Shaping our electricity future

Technical report

EIRGRID SONI

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Purpose

EirGrid Plc and SONI Ltd - the electricity system operators for Ireland and Northern Ireland, are publishing the inaugural '*Shaping Our Electricity Future Report 2030*' in support of decarbonisation policies set by the Government of Ireland and the Government of the United Kingdom.

70% RES-E target has become a legal obligation as part of Ireland's National Energy and Climate Plan (NECP) 2021-2030, which is Ireland's contribution to the European Union's Clean Energy Package.

While energy policy is yet to be set in Northern Ireland, we are encouraged by the Economy Minister's aspiration of no less than 70% electricity from renewable sources by 2030. SONI continues to support the Minister and officials in their policy development and we anticipate this document, and subsequent consultations, will provide further input to this process.

EirGrid and SONI seek to provide electricity, at the most economic price possible – today, tomorrow and for decades to come. We want to provide a cleaner, more efficient, reliable, and secure electricity supply for consumers on the island by 2030. This commitment is at the heart of this project; this document informs the consultation to assist in setting out the roadmap to achieving this important ambition.

Shaping our electricity future

1. Introduction

1. Introduction

1.1. Context

1.1.1. Decarbonisation ambition

At the end of 2019, EirGrid Plc and SONI Limited launched their five-year strategy to transform the electricity systems in both jurisdictions. These strategies focus on the transformation of the power system and electricity market, so that 70% RES-E is achieved in Ireland and Northern Ireland by 2030.

Since then, a 70% RES-E target has become a legal obligation as part of Ireland's National Energy and Climate Plan (NECP) 2021-2030 , which is Ireland's current contribution to the European Union's effort-sharing approach of the Clean Energy Package . Note that the 70% RES-E target in Ireland was set prior to the Programme for Government's intention to increase its decarbonisation ambition to achieve a 7% annual reduction in greenhouse gas emissions between 2021 and 2030. The next opportunity to revise Ireland's NECP and thus legally-binding RES-E target is in 2023.

Northern Ireland is currently developing a new energy strategy, with a call for evidence closed in April 2020. We are encouraged by the ambition laid out by the Economy Minister in recent statements in relation to no less than 70% of electricity from RES by 2030. The Minister's vision aligns closely with that of all of SONI's regional neighbours.

1.1.2. Delivering the decarbonisation ambition

The key to delivering on our new strategy is to evolve the power system so it can handle world-leading levels of RES, predominantly variable RES such as offshore wind, onshore wind and solar energy.

To achieve a 70% RES-E ambition, the electricity system on the island could need up to an additional 10,000 megawatts (MW) of RES by 2030, approximately 8,400 MW in Ireland and 1,600 MW in Northern Ireland, depending on factors such as electricity demand growth, the dispatch-down mitigation measures delivered as well as the remaining system mix, for example interconnection and storage. Such high shares of variable RES will impact power system planning and operation and market design.

1.2. Work streams – markets, networks and operations

Shaping Our Electricity Future is a study spanning across the three dimensions of transmission networks, power system operation, and electricity markets with the aim of developing an integrated all-island vision of the 2030 power system and electricity market. Figure 1 shows a summary of the work steams.

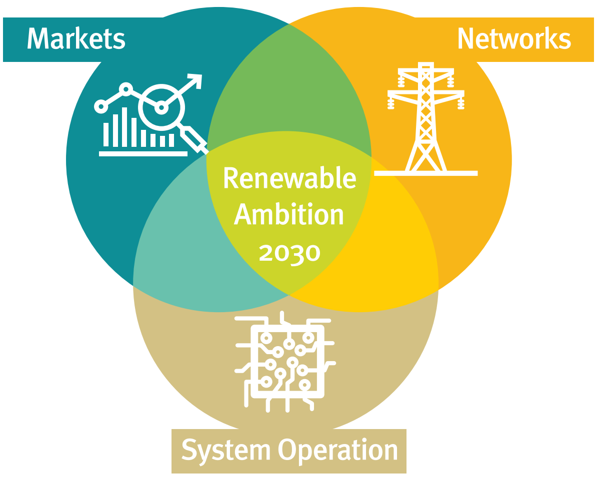


Figure 1: Three work streams

The purpose of this study is to:

- Establish the basis for developing an economic and deliverable solution for 2030, which also supports delivery of the Renewable Ambition;
- Articulate the pathway for its delivery; and
- Create the framework for an informed discussion with stakeholders on the island of Ireland.

2. Power System Transition

2. Power System Transition

2.1. The all-island power system

The Ireland and Northern Ireland power system is a synchronous system with limited HVDC interconnection to Great Britain. At the time of writing this report, the power system had experienced an all-time peak load of 6.5 GW which occurred in December 2020, and a maximum all-time wind output of 4.23 GW[1] which occurred in February 2020. At present, there are two HVDC interconnections between the island of Ireland and Great Britain: the 0.5 GW Moyle Interconnector and the 0.5 GW East-West Interconnector. There is over 5.5 GW[2] of wind capacity installed on the power system and there is approximately 10 GW of dispatchable capacity, including the interconnectors[3]. Table 1 shows a summary of the peak demand and installed capacity figures for the all island electricity system.

Table 1: Overview of the all-island electricity transmission system

	Northern Ireland	Ireland	All-island
Peak demand 2019 (MW)	1,590	5,014	6,548
Installed wind capacity (MW)	1,276	4,234	5,510
Installed RES (MW)	1,610	4,744	6,354
Installed dispatchable generation capacity (MW)	2,491	7,525	10,016
Installed HVDC capacity import (MW)	450	500	950
Installed HVDC capacity export (MW)	500	500	1,000

EirGrid and SONI together operate the transmission systems - North and South - on an all-island basis. The transmission system in Northern Ireland is operated at 275 kV and 110 kV. The transmission system in Ireland is operated at 400 kV, 220 kV and 110 kV. The two transmission systems are connected by a 275 kV double circuit from Louth station in Co. Louth (Ireland) to Tandragee station in Co. Armagh (Northern Ireland).

The 400 kV, 275 kV and 220 kV networks form the backbone of the transmission system. They have higher power carrying capacity and lower losses than the 110 kV network. In Ireland, the 400 kV network provides a high capacity link between the Moneypoint generation station on the west coast and Dublin on the east. In Northern Ireland the 275 kV network is comprised of:

- A double circuit ring;
- A double circuit spur to Coolkeeragh Power Station; and
- A double circuit spur southwards into Co. Louth, in Ireland.

In Ireland the transmission network is comprised of single circuit lines which are interconnected to cover the wider geographical distances between stations. Typically large generation stations (greater than 200 MW) are connected to the 220 kV or 400 kV networks. The 110 kV circuits provide parallel paths to the 220 kV, 275 kV and 400 kV networks and are the most extensive element of the all-island transmission system, reaching into every county on the island of Ireland.

The all-island transmission system is generally comprised of overhead lines. There are exceptions to this, such as in the city centres of Belfast, Cork and Dublin, where underground cables are used. Figure 2 shows the all-island transmission system at the start of 2020.

1 EirGrid Group, System and Renewable Summary Report, 2021
2 EirGrid Group, Wind Installed Capacities – 1990 to date, 2021
3 EirGrid Group, All-Island Generation Capacity Statement 2020-2029 (GCS)

Transmission System Map

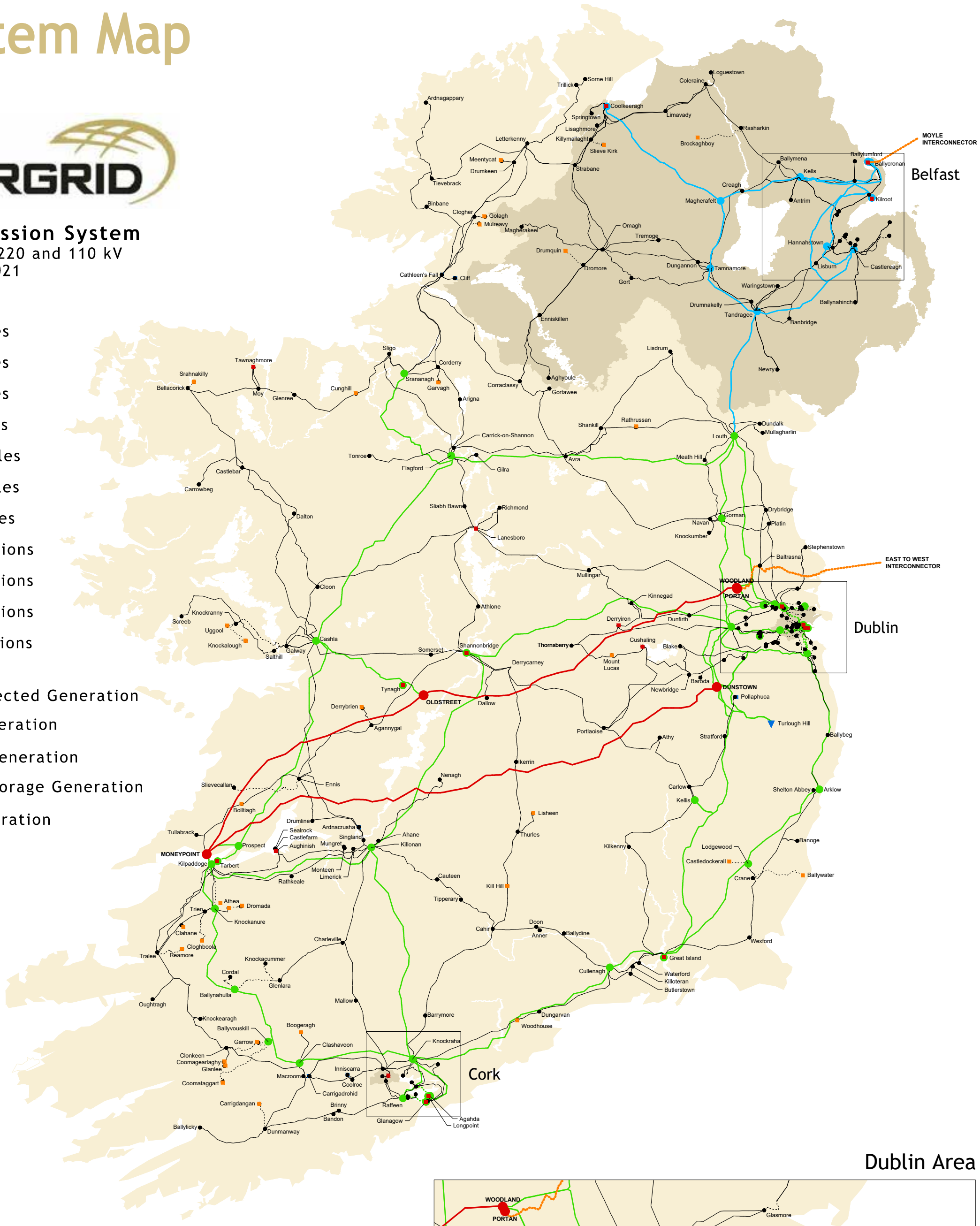
EIRGRID

Transmission System
400, 275, 220 and 110 kV
January 2021

- 400kV Lines
- 275kV Lines
- 220kV Lines
- 110kV Lines
- 220kV Cables
- 110kV Cables
- HVDC Cables
- 400kV Stations
- 275kV Stations
- 220kV Stations
- 110kV Stations

Transmission Connected Generation

- Hydro Generation
- Thermal Generation
- Pumped Storage Generation
- Wind Generation



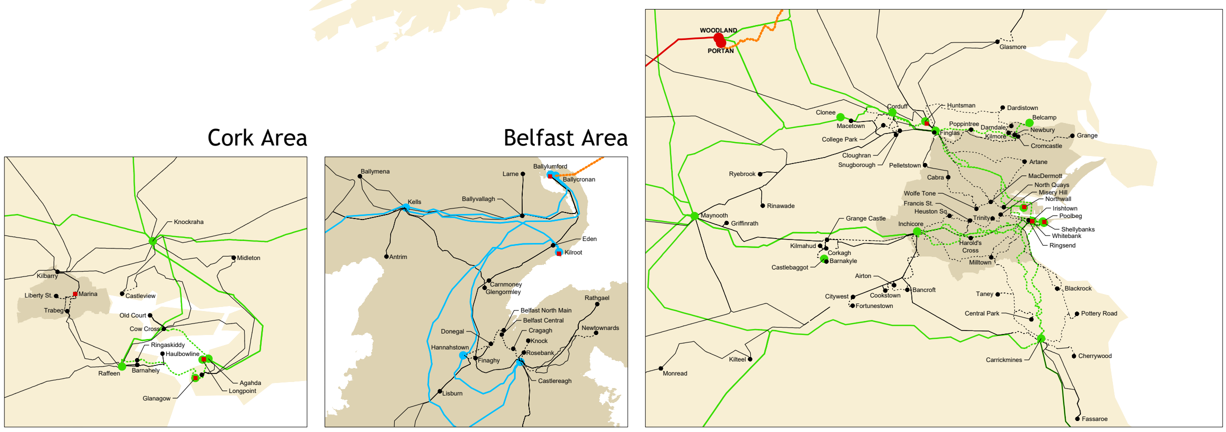


Figure 2: All-island transmission system in January 2020

As the energy sector moves towards a sustainable, low-carbon future there will be major changes in how and where electricity is generated, how it is connected to the grid, and in how it is bought and sold. There will also be major changes in how electricity is used, such as for transport and heat.

The electricity system will carry more power than ever before and most of that power will be from non-synchronous RES such as wind and solar. Coal and fossil oil-based generation will be phased out in the next decade. Concurrently, in isolation to the changes on the supply-side, there will be significant changes on the demand-side with new technology arriving which will allow electricity users to generate and store power, and return any surplus to the grid.

Realising these opportunities will require a significant transformation of the electricity system. More importantly, these changes will need to be managed in a coordinated way that delivers the best outcome for the public. As Transmission System Operator and Market Operator in Ireland and Northern Ireland, EirGrid and SONI have central roles to play in leading the radical transformation that is now required.

EirGrid and SONI employ scenario planning to manage the uncertainty present in the planning timeframe. The Tomorrow's Energy Scenarios (TES) and Tomorrow's Energy Scenarios Northern Ireland (TESNI) include a robust stakeholder engagement process which aims to set out plausible future scenarios for the electricity system. The latest TES and TESNI cycles focused on how electricity demand and supply could evolve over the next 20 years to 2040. This Shaping our electricity future study uses the TES and TESNI datasets that meet the RES-E ambition of 70% by 2030, namely Centralised Energy (CE) and Coordinated Action (CA) in Ireland; Addressing Climate Change (ACC) in Northern Ireland.

2.2. Generation portfolio

2.2.1. System adequacy

EirGrid and SONI assess the expected electricity demand and the level of generation capacity that will be required on the island over the next ten years. EirGrid and SONI carry out system adequacy studies to evaluate the balance between supply and demand for a number of realistic scenarios.

A number of capacity market auctions have been held which are central to system adequacy. New types of capacity such as batteries, demand side units, and flexible generators have entered the market as a result. Interconnection also plays a role in providing adequacy between different markets areas where a surplus in one market can provide power to meet a generation shortfall in another market.

Long term demand in Ireland is increasing and is forecast to increase significantly due to the expected expansion of many large energy users. With this increase in demand, and the expected decommissioning of generation plant due to decarbonisation targets and emissions standards, it is expected that new capacity will be required.

There is sufficient renewable energy capacity in the connection pipeline to meet the Renewable Ambition by 2030. Over the 10-year transition, demand will increase, older high emissions capacity will exit the market (approx. 20% of portfolio), and generator outages will tend to increase as older capacity, that is set to be decommissioned, struggles to justify funding for maintenance. The orderly coordination of the retirement of fossil fuel capacity, synchronised with the development and energising of new renewable and clean dispatchable generation, and matching the increased consumer demand is key to mitigating the risk of potential supply shortfalls.

Total Electricity Requirement in Northern Ireland has been relatively stable which is expected to continue.

2.2.1.1. Short – Medium Term Adequacy Assessment

There were a number of system alerts in Ireland in winter 2020/21 – this is not the first time we have had these on the system. They indicate to industry market participants that capacity margins are tight and a loss of a generator could mean difficulty in meeting demand.

This winter we experienced a combination of factors such as zero/low wind, low available interconnector support, poor plant performance and a cold snap resulting in record peak electricity demand. We expect the number of system alerts to increase over the coming winters as capacity exits and demand increases. We will be working with CRU and DECC to address these issues.

Relative to the Generation Capacity Statement 2020-2029[3], a number of factors have exacerbated the adequacy position in Ireland over the last 12 months:

- **Forecasted new generation failed to materialise** – new generation that was previously successful cleared in the capacity market auctions has been withdrawn by the developer.
- **Delay in building new capacity** – additional new capacity that was forecasted for delivery in 2022/3 has been delayed because of planning compliance, emissions audits and the global pandemic.
- **Emissions Limits** – Fossil fuel generation has been excluded from the capacity market from October 2024 because the plant will exceed new EU emission limits. In the absence of having a capacity contract it is assume that the plant seeks to close earlier than expected
- **Increase in generation outages** - the availability of a number of existing generators, including those plant expected to decommission in the coming years, has been lower than forecasted.

The capacity auction for the period 01 October 2024 to 30 September 2025 was run at the end of January 2021. The recent withdrawal of previously procured capacity and the failure of the recent auction to clear sufficient capacity means there is a significant capacity shortfall against security standards for Ireland.

The situation is challenging in the short term (current and next winter). System alerts are expected to continue during this period. The main issues are in October 2023 and 2024.

Studies are ongoing but the additional capacity required, over and above the recent 2024/25 capacity auction, could be the order of hundreds of MWs of new capacity on the system for October 2023 and also October 2024.

Analysis and potential solutions are currently underway in consultation with CRU and DECC, with the understanding that any proposed solutions need to be cognisant of the Programme for Government and the Climate Action Plan target to achieve 70% of our electricity to come from renewable sources by 2030.

The results of this analysis will be made available to stakeholders during that consultation process.

To cater for a range of credible future scenarios, and to ensure the transition is managed in a coordinated manner, EirGrid believes 1 to 2 GW of new clean, dispatchable capacity will be required between now and 2030 in Ireland. Gas-fired generation is expected to play a key role here. The quantum will be influenced by the evolution of the capacity portfolio and factors such as generator availability rates, transmission outage planning, locational elements etc.

Current analysis and projections for Northern Ireland indicate there is sufficient capacity in the short to medium term to meet system needs.

2.2.1.2. Long Term Adequacy Assessment

New dispatchable resources are needed to ensure that the generation portfolio continues to meet reliability standards and that demand can met on low RES output days. Gas-fired generation is expected to continue to play an important role, replacing retiring conventional plant and providing the multi-day capacity required to ensure security of supply during prolonged periods of low wind. This capacity is especially important when large continental-scale weather patterns affect the availability of RES in Ireland and in neighbouring electricity systems.

One of the most onerous of these for RES production are blocking anticyclones, whereby wind output is consistently low for multiple days to a week. During such times, the wind outputs in Great Britain and France will also be affected by the same weather regime. To compound this challenge, such instances can be accompanied by a cold snap in winter. In such cases, it is essential to have indigenous resources that can supply electricity over a multi-day, rather than multi-hour, period. Market designs must ensure that such multi-day capacity continues to play an important role in a reliable generation portfolio into the future.

SEM capacity auctions offer opportunities for fossil fuel plants to recover costs ensuring that they are available when needed. As more RES penetrates the energy market over time, there will be a growing need to price and procure additional system services such as ramping capability and adapt capacity markets to ensure that generation adequacy standards continue to be met.

2.2.2. Conventional generation

Due to Clean Energy Package legislation on CO_2 emission limits for capacity market payment eligibility[4], and planning decisions[5], it is expected that plant using coal, peat and oil as their primary fuel will decommission by 2030. In light of this, the capacity adequacy of the TES portfolios is ensured via the expansion of new gas-fired power plant, battery energy storage, interconnection, and demand side units. A summary of the conventional fleet capacity, summed to the nearest 100 MW, is shown in Table 2.

Table 2: Conventional power plant, storage, and demand side unit capacity assumptions for Ireland, 2030

Fuel Type	Ireland 2020 [MW]	Northern Ireland 2020 [MW]	Ireland 2030 [MW]	Northern Ireland 2030 [MW]
Combined cycle gas turbine	3,400	1,000	3,000	1,500
Open cycle gas turbine	300	0	1,200	600
Demand side unit	500	100	1,000	200
Battery energy storage	200	<100	600	300
Pumped hydro energy storage	300	0	300	0
Distillate oil	300	300	0	100
Heavy fuel oil	600	0	0	0
Coal	900	400	0	0
Peat	300	0	0	0
Total	**6,800**	**1,900**	**6,100**	**2,700**

New clean dispatchable resources are needed in Ireland to ensure that the generation portfolio continues to meet adequacy standards so that electricity demand is met when RES is not available or other generating plant / interconnection is forced out due to unforeseen events. Gas-fired generation is expected to play an important role, replacing retiring conventional plant and providing the multi-day capacity required to ensure security of supply during prolonged periods of low wind. The market design needs to attract the levels of capacity required to operate a safe and secure system in a future where energy is increasingly supplied by RES.

Reflecting the adequacy challenges facing Ireland, EirGrid are currently carrying out detail analysis to identify effective locations for new clean dispatchable technologies. It will identify a number of locations on the network where these new technologies could be located, so that they address both system wide and locational network issues.

2.2.3. Renewable generation

As part of the TES and TES NI consultations, Wind Energy Ireland and Renewables NI provided guidance regarding the onshore wind pipeline in Ireland and Northern Ireland. These pipelines are the basis of the onshore wind farm locations.

For Ireland, new RES connections were added based on where they are in the planning process. The generators were added until there was sufficient system-level capacity using those generators with planning consent (i.e. approximately 1 GW) and those in the planning process or going into planning before 2023 (i.e. approximately 4 GW).

4 SEM Committee, Capacity Remuneration Mechanism 2024/25 T-4 Capacity Auction Parameters and Compliance with the Clean Energy Package, 2020
5 ABP, West Offaly Power Station decision, 2019

Therefore, for the Co-ordinated Action (CA) scenario for 2030 where 8.2 GW of installed onshore wind capacity is considered, the portfolio is composed of the following:

- The current onshore wind accounting for 4.3 GW;
- The full capacity of generators with planning consent (i.e. approximately 1 GW); and
- The capacity of those generators in the planning process or going into planning before 2023 scaled to the appropriate value on a pro-rata basis (i.e. approximately 2.9 GW out of estimated 4 GW). The scaling approach ensures that all locations are considered. In such a way, the probability of which wind farms will connect ahead of others is not speculated upon.

Of the 4.3 GW of current onshore wind farms, it is assumed that the 0.9 GW of farms that reach end of life (i.e. 20 years) by 2030 repower to their current capacity.

For Northern Ireland, new RES connections were added using a similar approach. For the Addressing Climate Change (ACC) scenario for 2030 where 2.034 GW of installed onshore wind capacity is considered, the portfolio is composed of the following:

- The current onshore wind accounting for 1.238 GW;
- Projects in the planning process accounting for 0.220 GW;
- The assumed replanting of wind farms according to scenario specific assumptions (i.e. approximately 0.204 GW);
- Additional capacity from Renewables NI data assigned to clusters as needed (i.e. approximately 0.254 GW); and
- Projects in Renewables NI data located in sensitive areas (i.e. approximately 0.118 GW).

Assumptions made regarding the quantities of RES (i.e. onshore wind, offshore wind and solar) per jurisdiction are based on the TES and TES NI and are given in Table 3.

Table 3: Summary of assumed variable renewable generation sources

Source	Jurisdiction	2020 [GW]	2030 [GW]	Delta [GW]
Onshore Wind	IE	4.3	4.40 – 8.20	0.10 – 3.90
	NI	1.24	1.40 – 2.00	0.16 – 0.76
Offshore Wind	IE	0.03	1.80 – 4.50	1.77 – 4.47
	NI	0	0.35 – 0.70	0.35 – 0.70
Solar	IE	0.05	0.60 – 2.00	0.55 – 1.95
	NI	0.25	0.6	0.35
Total	**IE**	**4.4**	**9.5 – 12.0**	**5.1 – 7.6**
	NI	**1.5**	**2.7 – 3.0**	**1.2 – 1.5**

The assumptions pertaining to the spatial distribution of the variable RES connections, as well as some of the remaining generation portfolio are shown in Figure 3.

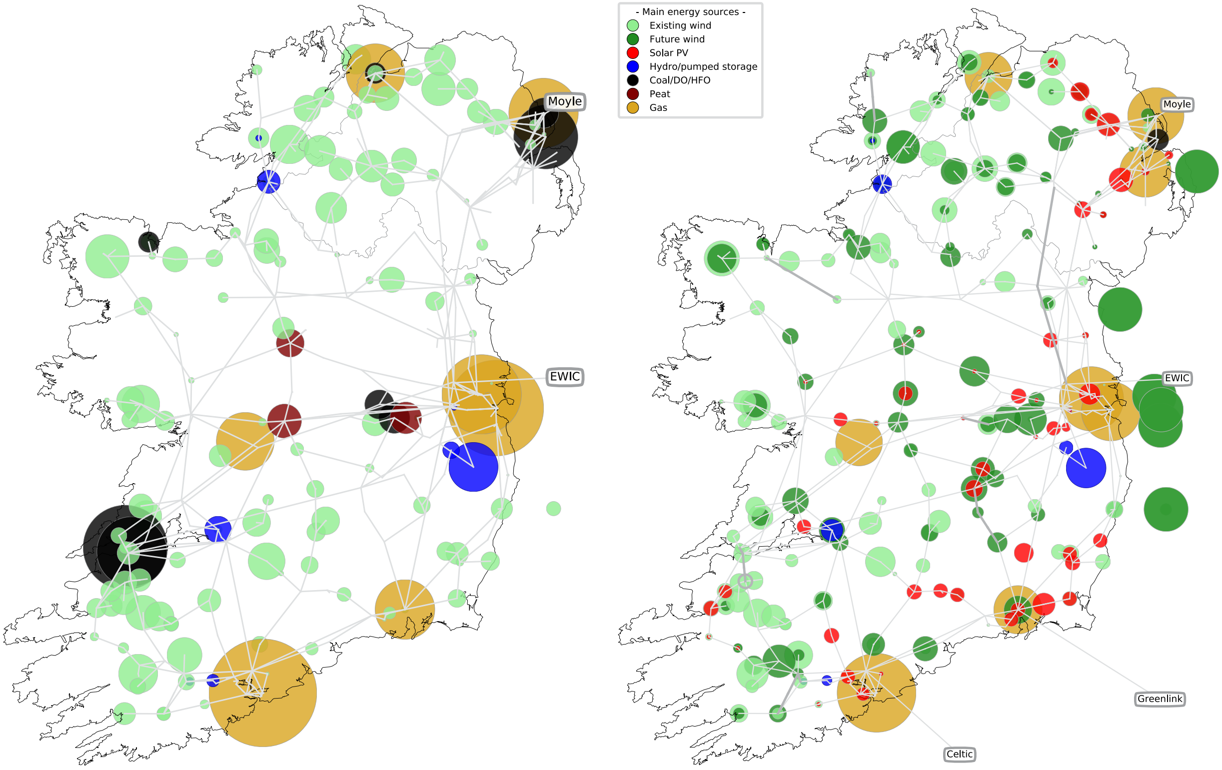


Figure 3: Generation mix, 2020 and 2030[6]

The location of new generation and new demand are key drivers of the need to develop the transmission network.

2.3. Interconnection

Our studies assume that the following new interconnectors are in service according to their stated schedule, which precedes 2030. These are:

- **The 2nd North-South Interconnector** – an alternating current (AC) interconnection between Ireland and Northern Ireland (ENTSO-E TYNDP project 81);
- **Celtic Interconnector** – a HVDC interconnection between Ireland at Knockraha station and the northern transmission network of France (ENTSO-E TYNDP project 107); and
- **Greenlink** – a HVDC interconnection between Ireland at Great Island station and a transmission station in western Wales (ENTSO-E TYNDP project 286).

In our studies, no further interconnections such as the Renewable Integration Development Project (ENTSO E TYNDP project 82), the MARES Organic Power Interconnector (ENTSO-E TYNDP project 349) or LirIC (ENTSO-E TYNDP project 1040) were assumed before 2030. This was to ensure alignment with the assumptions used in the TES and TES NI.

6 The 2030 case reflects the Co-ordinated Action (CA) scenario in Ireland and the Addressing Climate Change (ACC) scenario in Northern Ireland

2.4. Demand composition

The assumptions on demand and how it is likely to change in the period from 2020 to 2030 is taken from TES for Ireland and TES NI for Northern Ireland. The demand assumptions remain consistent with the latest demand assumptions contained in the GCS.

The Total Electricity Requirement (TER) is expected to increase significantly from 2020 to 2030 in Ireland, with more modest growth in Northern Ireland, as shown in Table 4. The primary drivers of demand growth are data centres in Ireland and electrification of heat and transport in both jurisdictions.

Table 4: Total Electricity Requirements (TER) components

Source	Jurisdiction	2020 (Pre-Covid forecast) [TWh]	2030 [TWh]
Transport	IE	<0.1	2.7 – 4.3
	NI	~0.0	0.7
Residential	IE	8.7	9.0 – 9.1
	NI	2.9	2.8
Industrial	IE	7.9	9.4 – 9.7
	NI	3.0	3.5
Large Energy Users	IE	4.8	9.8 – 12.6
	NI	0	0.0
Tertiary	IE	7.7	7.2 – 7.4
	NI	2.2	1.8
System Losses	IE	2.4	2.7 – 2.9
	NI	0.7	1.0
Total	**IE**	**31.4**	**41.3 – 45.5**
	NI	**8.8**	**9.9**

The spatial distribution of electric vehicle and heat pump demand is based on the distribution of existing distribution system operators (DSO)s load as well as regional population growth projections. These are shown in Figure 4. It can be seen that their distribution broadly follows the sizes of towns and cities across the jurisdictions.

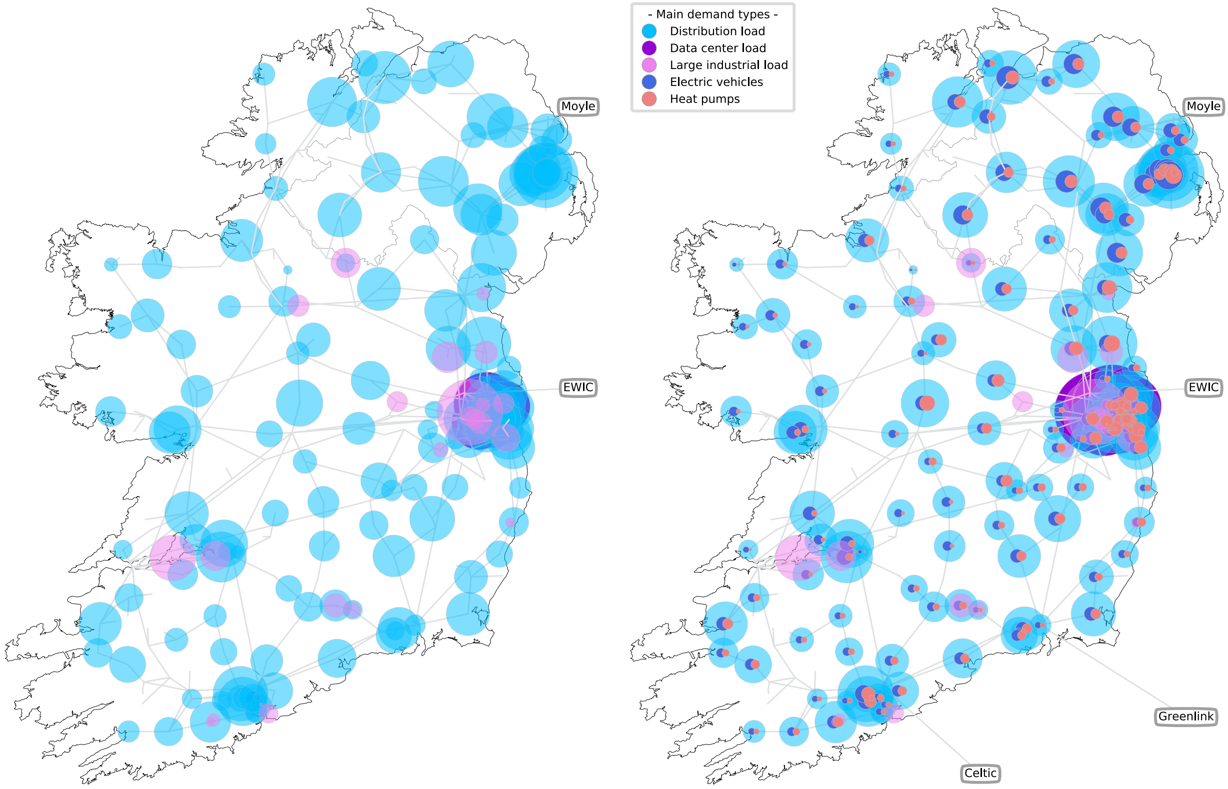


Figure 4: Demand spatial distribution, 2020 and 2030[7]

The network capacity and location of new loads are key drivers of the need to develop the transmission network.

2.5. Consequences for network performance

The scale of the impact of the low carbon transition outlined in TES and TES NI is assessed as part of the System Needs Assessment[8] conducted in each jurisdictions. The System Needs Assessment identifies the elements of the transmission system that do not meet the required performance levels in tests selected from the Transmission System Security and Planning Standards. Figure 5 illustrates the needs identified as part of the TES and TES NI System Needs Assessment processes.

The volume and scale of transmission elements that performed outside of the planning standards indicates that the "existing" network – note that approved reinforcements were assumed in-service in the studies – does not have sufficient capacity to integrate the levels of RES needed to achieve a 70% RES-E ambition.

Consequently, if no further transmission network development occurs, additional RES capacity will need to be installed to offset the RES dispatch-down associated with maintaining transmission elements within their ratings, lest the RES-E ambitions in both jurisdictions be missed. Lack of transmission network investment will also create challenges for future power system operational planning and operations, for example outage scheduling and voltage control.

7 The 2030 case reflects the Co-ordinated Action (CA) scenario in Ireland and the Addressing Climate Change (ACC) scenario in Northern Ireland

8 The 2030 case reflects the Co-ordinated Action (CA) scenario in Ireland and the Addressing Climate Change (ACC) scenario in Northern Ireland

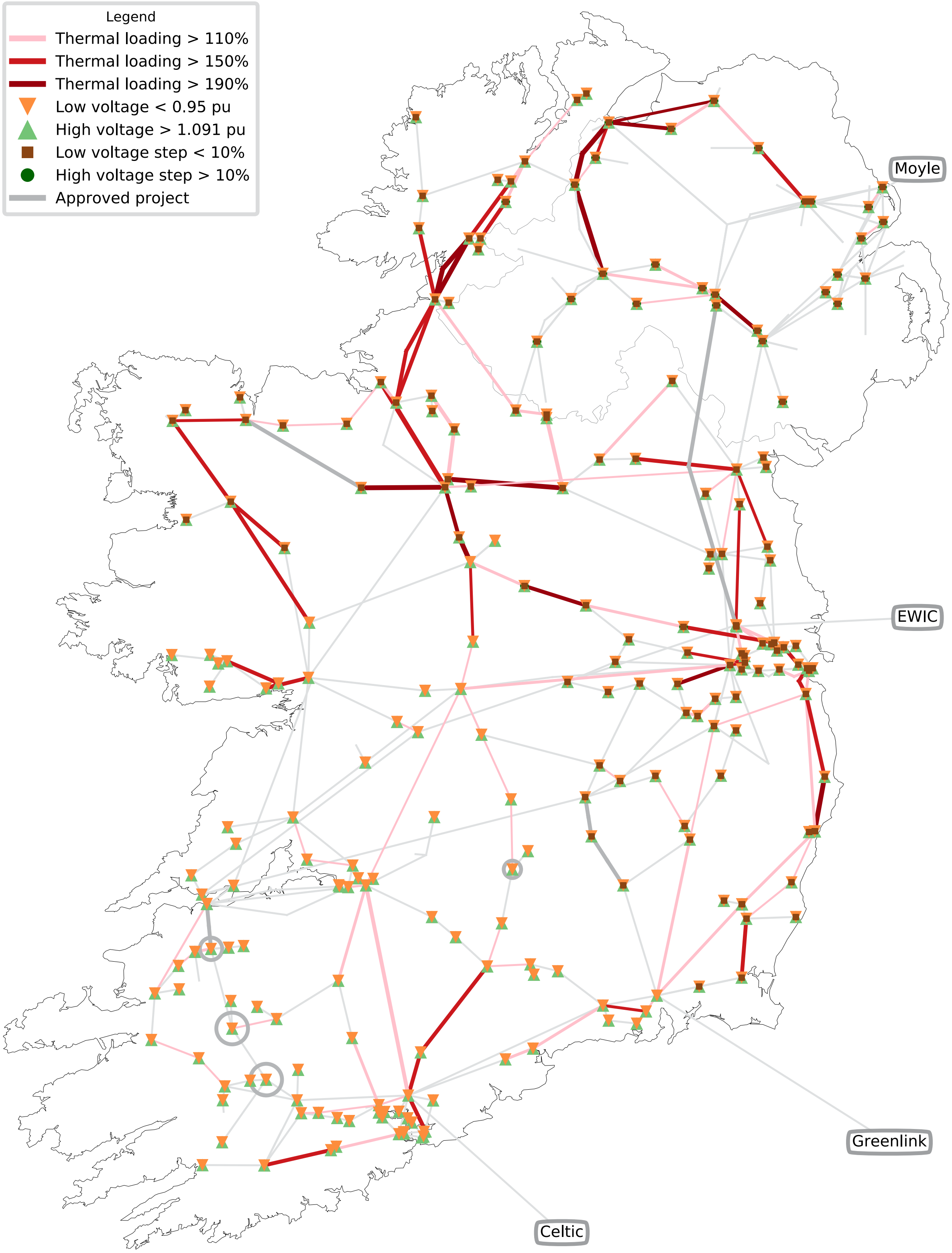


Figure 5: Illustration of transmission network needs identified under future scenarios, 2030[9]

9 The 2030 case reflects the Co-ordinated Action (CA) scenario in Ireland and the Addressing Climate Change (ACC) scenario in Northern Ireland

2.6. Operational challenges

Currently we operate the grid with c. 40% of our annual electricity needs being met from RES, predominantly onshore wind. To achieve this 40% annual level, the system is operated up to a maximum SNSP level of 65% in real time (as of January 2021 we are trialling 70% SNSP).

Recent Government policy in Ireland and the UK has set ambitious targets that will further affect how electricity is generated. In Ireland, the Climate Action Plan 2019[10] states that 70% of electricity will be generated from RES by 2030.

In the UK, the government is pursuing net zero carbon emissions by 2050. Whilst a target has not been set specifically for Northern Ireland, we note the ambition recently announced where the Northern Ireland target may be in excess of 70% by 2030[11]. Both of these targets will require us to break new ground in the amount of RES we manage on the electricity system.

In September 2019, EirGrid and SONI launched its five-year strategy to transform the all-island electricity system. The strategy focuses on the transformation of the power system and electricity market in order to ensure that RES targets adopted under the Clean Energy Package are met.

Key to the new strategy is upgrading the power system so that it can handle unprecedented levels of variable non-synchronous RES, supplied through a combination of offshore and onshore wind, along with solar energy. The combination of the variability and non-synchronous nature of the wind and solar resources coupled with the increasing volumes of non-dispatchable small-scale RES will introduce challenges for EirGrid and SONI.

Table 5 sets out the key changes to the power system by 2030.

10 Government of Ireland, Climate Action Plan, 2019
11 UK government, The Climate Change Act 2008 (2050 Target Amendment) Order 2019, 2019

Table 5: Key changes to the power system by 2030

The Power System in 2030	Key Impacts
70% RES-E	Reaching the 2030 targets will require close to 100% instantaneous non-synchronous RES penetrations, surpassing the world leading levels currently achieved under the DS3 programme. There will need to be significant changes to how the system operators manage the grid.
Up to 15 GW of RES	Significant growth in grid scale RES is expected, particularly new offshore wind, onshore wind and solar technologies. This large growth in RES will be coupled with the phasing out of baseload coal and peat plants and the introduction of new technologies such as battery energy storage.
Electrified heat and transport (700k+ heat pumps & 1m+ electric vehicles)	Electrification of heat and transport coupled with domestic level generation will lead to a change in demand profiles. New frameworks will be required for TSO-DSO coordination to ensure optimal operations across transmission and distribution networks.
Up to 1680 MVA of additional demand from large energy users	Transformation in electrical generation will be coupled with significant growth in demand driven by large energy users, particularly increased data centre connections. The TSOs will need to collaborate with innovative solution providers to more actively manage grid capacity and demand from customers.

This transformational change needs to take place whilst ensuring the quality of supply of electricity and the resilience of the power system that consumers have come to expect is maintained. Electricity is essential to our economy and way of life. It powers everything from our household appliances to complex, multi-billion euro industries. It is one of the core infrastructures that keeps our society functioning and our economy operating. The all-island power system is thus of fundamental importance. Consequently, maintaining the quality of supply and resilience of the power system now and into the future is a core remit of EirGrid and SONI.

3. Transmission Network

3. Transmission Network

3.1. Network development methodology

The analysis of the transmission network makes use of well-established methods and techniques that are described in the Ireland and Northern Ireland planning standards.

A number of different approaches were developed to reinforce the transmission network to address the identified needs. The purpose is to identify the relative merits of each approach and provide meaningful information on what is the most advantageous pathway to follow when developing the transmission network of the future.

3.1.1. Description of approaches

A number of strategic network approaches have been developed to reflect alternative ways of achieving the Renewable Ambition in both jurisdictions. It is critical that an effective approach is implemented over the next decade.

The approaches discussed in this report represent the strategic view of how to develop the grid. The approaches are designed to evaluate the consequences and factors to be considered when developing the grid according to a particular theme that is as much a reflection of the technology available as the broader stakeholder environment. As such, the approaches are not to be confused with the detailed design options that would make their way into a typical project development stage.

The strategic approaches proposed are illustrated in Figure 6.

Figure 6: Illustration of approaches

The approaches are provided in Table 6 along with brief description and likely outcomes.

Table 6: Summary of strategic approaches

Approach	Description	Likely Outcomes
Generation-Led	• Government policy determines the location of new generation. • Developers build new generation in these specific locations. • Preferred locations will consider the strength of the existing grid and the local demand for electricity. • Approx. 5 GW of offshore wind, < 1 GW of onshore wind and solar.	• Highlights the pros and cons of mandating the location of new generation consistent with the current topology of the power grid. • Most likely to lead to more offshore wind generation close to major cities, with less need for new onshore renewable generation.
Developer-Led	• Continue to connect new renewable resources in developer requested locations as done today. • Expand existing network infrastructure to connect new resources to load centres. • Approx. 2 GW of offshore wind, 4 GW of onshore wind and 2.5 GW of solar.	• Based on assumed capability, new infrastructure cannot be delivered in time to meet Renewable Ambition in 2030. • New resources will connect quicker than new infrastructure will be built, constraining renewables.
Technology-Led	• Utilise proven technologies not commonly deployed on power grids. • Utilise radially connected underground cables to carry high voltage direct current. • Utilises smart devices (an emerging sector of the electricity industry) to optimise flow through existing networks. • Approx. 2 GW of offshore wind, 4 GW of onshore wind and 2.5 GW of solar.	• Moves clean electricity from west to east in bulk, not integrated into wider transmission network. • High voltage underground cables are expensive, complex and therefore not often used in national power grids. • Active power flow control technologies will improve the flow and limits on existing infrastructure.
Demand-Led	• Government policy determines the location of new large energy users in Ireland. • Concepts applicable to Northern Ireland should large energy user projects progress. • Existing technology application. • Approx. 2 GW of offshore wind, 4 GW of onshore wind and 2.5 GW of solar.	• Large energy users are located close to RES. • May lead to more onshore renewable generation on the west coast – less need for new offshore renewable generation.

Reflecting the fact there is a large pipeline of new Large Energy User projects in the Dublin area, the Demand-Led approach looks at moving demand in Ireland only. However, we expect the concepts illustrated in this approach would be applicable to Northern Ireland should significant amounts of Large Energy User projects progress.

Detailed network planning studies are undertaken for each of these approaches to formally work out what potential projects would be needed. These would then be used to define functional specifications at an appropriate level of detail to enter EirGrid's Framework for Grid Development or SONI's 3 Part Process for Developing the Grid. The list of projects are developed using a pragmatic application of the planning standards in Ireland and Northern Ireland that could require additional project elements once detailed studies are completed as part of the grid development processes.

As a result, the list of approaches developed as part of these studies to define our electricity future should not be seen as a formal plan or programme of works. Following consultation on the alternative approaches to develop the grid to meet the RES-E ambitions of both jurisdictions, we will develop a programme for project approval that will be subject to EirGrid and SONI governance frameworks and the appropriate regulatory approvals where required.

The final approach is likely to be a blend of these approaches.

3.1.2. Overview of analysis

Future possible scenarios used to describe generation and demand in 2030 are taken from Tomorrow's Energy Scenarios for Ireland and Northern Ireland, focusing on those that corresponds with 70% RES-E. These scenarios were analysed using times-series alternating current (AC) power flow analysis to identify the needs of the transmission network. Further time-series analysis then assessed the relative performance of the reinforcements of the needs for each of the approaches.

The process followed in this analysis can be described in four distinct steps, namely:

- Create generator dispatch schedules over the year that realise the 70% RES-E ambitions of both jurisdictions. Market simulation software (i.e. PLEXOS) is made use of to prepare these schedules;
- Test the performance of the transmission system for each of the hourly generator schedules produced as part of the previous step. Performance is assessed using AC power flow analysis software (i.e. PSS/E) that tests power system according to the requirements set out in the Transmission System Security Planning Standards (TSSPS) for each time period of the schedules. The analysis focuses on the single contingency test given the strategic nature of the analysis. The results are used to identify the needs of the transmission network;
- Identify transmission network reinforcements that satisfy each of the needs that were identified. This is done using the same AC power flow analysis software (i.e. PSS/E) used to identify the needs of the transmission system. The programme of reinforcements is consistent with the approach being considered and ensures that at least 70% RES-E is met. For every approach, the programme is designed to maximise the use of the existing transmission network and therefore minimises the need for new infrastructure; and
- Multi-criteria analysis is applied to each of the approaches to identify their relative advantages and disadvantages.

3.1.3. Scheduling analysis

The aim of this analysis is to create credible hourly supply and demand patterns. In order to do so, taking cognisance of the requirement to facilitate high levels of variable renewable generation, unit commitment and economic dispatch software was used to create chronological snapshots. These are used as an input to the network planning studies to understand if and where the network is congested, based on the selected set of demand and generation assumptions.

With regard to future operational rules assumptions, we are planning to be able to operate at SNSP levels up to 95%, to have a reduced Inertia Floor, to have implemented a secure RoCoF limit of 1Hz/s (an operational trial is currently underway) and to have a significantly reduced Minimum Number of Units requirement. A number of must-run generating units in Ireland and Northern Ireland were selected to maintain good voltage performance in the AC power flow simulations. Eligibility for inclusion in the Northern Ireland must-run rule is limited to plant connected at 275 kV.

3.1.4. Transmission network needs identification

Each time period (hour) of the schedule is used to create an AC power flow snapshot. This generates a large dataset of study cases, or snapshots, that cover each hour of the year in 2030. Each snapshot is analysed in great detail using AC power flow analysis. This allows for a larger number of metrics to be employed when analysing network performance and permits, for example, the identification of the most frequently occurring network needs.

A need to develop the transmission system is identified by testing the performance of the power system against a subset of the standards set by the Transmission System Security and Planning Standards (TSSPS)[12]. The subset of the standards focus on testing performance of the intact power system and the power system when there is an outage of a single item of transmission equipment, such as a circuit, which is referred to as the single contingency performance test (i.e. N-1). These tests are appropriate as the primary tests of the adequacy of transmission system security at this strategic stage of the analysis.

The impact on circuit loading and station voltage was used to identify grid reinforcement needs throughout the system. The following TSSPS variables were monitored for limit breaches:

- Thermal loading;
- Voltage range (high and low); and
- Voltage step (high and low).

3.1.5. Network development principles

3.1.5.1. Policies

Along with the TSSPS, the development of the transmission system is informed by transmission investment policies that describe acceptable practices, minimum requirements and equipment specification.

In Ireland, EirGrid applies policies[13] in respect of overhead lines, cables, transformers and station configuration. These policies complement the TSSPS and are also applicable when developing network reinforcement alternatives.

In Northern Ireland, SONI makes use of certain policies, such as those relating to technologies, which are set by the asset owner, NIE Networks.

3.1.5.2. Developing technical solutions

A standard process of dealing with network limitations was followed to design the different approaches:

- Each of the solutions was treated in a consistent and repeatable manner, which meant that the process was iterative;
- Each case built on the last which ensured that each approach was treated in a similar manner; and
- The impact of each individual reinforcement within the approach was assessed which meant that the risk of over-building the network was reduced.

12 The most recent TSSPS for Ireland was approved in May 2016, and that for Northern Ireland was approved in September 2015.
13 EirGrid, Transmission policies and standards

3.1.5.3. Study scope and limitations

Technical solutions are designed by considering the minimal and obvious workable choices that addressed the problem presented. There therefore remains room for further optimisation which would be dealt with as part of the normal network development process but is outside of the scope of this study.

These studies focused only on the year 2030. No other near-time period was considered. Similarly, no time period after 2030 has been assessed.

This analysis will in future form part of a broader suite of analysis that will consider the longer-term RES-E ambitions of EirGrid and SONI.

For example, studies are also not sufficiently detailed to confirm whether new circuits are to be designed as overhead lines or underground cable. Therefore, where a need for a new circuit is identified it will not be specific over whether it is overhead line or underground cable.

Solutions for reactive compensation system needs have not been identified as part of the studies and new reactive compensation reinforcements are not listed for each of the four development approaches. Solutions for reactive compensation needs in 2030 will be studied in more detail over the coming years as levels of certainty relating to the reactive capabilities of the evolving generation fleet, new HVDC interconnectors and storage technologies increases.

3.1.5.4. Transmission network technologies

There are a range of technologies that can be considered when developing the transmission system. Different combinations of technologies can be selected depending on the approach that is taken to achieving that development.

These technologies are taken from a standard suite of technologies that are agreed with the Transmission Asset Owners (TAO) in Ireland and Northern Ireland.

3.1.5.5. Planned grid development assumptions

EirGrid and SONI are already committed to a number of grid infrastructure projects that are reflected in the Transmission Development Plans of Ireland and Northern Ireland. These projects are critical and needed to maintain the security of supply of the power systems of in their respective jurisdictions.

The most relevant reinforcements to the transmission network assessment are assumed in service for the analysis.

With regard to circuits, the following was assumed:

- North South 400 kV Interconnection Development;
- North Connacht 110 kV Reinforcement Project (Moy to Tonroe);
- Laois - Kilkenny Reinforcement Project;
- Cross-Shannon 400 kV cable; and
- Moneypoint – Knockanure 220 kV Project.

With regard to reactive compensation, the following was assumed:

- Series capacitors at Dunstown, Moneypoint & Oldstreet;
- STATCOMs at Ballynahulla, Ballyvouskil & Thurles; and
- Reactors at Knockanure, Ballyvouskil, Tandragee & Tamnamore.

The grid developments identified as part of this work are in addition to these committed projects. All projects identified as part of this initiative will need to enter EirGrid’s Framework for Grid Development process or SONI’s 3 Part Process for Developing the Grid. Both have their own detailed analysis requirements.

3.1.6. Comparing performance of network development approaches

The relative performance of each alternative approach is compared and assessed to identify the relative merits of each approach. Multi-criteria analysis is the established way for undertaking such a comparison, which is already well established within EirGrid and SONI:

3.1.6.1. Multi-criteria analysis

Multi-criteria analysis is a method used to compare and contrast alternatives on the basis of multiple factors. The comparison is typically used to identify the best performing alternative.

A characteristic feature of multi-criteria analysis is that the evaluation is based on a number of explicitly formulated criteria. For this application, namely the evaluation of alternative approaches to developing the transmission network, the criteria need to take cognisance of the strategic nature of the work being done. The purpose of the criteria is therefore to ensure that the alternative mitigation approaches are consistent, transparent, and rigorous.

3.1.6.2. Overview of criteria

The criteria that are used as part of the multi-criteria analysis are selected to reflect the range of topics that are relevant for a strategic comparison of the different approaches. The multi-criteria analysis uses five criteria to assess performance, namely:

- Technical performance;
- Economic performance;
- Environmental impact;
- Society and social acceptability; and
- Deliverability.

These criteria seek to represent performance as a single cell that aggregates a broad range of analysis. Pragmatism and discretion is required to strike the correct balance between a comprehensive enough quantification of performance; with the level of modelling required to complete this for multiple approaches to grid development.

