new gas turbines – combined, firstly, with the experience of the generation capacity shortfall crisis in 2022, and, secondly, with the future need to replace an ageing fleet of fossil fuel generation plant - suggests that the capacity market mechanism to procure back-up generation should be reviewed to ensure that it is fit for purpose and that there is accountability for the provision of adequate back-up generation capacity at all times as electrification drives greatly increased maximum demand over the next 25 years.

17. The key challenges to deliver the energy transition are the development of transmission infrastructure and back-up generation plant with sufficient capacity to ensure an adequate and reliable electricity system. This requires an electricity infrastructure masterplan.

18. Responsibility for preparing this masterplan should be assigned to EirGrid and ESB Networks. The first essential task would be to take the existing scenario analysis in EirGrid's Tomorrow's Energy Scenarios 2023 report forward and set an appropriate and conservatively high level of the electricity requirement and maximum demand in 2050 to meet the needs of new housing, industry and the electrification of energy services for a growing population.

19. Having prepared the masterplan, ESB Networks and EirGrid should be given the authority to deliver it along with the accountability. The central lesson from the electricity generation shortfall crisis of 2022 is that when responsibility is spread across a number of bodies, no one is accountable.

20. The masterplan should be embedded at all levels of the national planning hierarchy to give greater certainty to essential electricity infrastructure projects at the consenting stage.

21. EirGrid / ESB Networks should plan projects from the masterplan and secure long-duration consents in advance of need. To the extent that demand might lag supply, projects can be deferred.

22. The masterplan would provide a framework within which the existing CRU-overseen planning by EirGrid would continue and its purpose would be to ensure that projects with lead times greater than CRU time horizons of five years and ten years would progress early to avoid future delays.

23. The electricity infrastructure masterplan should be subject to Strategic Environmental Assessment to ensure that major environmental impacts – notably the visual impact of high voltage overhead transmission lines – are recognised long in advance of individual projects being brought forward from the masterplan to the consenting stage.

24. Just as there is a need to plan for the procurement of increasingly long lead time gas turbines, so also the masterplan would support the procurement of long lead time high voltage transformers.

25. The four State-owned energy companies - ESB, EirGrid, GNI and NORA - face inter-related and overlapping challenges to deliver the energy infrastructure required for the energy transition. Their roles and responsibilities should be reviewed and, if warranted, restructured to ensure the energy transition is delivered efficiently and effectively.
26. Since 2014, Ireland's energy security has deteriorated because of the cessation of peat and coal fired generation and following the decommissioning of the Kinsale gas storage facility. Nothing has been done to replace the security of supply these three resources gave for the generation of up to 8 TWh of electricity.
27. Ireland's lack of any gas storage capacity contracts starkly with that of other countries - Britain with 21 days storage, Denmark with 181 days and the Netherlands with 199 days – from a combination of LNG tanks and geological stores.
28. The National Risk Assessment 2024 correctly highlighted the need for increased diversity in sources of natural gas and for a strategic store should supply be curtailed for any reason.
29. Government's proposed FSRU solution to mitigate these risks is too small both in terms of storage capacity and in terms of gas send out rate. These need to be set by reference to future requirements in 2050 when the ***power*** to be delivered by gas will be higher than it is today even though the ***energy*** - and, therefore, the GHG emissions - will be lower.
30. Energy policy needs to revisit the specifications of the LNG capacity the country requires over the next 25 years and beyond.
31. While it is uncertain that SMRs could provide an option to support the energy transition, the lead time for commencing a nuclear energy programme is so long that Ireland should lay the foundations for a possible future nuclear programme by following the IAEA's milestone approach for countries which do not have nuclear power to introduce one. This would be low cost and would provide a basis for the future consideration of nuclear power if SMR technology proves itself.
32. The energy transition will shape how the country's energy needs will be met for many decades after 2050 and it is important that the current generation does not close off options which future generations might need and be prepared to depend on.
33. This report does **not** suggest that efforts to reduce GHG emissions should be abandoned. Rather, it suggests that a more appropriate balance be struck between the three legs of the energy trilemma: sustainability, prices and energy security.
34. The rebalancing of Ireland's energy policy would represent a fundamental, but essential, change to the current failing policy approach and, importantly, would have no negative effect on Ireland's climate because declining national emissions are so low (58 Mt CO_2eq in 2024) compared to increasing global emissions (53,817 Mt CO_2eq in 2023).
35. The energy transition requires policy informed by engineering realities. Current policy is set by an impossible legal objective and is characterised by consistent failures to meet carbon budgets, unrealistic targets for renewables and hopelessly ambitious obligations set for Ireland in the EU's Effort Sharing Regulation and in the Renewable Energy Directive. Such consistent failure undermines public confidence in policy and threatens the energy transition.
36. The starting point to rebalancing national energy policy is to remove the impossible obligation in law to achieve climate neutrality by 2050 and, having done that, to ensure that all State companies and agencies are free to work to achieve a balance between sustainability, price and energy security which maximises economic welfare.

