THE IRISH ACADEMY OF
ENGINEERING
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THOUGHT LEADERSHIP IN A TIME OF GREAT CHANGE

THE ENERGY TRANSITION

What is the 2050 Action Plan and Timeline?

Wishful thinking needs to be replaced by the realities of engineering, finance and project delivery

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THE IRISH ACADEMY OF ENGINEERING

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EXECUTIVE SUMMARY

Against the background of the legal obligation for Ireland to be climate neutral by 2050, national energy policy needs to decisively address the challenges of energy security and the intermittency of renewables.

Whereas the annual National Risk Assessment has, since 2014, correctly identified the country's vulnerability to energy supply disruptions - notably natural gas - Government policy has, to date, actively prevented this risk being mitigated.

The exposure to a natural gas supply risk is particularly egregious because of the inescapable reliance the country will have on natural gas as the energy source of last resort until at least 2050 and, likely, beyond. The fundamental challenge arising from the intermittency of renewables has not been adequately addressed to date and energy policy needs to recognise that there is no currently available or prospective alternative to natural gas to meet this essential need.

If there is to be a wholesale transition away from fossil fuels for transport and heating, Ireland's electricity system will – in a short period of just 25 years – have to expand to cater for an electricity requirement of 80 TWh in 2050 (compared to 33 TWh in 2024) at a power demand level of up to 12,000 MW (compared to 6,000 MW today).

This will require the completion of over 350 large energy infrastructure projects all of which will require environmental impact assessment and planning consent. These projects will include many hundreds of kilometres of overhead transmission lines and over 200 large onshore wind and solar projects. Such projects will, inevitably, face considerable local opposition and, if they are to proceed, unequivocal policy clarity and support is essential to ensure that planning authorities have no policy grounds on which to refuse planning permissions.

Government has set a target to achieve a climate neutral electricity system by 2050 - and accepted the imposition of enormous financial penalties by the EU if this objective is not achieved - without first understanding and demonstrating how it is feasible.

Moreover, this has been done without estimating how much the endeavour will cost and what impact it will have on the already high price consumers pay for electricity in Ireland.

Ireland needs an energy policy which goes beyond wishful thinking to recognise engineering, financial and project delivery realities, even if the consequences of this could mean having to revise the legal and policy objective of climate neutrality by 2050.

1. INTRODUCTION

The *EU Climate Law of 2021* established the framework for achieving climate neutrality in Member States and, in Ireland, the *Climate Action and Low Carbon Development (Amendment) Act 2021* set the objective for Ireland to become climate neutral by 2050.

Climate neutrality requires that the energy sector is decarbonised and this, in turn, is largely dependent on decarbonising the electricity sector

Whether this can be done by 2050 depends on three things:

- Availability of technologies to allow the objective of decarbonising the electricity sector to be achieved
- Implementation of a programme of large energy infrastructure projects on the supply side[1]
- Electrification of energy services on the demand side (by individuals, households, and industry)

This report focuses on the supply side challenges of technology and project delivery and, beyond this, considers the other two legs of the energy trilemma beyond sustainability, namely energy security and cost. [2]

1 The challenges to deliver large energy infrastructure projects is multi-faceted and include, not only, technology but also consenting and finance. Generation projects and interconnector projects need to be de-risked if they are to be financed. This requires the transfer of risk to consumers by way of two-way contracts for difference for large renewables projects, cap and floor schemes for interconnectors and guaranteed capacity payments for conventional back-up generation plant.

2 The *World Energy Council* explains the Energy Trilemma well and provides comparative analysis of how countries balance the competing requirements of energy sustainability, security of supply and the cost of energy.

2. BACKGROUND

Ireland's approach to climate policy is top down, starting with the national objective in the *Climate Action and Low Carbon Development (Amendment) Act 2021:*

> *The State shall, so as to reduce the extent of further global warming, pursue and achieve, by no later than the end of the year 2050, the transition to a climate resilient, biodiversity rich, environmentally sustainable and climate neutral economy.*

From this objective, five-year carbon budgets came into effect in April 2022:

Budget 1: 2021-2025: 295 $MtCO_{2eq}$ - an average reduction in emissions of 4.8% per annum for the first budget

Budget 2: 2026-2030: 200 $MtCO_{2eq}$ - an average reduction in emissions of 8.3% per annum for the second budget

Budget 3: 2031-2035: 151 $MtCO_{2eq}$ (provisional) - an average reduction in emissions of 3.5% per annum for the third budget

The achievement of these budgets is predicated on a set of sectoral emissions ceilings. Government approved the sectoral emissions ceilings for the first two carbon budget periods in July 2022. The sectoral emissions ceiling for the electricity sector for 2021-2025 is 40 $MtCO_{2eq}$ and 20 $Mt\,CO_{2eq}$ for 2026–2030.

In its Annual Review 2024, the Climate Change Advisory Council noted that:

> *Generation from renewable sources increased slightly [in 2023], primarily driven by solar power, but it remains significantly below the annual increase needed to meet growing demand and simultaneously satisfy 2030 targets for emission reductions. Delays and appeals in the planning process for onshore wind projects in particular are significantly hindering progress.*[3]

In addition to it being all but certain that Ireland will miss its 2030 targets, it is equally likely that the ultimate target for the electricity sector of achieving climate neutrality by 2050 will not be met.

3 Climate Change Advisory Council (2024), *Electricity Sectoral Review: Annual Review 2024*

2.1 Electrification of energy services

The challenge of eliminating emissions in the electricity sector is compounded by the additional challenge of exponential growth in electricity demand due to the electrification of energy services which are, today, dependent on fossil fuels, notably oil and natural gas.

GHG emissions are a function of the size and make-up of the country's Primary Energy Requirement (PER). In 2023, this was 163.8 TWh (*Table 1*) with 80.1 TWh (49%) accounted for by oil and 48.3 TWh (29%) by natural gas.

TWh	Coal	Oil	Natural Gas	Renewables[4]	Non-Renewable Waste	Electricity[5]	Total
Primary Energy	5.1	80.1	48.3	23.0	2.0	3.3	163.8
	3%	*49%*	*29%*	*14%*	*1%*	*2%*	*100%*

Table 1: Primary Energy Requirement, 2023 *Source: SEAI*

After transformation losses - primarily from electricity generation, transmission and distribution - the total Final Energy Consumption (FEC) available to supply energy services in 2023 was 140.8 TWh (*Table 2*).

TWh	Coal	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	1.1	12.1	5.4	1.3		8.1	29.6
Commercial Services	0.0	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	**1.7**	**78.3**	**19.3**	**7.4**	**0.9**	**31.6**	**140.8**
	1%	***56%***	***14%***	***5%***	***1%***	***22%***	***100%***

Table 2: Final Energy Consumption by sector, 2023 *Source: SEAI*

The primary means of reducing oil (78.3 TWh) and natural gas (19.3 TWh) in Final Energy Consumption is the electrification of transport and heating. While this will lead to a large increase in the electricity requirement, it will - for the same level of energy services - result in a decline both in PER and in FEC. For example,

- 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.

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

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

- 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.

Looking ahead to 2050, the electrification of energy services will cause electricity to become the dominant energy vector in Ireland's energy sector.

2.2 Emissions from the electricity sector

Over the last 33 years, specific emissions from Ireland's electricity sector have reduced by 72% from 896 gCO_2 per kWh in 1990 to 255 gCO_2 per kWh in 2023 (Figure 1).

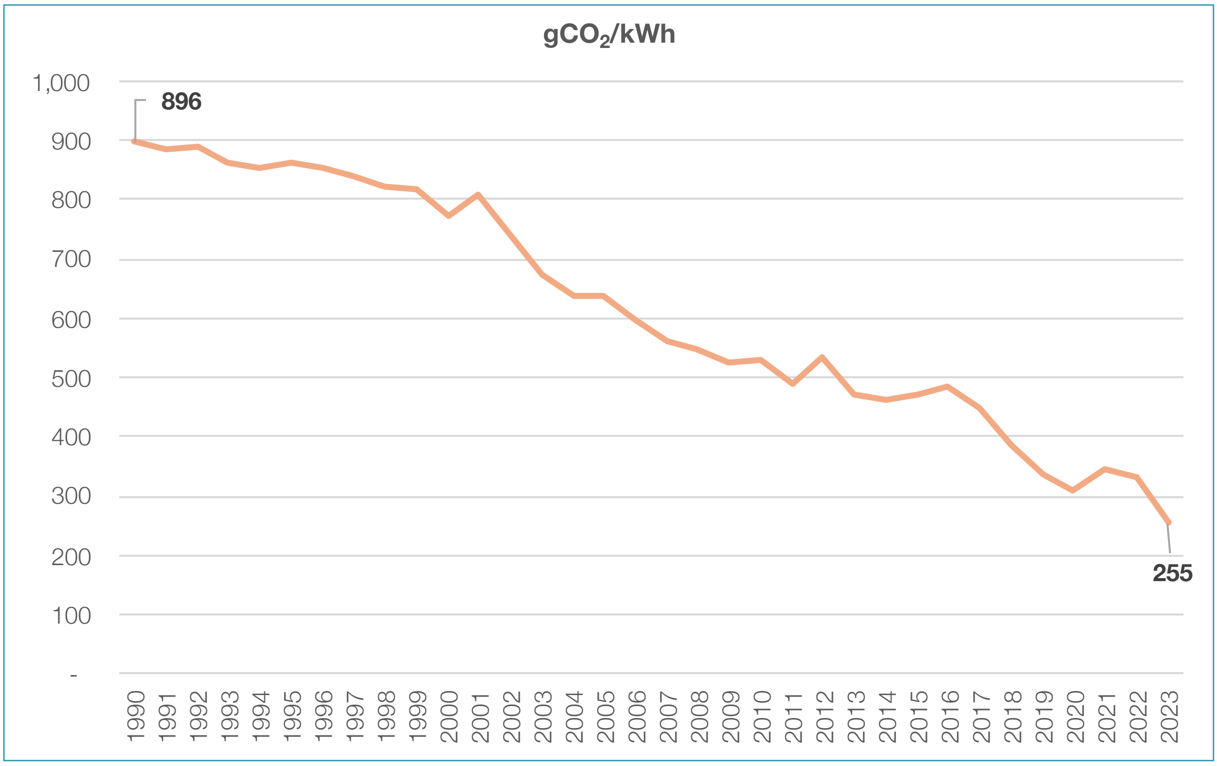

Figure 1: Trends in power generation CO_2 emissions, 1990 to 2023 *Source: EirGrid*

This has been achieved by a combination of three drivers *(Table 3):*

- The replacement of higher emission fossil fuels (coal, peat and oil) by natural gas.
- A large increase in renewables.
- An increase in electricity imports - 10% in 2023 and 15% in 2024 (*Table 16*) - the emissions from which are attributed not to Ireland, where the electricity is consumed, but to Britain, where the electricity is generated.[6]

	1990	2023	Change	% change	% in 2023
Coal	5,918 GWh	1,211 GWh	- 4,707 GWh	-80%	3.5%
Peat	2,245 GWh	152 GWh	- 2,093 GWh	-93%	0.4%
Oil	1,411 GWh	228 GWh	- 1,183 GWh	-84%	0.7%
Natural Gas	3,941 GWh	15,357 GWh	11,416 GWh	290%	44.3%
Non-Renewable Waste	-	318 GWh	318 GWh	-	0.9%
Non-renewables	**13,515 GWh**	**17,266 GWh**	**3,751 GWh**	**28%**	**49.8%**
Hydro	697 GWh	942 GWh	245 GWh	35%	2.7%
Wind	-	11,665 GWh	11,665 GWh	-	33.7%
Solar PV	-	644 GWh	644 GWh	-	1.9%
Other Renewables	-	848 GWh	848 GWh	-	2.4%
Renewables	**697 GWh**	**14,099 GWh**	**13,402 GWh**	**1,923%**	**40.7%**
Net Imports	**-**	**3,275 GWh**	**3,275 GWh**	**-**	**9.5%**
Total	**14,212 GWh**	**34,639 GWh**	**20,427 GWh**	**144%**	**100.0%**

Table 3: Change in Ireland's Electricity Fuel Mix between 1990 and 2023 *Source: EirGrid*

2.3 Electricity requirement and peak demand in 2050

The scale of the challenge to eliminate emissions from the electricity sector by 2050 can only be understood by reference to the expected electricity requirement in 2050.

Unfortunately, there is no set view in policy as to what the electricity requirement will be in 2050.

However, EirGrid's Tomorrow's Energy Scenarios 2023 does include projections under four scenarios as shown in Figure 2. These scenarios are based on different assumptions regarding, for example, the development of a hydrogen economy and the growth of electricity exports.

6 The displacement of the carbon emissions associated with Ireland's electricity consumption to another jurisdiction reduces Ireland's exposure to fines for failing to meet EU emissions targets set for Ireland (as described in Section 4). However, it does nothing to reduce Ireland's contribution to global GHG emissions.

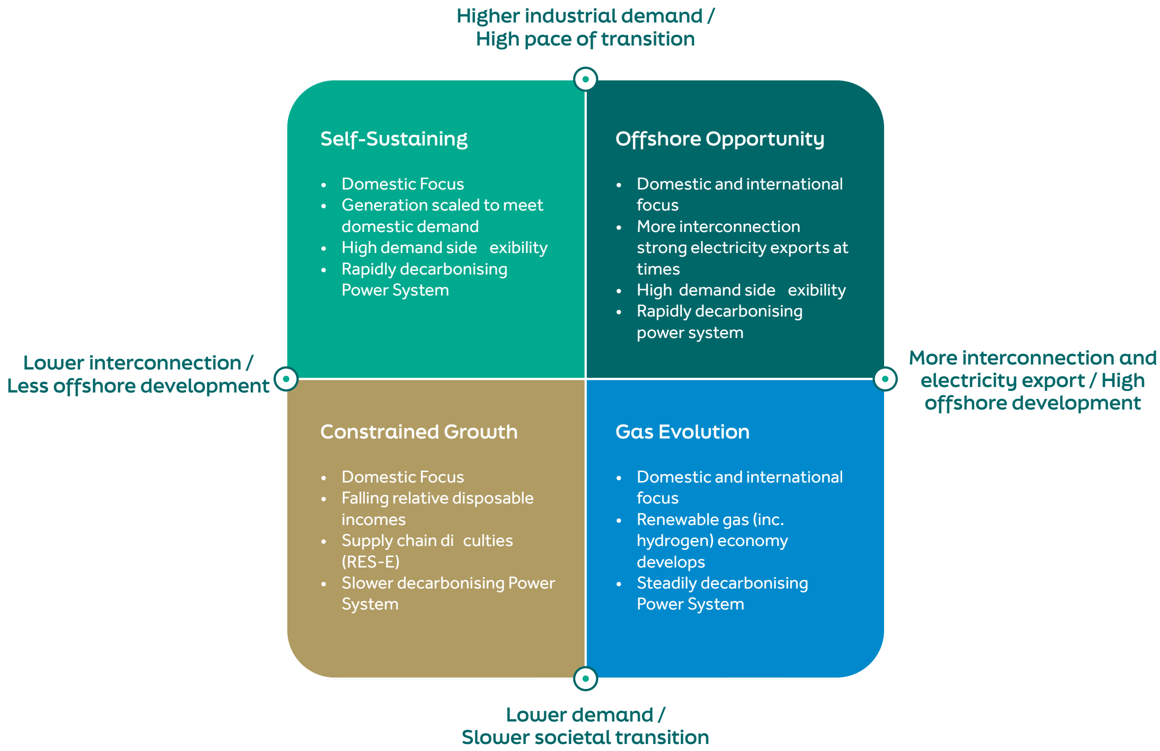

Figure 2: Scenarios modelled in Tomorrow's Energy Scenarios, 2023 *Source: EirGrid*

This report has used these four scenarios to arrive at an indicative target level for the electricity requirement in 2050 as the basis, firstly, to form a view as to whether the target of net-zero can be attained or not and, secondly, to show the huge scale of the programme of energy projects that would need to be completed by 2050.

The 2050 electricity requirement under EirGrid's four scenarios ranges from 71.5 TWh to 86.1 TWh as summarised in *Table 4*.

In addition to projecting the electricity requirement, EirGrid also projects the peak demand across a range from 11,900 MW to 12,900 MW.

	Electricity requirement	Peak demand
2023	**33.1 TWh**	**5,900 MW**
2050 - Self-Sustaining	84.2 TWh	12,400 MW
2050 - Offshore Opportunity	86.1 TWh	12,900 MW
2050 - Gas Evolution	71.5 TWh	11,900 MW
2050 - Constrained Growth	73.2 TWh	12,300 MW
2050 – average of scenarios	**78.8 TWh**	**12,400 MW**
% increase from 2023 to 2050	138%	110%
Average annual growth rate	**3.3%**	**2.9%**

Table 4: Summary of energy and peak power demand projections under four scenarios
Source: Tomorrow's Energy Scenarios 2023, EirGrid

There are many variables inherent in the assumptions behind the four scenarios and in order to present a coherent analysis of what is required to complete the energy transition to 2050, this report assumes levels of electricity requirement and peak demand in 2050 as shown in *Table 5*.

2050	Value
Electricity requirement	80 TWh
Peak demand	12,000 MW

Table 5: Assumed electricity requirement and peak demand in 2050

It has been a general feature of carbon budgets during their first five year cycle to 2025 that annual emissions targets have been exceeded. If the ultimate target of zero emissions by 2050 remains unchanged, then the challenge to reduce emissions increases year by year between now and then.

In the electricity sector, the deployment of large scale renewables, particularly offshore wind, has been delayed by the slow implementation of policy (**Appendix 1**). Elsewhere, the required expansion of the transmission grid - an essential prerequisite for the electricity requirement projected for 2050 - is not being achieved quickly enough.

In the late 1970s when nuclear power was considered in national energy policy, peak demand was in the order of 2,000 MW. Since then, it has grown at an average annual rate of 2.6% and has now reached 6,000 MW. Peak demand will continue to grow to 2050 at an indicative average annual growth rate of 2.9% to reach 12,000 MW (*Figure 3*).

Providing infrastructure in response to such high levels of exponential growth over such long periods is, inevitably challenging.

