Celtic Interconnector Project

Investment Request File

7th September 2018

EIRGRID

Rte Le réseau de transport d'électricité

Co-financed by the European Union
Connecting Europe Facility

Contents

Amendment

Date	Description
07/09/2018	Initial submission.
31/10/2018	Appendix A12 merged with main document as requested by the NRAs. Appendix A12 previously a standalone document. Correction to figures in Table 14.

Glossary

AC	Alternating Current
ACER	Agency for the Cooperation of Energy Regulators
CAPEX	Capital Expenditure
CBA	Cost Benefit Analysis
CBCA	Cross Border Cost Allocation
CEF	Connecting Europe Facility
CIGRE	The International Council on Large Electric Systems
CR	Congestion Rent
CRE	Commission de Régulation de L'énergie, the French energy regulator
CRU	Commission for the Regulation of Utilities, the Irish energy regulator
DC	Direct Current
EENS	Expected Energy Not Served
EEZ	Exclusive Economic Zone
EIA	Environmental Impact Assessment
EIB	European Investment Bank
ENTSO-E	European Networks of Transmission System Operators for Electricity
EPC	Engineer, Procure and Construct
EU	European Union
EUCO	European Commission developed 2030 Scenario
EWIC	East-West Interconnector
FID	Final Investment Decision
GB	Great Britain encompassing England, Scotland and Wales
GHG	Green House Gases
GTC	Grid Transfer Capacity
GW	Giga Watts (1,000,000,000 Watts)
GWh	Giga Watt Hours
HVAC	High Voltage Alternating Current
HVDC	High voltage Direct Current
IJV	Incorporated Joint Venture
IE	Republic of Ireland
I-SEM	Integrated Single Electricity Market
IRR	Internal Rate of Return
kV	Kilo Volt
LSI/LSO	Largest System Infeed/Outfeed
M€	Million €
MI	Mass Impregnated Cable
MVA	Mega Volt Amp
MW	Mega Watt (1,000,000 Watts)
MWh	Mega Watt Hour
NGO	Non-Governmental Organisation
NI	Northern Ireland
NPV	Net Present Value
NRA	National Regulatory Authority
NSI	North South Electricity Interconnections
OJEU	Official Journal of the European Union
O&M	Operation and Maintenance
OPEX	Operating Expenditure

PCI	Project of Common Interest, a list of key energy infrastructure projects drawn by the EC
RAB	Regulatory Asset Base
RES	Renewable Energy Sources
RTE	Réseau de Transport d'Électricité
SEM	Single Electricity Market
SEW	Socio-Economic Welfare
SoS	Security of Supply
SNSP	System Non-Synchronous Penetration
TEN-E	Trans-European Networks for Energy
TSO	Transmission System Operator
TUoS	Transmission Use of System Charges
TWs	Territorial Waters
TYNDP	Ten Year Network Development Plan
TYTFS	All-Island Ten Year Transmission Forecast Statement 2017
UK	United Kingdom
UXO	Unexploded Ordnance
VoLL	Value of Lost Load
VSC	Voltage Source Conversion
WACC	Weighted Average Cost of Capital
XLPE	Cross Linked Polyethylene Cable

Introduction

The Celtic Interconnector would be the first direct energy link between Ireland and France, running from the south coast of Ireland to the north-west coast of France. The project promoters are EirGrid and Réseau de Transport d'Électricité (RTE), the Transmission System Operators in Ireland and France. EirGrid and RTE have jointly conducted studies to assess the feasibility of the project and have carried out the cost-benefit analyses (CBAs) included in this Investment Request.

Interconnection is a very important part of modern power grids offering multiple benefits to the electricity consumers:

- Facilitates increased electricity trading resulting in downward pressure on the cost of electricity,
- Enhances security of supply by providing an additional supply of power and increased diversification, and
- Reduces emissions by facilitating the development of renewable sources, particularly variable sources such as wind.

The European Commission sees increased interconnection as a key step towards achieving a more integrated electricity system and considers the Celtic Interconnector to be an important move towards achieving such integration.

The Celtic Interconnector was designated as a Project of Common Interest (PCI) in 2013 and has retained that label during the reviews in 2015 and 2017. It has also been designated as an Electrical Highway under the EU supported e-Highway 2050 project. This identifies the project as part of developments on the European grid needed to meet the EU's 2050 low carbon economy goals. The Celtic Interconnector is one of the few to achieve this double labelling. PCIs can benefit from accelerated planning and permit granting. They also have access to financial support from the Connecting Europe Facility (CEF). The Interconnector has already been supported with over 3.5 M€ provided for the Feasibility Phase of the project and a further 4 M€ allocated for the current phase of the project.

The ENTSO-E's Ten-Year Network Development Plan (TYNDP) 2018 assessment of the Celtic Interconnector is the foundation of the Cost Benefit Analysis (CBA) included in this Investment Request. It constitutes the basis for PCI assessment and selection under the EU Regulation No 347/2013 on guidelines for trans-European energy infrastructure (TEN-E Regulation). Both project promoters are confident of the maturity of the project. To deliver this new interconnector, they have decided to submit a grant application under the framework of the CEF process and consider that a grant at an appropriate level is crucial to realise the project. Prior to this application, and pursuant to Article 12 of TEN-E Regulation, EirGrid and RTE are now submitting a joint Investment Request to the concerned national regulatory authorities (NRAs) for approval.

The NRAs, the Commission for Regulation of Utilities (CRU) in Ireland and the Commission de Régulation de l'Énergie (CRE) in France, are requested to consider this Investment Request and decide on the approval for inclusion in each country's tariffs and a decision on Cross-Border Cost Allocation (CBCA) for the project.

Document Structure

There are 8 sections in this document.

Sections 1 to 3 set out a description of the project, its current status and forecasted costs.

Section 4 details the CBA for the Celtic Interconnector. This has been performed in the framework of the pan-European TYNDP 2018.

Section 5 presents an analysis of the Celtic Interconnector's impact at a national level. This is to identify if there are countries other than Ireland and France that should be considered as part of the CBCA.

Section 6 outlines the additional externalities of the Celtic Interconnector that are not captured within the CBA. These include the positive externalities of solidarity, market integration and sustainability, at least one of which is required under EU legislation to be eligible for EU grant funding under CEF.

Section 7 sets out the project business plan which includes analysis of forecasted annual cash flows, grant funding eligibility, financing and regulatory arrangements.

Section 8 sets out EirGrid and RTE's proposal for CBCA for the project.

Extra supporting information is provided in the Appendices.

1 Project Description

The proposed Celtic Interconnector project consists of a High Voltage Direct Current (HVDC) link, rated at 700 MW, between East Cork (Ireland) and West Brittany (France). This section provides an overview of the main technical features of the project. Complementary technical information is provided in Appendix A1.

1.1 Main Technical Features

The main elements of the interconnector are illustrated in Figure 1 and consist of:

- A submarine circuit, approximately 500km in length placed on or beneath the seabed between France and Ireland.

and for each country:

- A landfall point where the submarine circuit comes onshore,
- A HVDC land circuit between the landfall and a converter station. This circuit is proposed as an underground cable,
- A converter station, to convert the electricity from HVDC to High Voltage Alternating Current (HVAC), which is used on the transmission grid,
- A relatively short HVAC land circuit between the converter station and the connection point to the grid. This circuit is proposed as underground cable, and
- A connection point to an existing substation on the transmission grid.