The five criteria are described as follows:

3.1.6.3. Technical performance criterion

This represents the technical performance of an alternative. It includes the following:

- Compliance with Transmission System Security and Planning Standards;
- The amount of additional capacity that is available for the future without further upgrades. This is referred to as "headroom".
- Expansion/extendibility: This considers the ease with which the solution option can be expanded, for example it may be possible to uprate an overhead line to a higher capacity or a new voltage in the future.
- The maturity of the technology being used or known operational risks associated with its application. This considers the extent to which it has already been applied on the island of Ireland and the familiarity of the Transmission Asset Owners with its lifetime management and maintenance.

3.1.6.4. Economic performance criterion

The economic performance criterion assesses the economic performance from implementing the particular network development approach. The economic assessment therefore considers the costs and benefits associated with implementing the programme of works identified in the technical analysis.

The criterion considers the following:

- **Programme costs - the programme cost metric refers to capital costs. These are calculated using the Transmission Interface Arrangements Standard Costs (TIASCs) for SONI and the Transmission Standard Development Costs (TSDCs) for EirGrid. For technologies not included in the standard costs, recent projects or appropriate literature was used.**

- **Programme benefits - the programme benefits refer to the benefits resulting from the delivery of the programme of works associated with the approach. The benefits selected are:**
- **Change in production costs;**
- **Reduction in CO_2 emitted from fossil fuel-fired generation, measured in tonnes;**
- **Increase in RES-E, measured in percentage of estimated gross final consumption of electricity;**
- **Reduction in renewable generation constraint, i.e. the RES spillage savings measured in gigawatt-hours; and**
- **Reduction in grid losses, measured in gigawatt-hours (GWh).**

The first four benefits are calculated as the difference between security-constrained unit commitment and economic dispatch simulations that have the selected network developments included and excluded. Grid losses are taken from the intact AC power flow simulations. A full year of expected operation is simulated for the selected scenario-year, i.e. 2030.

While production cost savings is inherently a monetary metric, the remaining metric can also be monetised:

- A reduction in CO_2 emissions can be monetised by multiplying the CO_2 emission reduction by the difference of the assumed societal cost of CO_2 and the cost of CO_2 assumed in the security-constrained unit commitment and economic dispatch simulations.
- A reduction in grid losses can be monetised by multiplying the losses by the marginal price.

3.1.6.5. Environmental impact criterion

The criterion assesses the broad impact of the programme of network reinforcements associated with the particular approach on the environment across a number of topics, including biodiversity, flora and fauna, population and human health, geology, soils and land use, water, air, climatic factors, material assets, and landscape and visual amenity.

The criterion considers the broad impacts of the reinforcement programme on the following:

- Biodiversity, Flora & Fauna: Assessment of the impact on biodiversity, flora and fauna, which could include an ecological desktop study.
- Water, Soil and Geology: Impact on soil/ subsoil geology, Irish geological heritage sites, and bedrock geology, etc. and water (water quality of surface waters and groundwater).
- Air and Climate: Long-term climate impacts (e.g. global warming) due to air pollutants during construction.
- Population and Human Health: Impacts in relation demographics population and development growth, adverse health outcomes;
- Material Assets: Impact on land use (forestry, farmland, bogs/peats, horticulture), houses, commercial and community properties, landfill sites, etc.
- Landscape and Visual: Assessment of landscape constraints and designations and the impact on visual amenity.
- Cultural Heritage, Recreation & Tourism: the impact on the cultural heritage resource and recreational activities and tourism.

3.1.6.6. Society and social acceptability criterion

The criterion assesses the likely social impact of the network reinforcements associated with the particular approach and therefore its social acceptability. It measures the intended and unintended social consequences, both positive and negative, of planned interventions of the approach and any social change processes invoked by those interventions among settlements, communities and individuals.

3.1.6.7. Deliverability criterion

The deliverability criterion assesses the logistical aspects of constructing and delivering a particular approach by 2030 in order to satisfy the RES-E ambitions of each jurisdiction. The criterion considers the following:

- **Implementation timelines and the ability to meet the 2030 deadline.**
- **Project plan flexibility: Does the programme allow for some flexibility if issues arise?**
- **Reliance on third parties: To what extent does the programme depend on actions and deliverables of third parties outside the control of EirGrid or SONI, and how much risk is there that they may not align?**
- **Supply chain constraints: Any constraints (e.g. small number of suppliers locally or internationally) that would affect the procurement of materials or services (e.g. cable laying vessels waiting list lead time) to implement the approach.**

3.1.6.8. Performance assessment

Each of the approaches to developing the transmission network is to be assessed against the abovementioned criteria as part of the multi-criteria analysis. The relative performance is assessed by comparing the criteria of each of the approaches against each other.

To do this, a performance scoring system is used to consistently assess performance. Relative performance per criterion is shown using a scaled colour-code comprising 5 scales. The relationship between the colour-code and performance is a function of the criterion being assessed and specifics of the developmental approach itself.

For each criterion, an assessment is required to indicate what the scoring scale represents for the project being assessed. This may be in terms of quantitative data, or qualitative data.

The colour code to be used in the performance matrices is illustrated as follows:

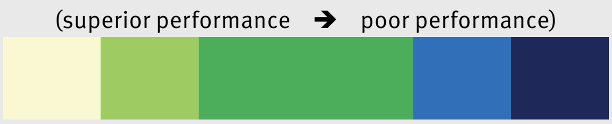


Figure 7: Standardised colour code for comparing performance

3.2. Evaluation of network development approaches

3.2.1. Generation-Led approach

This approach focuses on minimising grid developments by re-considering the preferred locations of new generation. The delivery of the grid is essential to achieving the renewables target and the minimisation of new infrastructure will reduce the risk to achieving this ambition.

The number of onshore grid reinforcements can be reduced when a larger share of the 70% RES-E ambition is achieved through offshore wind in the Irish Sea, i.e. 4.5 GW off Ireland's coast, and 0.7 GW off the Northern Ireland coast. As the offshore wind assumed in this approach is located along the East coast, the need for onshore reinforcement is reduced as more generation is connected at points closer to large demand centres such as Dublin and Belfast and in close proximity to the points of interconnection.

New onshore renewable generation are located at existing relatively strong onshore transmission nodes. The renewable generation portfolio used for the Generation-Led approach is described in Table 7.

Table 7: Variable renewable generation portfolio for the Generation-Led approach

Jurisdiction	Onshore Wind Capacity [GW]	Offshore Wind Capacity [GW]	Solar Capacity [GW]
Ireland	4.40	4.50	0.60
Northern Ireland	1.40	0.70	0.60

The conventional generation portfolio is per the corresponding TES and TES NI scenarios.

This approach permits maximising the capacity available on the 220kV and 275kV grid – especially in the midlands and on the east coast of Ireland and Northern Ireland.

The ability to deliver the quantity of offshore renewable generation in the Irish Sea and North Channel (i.e. up to 5.2 GW) by 2030 is a key risk for this approach.

3.2.1.1. Technical performance

The approach is designed using the TSSPS to achieve the requisite performance level.

The approach focuses on offshore wind generation connections. The result is fewer parts of the existing transmission grid require development – and hence there are also fewer reinforcements.

The reduced number of reinforcements means that it is more achievable than those approaches that require significantly more reinforcements.

Figure 8 illustrates what a Generation-Led grid could look like.

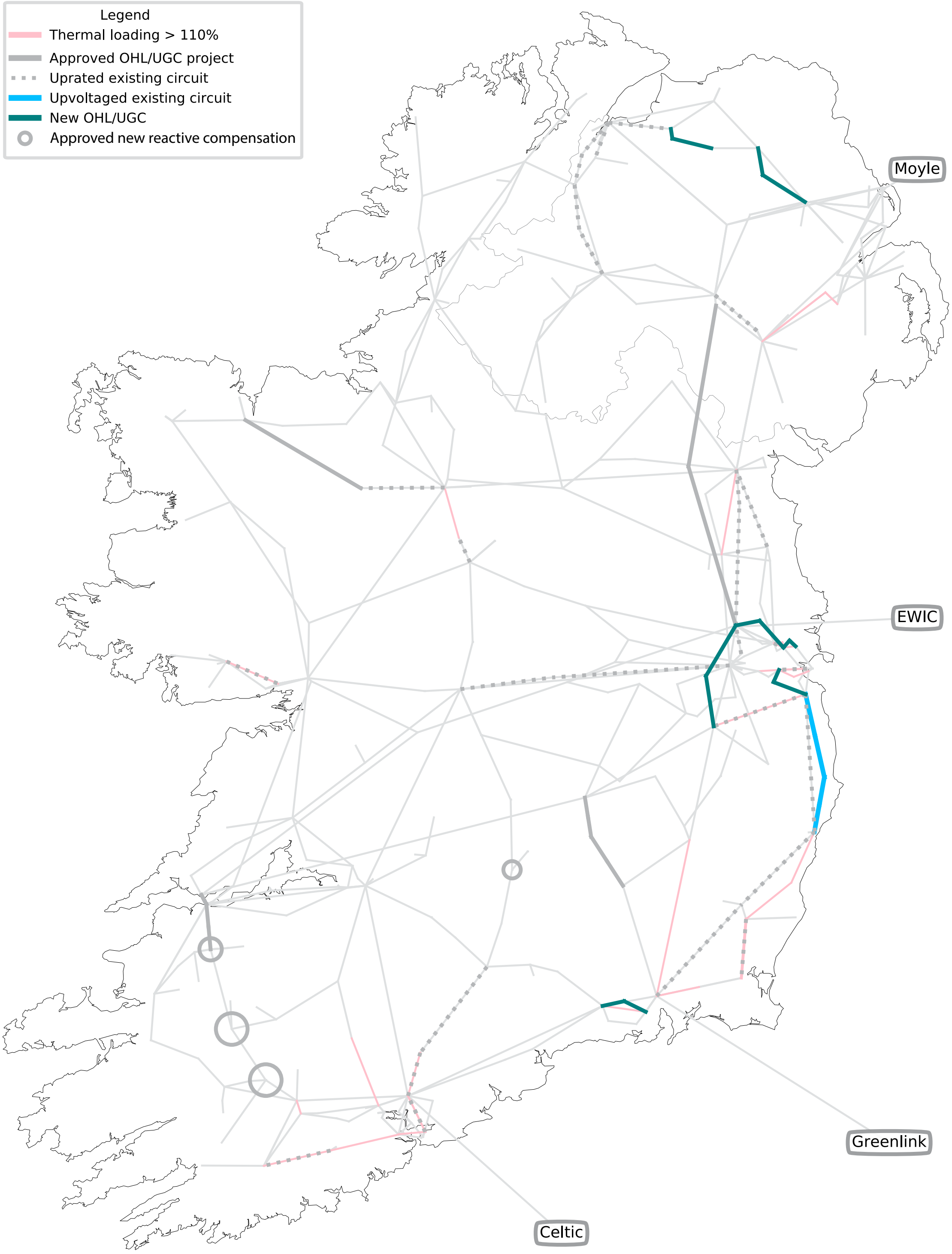


Figure 8: Illustration of reinforcements and limitations of a Generation-Led approach in 2030

In Northern Ireland two new 110 kV circuits bring more new capacity to the north-west part of the Northern Ireland grid while a number of existing 110 kV overhead lines that have high potential for rating increase are uprated.

The 0.7 GW of large-scale offshore is connected to the high-capacity double-circuit 275 kV grid in the east without the need for further transmission capacity.

In the north-west area of Ireland, the North Connacht project is assumed in place and a small number of 110 kV circuits are uprated.

In the mid-east region of Ireland, centred on the Dublin network, due to local data centre growth and to cater for the power transfer from renewable generation into the area, new reinforcements are required to ensure security of supply. Linking the two 400 kV Woodland and Dunstown stations and adding new capacity along the 220 kV corridor between the Woodland and Finglas stations is required.

Offshore wind generation off Ireland's coast is initially catered for by the replacement of the older low-capacity 220 kV cables. However further 220 kV underground cable capacity and 220 kV overhead line uprating is required to facilitate 4.5 GW.

A high level of reactive compensation is also required in Dublin to manage the impact on voltage as load grows and the large-scale gas units are displaced by RES elsewhere on the island.

In the Midlands, onshore generation clusters are connected to the uprated 220kV grid – in particular along the Maynooth – Shannonbridge 220 kV corridor.

In the south, to allow the Celtic and Greenlink interconnectors to operate efficiently, a number of 110 kV and 220 kV uprates are required. Without new circuits there is some operational constraint.

The reinforcement details are summarised in Table 8. A full list of the reinforcements identified as part of this approach is contained in Appendix C.

Table 8: Numbers of reinforcements by reinforcement type per jurisdiction for the Generation-Led approach

Reinforcement Category	Ireland Reinforcements [No.]	Northern Ireland Reinforcements [No.]	All-Ireland Reinforcements [No.]
Uprating of existing circuits	22	6	28
Upvoltage existing circuits	2	0	2
New circuits	5	2	7
New equipment	9	0	9
Total	**38**	**8**	**46**

The implementation of the reinforcements in Ireland and Northern Ireland facilitate the integration of the scale of RES, particularly offshore wind, needed to satisfy each jurisdiction's RES-E ambitions.

The approach is readily capable of being expanded and provide headroom to accommodate changes to generation and demand assumptions. This is reflected in the assessment of the technical criterion, shown in the Figure below, as superior.

Figure 9: Technical criterion rating for the Generation-Led approach

3.2.1.2. Economic performance

The estimated capital costs of the Generation-Led approach are summarised per jurisdiction in A total cost per reinforcement category is also provided and is shown in equivalent euro values.

Table 9: Estimated CAPEX by reinforcement type per jurisdiction for the Generation-Led approach

Reinforcement Category	Ireland Reinforcements [€ million]	Northern Ireland Reinforcements [£ million]	All-Ireland Reinforcements [€ million equivalent*]
Uprating of existing circuits	313	52	373
Upvoltage existing circuits	37	0	37
New circuits	295	68	373
New equipment	70	0	70
Total	**715**	**121**	**853**

Note *: assumed €/£ exchange rate is 1.13

The capital costs, also referred to as programme cost, are calculated using standardised unit costs applicable for Ireland and Northern Ireland respectively.

The benefits reflect the direct consequences of network development leading to higher penetrations of renewable generation. The economic benefits are described by assessing the changes or reductions in system production costs, CO_2 emissions, renewable generation constraint and system losses.

The economic performance of the approach is assessed for the year 2030:

- The RES-E levels that are expected match the ambitions of both Ireland and Northern Ireland.
- Generators are economically dispatched, leading to the optimal dispatch and hence the optimal production costs as a result.
- Assuming that the generation connects as expected, and that the reinforcements are in place by 2030, the levels of constraint will be minimised. For 2030, this is expected to be of the order of 5% and will correspond to approximately 1,700 GWh. At an average compensation rate of €89/MWh[14], this corresponds to a constraint cost of €151 million.
- System losses are expected to reduce by 890 GWh each year once the reinforcements are in place, relative to the transmission system containing only those reinforcements currently contemplated in the TDPs of Ireland and Northern Ireland. This translates to a combined reduction in the cost of losses for Ireland and Northern Ireland of approximately € 44 million per annum, assuming an average annual System Marginal Price of € 50 /MWh.

The estimated benefits are summarised in Table 10.

14 Cost of compensation determined based on a LCOE of €60/MWh for onshore wind and onshore solar PV; and LCOE of €120/MWh for offshore wind. The value is applicable for the scenario applicable for the approach, in this case Centralised Energy (CE) for Ireland and Addressing Climate Change (ACC) for Northern Ireland.

Table 10: Estimated benefits for the Generation-Led approach.

Metric	Volume	Monetisation [€m]
Production cost change p.a.	Generators are optimally dispatched due to the removal of network constraints	Optimised production cost per annum
CO_2 emission reduction t p.a.	Minimum level of CO_2 due to running most efficient plant	Minimised CO_2 cost due to the minimised level of CO_2 emissions
RES-E achieved in 2030	c.70 %	-
Renewable generation constraint p.a.	1,700 GWh c.5%	151
Grid losses change p.a.	-890 GWh	-44

The relatively lower capital cost arising from the reduced quantity of transmission network developments required, the low level of RES constraint and the reduction in system losses contribute to an assessed superior economic performance for this approach.

Figure 10: Economic criterion rating for the Generation-Led approach

3.2.1.3. Environmental factors

The Generation-Led approach seeks to influence the location of new generators to sites on the transmission system where there is capacity available to accommodate them. This significantly reduces the number of network reinforcements that are needed compared with the other approaches.

However, all statements regarding potential impact significance relate to the residual effects. This is because appropriate mitigation measures will be put in place and will be supported by environmental monitoring as required to cater for adaptive management of mitigation measures (e.g. in response to extreme weather conditions or construction practices). This recognises that project-level environmental assessments (see Section 3.1.6.5.) would be undertaken at the appropriate time and that there are unlikely to be any significant long-term negative impacts if the network reinforcements are realised.

Overall, the performance is moderate. By undertaking Strategic Environmental Assessment (SEA) on this pathway and applying best practice in design and appraisal in all stages should facilitate the avoidance of significant effects and appropriate routing/option development having regard to relevant environment considerations. This assessment is indicated in the Figure below.

Figure 11: Environmental criterion rating for the Generation-Led approach

3.2.1.4. Society and social acceptability

The Generation-Led approach seeks to influence the location of new generators to sites on the transmission system where there is capacity available to accommodate them. The effect is the amount of network reinforcements that are needed is reduced when compared with the other approaches.

Comparatively, underground cables present less risk and have a less significant impact than overhead lines in the context of all social criteria. In general terms overhead lines receive less social acceptance than underground cables. This arises from the perceived impact on sense of place and well-being of individuals, a community or network of communities.

To account for this, the society and social acceptability criterion is assessed as having moderate to high level of effect.

Figure 12: Society and social acceptance criterion rating for the Generation-Led approach

Following, Stakeholder Engagement, this assessment may be adjusted to reflect the summary of responses received and general opinion of society toward the approach. It should also be noted that stakeholder engagement is an iterative process and further engagement in future may have a bearing on the societal analysis and social acceptance of pathways shown in this report.

3.2.1.5. Deliverability

Deliverability refers to the logistical aspects of developing, planning, designing, constructing and commissioning the reinforcements associated with a particular approach in order to meet the RES-E target by 2030.

The relatively low number of reinforcements associated with the Generation-Led approach is assessed to be deliverable by 2030.

The approach makes use of existing technologies that are well established and supported by the TAO reducing any complication in respect of design and specification.

The ability to influence the connection of new RES offshore in the Irish Sea is a key assumption that the approach relies on. This means that the ability to achieve the 2030 target needs the developers to have the capacity to locate 5.2 GW in the Irish Sea, supported by regulatory authorities and government bodies in both jurisdictions. The marine planning aspects associated with their development are outside of the control of EirGrid and SONI, which will impact on the overall deliverability of the approach. The ability therefore to deliver the quantity of offshore renewable generation in the Irish Sea (i.e. up to 5.2 GW) by 2030 is a key risk for this approach.

To account for these issues, the deliverability criterion is assessed to perform well.

Figure 13: Deliverability criterion rating for the Generation-Led approach

3.2.2. Developer-Led approach

A Developer-Led approach considers future renewable generators to be distributed throughout most parts of the grid in both jurisdictions.

Future onshore wind and solar photo-voltaic (PV) generation are predominantly connected at 110 kV stations, while all offshore generation is connected at 220 kV stations in Ireland and 275 kV stations in Northern Ireland. RES is connected remotely from the main load centres – therefore this approach therefore relies on all voltage levels to share the burden for the transmission of power over long distances.

The generation portfolio used for the Developer-Led approach is described in .

Table 11: Variable renewable generation portfolio for the Developer-Led approach

Jurisdiction	Onshore Wind Capacity [GW]	Offshore Wind Capacity [GW]	Solar Capacity [GW]
Ireland	8.20	1.80	2.00
Northern Ireland	2.00	0.35	0.60

New transmission capacity is required to integrate the quantity of new renewable generators – particularly those located onshore. The grid is developed using existing standard technologies and practices. These are already agreed with the TAO.

3.2.2.1. Technical performance

Due to the distributed nature of the future renewable generation, more parts of the grid require development. The approach relies heavily on uprating the capacity of existing 110 kV circuits and the construction of a minimum number of new circuits at a minimum voltage level of 220 kV in Ireland and 275 kV in Northern Ireland. Reactive compensation is required to maintain voltage standards across the island as the level of fossil fuel generation is reduced to accommodate more RES.

Figure 14 illustrates what a Developer-Led approach could look like.

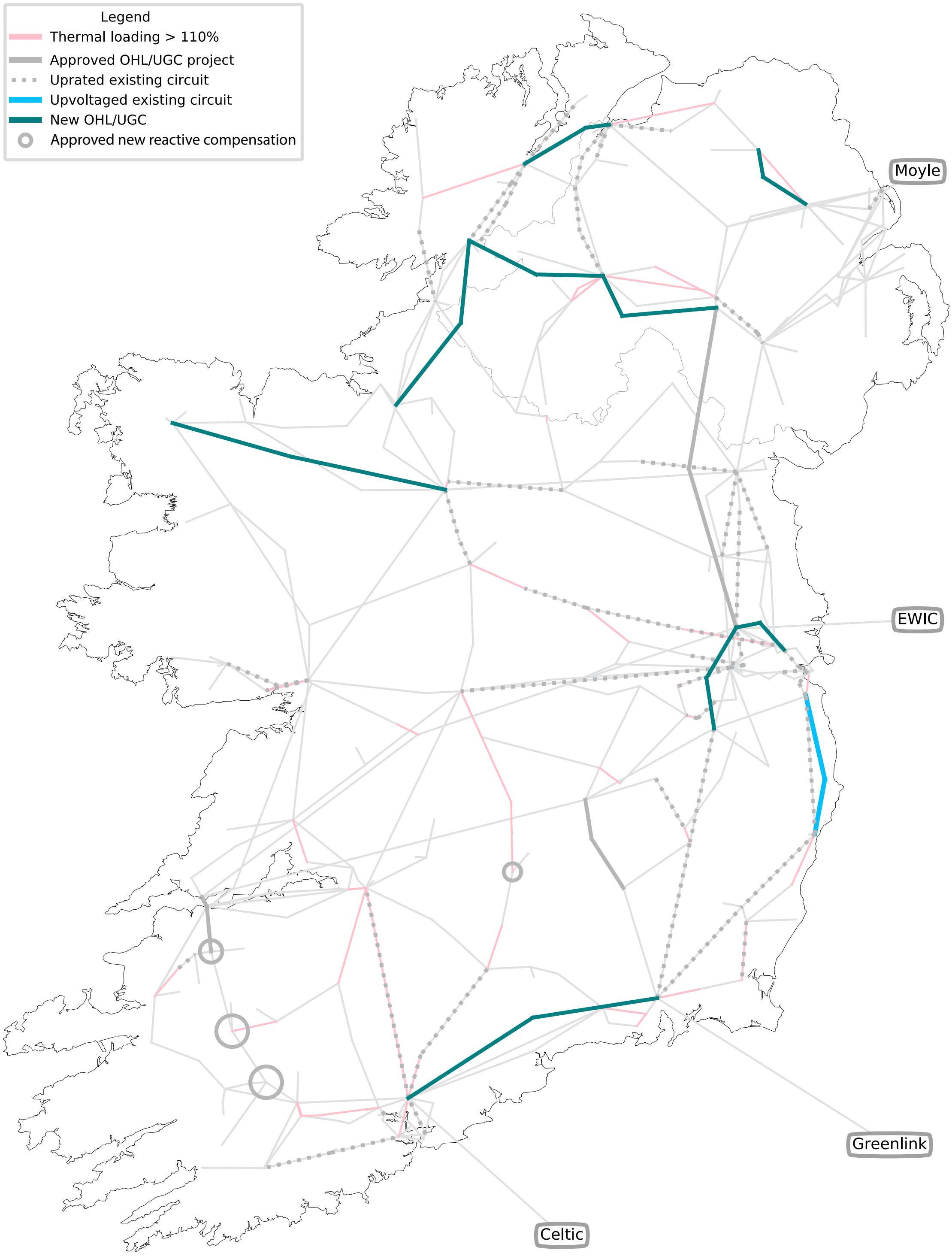


Figure 14: Illustration of reinforcements and limitations of a Developer-Led approach in 2030

In Northern Ireland, grid development centres on the cross-border circuits in the west. The need for these circuits is primarily driven by high onshore in the neighbouring Donegal area – however the reinforcements also deliver a solution for reliability for the western part of the Northern Ireland grid.

A number of 110 kV overhead line uprates are required with at least one new circuit, a second Kells – Rasharkin 110 kV line, in the east to facilitate further onshore wind generation. In this approach, due to the large-scale cross-border reinforcements, the need for a reinforcement like Agivey – Limavady 110 kV is delayed. Reactive compensation is required to manage a reduction in operational constraints.

In Ireland, a number of new circuits are required to facilitate the transmission of RES from the north-west. This is achieved in a number of ways:

- Uprating the 110 kV circuits that have the potential for a further rating increase;
- Extending the 220 kV grid further west and north-west; and
- Adding new capacity, more than one circuit, between Ireland and Northern Ireland using 275 kV connections. The use of 110 kV was not sufficient due to the level of onshore wind generation assumed in the Donegal area.

In the Mid-East region, centred on the Dublin network, due to local data centre growth and to cater for the transfer of renewables into the area, new reinforcements are required to ensure security of supply. In particular, a 400 kV circuit that links the Woodland and Dunstown 400 kV stations and adding new capacity along the 220 kV corridor between the Woodland and Finglas stations. A high level of reactive compensation is required around the Dublin 220 kV grid to manage the impact on voltage as load grows and the large-scale gas units are displaced by renewables elsewhere on the island. The growth of local offshore development is catered for by the replacement of the older low-capacity 220 kV fluid-filled underground cables.

To allow the local RES, combined cycle gas turbine plant and new interconnections in the southern part of the network to operate with minimised constraint, new capacity is required. This is required between the Knockraha and Great Island stations (when exporting) and the Aghada and Knockraha stations (when importing). A number of 110 kV and 220 kV uprates are also required.

The details of the reinforcements are summarised in Table 12. A full list of the reinforcements identified as part of this approach is contained in Appendix D.

Table 12: Numbers of reinforcements by reinforcement type per jurisdiction for the Developer-Led approach

Reinforcement Category	Ireland Reinforcements [No.]	Northern Ireland Reinforcements [No.]	All-Ireland Reinforcements [No.]
Uprating of existing circuits	52	12	66
Upvoltage existing circuits	2	0	2
New circuits	7	4	9
New equipment	16	3	19
Total	**77**	**19**	**96**

Although the end result is a strong grid with a robust level of reliability, the large number of reinforcements throughout the will grid impact security of supply, and the ability to operate and maintain the power system while they are being implemented.

The additional capacity acts as a platform for long-term RES growth. This grid design is also likely to keep the curtailment of RES at a minimum once fully implemented.

To account for the issues likely to arise during the implementation of the large number of reinforcements, the technical criterion is assessed as having a moderate performance level:

Figure 15: Developer-Led approach rating of the technical criterion

3.2.2.2. Economic performance

The programme cost, also referred to as capital costs, for the Developer-Led approach are calculated using standardised unit costs applicable for Ireland and Northern Ireland respectively. For technologies not included in the standard costs, recent reinforcements or appropriate literature were used to derive an estimated cost for the appropriate jurisdiction.

The estimated capital costs are summarised in Table 13.

Table 13: Estimated CAPEX by reinforcement type per jurisdiction for the Developer-Led approach

Reinforcement Category	Ireland Reinforcements [€ million]	Northern Ireland Reinforcements [£ million]	All-Ireland Reinforcements [€ million equivalent*]
Uprating of existing circuits	629	84	724
Upvoltage existing circuits	37	0	37
New circuits	1,103	254	1,390
New equipment	131	23	157
Total	**1,900**	**361**	**2,308**

Note *: assumed €/£ exchange rate is 1.13

The economic benefits reflect the direct consequences of network development that lead to higher penetrations of renewable generation. The economic benefits are described by assessing the changes or reductions in system production costs, CO_2 emissions, renewable generation constraint and system losses.

The economic performance of the option is assessed for the year 2030. Due to the large number of reinforcements associated with this approach, it is expected that all the grid developments will not yet be in place. This has a significant consequence, and economic impact, on a number of factors:

- The development of the transmission network assumes the delivery of the projects that currently committed to under the Transmission Development Plans for Ireland and Northern Ireland per their delivery schedule. In addition, a further approximately 40 projects of the total number of projects were assumed to be delivered by 2030 and are included in analysis.
- The RES-E levels that are expected to be reached are of the order of 63% compared to the ambition of 70%. This is because the reinforcements that are needed to integrate new renewable sources cannot be fully implemented by 2030 resulting in the spilling of a significant amount of the electricity they produce. No penalties for falling short of the 2030 ambition were assumed in this evaluation.
- Generators are also not able to be economically dispatched, leading to sub-optimal dispatch and higher production costs as a result.
- Assuming that the generation connects as expected and will be in place by 2030, high levels of constraint as a result can be expected. As a consequence, for 2030, this is expected to be of the order of 9% and will correspond to approximately 3,000 GWh. At an average compensation rate of € 69/MWh[15], this corresponds to a constraint cost of € 207 million.
- System losses are expected to reduce by 530 GWh each year once the reinforcements are in place, relative to the transmission system containing only those reinforcements currently contemplated in the TDPs of Ireland and Northern Ireland. This translates to a combined reduction in the cost of losses for Ireland and Northern Ireland of approximately € 30 million per annum, assuming an average annual System Marginal Price of € 50 /MWh.

15 Cost of compensation determined based on a LCOE of €60/MWh for onshore wind and onshore solar PV; and LCOE of €120/MWh for offshore wind. The value is applicable for the scenario applicable for the approach, in this case Co-ordinated Action (CA) for Ireland and Addressing Climate Change (ACC) for Northern Ireland.

The estimated benefits are summarised in Table 14.

Table 14: Estimated benefits for the Developer-Led approach.

Metric	Volume	Monetisation [€m]
Production cost change p.a.	Sub-optimal generator dispatch	High production costs relative to an un-constrained dispatch
CO_2 emission reduction t p.a.	Higher level of CO_2 due to running inefficient plant, possibly more thermals plant	Higher CO_2 cost due to the higher level of CO_2 emissions
RES-E achieved in 2030	c.63 %	N/A
Renewable generation constraint p.a.	3,000 GWh c.9 %	207
Grid losses change p.a.	-530 GWh	-30

To account for the high capital cost of the approach; and the costs associated with constraining new RES in 2030, the economic criterion is assessed as having poor performance.

Figure 16: Economic criterion rating for the Developer-Led approach

3.2.2.3. Environmental factors

The Developer-Led approach is characterised by a larger number of network reinforcements compared to the other approaches. Among the reinforcement, the approach calls for 9 new circuits.

All statements regarding potential impact significance relate to the residual effects. This is because appropriate mitigation measures will be put in place and will be supported by environmental monitoring as required to cater for adaptive management of mitigation measures (e.g. in response to extreme weather conditions or construction practices).

It is recognised that project-level environmental assessments would be undertaken at the appropriate time and that there are unlikely to be any significant long-term negative impacts if the network of reinforcements are realised.

Overall, the performance is moderate[16]. By undertaking Strategic Environmental Assessment (SEA) on this pathway and applying best practice in design and appraisal in all stages should facilitate the avoidance of significant effects and appropriate routing/option development having regard to relevant environment considerations. This assessment is indicated in the Figure below.

Figure 17: Environmental criterion rating for the Developer-Led approach

16 The performance and key environmental issues relating to this pathway is developed using information presented in previous Strategic Environment Assessments undertaken, and other information including the review of EirGrid's (2016) Evidence Based Environmental Studies.

3.2.2.4. Society and social acceptability

The Developer-Led approach is characterised by a larger number of network reinforcements compared to the other approaches. The approach has identified the need for 100 reinforcements, 9 of which are new circuits.

Comparatively, underground cables present less risk and have a less significant impact than overhead lines in the context of all social criteria. In general terms overhead lines receive less social acceptance than underground cables. This arises from the perceived impact on sense of place and well-being of individuals, a community or network of communities.

This approach, due to the large number of new reinforcements and particularly new circuits, is more likely than other approaches to perform poorly in respect of society and social acceptability.

The risk of not achieving social acceptability for this approach may therefore be significant. This approach is therefore assessed as having a high risk in respect of society and social acceptability.

To account for this, the society and social acceptability criterion is assessed as having the highest level of effect.

Figure 18: Society and social acceptance criterion rating for the Developer-Led approach

Following, Stakeholder Engagement, this assessment may be adjusted to reflect the summary of responses received and general opinion of society toward the approach. It should also be noted that stakeholder engagement is an iterative process and further engagement in future may have a bearing on the societal analysis and social acceptance of pathways shown in this report.

3.2.2.5. Deliverability

Deliverability refers to the logistical aspects of developing, planning, designing, constructing and commissioning the reinforcements associated with a particular approach in order to meet the RES-E ambitions of both jurisdictions by 2030.

The large number of reinforcements associated with the Developer-Led approach is assessed to be deliverable in the decades following 2030. This is a combination of the number of reinforcements as well as the type of reinforcements.

Where the reinforcements are not in place by 2030, the consequence will be higher level of generator constraints and consequently higher constraint costs.

A significant portion of the developments is comprised of uprating or upvoltaging existing circuits which will require the associated circuits to be taken out of service for long periods of time in order to complete the related works. When circuits are taken out of service, they are usually done during periods of light loading, such as the summer months. This is necessary as the transmission system would be required to operate at lower levels of redundancy which is more manageable during those periods. It is not possible to take out a large number of circuits simultaneously, and particularly not in the same location. The consequence is that the outages need to be scheduled successively, directly impacting the ability to implement all the reinforcements comprising the approach by 2030.

To account for the issues likely to arise during the implementation of the large number of reinforcements, the deliverability criterion is assessed as performing poorly.

Figure 19: Deliverability criterion rating for the Developer-Led approach

3.2.3. Technology-Led approach

This approach evaluates opportunities to apply technologies in a way that is new to Ireland and Northern Ireland. In particular the approach focuses on the use of HVDC systems. HVDC technology has multiple applications, including long-distance power transfer and it can be employed to connect separate AC systems, for example the EWIC and Moyle sub-sea interconnectors to Great Britain. The HVDC technology selected here is voltage source converter technology with a combination of underground and sub-sea cables.

The approach also considers the use of new technologies to dynamically control power flow in the transmission network in order to maximise the available local capacity to avoid network constraints. The application of these technologies allows the overall number of grid developments to be minimised. In Ireland, two separate point-to-point ("radial") HVDC links are proposed. If compatibility is ensured during the design phase, these separate HVDC links could be joined in the future to create a multi-terminal system. Unlike a meshed configuration, no DC breakers are required.

The designed HVDC links are to evacuate RES from remote parts of the grid. They are "non-embedded" within the AC grid, which means that if there is a contingency on a HVDC link the sources of power are tripped/run back instead of its power being transferred to other nearby circuits in the AC grid.

The Technology-Led approach also makes use of power flow control devices. These devices provide series compensation to modify the reactance of the lines to which they are connected. This is beneficial in a meshed transmission network where, in some circumstances, they can help route power away from where the network is congested to areas where it is less utilised. The ability to control power flow in a network can improve how it is used and assist in deferring the more significant developments required to increase network capacity.

The generation portfolio used for the Technology-Led approach is described in Table 15.

Table 15: Variable renewable generation portfolio for the Technology-Led approach

Jurisdiction	Onshore Wind Capacity [GW]	Offshore Wind Capacity [GW]	Solar Capacity [GW]
Ireland	8.20	1.80	2.00
Northern Ireland	2.00	0.35	0.60

The majority of the renewable generation requirement is located onshore, with a lesser amount offshore in the Irish Sea (i.e. 2.15 GW offshore with 1.8 GW off the Irish coast and 0.35 GW off the Northern Ireland coast).

This approach is effectively an extension of the developer-led approach. However the afore-mentioned new technologies are incorporated to examine the impact on the number of network reinforcements required and, consequently, the constraints level and RES-E level.

3.2.3.1. Technical performance

For the Technology-Led approach, it was assumed that developers connect at their preferred locations. This is consistent with how connections are currently dealt with.

In remote areas, in the north-west for example, onshore wind generation is assumed to be clustered and connected via HVDC into distant strong points elsewhere on the grid that are electrically closer to the large load centres. This results in approximately 60 reinforcements.

In Northern Ireland, a 300 MW sub-sea HVDC circuit links the north-west to the grid in the Belfast area. The circuit helps evacuate renewable generation from the west of Northern Ireland and is not integrated with the local 110 kV grid.

The 275 kV grid is extended from Turleenan to Omagh by uprating one of the three circuits along this corridor. A second Kells – Rasharkin is assumed and the uprating of a number of 110 kV circuits is also required.

In Ireland, along the west coast, a 500 MW sub-sea HVDC link connects onshore wind in the north-west to the 400 kV grid at Moneypoint, utilising the existing Moneypoint site, when the onsite coal fire generators will be decommissioned. In Donegal, a 700 MW underground HVDC circuit connects local onshore wind generation directly to the grid in the Mid-East. Both HVDC connections are not integrated with the local 110 kV grid. A small number of 110 kV circuits are also uprated in the north-west area.

In the Mid-East region, centred on the Dublin network, due to growth in Large Energy Users and to cater for the transfer of RES into and out of the area, new reinforcements are required to ensure security of supply. The Dunstown and Woodland 400 kV stations are linked by a 400 kV circuit. Consistent with the Technology-Led approach, we assumed this was achieved by upvoltaging the existing Woodland – Maynooth - Dunstown 220 kV overhead line route. New capacity is added along the 220 kV corridor between the Woodland and Finglas stations. Offshore wind generation is catered for by the replacement of the older low-capacity 220 kV fluid-filled underground cables. In comparison to other approaches, less reactive compensation is required in the Dublin area due to the benefit of a new converter station in the vicinity.

In the South of Ireland, emphasis is placed on a combination of 220 kV overhead line uprating and power flow control systems, including the use of dynamic line rating, to create a high capacity corridor from the Cork area into the Midlands and onwards towards Dublin. The south of the system also benefits from having a new converter station at Moneypoint – this helps regulate powerflow and reactive power in the area. This facilitates the connection of new onshore RES and supports the more efficient operation of the Celtic and Greenlink interconnectors under these conditions.

Powerflow control technologies are deployed on a number of corridors to alter impedance of circuits to better balance power flow and ultimately reduced the dispatch-down of renewable generation. To maximise the capability, these corridors will also have to be uprated.

Figure 20 illustrates what the transmission network resulting from a Technology-Led approach could look like.

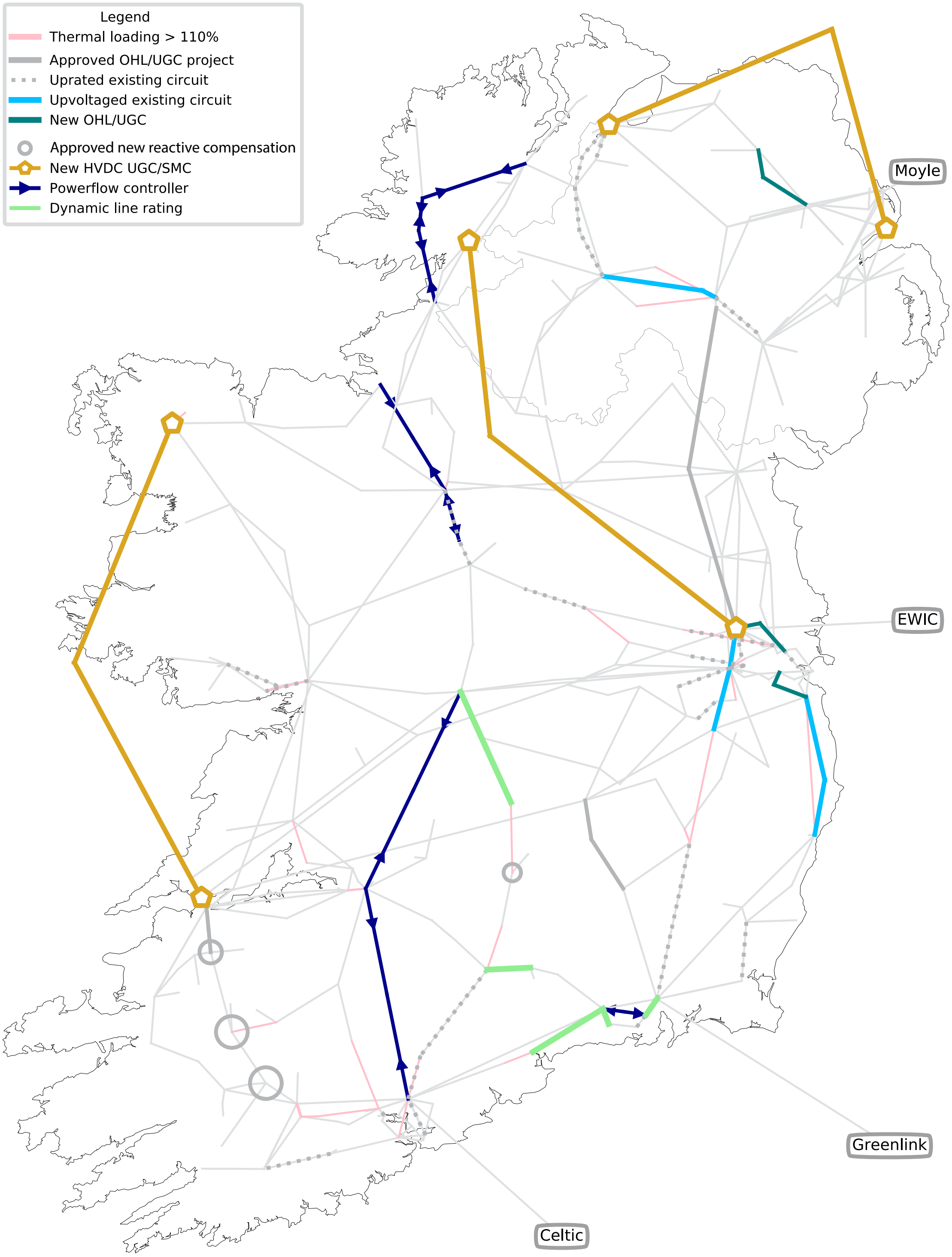


Figure 20: Illustration of reinforcements and limitations of a Technology-Led approach in 2030

The reinforcement details are summarised in Table 16. A full list of the reinforcements identified as part of this approach is contained in Appendix E.

Table 16: Numbers of reinforcements by reinforcement type per jurisdiction for the Technology-Led approach

Reinforcement Category	Ireland Reinforcements [No.]	Northern Ireland Reinforcements [No.]	All-Ireland Reinforcements [No.]
Uprating of existing circuits	30	5	35
Upvoltage existing circuits	4	2	6
New circuits	4	2	6
New equipment	8	5	13
Total	**46**	**14**	**60**

The use of HVDC systems and dynamic power flow control technologies increases the operational complexity of the transmission system. The reliability of HVDC systems and the use of underground cables negatively impact the reliability of the transmission network as any outages are likely to be prolonged and the impact is likely to be significant. The requirement for numerous large-scale HVDC circuits also adds significant risk to the deliverability of this approach given the complexity of the HVDC systems and not having experience of using them in this manner.

However, this is also a grid with high strategic value, one that can be built upon for future growth in renewable generation.

To account for these issues, the technical criterion is assessed as moderate:

Figure 21: Technical criterion rating for the Technology-Led approach

To account for these issues, the technical criterion is assessed as moderate:

3.2.3.2. Economic performance

The estimated capital costs of the Technology-Led approach are summarised per jurisdiction in Table 17. A total cost per reinforcement category is also provided and is shown in equivalent euro values.

Table 17: Estimated CAPEX by reinforcement type per jurisdiction for the Technology-Led approach

Reinforcement Category	Ireland Reinforcements [€ million]	Northern Ireland Reinforcements [£ million]	All-Ireland Reinforcements [€ million equivalent*]
Uprating of existing circuits	239	42	286
Upvoltage existing circuits	99	32	135
New circuits	674	215	917
New equipment	529	246	806
Total	**1,541**	**535**	**2,144**

Note *: assumed €/£ exchange rate is 1.13

The capital costs, also referred to as programme cost, are calculated using standardised unit costs applicable for Ireland and Northern Ireland respectively. The capital costs associated with the HVDC systems using underground cable are significant.

The benefits reflect the direct consequences of network development leading to higher penetrations of renewable generation. The economic benefits are described by assessing the changes or reductions in system production costs, CO_2 emissions, renewable generation constraint and system losses.

The economic performance of the Technology-Led approach is assessed for the year 2030:

- The RES-E levels that are expected match the ambitions of both Ireland and Northern Ireland, i.e. 70%;
- Generators are economically dispatched, leading to the optimal dispatch and hence the optimal production costs as a result.
- Assuming that the generation connects as expected, and that the reinforcements are in place by 2030, the levels of constraint will be minimised. For 2030, this is expected to be of the order of 5% and will correspond to approximately 1,700 GWh. At an average compensation rate of € 69/MWh[17], this corresponds to a constraint cost of € 118 million.
- System losses are expected to reduce by 660 GWh each year once the reinforcements are in place, relative to the transmission system containing only those reinforcements currently contemplated in the TDPs of Ireland and Northern Ireland. This translates to a combined reduction in the cost of losses for Ireland and Northern Ireland of approximately € 33 million per annum, assuming an average annual System Marginal Price of € 50 /MWh.

The estimated benefits are summarised in Table 18.

Table 18: Estimated benefits for the Technology-Led approach.

Metric	Volume	Monetisation [€m]
Production cost change p.a.	Generators are optimally dispatched due to the removal of network constraints	Optimised production cost per annum
CO_2 emission reduction t p.a.	Minimum level of CO_2 due to running most efficient plant	Minimised CO_2 cost due to the minimised level of CO_2 emissions
RES-E achieved in 2030	c.70 %	-
Renewable generation constraint p.a.	1,700 GWh c.5%	118
Grid losses change p.a.	-660 GWh	-33

To account for the high capital cost, the economic criterion is assessed as performing poorly.

Figure 22: Economic criterion rating for the Technology-Led approach

17 Cost of compensation determined based on a LCOE of €60/MWh for onshore wind and onshore solar PV; and LCOE of €120/MWh for offshore wind. The value is applicable for the scenario applicable for the approach, in this case Co-ordinated Action (CA) for Ireland and Addressing Climate Change (ACC) for Northern Ireland.

3.2.3.3. Environmental factors

The Technology-Led approach applies technology in a new or novel way in Ireland and Northern Ireland. This is characterised by the use of HVDC circuits overlaid on the existing HVAC transmission system and the installation of power flow control devices to modify flow of power in order to remove network restrictions. The HVDC circuits are comprised of underground cables or submarine cables. The power flow control devices are located at specific sites.

As in the environmental assessments of the previous approaches, all statements regarding potential impact significance relate to the residual effects. This is because appropriate mitigation measures will be put in place and will be supported by environmental monitoring as required to cater for adaptive management of mitigation measures (e.g. in response to extreme weather conditions or construction practices).

It is recognised that project-level environmental assessments would be undertaken at the appropriate time and that there are unlikely to be any significant long-term negative impacts if the network of reinforcements are realised.

Overall, the performance is assessed as being moderate[18]. By undertaking Strategic Environmental Assessment (SEA) on this pathway and applying best practice in design and appraisal in all stages should facilitate the avoidance of significant effects and appropriate routing/option development having regard to relevant environment considerations. This assessment is indicated in the Figure below.

Figure 23: Environmental criterion rating for the Technology-Led approach

3.2.3.4. Society and social acceptability

The Technology-Led approach applies technology in a new or novel way in Ireland and Northern Ireland. This is used to integrate a high volume of onshore wind generation. Onshore wind has been challenging in terms of social acceptance for some time and this is expected to continue with the connection of future onshore RES.

The approach is also characterised by the use of HVDC circuits connected to the existing HVAC transmission system. The HVDC circuits associated with this approach are expected to traverse significant distances of between 150 km and 225 km.

The approach also considers the installation of power flow control devices to modify flow of power in order to remove network restrictions. These are mostly localised and self-contained reinforcement elements and therefore expected to have a limited impact on society.

Comparatively, underground cables present less risk and have a less significant impact than overhead lines in the context of all social criteria. In general terms overhead lines receive less social acceptance than underground cables. This arises from the perceived impact on sense of place and well-being of individuals, a community or network of communities.

To account for this, the society and social acceptability criterion is assessed as having a moderate effect.

Figure 24: Society and social acceptance criterion rating for the Technology-Led approach

18 The performance and key environmental issues relating to this pathway is developed using information presented in previous Strategic Environment Assessments undertaken, and other information including the review of EirGrid's (2016) Evidence Based Environmental Studies.

Following, Stakeholder Engagement, this assessment may be adjusted to reflect the summary of responses received and general opinion of society toward the approach. It should also be noted that stakeholder engagement is an iterative process and further engagement in future may have a bearing on the societal analysis and social acceptance of pathways shown in this report.

3.2.3.5. Deliverability

The deliverability criterion assesses the logistical aspects of constructing and delivering a particular approach by 2030 in order to satisfy the RES-E ambitions of both jurisdictions. The approach involves the delivery of a large number of reinforcements by 2030. These are recognised as being difficult but achievable to deliver by 2030. Hence, the large number of reinforcements is a significant deliverability consideration.

A further consideration is the delivery of several complex HVDC systems. Both Ireland and Northern Ireland have experience of HVDC systems in the past, but these are for interconnections with the separate AC systems of neighbouring countries. In the context of using HVDC systems within the transmission systems of Ireland and Northern Ireland, these would be considered a new application of well-known technologies.

The approach makes use of significant distances of both underground cable and submarine cable. There are a limited number of cable manufacturers internationally and no formal procurement arrangements are likely to be in place which may impact procurement and design timelines.

The approach also calls for the use of power flow control devices. These devices are known and understood technologies albeit are not yet operational in Ireland or Northern Ireland.

To account for these issues, the deliverability criterion for the Technology-Led approach is assessed as being moderate-to-poor.

Figure 25: Deliverability criterion rating for the Technology-Led approach

3.2.4. Demand-Led approach

The Demand-Led approach considers influencing new Large Energy Users to locate at stations across the transmission network where capacity exists. It also considers close to renewable sources rather than concentrating in already congested areas distant from renewable sources. The scale of new grid development is therefore minimised.

Reflecting the fact there is a large pipeline of new Large Energy User projects in the Dublin area, this approach looks at moving demand in Ireland only. However, we expect the concepts illustrated in this approach would be applicable to Northern Ireland should significant amounts of Large Energy User projects progress.

While emphasis is placed on influencing where the demand growth is concentrated, the approach to grid development technology is similar to that of developer-led approach, just on a smaller scale.

The generation portfolio used for the Demand-Led approach is described in Table 19.

Table 19: Variable renewable generation portfolio for the Demand-Led approach

Jurisdiction	Onshore Wind Capacity [GW]	Offshore Wind Capacity [GW]	Solar Capacity [GW]
Ireland	8.20	1.80	2.00
Northern Ireland	2.00	0.35	0.60

The deliverability of the approach depends on the ability to incentivise large power users to locate at stronger parts of the network or closed to generation hubs. There are also further factors that also need to be considered, such as the availability and adequacy of the fibre network, when assessing the suitability of a new large power user to relocate.

This approach is effectively an extension of the developer-led approach. However here Large Energy Users are assumed to locate at stations across the transmission network where capacity exists to examine the impact on the number of network reinforcements required and, consequently, the constraints level and RES-E level.

3.2.4.1. Technical performance

For both Ireland and Northern Ireland, the generation connections are the same as the developer-led approach.

In Ireland, Large Energy Users are encouraged to connect outside the Mid-East region, closer to renewable generation resources. A number of urban locations outside the Dublin area are considered, among them: Cork, Galway, Limerick, Waterford, Letterkenny and Sligo. These locations were selected due to their close proximity to new RES generation, available demand capacity, and the strength of the network connecting these nodes to the rest of the power system. This total relocation of demand amounts to approximately 600 MW. This has the effect of reducing large power flows across the power system.

The Demand-Led grid is illustrated in Figure 26.