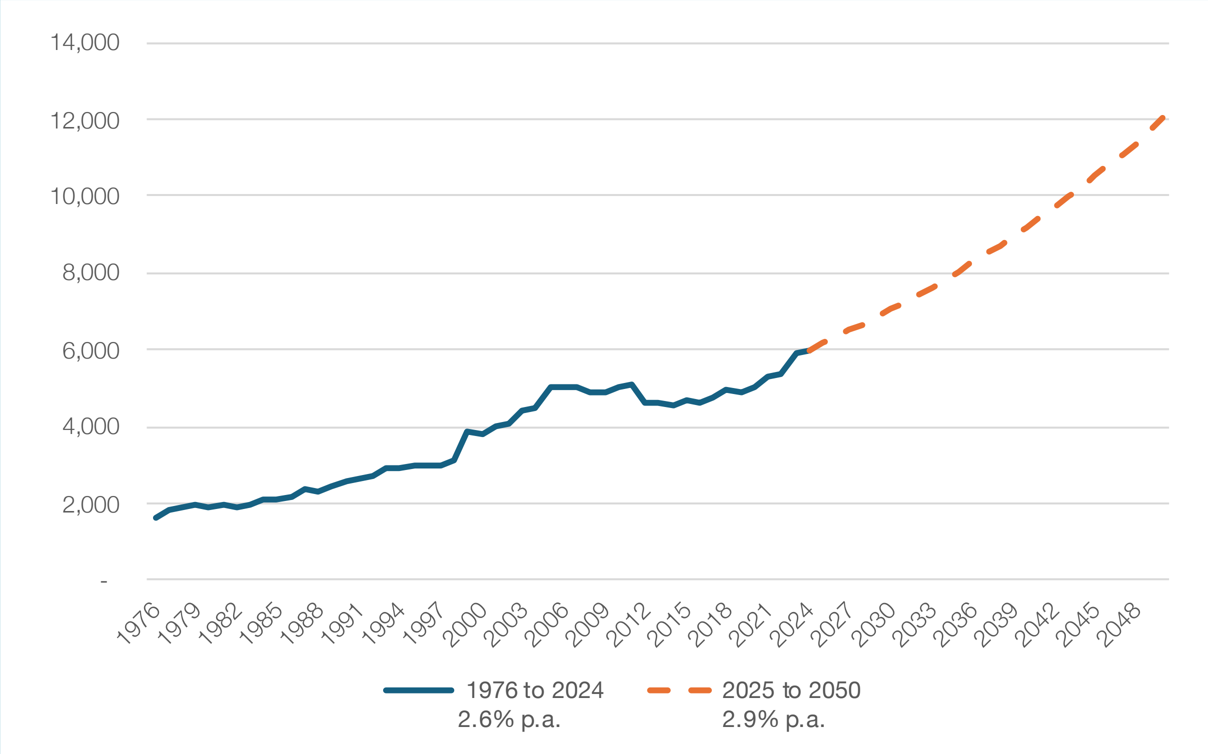

Figure 3: Trends in Peak Demand 1976 to 2024 and projection to 2050

The target of 80 TWh / 12,000 MW by 2050 provides the basis for the discussion in **Section 10** on the scale of the programme of large energy infrastructure projects that will be required to meet this challenge.

2.4 Data Centres

This report focuses on the supply side challenges of meeting an electricity requirement of 80 TWh by 2050. The 80 TWh includes growth due, not only to the electrification of heating and transport; it also implicitly assumes growth in demand from data centres based on the projections in EirGrid's four scenarios in TES 2023 (*Table 6*).

TES 2023 scenario	Data centres in 2050	Total electricity requirement	%
Self-Sustaining	19.8 TWh	84.2 TWh	24%
Offshore Opportunity	19.2 TWh	86.1 TWh	22%
Gas Evolution	17.1 TWh	71.5 TWh	24%
Constrained Growth	14.5 TWh	73.2 TWh	20%
Average	**17.7 TWh**	**78.8 TWh**	**22%**

Table 6: *Summary of data centre demand and total electricity requirement in EirGrid's four scenarios*
Source: Tomorrow's Energy Scenarios 2023, EirGrid

Demand from data centres grew at an average annual rate of 22.6% between 2015 (1.2 TWh) and 2023 (6.3 TWh). The 80 TWh electricity requirement assumed in this report provides for continued annual growth of 4.0% from 2023 to a level of 17.7 TWh in 2050.

3. THE ELECTRICITY SYSTEM IN 2050

3.1 An illustrative depiction of Ireland's electricity sector in 2050

The electricity system in 2050 will be considerably different from the system that powered the country up to the point where renewables became a significant source of power.

The transition from the conventional grid of the past - powered by synchronous generators (driven by gas, steam and water turbines) - to a renewables based grid requires one set of assets to be replaced by four sets of assets:

1. Renewables
2. Batteries and synchronous compensators to provide system resilience
3. Storage
4. Back-up generation plant

In addition to the challenges of increased complexity in the grid of the future, there is the additional challenge of scale arising from growth in power demand and electricity requirement as energy services are electrified.

In the absence of a single national energy infrastructure plan showing how the objective of developing a zero carbon (or net-zero) electricity sector might be achieved, *Figure 4* presents an indicative view as to how the country's electricity sector might be configured by 2050 based on the deployment of proven technologies over the next 25 years. The background to the numbers shown in *Figure 4* is explained in **Section 5**, **Section 6** and in **Appendix 1**.

The underlying assumption is that all of the energy infrastructure to be constructed between now and 2050 is based on proven technologies that are already commercialised and in operation as summarised in *Table 7*.

Proven technologies	Technologies not yet proven
Onshore wind	Floating offshore wind
Fixed-bottom offshore wind	Hydrogen
Solar PV	Small modular nuclear reactors
Storage	
Strategic storage of natural gas	
Interconnection	

Table 7: Summary of technologies considered in this report

The one exception to this in *Figure 4*, is the inclusion of hydrogen as a possible alternative to natural gas as the energy source of last resort. This has been done to facilitate a later discussion in **Appendix 2**.

In addition to the technologies shown in Table 7, there are other technologies with smaller potential - such as geothermal energy - which could make a useful contribution to decarbonising Ireland's energy supply.

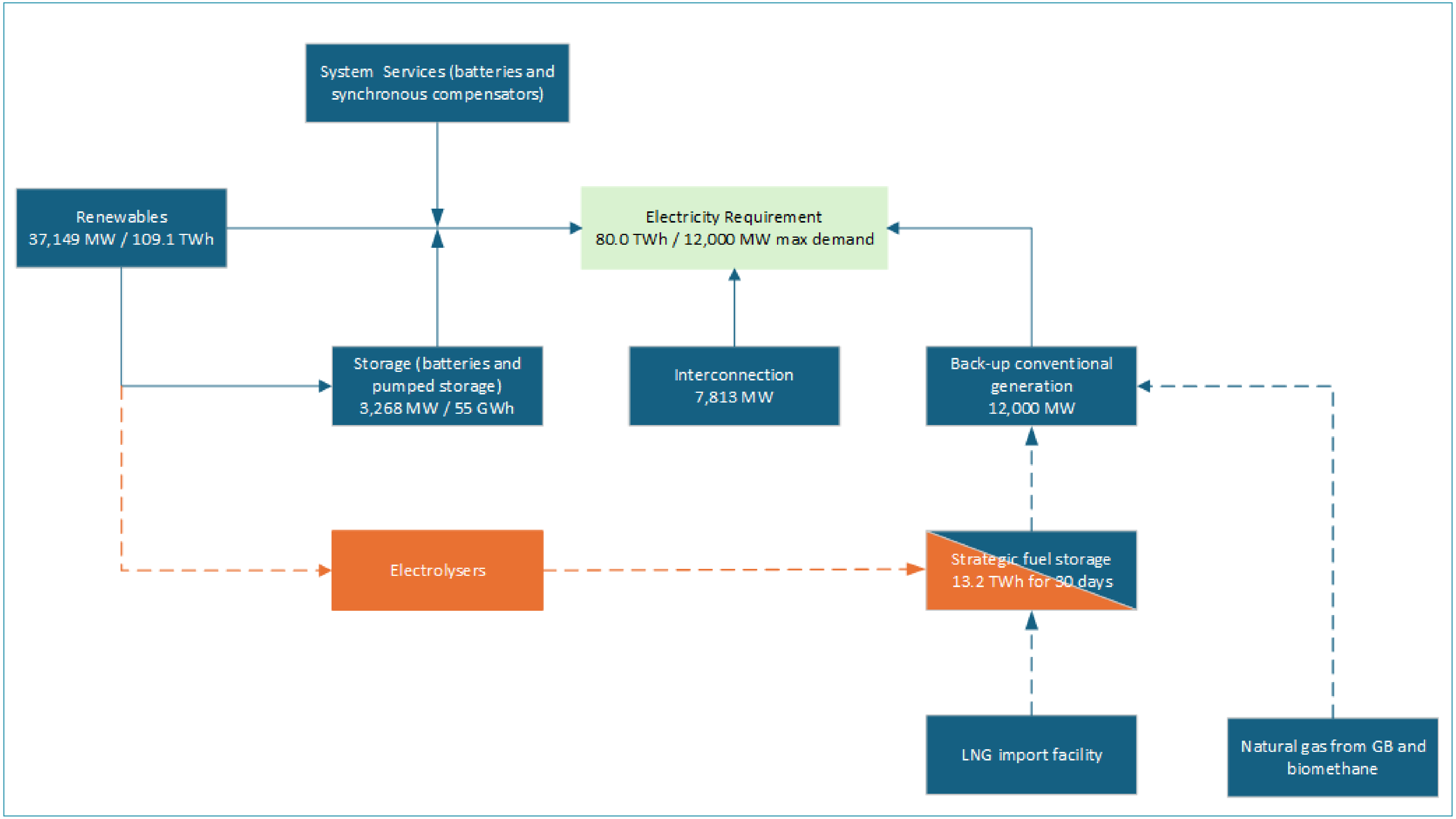

Figure 4: An illustrative depiction of Ireland's electricity sector in 2050 based on proven technologies but also showing the possible inclusion of hydrogen should the technology be proven

The first significant feature of *Figure 4* is that the electricity requirement of 80 TWh could conceivably be surpassed by 36% based on reasonable assumptions of what could be provided by a combination of onshore wind, fixed bottom offshore wind, and solar (109.1 TWh as shown in *Table 8*).

	MW	Contribution to electricity requirement	Reference in Appendix 1
Onshore wind	9,000 MW	22.1 TWh	Table 32
Fixed bottom offshore wind	20,149 MW	79.3 TWh	Table 35
Solar	8,000 MW	7.7 TWh	Table 37
Totals	**37,149 MW**	**109.1 TWh**	

Table 8: Breakdown of the contribution of different renewable technologies to total renewables in 2050

The 109.1 TWh shown in Table 8 is, however, significantly less than the 175.7 TWh implicit in renewables targets set by Government for 2030 (onshore wind and solar) and for 2050 (both fixed bottom wind and floating offshore wind) as shown in *Table 9*.

	Power capacity	Government target date	Assumed capacity Factor	Electricity capacity
Offshore	37,000 MW	2050	45%	145.9 TWh
Onshore	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 9: Government targets for renewable generation capacity in Ireland by 2050

These comparisons raise an important question: what renewables capacity should Ireland develop to meet an electricity requirement of 80 TWh by 2050?

3.2 Intermittency and oversupply

Intermittency requires the deployment of renewables with a power capacity significantly higher than demand (oversupply) because, as wind speeds fall, power output decreases rapidly (*Table 10*).

Fall in wind speed	Decrease in power output
10%	27.1%
25%	57.8%
50%	87.5%

Table 10: Impact of falling windspeed on wind turbine power output

The need to oversupply is illustrated in *Figure 5* in which the frequency distribution of the power output of Ireland's renewables in 2024 is shown by comparison to power demand levels (minimum, average and maximum) over the course of the year.

In 2024, the power capacity of wind (4,730 MW) was 179% of minimum demand (2,646 MW). However, for 2,127 hours during the year (24% of the time), the power output from wind was less than 500 MW.

Moreover, for 7,685 hours (88% of the time), wind output was less than minimum demand.

The reality of the intermittency of renewables has been inadequately recognised in energy policy to date. However, as much more renewables are brought online (particularly fixed bottom offshore wind) and as the electrification of energy services drives large growth in electricity demand, this reality will have to be definitively addressed in policy.

Intermittency requires that wind capacity be high in relation to power demand levels if renewables are to meet a high proportion of the electricity requirement.

For example, the power capacity of renewables in 2050 shown in *Table 8* would be 3.1 times the peak demand of 12,000 MW assumed in this report and the Government targets shown in *Table 9* would be 4.5 times higher. The contrast between the grid of the future and the grid of the past is stark. In a conventional grid, there would always have been more generating capacity than required to meet peak demand in order to ensure adequacy of supply. However, this excess would have been modest (perhaps 20% to 30%) by comparison to multiples of 3.1 to 4.5.

The contrast between the grid of the past and the grid of the future becomes even more stark when the requirement to have sufficient power generation capacity to back-up renewables is added in. Allowing for this, the multiples of 3.1 to 4.5 could increase to at least 4.1 to 5.5.

It is an inescapable consequence of a decision to increase the installed power capacity of renewables (in an effort to meet power demand for more hours in the year) that more electricity will, at times, be generated than is required (109.1 TWh in *Table 8* versus 80 TWh in *Table 5*).

An oversupply of power capacity creates an opportunity cost unless the surplus can be exported or used for an alternative purpose such as the production of hydrogen, however unclear it might be, today, that this can be achieved.

It is unclear how the power capacity target in national energy policy of 54,000 MW (*Table 9*) was arrived at. There appears to be an implicit assumption that Ireland will export its surplus electricity and / or use it to produce hydrogen with no consideration as to whether either of these options will be feasible or what the impact of a large surplus would be on Irish consumers due to the effect of price support mechanisms such as those introduced in ORESS1 and which appear likely to provide the template for future renewables auctions.

For reasons explained in **Section 4** and in **Section 5**, exports of renewable electricity will be subsidised by consumers through a combination of the terms and conditions of contracts for difference (CfDs) and the operation of the PSO levy.

This creates an optimisation challenge to determine the level of the power output from renewables to meet demand while not imposing too high a PSO levy on consumers. Resolving this challenge critically depends on Long Duration Energy Storage (LDES). LDES will be required to provide inter-day storage (days) as opposed to intra-day storage (hours). To date, short duration lithium-ion battery technology has been deployed primarily to provide grid resilience and facilitate the connection of higher levels of renewables.[7]

Inter-day storage options are beginning to become available and 100-hour battery projects are being developed in the US based on iron-air battery technology. In Ireland, planning permission has been received by *FuturEnergy* for the first deployment of this technology in Europe (**Appendix 1**).

Government policy has, to date, proposed very high levels of renewable capacity with suggested opportunities for the development of an electricity export sector and / or the development of a green hydrogen sector supplied by the surplus of electricity generated over and above domestic demand. This has been done with little analysis of the contribution LDES could make to better matching the intermittent output of renewables to demand. Moreover, Government policy has all but ignored the cost of a large renewables sector and its impact on the already high price consumers pay for electricity in Ireland.

7 For example, ESB opened a 150 MW (300 MWh) in Aghada and a 75 MW (150 MWh)) battery system in Poolbeg during 2024.

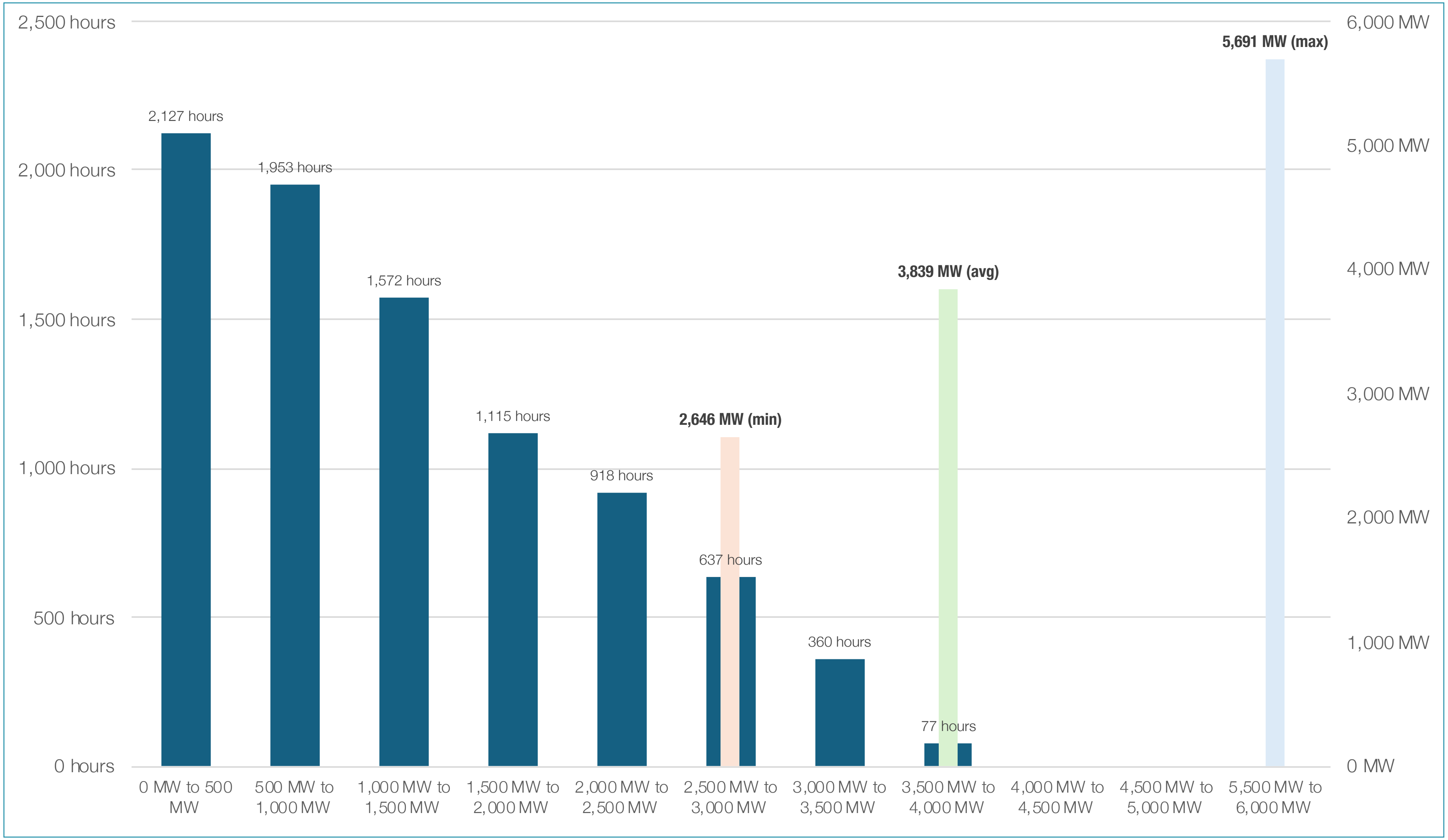

Figure 5: Frequency distribution of power output from wind in Ireland (left hand axis) juxtaposed with minimum, average and maximum power demand levels in 2024 (right hand axis)
Source: Analysis of EirGrid data

4. ELECTRICITY PRICES, PRICE SUPPORT MECHANISMS AND NATIONAL FINES

Beyond the technology and project delivery challenges of the energy transition, there are also important pricing and price support considerations which need to inform future policy and investment decisions.