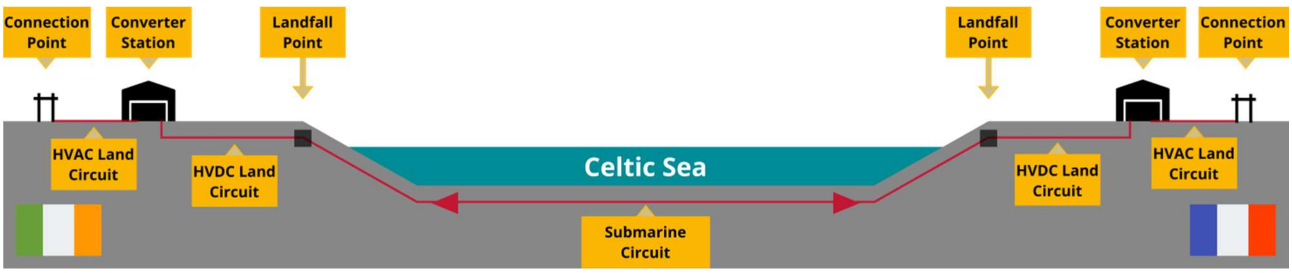


Figure 1 - Celtic Interconnector Project Elements

1.1.1 Technical Parameters

The technical parameters of the project were assessed during the Feasibility Phase and are proposed as follows:

Table 1: Technical Parameters of the Project

Technical Parameter	Value
Power rating	700 MW (plus losses)
AC voltage	220 kV in Ireland and 400 kV in France
DC voltage	320 kV (current option)
DC configuration (for example, monopole/bipole)	Symmetrical monopole
Converter Stations	Voltage Source Conversion (VSC) technology
Number of DC submarine cables	2
Submarine route length	500 km
Land cable length Ireland and France	75 km
Number of DC underground cables	2 in Ireland and 2 in France
Telecommunications	1 fibre optic cable laid alongside power cables

The parameters in Table 1 have been selected based on considerations including the technical maturity, cost and performance of the interconnector elements. Compliance with specific parameters relating to respective Grid Codes will be a requirement of the EPC Procurement Process.

1.2 Rationale behind the Technical Choices

Transfer Capacity

The current largest single infeed/outflow (LSI/LSO) to the Irish system is that of East West Interconnector (EWIC) at 500 MW. Engineering studies were carried out on a range of factors including the operational requirements and characteristics of the Irish transmission system. An interconnector capacity was sought which would make large grid reinforcements or operational changes unnecessary. The studies concluded that it would be feasible to support a 700 MW interconnector without major investment in the existing transmission grid and based on the general connection locations being considered. This 700 MW capacity was also confirmed through the Brittany voltage stability study.

A number of other options were considered (for example, 1,000 MW, 2x500 MW), and it was determined that, after balancing of cost versus benefit for both Ireland and France, 700 MW was the best size for this project.

Technology

HVDC technology is the only feasible option for the transfer of electricity over long distances in the marine environment. During the Feasibility Phase several HVDC scheme configurations were assessed based on their relative costs and benefits.

HVDC links can be classified chronologically according to the three basic HVDC converter technologies:

1. **Line Commutated Converters (LCC**) – Sometimes referred to as “conventional” HVDC or “classic” HVDC, this technology utilises thyristor valves at the converter stations. LCC has been installed and operational since the mid-1950s, with thyristors in use in LCC converter stations since 1972 (prior to that mercury arc valves were used).
2. **Voltage Source Converters (VSC)** – Voltage source converters use Insulated Gate Bipolar Transistors (IGBTs) instead of thyristors in the conversion process. Rather than relying on the network voltage for commutation, the IGBTs are switched on and off under the direction of a control system to develop an AC and DC voltage waveform. VSC technology was first introduced by ABB in 1997.
3. **Capacitive Commutated Converters (CCC)** – Capacitive commutated converters are a variation of LCC and use the same thyristor technology. CCC technology was introduced in 1990 to deal with issues with weak AC networks. The first CCC scheme was commissioned in 1999.

The Irish and French transmission system connection points have low Short Circuit Ratios (SCR) and this is why LCC or CCC HVDC technology would not be considered an optimum solution. VSC schemes have less reliance on SCR and can operate in a completely passive system with no generation, zero fault level and/or zero SCR.

VSC also provides the required characteristics to optimise the benefits of the project, for example:

- Operate in a system with low short circuit levels,
- Provide voltage support to the region,
- Provide black start capability, and
- Provide frequency response to faults on the system.

Based on the above it was decided that the Celtic Interconnector project will use HVDC VSC technology.

Converter Station Scheme Configuration

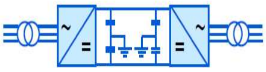
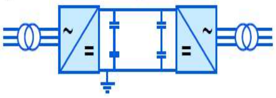
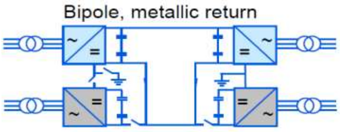
There are a number of different HVDC VSC scheme configurations which could be used for the Celtic Interconnector. EirGrid and RTE examined the three main options which are listed below:

- Symmetric Monopole,
- Asymmetric Monopole, and
- Bipole.

The terms “monopole” and “bipole” refer to the use of one or two high voltage DC polarities to interconnect the converters of an HVDC bulk power transmission scheme. A configuration with a single high voltage DC polarity (either positive or negative polarity relative to earth) is referred to as being monopolar or a monopole. A configuration with two high voltage DC polarities (one positive and one negative relative to ground) is referred to as being bipolar or a bipole.

Table 2 shows these three configurations with their key features and a summary of the analysis carried out.

Table 2 - Converter Station Scheme Options

Scheme	Key Features	Analysis Summary
Symmetric monopole 	▪ 2 high voltage cables ▪ 2 converter stations	▪ Lowest cost solution ▪ No special transformers ▪ Limited DC ground current
Asymmetric monopole, metallic return 	▪ 1 high voltage cable ▪ 1 Low voltage cable ▪ Special transformers ▪ 2 converter stations	▪ 20% more cost than Symmetric ▪ Very large high voltage cable needed ▪ Special transformer required
Bipole, metallic return 	▪ 2 high voltage cables ▪ 1 low voltage cable ▪ Special transformers ▪ 4 converter stations	▪ 70% more cost than Symmetric ▪ Special transformer required

Based on EirGrid and RTE's comparison of the economics and benefits of the possible configurations above, it was decided that **the optimum arrangement for the Celtic Interconnector project is to use HVDC VSC technology in a single terminal symmetric monopole configuration**.

Voltage Level

There are a variety of HVDC VSC voltage levels which could be used for the Celtic Interconnector. EirGrid and RTE have examined all of these options. Given the current status of feasible solutions, the 320 kV voltage level has been determined as the most appropriate and cost effective for a HVDC scheme of the characteristics of the Celtic Interconnector. The 320 kV voltage ensures that Engineer, Procure and Construct (EPC) tenderers will have significant flexibility in assembling attractive and competitive proposals to meet the requirements of the specification for the Celtic Interconnector. As 320 kV does not preclude the use of different cable insulation types, tenderers will have the option to propose either Cross-Linked Polyethylene (XLPE) or Mass Impregnated (MI) cables.

RTE and EirGrid will continue to examine the technical options available throughout the process of developing the specifications and the tendering process, and will engage in appropriate discussions with suppliers and contractors to assist this process. This will ensure that contractors' proposals will offer optimum interconnector technical and commercial arrangements which include configurations of voltage, cable type, equipment and materials.

1.3 Celtic Interconnector Route

Grid Connection Points and Grid Reinforcement

Analysis of the capability of the Irish and French transmission systems to accommodate the expected power flows from the Celtic Interconnector found that both systems can reasonably accommodate the expected flows.

For the Irish side of the project, EirGrid undertook a study to identify feasible connection points on the Irish transmission grid which were capable of accommodating the export and import of 700 MW of power to and from France. The study identified:

- The Knockraha substation (East Cork), and
- The Great Island substation (West Wexford).

These points were selected based on their strong connectivity in the Irish transmission grid and their location along the south coast of Ireland, as shown in *Figure 2* below.