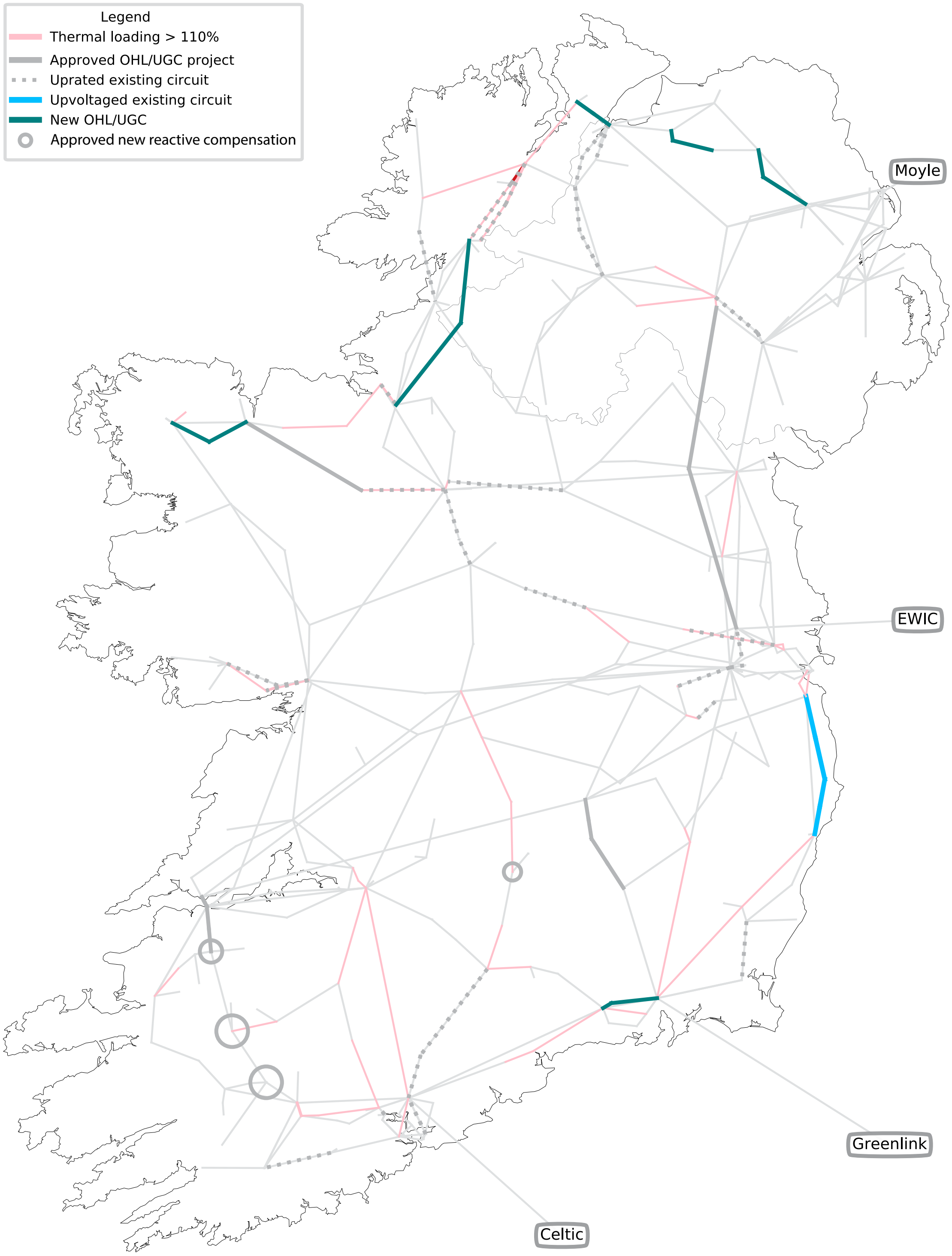


Figure 26: Illustration of reinforcements and limitations of a Demand-Led approach in 2030

In Northern Ireland, two new circuits in the north-west in combination with a number of 110 kV uprates facilitate the RES required.

In the north-west of Ireland, the North Connacht project is extended westwards to the Bellacorick 110 kV station via the Moy 110 kV station. This helps connect more renewable generation in the area but does not resolve all the constraint issues for renewable generation in the area.

Additional new capacity is required in south Donegal - this is achieved with a new 220 kV circuit that links a new Clogher 220 kV station to the main backbone 220 kV grid at Srananagh.

Grid integration is required between Donegal and Northern Ireland and a 110 kV circuit between the Coolkeeragh and Trillick 110 kV stations is assumed for our analysis. The Letterkenny – Strabane circuit, that utilises a phase-shift transformer, is also more relied upon for active power flow control. Overhead lines at 110 kV that can accommodate further capacity are also uprated.

The grid in the Mid-East region of Ireland has more capability to operate and experiences fewer issues due to a reduction in data centre growth. There is still a requirement to link the 400 kV stations at Dunstown and Woodland. Offshore wind generation is catered for by the replacement of the old low-capacity 220 kV underground cables.

To allow the Celtic and Greenlink interconnectors to operate efficiently, a new circuit is required between the Cullenagh and Great Island stations.

Some remote and weaker parts of the grid will remain relatively undeveloped and the dispatch-down of renewable generation is likely to be a more prominent feature in comparison to other approaches.

A full list of the reinforcements identified as part of this approach is contained in Appendix F. The reinforcements that comprise the Demand-Led approach are summarised in Table 20.

Table 20: Numbers of reinforcements by reinforcement type per jurisdiction for the Demand-Led approach

Reinforcement Category	Ireland Reinforcements [No.]	Northern Ireland Reinforcements [No.]	All-Ireland Reinforcements [No.]
Uprating of existing circuits	29	7	36
Upvoltage existing circuits	2	0	2
New circuits	4	3	7
New equipment	6	0	6
Total	**41**	**10**	**51**

During the period when the reinforcements are being delivered, the large number of reinforcements that are spread throughout the grid will impact security of supply and the ability to operate and the maintain the power system. Once the reinforcements are implemented, this grid design is likely to keep the curtailment of RES at a minimum.

In general, though, the transmission system performs well and provides the appropriate level of security of supply required by the planning standards. It is also readily expandable and has headroom to accommodate further demand or generation.

As a result, the technical criterion is assessed as superior:

Figure 27: Technical criterion rating for the Demand-Led approach

3.2.4.2. Economic performance

The estimated capital costs of the Demand-Led approach are summarised per jurisdiction in Table 21. A total cost per reinforcement category is also provided and is shown in equivalent euro values.

Table 21: Estimated CAPEX by reinforcement type per jurisdiction for the Demand-Led approach

Reinforcement Category	Ireland Reinforcements [€ million]	Northern Ireland Reinforcements [£ million]	All-Ireland Reinforcements [€ million equivalent*]
Uprating of existing circuits	181	45	232
Upvoltage existing circuits	37	0	37
New circuits	275	68	352
New equipment	49	0	49
Total	**542**	**113**	**670**

Note *: assumed €/£ exchange rate is 1.13

The capital costs, also referred to as programme cost, are calculated using standardised unit costs applicable for Ireland and Northern Ireland respectively. The capital costs associated the Demand-Led approach are among the lowest of the approaches considered.

The benefits reflect the direct consequences of network development leading to higher penetrations of renewable generation. The economic benefits are described by assessing the changes or reductions in system production costs, CO_2 emissions, renewable generation constraint and system losses.

The economic performance of the technology-led approach is assessed for the year 2030:

- The RES-E levels that are expected match the ambitions of both Ireland and Northern Ireland, i.e. 70%;
- Generators are economically dispatched, leading to the optimal dispatch and hence the optimal production costs as a result.
- Assuming that the generation connects as expected, and that the reinforcements are in place by 2030, the levels of constraint will be minimised. For 2030, this is expected to be of the order of 5% and will correspond to approximately 1,700 GWh. At an average compensation rate of € 69/MWh[19], this corresponds to a constraint cost of € 118 million.
- System losses are expected to reduce by 670 GWh each year once the reinforcements are in place, relative to the transmission system containing only those reinforcements currently contemplated in the TDPs of Ireland and Northern Ireland. This translates to a combined reduction in the cost of losses for Ireland and Northern Ireland of approximately € 34 million per annum, assuming an average annual System Marginal Price of € 50 /MWh.

The estimated benefits are summarised in Table 22.

19 Cost of compensation determined based on a LCOE of €60/MWh for onshore wind and onshore solar PV; and LCOE of €120/MWh for offshore wind. The value is applicable for the scenario applicable for the approach, in this case Co-ordinated Action (CA) for Ireland and Addressing Climate Change (ACC) for Northern Ireland.

Table 22: Estimated benefits for the Demand-Led approach

Metric	Volume	Monetisation [€m]
Production cost change p.a.	Generators are optimally dispatched due to the removal of network constraints	Optimised production cost per annum
CO_2 emission reduction t p.a.	Minimum level of CO_2 due to running most efficient plant	Minimised CO_2 cost due to the minimised level of CO_2 emissions
RES-E achieved in 2030	c.70 %	-
Renewable generation constraint p.a.	1,700 GWh c.5%	118
Grid losses change p.a.	-670 GWh	-34

The relatively lower capital cost, low level of RES constraint and the reduction in system losses contribute to an assessed superior economic performance for this approach. This is illustrated in the Figure below.

Figure 28: Economic criterion rating for the Demand-Led approach

3.2.4.3. Environmental factors

The Demand-Led approach seeks to influence the location of new Large Energy Users from existing congested sites on the transmission system to where there is capacity available to accommodate them. This reduces the amount and scale of new network reinforcements that are needed on the transmission system.

As in the environmental assessments of the previous approaches, all statements regarding potential impact significance relate to the residual effects. This is because appropriate mitigation measures will be put in place and will be supported by environmental monitoring as required to cater for adaptive management of mitigation measures (e.g. in response to extreme weather conditions or construction practices).

It is recognised that project-level environmental assessments would be undertaken at the appropriate time and that there are unlikely to be any significant long term negative impacts if the network of reinforcements are realised.

Overall, the performance is assessed as being moderate[20]. By undertaking Strategic Environmental Assessment (SEA) on this pathway and applying best practice in design and appraisal in all stages should facilitate the avoidance of significant effects and appropriate routing/option development having regard to relevant environment considerations. This assessment is indicated in the Figure below.

Figure 29: Environmental criterion rating for the Demand-Led approach

20 The performance and key environmental issues relating to this pathway is developed using information presented in previous Strategic Environment Assessments undertaken, and other information including the review of EirGrid's (2016) Evidence Based Environmental Studies.

3.2.4.4. Society and social acceptability

The Demand-Led approach seeks to incentivise the location of new Large Energy Users in Ireland to locations on the transmission system where there is capacity to accommodate them more readily. A large number of reinforcements are still required to integrate a high volume of onshore wind generation needed to match the RES-E ambitions of Ireland and Northern Ireland.

Comparatively, underground cables present less risk and have a less significant impact than overhead lines in the context of all social criteria. In general terms overhead lines receive less social acceptance than underground cables. This arises from the perceived impact on sense of place and well-being of individuals, a community or network of communities.

To account for this, the society and social acceptability criterion is assessed as having a moderate effect.

Figure 30: Society and social acceptance criterion rating for the Demand-Led approach

Following, Stakeholder Engagement, this assessment may be adjusted to reflect the summary of responses received and general opinion of society toward the approach. It should also be noted that stakeholder engagement is an iterative process and further engagement in future may have a bearing on the societal analysis and social acceptance of pathways shown in this report.

3.2.4.5. Deliverability

The deliverability criterion assesses of the logistical aspects of constructing and delivering a particular approach by 2030 in order to satisfy the RES-E target.

The approach requires the delivery of 51 reinforcements. They are assessed as being deliverable by 2030.

The ability to influence the connection of new demand to particular locations on the transmission system is a key factor determining the deliverability of the approach. In many cases, the requirements of developers are much broader than just a grid connection. These requirements may not be fully met if they were to locate at the preferred transmission notes and would therefore impact on the deliverability of the approach.

The deliverability criterion for the Demand-Led approach is assessed as being moderate. This is illustrated in the figure below.

Figure 31: Deliverability criterion rating for the Demand-Led approach

3.3. Emerging reinforcement requirements

3.3.1. Common reinforcements

A comparison of the potential reinforcements arising from each of the different approaches identified a number of reinforcements that were common to all of them. These developments could be seen as being justified regardless of the approach taken, where each approach could be seen as an alternative sensitivity or scenario under which the same reinforcement solution is identified.

Each of these projects will now be assessed in significantly more detail on an individual basis using the established grid development frameworks in Ireland and Northern Ireland, i.e. EirGrid's Framework for Grid Development process or SONI's 3 Part Process for Developing the Grid. Both have their own detailed analysis requirements. At the heart of these frameworks is engagement with industry, statutory bodies and the public.

A list of these common reinforcements in Ireland is contained in Table 23.

Table 23: Summary of reinforcements in Ireland that are common to the four approaches

	Project Component	Voltage (kV)	Length (km)	Path	Domain	Class	Type	Technology
1	Ballybeg - Carrickmines - 110 kV No.1	220	32	Upvolt	Circuit	HVAC	OHL	600 mm2 ACSR 'Curlew'
2	CAHIR - BARRYMORE TEE - 110 kV - No.1	110	43.7	Uprate	Circuit	HVAC	OHL	430 mm2 ACSR 'Bison'
3	KNOCKRAHA - BARRYMORE TEE - 110 kV - No.1	110	43.7	Uprate	Circuit	HVAC	OHL	430 mm2 ACSR 'Bison'
4	AGHADA - KNOCKRAHA - 220 kV - No.1	220	25.6	Uprate	Circuit	HVAC	OHL	586 mm2 GZTACSR 'Traonach'
5	AGHADA - KNOCKRAHA - 220 kV - No.2	220	25.6	Uprate	Circuit	HVAC	OHL	586 mm2 GZTACSR 'Traonach'
6	Arklow - Ballybeg - 110 kV No. 1	220	22	Upvolt	Circuit	HVAC	OHL	600 mm2 ACSR 'Curlew'
7	Ballybeg - Ballybeg - 220/110 kV - No.1	220/110	-	New	Static device	HVAC	Transformer	250 MVA ONAN/ ONAF/ ODAF/ OFAF
8	Ballybeg - Ballybeg - 220/110 kV - No.2	220/110	-	New	Static device	HVAC	Transformer	250 MVA ONAN/ ONAF/ODAF/ OFAF
9	Ballybeg 220 kV - No.1	220	-	New	Substation	HVAC	GIS	8-Bay Enhanced Ring
10	BANDON - DUNMANWAY - 110 kV - No.1	110	25.9	Uprate	Circuit	HVAC	OHL	430 mm2 ACSR 'Bison'
11	CRANE - WEXFORD - 110 kV - No.1	110	22.8	Uprate	Circuit	HVAC	OHL	430 mm2 ACSR 'Bison'
12	GALWAY - KNOCKRANNY - 110 kV - No.1	110	26.5	Uprate	Circuit	HVAC	OHL	430 mm2 ACSR 'Bison'
13	GREAT ISLAND - GREAT ISLAND - 220/110 kV - No.3	220/110	-	New	Static device	HVAC	Transformer	250 MVA ONAN/ ONAF/ODAF/ OFAF
14	LANESBORO - SLIABH BAWN - 110 kV - No.1	110	9.1	Uprate	Circuit	HVAC	OHL	430 mm2 ACSR 'Bison'

Similarly, a list of these common reinforcements in Northern Ireland is contained in Table 24.

Table 24: Summary of reinforcements in Northern Ireland that are common to the four approaches

	Project Component	Voltage (kV)	Length (km)	Path	Domain	Class	Type	Technology
1	COOLKEERAGH - KILLYMALLAGHT - 110 kV - No.1	110	14.5	Uprate	Circuit	HVAC	OHL	430 mm2 ACCC 'Totara'
2	COOLKEERAGH - STRABANE - 110 kV - No.1	110	27	Uprate	Circuit	HVAC	OHL	430 mm2 ACCC 'Totara'
3	KELLS - RASHARKIN - 110 kV - No.2	110	26	New	Circuit	HVAC	OHL	400 mm2 ACSR 'Zebra'
4	OMAGH - STRABANE - 110 kV - No.2	110	35.5	Uprate	Circuit	HVAC	OHL	430 mm2 ACCC 'Totara'
5	77010 Drumnakelly - 90310 TAMNAMORE - 110 kV - No.1	110	22.6	Uprate	Circuit	HVAC	OHL	191/45 mm2 'ZTAC INVAR
6	77010 Drumnakelly - 90310 TAMNAMORE - 110 kV - No.2	110	21.5	Uprate	Circuit	HVAC	OHL	191/45 mm2 'ZTAC INVAR'

3.3.2. Most frequently occurring technology choices

From an examination of the technology choices made for each of the approaches, a number of recurring choices were made. These are listed in Table 25.

Table 25: Summary of technology types used across the four approaches

Path	Domain	Class	Type	Voltage (kV)	Rating (MVA)	Technology#
Uprate	Circuit	HVAC	OHL	110	209*	430 mm2 ACSR 'Bison' (Uprate)
Uprate	Circuit	HVAC	OHL	220	*833**	586 mm2 GZTACSR 'Traonach'
Uprate	Circuit	HVAC	UGC	220	635*	1600 mm2 Cu XLPE
Up-voltage	Circuit	HVAC	OHL	220	*534**	600 mm2 ACSR 'Curlew' (Upvoltage)
New	Circuit	HVAC	OHL	110	219	430 mm2 ACSR 'Bison' (New)
New	Circuit	HVAC	OHL	110	*TBA*	400 mm2 ACSR 'Zebra'
New	Circuit	HVAC	OHL	220	*TBA*	600 mm2 ACSR 'Curlew' (New)
New	Circuit	HVAC	UGC	220	*518**	1600 mm2 Cu XLPE
New	Circuit	HVAC	OHL	275	*TBA**	2 x 485mm2 'Zebra' (New)
New	Circuit	HVDC	SMC	320	750	2500 mm2 Al XLPE (SMC, IE)
New	Circuit	HVDC	UGC	320	750	2500 mm2 Al XLPE (UGC, IE)
New	Circuit	HVAC	OHL	380	*1,944**	2 x 600 mm2 ACSR 'Curlew' (New)
New	Static device	HVAC	Transformer	220/110	250	250 MVA ONAN/ONAF/ODAF/OFAF
New	Static device	HVAC	Transformer	275/110	250	250 MVA ONAN/ONAF/ODAF/OFAF
New	Static device	HVAC	Transformer	275/220	250	250 MVA ONAN/ONAF/ODAF/OFAF
New	Dynamic device	HVAC	Voltage regulation	110	*TBA*	STATCOM
New	Dynamic device	HVAC	Voltage regulation	220	*TBA*	STATCOM
New	Dynamic device	HVAC	PFC	110	*TBA*	Details to be provided
New	Dynamic device	HVAC	PFC	220	*TBA*	Details to be provided
New	Substation	HVAC	GIS	220	*TBA*	4-Bay C-Type (220 kV GIS)
New	Substation	HVAC	GIS	275	*TBA*	4-Bay C-Type (220 kV GIS)
New	Substation	HVDC	Converter	320	750	VSC (Converter, IE)

Note *: For circuits, winter ratings are used. These are minimum ratings.
The technology type reflects what was assumed in studies and does not rule out a more appropriate technology capable of delivering the minimum capacity requirement

These technologies were based on what is already known and would constitute a minimum capacity requirement. Should newer and more effective options be available that are capable of satisfying the capacity requirements, then those would obviously be preferred. An example of this could be the consideration of newer conductors such as Aluminium Conductor Composite Core (ACCC) conductors instead of continuing with the deployment of Aluminium Conductor Steel Reinforced (ACSR) conductors. Such discussions should form part of a much broader discussion regarding appropriate technologies for the future. Obvious additions to what has been contemplated in the past are the use of HVDC voltage source converter (VSC) technology used with underground and submarine cables and the use of power flow control devices.

3.4. Comparison of network development approaches

3.4.1. Summary of results

The key parameters for each of the approaches is collated and summarised in Table 26.

Table 26: Summary of key performance parameters for each of the approaches

	Onshore Wind Capacity [GW]	Offshore Wind Capacity [GW]	Solar Capacity [GW]	Network Development [No.]	Cost [millions]	RES-E in 2030 [%]
1 Generation Led	IE: 4.4 NI: 1.4	IE: 4.5 NI: 0.7	IE: 0.6 NI: 0.6	IE: 38 NI: 8 Total: 46	IE: €717 NI: £120 Total: €853*	70%
2 Developer Led	IE: 8.2 NI: 2.0	IE: 1.8 NI: 0.35	IE: 2.0 NI: 0.6	IE: 77 NI: 19 Total: 96	IE: €1,900 NI: £361 Total: €2,308*	63%
3 Technology Led	IE: 8.2 NI: 2.0	IE: 1.8 NI: 0.35	IE: 2.0 NI: 0.6	IE: 46 NI: 14 Total: 60	IE: €1,541 NI: £535 Total: €2,144*	70%
4 Demand Led	IE: 8.2 NI: 2.0	IE: 1.8 NI: 0.35	IE: 2.0 NI:0.6	IE: 41 NI: 10 Total: 51	IE: €542 NI: £113 Total: €670*	70%

Note *: Assumed €/£ exchange rate is 1.13.

From the table it can be seen that, unlike the other approaches, the developer-led approach will not satisfy the RES-E ambition in 2030 for Ireland or Northern Ireland for the assumed levels of generation.

The technology-led approach has the highest capital cost of the four approaches. It is also approximately 3 times higher than the lowest cost approach, i.e. the demand-led approach.

3.4.2. Summary of performance

The performance of each approach is described in the preceding sections. From these performance assessments a corresponding colour code has been selected and is tabulated using a standardised colour code to reflect relative performance, which for completeness is shown in the Figure below.

(superior performance ➔ poor performance)

Figure 32: Standardised colour code for comparing performance

The purpose of summarising the relative performance of each approach in a single table is to facilitate the comparison of their relative merits and to support further debate regarding their overall preference. The table summarising the relative performance is shown in Table 27.

Table 27: Summary of performance

	Technical performance	Economic	Environment	Society & acceptability	Delivery
1 Generation Led					
2 Developer Led					
3 Technology Led					
4 Demand Led					

3.4.3. Risks

With each of the approaches, there are different risk considerations. Given the strategic nature of this assessment, the assessment of risks focuses on the broader risks. Project-level risks are not appropriate for consideration at this time and will be the focus of future work.

At the strategic level, the most important risks for each of the approaches were assessed and are described in Table 28. The risk probabilities for the different approaches are stated relative to each other.

Table 28: Risk matrix for each approach

Low | Moderate | High

		Risk probability for approaches			
Risk	**Impact**	**1 Generation Led**	**2 Developer Led**	**3 Technology Led**	**4 Demand Led**
Ability to achieve 70% RES-E by 2030	Renewable ambitions not met. Potential for penalties. Knock-on impact on future climate change commitments.	Moderate	High	Moderate	Moderate
Capital cost estimation	Costs based on unit costs. This underestimates overall project costs. Low capital costs skew cost-benefit assessments .	High	High	High	High
Ability to deliver reinforcements by 2030	Increased curtailment. Fall short of RES-E ambition of 70%.	Low	High	Moderate	Moderate
Technology complications, failures	Higher levels of technical complexity, unreliability. Impact system security.	Low	Low	High	Low
Misalignment between network development & RES projects progressing	Fall short of RES-E ambition of 70%.	High	Moderate	Moderate	Moderate

Table 28: Risk matrix for each approach

Low	Moderate	High
(green)	(blue)	(red)

Risk probability for approaches

Risk	Impact	1 Generation Led	2 Developer Led	3 Technology Led	4 Demand Led
Limits scope for future network development	Technology commitments limit future options. Undermine ability to achieve future RES-E ambitions e.g. 2050.	Low	High	Moderate	Low
High level of reliance on 3rd party for implementing the approach	Unable to achieve the design objectives of the approach. Delay in delivering the approach.	Moderate	Low	Moderate	High
Social acceptance of reinforcements and RES associated with the approach	Significant delays in delivering reinforcements; Increased curtailment Fall short of RES-E ambition of 70%.	Moderate	High	Moderate	Moderate
Operational risk	Operational constraints during construction; Complex operations; Increased system security risk. Outage feasibility.	Moderate	High	High	Low
Affordability	Capital rationing limits approaches; Regulatory perspective in respect of affordability.	Low	Moderate	High	Low

1 Generation-Led

A key risk area for this approach is the reliance on offshore wind materialising in both Ireland and Northern Ireland by 2030.

This approach depends on a large amount of offshore wind connecting in order to meet the RES-E ambitions by 2030.

Public acceptance of the scale of offshore wind farms will also be a risk.

2 Developer-Led

A key risk area for this approach is the ability to deliver the reinforcements by 2030. Given the large number of reinforcements, there is a greater likelihood that public acceptance may be a factor in delivering the reinforcements.

There is also a knock-on effect that any delays satisfying the 2030 ambitions for Ireland and Northern Ireland will impact any further future ambition, such as total de-carbonisation by 2050.

3 Technology-Led

The scale of adoption of the proposed technologies will by its nature increase the complexity of operating the system and may have unintended interactive consequences.

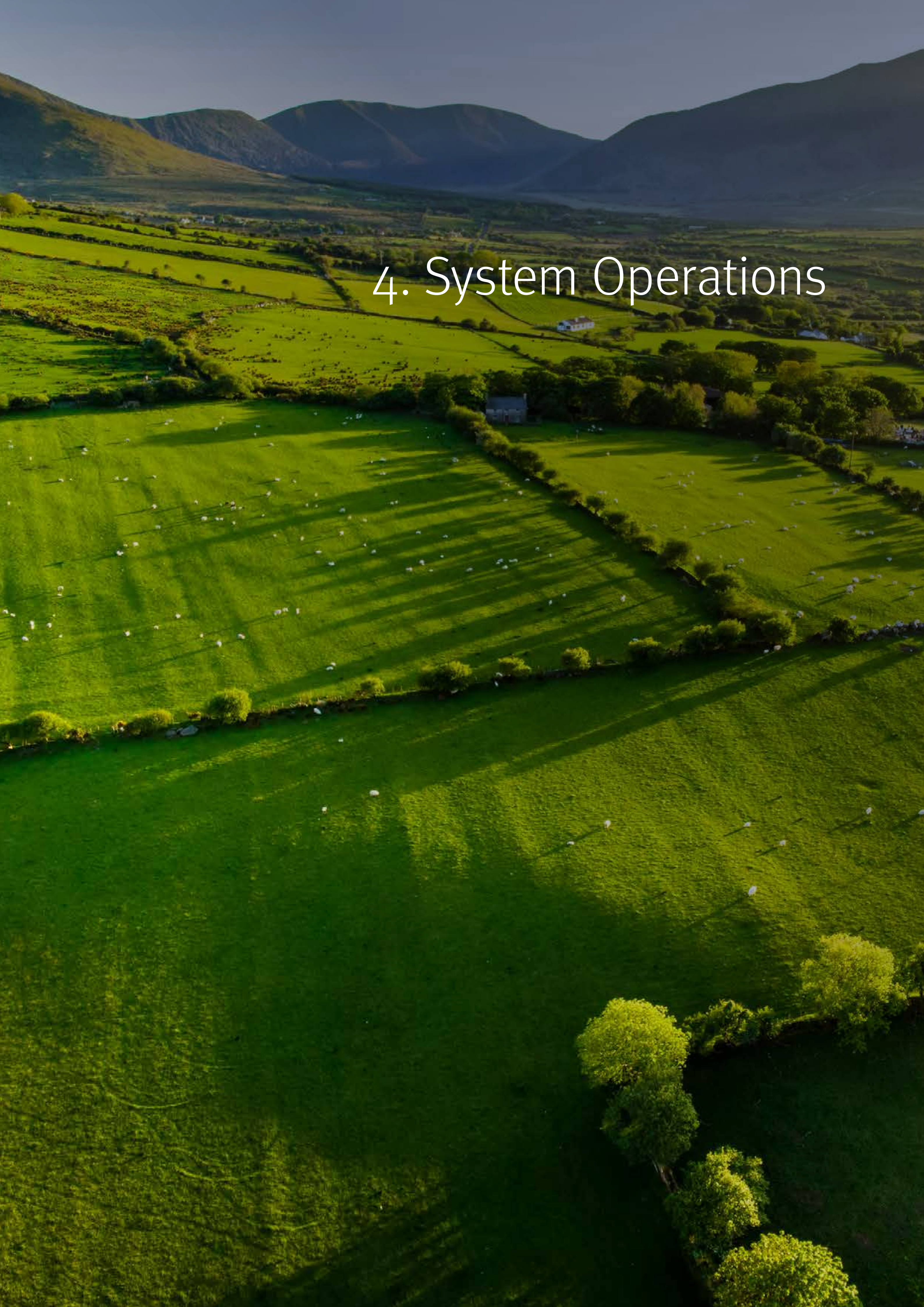
In addition, discovering the faults in scale of the HVDC technology may be difficult to pinpoint resulting in future congestion.

4 Demand-Led

A key risk area for this approach is the reliance on large energy users being willing to relocate to less congested load centres.

There remain a large number of reinforcements that may also risk being delayed.

Also, the fibre network development plans.



4. System Operations

4. System Operations

4.1. Findings and key messages

4.1.1. Technical and operational challenges

In order to deliver on government renewable energy policies, it will be necessary to accommodate unprecedented penetrations of variable non-synchronous RES such as offshore wind, onshore wind, and solar, whilst keeping curtailment levels to a minimum. This will require a significant evolution of the operation of the power system and for EirGrid and SONI to deal with unique challenges that will not be faced in larger power systems for years to come.

Four of the key operational metrics[21] that will need to evolve by 2030 are as follows:

- SNSP;
- Inertia Floor;
- Operational RoCoF; and
- Minimum Number of Large Synchronous Units.

By 2030, we are planning to be able to operate at SNSP levels up to 95%, to have a reduced Inertia Floor (reduction from the current floor of 23,000 MWs), to have implemented a secure RoCoF limit of 1Hz/s (an operational trial is currently underway) and to have a significantly reduced Minimum Number of Large Synchronous Units requirement (the current requirement is to keep 8 large conventional synchronous units synchronised across the island).

The purpose of evolving these, and other, operational metrics is to facilitate a reduction in the minimum level of conventional synchronous generation (in MW terms) required on the system. By reducing the minimum required level of conventional synchronous generation, increased levels of non-synchronous RES can be facilitated.

The specific inertia floor and minimum number of units requirement needed to facilitate the requisite reduction in the minimum synchronous generation level have not been specified at this point as they will be impacted by technology evolution and generation portfolio changes. With this in mind, we will take a flexible and agile approach to operational policy changes for these metrics and the development of new metrics as appropriate.

Operating the future power system with fewer synchronous units relative to today, allied to the large-scale integration of variable non-synchronous RES, will pose several technical and operational challenges, the scale of which have not been experienced by other power systems to date. These challenges can be broadly categorised as follows:

- Frequency Stability;
- Voltage Stability;
- Transient Stability;
- Congestion;
- Power Quality;
- System Restoration; and
- Generation Adequacy.

21 Each metric is explained in detail in Section 4 of this report.

These technical challenges will drive the need to significantly enhance our system operational capability. We are currently conducting detailed studies which aim to demonstrate some of the potential solutions to the suite of technical challenges. We are planning to publish a report on the collective outcome of these studies in Q2 2021.

4.1.2. Mitigations and facilitation of renewables

As part of the DS3 Programme, new system services arrangements were introduced in 2016, which enable the TSOs to procure a range of services from providers of different technology types to support the operation of the transmission system. This has been an important aspect in enabling increased levels of non-synchronous RES on the system to date.

It is likely that new system services above and beyond those already being contracted by EirGrid and SONI as part of the DS3 System Services arrangements will be required. In addition, the requirement for some services, such as steady state reactive power, is locational in nature. The exact locational requirement for such services will be dependent on the outturn generation portfolio and the network configuration.

We also consider that there would be benefits in procuring services from new types of service provider, or new services from existing providers, early in the decade to understand their operational impact, gain operational experience and deliver benefits to consumers earlier. For example, the provision of inertia from low-MW output devices could offer significant advantages. This could be facilitated through the existing Qualification Trial Process or another mechanism.

While there will be a wide-ranging programme of work required, the following activities will be key to safely and securely increasing the instantaneous amount of variable non-synchronous RES that can be accommodated on the power system:

- On-going studies and analysis on technical challenges and potential solutions;
- Setting and clarifying operational standards, including grid codes and system services protocols, and subsequently monitoring performance against these standards;
- Enhancing the DS3 System Services arrangements to introduce new services and facilitate service provision by new and innovative technologies;
- Removing barriers to entry and enabling the integration of new technologies at scale;
- Continued evolution of operational policies e.g. minimum number of large synchronous units;
- Developing new and enhanced control centre tools and systems;
- Working in collaboration with other TSOs to share learnings and potential solutions; and
- Working in partnership with the DSOs to coordinate and deliver for consumers.

4.1.3. Operational pathways to 2030

In order to achieve the 2030 renewable generation policy ambitions, we have developed a programme of work which will enable us to enhance our system operations capability out to 2030. This all-island programme of work is called Operational Pathways to 2030 and it will build upon the programme of activity that was carried out as part of EirGrid and SONI's "Delivering a Secure Sustainable Electricity System (DS3)" Programme previously established in 2011.

Looking out to 2030, we see there being four key pillars underpinning the Operational Pathways to 2030 Programme (see Figure 33), with each pillar comprising several work streams:

- **Standards and Services:**
  This pillar aims to ensure that we have the right operational standards (e.g. Grid Code) as well as appropriate commercial frameworks in place to support necessary investment in the capability required to mitigate technical challenges on the power system. This will build on the existing system services arrangements, introducing new services as appropriate.

- **Operational Policies and Tools:**
  The aim of this pillar is to continue to evolve our operational practices, developing the necessary operational polices and developing and putting in place new control centre tools to enable our engineers to safely and securely operate a resilient power system as complexity and uncertainty increases.

Figure 33: Operational pathways to 2030 – key pillars

- **Technology Enablement:**
  This pillar focuses on breaking down barriers to entry and enabling the integration of new technologies at scale. The existing FlexTech Initiative[22] will be central to achieving these objectives, in addition to other enabling initiatives developed throughout the duration of the Operational Pathways to 2030 Programme.

- **TSO-DSO:**
  Finally, with so many of the future generation and system service providers expected to be connected to the distribution system as the portfolio decentralises and diversifies, we will need to partner with the Distribution System Operators (DSOs) to ensure that the needs of both distribution and transmission systems, and ultimately the needs of consumers, are met.

The following are key milestones to meeting the challenges of operating the electricity system in a secure manner while achieving our 2030 RES-E ambitions:

- **2021:** 75% SNSP
- **2022:** Grid Code modifications approved
- **2023:** Go-Live of new DS3 System Services Arrangements
- **2025:** 85% SNSP
- **2030:** 95% SNSP

22 EirGrid and SONI, FlexTech Initiative

4.2. Scope and objectives

4.2.1. Introduction

As the energy sector moves towards a sustainable low-carbon future, the electricity system will carry more power than ever before and most of that power will be from variable non-synchronous RES such as wind and solar. Coal and oil-based generation will be phased out in the next decade. Concurrently, in addition to the changes on the supply-side, there will be significant changes on the demand-side with new technology arriving which will allow electricity users to generate and store power, and return any surplus to the grid.

In order to achieve the renewable ambition, it will be necessary to accommodate unprecedented instantaneous penetrations of variable non-synchronous RES such as offshore wind, onshore wind, and solar, whilst keeping curtailment levels to a minimum. This will require a significant evolution of the operation of the power system and for EirGrid and SONI to deal with unique technical challenges that will not be faced in larger power systems for years to come.

In response to these challenges, we are developing a programme of work which will enable us to enhance our power system operational capability out to 2030. This all-island programme of work is called Operational Pathways to 2030 and it will build upon the programme of activity that was carried out as part of EirGrid and SONI's "Delivering a Secure Sustainable Electricity System (DS3)" Programme[23] previously established in 2011. An overview of the DS3 Programme and its success to date is set out in the next section.

4.2.2. DS3 programme (2011-2020)

The DS3 Programme was established in 2011 with the aim of meeting the challenges of operating the electricity system in a secure manner while achieving our 40% 2020 RES-E targets.

The DS3 Programme was designed to ensure that we could securely operate the power system with increasing amounts of variable non-synchronous RES. As operators of an island power system, the TSOs have faced and continue to face unique challenges with regards to managing the variability of wind generation while maintaining power system stability and security.

As many of these challenges will not be encountered in larger systems for many years, Ireland and Northern Ireland have had the opportunity to lead the way in the integration of non-synchronous RES.

Figure 34: DS3 programme pillars

As set out in Figure 34, DS3 has been based around three pillars, each vital to the success of the programme: System Performance, System Policies and System Tools.

DS3 is not only about making the necessary operational changes to manage more RES, it is also about the evolution of the wider electricity industry and implementing changes that benefit the end consumer, in terms of decarbonisation. From the onset, the integration of wind generation presented a range of challenges previously unseen in the power sector. Through collaboration with the Regulatory Authorities, the Distribution System Operators and the wider electricity industry, DS3 has developed several innovative and progressive solutions.

23 EirGrid and SONI, DS3 Programme

The DS3 Programme employs SNSP as a useful proxy for the capability to operate the power system safely, securely and efficiently with high levels of RES. SNSP is a real-time measure of the percentage of generation that comes from non-synchronous[24] sources, such as wind and solar generation, relative to the system demand.

Over the course of the DS3 Programme, the allowable SNSP level has been increased to 65% from 50% following the successful conclusion of SNSP operational trials undertaken with 5% incremental increases. In January 2021, we increased the allowable SNSP level to 70% on a trial basis and, following completion of this trial, we expect to commence a trial at 75% later in 2021 as illustrated in Figure 35 below.

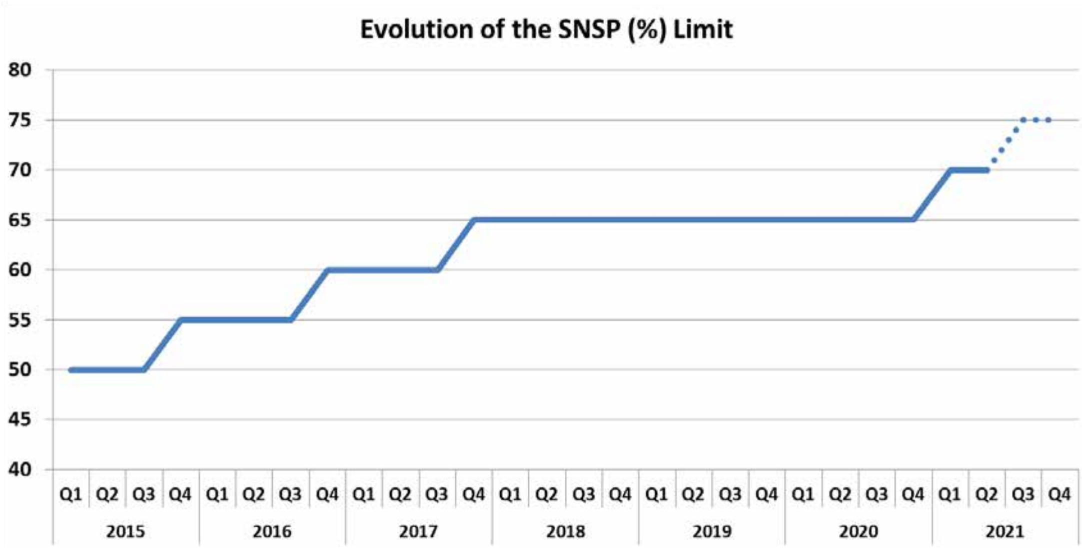


Figure 35: Evolution of SNSP to January 2021

As an example of this success, Figure 36 shows the SNSP levels during the period 10 – 22 February 2021, which shows the 70% SNSP limit being reached during the 70% SNSP trial.

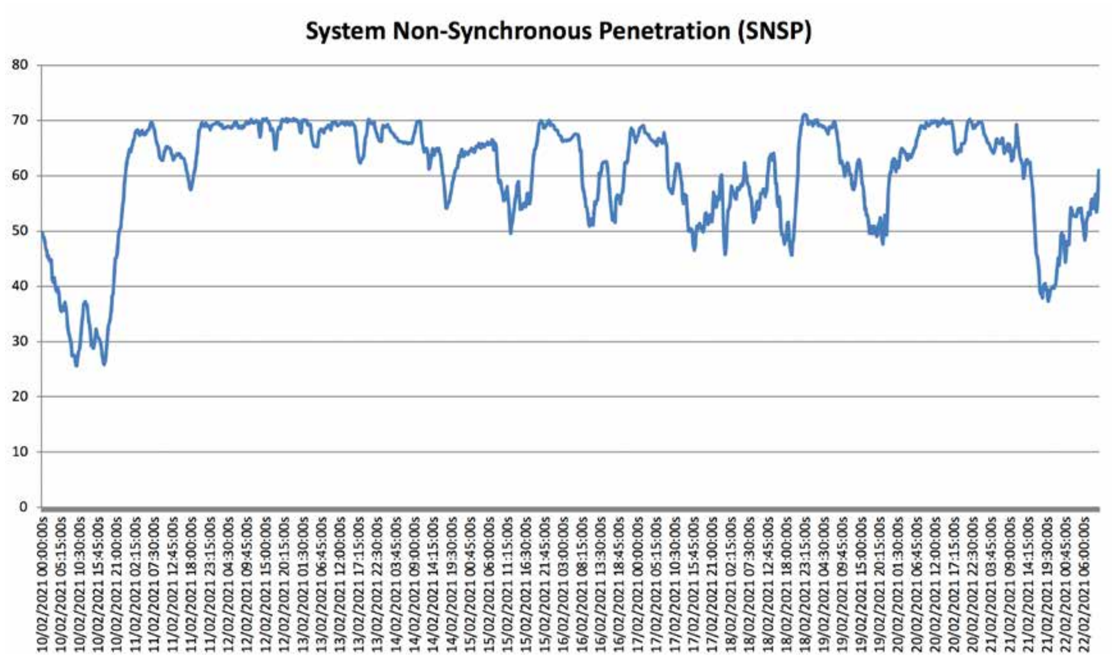


Figure 36: SNSP levels, February 2021 during the 70% SNSP trial

24 Non-synchronous generators supply power to the electrical grid via power electronics. Power electronics are used to adjust the speed and frequency of the generated energy (typically associated with wind energy) to match the speed and frequency of the transmission network.

The power system of Ireland and Northern Ireland is the first in the world to reach this 65% SNSP level (and current trial of a 70% SNSP level), making this a truly ground-breaking achievement.

With the DS3 Programme set to achieve its objective, and with greater clarity emerging on the 2030 Renewable Ambitions, it will soon be replaced by the next phase of work for the coming decade. This new phase of work, the Operational Pathways to 2030 Programme, will build upon the programme of activity that was carried out in DS3.

4.2.3. Operational pathways to 2030 programme (2020-2030)

The power system of Ireland and Northern Ireland is about to embark on a period of transformational change. This transformational change needs to take place whilst ensuring the quality of supply of electricity and the resilience of the power system that consumers have come to expect is maintained.

Electricity is essential to our economy and way of life. It powers everything from our household appliances to complex, multi-billion euro industries. It is one of the core infrastructures that keeps our society functioning and our economy operating. The all-island power system is thus of fundamental importance. Consequently, maintaining the quality of supply and resilience of the power system now and into the future is a core remit of EirGrid and SONI.

In that context, the key objectives of the all-island Operational Pathways to 2030 Programme are as follows:

- Increase the instantaneous amount of non-synchronous RES that can be accommodated on the Irish and Northern Irish power system in a safe and secure manner to 95%+ SNSP on an enduring basis;
- Identify the technical challenges that make the 95%+ SNSP target challenging to achieve, and provide incentives for the industry to invest in developing new technologies to address these;
- Remove barriers to entry and enable the integration of new technologies at scale; and
- Develop and implement operational policies and tools in the control centres to ensure the new technologies are utilised effectively.

The ultimate measure of achievement for the programme will be the ability of EirGrid and SONI to operate the power system of Ireland and Northern Ireland in a manner that enables the governments' renewable ambitions of 70%+ of electricity demand being met by RES by 2030.

4.2.4. Scope of the system operations review

The system operations review focused on identifying the main technical challenges that are likely to be seen in 2030 informed by a range of different analyses, as well as the implications of not sufficiently addressing those challenges. Some potential mitigations to deal with the technical challenges have also been identified. Finally, we focused on developing a programme of work which will enable us to enhance our system operations capability out to 2030.

Section 4.3 sets out and explains the key operational metrics/constraints which currently have the largest impact on RES curtailment levels.

In Section 4.4, we discuss the main technical challenges that are likely to be seen in 2030 informed by a range of different analyses, as well as the implications of not sufficiently addressing those challenges.

Section 4.5 outlines some potential mitigations that are under consideration to deal with the technical challenges identified. A high-level description of the evolution of operational policy to 2030 and some of the expected operational changes required is also provided.

Section 4.6 provides an overview of the Operational Pathway to 2030 programme.

We will use all feedback received through this consultation to refine and improve our Operational Pathways to 2030 Programme.

4.3. Current policy

4.3.1. Introduction

To enable safe, secure, reliable and efficient operation of the power system, EirGrid and SONI schedule and dispatch generating units in accordance with Operating Security Standards[25] [26]. This requires that operational constraints are respected and there are specific operational policies setting out how those constraints are managed.

The operational constraints can be categorised into a) operating reserve requirements and b) system constraints. Operating reserve is defined as the additional MW output from a range of resources which needs to be available and usable in real time operation to contain and correct any potential mismatch between supply and demand. System constraints are those constraints which ensure that safe operational limits are not breached.

Many of these constraints, requirements and policies will need to evolve over the coming decade to enable the integration of high levels of non-synchronous RES, whilst also ensuring that the system continues to be operated safely and securely. If we do not evolve operational policy, in conjunction with the connection of additional RES capacity over the next decade, the operational limitations will lead to a considerable increase in dispatch-down levels of RES. Dispatch-down of RES refers to generation that is available but cannot be used because of technical power system restrictions.

There are several reasons why it is sometimes necessary to dispatch-down RES:

- **Over-supply:**
  There will be times when the available RES exceeds the market and/or physical demand;
- **Network Constraint:**
  There will be times when the limitations of the local or wider network configuration limits how much power can be allowed onto the electricity network; and
- **Curtailment:**
  There will be times when system–wide operational requirements (discussed in this section) result in the need to reduce the output from RES.

Dispatch-down due to over-supply and network constraints are primarily market and network issues, respectively, and thus are dealt with in Sections 3 and 5 respectively. The issue of curtailment and the programme of work to minimise curtailment are discussed in this section of the paper (Section 5).

Before we discuss the operational policy evolution over the next decade, it is important to highlight and explain the current operational constraints. The key existing operational policies which currently have the largest impact on RES curtailment levels are as follows:

- SNSP Limit is 65% (a trial of operation with a 70% SNSP limit commenced in January 2021);
- Inertia Floor is 23,000 MWs;
- Operational RoCoF is 0.5 Hz/s (a trial of operation with a 1 Hz/s RoCoF limit commenced in June 2020)
- Minimum Number of Units is 8 large conventional synchronous units on the system; and
- Minimum Reserve requirements for Primary Operating Reserve (POR) and Secondary Operating Reserve (SOR) to cover 75% of the Largest Single Infeed (LSI) and requirements for Tertiary Operating Reserve 1 (TOR 1) and Tertiary Operating Reserve 2 (TOR 2) to cover 100% of the LSI[27].

An explanation of each of these metrics is now provided.

25 EirGrid, Operating Security Standards
26 SONI, Operating Security Standards
27 EirGrid and SONI, Operating Constraints

4.3.2. System Non-Synchronous Penetration (SNSP)

SNSP is an operational metric that is used to represent the amount of non-synchronous generation, such as Wind or Solar Generation, on the system at an instant in time. It is the ratio of the real-time MW contribution from non-synchronous generation and net HVDC interconnector imports to demand plus net HVDC interconnector exports. The equation to express SNSP as a percentage is thus formulated as follows:

$$SNSP(\%) = \frac{\text{Non-synchronous generation+net interconnector imports}}{\text{Demand + net interconnector exports}} \times 100$$

The power system can be thought of as a portfolio of generators connected via a single shaft that is spinning at a speed of 50 Hz. Conventional synchronous generators connected to the power system contain a spinning rotor which rotates at the same speed as the shaft. The kinetic energy of the rotating shaft is system inertia. If a conventional generator is disconnected, for whatever reason, the other remaining generators give up some of the kinetic energy stored in their spinning rotors to keep the shaft rotating at 50 Hz. The stored kinetic energy in the generator rotors is what contributes to the system inertia.

Synchronous generators have an electromagnetic connection to the system, analogous to the generator being connected to the shaft via gears and a chain, and so this contribution is inherent.

In contrast, non-synchronous generating technologies such as wind turbines and solar PV are connected to the system via power electronic control-based interfaces that respond to system conditions. This means that there is no electromagnetic connection and thus no inherent contribution to the system inertia. Following on from the analogy above, this would be like the wind turbines being connected to the shaft via elastic bands.

When the level of non-synchronous generation on an electricity system is increased there can be fewer and smaller synchronous generators available to rapidly support the system via their spinning rotors in response to a system event. If there is insufficient response to a system event the system can become unstable.

The DS3 Programme has facilitated the increase in SNSP on the all-island system from a limit of 50% up to the current limit of 65%. In January 2021, we commenced a trial of SNSP at 70% and expect to increase this to 75% later in the year.

4.3.3. Inertia floor

Inertia is an operational metric that represents the amount of kinetic energy stored in the rotating masses of generators. The power system's inertia determines the sensitivity of the system frequency towards supply demand imbalances. The higher the power system's inertia, the less sensitive is the frequency to temporary imbalances.

As mentioned above, in the event a generator disconnects from the system, the stored kinetic energy of the remaining online generators helps to reduce the rate at which the frequency or speed of the system drops. The more inertia there is on the system the slower the frequency will drop following a system event where a generator is disconnected. To ensure there is adequate kinetic energy in the generator rotors to keep the system stable following the loss of a generator, EirGrid and SONI dispatch the system with an Inertia Floor constraint[28] which defines the minimum amount of generator rotor inertia which must be carried at all times.

The loss of demand or an outfeed from the system can also result in frequency deviations which inertia can help to arrest. This is discussed further later in this consultation. The current inertia floor on the all-island system is 23,000 MWs.

28 Inertia from load is not explicitly included in the Inertia Floor or RoCoF metrics. This is due to its lack of visibility as well as its overall low contribution to the total system inertia (there is limited heavy industry with large motor load across the island). The adopted approach thus adds a small margin to the predicted system response.

4.3.4. Rate of Change of Frequency (RoCoF)

RoCoF (or Rate of Change of Frequency) is an operational metric that represents the rate at which the system frequency changes in the timeframe immediately following a system event which disconnects a generator or load from the system.

$$RoCoF = \frac{\text{System frequency} \times \text{Active Power}_{lost}}{2(\text{Inertia}_{system} - \text{Inertia}_{lost})}$$

Where: Active Power $_{lost}$ ***= Output of Generator in MW which was disconnected from the System, Inertia*** $_{system}$ ***= Total System Inertia being provided as stored kinetic energy by all rotating masses, including generation, on the System and Inertia*** $_{lost}$ ***= Inertia being provided by the Generator which was disconnected from the System.***

The Rate of Change of Frequency is related to the amount of inertia (or kinetic energy) that is stored in the rotating masses of the synchronous machines connected to the power system. When the system inertia is high, the RoCoF following a system event is lower. Conversely, when the system inertia is low, the RoCoF following a system event is higher.

An upper limit is set so that the RoCoF experienced following the loss of a generator is slow enough to permit time for frequency services to respond and contain system frequency and restore it to nominal. In addition, an upper limit on RoCoF is required to ensure that the RoCoF is tolerable for the protection settings on devices that are connected to the system.

EirGrid and SONI have been engaged in a significant project with the DSOs in Ireland and Northern Ireland (ESB Networks and NIE Networks respectively) over the last number of years to change protection settings to allow for an increase in the RoCoF standard from 0.5 Hz/s to 1 Hz/s (as measured over a sliding window of 500 ms). In addition, conventional generators across the island have undertaken detailed technical studies in order to confirm compliance with the new 1 Hz/s RoCoF standard. As a result of the collaboration of the TSOs, DSOs and generators, the new 1 Hz/s operational standard is currently being trialled in the EirGrid and SONI control centres.

4.3.5. Minimum number of units

Minimum Number of Units is an operational metric that refers to the minimum number of large synchronous conventional generators which must be connected to the all-island power system under standard operating conditions.

In addition to providing inertia and thus managing RoCoF levels, the Minimum Number of Units constraint also supports Voltage Control following a system event. Each large conventional generating unit on the system is capable of supporting the system voltage and, following a system event, each unit can respond by altering its position to either generate or absorb reactive power (MVArs), which helps to either push up or down the voltage as required.

This voltage control capability, in conjunction with the frequency control offered by conventional generators, is central to the Minimum Number of Units requirement. Variable non-synchronous RES does not at present offer the same level of reactive power. This is because the power electronic convertors currently utilised in variable non-synchronous RES are not typically capable of the same level of reactive power provision as conventional generators. Of course, developments in power electronics control over the coming years could help mitigate the challenge.

The current Minimum Number of Units requirement on the all-island system is 8 (minimum of 5 in Ireland and 3 in Northern Ireland).

4.3.6. Reserve

Reserve is an operational metric that refers to the levels of generation capacity and demand reduction capacity available to the system operator to meet changes in demand or to replace a loss of supply. Reserve is divided into separate categories based on how long it takes for the generation capacity to start generating power or for the demand reduction to take place as well as the duration of the response provided.