SECTION C APPENDICES

1. GLOBAL AND IRISH PRIMARY ENERGY TRENDS FROM 2000 TO 2024

TWh	Global				Ireland			
	2000		2024		2000		2024	
Oil	43,017	38.2%	55,292	33.0%	95.0	56.4%	80.1	48.9%
Natural Gas	23,994	21.3%	41,278	24.6%	40.0	23.8%	48.3	29.5%
Coal	27,456	24.4%	45,851	27.4%	30.4	18.1%	5.1	3.1%
Renewables	2,997	2.7%	11,235	6.7%	2.7	1.6%	23.0	14.0%
Nuclear	2,581	2.3%	2,817	1.7%	-	0.0%	-	0.0%
Other	12,500	11.1%	11,111	6.6%	0.1	0.1%	5.3	3.2%
Total	**112,545**	**100.0%**	**167,584**	**100.0%**	**168.3**	**100.0%**	**163.8**	**100.0%**
Fossil fuels	***94,467***	***83.9%***	***142,421***	***85.0%***	***165.5***	***98.3%***	***133.5***	***81.5%***

Source: Our World in Data and SEAI

2. THE MAKE-UP OF PRIMARY ENERGY IN EU MEMBER STATES AND IN NORWAY, 2023

TWh	Solid fossil fuels	Peat	Oil	Shale Oil	Natural gas	Renewables and biofuels	Non-renewable waste	Nuclear heat	Electricity	Heat	Total
Austria	27.9	-	132.3	-	68.5	131.1	7.8	-	- 0.1	0.0	367.7
Belgium	27.3	-	314.7	-	142.4	63.9	7.3	92.2	1.6	2.7	652.1
Bulgaria	43.2	-	56.4	0.0	25.3	29.3	0.6	49.1	- 3.3	0.8	201.2
Croatia	4.0	-	42.2	-	26.6	28.2	0.6	-	1.6	-	103.1
Cyprus	0.3	-	28.6	-	-	3.7	0.5	-	-	-	33.1
Czechia	124.7	-	111.8	-	66.9	60.9	3.7	88.1	- 9.2	0.1	447.0
Denmark	8.2	-	78.5	-	15.5	83.0	4.8	-	3.1	0.0	193.1
Estonia	- 0.0	0.1	1.6	27.4	3.1	16.3	0.4	-	3.3	-	52.2
Finland	20.0	7.1	93.6	-	15.0	154.8	3.7	93.3	1.7	1.5	390.7
France	69.8	-	824.5	-	340.6	390.1	19.5	1,025.0	- 50.5	-	2,619.0
Germany	492.9	-	1,102.6	-	745.0	572.4	47.6	21.6	9.2	-	2,991.3
Greece	13.7	-	156.2	-	46.2	46.4	0.1	-	4.9	-	267.5
Hungary	10.4	-	91.2	-	82.1	38.7	2.3	46.7	11.1	-	282.6
Ireland	5.1	2.9	84.2	-	48.1	23.2	2.0	-	3.3	-	168.8
Italy	56.0	-	633.8	-	585.3	339.7	13.7	-	51.3	-	1,679.8
Latvia	0.1	0.0	18.9	-	8.0	23.0	0.6	-	0.8	-	51.4
Lithuania	1.2	0.2	37.7	-	14.5	22.9	0.8	-	6.9	0.9	85.1
Luxembourg	0.3	-	26.2	-	5.7	5.1	0.4	-	5.2	-	42.9
Malta	-	-	31.8	-	3.9	0.8	-	-	0.6	-	37.2
Netherlands	44.0	-	453.5	-	260.4	109.2	9.6	10.8	- 5.7	2.2	884.1

TWh	Solid fossil fuels	Peat	Oil	Shale Oil	Natural gas	Renewables and biofuels	Non-renewable waste	Nuclear heat	Electricity	Heat	Total
Poland	395.9	-	387.3	-	183.3	163.6	11.3	-	3.7	0.2	1,145.4
Portugal	0.1	-	124.4	-	44.4	82.7	1.9	-	10.2	-	263.7
Romania	30.1	0.2	129.4	-	91.2	73.1	3.8	33.3	- 3.0	-	358.1
Slovakia	27.9	-	43.3	-	42.0	23.9	2.4	55.0	- 3.4	-	191.2
Slovenia	8.4	-	25.6	-	7.7	14.5	0.7	15.3	- 1.5	-	70.7
Spain	32.2	-	698.9	-	294.7	261.1	5.8	171.9	- 14.0	-	1,450.6
Sweden	16.9	0.3	129.4	-	8.8	274.1	10.4	134.6	- 28.5	-	546.1
EU 27	**1,461**	**11**	**5,859**	**27**	**3,175**	**3,036**	**162**	**1,837**	**-**	**8**	**15,576**
Norway	739	-	8,605	-	4,609	15,963	252	-	-1,525	199	28,842