Further analysis of these two connection points showed that the Knockraha connection point could accommodate the additional power flows associated with the interconnector significantly better than the Great Island connection point[1]. After offshore and onshore technical studies were completed, as referred to in this section, **Knockraha** was found to be the **most suitable connection point of the two in Ireland** and EirGrid publicly confirmed Knockraha as the Irish connection point in early 2018.

Following direction from the CRU in October 2017[2] (to start processing grid connection applications for interconnection projects with PCI status) a further assessment of the capability of the Irish transmission network to accommodate power flows from the Celtic Interconnector has been undertaken.

For the Irish connection point at Knockraha, a relatively minor, in relation to the scale of the interconnector, network upgrade solution is triggered. This consists of a single 110 kV circuit uprate and station work in two 110 kV substations. Network and operational system costs are discussed in further detail in Section 3.5.

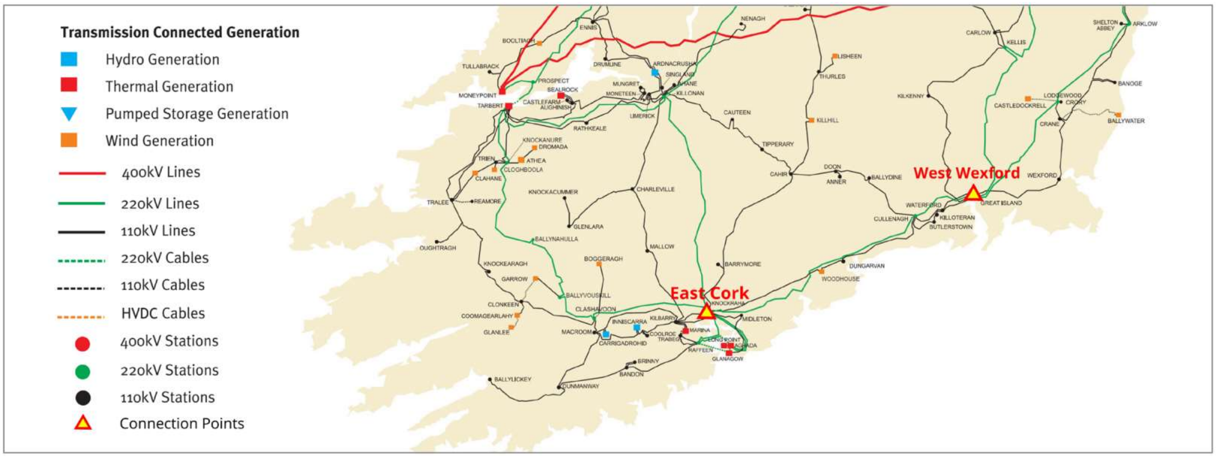


Figure 2 - Connection points identified in Ireland

For the French side of the project, RTE undertook a study to find feasible connection points on the French transmission grid which were capable of accommodating the export and import of 700 MW of power to and from Ireland. Its study identified:

- The La Martyre substation, and
- The Plaine Haute substation.

They were identified based on their connectivity in the Brittany transmission grid and their location along the north-west coast of France, as shown in *Figure 3*.

The grid study was integrated into a regional Brittany 2030 grid study. The interconnector was considered as a variant in the Brittany 2030 grid. The RTE grid studies were split into three separate parts; a deterministic AC load flow, a probabilistic DC load flow and a voltage stability study.

The study confirmed that the **most suitable** connection point in Brittany was **La Martyre**. The main weakness of Plaine-Haute is the lack of grid capacity as connection to the rest of France is realised

[1] http://www.eirgridgroup.com/site-files/library/EirGrid/Celtic-Interconnector-Feasibility-Phase-Network-Analysis.pdf
[2] CRU/17/300

only through 1 x 400 kV and 1 x 225 kV lines, while La Martyre is fed by 2 x 400 kV and 2 x 225 kV lines.

RTE have also carried out further assessment of the project connection point in France and have confirmed that there is firm capacity sufficient to accommodate the connection of the Celtic Interconnector in Brittany. Details of these assessments are provided in Appendix A3.

Figure 3 - Connection points identified in France

Marine Route

A desktop route investigation study[3] was done to identify potential marine routes between the south coast of Ireland and the North West coast of France. The study considered factors including the shortest reasonable route and potential engineering and environmental constraints. Six feasible marine route options were identified. Following a detailed constraints analysis a route alignment was selected which, although not the shortest route option, was considered the best performing route. This route, as shown in *Figure 4*, avoids more technical and environmental constraints when compared to other routes and also avoids UK territorial waters, which would introduce additional time during the consenting phase and enduring cost to the project.

A detailed marine survey of the best performing route was undertaken, in 2014 and 2015, in order to:

- Develop the offshore route,
- Assess seabed conditions and any technical constraints associated with cable laying, and
- Provide a robust basis for cost estimation.

The route was concluded as feasible. No major constraints were identified and largely favourable water depths of between 100 and 110 metres pertain for the majority of the route.

The marine survey was complemented by shipping, fishing and burial assessment studies to identify the density of maritime traffic along the cable route and determine the optimal burial depth for the cable beneath the seabed. These studies used the results of all of the previous marine studies along with evaluation of the risk using risk based quantification for the entire route.

[3] http://www.eirgridgroup.com/site-files/library/EirGrid/Celtic-Interconnector-Marine-Route-Investigation.pdf

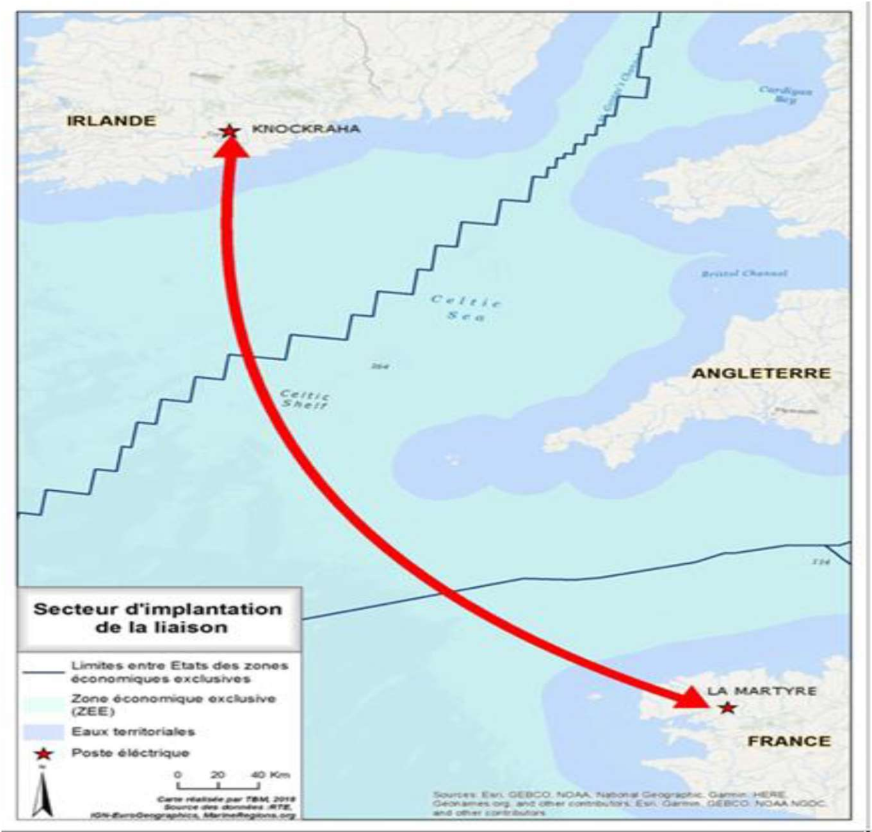


Figure 4 - Celtic Interconnector Marine Route Map

Onshore Route

Onshore investigations considering technical, environmental and planning constraints have concluded that there is a **range of feasible options for the various onshore elements** of the interconnector in France and Ireland. EirGrid and RTE will further develop and refine these options to identify the best performing option for each project element in Ireland and France at the appropriate time. Project stakeholders will be consulted throughout the development process.