Reserves are needed on the system to ensure that the system operators can always keep supply and demand balanced. Demand continually changes and unexpected generation tripping (loss of generation) requires reserves to be in place to provide backup/replacement generation or demand response as required to maintain the generation/demand balance.

For the all-island system, the size of reserves required is based on the risk presented from the loss of the largest infeed or generator on the system. This is because it is necessary to ensure there is sufficient generation reserve capacity and/or demand reduction capacity on the system to account for the possibility of the largest infeed or generator unexpectedly disconnecting from the system.

EirGrid and SONI signed three operational agreements in December 2019 relating to reserves. These are the Synchronous Area Operational Agreement[29], the Load Frequency Control Operational Agreement[30], and the Load Frequency Control Area Operational Agreement[31]. These agreements capture specific load-frequency control and reserve requirements from the Commission Regulation (EU) 2017/1485 establishing a guideline on system operation (System Operation Guideline - SOGL). Title II of each agreement received regulatory approval.

Table 29 shows the current operating reserve requirements on an all-island basis.

Table 29: All-island operating reserve requirements[32] and how they map to SOGL products

Category	All Island Requirement (% of Largest In-Feed)	Delivered By	Maintained Until	SOGL Product[33]
Primary Operating Reserve (POR)	75%	5 seconds	15 seconds	Frequency Containment Reserve (FCR)
Secondary Operating Reserve (SOR)	75%	15 seconds	90 seconds	Frequency Containment Reserve (FCR)
Tertiary Operating Reserve 1 (TOR 1)	100%	90 seconds	5 minutes	Frequency Restoration Reserve (FRR)
Tertiary Operating Reserve 2 (TOR 2)	100%	5 minutes	20 minutes	Frequency Restoration Reserve (FRR)

29 EirGrid and SONI, Operational Agreements for Ireland and Northern Ireland Synchronous Area – Schedule 1: Synchronous Area Operational Agreement (SAOA)
30 EirGrid and SONI, Operational Agreements for Ireland and Northern Ireland Synchronous Area – Schedule 2: LFC Block Operational Agreement (LBCBOA)
31 EirGrid and SONI, Operational Agreements for Ireland and Northern Ireland Synchronous Area – Schedule 3: LFC Area Operational Agreement
32 We are procuring Fast Frequency Response (FFR) which is faster than POR (MW response delivered within 2 seconds) and we are in the process of developing an operational policy for implementation in the control centres.
33 For a full mapping of existing balancing products with SOGL terminology, please see Appendix G.

In addition to the reserve requirements discussed above, there is also a negative reserve requirement for the system to cover the potential for sudden or gradual over-frequency events. The requirement stipulates that there must be a minimum of 150 MW of negative reserve available on the system to cover credible contingencies such as the loss of an interconnector on export.

Historically, this negative reserve was provided by conventional synchronous generators. In October 2020, EirGrid and SONI began an operational trial which allowed wind generation to provide up to 100 MW of this negative reserve requirement. The provision of negative reserve from wind generation allows us to increase the amount of wind generation on the system by bringing the output of synchronous generators closer to their minimum generation limit. The negative reserve trial, which was successfully completed in January 2021 and became enduring policy, has effectively enabled up to 100 MW of additional wind generation onto the system at times when it would otherwise have been curtailed.

Collectively, the various existing constraints discussed in the above sections drive the need for minimum levels of conventional synchronous generation on the power system thus displacing non-synchronous RES. The evolution of these constraints is therefore critical to facilitating increased levels of non-synchronous RES.

4.4. Challenges and implications

4.4.1. Technical challenge overview

In order to deliver on government renewable energy policies, it will be necessary to accommodate large penetrations of variable non-synchronous RES, whilst keeping curtailment levels to a minimum. This will require us to be able to operate the power system with SNSP levels of up to 95% with significantly reduced numbers of conventional units online. However, operating at such SNSP levels is unprecedented and poses several technical challenges, many of which have not been experienced by other synchronous power systems to date.

The Facilitation of Renewables studies[34] from 2010 outlined a range of scarcities and challenges associated with operating the power system in 2020 with high levels of RES. The analysis concluded that it would be possible to operate the system beyond 50% SNSP if major changes to the power system were implemented.

The current DS3 programme has implemented these recommendations; the changes encompass amendments to system policies, system tools and system performance, as well as continued system studies and analysis as the power system has evolved. A central aspect of addressing system performance with increasing levels of SNSP has been the procurement of DS3 System Services.

In much the same way that the Facilitation of Renewables studies in 2010 identified the challenges of operating a power system with significant levels of wind, and laid the ground-work for the DS3 programme and the drive towards the 40% RES-E target by 2020, the EU-SysFlex project, which is being co-ordinated by EirGrid and in which SONI is a key partner, can be viewed as scoping work for developing and planning the next programme which will enable us to transition to 95% SNSP and facilitate delivery of 70% RES-E by 2030.

EU-SysFlex, a Horizon 2020-funded project led by EirGrid, has innovation at its core, utilising research, technology trials and collaboration to solve the power system challenges associated with the integration of variable non-synchronous RES required to meet the ambitious European renewables target.

34 EirGrid and SONI, All-Island TSO Facilitation of Renewables Studies

The primary objective of EU-SysFlex[35] is to help ensure the stability, reliability and resilience of European power system operation as we transition to a system dominated by variable RES, such as wind and solar. EirGrid's and SONI's involvement has been centred on performing detailed analysis of the all-island power system, exploring its unique characteristics and the unprecedented challenges that lie ahead as well as demonstrating potential solutions.

Analysis from EU-SysFlex Task 2.4 *Technical Shortfalls for Pan European Power System with High Levels of Renewable Generation*[36], which was concluded at the start of 2020, identified significant challenges with operating at very high levels of RES. With the generation portfolio in 2030 expected to be dominated by non-synchronous RES, the EU-SysFlex Task 2.4 report noted a number of challenges and identified a number of additional emerging areas of concern, which will need to be taken into account when designing the future system services arrangements (which are discussed in greater detail in Chapter 5 on electricity markets) as well as the tools and operational policies needed to operate a safe, secure, reliable power system.

The work in EU-SysFlex Task 2.4 was built upon scenario development and methodology and tool development work that was completed earlier in the project. Details on the scenarios can be found in EU-SysFlex Task 2.2 *EU-SysFlex Scenarios and Network Sensitivities*[37]. The analysis conducted under Task 2.4 focussed primarily on load flow studies, time-domain simulations and critical analysis of pre-existing operational practices. Various categories of system stability were evaluated.

For the studies in EU-SysFlex, a number of operational policy assumptions were made for 2030. These included no SNSP Limit, no Inertia Floor, RoCoF of 1Hz/s and no minimum number of units requirement. Operating reserve requirements were included in the analysis.

We were also involved in another Horizon 2020 project called MIGRATE[38], with 12 European TSOs. The aim of the project was to investigate the technical challenges associated with increasing levels of inverter-based resources connecting to transmission systems and the feasibility of operating with no synchronous machines.

In the following sections, we discuss the main technical challenges that are likely to be seen in 2030 informed by a range of different analyses, including EU-SysFlex and MIGRATE, as well as the implications of not sufficiently addressing those challenges. While the next sections will focus primarily on the issues, section 4.5. will outline some potential mitigations that are under consideration.

35 More information can be found on the EU-SysFlex website: https://eu-sysflex.com/
36 EU-SysFlex, Task 2.4 Report
37 EU-SysFlex, Task 2.2 Report
38 H2020 Project MIGRATE Website

4.4.2. Technical challenge analysis

4.4.2.1. Frequency stability & control

Frequency stability describes the ability of a power system to return to an operating equilibrium following a severe system disturbance and to not cross load-shedding or generation-shedding thresholds in doing so. Operating a power system means balancing the active power of generation and load at any moment. Any imbalance results in a change of the system frequency.

Inertia
As previously set out above, we currently keep at least 8 large synchronous sets on the all-island power system at all times, and also have an inertia floor constraint of 23 GWs of inertia. Every dispatchable generator has a minimum generation level below which it cannot be operated. As such, a certain MW output is required to be generated by each of the 8 large sets at all times to allow them to run.

By generating using these large sets to maintain inertia and provide significant dynamic reactive power sources, at times[39] wind and solar generation is prevented from rising to higher dispatch levels. In order to integrate higher levels of RES and reach our ambitious targets, it is likely that by 2030 we will need to be able to operate at lower inertia levels than current levels or obtain inertia from sources other than conventional generators, for example from synchronous condensers.

Unless the inertia contribution from displaced conventional generation is replaced by other sources, higher levels of SNSP will result in lower system inertia levels (see Section 4.3.3) which yield faster frequency dynamics and higher RoCoF values. Figure 37 illustrates the projected falling inertia levels between 2020 and 2030 and the increased percentage of the year spent at lower system inertia levels.

At lower inertia levels, should there be a loss of a generator, the system frequency falls at a much higher rate than it would if the system inertia was higher.

This highlights the importance of being able to operate the system safely and securely with rates of change of frequency up to 1 Hz/s. A 1 Hz/s RoCoF limit and a 70% SNSP limit are currently being trialled.

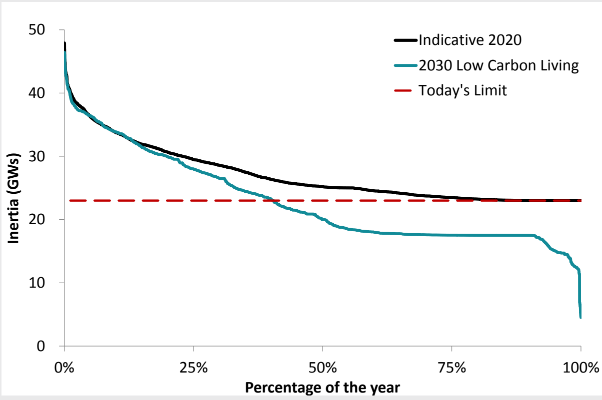


Figure 37: Comparison of inertia levels in 2020 and in the 2030 low carbon living scenario[40] [41]

The transition towards 1 Hz/s RoCoF could be supported by a reduced number of synchronous generator units operating alongside devices such as synchronous condensers or rotating stabilisers providing inertia or, if conventional generators can invest in adaptations that reduce their minimum operating limits without negatively impacting upon emission levels, then perhaps a higher number of large sets can remain on the system while still providing sufficient headroom for RES, whilst also enhancing system response to frequency events.

In relation to frequency events, currently the Largest Single Infeed (LSI) is 500 MW, which accounts for the situation where one of the two HVDC interconnectors is importing at full capacity.

39 If wind and solar levels are low and demand levels are high, maintaining 8 large sets will have limited impact on wind and solar generation moving to higher dispatch levels and there are few challenges associated with such a scenario. However, in order to accommodate high levels of wind and solar generation, it is necessary to reduce the minimum number of sets (or the cumulative minimum generation level) and there are considerable challenges associated with this. Consequently, we have chosen to focus on the challenges here, as opposed to the status quo.
40 Low Carbon Living is the scenario with the highest level of renewable generation utilised for the all-island power system studies in EU-SysFlex.
41 EU-SysFlex, Task 2.4 Report

By 2030, the size of the largest infeed is set to increase to 700 MW following the commissioning of the Celtic Interconnector. In addition, as new large-scale offshore windfarms connect to the system, there is the potential for the LSI to increase even further in the future. The increased LSI, coupled with lower inertia levels and lower levels of fast dynamic reserves as a result of the displacement of conventional generation, can mean that frequency nadirs[42] are lower and deeper. Frequency nadirs need to be maintained above 49 Hz to satisfy System Operation Guideline (SOGL) requirements[43] and to provide a margin of safety to avoid the triggering of load shedding which occurs at 48.85 Hz[44 45].

The next section will discuss the need to obtain fast reserve response from a range of technologies, including batteries and other inverter-based resources with advanced control methods, to help contain the frequency following the loss of the LSI.

Reserves

In a system with more non-synchronous generation the general trend is towards lower frequency nadirs as SNSP levels increase (see Figure 38 and Figure 39), particularly in the absence of frequency response from non-synchronous generation.

Furthermore, Figure 39 highlights that in the future there could be periods of low SNSP, when a lack of fast acting reserves may result in low frequency nadirs for cases where the LSI is particularly high. In cases with a reduced level of fast reserve, the frequency nadir will be reached before slower static reserve response is triggered from resources such as pumped storage and demand response, possibly resulting in a frequency overshoot (see Figure 40, which shows the simulated frequency profile results following the loss of the LSI for many different hours). In cases where the total fast dynamic reserve magnitude is equal to or exceeds the size of the infeed loss, an oscillatory response can develop (Figure 40).

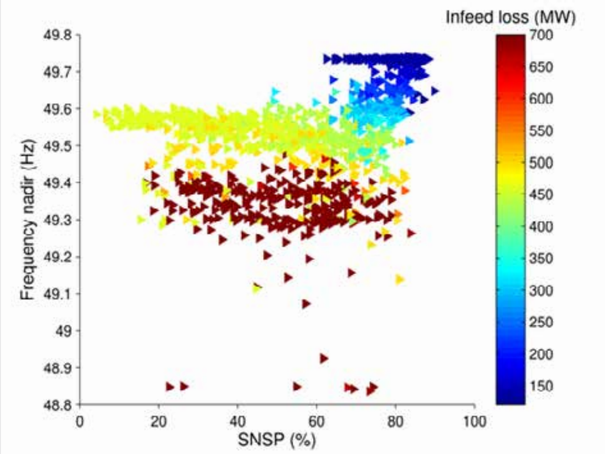


Figure 38: Frequency nadir –v- SNSP & infeed loss magnitude[46]

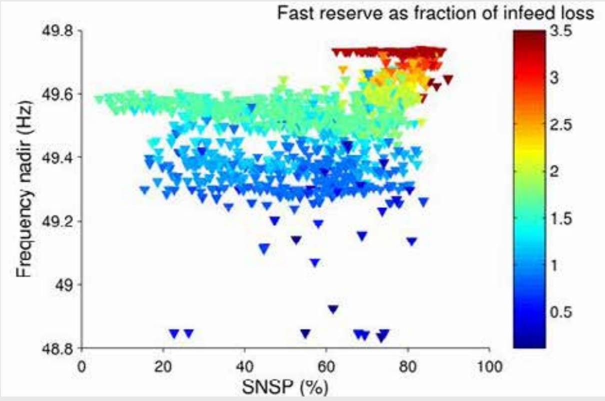


Figure 39: Frequency nadir –v- SNSP and fast reserves[47]

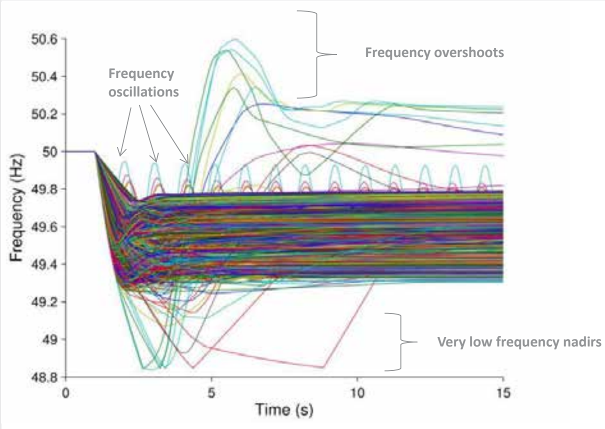


Figure 40: Lower system inertia leading to faster frequency dynamics[48]

42 Frequency nadir is the lowest point the system frequency reaches after a system event such as the loss of a large unit/infeed. We want to keep the nadirs high, as close to nominal frequency, as possible, and above any levels that might risk the triggering of load shedding mechanisms. Under-frequency load shedding relays are installed at designated substations and are triggered at an initial frequency of 48.85 Hz to disconnect load in order to stabilise system frequency.
43 SOGL Requirements
44 EirGrid, Operating Security Standards
45 SONI, Operating Security Standards
46 EU-SysFlex, Task 2.4 Report, 2020
47 EU-SysFlex, Task 2.4 Report, 2020
48 EU-SysFlex, Task 2.4 Report, 2020

Traditionally, the loss of an infeed has been the focus of frequency stability phenomena for the Ireland and Northern Ireland power system. However, with increasing levels of RES and increased interconnection levels, the loss of a HVDC interconnection at full export (Largest Single Outfeed (LSO)) becomes a credible threat to the system and therefore was also evaluated[49].

For over-frequency situations that occur during high wind generation periods, the Ireland and Northern Ireland power system employs Over-Frequency Generation Shedding (OFGS), which sheds various magnitudes of wind generation on pre-specified over-frequency magnitudes, shedding about 881 MW between 50.5 to 50.75 Hz[50]. It was found that frequency zeniths[51] stay below the highest acceptable zenith of 50.75 Hz and there were no under-frequency issues following the activation of the OFGS scheme.

The OFGS scheme proves to be an effective measure to arrest excessive over-frequency excursions and acts as a key resource in ensuring frequency stability in the event of a high magnitude export loss. It is expected that the use of OFGS will continue to be a part of the landscape going forward.

The bulk of system reserves have classically been provided by conventional plant. In the future, both the need for and source of reserves will change. From a system perspective, the likely reduction in the minimum inertia requirement on the system and an increase in the Largest Single Infeed/Outfeed (LSI/LSO) will necessitate an increase in the volume and speed of reserves. The exact nature of these reserves needs to be further studied, but with an expected increase in LSI to 700 MW (either offshore windfarms or new interconnectors) the dimensioning of reserves will increase.

As the generation portfolio evolves, more of the reserve services could be provided by non-conventional sources such as battery energy storage, interconnectors and demand response.

Faster frequency dynamics due to displacement of conventional generation and the requirements to carry enough reserve to match the LSI as outlined in the Synchronous Area Operational Agreement drives a possible need to increase the fast-acting reserve requirements. An analysis of the future fast-acting reserve requirements will be needed to determine suitable levels.

In the future, reserves could largely be provided by windfarms, solar farms, interconnectors, energy storage and demand side response, particularly at times of high RES output. In particular, unlocking the demand side proposition appears to have many positives in that demand side participants do not need to seek increases to their Maximum Import Capacity (MIC) to provide valuable positive frequency services. Chapter 5 discusses the incentivisation and remuneration of these services from a diverse range of technologies.

Additionally, demand is already present and therefore there is a reduced lead time in order to be in a position to exploit the reserve capabilities in comparison to the commissioning of new generation or other service providers. Co-ordination with the Distribution System Operators in relation to unlocking this capability will be critical to ensure that the wider system benefit is gained.

Ramping
Variable generation forecast errors pose a unique challenge to the operation of the power system on the island of Ireland. With the increase in weather dependent generation technology and the onset of a more participative demand sector, there are a range of scarcities that reveal themselves in the 1 hour to 10 hour time horizons.

The comparatively high installed capacity of variable generation (particularly wind) results in forecast errors of a scale that is a significant proportion of overall system demand.

49 EU-SysFlex, Task 2.4 Report, 2020
50 EU-SysFlex, Task 2.4 Report, 2020
51 Frequency zenith is the highest point the system frequency reaches after a system event such as the loss of a large outfeed/demand.

This is exacerbated by Ireland's location on the edge of Europe and the influence of the jet stream on its weather, which increases the potential errors, combined with the limited number of weather measurement points in the Atlantic Ocean[52].

Particularly concerning is the challenge of dealing with weather patterns which arrive ahead of or after they are forecast to when a large part of the system demand is served by wind and solar. An example of the spread of individual forecasts during a storm event is shown in Figure 41. This will necessitate the need for a greater volume of ramping services to be available in the appropriate time frame.

EirGrid and SONI currently schedule the system to meet the median production forecast of variable generation. As the installed capacity of variable generation grew, the magnitude of the possible forecast error approached the capability of back-up resources that were available by default. Therefore, ramping reserve products have begun to be scheduled to ensure sufficient capability is available to counteract forecast error events.

At 2020 levels of variable generation, forecast error events can be managed. However, since weather forecast accuracy is predicted to only improve marginally and due to the scale of the increase in installed variable generation that is predicted by 2030, the absolute magnitude of possible forecast errors is anticipated to grow. This will result in a greater need for ramping reserves.

By 2030, the largest possible forecast error may exceed the total scheduled system capability, even if ramping reserves are scheduled to cover the probable forecast errors. Ramping reserve requirements could be increased to cover less probable events but the increased operational costs and increased dispatch down of variable generation are unlikely to be acceptable. This economically imposed scarcity of capability will need to be remedied with new services that have high availability but low utilisation factors.

The sources of ramping are increasingly likely to come from battery storage, interconnectors, dispatched-down wind and solar together with offline conventional plant and also potentially from the demand side. Further work is required to dimension these ramping needs and capabilities but, based on previous analysis, we estimate that there will be an increased need for ramping services due to increasing levels of variable generation. Further information on incentivising service provision is provided in Chapter 5.

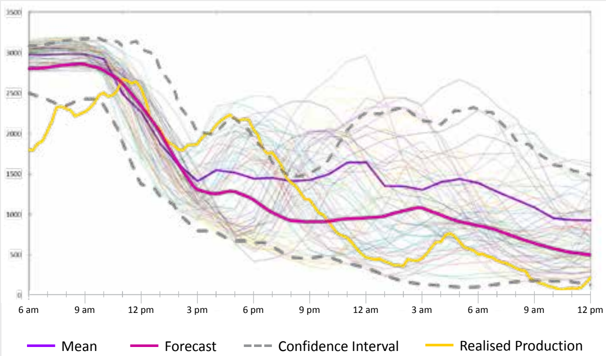


Figure 41: Renewable generation forecast and median values during a storm event in October 2019[53]

Very low frequency oscillations

Very low frequency oscillations are oscillations in system frequency between 0.03Hz and 0.08Hz. Lower levels of system inertia lead to more severe and more frequent frequency oscillations which can impact system stability.

As discussed earlier, the displacement of conventional generators by non-synchronous RES results in lower system inertia unless the inertia is replaced by alternative sources of inertial response.

A reduction in inertia makes the system more susceptible to very low frequency oscillations. To combat these oscillations, it is necessary to deploy operational measures when they occur. This can involve altering generation dispatches or turning on frequency response on wind and solar farms to smooth out the frequency oscillations.

Frequency response on wind and solar farms is a setting which can be enabled from the Control Centres in EirGrid and SONI.

52 Dr. Corinna Mohrlen and Ulrik Vestergaard, EirGrid Met Mast and Alternatives Study
53 J. Ging, J. Ryan, J. Jennings, J. O'Sullivan and D. Barry, "Integrating multi-period uncertainty ramping reserves into the Irish balancing market," in *Cigre Science and Engineering*, 2020.

When enabled, this frequency response controls the wind and solar farm output to help combat fluctuations in system frequency. When frequency goes above the nominal value, wind and solar farm output is reduced and when frequency goes below the nominal value wind and solar farm output is increased (if there is enough headroom available to do so).

EirGrid and SONI have conducted analysis into the cause and extent of very low frequency oscillations[54] and will continue to monitor and analyse this phenomenon as increasing levels of RES are accommodated on the all-island power system.

EirGrid and SONI are also currently examining the possibility of using a machine learning-based approach to determine the combination of system conditions that serve as predictors for very low frequency oscillation events.

4.4.2.2. Voltage stability

Static voltage stability
EU-SysFlex studies showed that as SNSP levels increase and conventional generation is displaced there will be a significant lack of steady state reactive capability if not replaced by other sources. This is because most of the current wind and solar generating technologies have less reactive power capability than large conventional generators, as it is limited by the rating of the power electronic converters.

A lack of steady state reactive capability can lead to larger deviations in steady-state voltage as well as increased instances of low voltage deviations. As reactive power is a local phenomenon, weaker parts of the network, with high levels of RES, are prone to requiring significant increases in reactive power services.

Mitigation of the static voltage stability issue will require the provision of reactive power support from non-conventional technologies deployed in specific geographical locations.

These technologies include, but are not limited to synchronous compensators, static VAr compensators (SVCs) and potential reactive capability from newer wind and solar generating technologies.

In addition to issues relating to low voltage deviations identified in the EU-SysFlex studies, there are also concerns relating to overvoltage issues. These overvoltage issues can be locational in nature and are an active area of focus.

Dynamic voltage stability
In the EU-SysFlex studies, it was found that when there are very few synchronous generators online, the reduction in reactive power online from conventional generation leads to a degradation in dynamic voltage performance. Analysis indicates the emergence of a system-wide scarcity in dynamic voltage control during fault recovery in some hours of the year, but localised scarcities in the majority of hours.

Results also demonstrate that in 2030 the magnitude of the post-fault voltage oscillations will become more significant (see Figure 42). This drives the need for more reactive compensation from a range of service providers. This may be provided by synchronous compensators or from wind and solar generating technologies, amongst others.

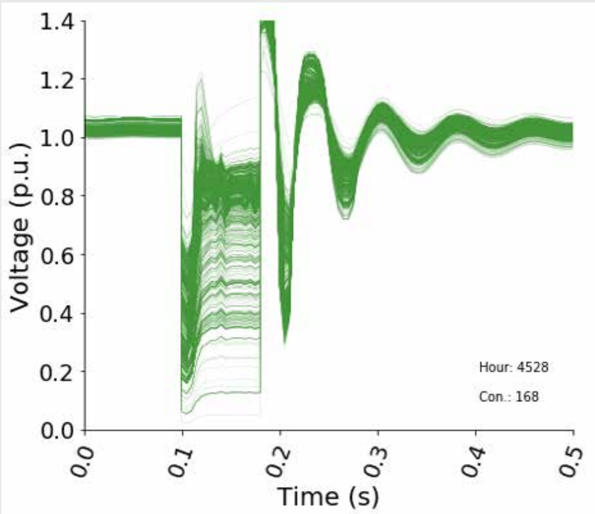


Figure 42: Transient voltage profile demonstrating post-fault voltage oscillations[55]

54 P. Wall, A. Bowen, B. O'Connell, N. Cunniffe, C. Geaney, R. Doyle, D. Gillespie, B. Hayes and J. O'Sullivan, "Analysis, Monitoring and Mitigation of Common Mode Oscillations on the Power System of Ireland and Northern Ireland," in *CIGRE*, 2020
55 EU-SysFlex, Task 2.4 Report, 2020

Reduction in available fault current
Although the fault current contribution of inverter-based generation such as wind and solar is inherently limited in comparison to conventional generation, in areas with significant levels of distributed RES the cumulative impact can raise the short circuit power in these regions at high SNSP.

However, in the future when inverter-based devices dominate, and when there are significantly less conventional plants online, there will be a reduction in fault current contributions which is a potential indicator of reduced local dynamic performance of the power system. In addition, reduced fault current may have implications for protection relay performance, which in turn impacts on the ability to clear faults and has safety implications. Fault current contributions will need to be sourced from non-conventional technologies in 2030.

4.4.2.3. Transient stability

Transient stability describes the ability of a power system to maintain synchronism when subjected to a severe transient disturbance. If large amounts of generation capacity are lost due to transient instability, the power system may collapse. Voltage and transient stability issues are inter-related and the same mitigation measures may apply.

Lack of synchronising torque
Having fewer synchronous generators online decreases the synchronising torque on the system. While a system-wide scarcity has not been identified in the EU-SysFlex studies, localised scarcities have been noted.

The scarcities are sensitive to specific unit commitment combinations (i.e. committing an additional OCGT near the unit that loses synchronism in the base case removes the instability) and certain contingencies but highlight the need for further detailed study based on future network configuration.
The lack of synchronising torque could be addressed by synchronous compensators, for example.

Lack of damping torque
Studies from EU-SysFlex[56] found a localised scarcity of oscillation damping. This scarcity can primarily be observed as a local oscillation in one or two units when a contingency occurs close to their point of connection. It was found that the cases with poor damping are heavily associated with quite specific contingencies and do not occur in general.

As such, the localised scarcity is not necessarily driven by SNSP but by the specific unit commitment schedule and the presence of isolated units that connect through weaker parts of the network, where a single contingency can impact the unit most significantly.

Inverter-driven stability
Inverter-Based Generators (IBGs) are generators which do not contain a spinning rotor. They convert energy (typically wind/solar) to electrical power through the use of an electrical inverter.

The increasing share of IBGs in the power generation mix leads to new types of power system stability problems. These problems arise from the different dynamic behaviour of IBGs compared to that of the conventional synchronous generators. The main stability challenges arise from interactions between IBG controls in weak areas.

A typical IBG relies on control loops and algorithms with fast response times, such as Phase Locked Loop (PLL) and inner-current control loops. The ability of the PLL to synchronise with the grid voltage during nearby faults is extremely challenging in weak networks.

In addition, the wide timescale related to the IBG controls can result in cross couplings with both the electromechanical dynamics of machines and the electromagnetic transients of the network, which may lead to unstable power system oscillations over a wide frequency range[57].

A full understanding of these new phenomena and a review of the adequacy of traditional tools and models, such as Root Mean Square (RMS) models, is needed to ensure integration of higher levels of RES in a safe and secure manner.

Electromagnetic Transient (EMT) modelling may be required when studying the impact of inverter-based resources under weak system conditions where RMS modelling may be unable to reliably predict control instability. These types of simulations are usually significantly more computationally expensive than RMS models. To address simulation speed issues associated with EMT models, state-of-the-art solution techniques are being progressively developed by software and hardware developers[58].

We have already started working with partners, and will continue to do so, to develop and implement adequate models and tools reaching the right balance between accuracy and computational feasibility. For example, we are currently working with external experts to complete work on Phase Lock Loop modelling of wind, solar PV and HVDC interconnection for inclusion in RMS simulations. Additionally, these external experts are developing grid-forming control configurations for use in our RMS models.

4.4.2.4. Congestion

The transmission and distribution systems have to transport power from where it is generated to where it is consumed. The ratings of all components on this route have to be adequate for these power flows. If this is not the case, the network is congested.

As SNSP increases and as RES connections increase, the studies indicate that there would be a significant rise in the frequency of transmission line overloading above 100% of thermal capability. This can be seen in Figure 43 where each dot represents a transmission line overloading over the course of one hour.

56 EU-SysFlex, Task 2.4 Report, 2020
57 N. Hatziargyriou, J. V. Milanovi, C. Rahmann, V. Ajjarapu, C. Canizares, E. Erlich, D. Hill, I. Hiskens, I. Kamwa, B. Pal, P. Pourbeik, J. J. Sanchez- Gasca, , A. Stankovi, T. Van Cutsem, V. Vittal and C. Vournas, "Technical Report PES-TR77:Stability Definitions and Characterisation of Dynamic Behaviour in Systems with High Penetrations of Power Electronic Interfaced Technologies," 2020.
58 B. Badrzadeh, Z. Emin, E. Hillberg, D. Jacobson, L. Kocewiak, G. Lietz, F. Da Silva and M. Val Escudero, "The need for Enhanced Power System Modelling Techniques and Simulation Tools," in *CIGRE*, 2020.

The studies have found that the areas of the network most affected by the loss of a single circuit are in the west of Ireland and Northern Ireland. These are the regions with considerable installed RES capacities in 2030 and where the local load is not high enough to absorb the high levels of RES resulting in overloads following a contingency[59] (in this case, the loss or failure of a transmission line).

Similarly, the Dublin region, despite having high local load which will increase over the coming decade as a result of the connection of large energy users, can experience thermal overloads at both low and high SNSP levels due to the large numbers of thermal generators and anticipated offshore wind farms. Addressing congestion traditionally requires new network infrastructure. Without significant additional infrastructure, there will be congestion issues in many parts of the transmission system in 2030. These issues will be exacerbated with increased demand and new generation to meet the long-term public policy objectives. Our approach to grid development and the delivery of new infrastructure is discussed in Chapter 3.

A key element of our approach to grid development will be the optimisation of existing grid assets, thereby minimising the need for new infrastructure where possible. In addition, there will be a need to encourage users to behave in a manner that can safely and securely alleviate the congestion. Consequently, towards 2030, and beyond to 2050, we will be exploring the use of congestion management services, which increase or decrease the demand in particular areas, as well as deployment of smart power flow control devices, power-to-gas and sector coupling, and other technological options.

These congestion management services have a direct impact on the power flows and the most appropriate manner in which to procure them is likely to be through the proposed system services auctions which are discussed in more detail in Chapter 5. The need for and value of providing these services will have a locational dependency.

The challenge of designing the congestion products will be tackled in the Operational Pathways to 2030 programme.

It should be noted also that, although not studied, it is likely that there will be increasing congestion on the distribution network which means that a holistic approach to mitigating congestion across all voltage levels will be required.

Figure 43: Transmission-level congestion issues with increasing SNSP. The results shown are for both summer (red) and winter (blue) seasons[60]

4.4.2.5. Power quality

Power quality is a measure of how closely the frequency, voltage level and voltage waveform correspond to the system specifications.

Conventional generators provide significant support to power quality due to their ability to alter their voltage output quickly in response to a system event as well as acting as a sink for harmonics. With non-synchronous wind and solar generation replacing conventional generators, power quality would be reduced unless mitigation actions are taken. In addition, the relatively large amounts of cable installed to connect wind farms in weak parts of the grid are introducing challenges for power quality.

However, with the ability to control power electronics in new wind and solar generators, new possibilities are emerging, and it is possible that, if used correctly, some of the challenges introduced could be mitigated by the same devices that create them.

59 A contingency is the loss or failure of a power system component, such a generator or a transmission line
60 EU-SysFlex, Task 2.4 Report, 2020

Doing so successfully will require significant focus on power quality studies both at individual connection and system wide level, focus on grid code requirements and their implementation, and robust system monitoring with a strategic approach[61].

Harmonics are waveforms at multiples of the fundamental frequency of the system. They are caused by the distortion of the voltage waveform from non-linear devices, such as power electronic converters in wind and solar farms. Harmonics increase the current in electrical systems and can cause issues for voltage waveform quality and potentially can damage electrical equipment.

It is generally expected that, if not addressed, the all-island power system will experience an increase in harmonic distortion over the coming years. This is partly due to the sheer amount of inverter-based generation being connected and partly due to possible amplification of existing distortion levels due to resonances introduced by cables in weak parts of the grid.

However, emphasis on the limitation of harmonic emissions has gained more attention over the past few years with modifications to grid codes, the development of a policy on harmonics and the implementation of power quality requirements as part of the standard connection offer process. These actions are driving a trend in the opposite direction, such that harmonic emissions from new plant, as a whole, is reduced at equipment level due to more advanced switching and control technologies being implemented and the stricter enforcement of grid code requirements.

The grid code requirements, together with the harmonics measurements and studies that we and customers undertake, have ensured that in recent years harmonic distortion has remained within international standards.

It is important that we continue to carry out due diligence studies related to potential cable resonances, particularly for new circuits placed underground, as well as the anticipated development of offshore wind, which would connect to the system through high capacity cables.

EirGrid and SONI will continue working on the integration of new RES and new technologies in a safe and reliable manner to ensure adequate power quality to all users of the transmission system, as stipulated in the grid codes. Performance monitoring will be a key component.

4.4.2.6. System restoration

In case of a total or partial system blackout, the restoration of continuous supply of electricity as quickly and safely as possible is required. Traditionally, power system operators develop an organised and considered procedure to ensure system restoration, called a Power System Restoration Plan (PSRP).

The PSRP sets out guidelines and procedures. The principle of the PSRP is to use generation stations that can be started without an external power supply in order to energise other parts of the transmission system and larger generators called target generators[62].

With increasing RES levels, provided that most variable RES (wind/solar PV) use constant power operation brought about by current controlled voltage sources to interface with the grid, the number and size of self-starting generating units is likely to decline.

Furthermore, as the geographical locations of various generation resources are likely to change with replacement of conventional generation by RES, the pre-existing restoration paths will need to be reviewed regularly[63].

61 C. F. Flytkjaer, B. Badrzadeh, M. Bollen, Z. Emin, L. Kocewiak, G. Lietz, S. Perera, F. F. Da Silva, M. Val Escudero, Power Quality Trends in the Transition to Carbon-Free Electrical Energy System CIGRE Science & Engineering Journal. Volume 17, Feb, 2020.
62 EU-SysFlex, Task 2.4 Report, 2020
63 EU-SysFlex, Task 2.4 Report, 2020

Hence, in view of these factors, the PSRP[64] needs to adapt, incorporating the evolving plant portfolio. A potential mitigation could include the use of black-start from wind farms equipped with grid-forming converters[65] or VSC HVDC interconnectors[66].

4.4.2.7. Generation adequacy

Another area of potential concern relates to the risk of the power system having very low levels of wind generation for a protracted period. High pressure/anticyclone weather conditions could result in wind output being consistently low for periods of multiple days to a week or more.

Different weather regimes (variability in weather on a spatial scale of about 1000 km and for time periods of more than five days) have been shown to impact upon wind speeds and different weather systems can extend over vast geographical areas[67]. Consequently, weather regimes can have a profound impact on wind electricity generation.

There is the potential for the island of Ireland, Great Britain and France all to experience unusually high and/or low wind periods concurrently. This could impact upon the ability to utilise interconnectors to import during times of low wind on the all-island power system, as there is a high likelihood that France and Britain will also be experiencing low wind generation.

From a power system operations perspective, it is important that there is enough capacity and system services capability available to ensure that a safe, secure and reliable system is maintained at all times. With gas expected to be the fuel source powering the bulk of the non-renewable generation fleet by 2030, maintaining security of supply on the island at times of low wind generation is implicitly linked to maintaining gas security of supply.

Due to the importance of this topic, we are planning future work and engagement with researchers in academia with an initial focus on getting a better understanding of the following:

- What is the expected likelihood, frequency and duration of periods of low RES output across the island? How much forecast notice (and accuracy) is possible for such periods?
- What are the (worst case) expectations for a daily, weekly, monthly, yearly, 1 in 10 year/ 50 year/100-year event?
- How does the development of the wind and solar portfolio over the next decade affect the likelihood and severity of periods of low RES output (e.g. locational and technological developments)?

4.4.2.8. Other technical challenges

In addition to the technical challenges listed so far in this section, we are conscious that there are other technical challenges, some of which have been previously identified and others which may appear in the future. A brief overview of some of these further technical challenges is provided below.

- VDIFD – A Voltage Dip Induced Frequency Deviation (VDIFD) is a phenomenon whereby a voltage dip leads to a large frequency deviation.
    - A voltage dip, caused by a fault on the system, can result in a drop in frequency. The voltage dip can lead to a drop in the active power output of large quantities of inverter-based resources. While conventional generators recover their active power output very quickly following a voltage dip, some inverter-based resources can be slower to restore their active power. This slower recovery of active power output from these inverter-based resources can result in a very rapid fall in frequency.

64 The amount and availability of black start providers is reviewed regularly and is sufficient for system security presently. However, more recently, we have noted developments such as the direction provided by ER NC Article 4 (Regulatory Aspects) and the rapidly evolving nature of the power system and the generation portfolio
65 Black start capabilities from a windfarm equipped with grid forming converters have been successfully demonstrated– https://www.scottishpowerrenewables.com/news/pages/global_first_for_scottishpower_as_cop_countdown_starts.aspx
66 VSC HVDC can be used for black start and system restoration https://www.hvdccentre.com/wp-content/uploads/2020/06/EPRI-Black-Start-from-HVDC-Project-final-report_reviewed_clean.pdf
67 C. M. Grams, R. Beerli, S. Pfenninger and I. Staffell, "Balancing Europe's wind-power output through spatial deployment informed by weather regimes," *Nature Climate Change*, 2017.

- The delayed recovery of active power in wind turbine generators after a severe voltage dip is typically implemented in order to limit the mechanical stress in the drivetrain. Figure 44 shows an actual recording of the response of a wind farm to a system fault in Ireland. The active power recovers to the pre-fault value in approximately one second after fault clearance.

- The greyed area represents the approximate energy deficit with respect to a synchronous generator, which would recover active power almost instantly upon fault clearance. This energy deficit can represent a threat to frequency stability in scenarios of high penetration of wind generation depending on the power system's size and characteristics as well as the recovery characteristics of the individual windfarms connected across the system. EirGrid and SONI are undertaking system studies to quantify the risk and develop mitigation options.

- A voltage dip, caused by a fault on the system, could also result in a rise in frequency if large demand customers were to disconnect from the power system.

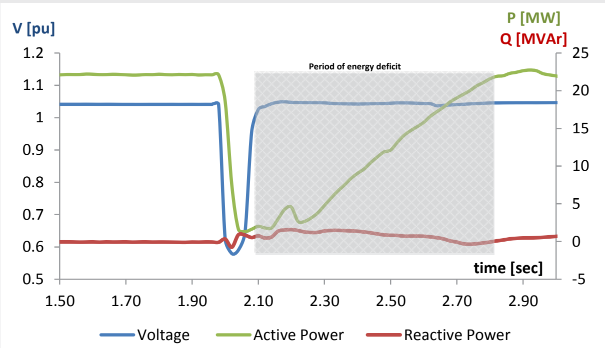


Figure 44: Energy deficit as a result of delayed recovery of active power

- Frequency regulation – Frequency regulation is the ability of the power system to maintain the system frequency within its normal operating range. Traditionally, frequency regulation is performed automatically by conventional generators. However, frequency regulation could become a challenge in the coming years due to the displacement of conventional fossil-fuel based generation coupled with the frequency fluctuations caused by the inherent variability of the RES.

- Power system protection schemes – The fundamental operation of most common power system protection schemes is based on the presence of large numbers of synchronous generators on the power system providing enough fault current. The presence of increasing levels of inverter-based resources will result in challenges for protection devices around available short circuit current and the detection of faults.

  - Within the MIGRATE project[68], the influence of increasing levels of inverter-based resources on the operation of various standard protection schemes, including differential protection, distance protection and over-current protection, was investigated.

  - It was found that the widely used distance protection would be impacted the most. Extensive analysis and real-time digital simulations showed that by increasing inverter-based resource penetration, distance protection experiences difficulties to identify and detect some faults and under specific circumstances may not operate. System integrity protection schemes were also found to be less reliable under conditions with high levels of inverter-based resources.

  - New tools, a clear definition of the required response of power electronics during short-circuits, and a more cross-disciplinary approach with the power electronics field will be required to prepare for the future.

68 "H2020 Project MIGRATE Website." [Online]. Available: https://www.h2020-migrate.eu/

- Telecoms/cyber security - As operators and developers of critical national infrastructure, we must ensure that our plans incorporate appropriate measures to manage cyber security risks posed to the power system and information systems.

- New HVDC interconnection – We will need to manage any additional operational complexity that could arise from the integration of future new HVDC interconnectors between the island of Ireland and neighbouring systems (Great Britain and France). We will need to review the systems and practices of the control centres in Ireland and Northern Ireland to ensure the necessary policies and systems are in place to manage the new interconnectors.

- Power system modelling – The power system will change from one that is largely based on passive network and synchronous generation to one with active network devices and inverter-based sources of generation. Understanding and reflecting the characteristics of these technologies in appropriate models will be critical to our planning and operation of the power system.

- Data requirements - The transition to a power system with greater levels of decentralised RES and system service provision will also see the advent of much greater quantities of data that will undoubtedly provide much valuable information. However, there are challenges associated with processing huge volumes of data. There will be data to be processed from the transmission system level, but also from the distribution system level, as well as from the supply-side, and increasingly, the demand-side. The Commission Regulation (EU) 2017/1485 establishing a guideline on system operation (System Operation Guideline - SOGL) covers off some of these data requirements via the Key Organisational Requirements, Roles and Responsibilities (KORRR) requirements.

- Maintenance/outages – Outages on the transmission system or of generators either as a result of capital project works, routine maintenance, or emergency maintenance result in system configurations which can cause challenges for TSOs. The energy transition will require increased numbers of outages to facilitate capital works which will be a complex scheduling task. Furthermore, the scheduling of routine outages on the grid will become increasingly complex as the generation portfolio and transmission grid evolve.

- Short term forecasting – The increasing penetration of weather dependent resources, such as wind and solar, on the power system coupled with more complex demand characteristics will drive the need for an increased focus on short term forecasting. The magnitude of short-term alterations in weather-dependent generation will increase as penetration increases and it will be important to ensure we are as informed as possible of these changes to ensure secure operation of the power system. The increase in demand side participation and the roll out of electric vehicles and electric heating will also drive more complex demand profiles with the potential for large changes in short periods of time. Again, it will be important to ensure we are as informed as possible of these changes to ensure secure operation of the power system.

We are cognisant that there are likely to be technical and operational challenges which have not yet been identified in the path to 2030 and beyond. With this in mind, we will continue to undertake extensive studies and analysis on the power system of the future, seeking to integrate any learnings from system events/ disturbances, and work in collaboration with other TSOs to share learnings to ensure we identify and address these challenges as they materialise.

4.4.3. Summary of the technical challenges in 2030

Table 30 summarises, at a high-level, the technical challenges with operating the power system in 2030 with high levels of variable non-synchronous RES.

Table 30: Summary of technical challenges

Challenges	Why is it becoming a challenge?
Frequency Stability and Control 1) Inertia 2) Reserves 3) Ramping 4) Very Low Frequency Oscillations	Reduced synchronous generation on the system providing inertia and insufficient reserve capability means that frequency varies more quickly in the case of power equilibrium incidents and is less manageable. Increase in weather-dependent generation and associated forecast errors results in need to carry ramping capability. Lower levels of system inertia lead to more severe and more frequent frequency oscillations which can impact on system stability.
Voltage Stability 1) Steady State Voltage Control 2) Dynamic Voltage Control 3) Reduction in Available Fault Current	Less synchronous generation available to provide reactive power support. Voltage variation effects due to connection of RES on the distribution system. Reduced fault current due to the replacement of synchronous machines and the limited capacity of inverters in terms of fault current injection.
Transient Stability	Less synchronous generation to maintain inertia and stability. Reduction in synchronising torque deteriorates stability margins. Reduction in damping torque. Increased share of inverter-based resources in weak parts of the grid resulting in instability during or following system faults.
Congestion	Increased generation capacity in weaker areas of the network. Lack of transmission capacity.
Power Quality	Less synchronous generation and increased inverter-based resources cause a reduction in power quality. Increase in inverter-based resources increases harmonic injections. Increased connection of cables in weak parts of the system introduces low order harmonic resonances that amplify harmonic distortion.
System Restoration	Less black start capable plants on the grid. Current restoration strategy mainly refers to large synchronous generation.
Generation Adequacy	Reduction in conventional generation driven by penetration of RES. Uncertainty and lack of capacity during weather related events.

4.5. Mitigations

4.5.1. Potential solutions

A range of mitigations could be deployed for each of the technical challenges that have been described in Section 4. These mitigations will be tested and developed as part of an ongoing suite of studies and analyses. While some of these mitigations are already in place as part of the current DS3 System Services arrangements, based on the analysis undertaken in EU-SysFlex Task 2.4, discussed in Section 4.4, in some cases it will be necessary to procure greater volumes of the these services from non-conventional technologies.

In other instances, it may be necessary to evolve the product design and/or specification of services. It should be acknowledged that there is no simple solution when it comes to mitigating the technical challenges. There are cases where the implementation of one measure may mitigate several of the technical challenges, while other cases may require a suite of mitigations to resolve a single issue.

In order to address these challenges, it is considered that, in addition to the existing 14 system services (see Appendix G for a high-level description of these services), additional system services may be required. Although the analysis has not yet been completed, it is possible that there will be a need for a frequency regulation product, a congestion management product, a damping/oscillation product and potentially a longer-term ramping product (e.g. multiple day timeframe).

Table 31 maps specific technical challenges to potential system services products which could help with mitigation of the issues identified in Section 4.4. Technologies with the potential capability to provide these system services are also set out. The identified mitigations are in no way exhaustive; Table 31 merely seeks to indicate the range and types of capabilities needed. We are very mindful that there may be technological developments in the coming years which could complement the technology options.

In the future power system, where we are operating at SNSP levels up to 95%, there will be specific technologies, such as wind generators and demand-side technologies, that are inherently going to be online/connected and operating at times of high wind. It is unlikely that many conventional generators, as they are synchronous generators, will be operating at times of high SNSP, by definition, and thus, the services and capability required to operate a safe, secure and economic power system will need to be provided by the technologies that are online and available.

In the future, a more diverse portfolio of technologies will be required. Traditionally, there was a reliance on conventional generation to provide the full range of services and capabilities, while in the future with less conventional generation synchronised at times of high variable RES output, the services must come from other technologies, which typically provide a subset of the required system services.

For example, demand-side response cannot provide voltage support, but it can provide a range of reserve services. Consequently, there are other technologies, often classed as network devices, which will be of vital importance, further highlighting that the future portfolio of resources must be diverse and multi-faceted.

As part of EU-SysFlex Task 2.6, we are currently conducting detailed studies which aim to demonstrate some of the potential solutions to the suite of technical challenges that have been discussed in Section 4.4. In addition, other short-term and long-term studies are planned to complement and enhance the outcomes of the EU-SysFlex studies. We are planning to publish a report on the collective outcome of these studies in Q2 2021.

Table 31: System technical challenges and potential solutions

Challenge	Why is it becoming a challenge?	Potential Solutions Identified
Frequency Stability and control 1) Inertia 2) Reserves 3) Ramping 4) Very Low Frequency Oscillations	Reduced synchronous generation on the system providing inertia and insufficient reserve capability means that frequency varies more quickly in the case of power equilibrium incidents and are less manageable. Increase in weather dependent generation and associated forecast errors results in need to carry ramping capability. Lower levels of system inertia lead to more severe and more frequent frequency oscillations which can impact on system stability.	**Technical solutions:** Technologies providing inertia such as synchronous generators, synchronous condensers, rotating stabilisers, technologies providing frequency response in various timeframes, in the range of seconds to hours and which are available during high SNSP (DSM, storage, wind, interconnectors), as well as grid-forming inverters, power to gas, Ramping from all technologies, standby peaking capacity, forecasting, power to gas. **System control:** Enhanced TSO-DSO coordination, improved weather forecasting, improved load forecasting, enhanced reserve monitoring and management, enhanced inertia monitoring and forecasting, enhanced system analysis tools, HVDC power oscillation damping and oscillation damping from other sources. **Enhanced market design:** Design of new services and products, and existing services including SIR, FFR, POR, SOR, TOR, RR, Ramping.
Voltage Stability 1) Steady State Voltage Control 2) Dynamic Voltage Control 3) Reduction in Available Fault Current	Less synchronous generation available to provide reactive power support. Voltage variation effects due to connection of RES on the distribution system. Reduced fault current due to the replacement of synchronous machines and the limited capacity of inverters in terms of fault current injection.	**Technical solutions:** STATCOMS, reactive support from conventional and non-conventionals, wind, solar photovoltaic (PV), and storage, FACTS devices, synchronous compensators, rotating stabilisers, dynamic reactive resources, transmission network reinforcement. **System control:** Enhanced TSO-DSO coordination, voltage optimisation/ scheduling and tools. **Enhanced market design:** Design of new services and existing services including DRR, SSRP and FPFAPR.
Transient Stability	Less synchronous generation to maintain inertia and stability. Reduction in synchronising torque deteriorates stability margins. Reduction in damping torque. Increased share of inverter-based resources in weak parts of the grid can result in instability during or following system faults.	**Technical solutions:** Dynamic voltage support from modern variable RES, synchronous condensers, STATCOMS, FACTS devices. Improved and optimised controls in existing grid following non-synchronous generation. Grid-forming control of non-synchronous generation. **System control:** Enhanced monitoring and Look Ahead DSA tools. **Enhanced market design:** Design of new services as well as existing DRR service.

Table 31: System technical challenges and potential solutions

Challenge	Why is it becoming a challenge?	Potential Solutions Identified
Congestion	Increased generation capacity in weaker areas of the network. Lack of transmission capacity	**Technical solutions:** Application of network control and measurement technologies, distributed energy resources, advanced control and forecasting tools, DSM, sector coupling, power-to-gas, storage; Dynamic Line Rating, Distributed Power Flow Controllers. **System control:** TSO-DSO coordination, enhanced system analysis tools, power flow optimisation enhanced by frequent system studies, flexible outage planning. **Enhanced market design:** Design of congestion products. Flexible network framework.
Power Quality	Less synchronous generation and increased inverter-based resources cause a reduction in power quality. Increased inverter-based resources increases harmonic injections. Increased connection of cables in weak parts of the system introduces low order harmonic resonances that amplify harmonic distortion.	**Technical Solutions:** Harmonic mitigation, optimised control of inverter-based resources to minimise or cancel out harmonic emissions. **System control:** Enhanced monitoring capability in real time, frequent power quality studies and continuous enforcement of grid code for new and existing connections.
System Restoration	Less black start capable plants on the grid. Current restoration strategy mainly refers to large synchronous generation.	**Technical solutions:** Utilisation of distributed energy resources, grid-forming technologies, storage. **System control:** TSO-DSO coordination, enhanced restoration strategy, improved tools for blackstart and restoration, TSO-TSO coordination across HVDC interconnectors. **Enhanced market design:** Design of black-start services in future system services.
Generation Adequacy	Reduction in conventional generation driven by penetration of RES. Uncertainty and lack of capacity during weather related events.	**Technical solutions:** Potential solutions lie in the utilisation of synchronous generation using renewable fuel, distributed generation, energy storage, DSR, interconnection, power-to-gas, sector coupling. **System control:** Cross-border coordination, TSO-TSO coordination, TSO-DSO coordination. **Enhanced market design:** Modification of the system services and capacity markets to ensure business case of required units remains viable.