4.1 Electricity prices in Ireland

Electricity prices in Ireland are high compared to prices in other EU countries and this has been the consistent pattern for many years. In the first half of 2024, for example, household electricity prices (excluding taxes and levies) in Ireland were 61% higher than the EU average (*Figure 6*).

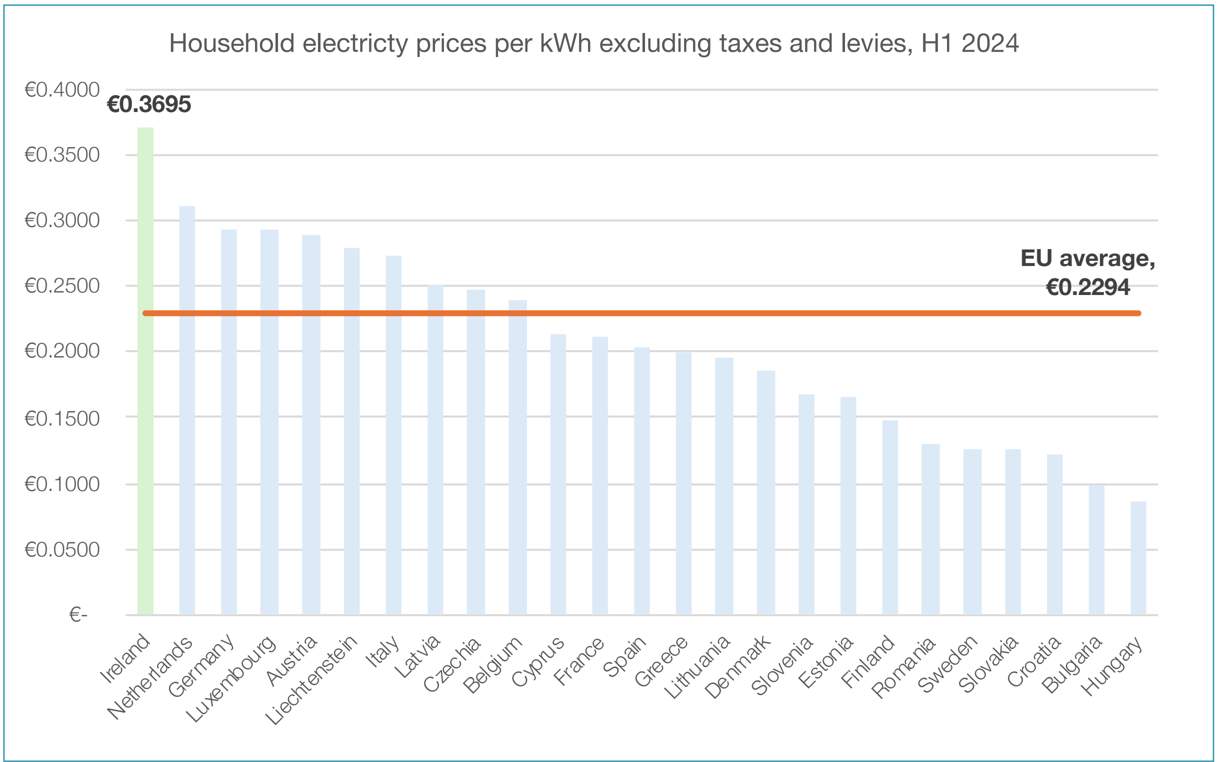

Figure 6: Comparative price (excluding taxes and levies) of household electricity in the EU in the first half of 2024
Source: Eurostat

Ireland taxes electricity at a lower level than other countries and, additionally, credits have been provided by Government through the Public Service Obligation (PSO) to reduce the impact of high electricity prices on households in recent years (*Table 11*).

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

Table 11: Value of the PSO in recent years *Source: CRU*

Even allowing for this, prices (including taxes and levies) were the third highest in the EU in the first half of 2024 and were 19% above the EU average when taxes and levies are taken into account (*Table 12*).

The high price of electricity in Ireland applies equally to non-household consumers and, in 2024, prices were 51% higher than the EU average (*Table 12*).

Category	EU average	Ireland	Rank
Household price excluding taxes and levies	€ 0.2294	€ 0.3695	Most expensive
Household price including taxes and levies	€ 0.2977	€ 0.3548	3rd most expensive behind Germany (€0.41)
Non-household price excluding taxes and levies	€ 0.1516	€ 0.2294	Most expensive

Table 12: Comparison of electricity prices in Ireland with EU averages, H1 2024, € per kWh
Source: Eurostat.Based on analysis in Appendix 3

The price excluding taxies and levies provides an important indication of the competitiveness of Ireland's electricity sector.

Ireland's electricity prices will remain high in the future unless underlying costs of generation, transmission and distribution can be reduced. Given the large investments required in the transmission grid and in the distribution system – all of which is passed through to consumers – there is no reason to believe that this can happen.

There has been a misleading narrative that more renewables will lead to lower electricity prices. This is frequently based on a comparison of the levelised cost of electricity (LCOE) for different renewables technologies by comparison with, for example, coal-fired, gas-fired or nuclear generation.

In the grid of the future, the average price of electricity paid by consumers will be determined by the combination of a range of cost inputs including:

- Strike prices for renewables supported by CfDs
- Prices paid for electricity supply from storage
- Fixed charges passed onto customers for use of the transmission and distribution systems
- Capacity payments for back-up generation needed when renewables cannot meet demand
- Payments to providers of system services to provide grid resilience
- Subsidies that might be required to provide strategic storage of fuels required for energy security
- Subsidy payments to operators of interconnectors under cap and floor arrangements if revenues fall below an agreed floor level
- The margins of electricity retailers

The success of the energy transition will depend, firstly, on consumers electrifying heating and transport and, secondly, on the delivery of the programme of large energy infrastructure projects required to provide zero-carbon (or net-zero) electricity.

There is a risk that - if the promise of lower electricity prices does not materialise - consumers will be disincentivised from making decisions to move away from fossil fuels.

4.2 Price support mechanisms for renewables

The deployment of renewables requires support guarantees which give sufficient revenue certainty to investors to facilitate their raising capital to finance renewables projects.

Between 1995 and 2006 support was provided through the Alternative Energy Requirement (AER) and Renewable Energy Feed-in Tariff (REFIT), schemes.

Since 2020, the terms of renewables support schemes have developed over the course of four Renewable Electricity Support Scheme (RESS) auctions and one Offshore Renewable Electricity Support Scheme (ORESS) auction.

Over time, the support mechanism has developed from a one-way Contract for Difference (CfD) – in which a project's downside is protected by top-up payments through the PSO when wholesale market prices are lower than the strike price set at auction - to a two-way CfD – in which this also happens but, in addition, when wholesale prices are higher than the strike price, the difference is rebated to customers via the PSO.

The ORESS1 auction of 2023 additionally set terms and conditions whereby the strike price was subject to adjustment for changes in steel prices up to the point of construction and for annual changes in inflation over a 25 year period.[8] Furthermore, ORESS1 provides for payments to generators when they are curtailed or when renewables exceed demand through the *Unrealised Available Energy Compensation* (UAEC) mechanism.[9]

If the terms and conditions of future auctions mirror those of ORESS1, then there will be related impacts on wholesale prices and on the PSO levy.

In the future, an oversupply of power generation capacity bidding into the wholesale energy market will drive wholesale prices down. The greater the surplus of capacity the stronger the forces driving prices down will be. This will provide an illusion of competition because losses by generators who bid below their strike prices will be compensated by payments directly from consumers through the PSO.

As this happens, however, competition within the wholesale market will provide export opportunities subsidised by consumers, and it is important that the capacity of renewables in Ireland does not reach a level where there is an excessive level of subsidy paid by consumers to generators.

Beyond generation, transmission and distribution costs are set by the CRU through its *Price Control Regulatory Framework*.

When combined with the fixed payments for transmission, distribution and for capacity (of what will increasingly be a fleet of back-up generating plant rather than base load plant), the electricity market is reverting - from a consumer perspective - to a cost recovery market similar to what existed prior to market liberalisation.

With so much investment required in transmission and distribution infrastructure and given the increased prevalence of CfDs in the generation sector, there is little margin for competition in the retail sector to reduce average prices in the future.

Promoters of renewable energy frequently make the case that renewable electricity is low cost. However, when the full costs of running an enlarged system based on renewables are taken into account, it is unlikely that electricity costs for consumers will fall. Recent experience in Ireland and elsewhere supports this view.

8 Terms and Conditions for the First Offshore Wind RESS Competition ORESS1, November 2022

9 Renewables can be despatched down in three situations: when supply exceeds demand; curtailment; grid constraints. The UAEC is designed to compensate in the first two situations but not where wind farms are limited by grid capacity constraints.

4.3 National fines for failure to meet EU targets

The Irish Fiscal Advisory Council has published a report giving estimates of the cost to Ireland of fines from the EU for not meeting climate change targets.[10]

The range of the cost of these fines is extremely wide, from a lower estimate of €5.9 billion to a higher estimate of €20.8 billion by 2030 alone if targets for the energy transition are not met (*Table 13*).

The report also says that *if the Government follows through on plans it has still not enacted, it could reduce this risk and potential costs to between €3 and €10 billion. The Government would need to be even more ambitious to reduce the costs further.* By way of example, the report suggests that Government could invest €7 billion to upgrade Ireland's transmission grid.

	With existing measures		With additional measures	
	lower	higher	lower	higher
Effort Sharing Regulation[11]	€ 5.4 billion	€ 16.2 billion	€ 2.7 billion	€ 7.6 billion
Renewable Energy Directive[12]	€ 0.5 billion	€ 4.6 billion	€ 0.2 billion	€ 2.6 billion
Energy Transition	**€ 5.9 billion**	**€ 20.8 billion**	**€ 2.9 billion**	**€ 10.2 billion**
Land use and forestry regulation	€ 1.6 billion	€ 5.8 billion	€ 0.5 billion	€ 1.7 billion
Total	**€ 7.5 billion**	**€ 26.6 billion**	**€ 3.4 billion**	**€ 11.9 billion**

Table 13: Irish Fiscal Advisory Council analysis of the potential costs of Ireland not meeting its climate targets by 2030

This suggestion highlights a problem at the core of energy policy in Ireland, namely the lack of a clear plan for a programme of large energy infrastructure projects. Implicit in the suggestion of investing €7 billion in grid infrastructure is a lack of appreciation for the long-term planning needed to deliver a single large energy infrastructure project let alone an enormous programme of such projects.

The national targets for the energy transition to 2030 and the EU commitments (with associated penalties) have, in a relatively short time, proven themselves to be unrealistic.

Looking to 2050, it is unclear how Ireland can develop a net-zero electricity sector – let alone a net-zero energy sector – based on the proven energy technologies available and given the absence of a clear plan for the delivery of a multitude of supply side energy infrastructure projects.

Insufficient attention has been paid to engineering, financial and project delivery realities in the development of Ireland's climate change policies. It is important that these realities are recognised for the future so that there are realistic expectations of what can be achieved to decarbonise the electricity sector and the wider energy sector, even if this could require acknowledging that the net-zero objective by 2050 may not be achievable.

10 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

11 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.

12 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.

5. INTERCONNECTION

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 14*).

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	750MW	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 14: Summary of existing and planned interconnectors

EirGrid has assumed very high levels of interconnection in 2050 under its four TES 2023 scenarios (*Table 15*).

Interconnector	Self-Sustaining	Offshore Opportunity	Constrained Growth	Gas Evolution	Average
IE-GB	3,750	5,750	2,450	3,200	3,788
IE-CE	3,900	7,400	1,400	3,400	4,025
Ireland	**7,650**	**13,150**	**3,850**	**6,600**	**7,813**
NI-GB	2,200	3,200	1,900	2,100	2,350
IE-NI	700	700	700	700	700
Northern Ireland	**2,900**	**3,900**	**2,600**	**2,800**	**3,050**
Totals	**10,550**	**17,050**	**6,450**	**9,400**	**10,863**

Table 15: TES 2023 interconnection assumptions in 2050

Based on the average capacities shown in *Table 15*, the aggregate capacity of interconnectors between Ireland and Britain and Ireland and France could be 7,813 MW by 2050. **This implies an increase in the capacity between Ireland and these countries of 6,113 MW over the next 25 years, equivalent to ten new interconnector projects of 600 MW each.**

Interconnection between Ireland and other countries is often discussed in the context of the potential for Ireland to develop a large electricity export sector based on an abundance of renewables. However, over the past decade, interconnector flows have been predominantly inwards into Ireland (*Table 16*).

	Net Imports	% of electricity requirement
2014	2.1 TWh	7.7%
2015	0.7 TWh	2.3%
2016	- 0.7 TWh	-2.4%
2017	- 0.7 TWh	-2.3%
2018	- 0.0 TWh	-0.1%
2019	0.6 TWh	2.1%
2020	- 0.2 TWh	-0.5%
2021	1.6 TWh	4.8%
2022	0.3 TWh	0.7%
2023	3.3 TWh	9.5%
2024	5.1 TWh	14.8%

Table 16: Net electricity imports into Ireland, 2014 to 2024:
Source: EirGrid System & Renewable Summary Report spreadsheet

5.1 Interconnector flows during 2024

During 2024, the trend of electricity flowing into Ireland increased by 55% (compared to 2023) to 5.1 TWh split 53% / 47% between the EWIC and cross border transmission lines (*Table 17*).

	Moyle I/C	Inter-jurisdictional Flow	EWIC I/C
	+ import to NI	**+ from south to north**	**+ import to Ireland**
+	2,688 GWh	62 GWh	2,829 GWh
-	-255 GWh	-2,472 GWh	-135 GWh
Net	**2,433 GWh**	**-2,410 GWh**	**2,694 GWh**

Table 17: Interconnector flows, 2024
Source: Analysis of EirGrid System Quarter hourly data 2024

The trend of inward flows was consistent throughout the year, and the proportion of Ireland's electricity requirement met by imports ranged from a low of 10.5% of demand in January to a high of 21.2% in June. Overall, interconnectors met 15.1% of the country's electricity requirements in 2024 (*Table 18*).

GWh	Moyle I/C	Inter-jurisdictional Flow	EWIC I/C	Net Ireland	IE Demand	Net Ireland import as % of IE demand
	+ import to NI	+ from south to north	+ import to Ireland	+ import to Ireland		
Jan	174	-157	174	331	3,142	10.5%
Feb	170	-168	170	338	2,824	12.0%
Mar	170	-177	178	355	2,973	11.9%
Apr	223	-213	223	436	2,732	16.0%
May	237	-232	271	502	2,665	18.9%
Jun	234	-251	275	527	2,484	21.2%
Jul	257	-250	302	552	2,639	20.9%
Aug	188	-233	279	512	2,628	19.5%
Sep	237	-204	233	437	2,661	16.4%
Oct	170	-170	199	369	2,877	12.8%
Nov	200	-134	223	356	3,010	11.8%
Dec	176	-223	167	389	3,086	12.6%
Total	**2,433**	**-2,410**	**2,694**	**5,104**	**33,719**	**15.1%**

Table 18: Net monthly electricity imports into Ireland, 2024
Source: Analysis of EirGrid System Quarter hourly data 2024

The net electricity imported through the Moyle interconnector (2.4 TWh) was almost exactly matched by the electricity that came over the border. The combined capacities of the Moyle and East-West interconnectors is 1,000 MW and the 5.1 TWh imported was equivalent to 58% of the aggregate capacity of these two interconnectors.

5.2 The price obstacle to developing an electricity export market

For Ireland to export surplus electricity, prices in the wholesale market would have to be competitive with those in the markets we would hope to sell to. This is not currently the case (**Appendix 3**).

However, Irish prices could become competitive by way of the price support mechanisms for renewables described in **Section 4.2**.

The CfD contracts granted to the winners of the ORESS1 auction guarantee that offshore wind farm projects will receive a strike price (which escalates annually) over the 25 year period of the contract regardless of what price the wind farms receive in the wholesale electricity market. This guarantee is underwritten through the PSO levy the level of which is set annually by the CRU.

If anything approaching the very high levels of renewables described in **Section 3.2** is achieved, then wholesale market prices could be driven to a low enough level that it might become profitable, at times, to export surplus renewable electricity over interconnectors.

5.3 The scale of the electricity markets to which Ireland might aspire to export

There has been an unfortunate characterisation of Ireland as the *Saudi Arabia of Wind* and there is a danger that energy policy could be unduly influenced by an unrealistic belief that Ireland can become a major exporter of electricity.

Assuming the Government target of 54,000 MW of renewable capacity (*Table 9*) could be achieved and assuming an electricity requirement of 80 TWh in 2050, then there could be a theoretical surplus of 95.7 TWh available for export. This would be 3.6% of the total electricity production in the EU 27 of 2,695.5 TWh in 2023 (*Figure 7*). Just as Ireland's electricity requirement will increase by 2050, so also will the EU's and the 95.7 TWh might be equivalent to 1.5% of EU production in 25 years' time.

The level of surplus renewable electricity that Ireland might have to offer will only ever be a small proportion of the demand in markets we might aspire to export to. That being the case, Ireland will never have market power and will always be a price taker.