1.4 Social and Environmental Impact

For the onshore aspects of the project, high level social and environmental impact assessment baseline reports have been prepared examining issues like:

- The geographical setting,
- Environmental constraints, and
- Communities and amenities of the project study area.

Feasible options for each of the elements of the proposed project have been identified and given that the majority of the onshore circuit route would be installed underground and would follow the existing road network it can be reasonably concluded that the social impact would be minimal and restricted to the Construction Phase of the project. While further detailed social and environmental impact assessments are required and planned to be carried out in 2019 as part of the formal consenting process in Ireland and France, assessments carried out at this stage do not foresee any major impacts from the proposed project.

For the offshore aspects of the project, a detailed benthic (environmental) investigation has been carried out as an integral part of the marine surveys. A large variance of habitats was encountered along the project's offshore route. However, no evidence of any particularly sensitive habitats was identified. The investigations that were carried out and the samples recovered provided an excellent quality basis for the offshore environmental impact assessment which will be carried out in parallel with the onshore assessment. Engagement with fisheries interests in both Ireland and France has been a feature of this stage and this will continue throughout the project to ensure minimal impact on these and other marine users.

2 Project Organisation and Implementation

2.1 Project Organisation

EirGrid and RTE are both state-owned TSOs responsible for the development and operation of the high voltage transmission systems in Ireland and France respectively. RTE is also responsible for the maintenance of Europe's largest transmission grid system. Between them they have extensive experience in the development, operation and maintenance of subsea HVDC interconnectors:

EirGrid

- East West Interconnector (EWIC), 500 MW interconnector between Ireland and Great Britain (GB), commissioned in 2012.

RTE

- Interconnexion France-Angleterre (IFA2000), a 2,000 MW interconnector between GB and France, commissioned in 1986 and operated by RTE and National Grid,
- IFA2, a 1,000 MW interconnector between GB and France, developed by RTE and National Grid and under construction since 2018,
- FAB Link, a 1,400 MW interconnector between France and GB, developed by RTE and FAB Link Ltd, and
- Biscay Gulf, a 2,000 MW interconnector between France and Spain, developed by RTE and Red Eléctrica de España (REE).

EirGrid and RTE began studying the Celtic Interconnector project in 2011 and have been developing it under various Cost Sharing Agreements since 2014 with the costs of studies being split on a 50/50 basis. Based on an assessment of international best practice for the effective delivery of the future phases of the project, EirGrid and RTE have established a special purpose vehicle in the form of an Incorporated Joint Venture (IJV), which has been incorporated as a Designated Activity Company (DAC) under Irish law.

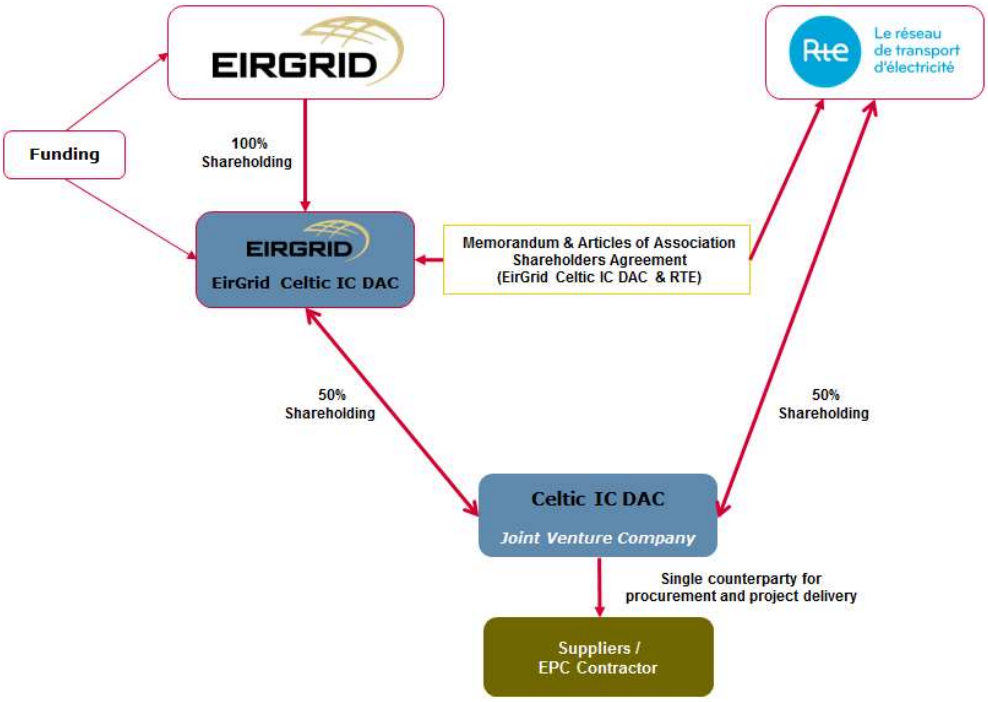


Figure 5 - Celtic Interconnector DAC (IJV) Organisational Structure

The organisational structure of the IJV is outlined above in Figure 5. The IJV will streamline the activities of both organisations and provide an efficient corporate structure in order to procure the project and ensure its delivery to the highest standards of safety and quality and value for money.

To date EirGrid and RTE have adequately resourced the project team with internal resources and carried out joint procurement for specialist external expertise as required. EirGrid and RTE will continue to ensure resources are available as required throughout the project phases.

2.2 Project Implementation Roadmap

The project implementation roadmap is detailed in Figure 6 below and a description of each phase is outlined thereafter.

Phase Description	Preliminary Feasibility	Feasibility	Initial Design & Pre-Consultation	Detailed Design & Consents	Construction
Timetable	2011 - 2014	2014 - 2016	2016 - 2019	2019 – 2021	2021 – 2025/26
Work Streams	Benefits Technology Costs	Marine survey Project Parameters Economic & Financial Analysis	Initial Design Pre-Consultation Investment Request Grant Application	Detailed Design EPC Procurement Consenting	Contract Award Manufacturing Energisation

Sept 2018

Figure 6 - Project Roadmap

<u>Feasibility Phase</u>

After the Pre-Feasibility Phase in 2014, EirGrid and RTE agreed to proceed to the Feasibility Phase of the project. A detailed suite of activities were carried out to confirm the project's feasibility including:

- Desktop study of marine route options,
- Marine survey along best performing 500km route between Ireland and France,
- Onshore studies of connection options and associated grid assessment,
- Economic and financial analysis, and
- Cost assessment based on findings of technical studies.

Further details on the Feasibility Phase are presented in Appendix A1.

<u>Initial Design and Pre-Consultation Phase</u>

Following the completion of the Feasibility Phase in 2016, EirGrid and RTE were satisfied as to the feasibility of the project and agreed to proceed to the current phase of Initial Design and Pre-Consultation. This phase has focused on:

- Initial design of the project, including refinement of marine route options,
- Technical studies associated with the project's development onshore in Ireland and France,
- Pre-consultation activities in line with the consenting requirements of the project,
- Preparation of the Investment Request for submission to NRAs, and
- Preparation of application for CEF funding for remaining phases of the project.

The current phase of the project is now nearing its conclusion and preparation is underway for the commencement of the Detailed Design, EPC Procurement and Consenting Workstreams, which will be key components of the next phase.

Detailed Design and Consents Phase

The Detailed Design and Consents Phase is due to start in 2019 and, subject to a successful outcome to this Investment Request and planned application for CEF funding, EirGrid and RTE will commit to the launch of the EPC procurement process and the submission of formal consenting applications.