In the following sections, we describe a subset of potential service providers (wind, demand side response and network devices) in more detail and subsequently provide a high-level overview of the work currently on-going on the development of the DS3 System Services Future Arrangements.

4.5.1.1. Renewable generation as a service provider

The DS3 System Services Proven Technologies List sets out the types of technology which the TSO considers eligible to procure for a DS3 System Services contract at this time. Wind generation features on the TSOs' DS3 System Services Proven Technology List[69].

Wind generation has been proven to be capable of providing many different system services including reserve services (FFR, POR, SOR, and TOR1), as well as reactive power services (SSRP and DRR) and the capability to recover to normal operating conditions following a system disturbance in certain specified timeframes (FPFAPR).

All the reserve services as well as the SSRP service are required at all levels of RES penetration. However, DRR and FPFAPR in particular will be more critical at SNSP levels of 75% and higher. The procurement of these services will be considered as part of the DS3 System Services Future Arrangements work which is discussed in Chapter 5, while the operational aspects of utilising these services will be part of the Operational Policy and Tools pillar which is discussed in Section 4.6.5.

In a power system with very high levels of wind and solar generation, it is important that these technologies are enabled to provide key system services. With a reduction in the number of synchronous generating units committed during hours of high wind, the services will need to come from elsewhere.

With significant developments in wind turbine technologies and grid-forming converter technologies (although only at demonstration stage presently), it is possible that wind power plants with built-in grid-forming capability will begin to appear. We will keep a watching brief on developments in this area and are interested in exploring the potential to collaborate on grid-forming technology trials of key system services as well as black-start capability[70].

It is likely that other RES technologies such as solar will act as service providers in a similar way under the system services future arrangements.

4.5.1.2. The demand-side as a service provider

Over the last decade, we have seen the emergence and rapid growth of the demand response sector. This has predominantly been achieved through the Demand Side Unit (DSU) arrangements. There is currently c. 550 MW of DSU capacity contracted in the capacity market while DSUs have also been contracted to provide a range of system services.

A significant advantage of demand side response from a service provision perspective is that, at times of high wind when there may be few other resources online, the demand will be there so system operators can rely on the availability of demand response at an aggregate level.

It is important here to make the distinction between DSUs and Demand Side Management (DSM) more generally. Currently, DSUs are typically commercial and industrial-scale demand sites and are proven to be able to provide FFR through to TOR2, Replacement Reserve and all three ramping services.

Demand side response from residential customers (Residential DSM or RDSM), on the other hand, is not yet proven. With well-designed control algorithms and close collaboration between the TSOs and DSOs, aggregated residential loads have significant potential to not only provide significant levels of reserve services over multiple-time scales (FFR to TOR2), but to also contribute to congestion management and energy arbitrage.

The use of RDSM aligns with EU objectives to allow the public to engage in the energy sector, it can benefit the end customer and has the potential to reduce the scale of infrastructure development needed. It will be important that residential customers are engaged effectively and given the correct incentives. The emergence of RDSM would help exert long term competitive pressure on the cost of system services.

69 DS3 System Services Proven Technologies List
70 For info, black start capabilities from a windfarm equipped with grid forming converters were successfully demonstrated – https://www.scottishpowerrenewables.com/news/pages/global_first_for_scottishpower_as_cop_countdown_starts.aspx

However, to date, there has been no appropriate incentive to stimulate this market, nor complementary enabling mechanisms to credibly and prudently procure residential system services. EirGrid and SONI envisage real benefits from RDSM in reducing and shifting demand levels and the provision of essential system services. To successfully deliver value to the wider system and the public, RDSM will require close collaboration between the TSOs and DSOs across planning, operations and systems.

The current absence of smart metering is likely to impact energy services being provided at scale by residential customers but should not be a barrier to the provision of certain system services products.

Following on from the success of the EirGrid Power Off and Save pilot project[71], operational complexities associated with automated response from in-home technology are now being investigated. There are significant challenges and barriers to residential demand-side response. The FlexTech initiative, as well as the Qualification Trials Process (QTP), seeks to work with industry to break down some of these barriers. These initiatives are described further in Section 4.6.6.

In the 2019 QTP procurement process, two RDSM participants were successful and are now seeking to demonstrate system services capability using different methodologies and technologies. The participants are Energia and Solo Energy. The system services being trialled are FFR, POR, SOR, TOR1 and TOR2. These system services are detailed in Appendix G. More details on these trials can be found in the EU-SysFlex Task 4.5 report entitled "*Operation and integration considerations for distinct Qualifier trial providing units of system services*"[72].

- The Energia trial involves the aggregation of residential solar PV systems with smart battery storage solutions. Twenty such systems have been installed in Ireland with scope for a further five battery installations in Northern Ireland. The objectives are to demonstrate and prove that aggregated residential electrical appliances can be a technology class for the provision of system services, to develop a platform to facilitate RDSM, to assess operational complexities and to investigate barriers to market entry for residential demand sites, all whilst ensuring there are no adverse effects on consumer comfort.
- Solo Energy's cloud-based software platform *FlexiGrid™* aggregates batteries, Electric Vehicles (EV) via unidirectional or Vehicle-to-Grid (V2G) chargers and other Distributed Energy Resources (DER) in order to operate as a centrally controllable Virtual Power Plant (VPP). The Solo trial seeks to demonstrate the provision of system services from residential customers and to investigate the barriers that exist.

Both trials have a duration of 18 months and are due to conclude in March 2021.

In conjunction with the two QTP trialists, we hope to be able to explore the potential for conducting a RDSM Trial with the DSOs to explore the potential approaches, mechanisms and systems required to facilitate RDSM and rollout. It is acknowledged that there are significant challenges to tapping into the RDSM resources, including aggregation, design of control algorithms, incentivising adoption and monitoring of performance.

4.5.1.3. Network devices providing required service capability

While the work that is discussed in these sections is focussed primarily on the programme of work for the evolution of power system operations over the coming decade, there is an inextricable link between system operation and transmission network development.

71 EirGrid and SONI, Power Off & Save
72 EU-SysFlex, Operation and integration considerations for distinct Qualifier trial providing units of system services

EirGrid and SONI are already committed to several grid infrastructure projects that are reflected in the Transmission Development Plans of Ireland and Northern Ireland. In addition, the networks-related work set out in Chapter 3 seeks to make optimal use of current network assets and to minimise requirements for new infrastructure, in line with EirGrid and SONI's Grid Development Strategies[73].

From an operational point of view, it is also acknowledged that many network device technologies will need to be considered as potential options for the provision of required system services capability. This is also an acknowledgment of the fact that the system operators must exploit all assets at our disposal as the power system makes the transition to unprecedented levels of non-synchronous RES.

Network devices such as static VAr compensators (SVCs) and static synchronous compensators (STATCOMs) are traditionally used for controlling the reactive power in very specific locations in the network. As a result of the displacement of conventional generation by wind generation, and the decrease in reactive power capability, there may be a requirement for more of these types of technologies, dispersed throughout the system.

Other technologies such as Power Flow Controllers, Dynamic Line Rating and Nodal Voltage Controllers could also be vital in assisting with better network utilisation.

In 2015, the TSOs and the DSOs sought to assess the possibility of utilising Nodal Voltage Controllers which coordinate distribution-connected wind farms to help manage transmission network voltages whilst still respecting the distribution system limits[74]. Currently, most of the wind generation connected to the distribution networks does not offer reactive support to the transmission system.

In recognition of the increasing amount of distribution-connected wind generation and in anticipation of a reduction in available reactive power capability more generally across the system, the Nodal Voltage Controller pilot was launched in 2017 with ESB Networks and NIE Networks.

The Nodal Controller is designed to take instructions from the TSOs and to control the reactive power provided by participating distribution-connected wind farms based on their capabilities (subject to local constraints). The project is on-going and represents the type of innovation and ambition that will be required to operate the future power system.

Separately, power flow control devices and impedance-changing devices can be deployed on the power system to increase or decrease power flows on circuits and the associated network. They can assist with congestion management and could help to alleviate or defer the need for grid reinforcements.

Deploying these types of devices and technologies at scale will require significant telecoms infrastructure as well as careful consideration of how they are integrated with system operations, how power flows are managed and how the integrity of situational awareness for the system operators can be maintained (see Section 4.6.5.1 on the Control Centre of the Future project).

EirGrid is currently exploring the possibility of working with partners on a project to develop a suite of software tools that could be used to co-ordinate control of power flow control devices.

Should these types of devices be deployed on the grid, the tools would enable the control centres to optimise the use of power flow control devices to maximise the amount of RES that can be transported. To get the maximum benefit offered by these devices, power flow analysis tools would be required to support both real time operation and day ahead operational planning processes.

73 EirGrid, Ireland's Grid Development Strategy
74 D. Corcoran, T. Hearne, M. Val Escudero, M. Rafferty, D. Molloy, J. McGuickin, S. Nolan, D. McSwiggan and J. O'Sullivan, "Co-ordinated Approach between TSO and DSO for the Utilisation of Voltage Control Resources using Distributed Wind Generation in Ireland," in *CIGRE Science and Engineering*, 2020.

4.5.2. System services future arrangements - next steps on product design

As part of the DS3 Programme, new system services arrangements were introduced in 2016, which enable the TSOs to procure a range of services (both pre-existing and new) from providers of different technology types to support the operation of the transmission system. This has been an important aspect in enabling increased levels of non-synchronous RES on the system.

Developments in European Regulations have led the SEM Committee to conclude that a review of the arrangements is required. In July 2020, the SEM Committee published a consultation paper[75] on the scope of the development of a framework for the procurement of System Services to apply from 1 May 2023.

In parallel with that consultation, as set out in Section 4.4, the TSOs completed a set of studies to assess the technical challenges with operating the power system in 2030 and identified a range of technical scarcities. A summary of the outcomes of these studies is included in Section 4.4.3. Further studies are likely to be required in certain areas (e.g. frequency regulation) while, more generally, there will be a need to update the studies on a reasonably regular basis to take account of new information.

In addition to the work already completed on potential solutions, the TSOs are currently undertaking a series of more detailed studies to identify and confirm further potential solutions to the challenges identified. We plan to publish a report on the outcome of these studies in Q2 2021.

Once these studies are complete, we will start the design of future system services products, consulting with stakeholders as appropriate throughout that design process. It is likely that new system services above and beyond those already being contracted by EirGrid and SONI as part of the DS3 System Services arrangements will be required. The requirement for some services, such as steady state reactive power, is locational in nature. The exact locational requirement for such services will be dependent on the outturn generation portfolio and the network configuration.

We will need to conclude the detailed product design work in 2022 to be able to ensure that commercial, contractual, settlement and performance monitoring arrangements can be put in place ahead of the planned Future Arrangements Go-Live on 1 May 2023.

Following go-live, we will monitor the efficacy of the arrangements in conjunction with the regulatory authorities and other stakeholders, adjusting as necessary to ensure that the necessary investment in system services capability is delivered.

We also consider that there would be benefits in procuring services from new types of service provider, or new services from existing providers, early in the decade to understand their operational impact, gain operational experience and deliver benefits to consumers earlier. For example, the provision of inertia from low-MW output devices could offer significant advantages. This could be facilitated through the existing Qualification Trial Process or another mechanism.

Figure 45 provides a summary of these key steps in the system services design process.

75 SEM-20-044 System services future arrangements scoping paper

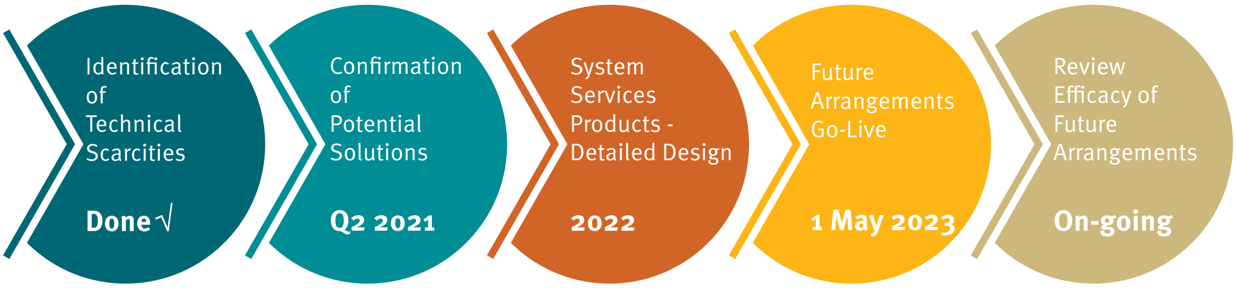


Figure 45: Timeline for system services future arrangements

4.5.3. Evolution of operational policy

The TSOs acknowledge that, in conjunction with the arriving RES capacity and the procurement of system services capability, there needs to be a commitment to evolve operational policy over the coming decade, and beyond, to accommodate increasing RES levels and fully exploit the arriving technical capabilities.

Without evolving operational policy in conjunction with the arriving RES capacity, there would be a considerable increase in dispatch-down levels due to operational limitations.

We foresee a gradual evolution of operational policy between now and 2030. This evolution will lead to increased levels of SNSP on the power system which will in turn facilitate increased levels of RES and ensure excessive levels of curtailment are avoided.

The evolution of operational policy to 2030 will encompass a range of operational changes. Four of the key operational metrics that will need to evolve by 2030 are as follows:

- SNSP;
- Inertia floor;
- Operational RoCoF; and
- Minimum Number of Large Synchronous Units.

These metrics are explained in detail in Section 4.3 “Current Operational Policy”. By 2030, we are planning to be able to operate at SNSP levels up to 95%, to have a reduced Inertia Floor (reduction from the current floor of 23,000 MWs), to have implemented a secure RoCoF limit of 1 Hz/s (an operational trial is currently underway) and to have a significantly reduced Minimum Number of Large Synchronous Units requirement (the current requirement is to keep 8 large conventional synchronous units synchronised across the island).

Both the EU-SysFlex studies and the Tomorrow’s Energy Scenarios (TES)[76] [77] analysis highlighted the need for operational policy changes to deliver higher levels of RES while reducing system curtailment to acceptable levels.

76 EirGrid, “Tomorrow’s Energy Scenarios 2019 Ireland,” 2019
77 SONI, “Tomorrow’s Energy Scenarios Northern Ireland 2020,” 2020

The TES analysis looked at the operating conditions required to ensure that 70% RES-E would be feasible in 2030. The amount of time each operational metric was at a certain level was analysed, and the results are illustrated in Figure 46.

For the two TES scenarios analysed, inertia levels need to be lower than today's minimum allowed level of 23,000 MWs for approximately 70% of the time. Consequently, as discussed earlier, RoCoF levels will rise and will be higher than 0.5 Hz/s for approximately 85% of the time.

The studies found that SNSP levels will need to be significantly higher than today's limit of 65%, while the minimum number of large synchronous units required online will be less than today's requirement of 8 units for approximately 80% of the time. These results further highlight the need to evolve the four key operational metrics of SNSP, Inertia Floor, operational RoCoF and Minimum Number of Large Synchronous Units.

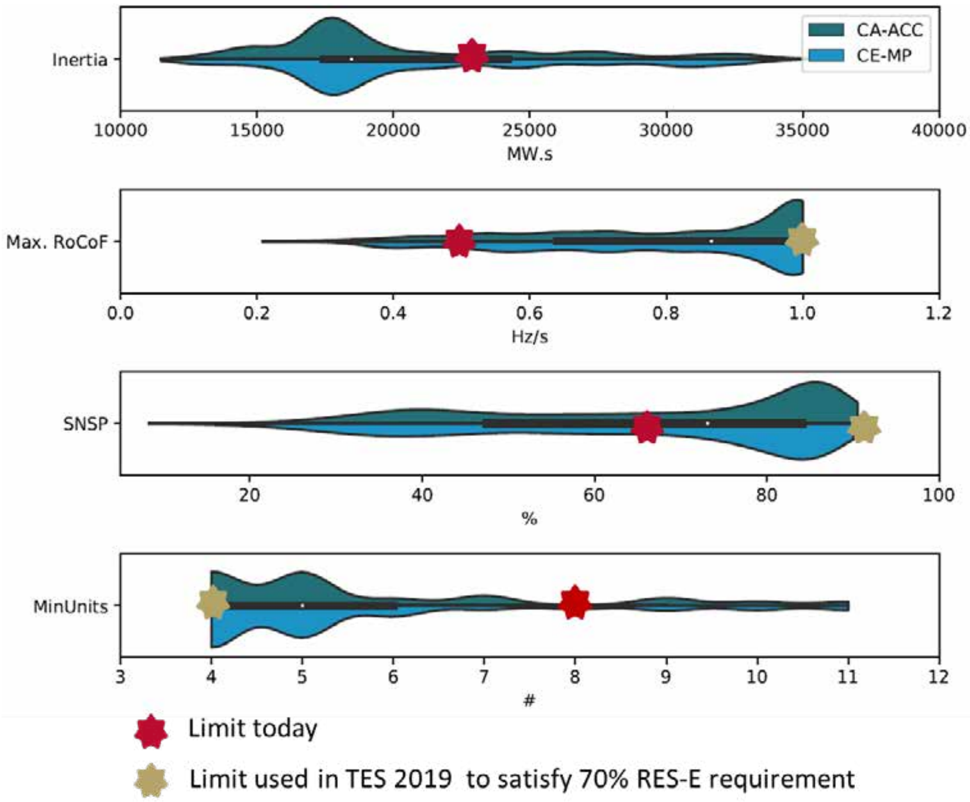


Figure 46: Summary of the Tomorrow's Energy Scenarios analysis which looked at the operating conditions required to ensure that 70% RES-E would be feasible in 2030

We are conscious that new and evolving technologies may change the operational needs of the system. With this in mind, we will take a flexible and agile approach to the delivery of operational policy change. For example, the presence of technologies such as synchronous condensers may reduce the need to lower the inertia floor. This is the reason that a specific future inertia floor has not been targeted at this stage.

In addition, the Minimum Number of Large Synchronous Units requirement needs to be reduced. However, if conventional generators can lower their minimum operating limits then the reduction in the number of units may not need to be as large. This flexible and agile approach will be crucial to the delivery of operational policy change over the next decade.

4.6. Operational pathways to 2030 programme

4.6.1. DS3 programme

The DS3 programme was launched in August 2011 as a multi-year programme of work. At its core, DS3 was designed to ensure the secure, safe operation of the power system in Ireland and Northern Ireland with increasing amounts of variable non-synchronous RES.

In the period since 2011, wind generation capacity has increased significantly (see Figure 47) with the result that the generation plant portfolio on the Island has been transformed from the traditional mix of conventional generation - mostly gas and other thermal plant - to a portfolio where today, variable non-synchronous onshore wind generation accounts for approximately 40% of all electrical power generated on the Island (there are also contributions from other RES such as hydro, solar and biomass).

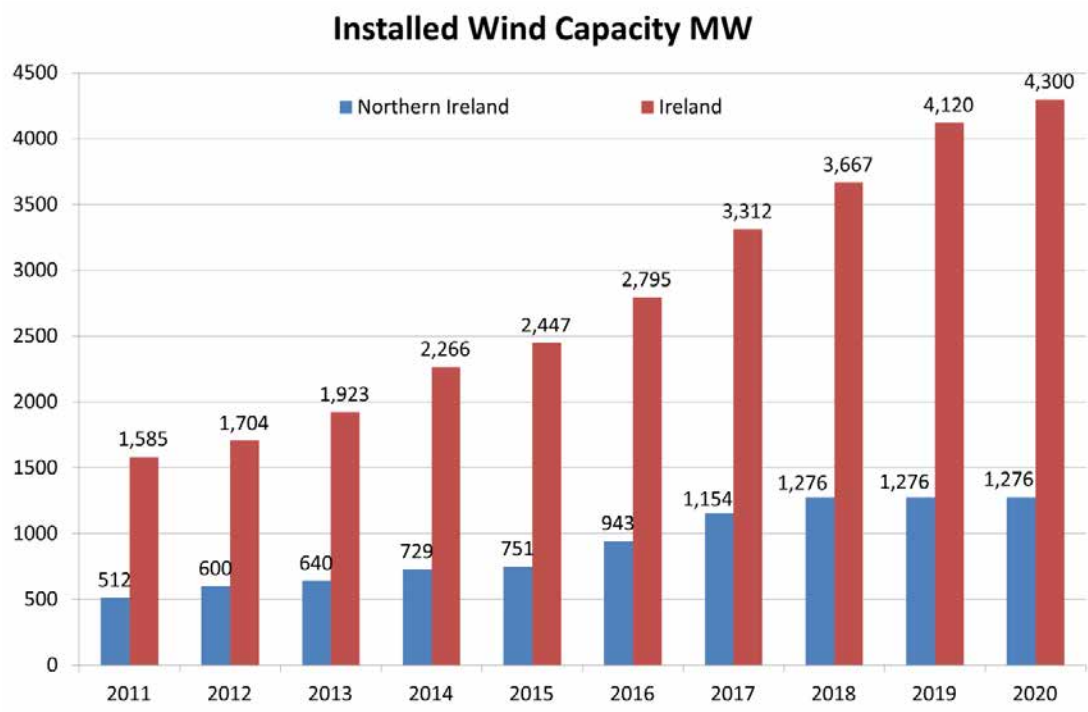


Figure 47: Installed wind capacities between 2011 and 2020[78]

Over the course of the DS3 Programme, the allowable SNSP level has been increased to 65% (and in January 2021 we commenced a trial of 70%) from 50% following the successful conclusion of SNSP operational trials undertaken with 5% incremental increases. In addition, the RoCoF capability of all generators on the system has been upgraded to 1 Hz/s and the individual minimum operating limits of conventional generators on the all-island power system have been reduced.

The DS3 programme is now in its final stages but there is still important work being undertaken to support the renewable ambitions of Ireland and Northern Ireland. In particular, the remaining operational trials associated with the programme are expected to be completed in 2021. These trials will deliver the capability to operate the power system at 75% SNSP with a RoCoF limit of 1 Hz/s.

78 EirGrid Group, Wind Installed Capacities – 1990 to date, 2021

4.6.2. Operational pathways to 2030

Recent Government policy in Ireland and the UK has set ambitious targets that will significantly affect how electricity is generated across Ireland and Northern Ireland.

In Ireland, the Climate Action Plan 2019[10] states that 70% of electricity will be generated from RES by 2030. In the UK, the government is pursuing net zero carbon emissions by 2050. Whilst a target has not been set specifically for Northern Ireland, we note the ambition recently announced where the Northern Ireland target may be in excess of 70% by 2030[79].

These targets will require us to break new ground in the amount of RES we manage on the electricity system. The technical challenges created by these changes drive the need to significantly enhance our system operational capability.

In order to achieve the 2030 renewable ambition, we are developing a programme of work which will enable us to enhance our system operations capability out to 2030. This all-island programme of work is called Operational Pathways to 2030. The key objectives of the Operational Pathways to 2030 Programme are as follows:

- Increase the instantaneous amount of non-synchronous RES that can be accommodated on the Irish and Northern Irish power system in a safe and secure manner to 95%+ SNSP on an enduring basis;
- Identify the technical challenges that make the 95%+ SNSP target challenging to achieve, and provide incentives for the industry to invest in developing new technologies to address these;
- Remove barriers to entry and enable the integration of new technologies at scale; and
- Develop and implement operational policies and tools in the control centres to ensure the new technologies are utilised effectively.

The ultimate measure of achievement for the programme will be the ability of EirGrid and SONI to operate the power system of Ireland and Northern Ireland in a manner that enables the governments' renewable ambitions of 70% RES-E by 2030.

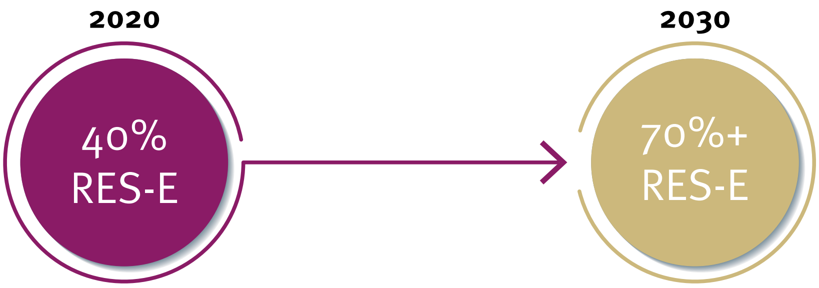


Figure 48: Renewable electricity ambitions

79 Department of Business, Energy and Industrial Strategy, The Climate Change Act 2008 (2050 Target Amendment) Order 2019

4.6.3. Overview of the programme

Looking out to 2030, we see there being **four key pillars** underpinning the Operational Pathways to 2030 Programme:

- Standards and Services;
- Operational Policies and Tools;
- Technology Enablement; and
- TSO-DSO

As illustrated in Figure 49: Overview of the proposed Operational Pathways to 2030 Programme, each pillar will comprise several proposed work streams, and it is through these work streams that activities will be planned and executed in line with the programme timelines.

Figure 49: Overview of the proposed Operational Pathways to 2030 Programme

Starting with Standards and Services, we need to ensure we have the right operational standards (e.g. Grid Code) as well as appropriate commercial frameworks to support necessary effective investment to mitigate technical scarcities on the power system. This will build on the existing system services arrangements, introducing new services and remuneration mechanisms as appropriate.

We will also need to continue to evolve our operational practices, developing the necessary operational polices and developing and putting in place new control centre systems and tools to enable our engineers to safely and securely operate a resilient power system as complexity and uncertainty increases.

The Technology Enablement pillar relates to the need to remove any technical or market barriers to the integration of new technologies at scale. The FlexTech initiative and Qualification Trial Process are key elements here.

Finally, with so much of the future generation and system service providers expected to be connected to the distribution system as the portfolio decentralises and diversifies, we will need to partner with the DSOs to ensure that the needs of both distribution and transmission systems, and ultimately the needs of consumers (decarbonised system, reliability maintained and economically delivered) are met.

In the following sections, we will expand on the key aspects of each of these pillars.

4.6.4. Pillar 1: Standards and services

The Standards and Services pillar is designed to ensure that:

- We provide clarity to the industry on future operational standards (e.g. Grid Code standards); and
- The investment signals across the electricity sector are appropriate and timely to drive the investment in capability to manage the all island power system in a high RES world.

To provide this capability, this pillar is focused on the design and implementation of future operational standards (Grid/Distribution Code modifications) as well as the design, procurement, and performance monitoring of the system services[80] required for the safe secure operation of the power system in 2030.

Considering the impending changes to the power system, the existing system services arrangements will be reviewed. This will support the development of a portfolio aligned with the long term needs of the system.

The key objectives are to:

- Clarify the system technical needs, both now and projected for the future;
- Review the Grid Code and Distribution Code and bring forward modifications, as appropriate;
- Establish if the existing system services arrangements will provide the reliable performance required for a system operating with increased levels of RES;
- Design new services if needed, determine appropriate valuation of these services and develop new or revised payment structures that foster a continued focus on performance and where appropriate drive investment;
- Develop a new commercial framework for procurement of system services, taking effect from 1 May 2023;
- Design and implement an auction system (assuming that the new system services procurement arrangements will be based on competitive auctions) and a settlement system in time for go-live of the new arrangements;
- Publish the standards that service providers will need to adhere to and monitor the performance of service providers against these standards on an ongoing basis;
- Develop a framework for flexible network management that will seek to incentivise the supply and demand sides to provide flexible network services and alleviate network congestion.

We will also explore the potential for portfolio arrangements which would allow system service providers the capability to utilise a portfolio of assets to provide the required services. The practical implementation of these portfolio arrangements will need to be determined as part of the DS3 System Services Future Arrangements work.

There are several technical issues being studied at this time. Some of these issues may necessitate the development of new products in the future.

To achieve the objectives set out above, we propose that the Standards and Services pillar would comprise four work streams, which are outlined in Table 32.

80 System Services are those services, aside from energy, that are necessary for the secure operation of the power system. These services are also referred to as Ancillary Services and System Support Services.

Table 32: Overview of standards and services pillar

Standards and Services	
Purpose	
Ensure we have the right operational standards (e.g. Grid Code) and that we have appropriate system services product designs and commercial frameworks to support investment in the capability required to mitigate the technical challenges on the power system.	
Work streams	
Long Term Scarcity Product Design	Design new and/or enhanced system services products required to address identified technical scarcities.
System Services Commercial Framework	Develop a new commercial framework for system services to incentivise the industry to develop and supply the services required.
Standards & Performance Monitoring	Provide clarity to the industry on the future operational standards (e.g. Grid Code) and how performance will be measured and enforced for these standards as well as for the provision of remunerated system services.
Flexible Network Framework	Develop a framework to incentivise the supply and demand sides to increase the flexibility in the power system and alleviate network congestion.
Outcomes	
An investment framework for system services based on competitive procurement, which breaks down barriers to entry and enables the provision of services from new and existing technologies. Standards (e.g. Grid Code, existing system services products) will be reviewed and revised where appropriate, and performance against these monitored.	

4.6.5. Pillar 2: Operational policies and tools

Considering the impending changes to the power system, the existing operational policies, operational systems, control centre tools, and operational training programmes will need to be reviewed. This will provide an informative view on our current operational capabilities and identify what is required to be able to operate the power system in a safe and secure manner with 70%+ RES-E (and 95% SNSP).

The key objectives are to:

- Identify technical scarcities, system needs and operational needs, both now and projected for the future;
- Establish what new/enhanced operational systems and control centre tools for power system operation with increased levels of variable non-synchronous RES, increased levels of demand and an evolved network;
- Design specifications for new control centre systems and tools, if needed;
- Revise and develop new operational policies to assist in operating the power system with new system services provision capabilities, and the new operational systems and tools;
- Train our people on the new operational policies and tools that will be implemented during the programme.

To achieve these objectives, we propose that the Operational Policies and Tools pillar would comprise five work streams, which are outlined in Table 33.

Table 33: Overview of operational policies and tools pillar

Operational Policies and Tools	
Purpose	
Evolve our operational practices, develop the necessary operational polices and develop and put in place new/enhanced control centre systems and tools to enable our engineers to safely and securely operate a resilient power system as complexity and uncertainty increases.	
Work streams	
Long Term Planning Studies & Scarcity Identification	Identify technical scarcities and potential mitigations through long term studies to inform what system services and/or other solutions are required.
Short Term Operational Studies & Operational Policy Evolution	Identify the operational needs; ongoing studies to ensure the system can operate safely and securely with increasing levels of RES, and evolve the operational policies as needed.
Control Centre Tools	Identify and implement enhanced or new control centre systems and tools required to operate the system with increasing levels of variable non-synchronous RES.
Training	Provide training to our people to ensure the system can be safely and securely operated using the new capabilities available.
Flexible Network Management	Utilise appropriate network flexibility services available when operating the power system.
Outcome	
Technical scarcities identified to inform the system services requirements. Revised operational practices through the development of new operational policies, on-going studies, new control centre capabilities and provision of training.	

4.6.5.1. Control centre of the future

A key initiative under the Operational Policies and Tools pillar is the Control Centre of the Future project. This is aimed at developing a roadmap of the control centre out to 2030.

Due to the changing system portfolio and the need to operate the power system in a more dynamic and responsive way, we will need to develop the control centres in accordance with international best practice utilising the most up to date systems and tools.

There is a need to review the adequacy of the systems and tools in the control centres and determine whether additions are needed. To this end, the TSOs are currently undertaking a Control Centre of the Future project.

The aim of the project is to review existing control centre operations, assess international best practices and develop a vision of the control centres in 2030 as well as a detailed roadmap with an implementation programme out to 2030.

It is acknowledged that there will be larger volumes of data and information going into the control centres making operations more complex. The control centre of the future will in principle have the capability for those tasks which can be automated, to be automated.

While the specific control centre tools needed by 2030 have not yet been developed, the following tools and capability are likely to be needed;

1. Constraint management and forecasting tools;
2. Enhanced real-time and look-ahead analysis tools that model the changing characteristics of the power system and allow us to ensure that operational standards are maintained;
3. Decision support tool to amalgamate and effectively display the information from the various other systems and tools;
4. Tools which interface with the DSOs effectively to allow mutual support between TSOs and DSOs.

The ability to design and operate the control centres and processes for the control engineers of the future is of paramount importance so that we can operate the system:

- With very high levels of non-synchronous RES;
- With a range of new network devices and service providers;
- With an increased level of generation and service provision connected to the distribution system necessitating enhanced sharing of data and coordination between the TSOs and DSOs.

4.6.6. Pillar 3: Technology enablement

The Technology Enablement pillar focuses on breaking down barriers to entry and enabling the integration of new grid technologies at scale. The existing FlexTech initiative will be central to achieving these objectives, in addition to other enabling initiatives developed throughout the duration of the Operational Pathways to 2030 Programme.

The FlexTech initiative was established in 2019[81] and is a platform of engagement for the Transmission System Operators, Distribution System Operators, industry, regulators and other stakeholders from across the island to maximise opportunities for effective use of new and existing technologies and to identify and break down key barriers to integrating RES[82].

In an effort to meet the ambitious RES-E targets by 2030, the electricity industry is evolving, and needs to continue to evolve, at an ever-increasing pace. We recognise the need for positive and proactive engagement with all stakeholders in order to meet the challenges associated with decarbonisation and to ensure the best use of new and existing technologies. Key to this is transmission and distribution system operators working together in an agile and efficient way to embrace opportunities and resolve issues as they arise.

FlexTech currently has a programme of work focused on the following work streams:

- Hybrids
- DSM - Deliverables
- Renewables & SSG
- Storage
- Large Energy Users

These work streams are likely to evolve as the Operational Pathways to 2030 Programme progresses.

81 EirGrid and SONI, FlexTech Initiative
82 EirGrid and SONI, FlexTech Consultation 2019

One of the key objectives of the FlexTech initiative is to inform future Qualification Trial Processes (QTP), which determine what technologies should be tested and which prove capable of providing the required flexibility.

We propose that the Technology Enablement pillar will initially be focused primarily on the existing FlexTech work streams with the potential addition of a new "Other Technologies" work stream in time. In time, it is also envisaged that the pillar will be expanded further to include other work streams. This pillar is summarised in Table 34 below.

Table 34: Overview of technology enablement pillar

Technology Enablement	
Purpose	
Break down barriers to entry, enabling integration of new technologies at scale.	
Work streams	
Hybrids	Enable hybrid connections and arrangements with a view to optimising use of existing infrastructure.
Storage	Address the challenges associated with the integration of large scale storage technology.
Renewables & Small-Scale Generation	Facilitate the provision of System Services from new and existing RES as well as small-scale flexible generation.
Demand Side Management (DSM)	Identify and remove barriers for DSM to maximise its potential.
Large Energy Users	Proactively engage with large energy users to investigate the potential for large energy users to contribute to system flexibility.
Other Technologies	Proactively engage with industry and academia to review and evaluate emerging technologies which are not covered by the other work streams.
Outcome	
Facilitation of the development and integration of new technologies and innovations on the power system.	

4.6.7. Pillar 4: TSO-DSO

With so much of the future generation and system service providers expected to be connected to the distribution system, we will need to partner with the DSOs to ensure that the needs of both distribution and transmission systems, and ultimately the needs of consumers, are met. In recognition of the need for co-operation and interaction between system operators, the TSOs are committed to the following programmes of work:

- Establishing a TSO-DSO operating model, defining the vision, roles and responsibilities, and ways of interaction for the TSO and DSOs;
- Developing interfaces between the TSO and DSOs that enable the sharing of data and coordination in decision making;
- Working with the DSOs to manage changes on the distribution network and how those changes impact the operation of the transmission network (and vice versa). In designing the mitigations for congestion, it is envisioned that congestion products will be in place for both the transmission and distribution networks. Flexible network co-ordination will be required to deliver these products.

The TSOs will work with the DSOs to ensure that, where appropriate, we have complementary work streams and approaches.

The key objectives are to:

- Reach agreement with the DSOs on the scope of works throughout this programme;
- Develop an implementation plan based on the agreed scope;
- Agree and implement a 2030 TSO-DSO operating model with the DSOs; and
- Foster a partnership between the TSOs and DSOs that ensures that the needs of both distribution and transmission systems, and ultimately the needs of consumers, are met.

To achieve these objectives, we envisage that the TSO-DSO pillar would comprise four work streams, which are outlined in Table 35.

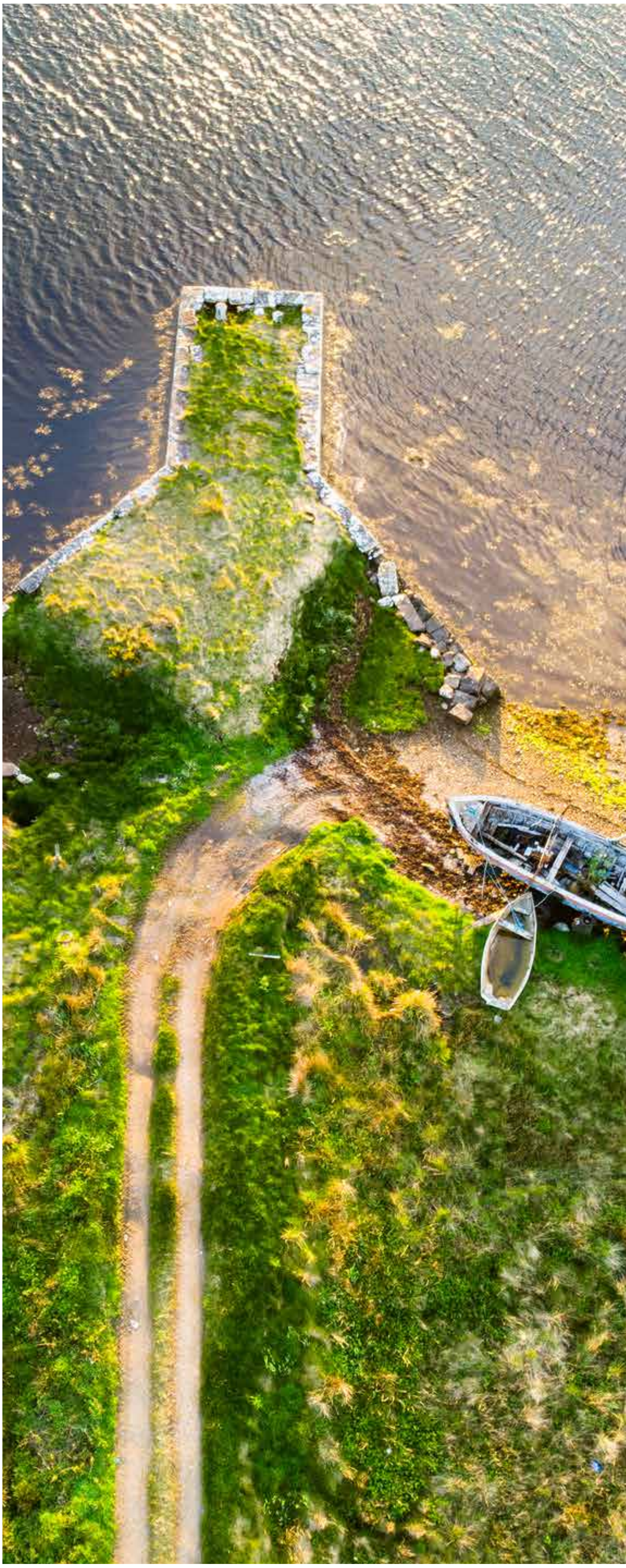


Table 35: Overview of TSO-DSO pillar

TSO-DSO	
Purpose	
Establish the TSO-DSO operating model and ways of working together to fully utilise new and existing capabilities connected to the distribution network; ensure that the needs of the distribution and transmission systems, and ultimately the needs of consumers, are met.	
Work streams	
TSO-DSO Operating Model	Establish the TSO-DSO operating model, defining the vision, roles and responsibilities, and ways of interaction for the TSOs and DSOs.
TSO-DSO Interfaces	Develop interfaces between the TSOs and DSOs that enable the sharing of data and coordination in decision making.
System Services	Facilitate the provision of system services from distribution-connected providers by working with the DSOs.
Flexible Network Coordination	Managing changes on the distribution network and how those changes impact the operation of the transmission network (and vice versa).
Outcome	
Where appropriate, the TSOs and DSOs have complementary work streams and approaches that enable the necessary changes to be made to how the transmission and distribution systems are operated in order to facilitate the achievement of the 2030 renewable policy objectives.	

4.6.8. Operational pathways to 2030 delivery approach

To deliver the Operational Pathways to 2030 programme and enable a smooth transformation of the power system, we have established a programme delivery approach that couples an implementation plan with an over-arching four-phase strategy.

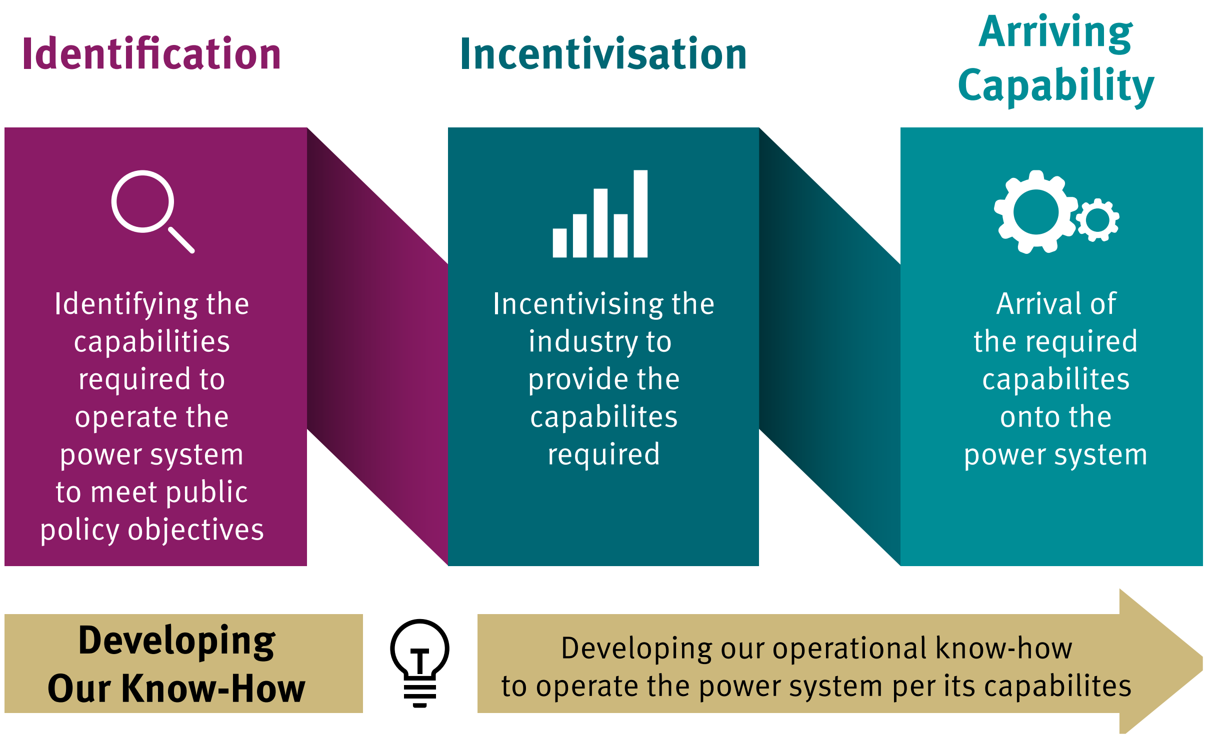


Figure 50: Programme delivery approach

Phase 1 – Identification:

The objective of the Identification phase is to identify capabilities required by the programme that will enable EirGrid and SONI to operate the power system at the levels of RES penetration required to meet the public policy objectives.

Under the Operational Policies and Tools pillar, the starting point for the delivery of the programme is the conducting of the studies and analysis required to identify the technical challenges on the system and the potential solutions. The output of these studies and analysis will lead, where appropriate, to the modification of Grid Code standards as well as to the augmentation of the current system services arrangements through the Standards and Services pillar. We will identify the system services that are required to operate the system both in the short-term and further into the future.

The other focus areas in this phase include identifying the needs of the Control Centre from a tools, systems and process perspective, determining the operational policies that need to be revised as new systems and tools come on-board, and identifying how training should be provided as we enter this period of considerable change. Ongoing operational studies and analysis will also be conducted, to ensure that we can operate the power system in a safe and secure manner while increasing the levels of RES on the system.

In the TSO-DSO pillar, the focus in this phase is to establish the TSO-DSO Operating Model. This will define the vision, roles and responsibilities, and ways of interaction for the TSOs and DSOs. Work on developing interfaces between the TSO and DSOs to enable the sharing of data and coordination in decision making will also get underway.

Phase 2 – Incentivisation:

The objective of the Incentivisation phase is to establish commercial frameworks that incentivise the industry to develop the capabilities required to address the technical scarcities and operational needs identified in the Identification phase (Phase 1).

In the Standards and Services pillar, the focus in this phase is on the design and launch of a new commercial framework for system services. This new framework is required by 1 May 2023 to replace the existing arrangements which will expire at this time.

Prior to the launch of the new system services arrangements, the technical specification of the system services products required to deliver on the objectives will be published. These specifications along with the commercial frameworks will allow the capabilities we require to be developed. The arrival of these capabilities (Phase 3) and how we develop our expertise to utilise these capabilities is detailed below.

Phase 3 – Arriving capability:

The objective of the Arriving Capability phase is the integration of new capabilities into our operation of the power system.

In the Standards and Services pillar, the focus in this phase will be on the integration of system services and network flexibility services.

In the Operational Policies and Tools pillar, the focus in this phase will be on the integration and adoption of the new operational policies, enabling our people to use the new services, systems and tools that are available to them. We will develop knowledge and gain experience of new tools and systems which are delivered as part of the Control Centre of the Future work.

In the TSO-DSO pillar, the focus in this phase will be on facilitating the provision of system services from distribution-connected providers by working with the DSOs. It will also focus on using the information available via the TSO-DSO interfaces and the open lines of communication to aid decision-making when operating the grid.

Phase 4 – Developing our know-how:

Throughout the entire programme, there will be a focus on continued learning and developing our know-how. It is vital that we continuously develop our operational capabilities in order to enable our people to utilise the new capabilities when they arrive.

The focus throughout will be on revising existing operational policies and creating new ones if required to ensure our people are able to utilise the new capabilities that arrive in response to the incentives under the system services arrangements. Training will also be provided to our people on these new policies and on how to use the systems and tools that are available to them.

The phased programme delivery approach is highlighted in Figure 51.

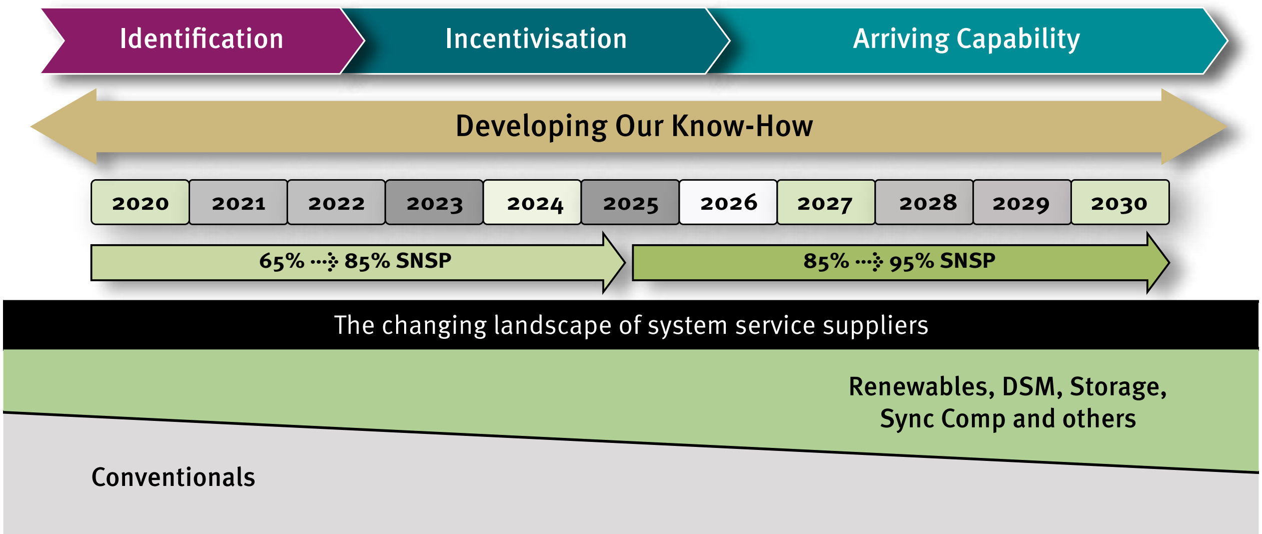


Figure 51: Evolution of SNSP and the changing landscape of system services providers

Present throughout this phased delivery approach is an engagement model that facilitates continuous engagement with our stakeholders across all pillars.

4.6.9. Key milestones of the operational pathways to 2030 programme

A detailed programme plan with key deliverables identified for each of the workstreams under the four programme pillars will be developed over the coming months to deliver the aims of the Operational Pathways to 2030 Programme. This plan will take account of the feedback received on the various proposed workstreams as part of this consultation.

However, while the detailed workstream plans will need to be finalised, it is clear at this point that the following are key milestones to meeting the challenges of operating the electricity system in a secure manner while achieving our 2030 RES-E ambitions:

- **2021:** 75% SNSP
- **2022:** Grid Code modifications approved
- **2023:** Go-Live of new DS3 System Services Arrangements
- **2025:** 85% SNSP
- **2030:** 95% SNSP

4.6.10. Programme governance

A robust programme governance framework that is in place throughout all phases of the programme is required to ensure there is clarity in relation to roles, responsibilities and accountabilities within the programme.

The Operational Pathways to 2030 Programme governance framework needs to:

- Provide for efficient governance arrangements which support the achievement of programme timelines, and which enable each party with responsibilities to the programme to be fully informed of the status of the programme and when decisions or actions are required;
- Respect the roles of the Commission for the Regulation of Utilities (CRU), the Utility Regulator (UR) and the Single Electricity Market (SEM) Committee;
- Provide clarity on the roles of EirGrid, SONI, ESB Networks (DSO in Ireland) and NIE Networks (DNO in Northern Ireland).

During the consultation over the next few months, we will work with all relevant parties to put in place an appropriately robust governance framework.

4.6.11. Stakeholder engagement

The Operational Pathways to 2030 Programme is significant to the electricity industry of Ireland and Northern Ireland, and EirGrid and SONI will require continuous engagement and collaboration with stakeholders throughout the programme lifetime to ensure alignment with the changing needs of the electricity system. The continuous stakeholder engagement model is illustrated in Figure 52.

To ensure the successful delivery of the Operational Pathways to 2030 programme, EirGrid and SONI will work closely with key stakeholders including policy-makers, regulators, industry, and academia. The objective is to ensure that the 2030 renewable policy targets are delivered in an economic manner while maintaining the security of supply standards of the all-island power system.

The delivery of the key parts of this programme will only be achieved with the full engagement and support of stakeholders across the electricity sector. As part of the DS3 programme, a range of stakeholder activities were undertaken including the use of, and engagement through:

- DS3 Advisory Council[83], comprised of industry experts;
- Industry workshops;
- DS3 Programme and System Services industry forums and updates;
- Multiple industry consultations.

The insights and learnings from the DS3 Programme will be used to inform the approach taken to stakeholder engagement on the Operational Pathways to 2030 Programme.

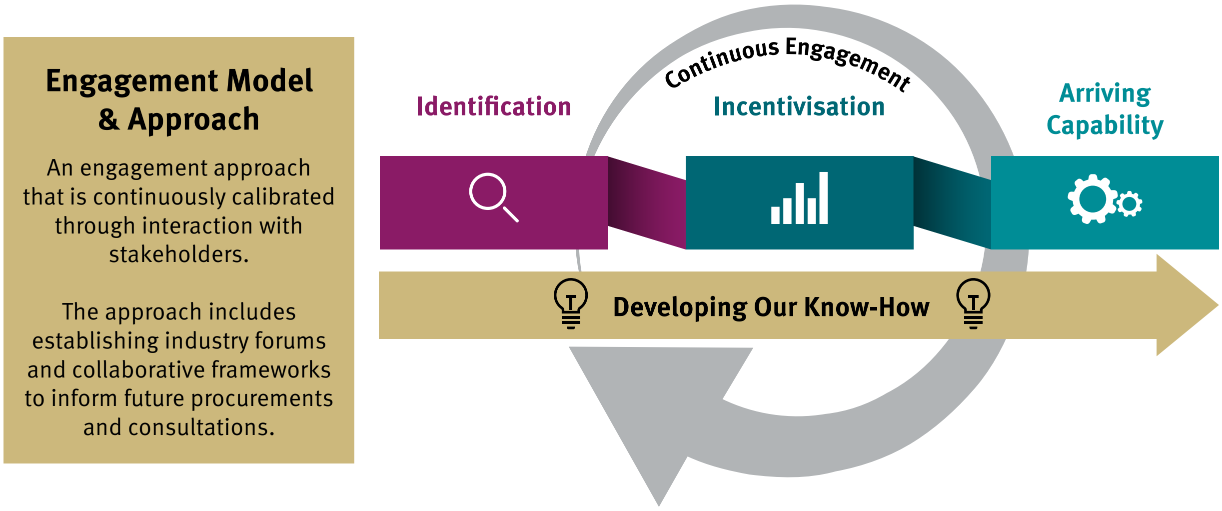


Figure 52: Continuous stakeholder engagement model

83 The DS3 Advisory Council was established in 2011 to provide a forum to discuss issues associated with achieving 40% RES-E by 2020. It consists of experts from across the power industry. This includes representatives from academia and industry across Northern Ireland, Ireland and Europe. Meetings are held approximately every four months.