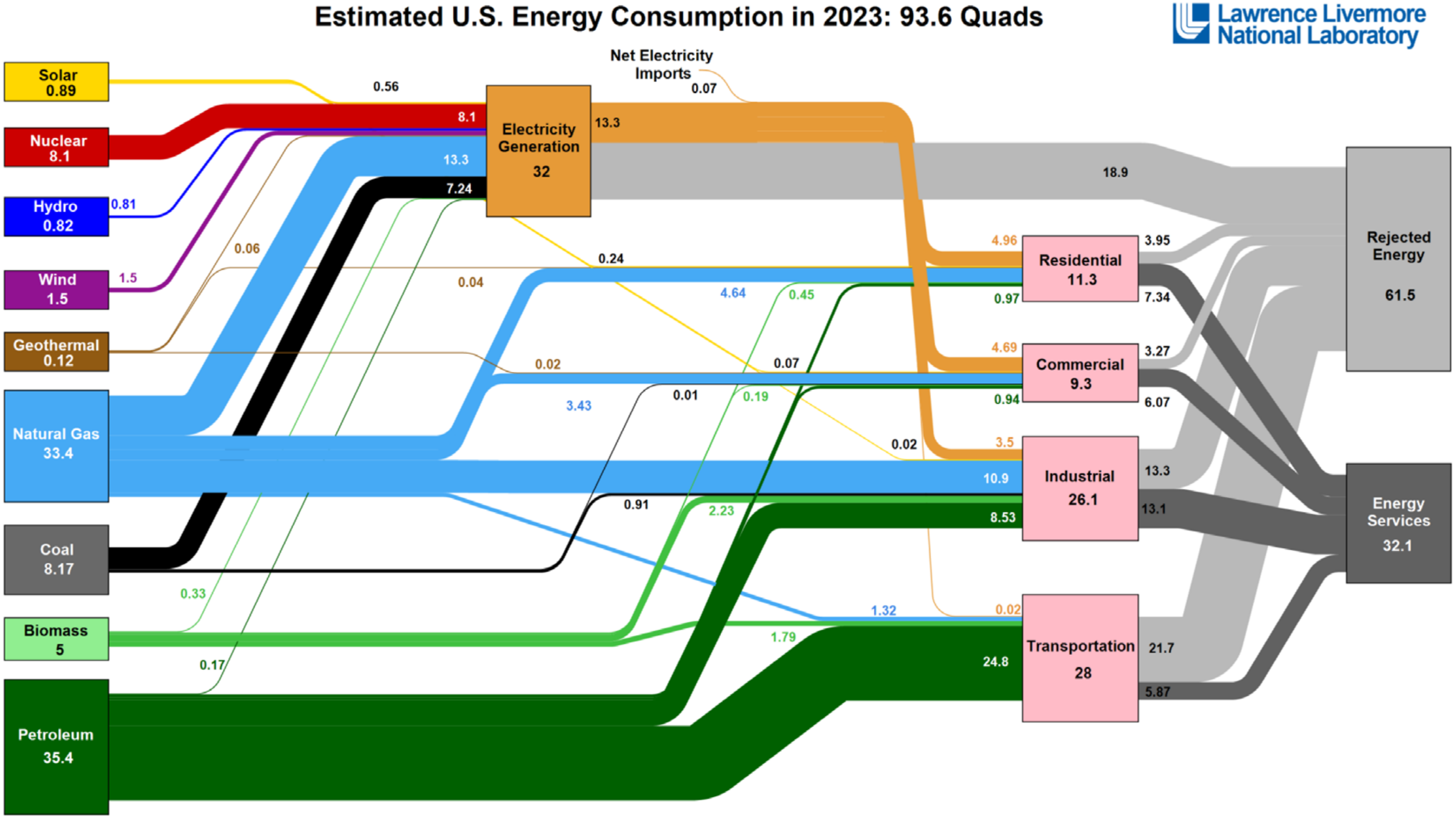
Source: *Eurostat*

3. GHG EMISSIONS FROM ELECTRICITY GENERATION IN THE EU AND UK AND FUEL MIX, 2024

	g CO_2 eq per kWh	Nuclear / hydro %	Wind / solar %	% EU emissions	Mt CO_2 eq	TWh
Austria	103	57%	23%	1.4%	8.1	78.5
Belgium	118	42%	31%	1.5%	8.8	74.9
Bulgaria	264	50%	18%	1.7%	9.8	37.1
Croatia	174	44%	22%	0.5%	2.7	15.4
Cyprus	512	0%	23%	0.5%	2.9	5.7
Czechia	414	44%	6%	5.2%	30.2	73.0
Denmark	143	0%	69%	0.9%	5.1	35.5
Estonia	341	0%	35%	0.4%	2.1	6.1
Finland	72	56%	26%	1.0%	6.0	83.6
France	44	80%	12%	4.2%	24.6	557.7
Germany	342	5%	43%	28.0%	164.1	479.7
Greece	320	5%	43%	3.1%	18.3	57.2
Hungary	183	43%	26%	1.2%	7.0	38.2