EPC Procurement

- Preparation for EPC Procurement has already started and includes development of a procurement working procedure followed by development of main contract principles and contract strategy, technical strategy, preparation of contract, technical scope of works and technical specifications,
- Publication of an OJEU notice is anticipated in September 2019,
- Pre-qualification process and evaluation is expected to take about 4-6 months in tandem with finalisation of technical specifications, and
- Formal launch of invitation to tender in early 2020 with subsequent evaluation and negotiations expected to take about 15-18 months to complete.

Consenting

- EirGrid started pre-consultation activities in 2017 during the Initial Design & Pre-Consultation Phase in line with its Framework for Grid Development including consultation and engagement with stakeholders in East Cork,
- RTE has submitted a Justification Technico-Économique (JTE) to the Direction Générale de l'Énergie et du Climat (DGEC) on 26th July 2018,
- The JTE acts as the formal notification to the PCI Competent Authority in France. The notification to the PCI Competent Authority in Ireland is expected to issue by the end of September 2018, and
- The submission of formal consenting applications in both jurisdictions is planned for the second half of 2020, with consent expected to be achieved before the end of 2021.

Construction Phase

Subject to the successful outcome of the EPC Procurement and Consenting Workstreams a Final Investment Decision (FID) will be made before awarding contracts and committing to proceed with the Construction Phase of the project.

The Construction Phase is expected to start in late 2021 with practical completion in 2025 and the interconnector would be operational in early 2026.

3 Project Costs

3.1 Introduction

EirGrid and RTE have developed a robust project cost estimate for the Celtic Interconnector project. Following the completion of the Feasibility Phase in 2016, the major technical parameters of the system were defined (that is, nominal power, voltage level, VSC technology) along with some of the main assumptions with regards to grid connection points and landfall areas. The greatest degree of uncertainty with projects such as the Celtic Interconnector is related to the marine environment and the associated constraints intrinsic to offshore cable installation. A full suite of detailed marine survey investigations was completed as part of the Feasibility Phase and the results of these studies provided the basis for developing a project costs estimate with a greater degree of certainty.

3.2 Project Costs

An overall technical assessment of the project has been developed by EirGrid and RTE experts, taking into account all data available from various studies undertaken during the Feasibility Phase. These include, initial desktop analysis of environmental, technical, third-party and economic factors, subsequent in-depth studies on these same topics and detailed marine seabed survey and onshore investigations.

Therefore, a viable and robust solution for the design and installation of each project lot (grid connection point work, converter stations, underground cable, and marine cable) has been defined, to finalise an appropriate estimate of the expected outcome from the market at the conclusion of the EPC contract tender workstream.

A full CAPEX assessment has been undertaken for the design, integrating associated risks. This is based on:

- Internal market knowledge for each facet of the project, which is continuously improved by benchmarking with other TSOs,
- Feasibility studies from manufacturers or consultants, and
- In-house experience of HVDC and/or submarine EPC projects.

The Celtic Interconnector project costs are estimated at 930 M€. The detailed cost assessment is presented in Table 3 overleaf including its breakdown according to coherent technical units.

The conclusions of the surveys and studies confirmed the central price of 930 M€, with an uncertainty range of [- 110 to + 140] M€, dependent mainly on the prevailing market prices during the procurement process. Further details that support the reliability of this range are provided in Appendix A2.

The project cost will only be confirmed once the outcome of the EPC procurement workstream is known. At this point, and prior to awarding contracts and committing to proceed with the Construction Phase of the project, EirGrid and RTE will be in a position to confirm the project budget which is expected to be in the range identified.

Following an assessment of the distribution of the submarine cable among French, Irish and International geographical areas, according to their respective lengths, the costs of the submarine cable are broadly distributed 50/50 between Ireland and France. This takes into account minor remaining uncertainties due to expected challenges to be overcome during works and potential for future micro-routing of the final route. The same principle of a project cost split was adopted for onshore cables and converter stations.

Table 3: Project Cost Breakdown

Item	Description	Cost (M€)
Feasibility Phase	Undertaking marine survey route investigations, determination of project parameters, economic and financial analysis	
Initial Design and Pre-Consultation Phase	Carrying out initial design of the project, pre-consultation activities, submission of investment request and preparation of grant application	
Detailed Design and Consents Phase	Detailed design of project, EPC procurement and statutory consenting process in Ireland and France	
SUB-TOTAL (Pre-Construction Phases)		
Marine Installation	Preparation Operations *(including HDDs, 3rd party crossings, UXO detection, pre-lay survey, preventative archaeological analysis)*	
	Cable Laying Operations *(including element of weather allowance)*	
	Protection Operations *(based on review of marine survey data including mechanical trenching, jetting, rock placement etc. and including element of weather allowance)*	
	Monitoring / Supervision and Routing Contingency	
	Contractor's Project Management	
Cable Supply	Submarine Cable	
	Land Cable	
	Cable System Type Tests	
Land Cable Installation	Land Cable Installation	
	Contractor's Project Management	
Converter Stations	Converter Station Supply and Install[4] *(including contractor's project management, design, procurement and manufacture of all converter station components along with land acquisition, installation and commissioning)*	
Other Costs	Construction All Risks Insurance	
	Joint Venture Staff	
	Grid Connection Costs	
SUB-TOTAL (Construction Phase)		
TOTAL		**930**

[4] This has been assessed based on benchmarking from several reference projects. Due to the variability observed in the various cost components it would not be appropriate to provide a more detailed breakdown

3.3 Project Cost Uncertainty Range

The project cost of 930 M€ takes into account some contingencies regarding marine operations. The risk analysis characterises the reduction opportunities and the risks of increases included in the cost assessment which result in the uncertainty range of [- 110 / + 140] M€ as detailed in Appendix A2.

3.4 Operation and Maintenance Costs

From RTE's experience, the main component of maintenance costs for an interconnector comes from damage to the submarine cables. Damage is very rare but any repairs can be very expensive, which is why the variability of the effective maintenance cost could be very wide.

An assumption of 8.4 M€ per annum for Operation and Maintenance (O&M) costs (real in 2018 values) has been made for the Celtic Interconnector. These operating costs are based on the experience EirGrid has in operating EWIC and that RTE has in operating a submarine interconnector for more than 30 years particularly in terms of strategy used for protecting cables against external threats.

The final maintenance strategy will be devised and agreed by EirGrid and RTE.

3.5 Network and Operational System Costs

As discussed in Section 1.3, a relatively minor, in relation to the scale of the interconnector, network upgrade solution is required in Ireland. This consists of a single 110kV circuit uprate and station work in two 110kV substations and the assumed solution is estimated to cost 15.7 M€. Full details of the analysis undertaken are provided in Appendix A3.

Consideration has also been given to the potential impact of the Celtic Interconnector on the operation of the transmission systems. As could be expected, there are no impacts on the operation of the French system which already caters for interconnectors and generation units in excess of the capacity of the Celtic Interconnector. EirGrid has undertaken a suite of frequency and transient stability studies to assess the impact of a generic 750MW interconnector on the Irish system. Issues identified were proven to have implementable solutions, and there are no foreseen operational issues with enabling a 750MW interconnector. However, an interconnector of this capacity would increase the LSI and LSO from 500MW, currently set by the Moyle and EWIC Interconnectors, and this could have a system operational cost.

The LSI impact could drive the need for additional operating reserve and based on a simple cost-based assessment this potential cost is estimated at between 1.4 M€ to 2.8 M€ a year. Further details of the assessment are provided in Appendix A3.

The above network and operational costs are not included in the CBA detailed in Section 4 on the basis that the Celtic Interconnector would also provide a suite of services to assist with the operation of the Irish transmission system which are also not included in the CBA. These include for example, black start, voltage support and dynamic frequency response. The cost of providing these benefits via other means, for example via the installation of a static synchronous compensator (Statcom), is considered to exceed any system cost impacts referenced above.