5. Electricity Markets

5. Electricity Markets

5.1. Findings and recommendations

Through our detailed analysis and review of existing market mechanisms we outline our findings and recommendations below;

5.1.1. Material consideration

We define three key areas that must be considered in order to ensure the continued development of energy policy and regulation, whilst preserving an overall robust system design and transition to overall market maturity:

- **Ireland and Northern Ireland challenges:**
  Public policy objectives must jointly allow optimal operational SNSP and RES-E targets to be met across both jurisdictions of the all-island power system.
- **Evolving EU and UK energy policy and regulation:**
  Aligning UK and EU policy, network codes, cross-border arrangements, and the terms of the Clean Energy Package must ensure markets adhere to regulatory requirements.
- **Systems Design Build and Market Maturity:**
  Ensuring that systems design and build is appropriate for the transition that is required both operationally and from a markets perspective will be critical to ensure that markets can evolve to facilitate the 2030 requirements. It will be important to include stakeholder engagement during design phases in a manner that helps deliver timely system changes. We will evaluate the most appropriate options for engaging with stakeholders to help achieve this and ensure alignment across existing market focused stakeholder fora.

5.1.2. Pragmatic market design and consideration

We find that three principles should guide development of the various market components as follows:

- **Alignment:**
  Enabling alignment between Energy, Capacity, System Services, support schemes and network tariffs and also more closely to operational requirements.
- **Commitment:**
  Instilling confidence in market participants that the TSOs will continue to provide the necessary operational and investment incentives.
- **Clarity:**
  Using the tenets of "market discipline" (i.e., the rules and incentives for desired market outcomes) and "usability" (i.e., balancing of risk between investors and the consumer) to effectively identify and signal risks to all market participants.

5.1.3. Energy market

Renewable energy, such as wind and solar, is both unpredictable – forecasted generation may not come online as predicted, and variable – the amount of supply available for each dispatch period is uncertain. We propose an alignment of the ex-ante market with operational practice as well as facilitating full RES participation in the SEM as required by EU legislation. This will require changes to TSO and wider market systems and operational systems as well as ensuring RES units can be dispatched to their market position where required.

We propose a significant review of the existing Market Roadmap to enable focus on the emerging issues above.

In the longer term we will fully engage with regulators and industry to review the future design of the energy market. This review should materially consider the “self” and “central” dispatch models, as well as full network code implementation in line with recoupling with Europe for when interconnection to another Member state is well on the well to delivery.

It is likely that new or much enhanced market systems and data management systems will be required to facilitate the above changes and the transition to a 100% SNSP system. We will ensure that this is captured in future market design.

We will have to engage heavily in the development of the Multi Region Loose Volume coupling arrangements that are required as part of the UK-EU Trade and Cooperation Agreement, and aim to establish suitable Day Ahead trading arrangements with GB that do not hinder future pan-EU trading once we are reconnected to Europe.

5.1.4. Capacity market

We propose aligning the Capacity Market to a high RES world by altering the modelling of the capabilities in the SEM in the Generating Capacity Statement and Auction. These modelling changes will require moving from the existing backward casting approach (how have they performed and projecting that forward) to a forward casting (how does the system need them to perform) approach. This approach will need to be tailored to ensure different types of plant are modelled appropriately (conventional, demand response, hybrid).

We propose clarifying that the delivery of reliability needs to be related to both availability and the ability to meet dispatch instructions when issued. For new investment improved market discipline will require increased information (annual commitment) to delivery of the adequacy especially if an improved capability is modelled in the auction or the unit is receiving a ten-year contract.

Alignment of the CM with high RES will need to consider the appropriate treatment of the NET CONE calculation and in particular the concept of Best New Entrant plant or equivalent.

5.1.5. System services

We will need to redesign System Services to meet the technical challenges identified in our operational analysis work. This redesign will be based on daily auctions for suitable services. These daily auctions will be developed to deliver predetermined system need volumes as the portfolio evolves over the decade.

The core design change will be to move the procurement process from price to volume regulation. These volumes will evolve for the various services as the portfolio evolves. Consideration for what products and services are suitable for these auctions is important. For some of the services there is a need for a locational signal which was not included in the original design of DS3 System Services.

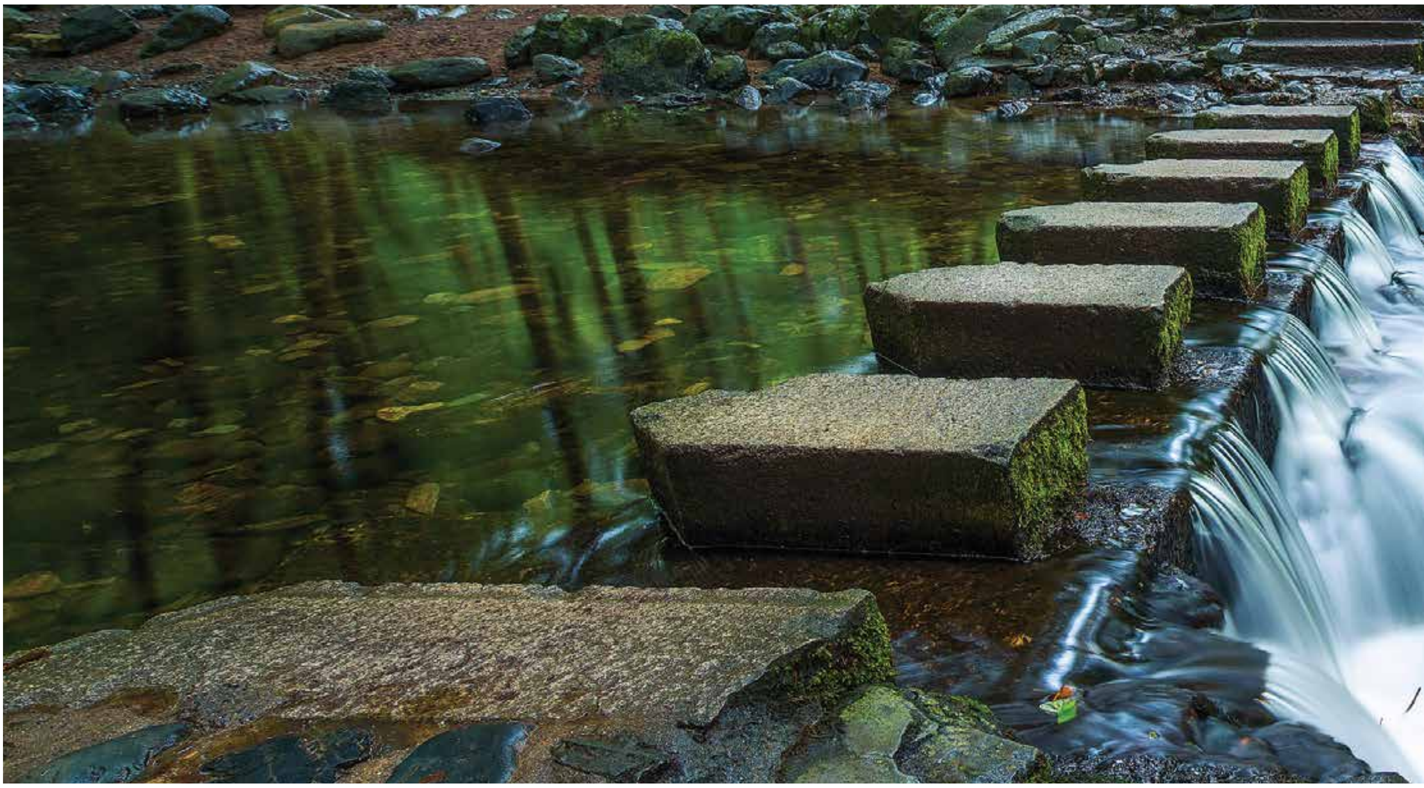
The service range will likely need to include all the existing services as well as congestion , frequency regulation products as well as other possible services that emerge as important during technical analysis

The design and high-level design work needs to be completed and approved by the Regulatory Authorities by the end of 2021 to ensure that required service investment delivery is managed successfully to align with increasing RES due to come on stream by 2024

New product or provider type testing will be important- we will explore with the regulators how innovation is best supported to ensure timely deployment of new solutions.

5.1.6. Renewable supports

Support schemes in both jurisdictions need to be in place to match the scale and ambition of government policy. Without these in place in a timely fashion it is difficult to see how the necessary investment in wind and solar can be made.



At present there is good coordination of support schemes with the energy market. However, as the Capacity and System Services Markets are a material part of the markets architecture to 2030 and beyond it seems appropriate that all supported technology is expected to receive some revenues from the Capacity and System Services arrangements, and therefore this will need examination in relation to RES support revenue. The exact modalities of this will need consultation with departments, regulators and industry.

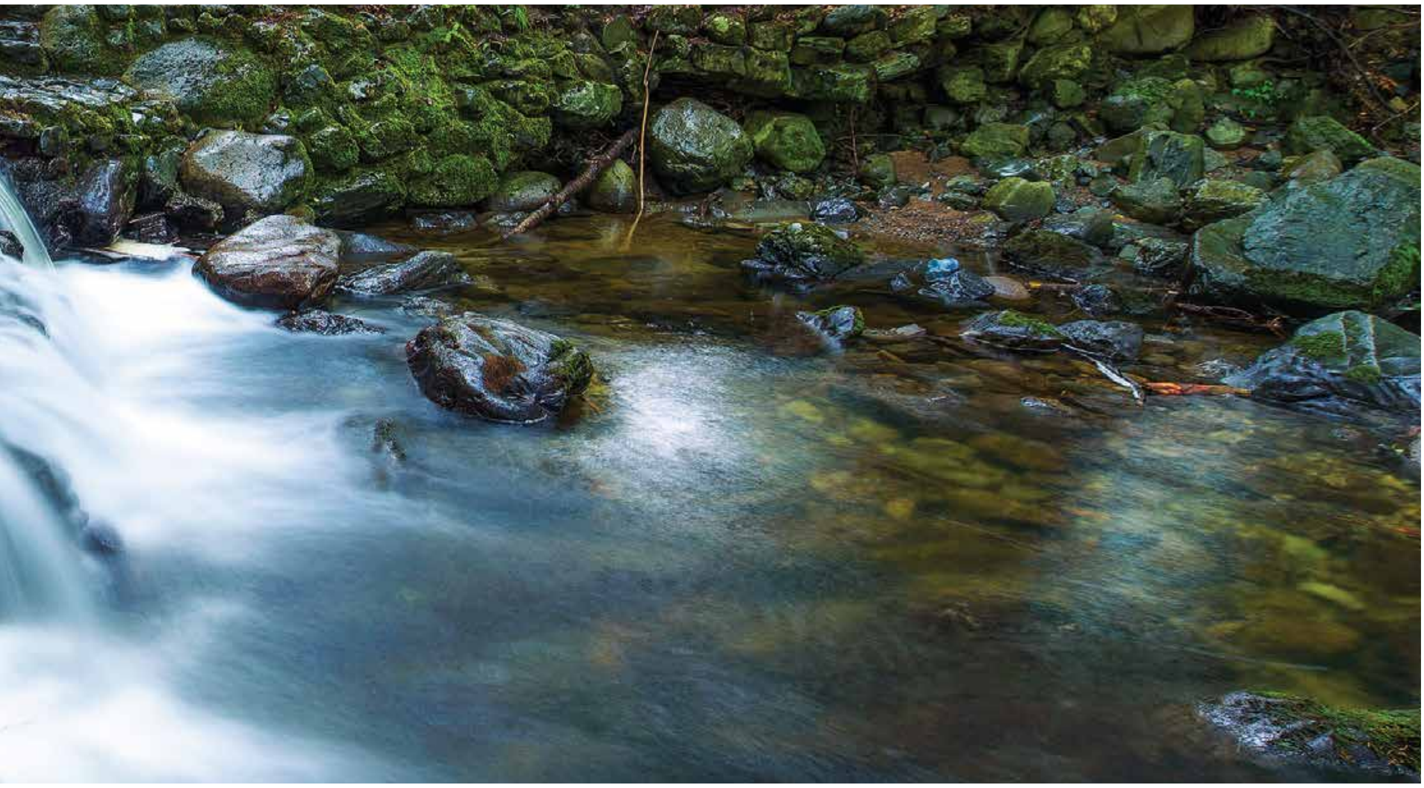
The payment and volume of "oversupply" needs appropriate consideration. In the first instance the expected "oversupply" needs to be clearly identified. Secondly once identified a financial mechanism could be developed to ensure the correct beneficiary pays and in the right timeframe. This may be a significant issue for the affordability of the transition in the next decade.

5.1.7. Network tariffs

We will need to complete a review and implement a new tariff structure, as identified by both regulatory authorities, focused on the design and purpose of the tariffs. In particular we will look at the possibility of sending stronger locational signals for all users but especially large generators or demand, consistent with the network congestion issues identified.

We will need to explore the possibilities of incentivising the nature of user participation including active residential demand side and storage. This will need to be balanced against the impact on forecasted network operator operating revenues.

While these are the main recommendations for each of the markets, through this review we have identified some critical enablers to achieving these outcomes and helping the markets to work more closely together. These enablers are essential as necessary building blocks for effective markets and operations given the scale of the financial and engineering challenges, which are covered in more detail in Chapters 3 and 4.



5.2. Scope and objectives

5.2.1. Process

This Markets Technical report provides the context, consideration and analysis of the existing Energy, Capacity, System Service markets and associated market drivers of Renewable Supports and Network Tariff markets in this light. In particular we explore the original design and intent of each of the markets, review feedback from the industry on these, review performance against the original intent and, most importantly, explore the functioning in a high RES-E world when many periods of the year the energy markets will be expected to be zero or negatively priced. From this work a set of pragmatic and, in our view, fully realisable recommendations are provided to how best this can be achieved.

During the development of the concepts and proposals in this section we conducted in depth discussions with a number of industry stakeholders to gain their views on current and future market design requirements to help inform our understanding of investor concerns and risks.

Our review of international studies into electricity market design has helped frame our market design considerations in line with best practice globally.

5.3. Critical success factors & enablers

5.3.1. Critical success factors

EirGrid and SONI consider that well-functioning markets are going to be critical to achieving the 2030 target and doing so at reasonable cost to the consumer. In principal, the financial mechanisms which bring forward the generation and demand reduction resources that will be necessary to meet the 2030 target do not directly matter. In practice, the way that such resources are primarily made available today is through a series of market mechanisms – the energy and capacity markets and competitive auctions for the provision of various system services.

In general, these market mechanisms are considered to be more desirable than other alternatives, such as centrally planned solutions, as market mechanisms can provide greater diversity, facilitate innovation and allow industry and market dynamics to select the most cost-efficient outcome. The requirement for markets is also written into energy legislation active in Ireland, Northern Ireland, UK, and Europe, with certain market structures and market rules mandated, e.g. wholesale energy trading arrangements and balancing services markets.

However, where market design does not align with operational requirements this can lead to market outcomes not matching actual requirements and increased TSO intervention for security of supply reasons leading to increased cost to the consumer. EirGrid and SONI's views are that the primary mechanisms by which the technical and operational challenges of the transition to the 2030 targets (and beyond) should be met is through the use of existing market mechanisms (energy, capacity and system services and supporting areas such as tariffs),acknowledging that there will need to be significant modifications to the markets. We also consider that we need to ensure key enablers are reviewed and developed to ensure potential barriers to delivery of the market and operational changes required are removed.

5.3.2. Key enablers

We have identified critical enablers that we consider are key to enabling cohesive market design changes and ensure alignment with operational requirements.

5.3.2.1. Flexible network approach leading to portfolio arrangements

Achieving the 2030 target will see a shift towards high levels of variable RES generation together with an increase in overall energy consumption driven byincreased electricification of energy needs including; electric vehicle charging, electric space heating and, in Ireland, datacentres. Our analysis shows that these developments are going to result in major changes in the usage of the power system, leading to both an increase in the overall burden placed on the transmission and distribution networks and a diversification in the patterns of usage.

New Grid Code and, where appropriate and established collaboratively with the DSOs, Distribution Code rule sets will be required for 2030. This will need to provide clarity on the essential requirements that all new technology will need to comply with. New technologies will include storage, wind, solar, HVDC and synchronous condensers. Other technologies may emerge, such as various forms of synthetic inertia and hybrid connections with a mix capability from storage, demand, wind and other generation. Where there are existing standards and requirements, it will be necessary to ensure that these do not implicitly and inadvertently favour existing technologies, and instead define the needs of the system, such that the scope for fulfilling those needs is as wide as possible.

The current regime for connecting and allowing access to use the system was developed in the context of a power system with small numbers or large, conventional, transmission-connected generators with passive demand served on distribution networks with essentially radial flows. This will have ramifications for connection policies and network charging, as well as requiring a revolution in the way the system is planned, including a redefinition of traditional planning and security standards. This ultimately challenges the existing transmission planning standard approach (e.g. N-1-G) and will require new operational tools and practices. However, it also fundamentally changes the nature of connection agreements (at least for new connectees). The current assumptions are that a User has, in essence a property right to the network capacity allocated, and can use up to that capacity allowance. However, this model will be challenged when the grid is unable to support all the rights already allocated. It may be necessary to review the principles underpinning the nature of MIC, MEC and firm access and potentially consider a redesign to ensure the power system functions efficiently in future.

In addition, the much greater diversity of users and network usage will mean also that managing the power system will no longer rely on instructing actions by specific, identifiable users but will more and more rely on the co-ordination and collective action of portfolios (or grouping) of distributed users. The nature of System Operation will thus change, with less emphasis being placed on 'command and control' of large users, and more emphasis on creating conditions, including provision of information and incentives, to which a diverse range of users can respond. The role of aggregators will become increasingly important in facilitating these changes. Actions by smaller numbers of users, or individual users, will also be required to solve local network issues, as the demands on these networks increase. In essence the ability to directly dispatch may not be feasible to apply to a cohort of aggregated demand side/hybrid plant on the distribution network. In general, the system may need to move from a concept of "command and control" to "incentivise and influence".

These "portfolio arrangements" (connection approach that facilitates hybrid connections (multiple technology types behind one connection point) combined with an "incentivise and influence" control philosophy) will require the mobilisation of a wide range of technologies, including smart grids, big data and the internet of things. Many of these developments are going to be outside the direct control of the TSOs and DSOs but will require a more active consideration by system operators of the ability of the network to manage flow and the real time behaviour of all users (including the possible use of congestion products). As important though will be the connection agreement and the need to share connections as well as effectively allowing people to allocate and use the network as they see fit from instance to instance in a coordinated manner that meets the security challenges that not building to N-1-G brings.

However, Regulators, TSOs and DSOs will need to explore ways to identify and monetise the potential of these technologies, if the considerable benefits of mobilising the collective actions of small users are going to be realised. Validation of service capability and the ability to track service delivery will be key in this regard.

5.3.2.2. Demand side

The 2030 system will see increasing opportunities for providing system services and managing system requirements using demand side measures. Thus far, the inroad the demand side has made into the market has, to a large extent, been achieved through behind-the-meter generation, with a relatively modest amount of flexible demand (cold stores etc.). However, particularly with substantial amounts of electrical vehicle – including Vehicle-to-Grid – and electric space heating, as well as the increase in water-heating load this induces, there will be more and more opportunities for residential DSM to provide flexibility by matching demand to generation rather than the traditional matching of generation to demand. In addition, residential DSM side will also be able to provide various system services, particularly reserve and frequency control services, as well as providing capacity products and hence contributing to system adequacy.

As with all portfolios of small users, mobilising this potential will depend on a wide range of enabling technologies. It will also involve a wide variety of intermediaries who can co-ordinate the actions of users and deliver useful services, at large and small scale, for managing the system at system-wide and local levels.

An advantage of demand-side resources is that, particularly with the diversity of the demand-side, resources are likely to be always available from one segment of the portfolio or another. Unlike generation, where system services provision may not align with the energy market, such that generators may need to be constrained off so that others can be constrained on to provide system services, demand side resources are generally always there.

Patterns of usage of certain demand types, e.g. EV, may vary, but by exploiting diversity the demand base will always be able to make a significant proportion to the needs of the system. Unlike new generation resources, obtaining services from the demand side will not be always be contingent on there being sufficient property right of a connection agreement that gives permanent access to the infrastructure.

Moreover, the ability of the demand side to manage demand and provide services will ultimately provide end customers with revenue-earning opportunities. Benefits to consumers will be realised in at least two ways. First, services provided by the demand side may be cheaper than the same services provided by non-demand- based service providers, lowering the overall cost of the managing the system, and thereby lowering the costs borne by consumers. Secondly, demand-side provision of services will provide revenue opportunities to customers for providing those services. This is likely to have an even greater effect on lowering the net cost to consumers, but care must be taken to ensure an equitable transition is achievable. Moreover, with skilful deployment of technology, the loss of utility to consumers as a result of providing services to the system will be negligible whilst releasing the maximum capability.

This mobilisation of the demand side will be very much consistent with the aims of EU legislation in empowering consumers. For the SEM, it will represent a ‘no regrets’ option for managing the system, in that the risks often associated with major investment in transmission and distribution system infrastructure, i.e. that they can be stranded if patterns of usage change, are much reduced.

However, to facilitate such participation will require the development and delivery of new communication and market interaction systems for new types of participants. We anticipate that new business models and market players are likely to enter the energy industry, who are not coming from the legacy utility world. There will be a requirement to evolve and develop market systems and interfaces to facilitate a changing market dynamic. This will need coordinated development between EirGrid, SONI, NIE Networks and ESB Networks to ensure that barriers to entry for new players are minimised.

5.3.2.3. Enhanced market systems and communication platforms

To enable new participants and facilitate a much greater level of dynamic activity in the market place over the coming years it will be critical that we as TSOs can develop and deliver enhanced market systems and communication platforms, in conjunction with the DSOs, to ensure barriers to entry are removed and transparency is facilitated.

The timelines for market system development can be considerable as evidenced during the I-SEM programme to enable the introduction of cross border coupling and balancing market introduction. With this in mind, and with the likely rapid evolution of new participant models and the need to integrate new market arrangements with GB, and future pan-EU balancing platform integration the scale of change required to our existing market platforms will be significant.

We have recently integrated a data focus into our everyday and future looking operations, but we will need to work closely with DSOs and stakeholders to ensure that market system development is fit for purpose out to 2030.

From a review of the enablers it is recommended that EirGrid SONI develop specific roadmaps:

- **A Demand Side Roadmap to remove/reduce barriers to participation in energy, capacity and system services markets. For Capacity Market these changes need to be made within the existing state aid approval and should be fully implemented latest by 2023. For System Services the focus needs to move to the residential consumer. In any case the proposition to the end user has to move from a "energy" only consideration to the "utility" of the consumer. There is significant work to be done to realise this.**
    - **We will develop a Demand Side Strategy to break down barriers for industrial/commercial to participate in all markets**
    - **We will seek to evolve this to residential demand side and help enable the requirements of EU regulations on consumer participation.**
    - **The DSOs are essential actors in enabling the participation of demand side and we commit to working with the DSOs and the industry to break down the barriers to allowing Demand Side management to be active and effective participants in all markets.**
- **Flexible Network/Portfolio Roadmap - A full review of the property /network capacity rights associated with current connection process in light of the likelihood of moving more generally to a "flexible network" paradigm. This review needs to address the principles of aggregate responsibility, rather than distinct obligations; the use of incentives and not commands; the need for operational security measures when incentives fail to provide the correct real time behaviours and market power issues with allowing obligations to be shared across multiple sites.**
- **A Market Systems and Communication Platforms Roadmap to ensure that market systems and communication platforms are fit for purpose in a rapidly evolving system- both from a market facing and operational perspective. This will need close collaboration with DSOs and will need to facilitate input from industry participants.**

5.4. Energy market assessment

5.4.1. Background and performance against design

The all-island Single Electricity Market (SEM) has seen significant change over the past number of years, and this is set to continue, with the consequences of the exit of the UK from EU market arrangements and the need to continue to evolve markets to facilitate climate goals.

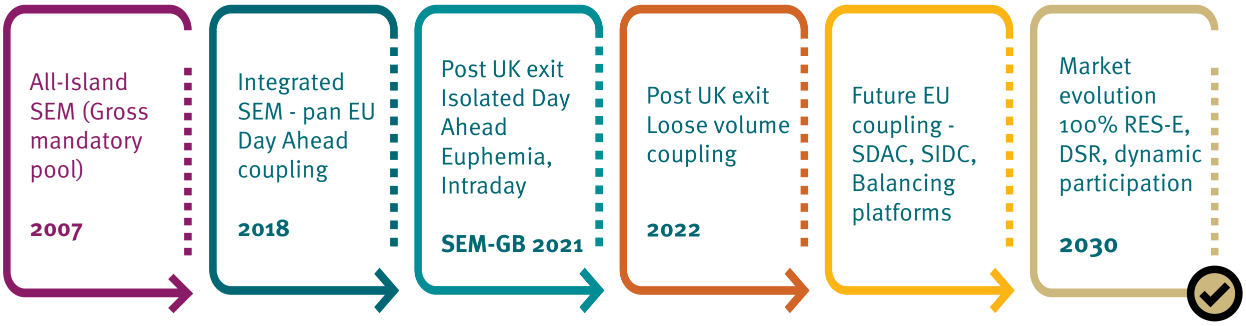


Figure 53: Timeline of SEM development

In October 2018 new trading arrangements were implemented based on the requirements of the EU Regulations on Forward Capacity Allocation (FCA) and Capacity Allocation and Congestion Management (CACM) which make up part of the EU Target Model, along with the regulation on Electricity Balancing (EB).

The CACM regulation specifically sets out the rules for the implementation and operation of the day-ahead coupled market and the intraday continuous trading market on a pan–EU basis. The day-ahead market uses a trading platform, named EUPHEMIA (the Pan European Hybrid Market Integration Algorithm), where multiple markets share their order books in one platform which clears volumes in all linked markets, and schedules inter-market flows based on local market prices.

Interim intraday markets were implemented in advance of the pan-EU SIDC (Single Intraday Coupling) market via the SEM-GB interim intraday regional auctions between the SEM and the GB market, BETTA, with an additional local intraday auction.

A further element of the new trading arrangements was to incentivise active participation by supplier companies in the ex-ante markets where they were expected to purchase their electricity requirements in the day-ahead market with adjustments in the intraday markets, implementing a solution where all participants in the market would be balance responsible.

The final component of the SEM arrangements is the balancing market and imbalance settlement. The balancing market is the responsibility of the Transmission System Operators where TSOs receive physical notifications (PNs) from generators and demand side units setting out their intended running schedule based on their cleared market positions from the ex-ante markets. All dispatchable units are required to submit a PN with technical and commercial offer data to the TSOs which is then used to determine the optimum running of the power system taking account of the requirements on the TSOs to balance the power system, maintain system frequency, maintain security of supply, maximise the output from priority dispatch generators and minimise the cost of deviation from the submitted PNs. The Electricity Balancing Guideline (EBGL) mandates participation in relevant pan-EU balancing platforms for balancing products such as replacement reserves (TERRE) and manual frequency restoration reserves (MARI). EirGrid and SONI, with the respective regulatory authorities, have been progressing EBGL implementation, albeit at a longer timescale than other EU TSOs due to an extended timeline for Ireland and Northern Ireland. Participation in balancing platforms (e.g TERRE and MARI) will only be possible once we are connected to another EU Member State.

The SEM operates according to central dispatch principles, meaning that no generator or demand side unit is permitted to change its physical output unless this has been reflected in an instruction from the TSOs. Given the conditions on the power system and whether the market was long or short, the TSOs may be required to take a number of dispatch actions to run a unit in a way which deviates from their PNs. As part of an ex-post process, these actions are flagged and tagged to identify non-energy actions taken for system reasons and energy actions to balance the market. Only energy actions are used in the determination of the imbalance price.

5.4.1.1. Performance against the initial design Issues

Looking at market data from before and after the switch over to the new arrangements provides evidence on how the new design delivered on some of its key objectives. Figure 54 shows power flows between the SEM and GB before the new arrangements were put in place.

To explain the graph, from the top of the image to the bottom relates to import and export flows between the SEM and GB. Meanwhile left to right of the graph relates to the price differential of the same from low to high, respectively. This means that economically, the SEM should be exporting to GB when SEM prices are lower than GB and should be importing from GB when the SEM prices are higher. This shows as power flows only appearing in the bottom left hand and top right-hand quadrants.

The graph shows a significant volume of imports to the SEM from GB while the SEM prices are lower than those in GB. This means that more expensive energy from GB is displacing cheaper generators in the SEM. These are clear examples of perverse power flows. While there are less instances of exports to GB while the SEM prices are higher than GB prices, these are still examples of perverse power flows which market coupling is intended to solve.

Figure 55 provides data on scheduled power flows on Moyle and EWIC in the year after the implementation of the new arrangements. While there are still examples of perverse power flows, the bulk of the power flows scheduled from the ex-ante markets are in the correct direction. Remaining perverse power flows are likely due to limits such as in ramping between periods, where the price differential direction may have changed between the periods, but the interconnector could not be scheduled to change direction while complying with ramping limits. This shows how the new trading arrangements have delivered more efficient power flows between SEM and GB.

Figure 54: Cross border scheduled power flows under old SEM arrangements

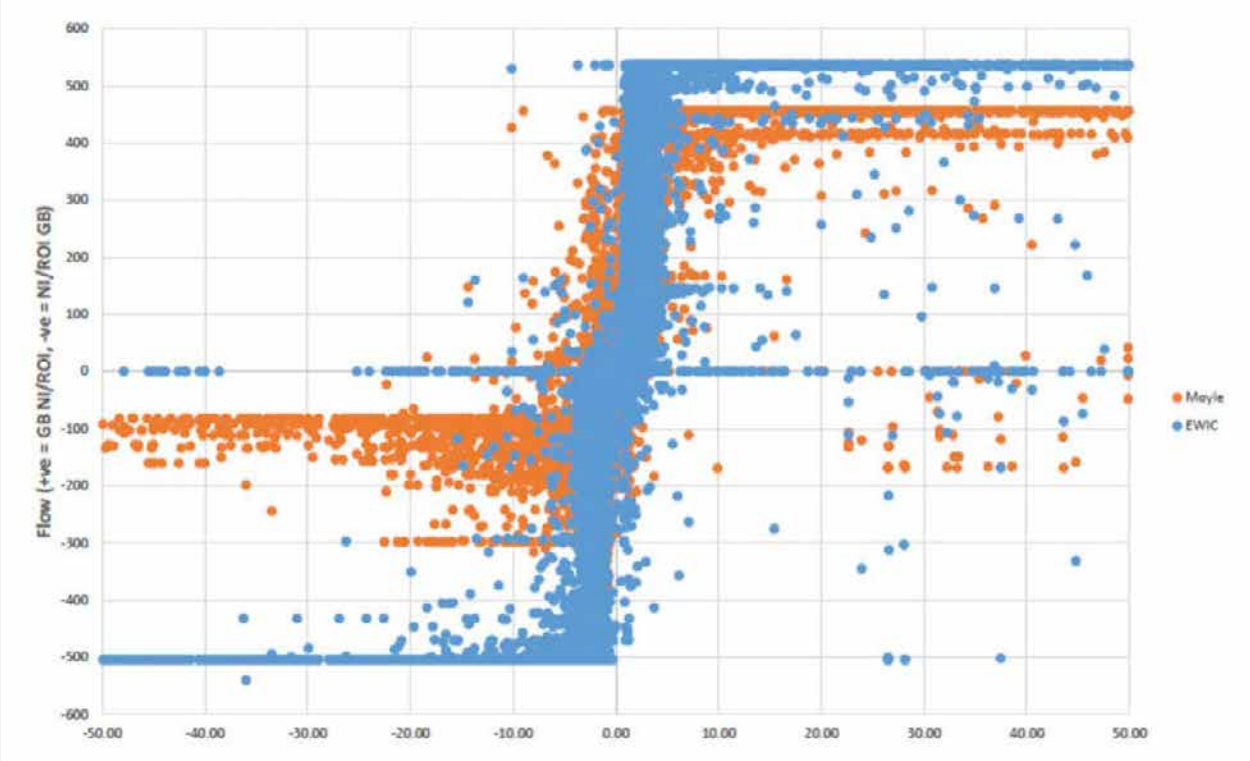


Figure 55: Cross border scheduled power flows post I-SEM

5.4.1.2. Challenges following the exit of the UK from the European Union

Following the publication of the Trade and Cooperation Agreement established between the EU and UK, and its implementation on 01 January 2021, Great Britain is no longer able to participate in European electricity markets. While the NI Protocol provides for the continuation of the SEM, the departure of GB from the pan-EU coupling arrangements has had direct implications for the efficiency of the SEM ex-ante arrangements, especially when considering cross border allocation of capacity. The day-ahead market for the SEM is now run in isolation using EUPHEMIA with no cross border capacity available. The intraday auctions which were designed as regional arrangements between the SEM and GB continue to allocate available cross border capacity. However, as a significant level of I-SEM contracts are indexed to the day-ahead price, this has resulted in the day-ahead market retaining most participation with most trades being cleared in the uncoupled auction in advance of the intraday auctions. There is no prospect in the short-term for the cross border exchange of energy and energy balancing standard products using EUPHEMIA, SIDC, TERRE, or MARI).

Additionally we now have to engage in the development of new loose volume coupling arrangements with GB in conjunction with other EU TSOs. This work is mandated in the UK-EU Trade and Cooperation Agreement and will now require attention and resource commitment from EirGrid and SONI. However we will also need to ensure that we prepare for a future date of integration with EU platforms and market coupling if the Celtic Interconnector is successfully deployed, reconnecting the SEM to EU markets and systems.

The immediate priority will be to ensure that the effects of Brexit are managed prudently and efficiently, and that arrangements are developed for the existing interconnections with Britain. We will aim to ensure that these new arrangements do not hinder the future evolution of new pan- EU trading arrangements once we are re-connected with Europe and ensure there are no inefficiencies embedded that favour one set of interconnectors (those to GB) over others (those to mainland EU).

Given these parameters, it will be important to gain stakeholder views and work with regulators on how we prioritise local market and operational developments, and afford flexibility, at least in the short to medium term, to allow the SEM to develop market and balancing arrangements that will recognise the particular challenges of operating the SEM in 2030 with unprecedented levels of non-synchronous generation on a small, HVDC connected system, and prepare for re-integration with pan-EU platforms at a later date.

5.4.1.3. Challenges with meeting high RES-E

Typically power markets are designed for large synchronously connected networks with neighbouring systems. In a European context many Member States meet their respective renewables and low carbon targets with significant proportions of hydro and nuclear generation. Both of these generating technologies have similar electrical characteristics to conventional generators and do not require radical changes to be made to system operation or a requirement for targeted adequacy and system services. Consequently, the EU market design has to date been focussed on an energy-only market, with comparatively little attention to non-energy services.

While it may be considered that renewable generators do not need to participate in the ex-ante markets at the moment, given the TSOs obligation to maximise generation from renewable sources, in current practice there is considerable trading by or on behalf of renewable generators.

This can result in significantly higher volumes of renewable energy clearing than can be feasibly utilised by the TSOs which serves to highlight the misalignment of energy only ex-ante markets with the operational challenges of managing very high levels of non-synchronous generation.

As the ex-ante market solves only on price it does not consider potential gaps in technical requirements e.g. inertia which then results in changes by the TSOs to the ex-ante dispatch schedule to ensure technical requirements are provided as part of the energy mix.

Figure 56 shows an example of this from 05 July 2020.

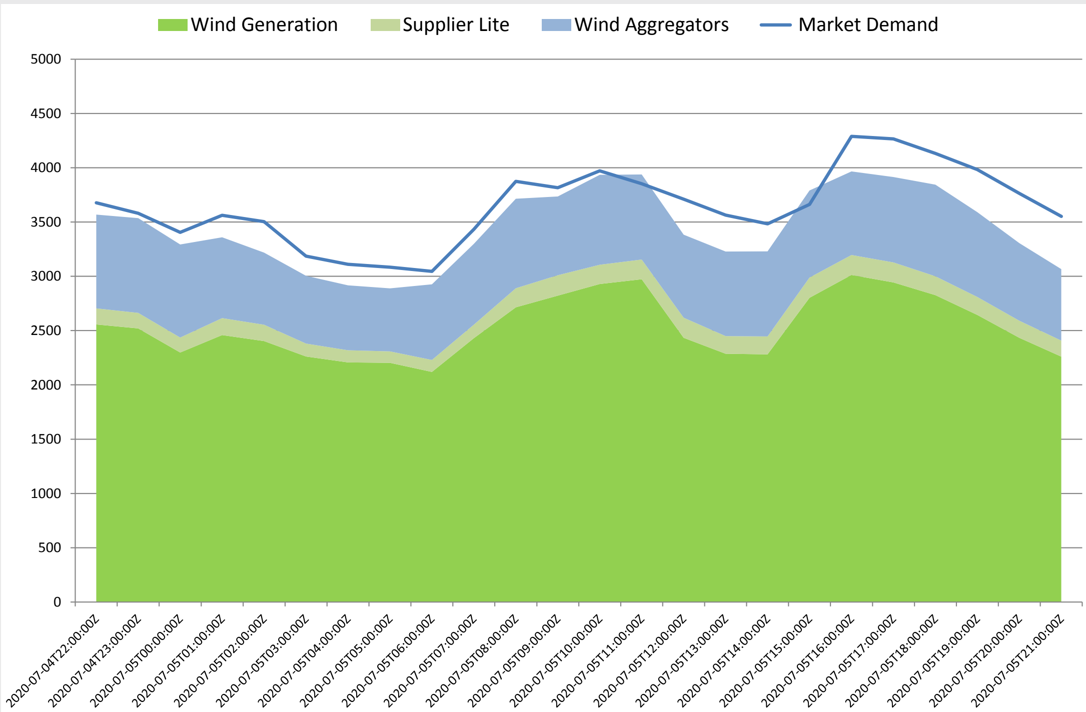


Figure 56: Market demand met by energy from renewable sources on 05 July 2020

In many hours across the trading day, almost all the system demand (including interconnector exports) was met in the ex-ante market by energy from renewable sources (either traded by wind generators directly or by wind aggregators on their behalf). With a position where the TSO must maximise generation from priority dispatch units and minimise deviation from PNs for other units, the starting point for the TSO dispatch for this date would look like Figure 57, i.e. almost all energy demand met by wind.

To meet system security requirements (e.g. inertia, voltage considerations) a significant repositioning of units was required which Figure 58 demonstrates, as evidenced by the large increase in conventional fuel plants in the final dispatch.

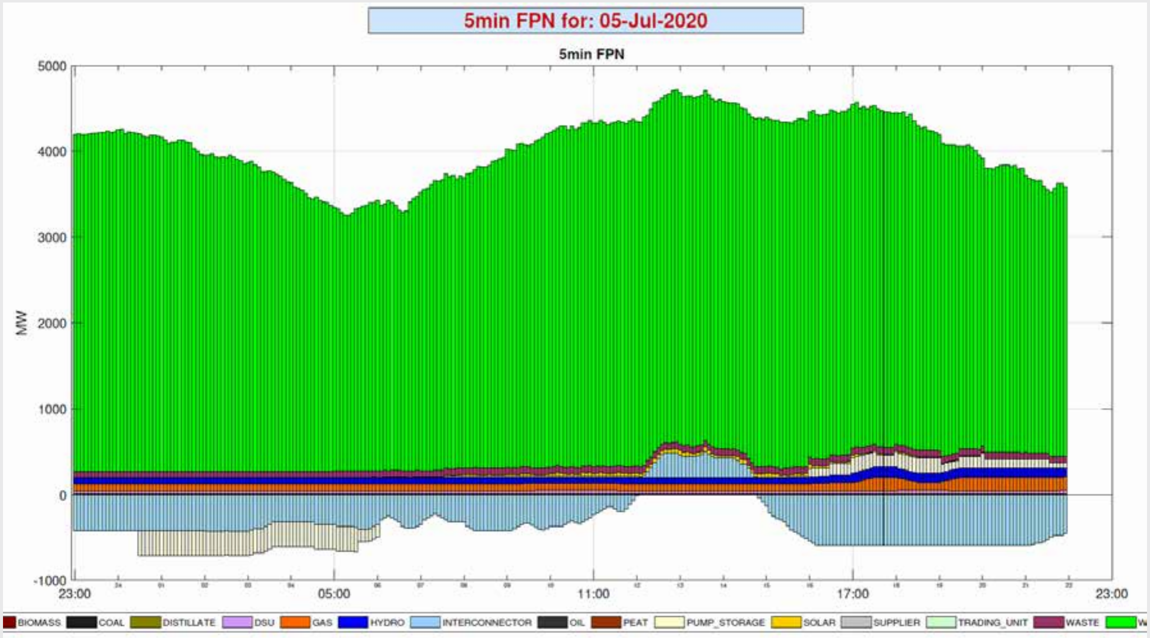


Figure 57: Starting point for TSO dispatch on 05 July 2020

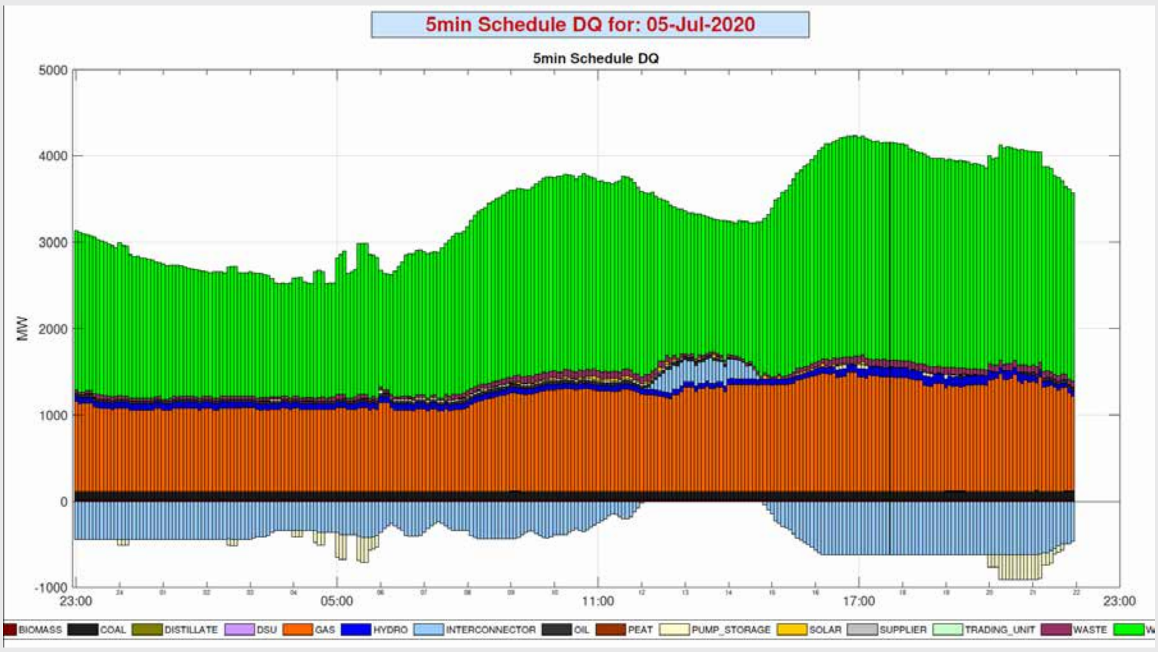


Figure 58: Re-dispatch of plant from starting position on 05 July 2020

This trading led to a significant number of negative prices in the ex-ante markets and the imbalance price, as well as significant payment to generators for re-dispatch away from their market position.

The energy market outcome of 05 July resulted in a deficient system from an operational constraints and system services perspective. The operational policy for system stability requires 8 units from a predetermined pool to be on load at all times, 3 in Northern Ireland and 5 in Ireland. Figure 59 shows how the energy market outcome resulted in none of these units getting a day-ahead position and subsequent Final Physical Notification (FPN) due to the volume of wind that cleared ex-ante. It is also clear how the minimum number of 8 units was dispatched and received a Dispatch Quantity (DQ) in order to meet this system stability requirement. This is a stark reminder of how an unconstrained Day Ahead market design is not aligned with operational policy, which ultimately results in significant cost to the consumer through additional imperfections costs. Unless addressed in future operational and market design instances such as these will become the norm.

As indicated previously we intend to be able to operate the system to 95% SNSP by 2030. With a greater alignment between operational capability and market availability we anticipate that not only will there be savings in non-market based redispatch compensation, but Dispatch Balancing Costs (DBC), renewable support costs and reductions in inefficiencies in system services.

The earlier the ex-ante markets can be aligned with the needs of the system, the sooner that these cost reductions can be realised. The recent RESS 1 auctions will see another 1200 MW of non-synchronous plant building out in the next few years, adding to the 5000 MW of mostly non-synchronous plant that has been added to the system under ROC and REFIT. We thus believe that it is important to ensure that where possible, opportunities to achieve greater alignment are identified and actioned as soon as possible.

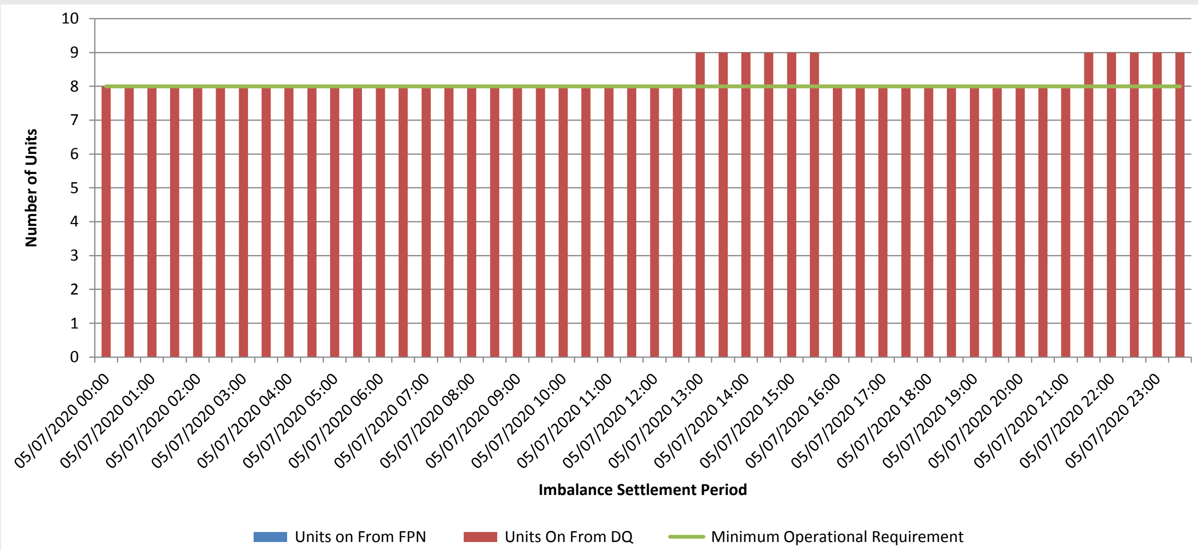


Figure 59: Number of units providing system stability from FPN and actual dispatch on 05 July 2020

5.5. Capacity market assessment

We have examined the current Capacity Market in terms of design and legislative background, in order to determine whether it has delivered against this design and outline our findings below. We also consider whether the current design is fit for purpose in a high RES world and what some of the emerging issues may be.

5.5.1. Background and design

EU Legislation permits Member States with identified resource adequacy concerns to develop and seek State Aid approval for adopting measures to address market failure or regulatory distortion which may lead to resource shortfall. There has been a capacity mechanism in place on the island since 2007 due to resource adequacy concerns. The introduction of the new market arrangements in 2018 brought a change in the approach to remunerating capacity in order to ensure generation adequacy requirements are met. This moved the approach away from the previous market-wide capacity payment mechanism which incentivised availability with more specific targeting towards periods with higher load and loss of load probability. The new design introduced a Reliability Option mechanism to introduce a competitive, auction-based capacity market which incentivises delivery during periods of system stress. The new CRM design (that received a 10-year State Aid Notification approval from the EU Commission in November 2017 , for the period of 2018-2028) included a comprehensive resource adequacy assessment carried out by EirGrid and SONI detailing significant concerns over future generation adequacy and security of supply in the SEM.

Under this mechanism, capacity providers compete at auction to sell pre-qualified capacity based on the required generation capacity for a future year. The requirements for a given year are modelled to determine what capacity is needed both system (all-island) wide (based on a Loss of Load Expectation (LOLE) of eight hours) and also in geographical regions where locational transmission or operational constraints mean that the supply into that region is restricted. The capacity auction process is comprised of annual auctions for varying numbers of years ahead of the delivery year for which the capacity is being procured. In order to participate in an auction, capacity providers must first meet qualification requirements.

A de-rating process (examining reliability and variability of the providing unit) is undertaken by the System Operator to determine the maximum available capacity that resources could deliver, under optimum conditions, accounting for real world limitations, with different de-rating factors set for different technology types. This ensures that total volume of procured capacity meets the adequacy requirement taking into account various factors that could lead to diminished resource availability in real time such as outages, technical limitations, variability of the capacity source, etc. The capacity requirement subtracts capacity that is procured outside of the market (non-participating) – this includes wind, solar and any units that have been granted 10-year contracts in previous auctions.

Capacity contracts typically have a duration of one year and are awarded up to a maximum of four years in advance. However, contracts lasting up to ten years are possible provided the adequacy provider meets a range of pre-qualification criteria set out by the relevant regulatory authority. Both new and existing providers compete in the auction, with new providers being required to post a performance security and meet completion milestones ahead of the delivery year. Where a new provider defaults on their delivery obligations they can be subject to termination of their capacity award and are liable for termination fees, which can be drawn from their performance security bond if not otherwise paid when invoiced. This provides an incentive for the provider to deliver and gives some assurance to the System Operator that the necessary capacity to deliver on adequacy requirements will be delivered in future years.

Capacity providers who are successful in one of the annual capacity auctions receive a regular payment. In return they have an obligation to deliver generation or demand reduction when the system is stressed. This obligation manifests in a requirement to make payments whenever the imbalance price exceeds a regulated strike price and the provider is determined not to have delivered on their capacity obligation (by not having traded the requisite quantities). These payments place an incentive on the contracted provider to deliver whenever such a price event occurs.

Capacity providers are also required to make such payments whenever they have delivered on their capacity obligation by having traded quantities representing energy generation or demand reduction, and the relevant reference price of those trades exceeds the strike price, effectively removing energy revenue in excess of the strike price. These payments, based on the difference between the relevant traded energy price or imbalance price and the strike price, are used to fund payments to suppliers based on their traded quantities or imbalances representing energy consumption at the relevant reference price if it exceeds the strike price. This serves to provide a hedge against prices for suppliers, in return for funding regular capacity payments to capacity providers, such that their exposure to elevated prices is limited by the strike price.

5.5.2. Performance of the capacity market to date

The capacity arrangements have helped to ensure that generation adequacy requirements are met sufficiently across the island. They have served to allow for existing resources to continue operating and also provided incentives for the delivery of relatively modest amounts of new capacity. In spite of this, a number of issues have arisen already or are anticipated in future. The revised arrangements moved from a predominantly price regulated approach, paying out a fixed amount of money to all capacity providers (a sum based on the capacity requirement to meet the generation security standard) to a predominantly volume regulated approach paying a fixed volume of capacity based on prices determined at competitive auctions (with price caps applied based on best new entrant costs). This has led to reduced costs in capacity with total annual payments over the last five years of the previous approach in the region of 520 to 575 million euro as compared to payments in the region of 330 to 360 million euros from 2018 to the current day.

In general, the entry of new capacity has been limited, with a large proportion of capacity revenues being awarded to existing assets. The type of new capacity that has been successful in the auctions to date is also worthy of examination as only very small amounts of new RES have been successful; however, new storage resources have been more successful recently.In relation to the regional procurement aspects, in the greater Dublin area margins remain tight and the rate of delivery of new capacity is potentially insufficient to deliver adequacy in the longer term. This is of particular concern in the context of potential retirements of existing assets in the future.

Issues have emerged in terms of the interaction with Grid Code requirements to give three years notice when retiring a generator. Where an exit signal is given such that a generator may decide to retire, it is critical that the interaction with the retirement process allows for an orderly exit, and in line with Grid Code requirements[84]. In order to achieve this, exit signals ideally need to be present far enough in advance of the point where they become active. Where such exit signals precipitate early exit decisions (i.e. before the three years notice period) for generators which – upon examination – are deemed to be required for system security, it may be necessary for the System Operator to enter into direct contracting arrangements for system security purposes.