Ireland	280	2%	40%	1.5%	8.6	30.9
Italy	288	19%	22%	13.0%	76.1	264.4
Latvia	136	50%	12%	0.2%	0.9	6.5
Lithuania	139	6%	65%	0.2%	1.0	7.3
Luxembourg	135	9%	51%	0.0%	0.2	1.6
Malta	484	0%	16%	0.2%	1.1	2.2
Netherlands	253	3%	45%	5.3%	31.1	123.0
Poland	615	1%	24%	17.9%	104.7	170.2
Portugal	112	30%	46%	0.9%	5.2	46.7
Romania	246	47%	20%	2.2%	13.0	52.9
Slovakia	96	78%	2%	0.5%	2.8	29.3
Slovenia	227	65%	9%	0.7%	3.9	17.0
Spain	146	31%	43%	7.0%	41.0	280.4
Sweden	36	67%	26%	1.1%	6.2	173.3
Total EU in 2024	**213**	**37%**	**29%**	**100.0%**	**585.5**	**2,748.3**
UK	216	16%	35%		61.5	285.2

Source: Ember

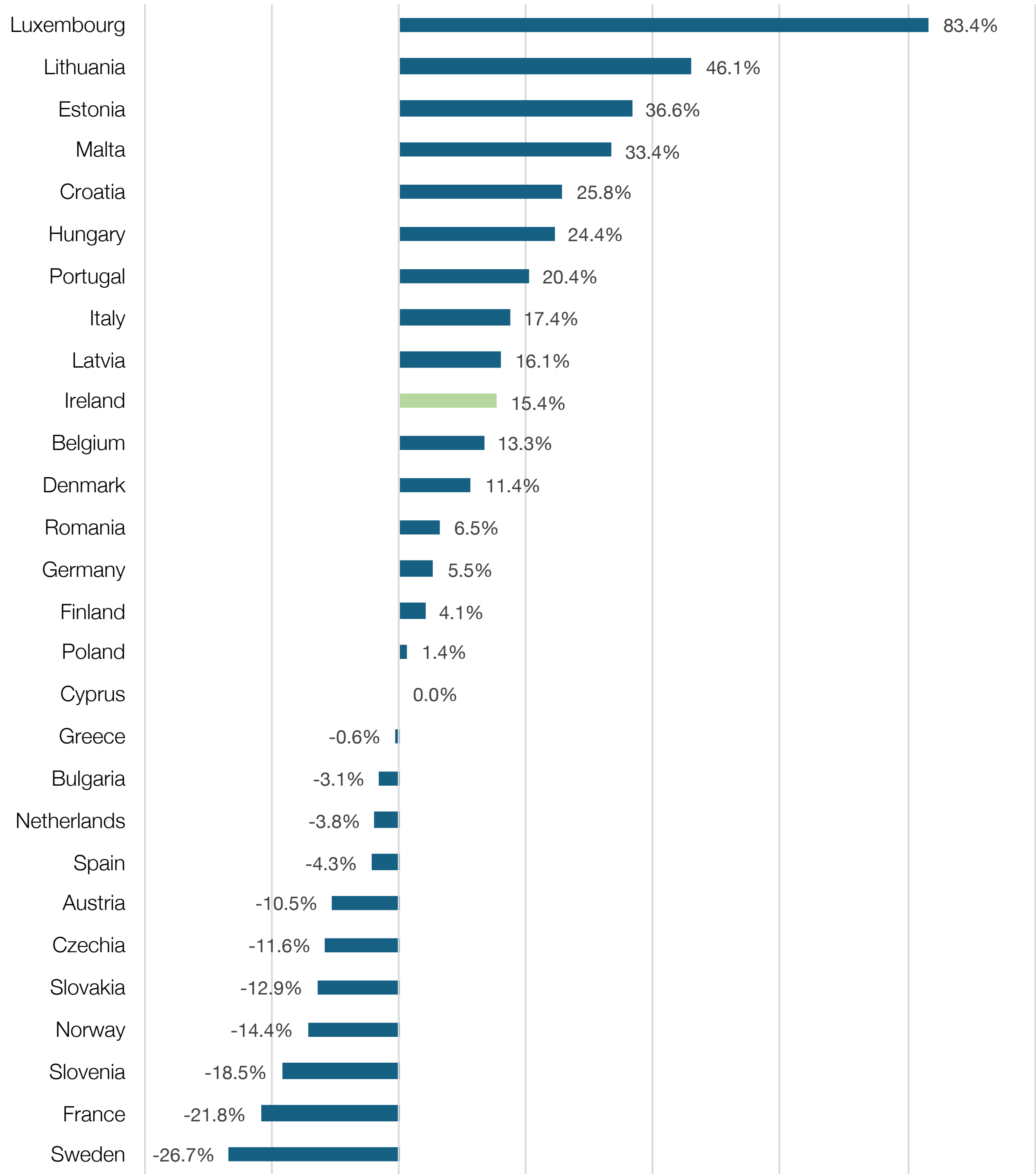
4. ENERGY FLOWS IN THE US 2023 [76]