4 Cost-Benefit Analysis

The European Union (EU) TEN-E Strategy is focused on linking the energy infrastructure of EU countries. As part of that strategy, nine priority corridors, which cover at least two EU countries, have been identified as requiring urgent infrastructure development in electricity, gas or oil. This infrastructure will connect regions currently isolated from European energy markets, strengthen existing cross-border interconnections, and help integrate renewable energy sources (RES).

The North South Electricity Interconnections in Western Europe (NSI West) Electricity corridor to which France and Ireland belong faces many challenges over the coming decades. These include the integration of high levels of RES generation that is required to achieve the transformation from thermal to CO_2 free energy sources and meeting climate change mitigation targets. Another challenge relates to the security of supply (SoS). The increased reliance on variable RES generation means that weather will have a greater impact on the future energy system. In this context, mutual support between the Member States of the NSI West corridor will be increasingly important in order to maintain SoS while optimising the efficient use of our energy resources.

Transmission projects are by their nature multi-purpose. In addition to other benefits, interconnection has long been identified as an appropriate solution for improving SoS and more generally increasing European socio-economic welfare (SEW).

Regulation (EU) 347/2013 on guidelines for trans-European energy infrastructure (TEN-E Regulation) came into force in April 2013. This Regulation defines PCIs, which are electricity projects that have significant benefits for at least two Member States. It also stipulates that ENTSO-E's TYNDP be the reference basis for the assessment of PCIs. ENTSO-E is also mandated to develop a corresponding CBA methodology for the assessment of transmission infrastructure projects.

The TYNDP process is the dedicated pan-European framework for assessing the benefits that can be expected from the projects likely to satisfy the needs which stem from European policies on market integration, sustainability and SoS. Each project included in the TYNDP is assessed using the CBA 2.0 methodology which has undergone public consultation and been reviewed by ACER and the European Commission. The benefit of each TYNDP project is assessed against defined assessment metrics (indicators) ranging from SEW to environmental impact.

The TYNDP 2018 assessment of the Celtic Interconnector is the basis of this CBA. This Investment Request also contains sensitivity analysis and a scenario specific to the Celtic Interconnector project that has been performed to provide information additional to that provided by the TYNDP 2018 assessment.

4.1 Cost-Benefit Analysis Assumptions and Methodology

This section outlines the methodology utilised within the TYNDP and for this Investment Request. Further details are given in Appendix A4.

4.1.1 Scenarios and Input Assumptions

All projects included in TYNDP 2018 are assessed using a number of future scenarios for Europe. The three main scenarios used in the assessments are for the year 2030. There is one scenario for 2025 that is used to provide a starting reference point for the Net Present Value (NPV) calculation for projects due to be commissioned before 2030. The TYNDP 2018 scenarios have been developed through consultation with TSOs, Member States, Regulators, European Commission, Non-Governmental Organisations (NGOs) and other interested parties.

In addition to the TYNDP 2018 scenarios, the Irish and French NRAs have also requested the inclusion of a fourth scenario specifically for the assessment of the Celtic Interconnector in this Investment Request. That scenario is based on the TYNDP 2016 Vision 1 ("Slowest Progress") scenario with low RES generation, low carbon price and over-capacity in Ireland and France. It has been included to assess the Celtic Interconnector in a scenario where RES integration and climate objectives are not achieved.

These scenarios set out the main input assumptions, including demand, generation mix and fuel prices to be used in the CBA. A brief synopsis of the three TYNDP 2018, and additional NRA, scenarios is given below. A more detailed description of each scenario is given in Appendix A4.3.

TYNDP and NRA Scenarios

Sustainable Transition: has national actions as the key driver for the development of the power system

Distributed Generation: represents decentralised development with a focus on end user technologies and has high penetration of photovoltaic generation and additional battery storage

EUCO2030: is a scenario produced by the European Commission. The scenario models the achievement of 2030 climate and energy targets as agreed by the European Council in 2014, but includes an energy efficiency target of 30%

"Slowest Progress": is a "Behind the Targets" scenario specified by the NRAs in Ireland and France for inclusion in the Celtic CBA. It is based on the Vision 1 (also called Slowest Progress) scenario from TYNDP 2016 and has a low level of RES generation and a low carbon price.

Figure 7: Short description of scenarios used in the Cost-Benefit Analysis

4.1.2 Cost-Benefit Analysis Methodology

Details of the pan-European CBA methodology used in the TYNDP studies is provided in Appendix A4. The CBA methodology sets out the ENTSO-E criteria for assessing costs and benefits of a transmission project, all of which stem from European policies on market integration, SoS and sustainability. Some of the indicators are monetised while others due to their nature are not but are quantified in their typical physical units (such as tonnes or GWh).

In previous TYNDPs, only the SEW and Losses indicators were monetised. However, it is widely recognised that these indicators only capture a portion of the economic impacts of an interconnector. ENTSO-E has identified a number of other indicators that should be monetised once appropriate methodologies have been developed. For TYNDP 2018 a dedicated ENTSO-E task-force was set up to trial a new methodology to monetise the adequacy component of the SoS of projects. This is discussed further below.

A schematic of the ENTSO-E TYNDP Economic Assessment Framework is shown in *Figure 8* and a brief description of the main assessment indicators is given below:

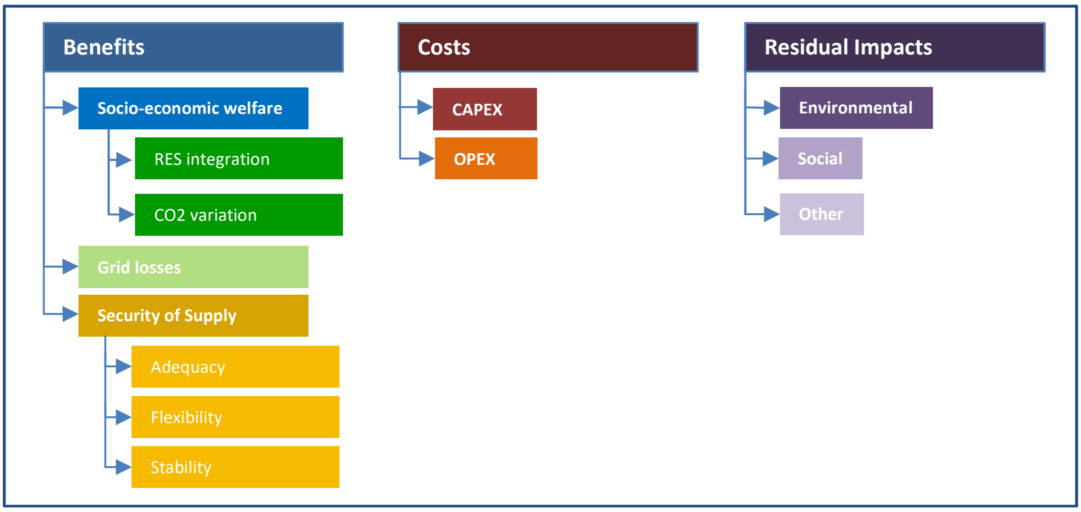


Figure 8: ENTSO-E TYNDP Economic Assessment Framework

Socio-Economic Welfare (SEW): A project is characterised by its ability to reduce congestion and provide fuel cost savings. It thus provides an increase in transmission capacity that makes it possible to increase commercial exchanges, so that electricity markets can trade power in a more economically efficient manner. This benefit is the SEW provided by the project and is expressed in millions of euro a year.

Renewable Energy Sources (RES) Integration: Contribution to RES integration is defined as the ability of the system to allow the connection of new RES generation, unlock existing and future "renewable" generation, and minimise curtailment of electricity produced from RES. RES integration is one of the EU 20-20-20 targets. This benefit indicator is expressed in MWh a year and is not included in the NPV calculations.