84 EirGrid and SONI, Generation Plant Closures, 2017

Performance security requirements and delivery milestones, whilst providing an incentive for new capacity to deliver in a timely fashion, may also be an area that warrants improvement. Whilst there is a potential disincentive in terms of termination charges, the long stop date for delivery of new capacity with a ten year contract is eighteen months meaning that a new unit can be absent for the entire first year and a half that it is contracted to deliver capacity, which can put system adequacy at risk during winter months. A stronger incentive to deliver earlier is required as this has significant implications for generation adequacy. It may be possible to strengthen these delivery incentives and target them more precisely to encourage faster delivery, for example by applying a process whereby the size of performance security being posted must increase following a missed milestone until that milestone is met.

Stronger delivery incentives to ensure market discipline and effective delivery are needed to ensure that benefits from the capacity mechanism to consumers, who ultimately fund the capacity payments, are maximised both in terms of system security and energy costs. Similarly, delivery in real time should be incentivised, but charges should not be so punitive as to dis-incentivise new projects.

As it stands, there will be a shortfall in procured capacity for the 2024/25 delivery year in Ireland (sufficient capacity has been procured in Northern Ireland), primarily due to insufficient capacity qualification in Ireland at auction. This is further evidence that based on the current modelling and de-rating standards, the rate at which new capacity is being delivered to replace existing capacity and meet growing demand is not deemed adequate to ensure that the required system security standard can be delivered. There is a clear need to address this adequacy issue as a matter of urgency but without unduly negatively impacting on progress towards the 2030 Renewable Ambition. This will require a careful strategy to ensure sufficient generation is delivered and retained. Care must also be taken to ensure that the timing of entry and exit of generation and the characteristics of any new generation do not impinge on delivery of the 2030 vision.

While the capacity market works relatively well at providing a financial incentive to some classes of generation, it is perhaps not reflective of the changing generation mix on the island. The current process used to determine the parameters used in setting auction price caps - NET CoNE (Cost of New Entrant) is focused on thermal generation, indeed recent publications by the SEM Committee have highlighted that the current technology selected for NET CoNE does not actually meet the emission limits set by EU legislation. From the perspective of RES (wind and solar) these are substantially de-rated with important interactions between capacity market revenues and support revenues. The requirement for participation in the balancing arrangements also means that there is no direct participation in capacity auctions for non-market de-minimis generation, with the exception of participation via aggregation whereby supplier volumes results in diminished capacity charges for such suppliers or direct payment when registered as a "Supplier Lite". There is a strong argument that this is not appropriate for the envisioned 2030 power system where ever-larger proportions of intermittent RES and demand side resources will be required.

Evidence is emerging that the intended delivery incentive for periods of system stress, whereby capacity providers are exposed to uncovered difference charges when the imbalance price exceeds the strike price and providers do not deliver on their capacity obligations may not be wholly effective. This is because currently the strike price is very rarely exceeded, noting that a large proportion of Generators provide maximum prices just below the strike price. It is therefore appropriate to consider whether the strike price itself is being set at an appropriate level and whether alternative or additional incentives for delivery are needed. Alternatively, changes to the Administered Scarcity Pricing approach could be considered, noting that this mechanism has not been triggered since its inception with the revised SEM arrangements, although this could impact on the imbalance price itself and so may not be preferred.

There is further evidence that generation adequacy is not being delivered to a sufficient extent to meet the current LOLE standard of 8 hours. Recent increases in amber alert indicating system stress/reduced margins and real time availability declarations which are lower as a proportion of maximum availability than under the previous arrangements. The gaps between forecasted delivery through the capacity mechanism and actual delivery may be a function of the type of modelling conducted and the emerging evidence from operational experience; These tight margins are sometimes as a result of:

- **Low amounts of variable generation - Modelling is based on historic wind and demand and uses an average**
- **Unplanned outages/reduced availability of resources - Unplanned outages are modelled using historic data; however, the frequency of unplanned outages has increased recently. Scheduled outages are optimised by the model to occur at times of low system stress (summer) which is not always the case in reality**
- **Simultaneous interconnector exports Due to price differentials with Great Britain - Modelling is limited to a percentage of rated capacity at all times**
- **System constraints and modelling assumptions are simpler than on the ground constraints. Differences between the day-ahead market outcomes and physical dispatch requirements; this is not modelled given the complexities of modelling 4 years out, but experience is that unconstrained Day Ahead market outcomes leads to scheduling of interconnectors and inaccurate positioning of critical plant for system security requirements, which can lead to tight margins and a need to re-dispatch interconnectors if possible. Additionally, Day Ahead unconstrained markets and changing wind forecasts can lead to tight margins on occasion**
- **Loss factors and scheduling of interconnectors**

These instances of low margin could become more prevalent if increased dependence on variable generation and unplanned outages due to ageing traditional thermal resources, or requirements for greater outage periods to dealing with changing utilisation of assets are not sufficiently counteracted by enhancements in capacity procurement. These enhancements need to be delivered carefully or there is a risk that the capacity requirement – and therefore capacity costs – will increase in a suboptimal way in terms of efficient delivery of generation adequacy.

5.5.3. Clean energy package and state aid requirements

The Electricity Market Regulation 2019/943 lays out some clear parameters for Capacity mechanisms, that will have to be examined upon the commencement of any re-design. These include:

- Robust resource adequacy analysis in line with the European Resource adequacy assessment methodologies recently published,
- The application of appropriate disincentives to capacity providers that are not available in times of system stress,
- Be constructed so as to ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded, and
- Enable the participation of capacity providers from other Member States.

In addition, a Modification to the Capacity Market Code to transpose Clean Energy Package requirements regarding prohibition of capacity payments to providers which exceed prescriptive emissions limits was introduced in April 2020. This will aid in ensuring a capacity market that delivers efficient exit signals to emission-intensive fossil fuel fired thermal generation. It also means that the broader capacity market design needs to evolve to more effectively represent an evolving generation fleet.

The European Commission's state aid approval required changes in the treatment of Demand Side Units (DSUs) within the Capacity Market to ensure continued compliance. An interim approach has been implemented to ensure this compliance in the short term, but this is not an enduring treatment. The SEM Committee decision in this area sets out a high-level principle for an enduring approach which provides for more complete participation of DSUs in the energy markets in line with Clean Energy Package requirements. This will necessitate the development of processes to procure revenue class metering and a settlement quality measure of delivered demand reduction. This presents an opportunity to leverage this change to also make enhancements to performance monitoring of DSUs which could be used to also introduce more effective de-rating approaches and delivery incentives.

Additionally, the CEP requires that cross border participation in capacity markets is facilitated between Member States (e.g. a unit in Member State A could bid to deliver capacity in a neighbouring Member State B's capacity market and vice versa). This will most likely have to form part of our EU focused work over the coming years for when we are reconnecting to another Member State.

5.5.4. Challenges with high RES-E

The main aims of the new Capacity Market were to ensure continued generation adequacy, to introduce efficient competition, to move from a purely availability-based mechanism to one which incentivises delivery, and also to provide a hedge to suppliers against high prices. The design also had to ensure compliance with EU state aid provisions to ensure that it could be approved by the European Commission and the where possible was cognisant of the direction of travel of the (at the time) pending Clean Energy Package provisions. It also sought to ensure that adequate market power mitigations were in place.

Although the revised capacity mechanism has delivered beneficial enhancements in these areas, it was designed for the current power system and generation mix as opposed to that which is envisioned for 2030 and beyond. As a result while it is, broadly speaking, delivering adequacy and energy security with reasonable efficiency for today's needs, the issues that have emerged to date highlight that the aspects of the design need some further consideration.

In the longer term, with the transition to a decarbonised and decentralised power system in order to ensure that adequate capacity is available to meet a more dynamic energy demand profile we believe further consideration of technology specific aspects will need detailed examination and improvement.

Non-dispatchable RES and Demand Side is heavily de-rated currently. There is little participation from RES in the auctions due to participation in support mechanisms which would offset any capacity revenues in their support revenues. In addition, due to the variable nature of RES generation there is a higher risk of not delivering on their capacity obligation during a period of system stress and being exposed to uncovered difference charges. As a result, capacity awards are heavily weighted towards dispatchable thermal generation and competition between these resource types is extremely limited, given that many units apply for Unit specific price caps. The CEP has set out provisions for the cessation of priority dispatch of both new and existing generators.

RES will compete for redispatch via market-based mechanisms in the balancing market in the future, which may also result in more competitive trading behaviour in Ex-Ante markets. Along with a more economically competitive framework for RES in energy there will be further increases in RES capacity as well as innovative technologies that assist with increased utilisation and flexibility in the future. This can allow for RES to provide required capacity during certain periods and contribute more meaningfully to system security and generation adequacy going forward and as such it is critical that the capacity arrangements evolve to recognise these changing dynamics.

In the future, as we transition beyond the expiry of the existing state aid approval from the European Commission (the current approval applies for a period of ten years from May 2018), the design and implementation of alternative arrangements may also be needed to ensure adequacy and efficient entry and exit signals.

5.5.4.1. Flexibility, generation mix and new technologies

Today's capacity mechanism is geared towards ensuring adequacy and providing investment signals for the generation and technology mix that was in place a number of years ago. As the set of generation and demand response resources on the island continues to evolve towards that of a more flexible, decentralised and lower carbon power system it is critical that the appropriate entry signals are in place. The current technology modelled to determine the Net Cost of New Entry (Net CONE) i.e. the Best New Entrant is an OCGT, firing on distillate fuel, located in Northern Ireland, is not compliant with Article 22(4)(a) of the Electricity Regulation 2019/944.

Updating the modelling and assumptions used to determine the parameters for the Capacity Market will be essential to ensure that the necessary resources are available to maximise the economically efficient utilisation of RES and demand response. In order to realise this vision, it is necessary not only to discourage and prohibit carbon intensive power sources via emissions linked disincentives and encourage expansion of RES capacity, but also to ensure that the correct investment signals are in place to incentivise the flexibility needed to securely and economically operate the power system of the future.

Much of this investment signal will come from the System Services market but, in order to ensure efficiency and delivery of the necessary flexibility, it is important that the capacity and system services market investment signals work synergistically and do not counteract one another in any way. There is scope to improve in this area by seeking to target rewards from capacity in such a way that incentivises flexible resources by introducing mechanisms that recognise that one de-rated MW of capacity is not necessarily equivalent to another.

The CEP Package acknowledges that capacity mechanisms should be *open to participation of all resources* ***that are capable of providing the required technical performance, including energy storage and demand side management***. These will be important factors to consider during any re-design focus.

5.5.5. Capacity market modelling challenges

The capacity requirement and a set of technology de-rating factors are produced in advance of every capacity auction. These values determine the amount of capacity that is procured at capacity auctions and the contribution that each technology class makes to system adequacy.

Adequacy modelling to enhance efficiency in terms of the volume of capacity which is procured and target payments only to useful capacity, thereby seeking to give efficient entry and exit signals and deliver cost savings was another welcome improvement but again leaves scope for further development based on experience of its operation. Where capacity awards are given to older thermal plant, which has already recovered any sunk investment costs and may be less clean, efficient or flexible than preferred newer technologies, this may contribute to the absence of efficient exit signals. Conversely, where existing capacity is unsuccessful at auction this can lead to targeted contracting mechanisms if such plant are required.

Modelling of the contribution of RES towards capacity adequacy is also challenging due to the absence of an accurate treatment of inter-temporal technical consideration such as modelling of run hour limitations or energy limited resources such as hydro or storage technologies. The current adequacy modelling approach relies on 'back casting' based on the existing generation fleet as opposed to forecasting based on the desired set of resources. This influences the subsequent procurement process, as units with no energy limitations may receive better de-rating factors due to dispatch assumptions made on a technology (i.e. not unit) basis. This is an area that would benefit from future enhancement and further alignment with best practice modelling.

5.5.5.1. Modelling of flexible technologies

RES
Currently, the de-rating factors for wind and solar units are based on capacity credits, which determine the quantity of perfect plant that these technologies could replace. As a result of this, these technologies receive de-rating factors in the order of 10%, i.e. only 10% of the installed capacity is considered to contribute to system adequacy[85].

Additionally, participation in the capacity market would preclude wind and solar units from receiving other RES support payments and would require them to pay difference charges if they were unable to provide capacity when the strike price is exceeded. No solar units and only a small number of wind units participate in the capacity market as a result of these limitations, but their capacity is counted in the volumes of non-participating capacity, so does reduce the overall capacity amount procured.

Storage
Currently, the only storage technology that is modelled is pump hydro storage, specifically the 4 units of Turlough Hill.

Modelling these units relies on the assumption that they are deployed every day of the year, with a pumping/charging phase taking place overnight (modifying the demand curve) and dispatched for 5 hours over the peak of every day. Adding more storage units to the system, using the current modelling process, would decrease de-rating factors for all storage units due to the fact that the peak would become progressively flatter. Appropriate modelling of storage will be essential as the system evolves to have greater levels of storage, so that we can maximise the resource adequacy contribution storage can make.

85 EirGrid and SONI, Capacity Market – Final Auction Information Pack FAIP2425T-4, 2020

5.5.5.2. DSU de-rating issue

DSU de-rating factors have dropped by approximately 40% for the 2024/25 T-4 Auction when compared with the 2023/24 T-4 auction. The reason for this change is that during the de-rating calculation process, all DSUs are no longer modelled as 24h available conventional generators. Instead, a portion of them (DSU qualifying with a 2hour run-hour limitation) are now modelled as run-hour limited “storage” units that do not require charging.

This modelling approach is not an ideal solution, but it was one of the only ways to “model” DSUs currently. The consequence of this change is an increased amount of run-hour limited plant on the system, which results in a drop of de-rating factors for all run-hour limited units (including pumped hydro units).

We will continue to assess the viability of the implementation of the de-rating process and continue to engage with stakeholders on this.

5.5.5.3. Modelling of locational capacity constraints

For the modelling of the level 1 locational capacity constraints, i.e. Ireland and Northern Ireland, separate capacity requirements are determined for the two jurisdictions, based on the portfolios in each jurisdiction, with some additional capacity provided in each jurisdiction through the North-South tie-lines.

A PLEXOS-based adequacy model would be capable of modelling the transmission network in a greater level of detail than that currently used. We will seek to determine the most appropriate modelling of locational capacity constraints

5.5.5.4. PLEXOS and flexible technologies

A Monte Carlo based model, created in a tool such as PLEXOS, could more accurately represent the interaction between RES, storage and DSU. This would likely ascribe greater value to the adequacy provided by flexible and RES technologies and is used in other jurisdictions for such modelling.

The current approach to DSU modelling has been developed in-house and as outlined above a move to a PLEXOS based model might help address some of the emerging issues.

However, moving to PLEXOS will require a significant amount of modelling and analysis. It will be important to look at other jurisdictions that use such modelling and understand any potential limitations and their implications for the SEM. Clearly any such change in modelling practice would have to be reviewed and authorised by the Regulatory Authorities and SEM Committee and would be likely be subject to consultation.

5.6. System services assessment

5.6.1. Background to design of DS3 system services

In 2011, the DS3 "Delivering a Secure Sustainable Electricity System" programme was initiated to address the future needs of the power systems of Ireland and Northern Ireland. It comprised three distinct yet interlinked aspects: system policies, system tools and system performance. One of the central aspects of the system performance workstream is system services. In power systems largely comprised of conventional generation, ancillary services have traditionally been used to help grid operators to maintain secure and reliable power systems. Yet, as conventional generation is displaced by non-synchronous generation such as wind, the inherent characteristics of the units supplying energy to the grid change. Studies in Ireland and Northern Ireland concluded that the displacement of synchronous generation would give rise to technical scarcities, requiring the provision of new ancillary services or "system services".

Extensive industry consultation was carried out from 2014 to 2016 and a suite of 14 system services was developed in conjunction with the regulatory authorities. Existing ancillary services comprising reserves across varying timeframes (POR, SOR, TOR1, TOR2) were retained as part of the new framework. The definitions of both existing Replacement Reserve (RR) and Steady State Reactive Power (SSRP) services were modified. But rather than now being procured just from conventional generation, service provision was opened to all qualifying technologies, and both transmission and distribution connected. Seven additional system services were developed to address the technical scarcities that arise with a high level of variable generation, five of which have been procured to date. Three ramping services over various time horizons (RM1, RM3 and RM8) have been designed to manage variable RES and changes in interconnector flows while maintaining system security. A new fast-acting reserve service, Fast Frequency Response (FFR), addresses sudden power imbalances by increasing the time before the frequency nadir is reached and mitigating the rate of change of frequency (RoCoF) in the same period. A synchronous inertial response service (SIR) has been developed, which helps to address RoCoF during power system events. Two additional new services, Dynamic Reactive Response (DRR) and Fast Post Fault Active Power Recovery (FPFAPR), have been designed for use when the system is operated with more than 70% of instantaneous RES.

The DRR service will reward the provision of a fast-reactive current response for large voltage dips. The FPFAPR service will be provided by units that can recover their MW output quickly following a voltage disturbance (including transmission faults) to mitigate the impact of such disturbances on the system frequency.

To date, twelve services (excluding DRR and FPFAPR) have been procured from a range of technologies including conventional generators, wind farms, interconnectors, batteries and demand side units.

The current arrangements comprise a qualification system which allows flexible management of contracts. An Official Journal of the European Union (OJEU) tender process was established in 2018, awarding contracts that would last for up to five years. A gate system was put in place whereby every six months new applications from "providing units" wishing to join the qualification system are considered and existing units can apply to amend their contracted volumes. While there is a maximum specified volume per service that may be procured from an individual providing unit, units' maximum capability is assessed during a compliance test. A tariff is applied to each service, the level of which is set by the SEM Committee. Units are paid based on their availability to provide a service within a 30-minute trading period. Additionally, scalars are provided for to weight payments, and can be targeted to reward enhanced service delivery and to incentivise delivery of services in certain locations.

The arrangements also provide a qualification trial process (QTP) for new technologies, allowing them to prove their capability for service provision.

To address the need for long-term certainty for new-build investors, a competitive tender, namely the Volume Capped (or Fixed Contracts) arrangements for system services was launched in March 2019. An auction was run for a bundle of 140MW of a subset of reserve services (FFR-TOR2) to be provided by new-build service providers. There were three auction winners, all battery storage, with awarded volumes totalling 110MW. Contracts will run for a six-year term.

5.6.2. DS3 system services performance to date

Incentives offered by DS3 System Services, coupled with changes in the capacity market rules, have encouraged conventional units to re-examine their operational modes and to offer enhanced behavioural flexibility, optimising the levels of system services that they can provide. An increasing number of the existing services, designed to address the technical scarcities arising from the displacement of synchronous generation, are being contracted from new technologies such as wind, demand side units, batteries and interconnectors.

For example, looking at the Fast Frequency Response service, it is interesting to note the total service volume which is being contracted from non-conventional units, as shown in Figure 60. When the service was first launched in 2018, conventional units provided 68% of the total contracted volume of FFR. In the April 2020 gate, that had decreased to 47%. This increase in provision from non-conventional units is largely due to the qualification of interconnectors to provide FFR. However, it is significant that 53% of the FFR service volumes are now being contracted from new technologies including wind and demand response.

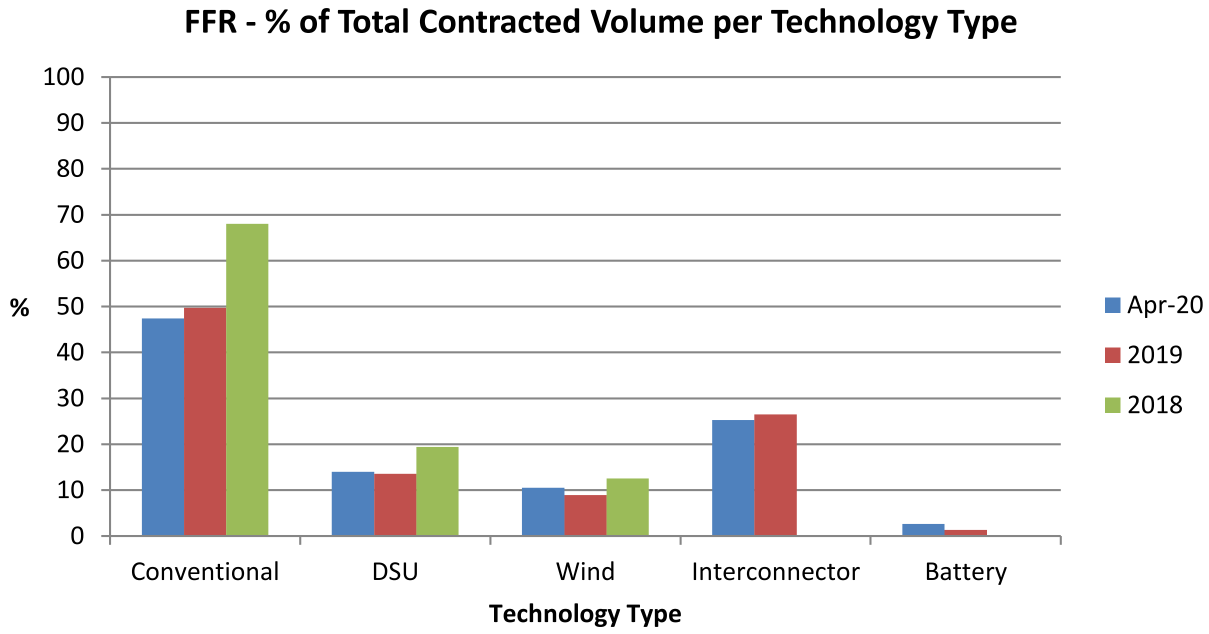


Figure 60: Percentage contracted FFR volume by technology

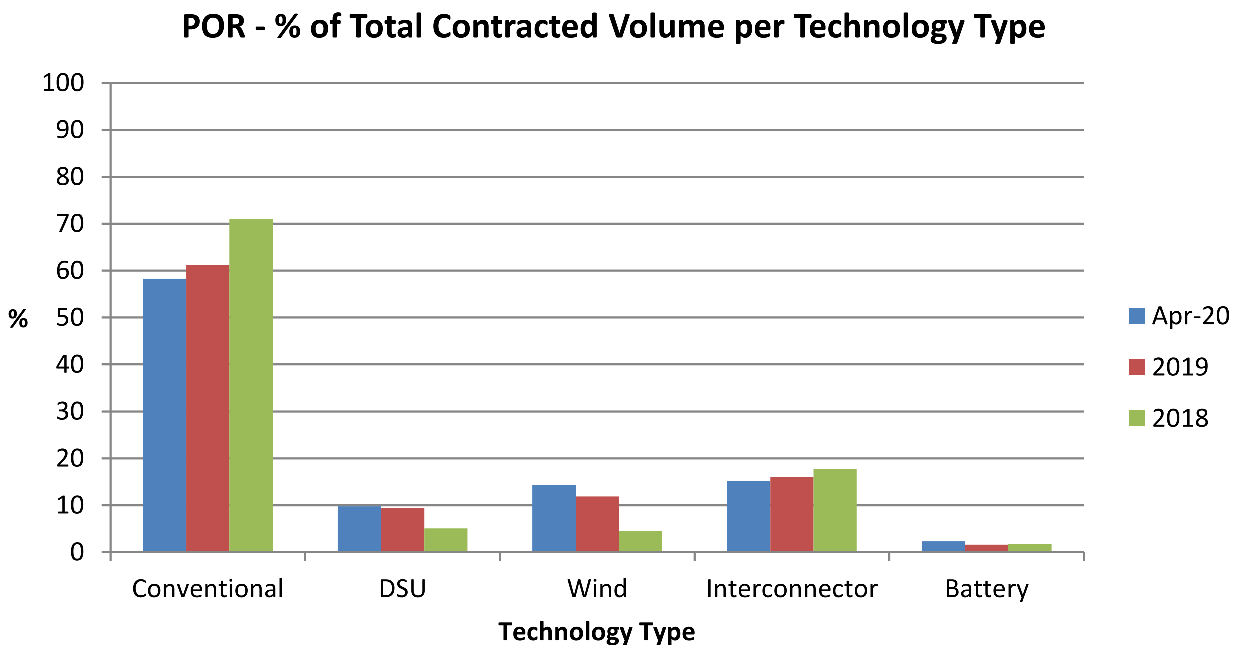


Figure 61: Percentage contracted POR volume by technology

Figure 61 shows a similar graph for the POR service. Here too, the percentage of total volume contracted from new technologies has increased from just under 30% in 2018 to just below 42% in April 2020. The increase can in part be accounted for the retirement of two conventional units. However, increases in service provision from new technologies have been seen across all reserve services. This is a necessary development, as the level of installed RES increases and conventional units are retired, new technologies need to contribute to the resilience of the power system.

However, as the current arrangements reward availability for service provision with tariff-based payments, as the volume of contracted parties increases so too do the overall costs of DS3 system services remuneration. Providing units are paid the higher of their market position or physical dispatch. While some providers are available to provide services, they may be dispatched differently for system security or scheduling reasons. While the tariff-based arrangements have provided a transparent framework to attract investment in system services provision, the TSOs recognise the need to move to a volume-based approach rather than a price based approach for service provision.

5.6.3. Challenges of high RES-E

Although the current arrangements have been successful in increasing the level of services being contracted from non-conventional units, they were designed to meet 2020 targets and are not suitable to enable us to meet 2030 targets. The current arrangements are based on price regulation, while the TSOs believe that the most suitable arrangements to help to achieve the 2030 targets should be based on volume regulation. While many of the current services will be needed to address the technical scarcities of 2030 and beyond, additional services such as products to address the predicted increased levels of network congestion will most likely be needed. In addition, there are a number of EU regulation requirements which impact the way in which system services should be procured and which need to be taken into account when designing the future arrangements. There also needs to be a coherent alignment between all revenue streams (energy, capacity, system services and others such as RESS auctions in Ireland), for market participants/service providers and this aspect needs to be carefully considered in the design of future arrangements for system services. It is important that a design for the future arrangements is agreed as soon as possible to ensure that appropriate arrangements can be implemented to ensure that there is no break in the investment that is needed to meet 2030 targets.

5.6.3.1. Technical scarcities in 2030

Analysis from EU-SysFlex Task 2.4 *Technical Shortfalls for Pan European Power System with High Levels of Renewable Generation*[86] which was concluded at the start of 2020, concurred with the previous findings in the Facilitation of Renewables studies, regarding the significant challenges associated with operating at very high levels of RES. However, the EU-SysFlex Task 2.4 report also noted additional technical issues and emerging areas of concern, which should be taken into account when designing the future arrangements. These issues included frequency stability and control; voltage stability; rotor angle stability and congestion. There are additional issues which were outside the scope of the study that will need to be analysed. They include oscillations, frequency regulation, ramping and negative reserve, which were not covered in EU-SysFlex.

A complete understanding of all the technical issues facing the system will be needed for the design of future system services products.

Without appropriate modifications to System Services through the future arrangements design it is likely that curtailment levels in 2030 will be high, such that they will not be possible to mitigate through operational policy alone and the 70% RES-E target will not be achieved. Therefore, making adequate provision for System Services consistently will be a critical factor in meeting these targets.

5.6.3.2. Mitigations to technical scarcities

A range of mitigations will be necessary to address the technical scarcities, and these will be tested and developed as part of ongoing studies. It is important to note that while some of these mitigations are already in place as part of the current DS3 System Services arrangements, based on the analysis in EU-SysFlex Task 2.4, discussed above, in some cases it will be crucial to procure greater volumes of the these services from non-conventional technologies and in other instances it may be necessary to evolve the product design and specifications.

86 EU-SysFlex, Technical Shortfalls for Pan European Power System with High Levels of Renewable Generation, 2020

Table 36: Technical scarcities, potential system services and technology options

Category	Scarcity	Potential System Services	Technology Options
Frequency Stability & Control	Insufficient contingency reserve	DS3 FFR, POR, SOR, TOR, RR[87]	Reserve from tech available during high wind (DSM, storage, wind, ICs), grid-forming inverters, power to gas etc.
	Lack of inertia	DS3 SIR	Synchronous generators, Synchronous compensators, Rotating Stabilisers.
Voltage Control	Lack of Steady state reactive power	DS3 SSRP	STATCOMS, reactive support from conventionals and non conventionals, D-FACTS devices, DSM.
	Lack of dynamic reactive power	DS3 DRR, DS3 FPFAPR	Synchronous compensators, Dynamic Reactive resources.
	Lack of system strength	DS3 DRR	Synchronous compensators, Rotating Stabiliser
Rotor angle stability	Lack of synchronising torque	DS3 DRR	Synchronous compensators.
	Lack of damping torque	DS3+ Damping product (localised)	Conventional generators, Sync comps, grid-forming control of non-synchronous generation.
Congestion	Lack of transmission capacity	DS3+ Congestion Product	DSM, Power-to-gas.
Adequacy/ Ramping	Uncertainty and lack of capacity during weather related events (hours -> days) . Also consideration of gas emergency situations	DS3 ramping products, DS3+ Capacity Product	Ramping from all technologies. Standby peaking capacity, Forecasting, power to gas.
Blackstart services	Consideration of provision of blackstart requirements in high SNSP system; provision by non-conventional providers	Blackstart restoration service	Blackstart from Storage integrated with generation technology. Grid forming technology.

87 EirGrid consider "synthetic inertia" as a form of Fast Frequency response rather a replacement for synchronous inertia

5.6.3.3. System services design for 2030

In general, the TSOs consider that, where possible, System Services should be procured using appropriate market arrangements, and closer to real time than the current procurement process. One of the key deficiencies of the existing DS3 System Services arrangements designed for 2020 is that they are based on price and not volume regulation. In such a design, there is a risk of under or over investment in service levels. There are signs of such an over investment beginning to materialise in the current arrangements for faster acting reserves while there is a shortfall in investment in low MW high inertia technologies such as synchronous condensers and/or rotating stabilisers.

Where flexible volume procurement makes sense in principle, there is a need to balance the inherent time it takes to design, consult, agree and implement such a market mechanism and for it to mature against the need for appropriate investment in a timely manner consistent with meeting the overarching Governments' policy objectives in both jurisdictions. In that regard, there is probably a lead time for such mechanisms to be effective. Volume based procurement will also introduce additional complexity as time-varying volume requirements for system services are likely to be an element of efficient future system operation.

To achieve 2030 targets, there will be a requirement to be able to operate the electricity system with 95% of generation coming from non-synchronous resources. As the level of renewables connected will increase over the coming years as successful RESS 1 applicants build out, the future arrangements need to provide for associated investment in system services to allow operation in excess of 75% SNSP. As the penetration of renewables increases, the requirements for system services across the four classes of services detailed in Table 37 will change. There will also be a dimensional shift in service requirements with new interconnection and the connection of large scale offshore windfarms.

As proposed in the recent SEMC Consultation on Future Market Arrangements[88], a move to daily auctions for at least some system services may be required. In general, such a move could help to allow technology which is dependent on weather patterns to better predict their availability and allow for better interaction with energy market trading.

If a daily procurement process is to be established, there is a need for a clear decision as early as possible in 2021 on the future design of system services to allow sufficient time for the implementation of the design and for the market to mature. The detailed studies on potential mitigation options for the technical challenges identified are due to be completed in Q2 2021. A daily auction design may be appropriate for reserve and ramping which are strongly related to energy market decision making by generation and demand. Congestion products should also fall into that category but are likely to take longer to implement as there is no market or product design currently in place for congestion. Design and delivery such as design will require close collaboration with the DSOs to ensure all services work cohesively to deliver system security. The products for Reserve and Ramping have already been developed (other than a potential longer-term ramping product for covering the long term loss of wind). Once fully developed, they should be considered for implementation in the daily auction process.

For other services it may be the case that there is insufficient time to have an effective daily auction mechanism in place by 2023 to get investment by 2025, particularly if there is no overarching design decision reached early in 2021. In this case the initial mechanism to expedite the necessary investment could be Fixed Term Contracts/ Tender Competition for specific services. To the extent it is possible and relatively seamless such services could be incorporated into the flexible volume regulation approach at a later stage. The design of a daily auction platform should be made as flexible as possible at the outset, to allow for that possibility.

88 SEMC, System Services Future Arrangements Scoping Paper, 2020

Table 37: System services classes and procurement/investment timeframes

Class of System Service	Suitable for Volume Regulation in principle	Need for increased service provision	Likely time that product design implemented	Effective Investment allowing for lead time
Reserves	Yes	From 2025	2023	2025
Ramping	Yes	From 2025	2023	2025
Congestion	Yes	From 2025	Needs to be agreed with DSO/DNO and industry	Unlikely before 2027
Electromagnetism and Inertia	Yes	From 2025	Complicated for daily auction design	Depends on market mechanism used

5.7. Network tariff changes

5.7.1. Background and design

Transmission tariffs that charge connected parties for use of the transmission system (either demand or generation) have a critical role in ensuring network operators have sufficient funding to operate and develop their networks and systems. In addition, the traditional role of network charging set out within economic theory suggests that charging should be structured in a way which facilitates change and focusses on ensuring that signals are sent which prioritise cost-efficiency of network use, including in relation to new technologies and use of system behaviours. In this context, the design of tariffs would seek to achieve cost-reflectivity so that users of the network 'internalise' the costs that they introduce to the system.

However, the magnitude of change which is expected in the electricity industry in the coming years is unprecedented. With this in mind it may be necessary for Tariffs to go beyond facilitation and become a more active driver of system change. Important in this context will be ensuring that the EU Tariff requirements as outlined in Articles 18 and 19 of the Internal Electricity Market Regulation 2019/943 are met. A good overview of current tariff design for Ireland and Northern Ireland in comparison to other EU Member States is available in an ACER Best Practice guide[89] published in December 2019.

Using tariffs to drive change may help to realise wider social objectives but may sacrifice an element of cost-reflectivity in the charging arrangements. As tariffs have a role in driving market participant behaviours, this could introduce incentives in operational and investment timescales which are not fully cost-reflective. With this in mind it will be important to consider tariff structures which are in the best interests of medium to long-term sector transition, even where potentially this is at the expense of some level of short to medium-term network cost minimisation.

Our analysis of the existing charging structures, emerging trends and review of international case studies, suggests several areas in which a review of tariff structures may be beneficial, to ensure that they can contribute in the manner intended.

89 ACER, ACER Practice Report on Transmission Tariff Methodologies in Europe , 2019

In summary, we identify two key drivers which support the need for a review of transmission tariffs:

- The potential social welfare benefits that changes to the tariff structures may deliver, especially in the context of sectoral transition
- The need to ensure that EirGrid and SONI (and potentially DSO companies) will continue to recover allowed revenues in a way which is 'demonstrably fair' and can optimise the network based on signals sent to, and received from, network users.

In four case studies that we have considered (GB, Australia, Spain and California), the transition of the electricity system has led to wide ranging reviews of charging arrangements. In the Netherlands, there have been calls to initiate a review of tariff structures in the near future.

In some of these cases, elements of reform have been undertaken reactively. While there may be a small number of higher priority issues, EirGrid and SONI largely have the opportunity to contribute to a review that can be proactive in introducing charging reform before issues become more significant.

Other electricity markets demonstrate the potential for effective market signals to enable the transition of the electricity system while achieving significant consumer savings. In GB, Ofgem has identified potential savings to consumers by revising how residual charges (changes based on consumption and ability to use the network) are determined to help ensure networks are appropriately remunerated in the transition to a flexible and dynamic system. A wider holistic reform of charging arrangements[90] is considered by Ofgem to be fundamental to realising these savings.

At the same time, the potential for new technologies to avoid a certain proportion of the charging base has been observed in many of the case studies we have assessed. For example, Spain introduced reforms in an attempt to prevent growing amounts of self-consumption from avoiding an energy-based charge in the presence of a significant tariff deficit. Spain also provides an example of the challenges inherent within such decisions and the importance of political acceptability. The so-called 'sun-tax' was introduced but subsequently removed after three years due to significant public opposition. A review of supplier-based charges may also be necessary (e.g. capacity charges, imperfections) to ensure that all incentives and charges work holistically to deliver the correct incentives for delivery of a low carbon electricity system by 2030.

5.7.2. Priorities for charging review

While we see benefit in a wide-ranging review of the charging structures in the SEM, it is important to note that charging reviews are complex and take time, often requiring years of consultation and design.

While interactions between different areas of charging highlight the importance of carrying out a holistic review, the length of time needed for such an approach suggests the need for EirGrid and SONI to carefully consider priorities. It is important to note that recently the CRU has issued clarification[91] for Storage units on tariff charges i.e. to apply D-TUoS and cease charging G-TUoS to commercial storage providers. The CRU has clarified that this decision should not be interpreted that storage providers should not be charged for the network costs associated with exporting energy, but that this proposal is a pragmatic interim approach which may provide consumer benefits in advance of a full review of the costs associated with storage providers' use of the network. It will be important to consider the longer-term requirements of tariff reviews and decision making in both Ireland and Northern Ireland.

90 OFGEM, Reform of network access and forward-looking charges, 2020
91 CRU, Network Charging for Commercial Storage Units, 2020

We identify one additional issue in the SEM which may need to be addressed ahead of a more comprehensive review, namely:

- **Large energy user capacity and charging:**
  Ireland has witnessed significant growth in electricity demand from large energy users in recent years. The propensity for these large energy users to locate around Dublin has increased network constraint challenges, exacerbated by the fact that large energy users may request higher connection capacities than they actually use. The only other region considered in our case studies that is facing a similar issue of sudden and significant demand growth (also driven by large energy users) is Denmark. We will aim to engage with the Danish TSO to understand if this having an impact on tariff revenues and considerations.

The timescales needed for a wholescale charging review may not allow for the speed of action needed to minimise certain negative impacts on the network, investors and consumers of quickly emerging issues. Therefore, there may be a case for 'fast-tracking' of certain issues in parallel with the launch of a wider review.

More broadly, we have identified three key areas on which to focus a review:

1. **Consideration of the charging base:**
   The tariff structures in Ireland and Northern Ireland have a significant energy-based component. Other than Denmark, the case studies show a trend towards increasing use of capacity, peak demand or fixed charging, partly driven by the emergence of technologies which can avoid an energy-based charge. Case studies also show a trend towards placing an increasing proportion of the charge on demand rather than generation. The Netherlands currently applies a 100% capacity-based charge while Spain is moving to a 100% capacity-based charge for the smallest consumers. EirGrid and SONI in conjunction with the industry regulators may consider, wider social objectives alongside traditional economic principles to a greater or lesser degree in determining the appropriate charging base.
2. **Locational signals:**
   There are locational signals present within the generation charge and in the transmission loss factor adjustments, however these are dampened. There are currently no locational signals for demand users. In addition to consideration of the signals sent to large energy users, the transition of the network may increase the need for locational use of system signals in order to maximise efficiency of network use. This may imply strengthening the locational signals on generation while potentially introducing locational signals for (at least some) demand users.
3. **Whole system interactions:**
   While it does not appear to be as significant a concern in the SEM as observed in other countries at present, one issue which has been prominent in California, Australia and GB has been the increase in generation connecting to the distribution network and the implications this has for charging. In GB, charging reviews of transmission and distribution charging arrangements have been undertaken together in order to minimise perverse incentives driven by inconsistencies between network voltages. As part of a review, it may also be prudent to consider the how charges are determined between Ireland and Northern Ireland, for example in relation to system services where there is the potential for divergence of system services requirements in different locations which may not be reflected in the current split of costs between regions. Additionally, it may be required to ensure that Distribution charges are also aligned or developed holistically with any changes to Transmission charges to ensure a whole system approach is taken to ensure the networks function effectively and deliver for consumers.

In summary, as tariffs form an important part of overall investor considerations when investing in a new plant, and on an ongoing basis in participation in generation or demand, it will be important that consider consideration is given to the need to review tariff structures to ensure they align with the requirement to deliver successfully and cost effectively the 70 by 30 targets while maintaining security of supply.

5.8. Support schemes – ROC, REFIT & RESS

Expanding the use of RES is an important political objective in the European Union (E.U.), and in the UK. The E.U. Commission has set a binding target that 50% of the Union's energy consumption should be sourced from RES by 2030, and for NI ongoing work on the Strategic Energy Framework has indicated high targets for RES.

In order to support investment in the deployment of RES in E.U. member states, the E.U. Commission has sanctioned state-aid clearance for European governments to adopt financial support measures for the industry. Directive 2009/28/EC allows different schemes of support for RES at a national level. However, there is a clear preference for mechanisms that are premiums to market revenues and not in themselves absolute.

The main financial support mechanisms available in member states throughout the E.U. (and UK) include:

- **Fixed feed-in tariffs (FIT), which are an effective method to support RES, as they help to minimise the risk to potential investors. However, FITs do not provide incentives for RES to adjust their output according to the needs of the system.**
- **Green premiums, which expose RES at least partly to market signals. Hence, RES have an incentive to adjust their output according to the system needs.**
- **Green certificates, which are seen as a cost-efficient method to reach a specific RES target. However, as the future certificate price is unknown, they expose RES investors to a higher risk compared to FIT or green premiums. Concerning the operation of RES, green certificates are comparable to green premiums.**
- **Investment subsidies, which are normally not linked to electricity production. If investment subsidies are not combined with any other support scheme, RES are fully integrated in the market.**
- **Tendering schemes, which aim for a cost-efficient implementation of a FIT or green premium. However, the uncertainty as to whether a project is chosen can discourage potential investors.**

In addition to financial support measures promoted by the EU and UK, RES generators also benefit from a range non-financial support mechanism. The most important non-financial supports include priority or guaranteed access and priority dispatch for RES. These additional non-financial support measures impact both the power system and energy market in different ways. Providing for priority or guaranteed access for RES generation impacts network development and influences the grid construction costs. Ensuring RES generators are given priority dispatch has a significant impact on the system and markets as it changes the way units are dispatched. The Clean Energy Package (EU Regulation 2019/943) is driving change in this regard and removing priority dispatch status for new renewable generation.

The use of different support schemes and various levels of support throughout Europe can have a direct impact on European power system operations and planning. One consequence is a national clustering of RES. Countries with a high level of support attract, in general, more investments than countries with a low level of support, and additionally countries with high levels of renewable resources and support see increased investment in renewables. As the support mechanism and the renewable resource availability are an important decision criterion for the location of new RES investments, this impacts grid planning and development, and can have negative consequences if the two are not fully aligned.

A second consequence of support measures is that a high penetration of RES has an influence on spot market prices. Different amounts of RES in different countries can provide incentives for increased cross-border trading if there is adequate grid and interconnection infrastructure in place.

From an operational perspective we consider that support mechanisms have an important role to play in helping to deploy increasing amounts of renewable generation around Europe; however, they also need to reflect the ability of the system to utilise the renewable generation, and this needs to be factored into future support design.

5.8.1. PPA considerations

In addition to Government support schemes, in Ireland under the Climate Action Plan the government has a goal of 15% of all electricity demand to be met by projects contracted under Corporate Power Purchase Agreements (CPPA) by 2030[10]. These fixed contracts may be utilised as a private market alternative to renewable support schemes.

Corporate PPAs are attractive measures for large corporate entities to meet their own Corporate Social Responsibility (CSR) and renewable energy objectives. It is assumed that a Corporate PPA will be structured specifically for the market that the development has to engage with and the technical and economic regulations that govern interactions with the power systems operations and wholesale markets. For example, windfarms above 5 MW will be fully dispatchable and above 10 MW will be obliged to enter into the energy market. EU Regulation 2019/943 on the internal energy market requires all renewable plant above 400kW to participate in the market. Such requirements will likely mean corporate PPA design will over time evolve to maximise the renewable output of the unit which is then traded to the corporate entity. As the markets evolve it is likely that PPAs will become more nuanced and aligned to the market signals. In the short term the impact of PPA is the arrival of more windfarms than the Government support systems and market values would in themselves deliver. However, the behaviour of those windfarms when connected will over time align to the long-term market signals.

5.9. Considerations for our market recommendations

In developing our recommendations for 2030 we have needed to consider specific actions to enable change, but also broader strategic issues so that the final roadmap is effective, deliverable and aligned with wider policy and regulation. Failure to deliver on these will ultimately undermine the affordability, timeliness of investment to meet government policy objectives, or indeed result in high costs for the electricity systems which fails to meet the renewable targets. We consider there are three main areas that need to be considered in depth to ensure that a final roadmap is achievable and are as are as follows:

- **The unique challenges facing Ireland and Northern Ireland in meeting public policy objectives.**
- **Evolving EU and UK energy policy and regulation**
- **Systems Design, Build and Market Maturity**

5.9.1. The unique challenges facing Ireland and Northern Ireland in meeting public policy objectives

The Ireland and Northern Ireland power systems are pioneering in relation to the high level of System Non-Synchronous Penetration (SNSP), with 70% SNSP currently under trial. Furthermore, with the UK target of full decarbonisation of the energy system by 2050 and Ireland's objective of 70% RES-E by 2030, it is clear that there are further improvements to be made in the coming years. Estimates indicate that to manage close to 70% annual RES-E from solar, biofuels or wind, whether onshore or offshore, will require an ability to operate up to close to 100% SNSP for over 35% of the hours a year.

By 2030, Europe is aiming for 50% of electricity to be generated from renewable sources including wind, hydro and solar. The European system is only, therefore, seeking to manage a maximum of 32% of its annual electricity by 2030 from non-synchronous variable generation, such as wind and solar. When reviewing the performance of the SEM, it is apparent that Ireland and Northern Ireland have not only already exceeded that level (in 2018), but have to meet increased targets which will push the amount of electricity from RES-E in excess of 50% and closer to 70% over the next decade. In this regard, the operational challenges faced by SONI and EirGrid are well in excess of those contemplated by the broader EU to 2030 and likely in years proceeding. Indeed, the SEM is well-placed to support and inform the wider Internal Energy market (IEM) in its resolution of these challenges, as we are seeing the impacts of high levels of non-synchronous generation across markets networks and operations.

From a market perspective these operational challenges will manifest themselves in many periods where there are low or negative prices in the SEM. Reviews of existing Plexos models of the impact of these generally estimates that the average energy price will fall approximately 20% by 2030 when the SEM is operating to 70% renewables. This percentage drop is consistent across these studies. When the detail of the models are explored further the reduction in the annual average price is achieved by having between 15-35% of time periods with low demand having zero or negative pricing. More importantly the market schedules that arise out of these studies cannot be operated without significant intervention from the TSO in generation schedules. For example, currently it is simply not possible to operate the power system with 100% SNSP even if the ex-ante market determines this as the most cost efficient outcome. This misalignment between market scheduling without the consideration of operational needs and technical boundaries of synchronous penetration further outlines the operational challenge expected.

Our Operational analysis work has corroborated previous DS3 and Facilitation of Renewables work in highlighting the complexity and interaction of these challenges to resiliently operate our power system above 75% SNSP. We advocate an approach whereby the experience of other comparable synchronous areas is used to inform our response to these challenges. Specifically, we note that the Australian Energy Market Operator recently issued a detailed Renewable Integration Study[92] where it aims to be able to manage 75% renewable generation by 2025. This report highlights that significant operational and market changes will be required to deliver this; the scale of such changes should be noted in when designing the optimal arrangements for the SEM.

92 AEMO, Renewable Integration Study, 2020

5.9.1.1. Evolving EU and UK energy policy and regulation

European Energy policy has been evolving over time and dictates how energy markets across the EU are organised and conducted. Generally, EU policy is implemented legally through legislative instruments such as Directives (which require national transposition in each Member State) or Regulations (which are directly applicable across the EU).

The scale of change that we have delivered to date to achieve alignment with EU policy (e.g. pan EU Day Ahead coupling, interim SEM-GB intraday-day auctions, synchronous area operational agreements, Grid Code changes, testing procedure changes, defence and restoration plan updates) underlines the significance of EU policy influence.

We continue to implement the existing Network Codes and key aspects of the Clean Energy package. There will likely be further developments as a result of the European Green Deal over the coming years, and also additional Network Codes on cybersecurity and Demand side flexibility. Revisions of existing EU policy legislation as part of the Green Deal is likely to create new rules for industry, system and market operators and so we will need to ensure we can actively engage in future design developments to ensure appropriate consideration of technical challenges and the need for investment signals are included in new developments. Some of the forthcoming changes include;

- **Revision of the EU Emissions Trading System (ETS) Q2 2021**
- **Amendment to the Renewable Energy Directive to implement the ambition of the new 2030 climate target Q2 2021**
- **Amendment of the Energy Efficiency Directive to implement the ambition of the new 2030 climate target Q2 2021**
- **Revision of the Energy Tax Directive Q2 2021**
- **ACER (European Union Agency for the Cooperation of Energy Regulators) Revision of Market Codes relating to the market such as Capacity Allocation and Congestion Management (CACM), Forward Capacity Allocation (FCA) and the EB (Electricity Balancing) Regulation.**

Ireland can and does play an active role in shaping EU policy and legislation through participation in ENTSO-E by EirGrid, ACER by the Regulatory Authority and EU Commission and Parliament by Government Representatives. However, it must be recognised that to-date, the drafting of the legislation and codes are more generally focused on central EU systems and operations which can create difficulties for full cohesive implementation. For example, the majority of European Member states have markets that are more generally founded on;

- Self-dispatch system,
- AC cross border interconnection and
- Ex-ante balancing price principles
- 15 min Imbalance Settlement Period

The current market design here in the SEM is based on our

- Central dispatch system,
- HVDC cross border interconnection and
- ex-post balancing price determination
- 30 min Imbalance Settlement Period

In future we will be required to coordinate system operation with a Regional Security Coordinator (CORESO), alongside other EU TSOs. This will create new operational processes in terms of how we manage interconnector flows and remedial actions, which ultimately will feed into market processes. This should also lead to increased transparency on market flows for market participants.

EU energy legislation seeks to ensure that markets and operations move to ensure that the decarbonisation of the electricity system is achieved in a manner that facilitates participation by all customers, communities and industry players. This includes the facilitation of renewable energy generation, energy storage, demand response and enhanced cross border trade. Capacity mechanisms are only feasible in limited circumstances and have to be well justified, and market based procurement of ancillary services used where possible. Capacity mechanisms have to be designed to apply appropriate penalties to capacity providers that are not available in times of system stress (currently only new providers are penalised for non-delivery) and ensure that the price paid for availability automatically tends to zero when the level of capacity supplied is expected to be adequate to meet the level of capacity demanded.

As outlined above, both Ireland and Northern Ireland are bound by EU energy legalisation that bring obligations to participate in pan-EU markets and align with standardised European methodologies in relation to everything from connection parameters to training standards. While we will continue to develop our system and processes to align with EU requirements and achieve compliance there are certain aspects of EU energy requirements that will prove difficult to comply with until we are connected to another Member State, for example;

- Access to the pan-EU Day-Ahead market is no longer possible and the day-ahead auction runs on an isolated SEM only basis, interconnectors are not scheduled until the first intra-day SEM-GB auction;
- The Interim intraday auctions between SEM and the GB market will operate as normal as these are outside EU arrangements;
- The integration with the wider pan-EU intraday arrangements (SIDC) will not be possible until we are connected with another member State;
- It will not be possible to integrate with the Balancing platforms until we are connected with another Member State;
- Access to capacity calculation services from CORESO will likely be delayed;
- Cross border capacity market participation from other EU countries will not be possible to be enabled until we are connected to another Member State; and
- Uncertainty remains in relation to a number of other areas of EU compliance that require further examination between system operators, market operators and Regulators.

5.9.1.2. Design, build and market maturity

The issue of market design is one that can take multiple years from high level regulatory decision to detailed design, vendor selection and finally project implementation before the markets are operational. From previous experience we have found that it takes approximately 4 years from a high level new system design to delivery. This is consistent with timelines experienced of the SEM, I-SEM and DS3 System Services programmes.

In addition, the programmes above were all principal markets design changes. These can take significantly longer as appropriate and detailed regulatory consideration is required and the development of new systems that then require implementation. Where changes are made that build on rather than seek to change the foundations of a market these changes can be more readily implemented from both a system and regulatory perspective. This is a critical factor in the selection of proposed market changes. With the proposals outlined, if we seek to change too much it is unlikely to be implementable in a timely fashion with adverse impact on necessary investment. However, if we do not make sufficient changes to existing market systems then delivery of the long term renewable objectives will be unlikely.

5.9.2. Pragmatic market design and consideration

5.9.2.1. Alignment

While the various market components of the electricity market – Energy, Capacity, System Services, support schemes and network tariffs–each require their own reforms, it is also necessary that the markets are aligned and, indeed, that these markets are also aligned with the transmission and distribution constraints and operational requirements of operation at high RES-E levels as required.

Theoretically the energy market should deliver the energy required to meet demand from the lowest cost providers with little intervention from the TSO. In practice, on the All-island system there are multiple (network and system security)constraints , meaning that some low cost (and priority dispatch renewable) generators are being constrained down or curtailed while other more expensive plants are constrained on. Yet the current market design for day-ahead does not recognise these constraints as it is run on an unconstrained basis. This then leads to multiple interventions by the TSO to ensure that system security is maintained and many plants moved to a certain position to deliver the required secure system.