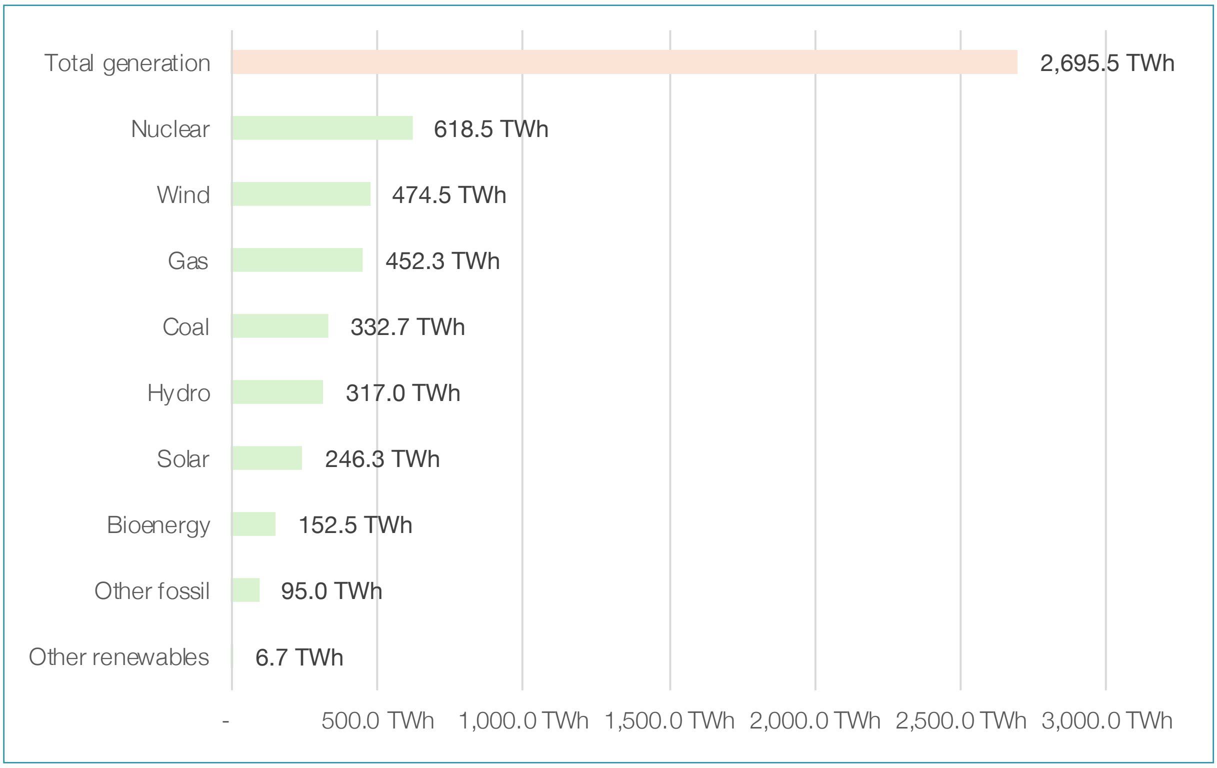

Figure 7: Electricity production in the 27 EU Member States, 2023 *Source: Ember*

In Britain, electricity generation in 2023 was 274.6 TWh (*Table 19*) and, if Ireland's abundance of wind is considered to create an export opportunity into this market, the reality of Britain's own plans to deploy renewables and nuclear - and past precedent - should temper expectations as to what might be possible.

Source	TWh
Gas	95.9 TWh
Wind and Solar	95.7 TWh
Nuclear	37.0 TWh
Bioenergy	29.8 TWh
Other fuels	6.1 TWh
Hydro (natural flow)	5.2 TWh
Coal	3.1 TWh
Oil	2.2 TWh
Pumped storage (net supply)	-0.5 TWh
Total generated	**274.6 TWh**
Net imports (Interconnectors)	*23.8 TWh*

Table 19: Electricity generation in GB, 2023 *Source: OFGEM*

Twelve years ago, a Memorandum of Understanding was signed between the Irish and UK governments to support the export of Irish renewable energy - onshore and offshore - to the mutual benefit of both countries.[13] The expectation was that wind energy would be exported from Ireland to the UK by 2020. Since that time, Britain has developed 14,000 MW of its own offshore wind farms. Nothing ever materialised from this initiative and now, more than a decade later, nothing has changed to suggest that the unrealised ambitions of 2013 can be achieved in the 25 years to 2050.

Finally, the correlation between weather systems in Ireland and Britain are such that when renewables in Ireland are in surplus, the likelihood is that renewables in Britain will also be in surplus.

In conclusion, rather than becoming a *Saudi Arabia of Wind*, Ireland can only ever be a small, high-cost, marginal producer of renewable electricity.

13 The *Memorandum of Understanding* was signed by the UK Secretary for Energy and Climate Change, Edward Davey and the Minister for Communications Energy & Natural Resources, Pat Rabbitte on 13th January 2013.

6. BACK-UP CONVENTIONAL GENERATION

One of the key challenges for EirGrid is to ensure that there is adequate generation capacity to meet demand at all times. The standard of supply expected by consumers is 24 / 7 / 365.

Peak demand is seasonal and the challenge to achieve and maintain this standard is greatest during the winter. EirGrid publishes a *Winter Outlook* report in Autumn each year looking ahead at the margin of capacity over demand. *Figure 8* shows how a system margin of 369 MW was projected on the day of highest peak demand for Winter 2024.

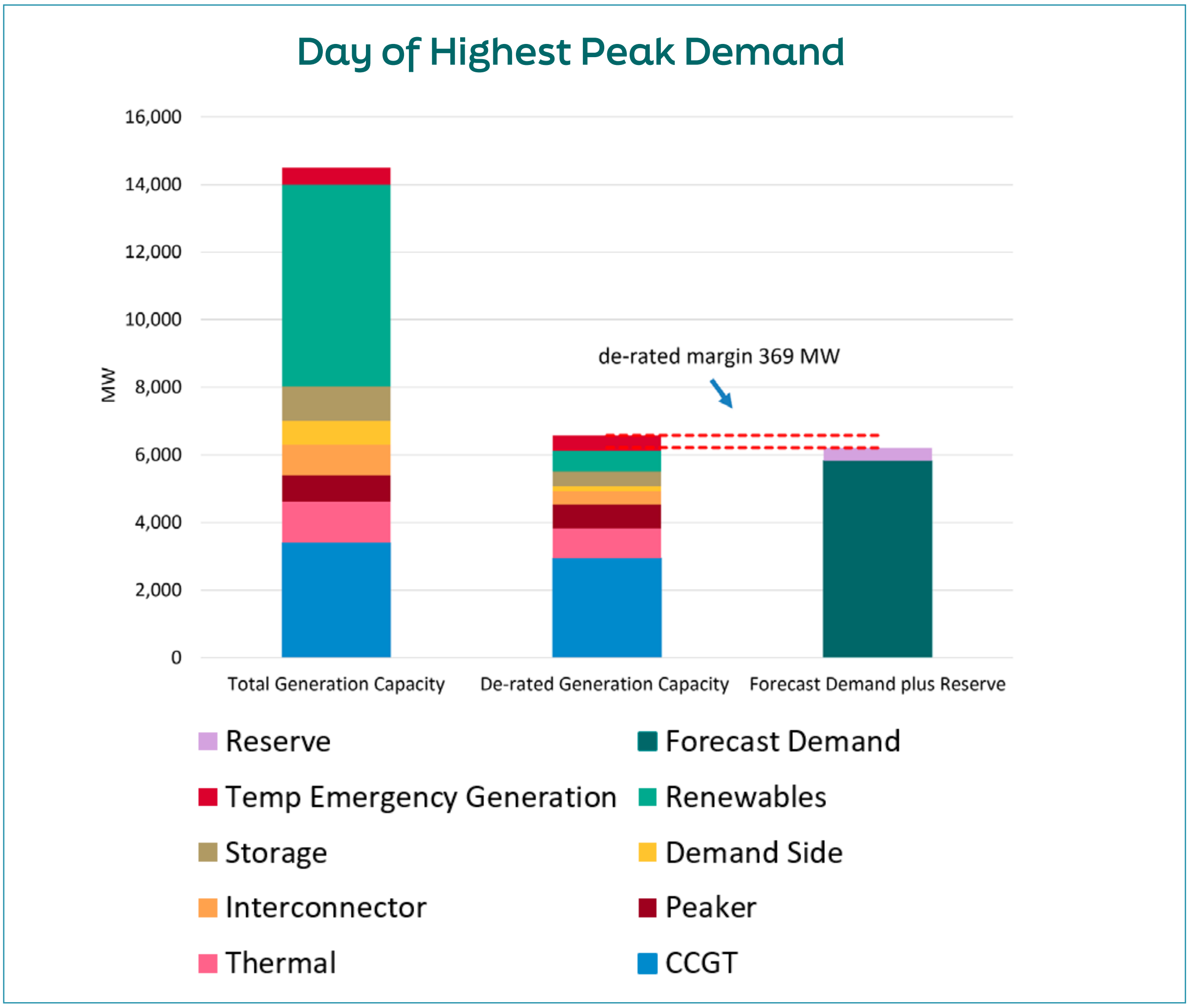

Figure 8: Generation capacity, demand and system margin, Winter 2024
Source: Winter Outlook 2024/25, EirGrid, October 2024

The sources of generation capacity shown in *Figure 8* comprise conventional plant, renewables, interconnectors, storage and demand side units.

The conventional plant includes the 5,907 MW fleet of generation units summarised in **Appendix 4** plus an additional 965 MW as follows:

- 505 MW of what is described as *temporary emergency generation* secured under the *Security of Supply Programme* (following the threatened generation capacity shortfall which emerged during 2021).
- 190 MW of new gas fired peaker plant and 270 MW of new batteries secured in capacity auctions during the year.

One of the consequences of the planned increase in renewables is that the fleet of conventional firm and dispatchable generation plant will increasingly function as a back-up to renewables. The 5,907 MW summarised in **Appendix 4** operated at a capacity factor of about 33% during 2024. As the penetration of renewables increases and as the capacity of storage and interconnectors grows, the capacity factor will fall to very low levels of, perhaps, 5% or less. As this happens, the fixed cost of this capacity will not fall and will remain a component of unit electricity prices.

In determining the scale of the future back-up generation fleet, there is an important decision to be taken as to the extent to which Ireland should place reliance on interconnectors as a source of last resort back-up generation.

Figure 4 shows a putative interconnection capacity of 7,813 MW equivalent to 65% of the peak demand assumed in 2050. Derating factors for interconnectors in 2050 need to take account of the potential for extreme events which could greatly limit the capacity Ireland might be able to rely on.

One obvious source of concern is the possibility of long-lasting periods (of days or even weeks) of high-pressure weather settled over Ireland, Britian and north-western France causing the output of renewables to drop precipitously in all three countries at the same time and as demand increases because of low temperature. This was exemplified in 2021 when wind speeds over Ireland, the UK and much of northwest Europe were, from July to September, consistently and significantly lower than they had been in the previous 30 years.[14]

In addition - and possibly coinciding with such a weather event - it is possible to imagine a major event on the British grid which would greatly increase demand for imports on its interconnectors with France, Belgium, the Netherlands and across the North Sea - or, alternatively, decrease the availability of power for export - thereby limiting what might be available to Ireland.

There is a risk that the huge growth in dependence on interconnection in recent years - 9.5% of demand in 2023 and 15.1% of demand in 2024 - could lead to an overreliance on interconnectors.

There would need to be a very compelling argument to include interconnectors to any significant extent, if at all, in the mix of Ireland's generation capacity of last resort in 2050.

Whatever decision EirGrid might ultimately come to regarding the country's dependence on interconnectors, it would need to be explicitly endorsed by Government to ensure that all organisations responsible for ensuring Ireland's energy adequacy and security (notably EirGrid, DECC and CRU) work to a common objective.

This did not happen in 2021 and the final paragraph of the review of the events of that year usefully identifies the background to the electricity crisis that occurred: [15]

The crisis in electricity supply triggered by the generation capacity shortfall described in this report are, to a degree, a consequence of ambition for the modernisation of the economy and the rapid transition to a more sustainable, lower carbon energy system. 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.

14 Low winds | Copernicus

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

However back-up generation capacity might be met in the future - from a combination of conventional plant, renewables, storage and demand side units – the increase in peak demand to 12,000 MW by 2050 will require an increase in the capacity of the fleet of conventional generation plant.

As a conservative estimate, it would seem reasonable to assume that not less than an additional 6,000 MW of gas turbines might be needed over the next 25 years. Assuming each plant had a capacity of 300 MW, that would suggest 20 new power plant projects between now and 2050.

Based on the views of the readiness of technologies set out in **Appendix 1** and in **Appendix 2**, the only realistic assumption is that the fleet of back-up generation plant will be fuelled by natural gas. Notwithstanding that this would continue a dependence on natural gas up to and possibly beyond 2050, there would be a possibility of co-firing these turbines on natural gas and hydrogen and ultimately moving to green hydrogen (or some other renewable gas) if and when hydrogen might become available as an option.

Given the uncertainties about hydrogen, the only basis that the back-up generation plant required by 2050 can be planned on is that it will operate on natural gas. *Table 20* below estimates the possible impact of this on emissions from the generation sector and suggests that instead of achieving a 100% reduction (as required by Irish law and in order to meet EU commitments and avoid punitive fines), Ireland might only be able to achieve a 90% reduction.

As discussed in **Section 10**, even achieving this lower target would require the completion of an enormous programme of energy infrastructure projects of unprecedented scale by a combination of State companies and private investment.

	Assumptions	Consequences
Electricity requirement in 2050	80.0 TWh	
Peak load in 2050	12,000 MW	
Capacity of back-up generation as % peak load	100%	
Back-up generating capacity required		12,000 MW
Proportion of electricity requirements from back-up plant	5.0%	
Electricity from back-up plant		4.0 TWh
Capacity factor of back-up plant		3.8%
Back-up plant average thermal efficiency (based on LHV)[16]	50.0%	
Natural gas consumed by back-up plant		8.0 TWh
Strategic storage period	30 days	
TWh of natural gas required for strategic storage		13.2 TWh
Average natural gas send-out rate from strategic storage		440 GWh per day
Specific GHG emissions from natural gas (based on LHV)	204 g CO_{2e} per kWh	
GHG emissions in 2050		816,000 tonnes CO_{2e}
CO_2 intensity of electricity production in 2050		10 g CO_{2e} per kWh
CO_2 intensity of electricity production in 2023	255 g CO_{2e} per kWh	
% reduction in CO_2 intensity by 2050		-96.0%
Electricity demand in 2023	33.1 TWh	
GHG emissions in 2023		8,440,500 tonnes
% reduction in CO_2 emissions by 2050		-90.0%

Table 20: Indicative carbon emissions from the electricity sector as a result of a continued dependence on natural gas to 2050

***Table 20* additionally estimates the size of a strategic store of natural gas (to provide 30 days of fuel for average demand) at 13.2 TWh.**

16 Fast response back-up generation capacity - such as the 505 MW procured under the Security of Supply Programme after the events of 2021 - is typically provided by open cycle gas turbines (OCGT) with a thermal efficiency in the order of 30%. As the proportion of renewables increases in the future, back-up generation capacity capable of operating for days at a time, rather than for hours at a time, will also be needed and combined cycle gas turbines (CCGT) with a thermal efficiency in the order of 60% (similar to the base load plants operating today) will be needed. The assumed figure of 50% for the average thermal efficiency back-up plant in Table 20 assumes a 1/3rd to 2/3rd split between OCGT and CCGT plant.

7. ENERGY SECURITY

However the required fleet of back-up generation plant might be fuelled, the issue of energy security will have to be addressed. Because the output from renewables can drop to zero, renewables cannot make a significant contribution to energy security.

In 1990, Ireland had a reasonable level of energy security in the electricity sector because of substantial indigenous resources of natural gas and peat and also because of the size of coal stocks in Moneypoint (*Figure 9*).[17]

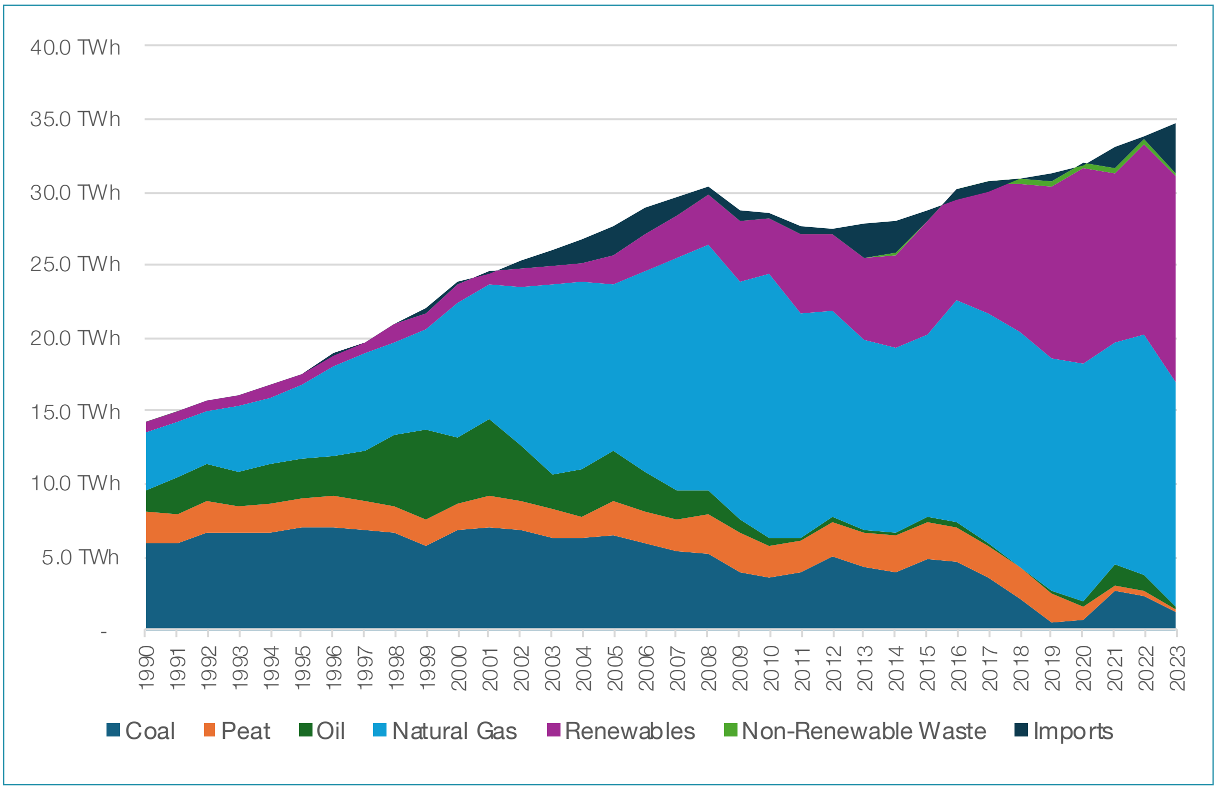

Figure 9: Trends in electricity production by fuel type, 1990 to 2023 *Source: EirGrid*

These sources of energy security have gradually diminished, and no action has been taken by Government to otherwise protect Ireland's energy security:

- The availability of peat for electricity generation was supported in the Public Service Levy (PSO) up to 2020 (*Table 21*). Peat generation produced 2,245 GWh in 1990, 919 GWh in 2020 and 152 GWh by 2023.
- The Kinsale gas field has been depleted and domestic gas from Corrib now meets only 23% of the country's demand (2023). This figure is declining as the gas field approaches the end of its operating life, likely by the mid-2030s.
- Moneypoint power station is being transformed from coal to oil (with limited run hours) with a target of ceasing operations altogether by 2029.