Variation in CO_2 Emissions: Variation in CO_2 emissions represents the change in CO_2 emissions in the power system due to the project. It is a consequence of changes in generation dispatch and unlocking RES potential. The aim to reduce CO_2 emissions is explicitly included as one of the EU 20-20-20 targets and is therefore displayed as a separate indicator. This benefit indicator is expressed in k-tonne a year and is indirectly included in the NPV calculations.

Variation in Grid Losses: Variation in grid losses in the transmission grid is the cost of compensating for thermal losses in the power system due to the project. Losses are assessed in the whole European interconnected network and on HVDC interconnectors. It is an indicator of energy efficiency and expressed in millions of euro a year. The building of a new interconnector can result in an increase (or decrease) of the losses accounted for as a negative (or positive) benefit for the project.

Security of Supply Adequacy (SoS): Adequacy to meet demand characterises the project's impact on the ability of a power system to provide an adequate supply of electricity to meet demand over an extended period of time. As stated in CBA 2.0, interconnectors are also likely to provide benefits as regards SoS through mutual support between interconnected countries. To assess this benefit (benefit B6 of CBA 2.0), also known as Capacity Value, EirGrid and RTE have applied a methodology that was jointly developed by RTE, EirGrid and ELIA (the Belgian TSO). This methodology has been trialled on the majority of projects in TYNDP 2018. The methodology is detailed in Appendix A4.2 and is also described in the appendices of ENTSO-E's TYNDP 2018 report. This benefit is expressed in millions of euro a year.

The approach used calculates the Expected Energy Not Served (EENS) saving due to a project and monetises the saving using the Value of Lost Load (VoLL). It allows for separate and complementary

SEW and SoS savings assessment. It incorporates adequacy assessment approaches that have been developed and extensively tested in the ENTSO-E Mid-Term Adequacy Forecast (MAF)[5]. Some adaptions (adequacy fine-tune) have been performed on the portfolios to ensure, where possible, that countries are at their national adequacy standard prior to assessing the SoS benefit of the interconnector. This provides an appropriate reference point for the assessment while the adaptions to the portfolios are minor.

The European Commission recognises that interconnection provides significant SoS benefits and has stated that interconnection must be accounted for in national and regional adequacy assessments and also included in capacity markets. However, currently there is no uniform approach to the valuation and remuneration of capacity in Europe. The analysis presented in this Investment Request is based on detailed state-of-the-art adequacy assessment techniques and shows that the Celtic Interconnector will provide significant SoS benefit to Ireland, France and Europe. However, the results should be interpreted within the context of the current lack of a uniform agreed approach to the valuation and remuneration of capacity in Europe.

4.1.3 Economic Net Present Value of the project from a European perspective

The NPV of the project is calculated using the forecasted project costs and the results of the economic analysis for each of the scenarios studied. The annual monetised values defined by the SEW, SoS and Losses assessment indicators are used in the calculation.

In the framework of the TYNDP 2018, the SEW and the losses were computed with simulation tools assuming a 100% availability rate for the interconnectors. This reflects a common agreement involving all the ENTSO-E contributors. Modelling of the unavailability rate of the interconnectors is not included in the current CBA methodology as some of the modelling tools used for TYNDP preparation do not have such a capability. Therefore, to take account of the availability rate and to ensure that the CBA outcome is realistic, the benefit indicators are reduced to 95% to align with the assumed the Celtic Interconnector availability rate of 95%[6] .

The approach to the discounting of costs and benefits is set out in the approved TYNDP CBA methodology and is in line with standard practice. As recommended by ENTSO-E's guidelines for CBA methodology 2.0, all costs and benefits are discounted to the present, and expressed in the price base of that year.

- A discount rate of 4% is applied over the assumed 25 years of operational life. That is, the project is discounted at 4% from 2026 to 2050 and for this NPV calculation it is assumed that there is no remaining value after 2050;
- The results from the 2025 scenario are used to provide a starting reference point for the project benefits and there is a linear interpolation between 2025 and 2030 to provide the inputs to the NPV calculation for the years 2026-2029. In line with the TYNDP CBA methodology, the benefits calculated for the 2030 scenarios are then assumed to persist for the remaining lifetime of the project. This approach aligns with the Agency for Co-operation of Energy Regulators (ACER) recommendations.
- The cost schedule has been estimated based on the approach set out in Section 3 and is given in Appendix A2.3. The projected lifetime for the infrastructure assets is equal to or greater than the

[5] Mid-Term Adequacy Forecast 2017 Edition

[6] For reference, the methodology used for assessing the availability rate of the Celtic Interconnector project is detailed in Appendix A1.

25 year discounting period, so they would not require replacing during this period (cable lifespan: 45 years; converters lifespan: 25 years).

Due to the inclusion of extensive additional analysis in this Investment Request specific to the Celtic Interconnector project, the CBA results presented in this section are the **average of the results** from the ANTARES and PLEXOS modelling tools. These are the software tools used by RTE and EirGrid respectively. They are core modelling tools used within the ENTSO-E TYNDP process. This is to ensure consistency across all scenarios and sensitivities. A third modelling tool was used for some of the indicators in TYNDP 2018 but this was not available to RTE or EirGrid for the additional analysis presented here. A comparison of the base case results presented in this section and the average of the three TYNDP 2018 models are given in Appendix A5.

4.2 Cost-Benefit Analysis Results

The SEW and Losses indicators and the resulting NPV values for the project are given in *Table 4* below. For this NPV calculation only the SEW and Losses are monetised.

Table 4: Cost Benefit Indicators and NPV calculation results for each of the four scenarios

	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress	Mean Value
B1. Socio-economic welfare (M€/Year)	91	82	76	66	79
B5. Variation in grid losses (M€/Year)	-22	-22	-26	-29	-25
Total Annual Benefit (M€/Year)	69	60	50	37	54
NPV (M€)	**-105**	**-200**	**-295**	**-420**	**-255**

The results show that the Celtic Interconnector would deliver significant SEW across the base case scenarios. The increase in SEW ranges from 66 to 91 M€ a year. The key drivers of this benefit are discussed further below. *Table 4* shows that when only SEW and Losses are monetised, the European NPV of the Celtic Interconnector is negative in each of the base case scenarios (-255 M€ on average).

As discussed above, the SEW and Losses capture only some, but by no means all, of the benefits of an interconnector. The SoS value that has been calculated using the methodology that has been trialled in TYNDP 2018 is given in *Table 5* below and ranges from 24 to 42 M€ a year. It shows that the Celtic Interconnector would deliver significant European SoS benefits in addition to the SEW benefits given in Table 4.

Table 5: Security of Supply Adequacy value (capacity value) for each scenario

	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress	Mean Value
ENTSO-E SoS Declared Indicator (M€/Year)	42	38	24	24	32
Total Annual Benefit including SOS (M€/Year)	111	98	74	61	86
NPV (M€)	**350**	**220**	**-15**	**-130**	**106**

Once the SoS value is included in the NPV calculation it leads to positive European NPVs in two of the four scenarios and a positive NPV on average across the four scenarios. The highest benefits are observed in Sustainable Transition and Distributed Generation. The lower values in the EUCO and the Slowest Progress scenarios are primarily due to over-capacity in both of those scenarios. This is because if a region is significantly over-adequate then a new project (generation, storage or interconnection) will add little additional value to SoS. This unrealistic over-capacity is a widely recognised short-coming of the EUCO and Slowest Progress scenarios.

While there is variation between the different scenarios, the average of the benefits from the four scenarios shows a large positive NPV. The NRA scenario also has low wind in Ireland and a low carbon price. Given that two of the main drivers of the project are RES integration and SoS, it was to be expected that these two scenarios would show lower benefit. There are large positive NPVs for the Sustainable Transition and Distributed Generation scenarios. This highlights that in scenarios where European policy objectives are achieved and there is an efficient use of resources (that is, balanced adequate portfolios) the Celtic Interconnector would have particularly significant positive value.