Source: LLNL October, 2024. Data is based on DOE/EIA SEDS (2024). If this information or a reproduction of it is used, credit must be given to the Lawrence Livermore National Laboratory and the Department of Energy, under whose auspices the work was performed. Distributed electricity represents only retail electricity sales and does not include self-generation. EIA reports consumption of renewable resources (i.e., hydro, wind, geothermal and solar) for electricity in BTU-equivalent values by assuming a typical fossil fuel plant heat rate. The efficiency of electricity production is calculated as the total retail electricity delivered divided by the primary energy input into electricity generation. End use efficiency is estimated as 65% for the residential sector, 65% for the commercial sector, 49% for the industrial sector, and, 21% for the transportation sector. Totals may not equal sum of components due to independent rounding. LLNL-MI-410527

76 Source: Lawrence Livermore Energy Laboratory. Energy units are Quads where 1 Quad = 293 TWh

5. ELECTRICITY IMPORTS AS % OF DEMAND IN EU MEMBER STATES AND NORWAY, 2024



Source: Eurostat. Imports: "+"; Exports: "-"

6. ELECTRICITY PRICES IN IRELAND, JANUARY TO JUNE 2024 (SEAI)

Band	Consumption	€ per kWh	% of consumption in band
DA	<1,000kWh	0.2980	6.5%
DB	1,000 kWh to 2,500 kWh	0.4380	10.9%
DC	2,500 kWh to 5,000 kWh	0.3740	34.4%
DD	5,000 kWh to 5,000 kWh	0.3320	40.9%
DE	>15,000 kWh	0.3050	7.2%
	Weighted Average	**0.3540**	

Electricity prices for households, January to June 2024, including taxes
Source: SEAI

Band	Consumption	€ per kWh	% of consumption in band
IA	< 20 MWh	0.3240	7.4%
IB	20 MWh to 500 MWh	0.3030	20.1%
IC	500 MWh to 2,000 MWh	0.2560	9.6%
ID	2,000 MWh to 20,000 MWh	0.2180	20.6%
IE	70,000 to 150,000 MWh	0.2070	7.3%
IF	20,000 to 70,000 MWh	0.1970	4.3%
IG	> 150,000MWh	0.1630	30.6%
	Weighted average	**0.2280**	