17 The coal yard at Moneypoint currently provides the capacity to generate in excess of 2,000 GWh of electricity at a power level of up to 900 MW.

PSO year	Peat capacity supported	Value of PSO support for peat
2019 / 2020	250 MW	€ 25.5m
2018 / 2019	250 MW	€ 65.5m
2017 / 2018	250 MW	€ 117.8m
2016 / 2017	250 MW	€ 123.7m
2015 / 2016	378 MW	€ 119.5m
2014 / 2015	370 MW	€ 119.0m
Total over six years		**€ 571.0m**

Table 21: Summary of the final six years of PSO support for peat stations
Source: CRU

7.1 National risk assessments

Government, correctly, identifies the risk of a lack of energy security annually in national risk assessments.

In 2014 the risk of a disruption to the country's energy supply identified geo-political risks following the Russian annexation of Crimea in 2014 (*Figure 10*). Having done this, no progress was made to mitigate this risk over the eight years until Russia invaded Ukraine in 2022. Over this period, there was an extant planning permission for the construction of an LNG terminal in the Shannon Estuary, but nothing was done to facilitate the project moving to construction.

Disruptions to Energy Supply

Ireland is completely dependent economically and socially on a secure energy supply – particularly on oil for transport and electricity for everyday life. Ireland imports nearly all of its energy needs, as indigenous energy production amounts to only about 14% of the total primary energy supply. Ireland's status as an island on the periphery of Europe renders it vulnerable to disruptions to the supply of oil, gas or electricity. Such disruption could arise from natural disaster or geo-political change, as the recent crisis in Ukraine has highlighted.

Figure 10: National Risk Assessment 2014, Section 2, Page 14

In 2024, the energy security risk was comprehensively identified in clear and concise terms (*Figure 11*). In particular, the lack of a diversity of supply for natural gas and the absence of storage were highlighted. The only action by Government in relation to securing Ireland's supplies of natural gas in recent years has been negative by way of the May 2021 Policy Statement on the Importation of Fracked Gas which directly led to a planning refusal for a second LNG project in the Shannon Estuary.

Energy security

Ireland is one of the most energy import dependent countries in the EU with limited diversity of supply. In 2022, 82% of Ireland's energy needs came from imports. 48% of energy used in 2022 was from imported oil and nearly 31% from natural gas. In 2022, 74% of Ireland's natural gas stemmed from imports through two interconnectors from the UK. Unlike other European countries, Ireland has limited diversity of supply and no gas storage. By 2030, with the continued reduction in production from the Corrib Gas Field, Ireland's dependence on natural gas imports, and associated undersea infrastructure, via Scotland, is expected to increase to over 90%. Ireland does not have a direct interconnection to Europe, active storage or Liquefied Natural Gas (LNG) facilities. Notwithstanding the increased use of renewables and energy efficiencies to be achieved over this time, Ireland will continue to rely on gas as we move away from other fossil fuels. The lack of diversity of supply sources and storage is a risk. While the Electricity Security Supply programme is delivering new capacity, a combination of deteriorating performance of the stock of existing thermal electricity generating power plants, the ongoing problems of delivery of planned thermal generation capacity through auction processes, and planning and permitting has left the outlook for Ireland's electricity supply in a very challenging state. Significant investment in our electricity grid is also required in the coming years. Failure to reconcile increasing demand, decarbonisation and our climate and energy commitments, with associated investment requirements, and the need to ensure a secure and sustainable energy supply, remains a risk.

Figure 11: National Risk Assessment 2024, Section 5.2, Page 31

The key to addressing the natural gas risk exposure is a combination of diversity of supply and storage such as has been achieved in Britain.

7.2 Natural gas security of supply risk exposure in Ireland compared to Britain

Ireland's risk exposure contrasts starkly with Britain. Whereas the UK has equally ambitious energy transition targets, it retains a diversity of natural gas supply including domestic production, pipeline imports - from Norway, Belgium and the Netherlands - and LNG imports from ten countries (*Table 22* and *Table 23*).

Ireland, by comparison, has a relatively small and declining indigenous production capacity (23% of national demand in 2023) and, when the Corrib gas field reaches its end of life, likely by the mid-2030s, the country will depend exclusively on supplies from Britain.

Notwithstanding the *Policy Statement on the Importation of Fracked Gas*, fracked gas is already imported into Ireland because up to 18% of demand in Britain is met by imports of LNG from the US.

The policy approach on fracked gas resembles the ban on nuclear power. Nuclear provides 14% of the electricity generated in Britain and, in 2024, met in the order of 2% of Ireland's electricity requirement. Nuclear will make an increased contribution to Ireland's electricity requirement once the Celtic Interconnector to France enters operation.

Source of supply	TWh	%
Indigenous UK production	382.7 TWh	54.6%
Pipeline imports	284.0 TWh	40.5%
Pipeline exports	-175.6 TWh	-25.0%
LNG Imports	210.9 TWh	30.1%
Adjustments	-1.0 TWh	-0.1%
Total demand GWh	**701.0 TWh**	**100.0%**

Table 22: Components of UK natural gas supply and demand 2023
Source: *Digest of UK Energy Statistics (DUKES)*

Country	TWh	%
USA	128.5 TWh	60.9%
Qatar	29.8 TWh	14.2%
Peru	19.6 TWh	9.3%
Other (7 countries)	33.0 TWh	15.6%
Total LNG imports	**210.9 TWh**	**100.0%**

LNG Terminal	TWh	%
Dragon (Milford Haven)	46.6 TWh	22.1%
Isle of Grain	81.5 TWh	38.7%
South Hook (Milford Haven)	82.8 TWh	39.3%
Total LNG imports	**210.9 TWh**	**100.0%**

Table 23: Analysis of UK LNG imports, 2023 *Source: Digest of UK Energy Statistics (DUKES)*

Where other countries - notably Germany - reacted to the energy disruptions that followed Russia's invasion of the Ukraine in 2022 by developing additional LNG import capacity, Ireland has, over the years, prevented two projects to develop LNG facilities in the Shannon Estuary from proceeding:

- 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.[18] 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 m3 (1.1 TWh) and a send-out capacity of up to 250 GWh per day. This planning permission is the subject of ongoing legal review.[19,20]

The continued deterioration in energy security and the failure by Government to address this risk (notwithstanding its clear identification by Government's annual National Risk Assessment report) is a major national failure which, if uncorrected, could cause catastrophic damage to the economy in the event of an energy emergency.[21]

18 An Bord Pleanála PA08B.PA0002
19 An Bord Pleanála 311233
20 Floating Storage and Regasification Unit
21 The Academy has consistently drawn attention to the country's energy security exposure in previous reports, most recently in 2018 and in 2022 (Appendix 6).

7.3 Energy security policy

In November 2023, Government published *Securing Our National Gas Supplies* in which five potential mitigation measures were analysed. The analysis of each mitigation considered energy security, affordability and sustainability. The outcome of this analysis is summarised in *Table 24*.

Mitigation	Storage TWh	Max Daily Send Out GWh/d	DECC conclusion / recommendation
New gas discovery	250	104	No change to the policy position set out in legislation not to grant any new authorisations for oil and gas exploration[22]
Underground gas storage	2.5 - 5	30 - 60	Research be carried out on potential sites for hydrogen storage, including consideration of the Kinsale gas fields future capacity
Third UK gas interconnector	n/a	300	Not recommended
LNG facility	2.4	360	Not recommended
FSRU[23]	1.2	80 - 250	Appropriate option

Table 24: Summary of mitigations considered by DECC for the natural gas supply risk
Source: Securing Ireland's Gas Supplies

To deliver the chosen option of an FSRU, the report established a State-led project (which could include public-private partnership) which,

- *can be implemented quickly,*
- *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.*

Government has now approved the development of a State-led strategic gas emergency reserve to be provided by an FSRU with a storage capacity of 170,000 m^3 equivalent to 1.0 TWh. [24]

The Government statement states that:

- *While not an entry point into the market, natural evaporation, known as boil-off, is unavoidable when natural gas is liquefied, and the generated boil-off gas (BOG) must be removed to preserve the tanks' pressure*
- *A minimum send out of gas from the FSRU to the national gas network will ensure gas is not lost in this manner*
- *Arrangements will be put in place to permit this minimum send out of gas into the national network, however this arrangement should not impact on the operation of the market*
- *This is likely to result in the strategic gas emergency reserve being refilled up to 6 times per year*

22 The policy does, however, allow holders of existing authorisations to progress to a conclusion (expiry, relinquishment, or production). The owners of the Inishkea West prospect in the Slyne basin, near the Corrib gas field, published updated prospective resource estimates in September 2023 suggesting an annual production potential of 48.3 TWh of natural gas with a lifetime of about ten years.

23 Floating Storage and Regasification Unit

24 Press Release, Government approves development of State-led strategic gas emergency reserve, 4th March 2025.

The concern that an LNG facility might inadvertently increase gas demand by increasing the supply available on the market does not stand up to analysis.

If renewables are deployed to the extent planned, then the consumption of natural gas (*Figure 12*) will decline.

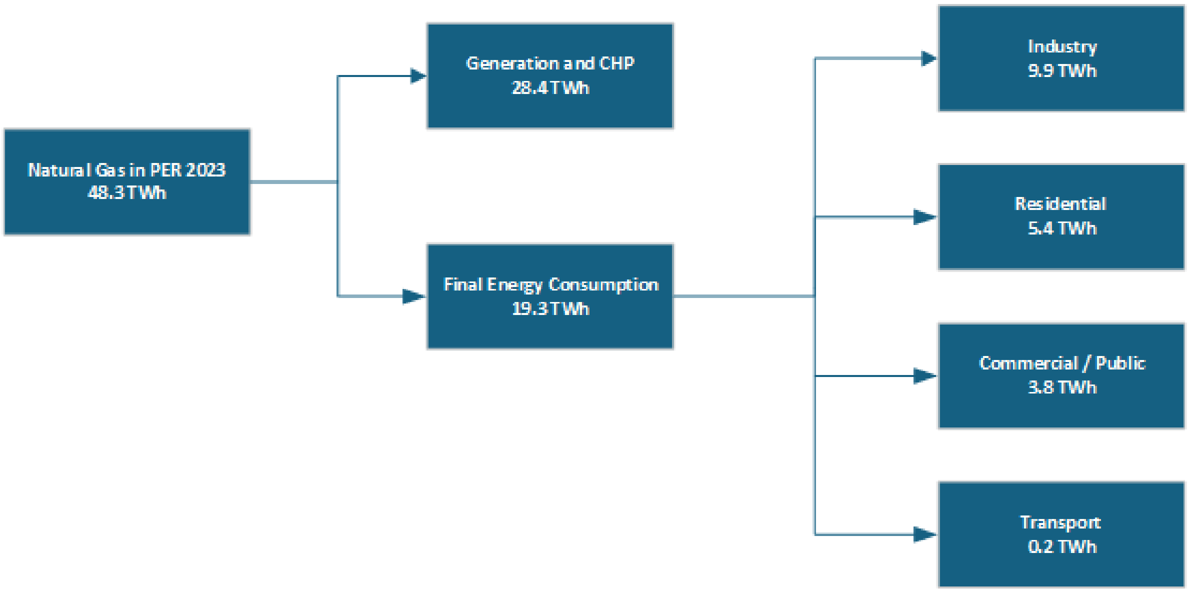

Figure 12: Natural gas in Ireland's Energy Balance, 2023

For example, the 28.4 TWh consumed in 2023 in power generation and CHP applications would be expected to decline to in the order of 8 TWh (as suggested in *Table 20*). Likewise, the 9.9 TWh consumed in industry would be expected to fall due to electrification or due to the use of net-zero alternative fuels. Finally, residential consumption of natural gas (5.4 TWh) and consumption in commercial / public services (3.8 TWh) will decline as a result of the transition from boilers to heat pumps. Enhancing the security of the national supply of natural gas will not affect consumption levels in these three sectors.

The 80 TWh electricity consumption in 2050 used in this report implicitly assumes that the industrial, residential, commercial services and public services all succeed in replacing their dependence on natural gas through electrification. As this causes the consumption of natural gas to decrease in the future, the nature of the LNG facility Ireland needs would change from being a source of supply and a strategic reserve to largely being a strategic reserve only.

Based on the analysis in *Table 20*, Ireland will, in 2050, need a substantial LNG facility with both a higher storage capacity and a higher gas send-out capacity than envisaged in the FSRU option shown in *Table 24* and as recently announced by Government.

Mitigating the energy security risk by maintaining a large stock of gas (13.2 TWh) would come at a cost which would be borne by consumers. This already happens in the case of oil where a levy of two cents per litre generates annual revenue for NORA of €132 million (2024).

For a strategic reserve of natural gas (and, in the long run, possibly hydrogen) a subsidy would be required and, if recovered through an arrangement similar to the NORA levy, could cost one eighth of one cent per kWh (based on 80 TWh by 2050) for every €100 million of subsidy that might be required.

The LNG facility to be developed in Ireland should be capable of being expanded in the future so that the storage and output capacity needed by 2050 for a large fleet of gas turbines (12,000 MW) could be met if, ultimately, that is what is required. The minimalist approach of a small FSRU procured on the basis of a lease arrangement and operated to *not impact on the operation of the market* will not meet Ireland's long-term energy security needs and could prevent access for consumers to cheaper gas.

8. TRANSMISSION GRID

The transmission grid comprises hundreds of circuits with thousands of kilometres of high voltage lines and cables as summarised in *Table 25*.

	Length	No. circuits	Average length
400 kV	439 km	4	110 km
220 kV	2,130 km	71	30 km
110 kV	5,708 km	350	16 km
Ireland	**8,277 km**	**425**	**19 km**
275 kV	926 km	19	49 km
110 kV	1,865 km	89	21 km
Northern Ireland	**2,791 km**	**108**	**70 km**
275 kV	150 km	2	75 km
110 kV	50 km	2	25 km
Cross border	**200 km**	**4**	**50 km**
Total	**11,268 km**	**537**	**21 km**

Table 25: Analysis of transmission circuits in Ireland and Northern Ireland

As power demand grows, increasing capacity at the 400 kV and 220 kV levels is essential. *Table 26* shows the two most recent transmission lines of significant length completed since market liberalisation.

Project	Length	Date Proposed	Completion Date	Peak demand in year of completion
Flagford – Srananagh 220 kV	55 km	1992	2012	4,650 MW
Cashla – Oldstreet 220 kV	48 km	2001	2003	4,400 MW

Table 26: Most recent transmission line projects completed at 220 kV / 400 kV

The key enabler to facilitate the decarbonisation of the energy sector over the next 25 years (during which time peak electricity demand will increase from 6,000 MW today to in the order of 12,000 MW by 2050) is an increase of grid capacity, particularly at these higher voltage levels.

Whereas additional capacity has been and continues to be provided by upgrading existing infrastructure (through, for example, reconductoring and dynamic rating), new additional infrastructure will, inevitably, also be required. It is remarkable that over the past 13 years, no significant new transmission line projects have been completed.

EirGrid's ten-year *Transmission Development Plan 2024* identifies 223 projects at various stages of progress (*Table 43* in **Appendix 5**). However, only six of these projects will deliver new build transmission capacity and, among these six, the only transmission line project is the long-delayed 137 km North-South Interconnector (*Table 44*).

Unless new transmission line projects are brought through planning early, there is a high risk that consenting delays will create even further backlogs and constraints. If projects to deliver new capacity at the 400 kV and 220 kV levels were to encounter similar delays as have been experienced with the North-South Interconnector - which, if energised in 2027, will have taken 27 years to reach completion – then this alone would render the net-zero target for the electricity sector unattainable by 2050.

Given the long lead time to deliver transmission line projects, there is a clear need to have a longer term and higher level understanding than is currently published by EirGrid to set out, in broad terms, how the grid needs to be developed over the next 25 years.

As is the case with other large national infrastructure projects, transmission line projects are difficult to steer through the planning consent system. Addressing this issue requires, as discussed later in **Section 10,** early clarity of what will have to be built and unequivocal support in policy.

The first step to address this challenge is to create a grid development masterplan comprising both near-term projects - which are well understood in terms of routes and design details - and longer-term projects, whose need and broad parameters can already, today, be specified with reasonable certainty.

EirGrid's *Grid25* provides a benchmark to get some sense of the scale of new transmission line development that might be required by 2050.

In 2008 - when peak demand was 4,900 MW - EirGrid published *Grid25* showing how it proposed to develop the transmission system in the years to 2025 to meet a peak demand of 8,000 MW. The overall development programme was costed at €4 billion (at 2008 prices) and included the development of 1,150 km of new transmission lines as summarised in *Table 27.*

Voltage	New lines	Upgraded lines	Total
220 kV / 400 kV	800 km	1,100 km	1,900 km
110 kV	350 km	1,200 km	1,550 km
Totals	**1,150 km**	**2,300 km**	**3,450 km**

Table 27: Summary of transmission network development in Grid25 *Source: EirGrid*

The recession of 2008 interrupted progress on many infrastructure projects and development plans, including grid plans, and what is needed now is an updated and detailed plan for the next 25 years.

Taking a conservative view - and assuming that the new capacity envisaged in Grid25 would suffice for the power levels in 2050 (12,000 MW) - *Table 28* below estimates that at least 46 sizable new transmission line projects might have to be completed over the next 25 years. In reality, more projects will almost certainly be required.

	Length	Average length	No. projects
400 kV / 220 kV	800 km	34 km	24
110 kV	350 km	16 km	22
Total	**1,150 km**	**25 km**	**46**

Table 28: Estimate of new transmission lines required in Ireland by 2050 based on Grid25

9. OTHER ENERGY VECTORS

Although electricity will be the dominant energy vector in the future, it will not be the only one and Ireland's energy requirements will also be met from other sources.

Natural gas, at the level of Primary Energy Requirement, amounted to 48.3 TWh in 2023 (*Table 1*). At the Final Energy Consumption level, natural gas was at 19.3 TWh (*Table 2*). Demand for the major part of the difference between these two figures (29.0 TWh) will reduce significantly as more and more renewables are deployed.

However, unless a zero or net-zero energy source can be found for the back-up generation that will be required, there could be a residual demand for natural gas of 8 TWh (*Table 20*).