Currently when a generator is compensated for being constrained-down or curtailed then that generator receives an infra-marginal rent, which is the energy market's signal and incentive to invest, but has not contributed to meeting customer demand. The issue of market alignment is whether it is appropriate that the energy market should create these incentives to invest in plant regardless of whether that plant can be used to meet customer demand. In particular, if at any given time the energy market gives incentives to plant which is 100% variable RES when the system cannot accept more than some lower limit – the SNSP limit - then it is inevitable that some of that generation will have to be dispatched down, and replaced by other, possibly conventional generation. The infra-marginal rents received by dispatched-down generation are a cost on customers, for which customers receive no benefit. Moreover, incentives given by the market to generation that doesn't run to meet customer demand does not contribute to meeting renewables targets.

At the same time, generation that is required to run, i.e. constrained on, to meet customer demand will generally not have received infra-marginal rents and hence this generation will not be subject to the incentives the market should be providing to produce an efficient generation mix. If unaddressed this could potentially cause market power issues to arise.

Clearly for a market to be able to deliver efficient outcomes, it needs to be aligned with operational requirements. While the Operational and Networks technical reports outline in detail the work planned to deliver a more cohesive system similarly markets will need to align to provide the correct signals that deliver required technical services, adequate capability and non-discriminatory access to multiple markets.

Our concern is that efficient investment in the energy market, and minimising energy costs to customers, is going to be improved only if the incentives provided by the markets (energy, capacity, system services) recognise the real-world constraints that affect whether generation can usefully contribute to meeting customer demand. It is likely that if the ex-ante market does not recognise technical constraints then customers will incur the cost of RES-E regardless of whether it is used to meet customer demand or is constrained off.

Alignment is an issue not just for the energy market. In the Capacity Market, it will become increasingly important that the capacity that is procured can usefully contribute to meeting customer demand at times of system stress. This may require holders of capacity obligations to have sufficient flexibility such that they can anticipate and react to stress events within the necessary timescales. Hence, the Capacity Market, like the Energy Market needs to ensure that it incentivises an appropriate mix of capacity, some of which can respond in short timescales while the remainder responds more slowly. Similarly, operational and transmission constraints may also limit the ability of capacity providers to contribute to system security depending on their location, and the Capacity Market will need to ensure that it does not give incentives to provide capacity where it cannot be used.

As with the energy market, if the capacity market provides incentives to plant which cannot meet customer demand, the result will be that unnecessary costs will be incurred by customers, whilst also the desired level of security of supply – the objective of the capacity market – will not be achieved.

Generally, it will be necessary to ensure that each of the market components not only provide efficient incentives, when considered in isolation, but provide incentives that are consistent with each other, and which provide incentives which are efficient when considered as a whole.

5.9.2.2. Commitment

In the energy market, there are many producers and many consumers. Providing there is adequate competition, market outcomes are not dependent on the actions of a single player. Market participants can thus make decisions based on their assessment of the market as a whole, and the underlying fundamentals such as fuel prices and the state of the wider economy.

If market participants are to have confidence to make the substantial investments that will be needed to achieve the 2030 target, it will be necessary that they have confidence that the TSOs and DSOs can provide the necessary infrastructure and procure the necessary system services to move operational policy and practice. This however must be achieved while maintaining our efficiency objective of alignment. While alignment suggests that the energy market should recognise the real-world SNSP constraint at any given time, it may be necessary for us to pre-commit to a particular SNSP limit at any given time, through a “SNSP trajectory” for a period of several years. This can inform market arrangements to ensure usability is considered as part of overall energy market design. Essentially this balances the risk between the consumer and the investor. The investor is clear that there are a range of issues that are outside of their control that need to be changed. In the first instance they are made clear and are borne by the investor. However the TSO commits to meeting a future trajectory that moves the risk of non-delivery to the consumer in a timely manner and provides the TSO sufficient time to resolve the challenge so that the long term risk to the consumer does not materialise.

Would-be system service providers will also need the confidence to make the investments necessary to provide the services. In particular, the risk of making long term commitments runs the risk that, at some point, the service is not required. This needs to be balanced with the risk of slow or reduced investment by service providers if appropriate forward commitments are not provided by the market design.

However, it may be possible to recoup some of this efficiency loss by making services tradable, such that services providers could offload their obligations on to other providers, or such that the TSO could buy its way out of a previous commitment in the event that the service is no longer required.

Balancing the risk of investment and clarifying who is best placed to bear the risk is critical in ensuring the collective markets work to deliver investment in a timely and effective manner. The consideration of arrangements and markets that exist for well over a decade are critical to achieving this.

5.9.2.3. Clarity

Clarity is of key importance to market participants to ensure the rules that govern market participation and incentives are transparent, clear and targeted at the necessary service. Explicitly defining relevant services, (locations if location specific) and developing incentives for service provision which are technology agnostic may help release capability across the portfolio and support a more holistic approach to enabling a high RES-E system.

We consider that in providing clarity it is necessary to focus on “Market Discipline” and “Usability”. Market Discipline covers the rules and incentives for delivering the necessary service through investment.

It includes incentives and also the institutional rules that these are based on. Grid Codes stipulate the technical requirements and are supported by commissioning and performance monitoring procedures to enforce delivery of the required technical services. The current DS3 System Services programme with its own protocol also follows this structure.

Usability concerns the balancing of risk between investors and the consumer. If investment is not targeted to where it can be realised (e.g. a new service provider should be located in an unconstrained network area so that delivery of the service is feasible at all times) the usability of that investment may be low. Where the risk of an investment in new service provision is wholly borne by the investor, and it is known that some of the service delivery is at risk it is likely to drive the cost of capital and finance for that investment high or undermine the investment happening at all, which in turn leads to a more expensive cost per service delivered. If the consumer (or in essence the TSO) bears the risk of new investments upfront then you may well get the necessary investment but much of it might be unusable. The cost to society in this mode would be high and the outcomes unlikely to meet government objectives. A significant part of clarity is identifying where the risk lies.

5.9.2.4. Market discipline

It is essential that the market design incentivises the introduction of the necessary capability to manage the technical scarcities of the future and not just the current system. This requires the incentives to be focused and of sufficient value to drive necessary investment. Given the challenges with operating up at high levels of RES-E it is necessary that these incentives meet these challenges and do not rely unduly on current practice or technologies. In this regard the redesign of System Services is to clarify the incentives for the services needed to maintain resilience when there is high RES-E and indeed when there is no RES-E due to weather conditions for an extended period of time. Improved definition of Capacity may produce better long term adequacy than the current rule sets which in places is clearly based on a consideration of conventional technology.

Clarifying the service and putting incentives against this which are not unduly specific to a distinct technology may release capability across the portfolio and support a more holistic approach to high RES-E.

Furthermore with service provision there is a need for the investor who has got a long term contract to build an asset to provide relevant information in a timely manner. There has been evidence that a range of investments have received system services or capacity contracts have suffered delays. While some of these are outside their control some of them reside with them. In those cases it appears there is a need to adjust some of the market discipline requirements on provision of information on a future investment.

5.9.2.5. Usability

Clarity is needed across all markets to cover the principle of “usability”. Where this is not clear it is likely that investors will need to bid in to cover the risk of ambiguity. Should they bid in to cover the risk due to ambiguity then the cost to the consumer goes up more than perhaps necessary. If the risk in this situation does not materialise the investor is in effect double paid at the expense of the consumer. Alternatively the investor considers the ambiguity too risky and does not make the investment. In this case a necessary capability is not making an investment and the system will struggle to meet the adequacy and system service needs at high RES-E. By clarifying how “usability” is managed in a market and ensuring the appropriate market discipline is in place which will crystallise the real risks to investors and allow more accurate bidding practices.

Ensuring those that are best placed to manage risks in a given scenario is likely, in our view, to be the best way to make long term investments. If the public policy objectives are considered a long term investment then there are two types of specific risk for individual projects. These are i) those which are fully in control of the investor and ii) those that are outside the immediate control of the investor. For those within the control of the investor, that risk should be fully borne by the investor. This is where clarity, alignment and market discipline matter.

However for those risks outside of their direct control (e.g. the ability of the power system to operate securely to 95%% SNSP, that there is sufficient network capability to meet a 40% demand increase and fundamental change in generation locations) who is best placed to manage these risks?

In Ireland connection offers currently reflect policy set by the CRU, and are made on a non-firm basis predominately. Therefore there may be no ability at the time of connection to fully manage the full output at the location because of system strength. Connection policy and processes in Northern Ireland are different to those underway in Ireland. SONI expects this to be considered further in collaboration with the industry as part of the NI Energy Strategy.

In the absence of alignment between feasible SNSP operational limits and the connection of greater levels of non-synchronous generation it will be very difficult for the TSOs to ensure that units are not re-dispatched. Given that investment in new generation is a choice taken by developers, once there is clarity on what these risks are and how they will be managed out by the TSO then the investor has sufficient detail to make an informed investment decision at the start. In general EirGrid and SONI believe the best answer is placing the risk initially with the investor. It is their choice what and where they invest in, provided they have visibility over the risks they will be exposed to. There will be an onus on the System Operators and Owners to build out the network in a reasonably timely fashion, or develop operating capability to increase SNSP to higher and higher levels.

5.9.3. Post 2030 considerations

While our focus in this review has been on the issues to meet and exceed the policy objectives over the next decade it is important to consider how these lay the foundation for markets for post 2030. In that regard it is clear that both EU and UK energy policy are aligning to be carbon neutral by 2050. The European Green Deal puts the EU on a path to climate neutrality by 2050, through the deep decarbonisation of all sectors of the economy, and higher greenhouse gas emission reductions for 2030.

Recent developments in EU legislation and policy will require Energy system or sector integration to become standard - delivering coordinated planning and operation of the energy system 'as a whole', across multiple energy carriers, infrastructures, and consumption sectors. This will require electricity TSOs to work more closely with gas TSOs and wider sectors of the energy chain than today (e.g. hydrogen production).

The EU has estimated that Electricity demand is projected to increase significantly on a pathway towards climate neutrality, with the share of electricity in final energy consumption growing from 23% today to around 30% in 2030, and towards 50% by 2050[93]. In comparison, that share has only increased by 5 percentage points over the last thirty years. This will result in the large scale electrification of heat and transport, but much wider sector coupling will also be required. Sector coupling involves the increased integration of energy end-use and supply sectors with one another. This can improve the efficiency and flexibility of the energy system as well as its reliability and adequacy. Additionally, sector coupling can reduce the costs of decarbonisation, and will require electricity, heat and transport sectors to work collaboratively to solve challenges interchangeably with other sectors. To foster the full potential of sector coupling it will be important that existing techno-economic, policy and regulatory barriers are removed. In this world with high levels of renewables and low marginal prices, the market perspective will be crucial to ensuring that sector coupling is efficient and affordable, and points to the need for a fundamental rethink of the overarching electricity market. It is unlikely in this world that a retail tariff structure of unit price and standing charge would remain. In this world there will have to be an evolution of market investment incentives and market design based on energy efficient sector coupling, to ensure sufficient low carbon energy generation to meet all sector requirements. It would appear that markets that better reflect utility of the consumer rather than specific commodities like electricity, hydrogen, gas appear to have the best chance of efficiently coupling.

With this in mind, our proposals to place increasing value on maintaining the resilience of the power system seem to fit into this future perspective and can be built upon. From a consumer perspective a supply of clean low carbon energy is desired but so too is an energy system that works as expected whenever it is required. That resilience is important to the consumer.

It is also important to consider that business models for energy supply may change dramatically as consumers integrate both generation and smart demand into homes and businesses, with incentives to supply services such as demand response or incidence response for those with the capability and desire to provide such. These evolving business models will impact how wholesale markets evolve and we as TSOs need to stay cognisant of such forthcoming change.

Appendices

Appendix A: Glossary and key concepts

Table A-1: Glossary and key concepts

Term	Abbreviation	Description
Appropriate Assessment	AA	An assessment of the potential adverse effects of a plan or project (in combination with other plans or projects) on Special Areas of Conservation and Special Protection Areas.
Alternating Current	AC	Alternating current is an electric current which periodically reverses direction and changes its magnitude continuously with time in contrast to direct current (DC) which flows only in one direction.
Addressing Climate Change scenario	ACC	Addressing Climate Change is a scenario in Northern Ireland's Tomorrow's Energy Scenarios. Sustainability is a core part of decision making, recognising that climate change as a risk and appropriate action is taken. The scenario meets the RES-E target of 70% by 2030. This scenario is comparable to Ireland's Coordinated Action scenario.
Centralised Energy scenario	CE	Centralised Energy is a scenario in Ireland's Tomorrow's Energy Scenarios that describes a plan-led world in which Ireland achieves a low carbon future. The scenario meets the RES-E target of 70% by 2030.
Co-ordinated Action scenario	CA	Coordinated Action is a scenario in Ireland's Tomorrow's Energy Scenarios where sustainability is a core part of decision making. Government and citizens recognise climate change as a risk and take appropriate action. The scenario meets the RES-E target of 70% by 2030. This scenario is comparable to Northern Ireland's Addressing Climate Change scenario.
CO_2 emissions	CO_2	Carbon dioxide emissions or CO_2 emissions are emissions stemming from the burning of fossil fuels and other manufacturing processes. They include carbon dioxide produced during consumption of solid, liquid, and gas fuels as well as gas flaring.
Constraint		Constraint (either up or down) refer to a change to any generator's output from the planned "market schedule" due to transmission network limitations or operating reserve requirements.
Curtailment		Curtailment refers to the dispatch-down of wind for system-wide reasons (where the reduction of any or all wind generators would alleviate the problem).

Term	Abbreviation	Description
Demand Side Management	DSM	The modification of normal demand patterns, usually through the use of incentives and/or control actions
Direct Current	DC	Direct current is an electric current which flows only in one direction, in contrast to alternating current which periodically reverses direction and changes its magnitude continuously with time.
Distribution System Operator	DSO	The Distribution System Operator is the designated authority responsible for the operation of the distribution system.
Dynamic Reactive Response	DRR	A DS3 System Services product. It is ability of a unit to deliver a reactive current response for voltage dips in excess of 30% that would achieve at least a reactive power in MVAr of 31% of the registered capacity at nominal voltage. The response must be provided within 40 ms of the voltage dip.
European Network of Transmission System Operators for Electricity	ENTSO-E	ENTSO-E, the European Network of Transmission System Operators, represents 43 electricity transmission system operators from 36 countries across Europe. ESB Networks Electricity Supply Board: Networks A subsidiary within ESB Group, ESB Networks
	EU-SysFlex	A Horizon 2020 project aiming to solve the power system challenges associated with the integration of variable non-synchronous renewable generation required to meet the ambitious European renewables target
Facilitation of Renewables	FOR	Detailed studies of the Ireland and Northern Ireland power system undertaken to more fully understanding the technical and operational implications associated with high shares of wind power.
Fast Frequency Response	FFR	A DS3 System Services product that incentivises the fast provision active power within 2 seconds following the frequency disturbance.
Fast Post-Fault Power Recovery	FPFAPR	A DS3 System Services product that is needed at high SNSP levels. It is the ability of resources to recover their active power output quickly after a voltage disturbance and can therefore mitigate the impact of voltage disturbances on system frequency.
Flexible AC Transmission System	FACTS	FACTs devices are power electronic devices which are used in AC systems to control power flows.
Frequency Containment Reserve	FCR	Frequency containment reserve in the European Union Internal Electricity Balancing Market means operating reserves necessary for constant containment of frequency deviations (fluctuations) from nominal value in order to constantly maintain the power balance in the whole synchronously interconnected system.

Term	Abbreviation	Description
Frequency Restoration Reserve	FRR	The active power reserves available to restore system frequency to nominal frequency and, for a synchronous area consisting of more than one Load-Frequency Control (LFC) area, to restore power balance to the scheduled value.
High-Voltage Direct Current	HVDC	A HVDC electric power transmission system uses direct current for the bulk transmission of electrical power.
HVDC embedded		A HVDC system that operates "in parallel" with the existing AC system. The loss of a dc circuit results in power transfer to the AC system, i.e. the dc circuits are part of N-1 secure operation.
HVDC meshed		A HVDC system with redundant paths.
HVDC multi-terminal		A HVDC system with the ability to interchange power between three or more converter stations.
HVDC overlay		A HVDC system that operates "above" the existing AC system, exporting power from one area to another. The loss of a circuit results in undelivered energy rather than power transfers to the AC system, i.e. the HVDC circuits are not part of N-1 secure operation.
HVDC radial		A HVDC system with converter station is connected to a single direct current line.
Largest Single Infeed	LSI	The size, in MW, of the largest single source of active power. This dictates the amount of under-frequency reserve that is carried.
Largest Single Outfeed	LSO	The size, in MW, of the largest single sink of active power. This dictates the amount of over-frequency reserve that is carried.
Mega Volt Ampere	MVA	Unit of apparent power. MVA ratings are often used for transformers, e.g. for customer connections.
Mega Volt Ampere Reactive	MVAr	Unit of reactive power.
Primary Operating Reserve	POR	A DS3 System Services product. It is the additional MW output (and/or reduction in Demand) required at the frequency nadir (minimum), compared to the pre-incident output (or Demand) where the nadir occurs between 5 and 15 seconds after an Event.
Production cost		Production Cost is the total generation cost including fuel, variable operations and maintenance costs, start and shutdown costs and emissions costs. It is measured in euro and typically over the period of a year.
Project implementation costs		The costs associated with the procurement, installation and commissioning of the reinforcement and therefore includes all the transmission equipment that form part of the reinforcement's scope.

Term	Abbreviation	Description
Regulatory Authority	RA	Authorities with obligations to regulate utilities in the public interest.
Replacement Reserve Desynchronised	RRD	A DS3 System Services product. The additional MW output (and/or reduction in demand) provided compared to the pre-incident output (or demand) which is fully available and sustainable over the period from 20 minutes to 1 hour following an event.
Rate of Change of Frequency	RoCoF	The Rate of Change of Frequency defines the maximum rate at which system frequency should change following an event on the power system. As such it defines the rate of change for which generators and demand should be able to withstand and remain connected to the power system.
Renewable Energy Sources	RES	Sources of electricity generation that use renewable processes, such as wind, solar radiation, tidal movement etc. to produce electricity.
Renewable Energy Sources for Electricity	RES-E	Electricity from renewable energy sources, i.e. the electricity generated from clean energy sources such as photovoltaic, hydro, tidal or wave, wind, geothermal, and renewable biomass.
Strategic Environmental Assessment	SEA	Defined by the Environmental Protection Agency as the process by which environmental considerations are required to be fully integrated into the preparation of plans and programmes prior to their final adoption.
Submarine cable	SMC	A submarine cable is a cable laid on the sea bed between land-based stations to carry electricity across stretches of open water such as the ocean and sea.
System Marginal Price	SMP	The System Marginal Price is the price set for each half hour of Single Electricity Market trading by the bid of the last generator that must be despatched to meet demand in that settlement period. All generators receive the SMP regardless of their bid.
System Non-Synchronous Penetration	SNSP	System Non-Synchronous Penetration is a real-time measure of the percentage of generation that comes from non-synchronous sources, such as wind and HVDC interconnector imports, relative to the system demand.
Technology Readiness Level	TRL	Technology Readiness Levels (TRL) are a type of measurement system used to assess the maturity level of a particular technology.

Term	Abbreviation	Description
Tertiary Operating Reserve	TOR	A DS3 System Services product. It is the additional MW output (and/or reduction in Demand) required at the frequency nadir (minimum), compared to the pre-incident output (or Demand) which is fully available and sustainable over the period from 90 seconds to 5 minutes (TOR 1) and from 5 minutes to 20 minutes (TOR 2) following an event.
Tomorrows Energy Scenarios	TES	Scenario plans for Ireland.
Tomorrows Energy Scenarios Northern Ireland	TESNI	Scenario plans for Northern Ireland.
Total Electricity Requirement	TER	The sum of annual electricity demand for residential, tertiary, transport, industrial sectors, including electricity produced by privately operated and owned micro-generators, as well as losses.
Transmission Asset Owner	TAO	The entity that owns the transmission assets. In Ireland ESB Networks owns the transmission assets and in Northern Ireland NIEN owns the transmission assets.
Underground cable	UGC	An underground cable is a cable that is buried below the ground and is used to convey electrical power.
Unit Commitment and Economic Dispatch	UCED	Unit commitment is the process of deciding when and which generating units at each power station to start-up and shut-down. Economic dispatch is the process of deciding what the individual power outputs should be of the scheduled generating units at each time-point.

Appendix B: Technology list

Table B-1: Technology list

DOMAIN	PATH	CLASS	TYPE	Description: VOLTAGE (kV)	Description: RATING (MVA)	Description: TECHNOLOGY
Circuit	New	HVAC	OHL	400	**1944**	Twin 600mm^2 Curlew ACSR @ 80°C
Circuit	New	HVAC	UGC	400 **750**	All circuits, rated to 750MVA	
Circuit	Up-voltage	HVAC	OHL	220 to 400	**1944**	Twin 600mm^2 Curlew ACSR @ 80°C
Circuit	New	HVAC	OHL	220	**534**	600mm^2 Curlew ACSR @ 80°C
Circuit	New	HVAC	OHL	220	**833**	586mm^2 393/46 GZTACSR Traonach @ 210°C (600mm Curlew ACSR equiv.)
Circuit	New	HVAC	OHL	220	**709**	539mm^2 GZTACSR Iolar @ 210°C (430mm Bison ACSR equiv.)
Circuit	New	HVAC	UGC	220 **570**	Meshed and tailed circuits with load in excess of 375MVA	
Circuit	New	HVAC	UGC	220 **375**	Tailed circuits with generation >286 & <375MVA, rated per generator needs	
Circuit	New	HVAC	UGC	220 **286**	Tailed circuits with generation less than 286MVA, rated to 286MVA	
Circuit	Up-voltage	HVAC	OHL	110 to 220	**534**	600mm^2 Curlew ACSR @ 80°C
Circuit	New	HVAC	OHL	110	**219**	425mm^2 Bison ACSR @ 80°C
Circuit	New	HVAC	OHL	110	**235**	308mm^2 D-GTACSR Cearc @ 150°C
Circuit	New	HVAC	OHL	110	**222**	220mm^2 D-SBGTZACSR Spideog @ 130°C
Circuit	New	HVAC	UGC	110 **223**	All circuits, rated to 223MVA	

Table B-1: Technology list

DOMAIN	PATH	CLASS	TYPE	Description: VOLTAGE (kV)	Description: RATING (MVA)	Description: TECHNOLOGY
Circuit	New	HVDC	OHL	TBD	**750**	None – TBD; Connected to 400kV AC infrastructure
Circuit	New	HVDC	OHL	TBD	**750**	None – TBD; Connected to 220kV AC infrastructure
Circuit	New	HVDC	OHL	TBD	**250**	None – TBD; Connected to 110kV AC infrastructure
Station	New	HVAC	AIS & GIS	400/220	-	400/220kV Onshore ring demand station (8 or less bay[2])
Station	New	HVAC	AIS & GIS	400/220	-	400/220kV Onshore ring demand stations (9-16 bay[2])
Station	New	HVAC	AIS & GIS	400/110	-	400/110kV Onshore ring Standard demand stations
Station	New	HVAC	AIS & GIS	400/110	-	400/110kV Onshore ring Core demand stations
Station	New	HVAC	AIS & GIS	220/110	-	220/110kV Onshore ring Standard demand stations
Station	New	HVAC	AIS & GIS	110	-	110kV Onshore ring demand stations
Station	New	HVAC	AIS & GIS	400	-	400kV Onshore generating stations
Station	New	HVAC	AIS & GIS	220	-	220kV Onshore generating stations (<3km OHL, <1.4km UG[5])
Station	New	HVAC	AIS & GIS	220	-	220kV Onshore generating stations (3+km OHL, 1.4+km UG[5])
Station	New	HVAC	AIS & GIS	110	-	110kV Onshore generating stations (<5.25km OHL, <1.5km UG[5])
Station	New	HVAC	AIS & GIS	110	-	110kV Onshore generating stations (5.25+km OHL, 1.5+km UG[5])
Station	New	HVAC	AIS & GIS	400	-	400kV Onshore customer demand station
Station	New	HVAC	AIS & GIS	220	-	220kV Onshore customer demand station (<3km OHL, <1.4km UG[5])

Table B-1: Technology list

DOMAIN	PATH	CLASS	TYPE	Description: VOLTAGE (kV)	Description: RATING (MVA)	Description: TECHNOLOGY
Station	New	HVAC	AIS & GIS	220	-	220kV Onshore customer demand station (3+km OHL, 1.4+km UG[5])
Station	New	HVAC	AIS & GIS	110	-	110kV Onshore customer demand station (<5.25km OHL, <1.5km UG[5])
Station	New	HVAC	AIS & GIS	110	-	110kV Onshore customer demand station (5.25+km OHL, 1.5+km UG[5])
Station	New	HVAC	AIS & GIS	400	-	400kV Onshore switching stations (8 or less bay[2])
Station	New	HVAC	AIS & GIS	400	-	400kV Onshore switching stations (9-12 bay[2])
Station	New	HVAC	AIS & GIS	220	-	220kV Onshore switching stations (8 or less bay[2])
Station	New	HVAC	AIS & GIS	220	-	220kV Onshore switching stations (9-16 bay[2])
Station	New	HVAC	AIS & GIS	110	-	110kV Onshore switching stations (8 or less bay[2])
Station	New	HVAC	AIS & GIS	110	-	110kV Onshore switching stations (9-16 bay[2])
Station	New	HVDC	VSC	TBD	**750**	None -TBD
Station	New	HVAC	AIS & GIS	400	**750**	400kV Offshore generating stations
Station	New	HVAC	AIS & GIS	220	**750**	220kV Offshore generating stations
Station	New	MVDC	AIS & GIS	110	**250**	110kV Offshore generating stations
Station	New	HVAC	AIS & GIS	400	**750**	400kV Offshore switching stations
Station	New	HVAC	AIS & GIS	220	**750**	220kV Offshore switching stations
Station	New	HVDC	VSC	TBD	**750**	None - TBD; offshore station
Static devices	New	HVAC	Transformer	400/220	**500**	500MVA Onshore Auto Transformer
Static devices	New	HVAC	Transformer	400/110	**500**	500MVA Onshore Double Wound Transformer
Static devices	New	HVAC	Transformer	220/110	**250**	250MVA Onshore Auto Transformer

Table B-1: Technology list

DOMAIN	PATH	CLASS	TYPE	Description: VOLTAGE (kV)	Description: RATING (MVA)	Description: TECHNOLOGY
Static devices	New	HVAC	Transformer	220/110	**250**	250MVA Onshore Double Wound Transformer
Static devices	New	HVAC	Transformer	220/110	**125**	125MVA Onshore Auto Transformer
Static devices	New	HVAC	Flow regulator	220	-	220kV; Phase shift transformer
Static devices	New	HVAC	Flow regulator	110	-	110kV; Phase shift transformer
Dynamic devices	New	HVAC	Flow regulator	400	-	400kV, Thyristor controlled Series Capacitors
Dynamic devices	New	HVAC	Flow regulator	220	-	220kV; Thyristor controlled Series Capacitors
Dynamic devices	New	HVAC	Flow regulator	110	-	110kV; Thyristor controlled Series Capacitors
Dynamic devices	New	HVAC	Flow regulator	400	-	400kV; Thyristor controlled Series reactors
Dynamic devices	New	HVAC	Flow regulator	220	-	220kV; Thyristor controlled Series reactors
Dynamic devices	New	HVAC	Flow regulator	110	-	110kV; Thyristor controlled Series reactors
Dynamic devices	New	HVAC	Flow regulator	400	-	400kV; Thyristor switched Series Capacitors
Dynamic devices	New	HVAC	Flow regulator	220	-	220kV; Thyristor switched Series Capacitors
Dynamic devices	New	HVAC	Flow regulator	110	-	110kV; Thyristor switched Series Capacitors
Dynamic devices	New	HVAC	Flow regulator	400	-	400kV; Thyristor switched Series Reactors
Dynamic devices	New	HVAC	Flow regulator	220	-	220kV; Thyristor switched Series Reactors
Dynamic devices	New	HVAC	Flow regulator	110	-	110kV; Thyristor switched Series Reactors
Static devices	New	HVAC	Flow regulator	400	-	400kV; Distributed Series Reactors (PLGs)
Static devices	New	HVAC	Flow regulator	220	-	220kV; Distributed Series Reactors (PLGs)
Static devices	New	HVAC	Flow regulator	110	-	110kV; Distributed Series Reactors (PLGs)
Static devices	New	HVAC	Flow regulator	110	-	110kV; Routers
Dynamic devices	New	HVAC	Flow regulator	400	-	400kV; Static Synchronous Series Compensation (SSSC)

Table B-1: Technology list

DOMAIN	PATH	CLASS	TYPE	Description: VOLTAGE (kV)	Description: RATING (MVA)	Description: TECHNOLOGY
Dynamic devices	New	HVAC	Flow regulator	220	-	220kV; Static Synchronous Series Compensation (SSSC)
Dynamic devices	New	HVAC	Multi-service	400	-	400kV; Unified Power Flow Controller (UPFC)
Dynamic devices	New	HVAC	Multi-service	220	-	220kV; Unified Power Flow Controller (UPFC)
Dynamic devices	New	HVAC	Multi-service	110	-	110kV; Unified Power Flow Controller (UPFC)
Dynamic devices	New	HVAC	Multi-service	400	-	400kV; Interline Power Flow Controller (IPFC)
Dynamic devices	New	HVAC	Multi-service	220	-	220kV; Interline Power Flow Controller (IPFC)
Dynamic devices	New	HVAC	Multi-service	110	-	110kV; Interline Power Flow Controller (IPFC)
Static devices	New	HVAC	Voltage regulator	110	-	Shunt capacitors: 110kV - 15Mvar
Static devices	New	HVAC	Voltage regulator	110	-	Shunt capacitors: 110kV - 30Mvar
Static devices	New	HVAC	Voltage regulator	400	-	Shunt reactors: 400kV
Static devices	New	HVAC	Voltage regulator	220	-	Shunt reactors: 220kV
Static devices	New	HVAC	Voltage regulator	110	-	Shunt reactors: 110kV
Static devices	New	HVAC	Voltage regulator	110	-	Magnetically Controlled Shunt Reactor: 110kV
Dynamic devices	New	HVAC	Voltage regulator	110	-	Static VAR Compensator (SVC): 110kV
Dynamic devices	New	HVAC	Voltage regulator	110	-	Static Compensator (STATCOM): 110kV

Appendix C: Reinforcements for Generation-Led Approach

Table C-1: Reinforcements for Generation-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
1	MIDLANDS 110 kV - No.1	110	New	Substation	HVAC	GIS	Ireland
2	MIDLANDS 220 kV - No.1	220	New	Substation	HVAC	GIS	Ireland
3	MIDLANDS - MIDLANDS - 220/110 kV - No.1	220/110	New	Static device	HVAC	Transformer	Ireland
4	MIDLANDS - MIDLANDS - 220/110 kV - No.2	220/110	New	Static device	HVAC	Transformer	Ireland
5	KELLS - RASHARKIN - 110 kV - No.2	110	New	Circuit	HVAC	OHL/UGC	Northern Ireland
6	LIMAVADY - AGIVEY - 110 kV - No.1	110	New	Circuit	HVAC	OHL/UGC	Northern Ireland
7	WOODLAND - FINGLAS - 220 kV - No.3	220	New	Circuit	HVAC	OHL/UGC	Ireland
8	BELCAMP - FINGLAS - 220 kV - No.2	220	New	Circuit	HVAC	UGC	Ireland
9	GREAT ISLAND - GREAT ISLAND - 220/110 kV - No.3	220/110	New	Static device	HVAC	Transformer	Ireland
10	INCHICORE - CARRICKMINES - 220 kV - No.1	220	New	Circuit	HVAC	UGC	Ireland
11	DUNSTOWN - WOODLAND - 380 kV - No.1	380	New	Circuit	HVAC	UGC	Ireland
12	ARKLOW - ARKLOW - 220/110 kV - No.3	220/110	New	Static device	HVAC	Transformer	Ireland
13	CULLENAGH - WATERFORD - 110 kV - No.2	110	New	Circuit	HVAC	OHL/UGC	Ireland
14	WOODLAND - ORIEL - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
15	LOUTH - ORIEL - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
16	ARKLOW - LODGEWOOD - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
17	POOLBEG - INCHICORE - 220 kV - No.1	220	Uprate	Circuit	HVAC	UGC	Ireland
18	AGHADA - KNOCKRAHA - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
19	AGHADA - KNOCKRAHA - 220 kV - No.2	220	Uprate	Circuit	HVAC	OHL	Ireland
20	CAHIR - BARRYMORE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
21	CRANE - WEXFORD - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
22	KNOCKRAHA - BARRYMORE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
23	ARKLOW - CARRICKMINES - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
24	LANESBORO - SLIABH BAWN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland

Table C-1: Reinforcements for Generation-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
25	GREAT ISLAND - LODGEWOOD - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
26	POOLBEG - INCHICORE - 220 kV - No.2	220	Uprate	Circuit	HVAC	UGC	Ireland
27	DRYBRIDGE - LOUTH - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
28	BANDON - DUNMANWAY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
29	KNOCKRANNY - GALWAY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
30	CARRICKMINES - DUNSTOWN - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
31	CORDUFF - FINGLAS - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
32	CORDUFF - FINGLAS - 220 kV - No.2	220	Uprate	Circuit	HVAC	OHL	Ireland
33	GORMAN - MAYNOOTH - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
34	MAYNOOTH - MIDLANDS - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
35	SHANNONBRIDGE - MIDLANDS - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
36	COOLKEERAGH - STRABANE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
37	DRUMNAKELLY - TAMNAMORE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
38	DRUMNAKELLY - TAMNAMORE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
39	COOLKEERAGH - KILLYMALLAGHT - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
40	COOLKEERAGH - LIMAVADY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
41	OMAGH - STRABANE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
42	ARKLOW - BALLYBEG - 110 kV No. 1	220	Upvoltage	Circuit	HVAC	OHL	Ireland
43	BALLYBEG - CARRICKMINES - 110 kV No.1	220	Upvoltage	Circuit	HVAC	OHL	Ireland
44	BALLYBEG - 220 kV - No.1	220	New	Substation	HVAC	GIS	Ireland
45	BALLYBEG - BALLYBEG - 220/110 kV - No.1	220/110	New	Static device	HVAC	Transformer	Ireland
46	BALLYBEG - BALLYBEG - 220/110 kV - No.2	220/110	New	Static device	HVAC	Transformer	Ireland

Appendix D: Reinforcements for Developer-Led Approach

Table D-1: Reinforcements for Developer-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
1	KELLS - RASHARKIN - 110 kV - No.2	110	New	Circuit	HVAC	OHL/UGC	Northern Ireland
2	DUNSTOWN - WOODLAND - No.1	380	New	Circuit	HVAC	OHL/UGC	Ireland
3	OMAGH 275 kV - No.1	275	New	Substation	HVAC	GIS	Northern Ireland
4	OMAGH - TURLEENAN - 275 kV - No.1	275	New	Circuit	HVAC	OHL/UGC	Northern Ireland
5	OMAGH - OMAGH - 275/110 kV - No.1	275/110	New	Static device	HVAC	Transformer	Northern Ireland
6	OMAGH - OMAGH - 275/110 kV - No.2	275/110	New	Static device	HVAC	Transformer	Northern Ireland
7	CLOGHER 220 kV - No.1	220	New	Substation	HVAC	GIS	Ireland
8	CLOGHER - CLOGHER - 220/110 kV - No.1	220/110	New	Static device	HVAC	Transformer	Ireland
9	CLOGHER - SRANANAGH - 220 kV - No.1	220	New	Circuit	HVAC	OHL/UGC	Ireland
10	WOODLAND - FINGLAS - 220 kV - No.3	220	New	Circuit	HVAC	OHL/UGC	Ireland
11	BELLACORICK - 220 kV - No.1	220	New	Substation	HVAC	GIS	Ireland
12	BELLACORICK - BELLACORICK - 220/110 kV - No.1	220/110	New	Static device	HVAC	Transformer	Ireland
13	BELLACORICK - BELLACORICK - 220/110 kV - No.2	220/110	New	Static device	HVAC	Transformer	Ireland
14	BELLACORICK - FLAGFORD - 220 kV - No.1	220	New	Circuit	HVAC	OHL/UGC	Ireland
15	CLOGHER - 275 kV - No.1	275	New	Substation	HVAC	GIS	Ireland
16	CLOGHER - CLOGHER - 275/220 kV - No.1	275/220	New	Static device	HVAC	Transformer	Ireland
17	CLOGHER - CLOGHER - 275/220 kV - No.2	275/220	New	Static device	HVAC	Transformer	Ireland
18	CLOGHER - CLOGHER - 220/110 kV - No.2	220/110	New	Static device	HVAC	Transformer	Ireland
19	CLOGHER - OMAGH - 275 kV - No.1	275	New	Circuit	HVAC	OHL/UGC	Ireland
20	CLOGHER - OMAGH - 275 kV - No.1	275	New	Circuit	HVAC	OHL/UGC	Northern Ireland
21	LETTERKENNY - 275 kV - No.1	275	New	Substation	HVAC	GIS	Ireland
22	LETTERKENNY - LETTERKENNY - 275/110 kV - No.1	275/110	New	Static device	HVAC	Transformer	Ireland
23	LETTERKENNY - LETTERKENNY - 275/110 kV - No.2	275/110	New	Static device	HVAC	Transformer	Ireland
24	LETTERKENNY - COOLKEERAGH - 275 kV - No.1	275	New	Circuit	HVAC	OHL/UGC	Ireland

Table D-1: Reinforcements for Developer-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
25	LETTERKENNY - COOLKEERAGH - 275 kV - No.1	275	New	Circuit	HVAC	OHL/UGC	Northern Ireland
26	KNOCKRAHA - GREAT ISLAND - 220 kV - No.1	220	New	Circuit	HVAC	OHL/UGC	Ireland
27	GREAT ISLAND - GREAT ISLAND - 220/110 kV - No.3	220/110	New	Static device	HVAC	Transformer	Ireland
28	FINGLAS - NORTH WALL - 220 kV - No.1	220	Uprate	Circuit	HVAC	UGC	Ireland
29	NORTH WALL - POOLBEG - 220 kV - No.1	220	Uprate	Circuit	HVAC	UGC	Ireland
30	POOLBEG - CARRICKMINES - 220 kV - No.1	220	Uprate	Circuit	HVAC	UGC	Ireland
31	POOLBEG - INCHICORE - 220 kV - No.1	220	Uprate	Circuit	HVAC	UGC	Ireland
32	POOLBEG - INCHICORE - 220 kV - No.2	220	Uprate	Circuit	HVAC	UGC	Ireland
33	CASHLA - SALTHILL - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
34	GALWAY - SALTHILL - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
35	CORDUFF - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
36	CRANE - WEXFORD - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
37	MAYNOOTH - BLAKE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
38	KNOCKRANNY - GALWAY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
39	BANDON - DUNMANWAY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
40	DRUMKEEN - LETTERKENNY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
41	AGHADA - KNOCKRAHA - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
42	AGHADA - KNOCKRAHA - 220 kV - No.2	220	Uprate	Circuit	HVAC	OHL	Ireland
43	MAYNOOTH - TIMAHOE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
44	MULLINGAR - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
45	DRYBRIDGE - LOUTH - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
46	BINBANE - CATHALEEN'S FALL - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
47	ARVA - CARRICK-ON-SHANNON - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
48	MAYNOOTH - RINAWADE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
49	MARINA - KILBARRY - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland
50	KNOCKRAHA - BARRYMORE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland

Table D-1: Reinforcements for Developer-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
51	WOODLAND - ORIEL - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
52	CAHIR - BARRYMORE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
53	LANESBORO - SLIABH BAWN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
54	LETTERKENNY - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
55	RINAWADE - DUNFIRTH TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
56	GREAT ISLAND - KELLIS - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
57	BARODA - MONREAD - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
58	DRUMKEEN - CLOGHER - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
59	GOLAGH TEE - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
60	CLAHANE - TRIEN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
61	BARODA - NEWBRIDGE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
62	MULLINGAR - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
63	LETTERKENNY - TRILLICK - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
64	KNOCKRAHA - KILLONAN - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
65	KNOCKANURE - TRIEN - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland
66	ARKLOW - CARRICKMINES - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
67	GORMAN - MAYNOOTH - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
68	GREAT ISLAND - LODGEWOOD - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
69	BANDON - RAFFEENB - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
70	CASHLA - GALWAY - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland
71	CASHLA - GALWAY - 110 kV - No.3	110	Uprate	Circuit	HVAC	OHL	Ireland
72	FLAGFORD - SLIABH BAWN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
73	ARKLOW - LODGEWOOD - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
74	KILKENNY - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
75	ATHY - CARLOW - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
76	GORMAN - LOUTH - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland

Table D-1: Reinforcements for Developer-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
77	DUNSTOWN - KELLIS - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
78	LOUTH - RATRUSSAN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
79	MAYNOOTH - SHANNONBRIDGE - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
80	DRUMNAKELLY - TAMNAMORE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
81	DRUMNAKELLY - TAMNAMORE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
82	COOLKEERAGH - STRABANE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
83	COOLKEERAGH - KILLYMALLAGHT - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
84	DRUMNAKELLY - TANDRAGEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
85	DRUMNAKELLY - TANDRAGEE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
86	NEWRY - TANDRAGEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
87	NEWRY - TANDRAGEE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
88	OMAGH - STRABANE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
89	COOLKEERAGH - 83510 LIMAVADY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
90	BALLYLUMFORD - BALLYVALLAGH - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
91	BALLYLUMFORD - BALLYVALLAGH - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
92	ARKLOW - BALLYBEG - 110 kV No. 1	220	Upvoltage	Circuit	HVAC	OHL	Ireland
93	BALLYBEG - CARRICKMINES - 110 kV No.1	220	Upvoltage	Circuit	HVAC	OHL	Ireland
94	BALLYBEG - 220 kV - No.1	220	New	Substation	HVAC	GIS	Ireland
95	BALLYBEG - BALLYBEG - 220/110 kV - No.1	220/110	New	Static device	HVAC	Transformer	Ireland
96	BALLYBEG - BALLYBEG - 220/110 kV - No.2	220/110	New	Static device	HVAC	Transformer	Ireland

Appendix E: Reinforcements for Technology-Led Approach

Table E-1: Reinforcements for Technology-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
1	KELLS - RASHARKIN - 110 kV - No.2	110	New	Circuit	HVAC	OHL/UGC	Northern Ireland
2	OMAGH - 275 kV - No.1	275	New	Substation	HVAC	GIS	Northern Ireland
3	DUNGANNON - OMAGH - 110 kV - No.1	275	Upvoltage	Circuit	HVAC	OHL	Northern Ireland
4	DUNGANNON - TURLEENAN - 110 kV - No.3	275	Upvoltage	Circuit	HVAC	OHL	Northern Ireland
5	OMAGH - OMAGH - 275/110 kV - No.1	275/110	New	Static device	HVAC	Transformer	Northern Ireland
6	OMAGH - OMAGH - 275/110 kV - No.2	275/110	New	Static device	HVAC	Transformer	Northern Ireland
7	DUNSTOWN - MAYNOOTH - No.2	380	Upvoltage	Circuit	HVAC	OHL	Ireland
8	DUNSTOWN - WOODLAND - No.2	380	Upvoltage	Circuit	HVAC	OHL	Ireland
9	COOLKEERAGH - 320 kV - No.1	320	New	Substation	HVDC	Converter	Northern Ireland
10	KILROOT - 320 kV - No.1	320	New	Substation	HVDC	Converter	Northern Ireland
11	COOLKEERAGH - KILROOT - 320 kV - No.1	320	New	Circuit	HVDC	UGC	Northern Ireland
12	CLOGHER - 320 kV - No.1	320	New	Substation	HVDC	Converter	Ireland
13	WOODLAND - 320 kV - No.1	320	New	Substation	HVDC	Converter	Ireland
14	CLOGHER - WOODLAND - 220 kV - No.1	320	New	Circuit	HVDC	UGC	Ireland
15	BELLACORICK - 320 kV - No.1	320	New	Substation	HVDC	Converter	Ireland
16	MONEYPOINT - 320 kV - No.1	320	New	Substation	HVDC	Converter	Ireland
17	BELLACORICK - MONEYPOINT - 380 kV - No.1	320	New	Circuit	HVDC	SMC	Ireland
18	GREAT ISLAND - GREAT ISLAND - 220/110 kV - No.3	220/110	New	Static device	HVAC	Transformer	Ireland
19	WOODLAND - FINGLAS - 220 kV - No.3	220	New	Circuit	HVAC	OHL/UGC	Ireland
20	INCHICORE - CARRICKMINES - 220 kV - No.1	220	New	Circuit	HVAC	UGC	Ireland
21	CASHLA - SALTHILL - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
22	GALWAY - SALTHILL - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
23	CRANE - WEXFORD - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
24	CORDUFF - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland

Table E-1: Reinforcements for Technology-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
25	BANDON - DUNMANWAY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
26	KNOCKRANNY - GALWAY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
27	MAYNOOTH - BLAKE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
28	CAHIR - BARRYMORE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
29	MAYNOOTH - TIMAHOE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
30	AGHADA - KNOCKRAHA - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
31	AGHADA - KNOCKRAHA - 220 kV - No.2	220	Uprate	Circuit	HVAC	OHL	Ireland
32	KNOCKRAHA - BARRYMORE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
33	MARINA - KILBARRY - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland
34	BARODA - MONREAD - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
35	MAYNOOTH - RINAWADE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
36	ARVA - CARRICK-ON-SHANNON - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
37	MULLINGAR - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
38	CLAHANE - TRIEN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
39	GREAT ISLAND - KELLIS - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
40	FINGLAS - NORTH WALL - 220 kV - No.1	220	Uprate	Circuit	HVAC	UGC	Ireland
41	GREAT ISLAND - LODGEWOOD - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
42	KNOCKANURE - TRIEN - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland
43	RINAWADE - DUNFIRTH TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
44	KILLOTERAN - WATERFORD - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
45	CASHLA - GALWAY - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland
46	CASHLA - GALWAY - 110 kV - No.3	110	Uprate	Circuit	HVAC	OHL	Ireland
47	FLAGFORD - SLIABH BAWN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
48	SINGLAND - ARDNACRUSHA - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
49	LANESBORO - SLIABH BAWN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
50	CLOON - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland

Table E-1: Reinforcements for Technology-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
51	COOLKEERAGH - STRABANE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
52	DRUMNAKELLY - TAMNAMORE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
53	DRUMNAKELLY - TAMNAMORE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
54	COOLKEERAGH - KILLYMALLAGHT - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
55	OMAGH - STRABANE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
56	ARKLOW - BALLYBEG - 110 kV No. 1	220	Upvoltage	Circuit	HVAC	OHL	Ireland
57	BALLYBEG - CARRICKMINES - 110 kV No.1	220	Upvoltage	Circuit	HVAC	OHL	Ireland
58	BALLYBEG - 220 kV - No.1	220	New	Substation	HVAC	GIS	Ireland
59	BALLYBEG - BALLYBEG - 220/110 kV - No.1	220/110	New	Static device	HVAC	Transformer	Ireland
60	BALLYBEG - BALLYBEG - 220/110 kV - No.2	220/110	New	Static device	HVAC	Transformer	Ireland

Appendix F: Reinforcements for Demand-Led Approach

Table F-1: Reinforcements for Demand-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
1	KELLS - RASHARKIN - 110 kV - No.2	110	New	Circuit	HVAC	OHL/UGC	Northern Ireland
2	CLOGHER 220 kV - No.1	220	New	Substation	HVAC	GIS	Ireland
3	CLOGHER - CLOGHER - 220/110 kV - No.1	220/110	New	Static device	HVAC	Transformer	Ireland
4	CLOGHER - SRANANAGH - 220 kV - No.1	220	New	Circuit	HVAC	OHL/UGC	Ireland
5	TRILLICK - COOLKEERAGH - 110 kV - No.1	110	New	Circuit	HVAC	OHL/UGC	Ireland
6	TRILLICK - COOLKEERAGH - 110 kV - No.1	110	New	Circuit	HVAC	OHL/UGC	Northern Ireland
7	BELLACORICK - MOY - 110 kV - No.2	110	New	Circuit	HVAC	OHL/UGC	Ireland
8	LIMAVADY - AGIVEY - 110 kV - No.1	110	New	Circuit	HVAC	OHL/UGC	Northern Ireland
9	GREAT ISLAND - GREAT ISLAND - 220/110 kV - No.3	220/110	New	Static device	HVAC	Transformer	Ireland
10	CULLENAGH - GREAT ISLAND - 110 kV - No.1	110	New	Circuit	HVAC	OHL/UGC	Ireland
11	SLIGO - SRANANAGH - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
12	SLIGO - SRANANAGH - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland
13	CASHLA - SALTHILL - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
14	GALWAY - SALTHILL - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
15	DRUMKEEN - LETTERKENNY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
16	KNOCKRANNY - GALWAY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
17	LETTERKENNY - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
18	CRANE - WEXFORD - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
19	BANDON - DUNMANWAY - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
20	CORDUFF - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
21	MAYNOOTH - TIMAHOE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
22	AGHADA - KNOCKRAHA - 220 kV - No.1	220	Uprate	Circuit	HVAC	OHL	Ireland
23	AGHADA - KNOCKRAHA - 220 kV - No.2	220	Uprate	Circuit	HVAC	OHL	Ireland
24	MARINA - KILBARRY - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland

Table F-1: Reinforcements for Demand-Led approach

	Reinforcement Component	Voltage (kV)	Path	Domain	Class	Type	Jurisdiction
25	KNOCKRAHA - BARRYMORE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
26	DRUMKEEN - CLOGHER - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
27	GOLAGH TEE - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
28	BINBANE - CATHALEEN'S FALL - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
29	CAHIR - BARRYMORE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
30	MAYNOOTH - BLAKE TEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
31	MULLINGAR - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
32	ARVA - CARRICK-ON-SHANNON - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
33	BARODA - MONREAD - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
34	MAYNOOTH - RINAWADE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
35	LANESBORO - SLIABH BAWN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
36	FLAGFORD - SLIABH BAWN - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
37	CLOON - NEW STATION - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Ireland
38	CASHLA - GALWAY - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Ireland
39	CASHLA - GALWAY - 110 kV - No.3	110	Uprate	Circuit	HVAC	OHL	Ireland
40	COOLKEERAGH - STRABANE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
41	DRUMNAKELLY - TAMNAMORE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
42	DRUMNAKELLY - TAMNAMORE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
43	COOLKEERAGH - KILLYMALLAGHT - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
44	OMAGH - STRABANE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
45	DRUMNAKELLY - TANDRAGEE - 110 kV - No.1	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
46	DRUMNAKELLY - TANDRAGEE - 110 kV - No.2	110	Uprate	Circuit	HVAC	OHL	Northern Ireland
47	ARKLOW - BALLYBEG - 110 kV No. 1	220	Upvoltage	Circuit	HVAC	OHL	Ireland
48	BALLYBEG - CARRICKMINES - 110 kV No.1	220	Upvoltage	Circuit	HVAC	OHL	Ireland
49	BALLYBEG - 220 kV - No.1	220	New	Substation	HVAC	GIS	Ireland
50	BALLYBEG - BALLYBEG - 220/110 kV - No.1	220/110	New	Static device	HVAC	Transformer	Ireland
51	BALLYBEG - BALLYBEG - 220/110 kV - No.2	220/110	New	Static device	HVAC	Transformer	Ireland

Appendix G: Mapping of DS3 system services

Table G-1: Existing products mapping table

DS3 balancing Service	Existing Scheduled and Dispatched products	SOGL	EBGL specific product	EBGL standard product balancing capacity	EBGL standard product balancing energy
SIR	Inertia	N/A	N/A	N/A	N/A
FFR (2-10 sec)	MMS Reports On	N/A	N/A	N/A	N/A
POR (5-15sec)	POR (5-15sec)	FCR	N/A	N/A	FCR
SOR (15-90sec)	SOR (15-90sec)	FCR	N/A	N/A	FCR
TOR1 (90sec-5min)	TOR (90sec-5min)	FRR	N/A	N/A	mFRR (12.5 min FAT)
TOR2 (5-20min)	TOR (5-20min)	FRR	N/A	N/A	mFRR (12.5 min FAT) RR (30min FAT)
RRS (20min-1hr)	RR (20min-4hrs)	RR	N/A	N/A	mFRR (12.5 min FAT) RR (30min FAT)
RRD (20min-1hr)	RR (20min-4hrs)	RR	N/A	N/A	mFRR (12.5 min FAT) RR (30min FAT)
RM1	MMS Reports On	N/A	N/A	N/A	N/A
RM3	MMS Reports On	N/A	N/A	N/A	N/A
RM8	MMS Reports On	N/A	N/A	N/A	N/A

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