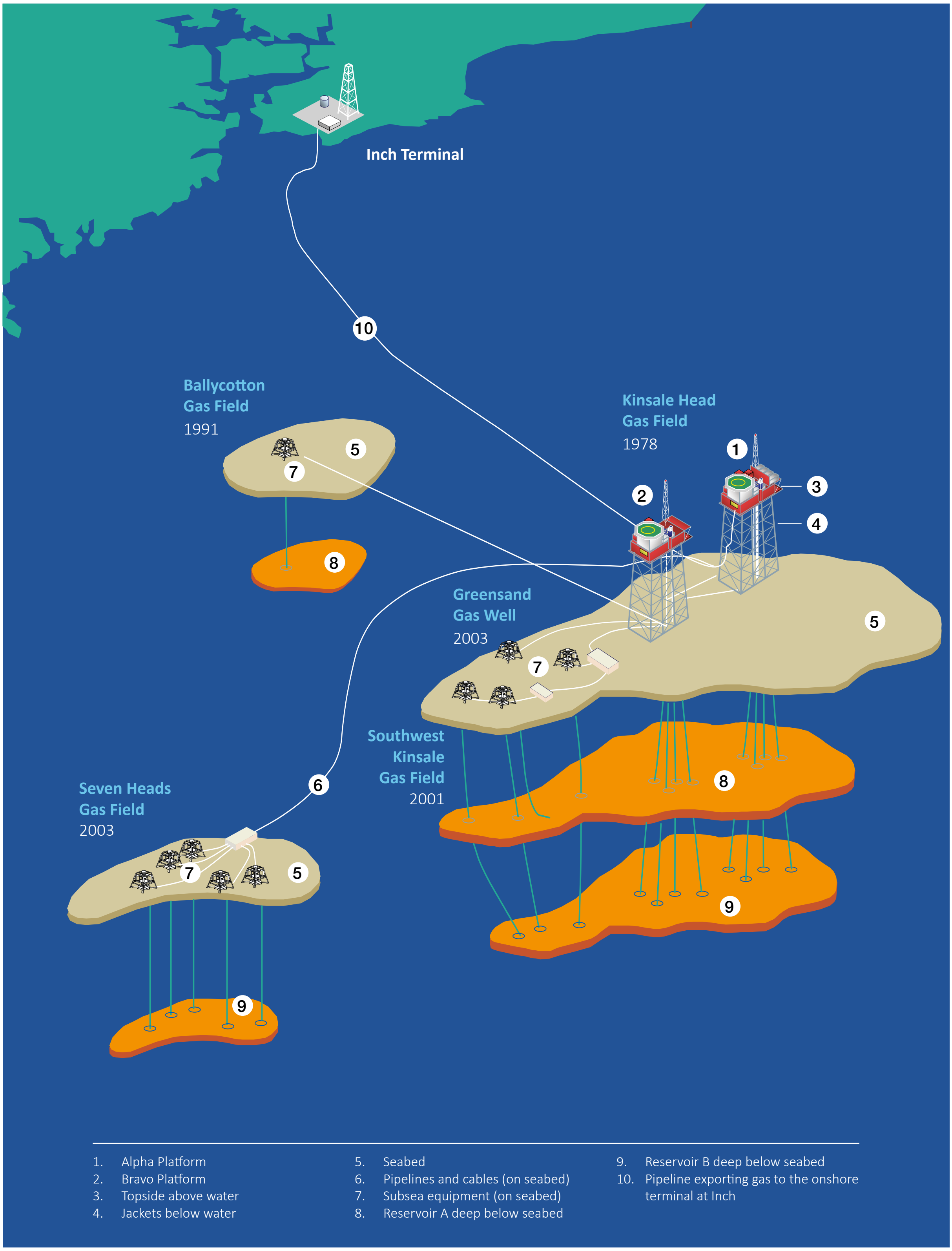
Electricity prices for business, January to June 2024, excluding VAT
Source: SEAI

7. ANALYSIS OF NATURAL GAS DEMAND AND STORAGE CAPACITIES IN THE EU COUNTRIES AND UK, 2024

	Demand 2023	Total storage capacity	# days storage
Latvia	8 TWh	25 TWh	1,113 days
Austria	76 TWh	102 TWh	491 days
Poland	177 TWh	151 TWh	312 days
Slovakia	46 TWh	37 TWh	296 days
Hungary	89 TWh	68 TWh	278 days
Czech Republic	73 TWh	45 TWh	227 days
Netherlands	283 TWh	154 TWh	199 days
Denmark	21 TWh	10 TWh	181 days
France	384 TWh	156 TWh	148 days
Romania	93 TWh	34 TWh	132 days
Italy	646 TWh	209 TWh	118 days
Germany	803 TWh	251 TWh	114 days
Spain	323 TWh	85 TWh	96 days
Croatia	26 TWh	7 TWh	94 days
Bulgaria	26 TWh	6 TWh	83 days
Portugal	47 TWh	9 TWh	71 days
Lithuania	15 TWh	2 TWh	60 days
Belgium	143 TWh	17 TWh	43 days
Greece	53 TWh	5 TWh	37 days
UK	681 TWh	40 TWh	21 days
Sweden	6 TWh	0 TWh	6 days
Estonia	3 TWh	0 TWh	0 days
Finland	13 TWh	0 TWh	0 days
Ireland	53 TWh	0 TWh	0 days
Luxemburg	6 TWh	0 TWh	0 days
Slovenia	9 TWh	0 TWh	0 days
Average	**158 TWh**	**54 TWh**	**126 days**