Oil in Final Energy Consumption in 2023 amounted to 78.3 TWh with 57.1 TWh consumed in transport (*Table 2*). Whereas electrification is an option for much of this oil consumption, there is no proven and available path to fully decarbonise transport particularly for heavy goods vehicles (HGVs).[25] If electrification cannot be achieved, then 9.0 TWh (based on 2023 levels) could be needed from energy vectors other than electricity.

Also, within transport, there was a large demand from aviation of 13 TWh in 2023.

Demand from these three sources alone could – at 2023 levels - amount to at least 30 TWh.

By comparison with the electricity sector, there is even less clarity, let alone certainty, about how this 30 TWh can transition to net-zero sources over the next 25 years.

9.1 Natural gas / biomethane

In 2023, natural gas, accounted for 29% (48.3 TWh) of the country's Primary Energy Requirement of 164.1 TWh. More than half of this natural gas (25.4 TWh) was used to generate electricity.[26]

Table 29 shows that the amount of electricity that was generated from natural gas was higher in 2023 (15.4 TWh) than it had been a decade earlier.

25 In 2023, heavy goods vehicles consumed 9.3 TWh in Final Energy Consumption comprising 8.5 TWh of oil and 0.8 TWH of biodiesel. (SEAI Energy Balance 2023).

26 These figures are taken from SEAI's Energy Balance 2023.

	TWh	% of electricity requirement
2014	12.6 TWh	45.2%
2015	12.4 TWh	43.0%
2016	15.3 TWh	51.9%
2017	15.7 TWh	52.3%
2018	16.0 TWh	51.9%
2019	15.9 TWh	50.7%
2020	16.2 TWh	51.0%
2021	15.2 TWh	45.7%
2022	16.5 TWh	48.8%
2023	15.4 TWh	44.3%

Tbale 29: Trends in electricity generation from natural gas, 2014 to 2023
Source: EirGrid

Natural gas will continue to be an important source of energy during the energy transition due to the inescapable requirement to have back-up generation capacity for renewables.

In the long-term, there is the possibility of replacing natural gas with zero or net-zero alternatives. Gas Networks Ireland published *Pathway to a Net Zero Carbon Network* in 2024 outlining a pathway to gradually replace natural gas with a combination of net-zero biomethane and zero-emission hydrogen (*Table 30*).[27]

	2027	2032	2046	2040	2045
Hydrogen	-	1.3 TWh	6.0 TWh	17.1 TWh	30.1 TWh
Biomethane	0.7 TWh	6.3 TWh	10.0 TWh	14.0 TWh	14.0 TWh
Natural gas	56.1 TWh	38.4 TWh	24.4 TWh	6.1 TWh	-
Totals	**56.8 TWh**	**46.0 TWh**	**40.4 TWh**	**37.2 TWh**	**44.1 TWh**

Table 30: Projection of gas volumes to 2045
Source: Pathway to a Net Zero Carbon Network, GNI, June 2024

The level of demand projected by GNI from a combination of different gases is 44.1 TWh by 2045 with an evolution of the existing grid to two grids (one for biomethane and one for hydrogen).

GNI's development pathway is intrinsically linked to the development of a hydrogen sector in Ireland, notably to power back-up generation:

27 In 2023, 60 GWh of biomethane was injected into the gas network. This was equivalent to 0.1% of the 48.3 TWh of natural gas in PER.

Post-conversion, and with our two networks supplying only renewable gases, our infrastructure will have been reviewed on a case-by-case basis to determine if gas assets were to be repurposed or to be decommissioned if they were no longer in use. Demand for sustainable networked gas is anticipated to recover somewhat. A maturing hydrogen economy will increasingly look to the national hydrogen ring main for supply and as an efficient means of moving hydrogen between points of production and centres of consumption. As electricity demand continues to increase, hydrogen-fired generation is likely to experience higher levels of utilisation, and with networked hydrogen widely available across the country, hydrogen will be a more accessible solution for heavy transport. 28

Whether Ireland continues to require natural gas as an energy vector, or hydrogen ultimately provides a zero carbon alternative to natural gas, the gas grid in Ireland will change considerably over the coming years as heating is electrified. If this happens, as envisaged in policy, the residual gas network required will only supply a small number of large customers.

In the same way that it is important to plan for the development of new energy infrastructure over the next 25 years, so also there must be a plan for the consolidation of the gas network as demand drops. If the financial viability of the gas grid is undermined by low volumes then it may need to be subsidised by consumers in the future to ensure its availability for the fleet of back-up generation assets. This would be the case regardless of what gas the network might transport.

9.2 eFuels

Beyond electrification and gas, there will remain large sources of energy demand (such as aviation's 13.4 TWh in 2023 and 9.0 TWh for HGVs) for which there are, as yet, no proven net-zero alternatives.

So great is the uncertainty of zero carbon or net-zero replacement fuels for oil becoming available in those sectors that will not be able to be electrified, it is inescapable that fossil fuels will continue to be required over the next 25 years and, most likely, well beyond.

This reality - together with the lack of a proven net-zero alternative to natural gas for back-up electricity generation – will make the attainment of a climate neutral energy sector impossible by 2050 notwithstanding the requirement in Irish law to achieve this and the onerous obligations (with financial penalties) under EU law.

28 *Pathway to a Net Zero Carbon Network*, Page 13, GNI, June 2024,

10. DELIVERING A LARGE PROGRAMME OF ENERGY INFRASTRUCTURE PROJECTS IN JUST 25 YEARS

Individual large infrastructure projects inevitably take a long time to move from concept to completion.

In the case of large energy projects, it would be prudent to plan on an indicative timescale of up to 20 years based on the following three examples:

- Corrib – 19 years from discovery to gas coming ashore
- North-South Interconnector – 27 years after the need for it was first identified to its planned energisation in 2027
- Shannon LNG – 17 years since planning permission was lodged for the first project

Notwithstanding changes to planning law, large infrastructure projects are inherently risky and the main contribution Government can make to reducing this risk is to ensure policy coherence and certainty.

These considerations highlight the essential need for a programme of the energy projects to be delivered over the next 25 years to 2050. This programme needs to be embedded in planning policy at all levels (Local Authority Development Plans, Regional Spatial and Economic Strategies and in the National Planning Framework) with no ambiguity between it and other national policy areas so that planning authorities, including An Bord Pleanála, can have no grounds to reject planning applications on policy grounds.

10.1 The scale of the programme

Based on the analysis and commentary in this report, *Table 31* gives an indication of the scale of the programme of projects that need to be completed by 2050.

Category	Assumptions	# projects	Reference
Onshore wind	4,270 MW at 60 MW per windfarm	71	Appendix 1
Fixed bottom offshore wind	20,149 MW at 700 MW per windfarm	29	Appendix 1
Solar	5,452 MW at 40 MW per project	136	Appendix 1
Interconnectors	6,113 MW at 600 MW per project	10	Section 5
Back-up generation	6,000 MW at 300 MW per project	20	Section 6
Transmission lines	1,150 km of transmission lines at 25 km per line	46	Section 8
Storage	2,000 MW / 50 GWh at 50 MW per project	40	Appendix 1
Total		**352**	

Table 31: Indicative scale of the programme of Energy Transition projects needed in the electricity sector

The estimates of the number and scale of individual projects are high level and are intended to give a sense of the scale of the implementation challenge Government faces to achieve its targets.

Importantly, in addition to the 352 projects identified in *Table 31*, there are hundreds more, smaller transmission and distribution system projects that also need to be completed to deliver the supply side capacity required for the energy transition.

10.2 The need to remove consents from the critical path

The main reason why so many infrastructure projects experience large delay is the systematic failure by Government and State agencies and companies to plan with a sufficiently long time horizon.

Wherever possible (most notably for transmission infrastructure), planning consents should be removed from the critical path of project delivery. This can be done by designing projects and bringing them through planning consent processes early so that there are planning permissions available to allow projects go to construction when the time is right.

Following the recent decision in the Apple tax case, Government found itself with €14 billion available. Many suggestions were made as to how this windfall might have been used to finance infrastructure projects. However, the reality is that there were no large, consented infrastructure projects which could have been quickly brought forward to construction.

For its part, An Bord Pleanála has demonstrated a willingness to grant long duration planning consents (15 years) within the context of a masterplan in recognition that the optimum timing of the construction phase can be uncertain at the time consents are applied for.[29]

10.3 The need for an overarching plan with unconditional political support

The Academy has previously noted that,

> *The very large renewables targets in current policy do not constitute a plan. Completing the energy transition will depend on societal acceptance of the developments that will be required including multiple large power generation and transmission line projects. It will also require considerable investment by businesses, households and individuals in building upgrades and heat pumps. A clear national plan with broad political support is an essential prerequisite.*[30]

Although there are many examples of poor project planning and delivery in Ireland, there are also examples of large infrastructure projects with State involvement being delivered based on good process.

For example, 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 are, today, routinely planned and delivered on time and on budget.

Likewise, the *Dublin Port Tunnel* took 11 years from the proposal to build the tunnel being made in the *Dublin Transport Initiative* report of 1995 to the tunnel opening in 2006.[31]

In the absence of a similar approach now by way of a national programme of large energy infrastructure projects with broad and unequivocal political support, the most likely outcome is that Ireland will fall well short of the targets to decarbonise the electricity sector by 2050. These targets will not be achieved by wishful thinking and a clear plan based on engineering, financial and project management realities is needed to bring us as close as possible to the emissions targets that have been set for 2050.

29 For example, Dublin Port's MP2 Project, An Bord Pleanála planning reference 304888

30 *SMALL MODULAR REACTORS - Ireland needs to consider SMRs to achieve a zero-carbon energy sector by 2050*, Page 15, June 2024

31 The process to deliver the Dublin Port Tunnel is usefully described in:"The Importance of Process in Planning: the Dublin Transportation Initiative", Pat Mangan, Jim Steer and Neil Chadwick, Built Environment Vol 48 No 4

11. SUMMARY AND CONCLUSIONS

1. Ireland has a target to become climate neutral by 2050. Climate neutrality requires that the energy sector is decarbonised and this, in turn, is dependent on decarbonising the electricity sector
2. Whether this can be achieved depends on a number of factors, including:
    - The availability of the required technologies
    - The implementation of a programme of large energy infrastructure projects on the supply side in a relatively short period of just 25 years
    - Electrification of energy services on the demand side
3. This report focuses on the supply side challenges of technology and project delivery and considers the other two legs of the energy trilemma beyond sustainability, namely energy security and cost.
4. In the absence of a demand target for the electricity sector to meet by 2050, this report has assumed an electricity requirement in 2050 based on the average of four scenarios projected by EirGrid in its publication *Tomorrows Energy Scenarios 2023*:
    - Electricity requirement - 80 TWh
    - Peak demand - 12,000 MW
5. The transition from the conventional grid of the past - powered by synchronous generators (driven by gas, steam and water turbines) - to a renewables based grid requires one set of assets to be replaced by four sets of assets:

    i. Renewables
    ii. Back-up generation
    iii. Storage
    iv. Assets to provide system resilience.
6. A combination of proven renewables technologies (onshore wind, fixed-bottom offshore wind and solar PV) could produce 109.1 TWh and would have a power output of 37,149 MW (3.1 times projected peak demand).
7. In combination with storage and interconnection, the major part of Ireland's electricity requirements could be met by renewables. Interconnection would help Ireland decarbonise because the carbon emissions of electricity imported are accounted for not where the electricity is consumed (Ireland) but where it is produced (Britain or France).
8. Ireland has developed a considerable dependence on interconnectors in recent years and, in 2024, 15.1% of demand was met by imports.
9. Ireland has high electricity prices and there is no prospect that a significant electricity export industry could be developed.
10. However, there is a danger that an oversupply of renewables - with price guarantees provided to generators through the public service obligation (PSO) levied on consumers – could make wholesale prices artificially competitive.
11. It is important that consumers are protected from excessive exposure to having to underwrite large renewable energy projects.
12. The combination of intermittency - and the lack of control on what level of capacity might be available from interconnectors - requires there to be a back-up generation fleet capable of meeting the peak demand of 12,000 MW over a protracted period in order to ensure system adequacy.

13. The only proven fuel for this back-up generation plant is natural gas and this will likely be the case until 2050 and, possibly, beyond.

14. As generation from peat was phased out, as the Kinsale gas field was depleted and as Moneypoint power station transitions from coal to oil before closing altogether in 2029, Ireland's energy security has deteriorated to an unacceptable level. This has been recognised by Government in all National Risk Assessment reports from 2014 to 2024.

15. A strategic store of natural gas with a capacity of 13.2 TWh would be required to meet up to meet 30 days of average demand in 2050.

16. There have been proposals to construct an LNG facility on the Shannon Estuary for almost 20 years which have not progressed. In November 2023, Government concluded that a State-led project for a floating storage and regasification unit (FSRU) was the appropriate option to mitigate Ireland's energy security exposure.

17. The scale of Ireland's future back-up generation requirements suggests that a larger LNG plant - with considerably more storage and a higher gas send out rate than suggested by Government - will be needed.

18. As the consumption of natural gas declines in the future, the nature of the required LNG facility would change from being a source of supply and a strategic reserve to largely being a strategic reserve only. As this happens, it is likely that a subsidy would be required and, if recovered through an arrangement similar to the NORA levy, could cost one eighth of one cent per kWh (based on 80 TWh by 2050) for every €100 million of subsidy that might be needed.

19. Because of the continued reliance on natural gas to 2050, Ireland will, most likely, fall short of the target to eliminate emissions in the electricity sector by, perhaps, 10%.

20. Although electricity will be the dominant energy vector by 2050, a residual requirement for natural gas will remain. Increased biomethane could potentially replace some of this natural gas.

21. In the same way that it is important to plan for the development of new energy infrastructure over the next 25 years, so also there must be a plan for the consolidation of the gas network as demand drops. If the financial viability of the gas grid is undermined by low volumes then it may need to be subsidised by consumers in the future to ensure its availability to the fleet of back-up generation assets. This would be the case regardless of the gas the network might transport.

22. There will a requirement for replacement fuels for sectors such as aviation and the marine. These could include efuels produced from electricity. However, there is no basis to predict when efuels might become available. If they do become available, they would be internationally tradable commodities and Ireland's requirements could be met by imports.

23. Given Ireland's historically high electricity prices and the prospects for continued high costs during the energy transition, there is no reason to believe Ireland might become competitive and develop domestic production of efuels.

24. Underpinning the energy transition is the requirement to increase the capacity of the transmission grid. This could require the construction of 1,150 km of new lines in 46 projects.

25. Including this transmission grid requirement, the energy transition requires the delivery of programme of an estimated 352 projects in a period of just 25 years.

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**

26. In addition to these projects, there are also hundreds more, smaller transmission and distribution system projects that will also need to be completed to deliver the supply side capacity required.

27. The programme of large energy projects needs to be embedded in planning policy at all levels (Local Authority Development Plans, Regional Spatial and Economic Strategies and in the National Planning Framework) with no ambiguity between it and other national policy areas so that planning authorities, including An Bord Pleanála, can have no grounds to reject planning applications on policy grounds.

28. Wherever possible, planning consents should be removed from the critical path of project delivery by designing projects and bringing them through consent processes early so that there are long duration planning consents (of 15 years or longer) available to allow projects go to construction when the time is right.

APPENDIX 1: PROVEN TECHNOLOGIES AVAILABLE BETWEEN NOW AND 2050

The 25 years to 2050 is not a long timeframe in which to complete multiple large energy infrastructure projects and the extent to which the net zero objective for the electricity sector can be achieved is dependent on implementing technologies which are proven and available today:

- Onshore wind
- Fixed-bottom offshore wind
- Solar PV
- Storage

Proven and available implies not only that the technologies are feasible but also that exemplar projects have been financed, completed and are in large-scale commercial operation elsewhere.

Onshore wind

Ireland has a large and growing capacity of onshore wind and total capacity increased from 117 MW in 2000 to 4,730 MW in 2023 (*Figure 13*) with a policy target to reach 9,000 MW by 2030.

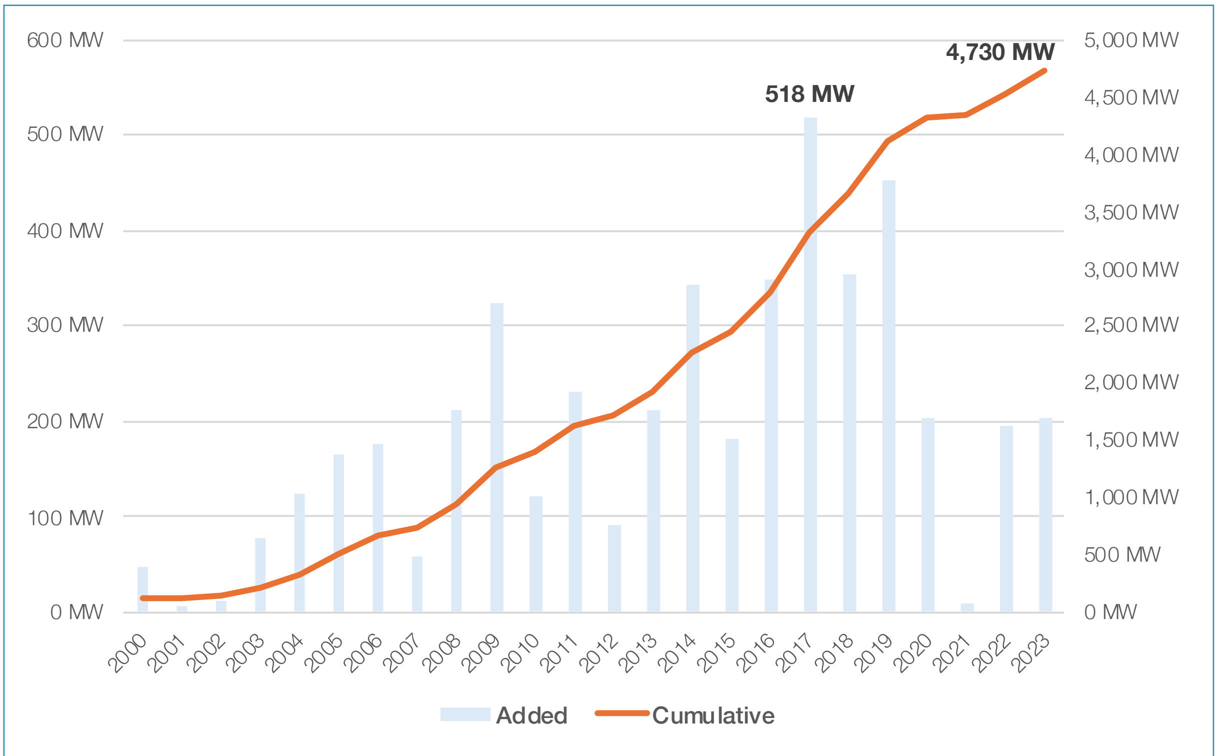

Figure 13: Growth in onshore wind capacity, 2000 to 2023

In 2023, the 4,730 MW operated with a capacity factor of 28% and produced 11.4 TWh of electricity. Assuming a similar capacity factor for the policy target of 9,000 MW by 2030 suggests that onshore wind could contribute **22.1 TWh** to the country's electricity requirement (*Table 32*).

Source	Assumption	MW	Capacity factor	Contribution to electricity requirement
Onshore wind	2030 target achieved by 2050	9,000 MW	28%	22.1 TWh

Table 32: Contribution of onshore wind to electricity requirement in 2050

To reach the 9,000 MW target would require an additional 4,270 MW of capacity to be added by 2030, equivalent to 610 MW per year.[32] This is in excess of the highest capacity added in any previous year (518 MW in 2017). Moreover, it is higher than the capacity of successful bids in any of the four RESS auctions to date (*Table 33*). The next auction (RESS5) for onshore wind and solar projects will take place in 2025 with an indicative commercial operations date for the projects of 2028.

	Date	# projects	MW
RESS1	Sep-2020	19	479 MW
RESS2	Jun-2020	14	414 MW
RESS3	Oct-2023	3	148 MW
RESS4	Sep-2024	4	374 MW
Totals		**40**	**1,416 MW**

Table 33: Summary of RESS auction results for onshore wind

In addition to RESS auctions, wind farms have a proven route to market via Corporate Power Purchase Agreements (PPAs) and more than half of the windfarms developed over the last decade have gone this route.

Onshore wind energy is well proven and the only technical challenge to achieving the target of 9,000 MW is the provision of grid connections.

The onshore wind sector has, however, faced considerable delays in planning due to a combination of Government's slowness in updating the *Wind Energy Development Guidelines 2006* and the dezoning of land in local authority development plans. The imminent publication of revised *Wind Energy Development Guidelines* as a *National Planning Statement* will, hopefully, resolve these issues.

The increased capacity of 4,270 MW required to meet the 9,000 MW target is equivalent to 71 projects, each with a capacity of 60 MW.

At this stage, it is reasonable to envisage the target of 9,000 MW being met, if not by 2030, then within a relatively short time after that. The question at that point will be to what extent even more onshore wind could be deployed in Ireland?

Denmark, with 60% of the land area of Ireland, has 4,832 MW of onshore wind turbines. A similar density of development in Ireland would suggest a potential capacity of onshore wind in Ireland of 7,900 MW. An increase in onshore wind to 9,000 MW would increase the density of onshore wind farms beyond what Denmark has today (*Table 34*). This comparison suggests that there is unlikely to be significant scope to increase the capacity of onshore wind beyond Government's 2030 target of 9,000 MW.

32 As the years progress, and as new windfarm capacity is added, some existing windfarms will reach their end of life (because planning permission will expire, or the plant will have reached the end of its operational life). It has been estimated by Wind Energy Ireland that this point will be reached for 850 MW of existing onshore wind capacity between now and 2030. The figure of 610 MW of additional capacity is, therefore, a net figure and, in reality, the annual increase in capacity required to 2030 is 731 MW per annum.

<table>
<tr><th></th><th>Capacity</th><th>Area</th><th>MW per 1,000 km^2</th><th>Population</th><th>MW per million people</th></tr>
<tr><td>Denmark</td><td>4,832 MW</td><td>42,952 km2</td><td>112.5</td><td>5.9 m</td><td>819</td></tr>
<tr><td>Ireland</td><td>4,732 MW</td><td rowspan="2">70,273 km2</td><td>67.3</td><td>5.3 m</td><td>893</td></tr>
<tr><td>Ireland (2050)</td><td>9,000 MW</td><td>128.1</td><td>6.0 m</td><td>1,500</td></tr>
</table>

Table 34: Comparison of onshore wind farm capacities in Denmark and in Ireland, 2023

Fixed-bottom offshore wind

Fixed-bottom offshore wind – in water depths up to a maximum of about 60 meters – is a well-established technology with over 14,000 MW deployed in waters around Britain alone.

As long ago as 2012, Government published *Harnessing Our Ocean Wealth. One of the key actions identified was to Develop an integrated approach to marine and coastal planning and licensing in order to maximise the potential for Ireland's ocean economy.* [33]

Nine years later, the Maritime Area Planning Act 2021 was passed and, based on this, the Maritime Area Regulatory Authority (MARA) commenced operations in July 2023. One of the key functions of MARA is to issue Maritime Area Consents (MACs) for offshore wind farm developments.

The Maritime Area Planning Act 2021 also provided for the creation of a Maritime Spatial Plan (by DHLGH) and Designated Maritime Area Plans (DMAPs) for offshore renewable energy (by DECC). Future offshore wind projects will be plan-led based on DMAPs.

The final relevant legislation that will complete the framework for offshore wind is the passing of the Marine Protected Areas Bill which has yet to happen.

As the requisite planning and environmental protection framework was being put in place, six projects – with an aggregate capacity of 4,249 MW – competed in the ORESS1 auction.[34] Four projects (3,074 MW) were successful and qualified for CfD contracts. Notwithstanding their being unsuccessful, the other two projects (1,175 MW) have nonetheless proceeded with applications for planning permission based on PPAs. If all six projects are completed, they could contribute **16.7 TWh** to Ireland's electricity requirement in 2050.[35]

The next phase of offshore development has commenced with the creation of the South Coast DMAP comprising four separate areas to a total of 1,315 km2.

An ORESS auction is due to take place in 2025 for 900 MW (**3.5 TWh**) located in one of the four areas (Area A or Tonne Nua). EirGrid is currently developing the project to deliver two offshore substation platforms to provide grid connections for whatever projects ultimately proceed.

Beyond that, the South Coast DMAP has the potential for a further 5,000 MW of offshore wind projects (**19.7 TWh**).

33 *Harnessing Our Ocean Wealth*, July 2012, Page 33
34 *ORESS 1 Final Auction Results*, June 2023
35 Based on an assumed capacity factor of 45%

The ultimate scale of the possible development of fixed bottom projects beyond the South Coast DMAP area will be determined by the creation of further DMAPs around the Irish coast and subsequent ORESS auctions. If a further 10,000 MW (**39.4 TWh**) could be developed in other DMAPs, then a total contribution to the country's electricity requirement from fixed bottom offshore wind could be **79.3 TWh** by 2050 (*Table 35*). This would be more than three times the contribution from onshore wind.

Assumption	MW	Capacity factor	Contribution to electricity requirement
Six ORESS1 projects proceed	4,249 MW	45%	16.7 TWh
Tonn Nua	900 MW	45%	3.5 TWh
Balance of South Coast DMAP	5,000 MW	45%	19.7 TWh
Assumed future DMAPs	10,000 MW	45%	39.4 TWh
Total fixed bottom offshore wind	**20,149 MW**		**79.3 TWh**

Table 35: Summary of fixed bottom offshore wind potential by 2050

If the average size of offshore wind project was 700 MW, then the target capacity of 20,149 MW would suggest the need for 29 projects.

Solar PV

The solar PV sector is not as long established as onshore wind and the installed capacity of solar in Ireland is reported to be 1,185 MW.[36] As of August 2024, there were seven grid connected solar farms with a total capacity of 537 MW, the largest having a capacity of 119 MW.[37]

Solar projects with a total capacity of 3,788 MW have been successful at RESS auctions since 2010 suggesting that there is a large pipeline of future solar projects (*Table 36*).

	Date	# projects	MW
RESS1	Sep-2020	63	796 MW
RESS2	Jun-2020	66	1,534 MW
RESS3	Oct-2023	20	498 MW
RESS4	Sep-2024	23	960 MW
Totals		**172**	**3,788 MW**

Table 36: Summary of RESS auction results for solar

Government has set a target to increase the capacity of solar to 8,000 MW by 2030.

Assuming 80% of the balance of the capacity required (from today's capacity of 1,185 MW) to meet the 8,000 MW target comes from utility scale projects and assuming further that each solar project has a capacity of 40 MW, then 136 projects would need to be completed to reach the 2030 target.

36 *Scale of Solar Report*, 2024, Irish Solar Energy Association

37 EirGrid *System & Renewable Summary Report*

If this were achieved by 2050, then the contribution of solar Ireland's electricity requirement could reach **7.7 TWh** (*Table 37*). This would be equivalent to 10% of the total electricity requirement of 80 TWh.

Source	Assumption	MW	Capacity factor	Contribution to electricity requirement
Solar PV	2030 target achieved by 2050	8,000 MW	11%	7.7 TWh

Table 37: Contribution of onshore wind to the electricity requirement in 2050

Ireland has been a slow starter in developing solar as shown in *Table 38*. However, the potential of solar to provide at least 10% of the country's electricity requirement is confirmed by what has already been achieved in other comparable countries.

Solar	2020	2024	AAGR	% of electricity requirement in 2024
Denmark	1.2 TWh	4.0 TWh	35.6%	11.2%
Netherlands	8.6 TWh	21.5 TWh	25.8%	17.7%
Belgium	5.1 TWh	8.9 TWh	15.0%	11.9%
United Kingdom	12.5 TWh	15.6 TWh	5.6%	5.5%
Ireland	0.1 TWh	1.0 TWh	100.5%	3.1%

Table 38: Comparison of solar generation in selected EU countries, 2020 to 2024 *Source: Ember*

Storage

Grid scale lithium-ion battery technology (typically providing up to two hours output at maximum power) is widely deployed internationally and in Ireland. As of December 2024, EirGrid reported that there were 20 transmission connected battery storage generation facilities in Ireland with a power capacity of 680 MW and a storage capacity of 849 MWh.[38]

According to Energy Storage Ireland, there is in the order of 1,200 MW of batteries on the island with a very large pipeline of projects (10,000 MW) at various stages of development from concept to planning. The main function performed by batteries today is to enhance grid resilience and the market for energy arbitrage in Ireland is not yet well developed.

Longer duration (100 hour) iron-air battery technology is beginning to be deployed in the US and a planning application for a 10 MW / 1,000 MWh battery has been approved (subject to appeal) in Donegal.[39]

In addition to batteries, storage is provided by Turlough Hill (292 MW / 1,752 MWh) and, if the project to build a second pumped storage facility at Silvermines proceeds, it would add another 296 MW / 2,175 MWh.

More battery storage capacity over the coming years will primarily serve to increase the penetration of renewables by better matching supply and demand over periods of hours or days. Batteries can also reduce curtailment due to grid constraints.

38 EirGrid *System & Renewable Summary Report*

39 FuturEnergy Planning application details ref *2461497*,Donegal County Council

EirGrid published a *Call for Evidence on the Market Procurement Options for Long Duration Energy Storage (LDES)* in October 2023 and, in this, listed four benefits for LDES as follows:

1. Increasing the penetration of renewables
2. Reduces Carbon Emissions
3. Reduces the level of renewables dispatch down
4. Reduces All Island Generation Cost

EirGrid subsequently published a *Response to the Call for Evidence on Long Duration Energy Storage (LDES)* in March 2024.

In parallel with EirGrid's consultation, The Climate Change Advisory Council (CCAC) published a working paper (*Review of Deployment of Long Duration Energy Storage in the Electricity Sector in Ireland*) in May 2024.

These two initiatives by EirGrid and CCAC serve to highlight the uncertainty around what LDES technologies might become available over the next 25 years.

Notwithstanding this high level of uncertainty, *Table 39* below shows an indicative figure of 3,268 MW / 55 GWh of storage being available by 2050. The assumed 2,000 MW of 25 hour LDES is speculative and is included in order to complete the indicative shape of the electricity system of 2050 depicted in *Figure 4*. It implicitly assumes that 100 hour iron-air battery projects being developed in the US and proposed in Ireland are successful and that the technology (or another equivalent battery technology) becomes sufficiently proven to allow large capacity battery storage projects to proceed in Ireland between now and 2050.

The scale and structure (in terms of the MW / MWh ratio) of the storage market in 25 years' time is impossible to predict and, given the scale of the pipeline of storage projects suggested by Energy Storage Ireland, the development of market structures which encourage investment could deliver a very different storage sector from that depicted in *Table 39*.

	MW	Duration	MWh
Turlough Hill	292	6.0 hours	1,752
Batteries	680	1.25 hours	849
Existing	**972**	**2.7 hours**	**2,601**
Silvermines	296	7.3 hours	2,175
LDES	2,000	25.0 hours	50,000
Additional	**2,296**	**22.7 hours**	**52,175**
Total by 2050	**3,268**	**16.7 hours**	**54,776**

Table 39: Indicative development of storage capacity to 2050

If the assumed 2,000 MW of additional batteries had an average project size of 50 MW, this would suggest 40 projects would need to be completed over the next 25 years.

APPENDIX 2: OTHER TECHNOLOGY OPTIONS NOT YET PROVEN BUT WHICH MIGHT BECOME AVAILABLE OVER THE NEXT 25 YEARS

There is a number of technologies which could make up any shortfall which might emerge with the proven technologies and, in addition, reduce (or even entirely remove) any vestigial GHG emissions from the electricity sector:

- Floating offshore wind
- Hydrogen
- Small modular nuclear reactors

While it would be premature to include such technologies in the programme of large energy infrastructure projects required by 2050, it is important that policy obstacles which might prevent the consideration of these technologies - to the point where they could potentially provide viable options - are removed.

Floating offshore wind

Ireland's wind resources are greatest in the relatively deep Atlantic waters off the west coast. By comparison to fixed bottom offshore, floating offshore technology is at an early stage of development. For example, where Britain has more than 14,000 MW of fixed bottom wind farms, the first substantial floating offshore windfarm project (400 MW off the east coast of Scotland) has only recently reached the stage of having a bid accepted in the UK's Allocation Round 6 (AR6) auction.

Table 40 compares the capacities and strike prices for different types of wind farm in the AR6 auction where the strike price for floating was 2.7 times the price for onshore wind projects and 2.4 times the price for fixed bottom wind farms.

How high the price was in AR6 can also be gauged by comparing the £139.90 per MWh for the 400 MW floating offshore project to a strike price of £92.50 for the Hinkley Point C nuclear project, with both prices stated in 2012 values.

	MW	Strike Price per MWh (2012 prices)
Onshore	990 MW	£ 50.90
Fixed-bottom offshore	3,363 MW	£ 58.07
Floating offshore	400 MW	£ 139.93

Table 40: Summary of UK Allocation Round 6 results, March 2024
Source: Department for Energy and Net-Zero

In contrast to the high strike price for the project in Scotland, a 250 MW floating project off the coast of Britanny had a bid accepted at a strike price of only €86 in May 2024.

There is some way to go before there could be an auction for floating offshore in Ireland which would be likely to attract bidders.

The experience of two small floating windfarm projects in Scotland - 30 MW Hywind (2017) and 48 MW Kincardine (2021) - has highlighted a significant operational challenge floating wind farms will face, notably the requirement for periodic tow-back of the floating turbines to port for major maintenance. This will be a major consideration in the design of projects in the heavy seas off the west coast of Ireland and could add substantially to the strike price in CfD contracts that will be necessary to support major capital investment.

Floating offshore windfarms will require nearby port facilities from which projects can be built and, over their lifetime, maintained. Two port infrastructure projects (at Moneypoint and at Foynes) are currently at the pre-planning phase.

The *Shannon Estuary Task Force*[40] identified a potential for 70,000 MW of offshore wind off the west coast and set out recommendations for the delivery of up to 30,000 MW by 2050. At these levels, floating offshore could contribute at least 118 TWh to Ireland's electricity requirements by 2050 and 276 TWh ultimately.[41]

The uncertainty about the feasibility / viability of floating offshore can be seen by considering the impact of tow-back. If 1,500 large turbines of 20 MW capacity were deployed and, assuming turbines had to be towed back to port for maintenance every ten years, then 30,000 MW of floating offshore wind would suggest that, on average, 150 turbines would need to be towed to and from Moneypoint and / or Foynes every year. Given the limited weather windows that would be available, this would be a considerable and costly operational challenge and would be a large burden on the economics of the proposition.

Notwithstanding this, because of the huge scale of the potential for floating offshore wind, it is important that work continues to see if this potential can be realised. In addition to bringing the Moneypoint and Foynes port projects through planning, it is also important that Government complete DMAPs off the west coast so that developers are not put off investigating the potential off the west coast.

Hydrogen

The National Hydrogen Strategy identified that,

> *Renewable hydrogen will have an important role in the electricity sector, both in decarbonising the conventional generation required at times when variable renewable electricity is less plentiful, enhancing energy security by diversifying supply, and as a method of storing electricity from variable renewable generation to address the challenges associated with system stability, seasonal wind variability and curtailment.*[42]

In July 2023, the Academy published a commentary which highlighted the challenges of using hydrogen in the manner suggested in the *National Hydrogen Strategy.*[43] These challenges manifest themselves in the low round trip efficiency of 20% in the cycle of using renewable electricity to create hydrogen as an intermediate fuel which could ultimately be used to generate zero emission electricity. The commentary also highlighted the challenge of finding and developing geological locations where hydrogen could be stored at the scale required.

In June 2024, the European Court of Auditors published a report on the EU's industrial policy on renewable hydrogen in which it made four observations: [44]

40 *Shannon Estuary Economic Taskforce Report*, June 2023

41 Based on a capacity factor of 45%

42 *National Hydrogen Strategy* , July 2023, Page 33

43 *A Commentary on the Medium Term Prospects for Ireland's Hydrogen Economy*, August 2023

44 *The EU's industrial policy on renewable hydrogen Legal framework has been mostly adopted – time for a reality check*, European Court of Auditors Special report, June 2024

- *The Commission set unrealistic hydrogen production and import targets - the EU is not on track for achieving them*
- *The legal framework is mostly complete, but its overall impact on the market is as yet uncertain*
- *There are multiple EU funding sources for hydrogen projects, but no guarantee that they will be appropriate for developing an EU-wide market*
- *Insufficient coordination efforts by the Commission, both internally and with member states, but also with industry*

The European Commission published its replies to the ECA report in July 2024 and in these replies included the following observation:[45]

> *… it is important to recognise that a European hydrogen ecosystem is still in a very early stage, and that the regulatory framework has not even been transposed into national legislation in some cases. Besides the necessary regulation, there are many different segments of the industrial value chain for hydrogen that need to be initiated simultaneously, including the development of additional renewable resources to produce renewable hydrogen, the upscaling of electrolyser technologies and associated manufacturing capacity to convert renewable electricity into hydrogen, the development of new pipelines, compressors, storage and hydrogen refuelling stations to bring hydrogen to the end-use sectors, as well as new industrial production processes, fuel cells, turbines and motors to replace the use of fossil fuels with hydrogen in end-use applications.*

From Ireland's perspective, the ECA report and the Commission's replies serve to highlight the high level of uncertainty about what can be achieved in Ireland by 2050 using hydrogen generated from renewable sources.