Source: IAE analysis of ENTSOG *data*

8. LAYOUT OF THE KINSALE HEAD GAS FIELDS



Source: Kinsale Area Gas Fields Decommissioning Project *Information Leaflet*

9. IRELAND'S ELECTRICITY GENERATION FUEL MIX, 2024

	Transmission grid	Distribution system	Total	% capacity	GWh	% GWh	Capacity factor
Fossil fuel	5,907	74	5,980	41.3%	15,181	44.3%	29%
Interconnector	1,000		1,000	6.9%	5,061	14.8%	58%
Pumped storage	*292*		*292*	*2.0%*			
Battery storage	*680*	*75*	*754*	*5.2%*			
Storage	972	75	1,046	7.2%	n/a	n/a	n/a
Wind	*2,691*	*2,314*	*5,004*	*34.6%*	*11,367*	*33.2%*	*26%*
Solar	*782*	*146*	*928*	*6.4%*	*714*	*2.1%*	*9%*
Hydro	*212*	*23*	*235*	*1.6%*	*758*	*2.2%*	*37%*
Renewables	3,685	2,482	6,167	42.6%	12,839	37.5%	24%
Biomass	*122*		*122*	*0.8%*			
Biogas		*18*	*18*	*0.1%*			
Biogas + AD		*3*	*3*	*0.0%*			
Biomass		*8*	*8*	*0.1%*			
CHP		*3*	*3*	*0.0%*			
Other renewables	122	32	154	1.1%	895	2.6%	67%
LFG		*39*	*39*	*0.3%*			
Waste to Energy		*93*	*93*	*0.6%*			
Other	-	132	132	0.9%	302	0.9%	26%
Total	**11,685**	**2,794**	**14,479**	**100.0%**	**34,278**	**100.0%**	**27%**
Split	***81%***	***19%***	***100%***				

Source: EirGrid

10. PREVIOUS REPORTS OF THE ENERGY & CLIMATE ACTION COMMITTEE

1	The Energy Transition - Wishful thinking needs to be replaced by the realities of engineering, finance and project delivery	Apr-25	*link*
2	Small Modular Reactors - Ireland needs to consider small modular nuclear reactors to achieve a zero-carbon energy sector by 2050	Jun-24	*link*
3	A Commentary on the Medium Term Prospects for Ireland's Hydrogen Economy	Aug-23	*link*
4	Restoring confidence in Irish energy supply	Nov-22	*link*
5	Response to Energy Security Report	Oct-22	*link*
6	Europe's Energy Crisis – Implications for Ireland	May-22	*link*
7	National Energy and Climate Plan - The Challenge of High Levels of Renewable Generation in Ireland's Electricity System	Mar-21	*link*
8	Sustainable Electricity in 2030	Sep-21	*link*
9	The Future of Electricity Transmission in Ireland	Oct-20	*link*
10	Data Centres in Ireland	Jul-19	*link*
11	Natural Gas - Essential for Ireland's Future Energy Security	Jul-18	*link*

11. GLOSSARY

Term / abbreviation	Description
AA	Appropriate Assessment
Capacity factor	A 10 MW generator running for 8,760 hours in a year would generate 87,600 MWh and would have a capacity factor of 100%. In practice generators run fewer hours in the year and not always at their maximum capacity. Their capacity factor is, therefore, less than 100%. In 2022, EirGrid reported that Ireland's installed wind capacity of 4,527 MW generated 10,895 GWh giving a capacity factor of 28%.
Capex	Capital expenditure
CCAC	Climate Change Advisory Council
CCUS	Carbon Capture Utilisation and Storage
CfD	Contract for difference. Investors in large energy projects require reasonable revenue certainty in order to be able to raise finance. This has been achieved in Ireland, and in other countries, by guaranteeing the unit energy price projects will earn over a defined period (typically 20 or 25 years). CfDs provide this certainty by ensuring that if the price received from wholesale markets is lower than an agreed strike price, then the difference will be made up by a supplementary payment. However, at times, wholesale markets will yield prices higher than the agreed strike price and, in these circumstances, projects are required to refund the difference. The net cost of supplementary payments and refunds is borne by customers.
CO_2eq	CO_2eq is a common measure used for the climate warming potential of different GHGs. It allows the contributions of different gases to global warming - including carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O) – to be added together to give a single overall measure of their combined impacts. The CO_2eq of a gas is calculated by multiplying its Global Warming Potential (GWP) by the mass of the gas (in kg or tonnes). The GWP of a gas is a measure of its cumulative warming impact over a specified time period usually 100 years, By definition, carbon dioxide (CO_2) has a GWP of 1.
CRU	Commission for Regulation of Utilities
DAC	Direct Air Capture
Despatch down	Despatch down is an instruction from the TSO (EirGrid) to renewables operators to produce less electricity or to shut down entirely. This can happen due to limitations in the power capacity of the local grid (constraint) or to the need for the TSO to limit the amount of renewables on the system in order to maintain system stability (curtailment).
DMAP	Designated Maritime Area Plan
DSO	Distribution System Operator (ESB Networks)
EIA	Environmental Impact Assessment
ENTSO-E	European Network of Transmission System Operators for Electricity