Whatever might be achieved with green hydrogen, Ireland will be a technology taker and will depend on the successful development of technologies and projects elsewhere in the EU and beyond to provide models which can be adapted and applied to meet the country's requirements.

ESB is progressing with pilot projects for power generation from renewable hydrogen and also with studies on large scale hydrogen storage.[46]

In addition, a one-year German / Irish initiative called *HyIreland* - sponsored by the Federal Ministry of Education and Research and by the Department of the Environment, Climate and Communications – was launched in November 2024 to investigate the technological, economic, and environmental potential for the production of green hydrogen and its synthesis products in Ireland, taking into account their transport to Germany. The Irish project partners are ESB and the International Energy Research Centre (IERC).

The pilot projects being undertaken in Ireland are modest in scale and the studies and investigations on the potential for green hydrogen are early stage and conceptual. There can be no certainty that feasible or viable options will emerge based on which large energy infrastructure projects might be completed by 2050 to provide the storage and back-up generation capabilities Ireland will need.

Ireland's energy security exposure is extreme and the rapid deployment of renewables over the coming 25 years requires the parallel development of adequate back-up generation capacity. Hydrogen cannot be relied on to meet either of these related requirements over the next 25 years and there is a possibility that it may never be able to.

45 Replies of the European Commission to The European Court of Auditors' Special Report, European Commission, July 2024.
46 Emerging Technology Insights 2024, ESB, November 2024

Small Modular Nuclear Reactors

Given the longstanding and proven capability of nuclear power, the development of Small Modular Nuclear reactors offers the possibility of nuclear power plants becoming available at a scale appropriate to Ireland's requirements.

However, there is uncertainty as to when at what cost this might happen.

In addition, there are legislative bans in place which prevent the development of nuclear power plants in Ireland.

The Academy has previously recommended that Ireland should develop the institutional capacity that would be required to reach the point where the country is *ready to make a knowledgeable commitment to a nuclear power programme.* [47,48]

Whether SMRs deliver on their promise remains to be seen and won't be known until the 2030s, at the earliest. However, the proven capacity of nuclear is such that it should not be ignored as a possible future option.

There is a current view in energy policy in Ireland that we are moving between two extreme points from a conventional system dominated by base load generating plant to one dominated by renewables. However, there is no reason why a future system incorporating both zero-emission base load nuclear plant alongside renewables could not meet Ireland's needs.

Power generation and transmission assets are long-lived. Ardnacrusha, for example, remains operational after 95 years and, in the case of nuclear power plants, the longest running plants in France and the US have been in operation for 47 and 56 years respectively (*Table 41*).

	France	US
Reactor Name	Bugey 2	Nine Mile Point 1
Type	PWR	BWR
Capacity (MWe)	910 MW	613 MW
Grid Connection	1978	1969
Load Factor (2024) (%)	66%	87%
Electricity Generated	5.2 TWh	4.7 TWh

Table 41: Longest operating nuclear power plants in France and the US, 2024
Source: World Nuclear Association

The Maritime Area Consents for the six ORESS1 offshore windfarms have terms of 45 years. These are longer than the operational lifetimes of the windfarms that will be developed on foot of these consents.

Taking a very long-term view, therefore, there is a possibility that windfarms developed between now and 2050 could, at the end of their working lives, be replaced by longer-lived nuclear assets. These would be in addition to any SMR plants that might be developed before 2050.

Ultimately, it could 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

47 *Small Modular Reactors - Ireland needs to consider small modular nuclear reactors to achieve a zero-carbon energy sector by 2050*, June 2024

48 This would bring Ireland to the first milestone of the International Atomic Energy Agency's (IAEA) approach for countries to develop a nuclear power programme *Milestones in the Development of a National Infrastructure for Nuclear Power*, IAEA, 2015

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.

The process of developing Ireland's electricity system - driven by the need to replace fossil fuels by renewables – will not simply stop once this objective has been achieved in 2050 or at some point after that. Rather, there will be a continuing need to replace generating plant and, as this happens, there will be opportunities to introduce new, improved and more efficient technologies.

APPENDIX 3: ELECTRICITY PRICES IN IRELAND

Household electricity prices (excluding taxes and levies)

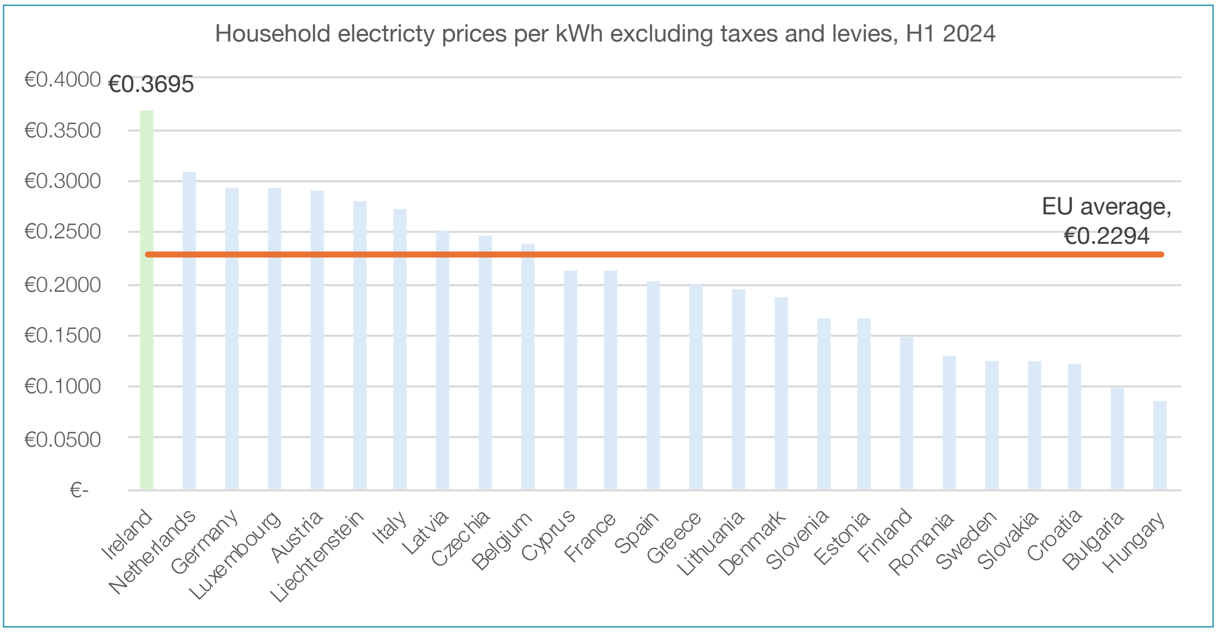

Figure 14: Comparative price (excluding taxes and levies) of household electricity in the EU in the first half of 2024
Source: Eurostat

Household electricity prices (including taxes and levies)

Figure 15: Comparative price (including taxes and levies) of household electricity in the EU in the first half of 2024
Source: Eurostat

Non-household electricity prices (excluding taxes and levies)

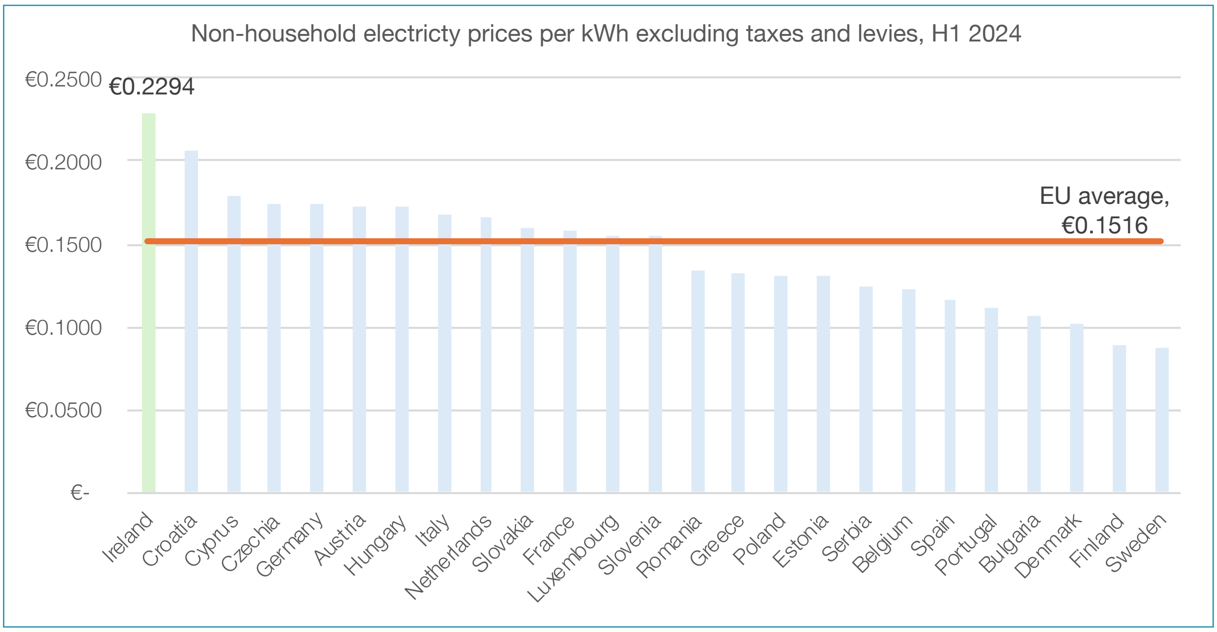

Figure 16: Comparative price (excluding taxes and levies) of non-household electricity in the EU
Source: Eurostat

Wholesale electricity prices

Figure 17 compares the average monthly wholesale prices for electricity in Ireland, Britain and France from January to August 2024. Over these eight months, average wholesale prices in Ireland were consistently higher than those in Britain and in France.

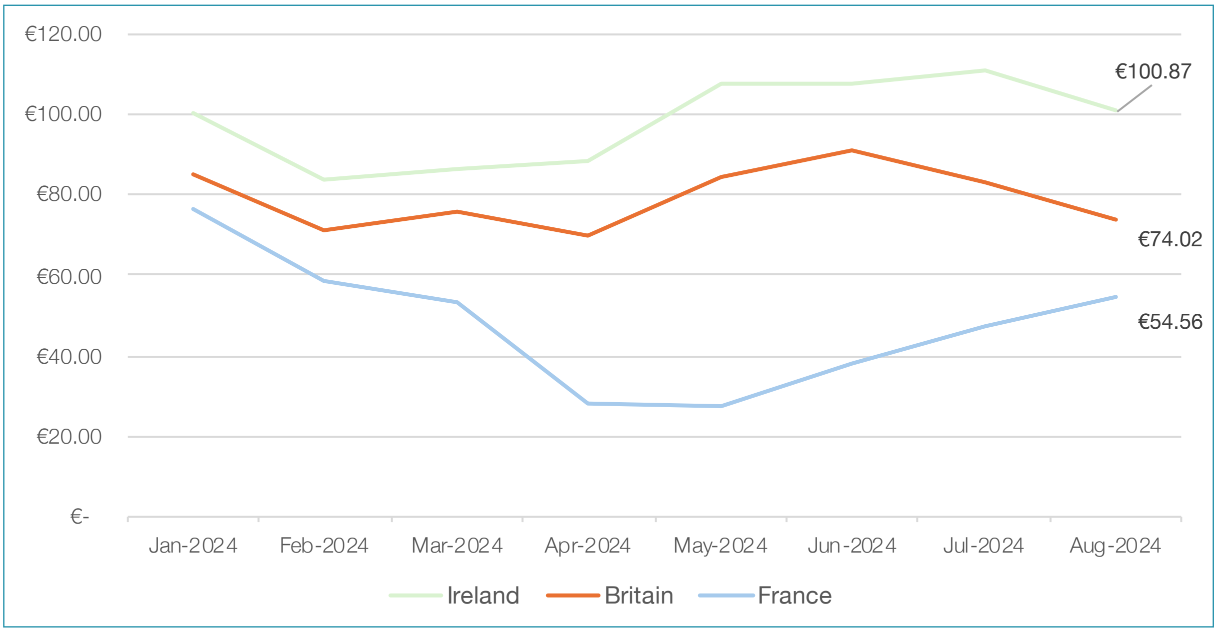

Figure 17: Trends in monthly average ISEM wholesale electricity prices with Britian and France, 2024

On average, the price in Ireland was €98.34 per MWh compared to €79.25 per MWh in Britain and €47.92 per MWh in France. Prices in Ireland were also significantly and consistently higher than those in any other market Ireland might conceivably be connected to in the future (*Table 42*).

€	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Average
Ireland	100.19	84.03	86.64	88.53	107.79	107.72	110.94	100.87	98.34
Britain	85.40	71.01	75.50	69.82	84.48	90.89	82.86	74.02	79.25
France	76.66	58.39	53.54	28.23	27.09	37.78	47.09	54.56	47.92
Belgium	78.63	61.53	61.13	48.04	54.45	60.92	54.59	65.53	60.60
Denmark	76.15	57.06	61.15	59.63	58.52	64.90	62.33	72.79	64.07
Germany	76.63	61.36	64.66	62.39	67.28	72.89	67.71	82.03	69.37
Netherlands	78.43	63.91	63.38	58.42	65.70	68.06	65.04	77.10	67.51
Spain	74.11	39.90	20.28	13.77	30.32	56.26	72.43	91.10	49.77

Table 42: Comparison of monthly average ISEM wholesale electricity prices with selected countries, 2024 (€)
Source: Ember and OFGEM

APPENDIX 4: NON-RENEWABLE GENERATION IN IRELAND[49]

Generator	Type	MEC (MW)
Poolbeg	Gas/DO	463 MW
Whitegate	CCGT	445 MW
Aghada CCGT	CCGT	431 MW
Dublin Bay Power	Gas	415 MW
Huntstown (2)	Gas	412 MW
Tynagh	Gas	404 MW
Huntstown (1)	Gas	352 MW
Moneypoint (1)	Coal	288 MW
Moneypoint (2)	Coal	288 MW
Moneypoint (3)	Coal	288 MW
Tarbert (3)	HFO	241 MW
Tarbert (4)	HFO	241 MW
Great Island CCGT	CCGT	216 MW
Great Island CCGT	CCGT	215 MW
Aughinish Alumina	CHP	162 MW
West Offaly Power	Peat	141 MW
Edenderry Peaking	OCGT	116 MW
North Wall (5)	Gas/DO	109 MW
Lough Ree Power	Peat	94 MW
Aghada (11)	Gas/DO	90 MW
Aghada (12)	Gas/DO	90 MW
Aghada (14)	Gas/DO	90 MW
Tarbert (1)	HFO	54 MW
Tarbert (2)	HFO	54 MW
Tawnaghmore Peaking 1	OCGT	52 MW
Tawnaghmore Peaking 2	OCGT	52 MW
Rhode PCP (1)	Distillate	52 MW
Rhode PCP (2)	Distillate	52 MW
Kelwin (KZ3)	Diesel	2 MW
Total		**5,907 MW**

49 As of April 2024, *System and Renewable Summary Report*, EirGrid

APPENDIX 5: SUMMARY ANALYSIS OF EIRGRID'S *TRANSMISSION DEVELOPMENT PLAN 2024*

EirGrid / SONI have a regulatory requirement to produce a *Ten-Year Generation Capacity Statement and an All Island Ten-Year Transmission Forecast Statement*.

Based on the *All-Island Ten Year Transmission Forecast Statement*, EirGrid produces a *Transmission Development Plan* setting out the pipeline of development projects to increase grid capacity in Ireland.

The current version - *Transmission Development Plan 2024* - identifies 223 grid development projects (*Table 43*).

	Border Midlands West	South-East Mid-East Dublin	South-West Mid-West	Multiple locations	Totals
New build capacity	5	15	2		22
New build connection	26	34	13		73
Uprate/Modify	28	19	10	3	60
Refurbish/ Replace	9	28	15	8	60
Other		4		4	8
Totals	**68**	**100**	**40**	**15**	**223**

Table 43: Summary of projects in EirGrid's Transmission Development Plan 2024 by type and by region

The 223 projects include 55 transmission cable / line projects (*Table 44*).

	# cable projects	km cable projects	# line projects	km line projects	Total # projects	Total km
New build capacity	5	114 km	1	137 km	6	251 km
Uprate / Modify			34	1,008 km	34	1,008 km
Refurbish / Replace	6	73 km	8	599 km	14	672 km
Other	1	-			1	-
Totals	**12**	**187 km**	**43**	**1,744 km**	**55**	**1,931 km**

Table 44: Analysis of cable and line projects by type in EirGrid'sTransmission Development Plan 2024

Of these 55 transmission cable / line projects, only six projects will provide new build capacity. Five of these are cable projects and only one (the 137 km North-South Interconnector) is a new transmission line project.

APPENDIX 6: PREVIOUS REPORTS OF THE ENERGY & CLIMATE ACTION COMMITTEE

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

GLOSSARY

Term / abbreviation	Description
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%.
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.*
CRU	Commission for Regulation of Utilities
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.
EWIC	East West Interconnector. A 500 MW and 260 km (186 km undersea) interconnector owned by EirGrid running between Ireland and Wales.
FID	Final Investment Decision
GHG	Greenhouse gases
GW	Gigawatt. 1 GW = 1,000 MW.
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

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.
Net-zero	In this report, the term net-zero refers to conventional generation plant fuelled by natural gas but with carbon capture and storage (CCS) or by fuels such as biomethane.
NORA	National Oil Reserves Agency
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.
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.
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.
Zero-carbon	In this report, the term zero-carbon refers to renewables or to thermal generation plant fuelled by fuels produced by renewables such as hydrogen or ammonia.

Disclaimer

The members of the Taskforce and the contributors participated in extensive discussions in the course of a series of meetings, and submitted comments on a series of draft reports. This report represents the collective view of the Academy , and its recommendations do not necessarily reflect a common position reached by all members of the Taskforce and do not necessarily reflect the views of individual members of the Taskforce, nor do they necessarily reflect the views of the organisations to which they belong.

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