Term / abbreviation	Description
ENTSOG	European Network of Transmission System Operators for Gas
EPA	Environmental Protection Agency
ETS	Emissions Trading Scheme
EV	Electric Vehicle
EWIC	East West Interconnector. A 500 MW and 260 km (186 km undersea) interconnector owned by EirGrid running between Ireland and Wales.
FEC	Final Energy Consumption is the energy required to provide services such as transport, heating, lighting and for industrial process (including cement manufacture, factories and data centres). FEC in 2023 was 140.8 TWh or 12,104 ktoe.
FID	Final Investment Decision
FSRU	Floating Storage and Regasification Unit
GHG	Greenhouse gases, including carbon dioxide (CO_2), methane (CH_4) and nitrous oxide (N_2O).
GW	Gigawatt. 1 GW = 1,000 MW.
IAE	Irish Academy of Engineering
IAEA	International Atomic Energy Agency
IFAC	Irish Fiscal Advisory Council
LCOE	The Levelised Cost of Energy is a measure of the average cost of producing energy over the lifetime of a generation asset, discounted to current prices. Its calculation incorporates a range of costs including capital investment cost, fuel cost, fixed and variable operating and maintenance costs, finance costs, and an assumed capacity factor. It provides a basis to compare the cost of generation by different technologies. For example, nuclear has a very much higher LCOE than, for example, solar. LCOE, however, has its limitations. Most electricity customers do not buy power from generators. Reliable power, available 24/7/365 is purchased from a power system. The price of electricity from the power system will be determined by the mix and usage of generation plant on the system. Use of simple LCOE comparisons can be misleading when considering the future price of electricity.
LDES	Long Duration Energy Storage
LEU	Large Energy User
LNG	Liquified Natural Gas
LOLE	Loss of Load Expectation
LULUCF	Land Use Land Use Change and Forestry
MAC	Maritime Area Consent
MARA	Maritime Area Regulatory Authority
MPA	Marine Protected Area

Term / abbreviation	Description
MW	Megawatt is a measure of the power output of a generator (or the power demand of a load, such as a factory, a town or a data centre). In power systems, the total power capacity is typically in the thousands of MW and GW is often used instead. 1 GW = 1,000 MW. Steam powered generators (including nuclear, coal and oil fired units) generate electricity at an efficiency in the order of 35% to 40%, i.e. 60% to 65% of the energy in the fuel is transformed into heat and is mostly wasted. Sometimes the output of a nuclear plant is stated in MWe to clarify that it is the electrical output that is being referred to. In this report, wherever MW (or GW) is used, it refers to electrical output.
Natura 2000	A network of SCA and SPA sites across EU member states
NEB	Nuclear Energy Board
NESC	National Economic and Social Council
NORA	National Oil Reserves Agency
NPWS	National Parks and Wildlife Service
OPEX	Operating expenditure
ORESS	ORESS is an abbreviation for the Government's Offshore Renewable Electricity Support Scheme. ORESS1 refers to the first auction run under this scheme. The final results of this auction were announced by EirGrid in June 2023.
PER	Primary Energy Requirement is the combination of the energy content of the fuels (oil, gas and coal) imported into or sourced in the country (gas, peat, waste) and of the energy generated by renewables or imported via interconnectors. Some fuels (notably gas and coal) are, for the most part, used to generate electricity and much of their energy content is lost in this transformation. PER in Ireland in 2023 was 163.8 TWh or 14,083 ktoe.
PSO	Public Service Obligation. A scheme operated by CRU to facilitate the collection of payments or the making of payments to electricity consumers arising from support schemes for in State contracts for renewables projects. The PSO has also been used as a means for exchequer support payments to be made to consumers.
RESS	RESS is an abbreviation for the Government's Renewable Electricity Support Scheme. The fifth RESS auction (RESS5) is due to take place in 2025.
SAC	Special Area of Conservation
SEM	Single Electricity Market (Ireland and Northern Ireland)
SEMO	Single Electricity Market Operator. SEMO is a contractual joint venture between EirGrid plc and SONI Limited as the licensed Market Operator for Ireland, and licensed SEM Operator for Northern Ireland, respectively. SEMO is licensed and regulated cooperatively by the Commission for Regulation of Utilities (CRU) in Ireland and the Utility Regulator for Northern Ireland (UREGNI, previously named NIAUR).
SMR	Small modular nuclear reactor

Term / abbreviation	Description
SPA	Special Protection Area
SPV	Special Purpose Vehicle
TAO	Transmission Asset Owner (ESB Networks)
TES 2023	Tomorrow's Energy Scenarios 2023. A report published by EirGrid.
TSO	Transmission System operator (EirGrid)
TWh	Terawatt-hour is a unit of energy. 1 TWh = 1,000,000 MWh (megawatt-hours) and 1 MWh = 1,000 kWh (kilowatt-hours). Also, 1 TWh = 86 ktoe.
UNFCC	United Nations Framework Convention on Climate Change

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ENGINEERING & TECHNOLOGY

THOUGHT LEADERSHIP IN A TIME OF GREAT CHANGE

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Published by: The Irish Academy of Engineering

ISBN: 978-1-7395317-7-5