As stated in the assessment indicator descriptions above, the RES Integration and Variation in CO_2 indicators are not directly included in the calculation of the NPVs. However, these are important indicators to illustrate the benefit of the Celtic Interconnector in helping to achieve national and European climate and RES integration objectives and are given in *Table 6* below. The project allows for the integration of an additional 813 GWh a year of RES, on average, in 2030. The substitution between different categories of fuel enabled by the project leads to average CO_2 emissions reduction of 331 k-tonnes a year.

Table 6: RES Integration and CO_2 Reduction results for each of the four scenarios

	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress	Mean Value
RES Integration (GWh/Yr)	871	884	811	688	813
CO2 Reduction (kT/Yr)	475	178	605	65	331

4.2.1 Cost-Benefit Analysis for France and Ireland

Table 7 details the benefits expected from the Celtic Interconnector in terms of SEW, SoS and losses for France and Ireland. This shows that the distribution of net benefits between France and Ireland is about 35% for France and 65% for Ireland.

Table 7: Benefits of Celtic for Ireland and France from SEW and SoS

M€/yr	SEW		Losses		SoS	
	IE	FR	IE	FR	IE	FR
Sustainable Transition	74	41	-11	-12	15	18
Distributed Generation	57	38	-9	-12	14	16
EUCO	47	32	-8	-16	19	1
Slowest Progress	43	38	-11	-19	19	3

The NPVs for France and Ireland (assuming a 50/50 split in costs) are given overleaf in *Table 8* and *Table 9*. *Table 8* shows that even when only the SEW and Losses indicators are considered, the NPV for Ireland is positive in three of the four scenarios and positive on average across the four scenarios. The only scenario with a negative NPV for Ireland is Slowest Progress which has the lowest levels of RES in Ireland and a low carbon price. These results are not surprising as two of the primary drivers of the Celtic Interconnector are facilitating increased RES generation in Ireland through the opportunity provided for export at times of high wind and providing Ireland with direct access to the continental market. Direct access to the continental market will lead to lower average prices in Ireland.

When only SEW and Losses are monetised, the NPV in France is negative for each of the scenarios.

Table 8: NPVs for France and Ireland when only SEW and Losses are monetised (assuming a 50/50 split in costs)

NPV (M€)	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress	Mean Value
France	-120	-160	-250	-220	-190
Ireland	245	100	10	-70	70

Table 9 gives the NPV results for Ireland and France when SoS is included in the calculations. After inclusion of the SoS value Ireland has positive NPVs in all scenarios. France has positive NPVs in two of the four scenarios, with a negative NPV on average across the four scenarios. Again, the lower values in the EUCO and Slowest Progress scenarios are primarily due to over-capacity in both of those scenarios.

Table 9: NPVs for France and Ireland when SEW, Losses and SoS value are monetised (assuming a 50/50 split in costs)

NPV (M€)	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress	Mean Value
France	70	15	-235	-180	-83
Ireland	420	260	215	145	260

This shows that if costs are shared equally between the project promoters and benefits accrue as detailed in *Table 9*, France is subject to net negative impacts in EUCO and Slowest Progress scenarios as well as on the average of the four base case scenarios. Therefore the Celtic Interconnector is a project that entails some risk for the French consumer.

4.2.2 Surplus Analysis for France and Ireland

The total surplus approach, which compares the producer and consumer surpluses for both countries, as well as the Congestion Rent (CR) between them, with and without the Celtic Interconnector, is a commonly accepted proxy for calculating the variation in SEW. It provides useful additional information on the benefits of the project.

Table 10 presents the results of the average of the four base case scenarios (more details for each scenario and some sensitivity analysis are given in Appendix A6):

- In Ireland, the consumer surplus is significantly positive and amounts to 85% of the overall Irish surplus. A large consumer surplus in Ireland indicates that the Celtic Interconnector significantly reduces wholesale electricity prices in Ireland.
- In France, the distribution of surplus between stakeholders is mainly in favour of the producers and TSOs (Congestion Rent (CR)).

Table 10: Surplus analysis based on the average of the four scenarios

M€	France	Ireland
Consumer	-2	47
Producer	19	6
Congestion Rent	20	4
DSR/Storage	0	0
Total	37	55

4.3 Cost Benefit Analysis Sensitivity

A range of sensitivity analyses has been performed to complement the main results presented above. This includes an analysis of the sensitivity to costs and commissioning date assumptions and an illustration of the importance of the SoS benefit of the project. A large number of additional sensitivities have also been performed to gain further insight into the factors which affect the project benefits.

4.3.1 NPV Sensitivity to a Delay in Celtic Commissioning

In this sensitivity it is assumed that all the interconnector construction has been achieved on schedule (end of 2025) but because of technical issues during the commissioning phase, the Celtic Interconnector commercial operation is delayed by one year as are the revenues expected in the CBA. In parallel, the last and final payment is delayed by one year (90 M€ from 2026 to 2027).

Table 11: NPV Sensitivity to a commissioning delay

Figures in M€	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress	Mean Value
NPV (reference scenario)	350	220	-15	-130	106
NPV (commissioning delay)	340	205	-30	-150	91

This sensitivity illustrates the impact of a delay in the commercial operation of the Celtic Interconnector. The average NPV across the four scenarios is reduced by 14%.

4.3.2 NPV Sensitivity to CAPEX Assumptions

A 10 M€ increase or decrease in the CAPEX of the Celtic Interconnector results in a decrease/increase of the NPV of about 7.9 M€, bearing in mind that the NPV is calculated in 2018 while the CAPEX comes in later years.

Given a possible maximum increase of 140 M€ (and respective maximum decrease of 110 M€) consistent with the range of variations of the Project Cost detailed in Appendix A2 [-12%; 15%], the corresponding NPV decrease would be 112 M€ (respective increase of 88 M€).

4.3.3 NPV Sensitivity to O&M Cost Assumptions

O&M costs are expected to vary in a limited range compared to other parameters. Nevertheless, so as to appraise the sensitivity of the NPV to this parameter, an assessment with a 50% increase of the cost has been carried out.

Table 12: NPV Sensitivity to O&M Cost Assumptions

Figures in M€	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress	Mean Value
NPV (reference scenario)	350	220	-15	-130	106
NPV (O&M 50% increase)	300	170	-65	-180	55

An O&M increase of 50% (+4.2 M€ a year) results in a 50 M€ decrease of the Celtic Interconnector's NPV, with the NPV remaining positive on average across the four scenarios.

4.3.4 NPV Sensitivity to Security of Supply Generation Adequacy Benefit

As stated above, the SoS value of the Celtic Interconnector has been assessed using a new detailed methodology that aligns with the ENTSO-E adequacy assessment approach. This methodology has been trialled in TYNDP 2018 and its outcomes may be affected by possible residual uncertainties. That is why, at the request of the NRAs, a sensitivity analysis was applied to SoS Value. It consists of assessing the consequences on the Celtic Interconnector's NPV of a variation of -/+ 20% of the SoS Value. It can be seen that variation in the SoS Value has a significant impact on the Celtic Interconnector's NPV results.

Table 13: NPV Sensitivity to SoS Value

Figures in M€	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress	Mean Value
NPV (SOS -20 %)	260	140	-70	-185	35
NPV (reference scenario)	350	220	-15	-130	106
NPV (SoS +20%)	445	305	45	-70	180

4.3.5 Celtic Interconnector Economic Key Drivers

This section identifies the key-drivers of the Celtic Interconnector benefits and assesses the directionality of the Celtic Interconnector's NPV in relation to those key-drivers.

Figure 9 illustrates the effects of the Celtic Interconnector in the Integrated European Market. It details the generation shifts and what happens to the energy mix resulting from the addition of the Celtic Interconnector. This plot uses results from the Sustainable Transition scenario, but the same conclusions can be drawn from the other TYNDP 2018 scenarios which have similar results.

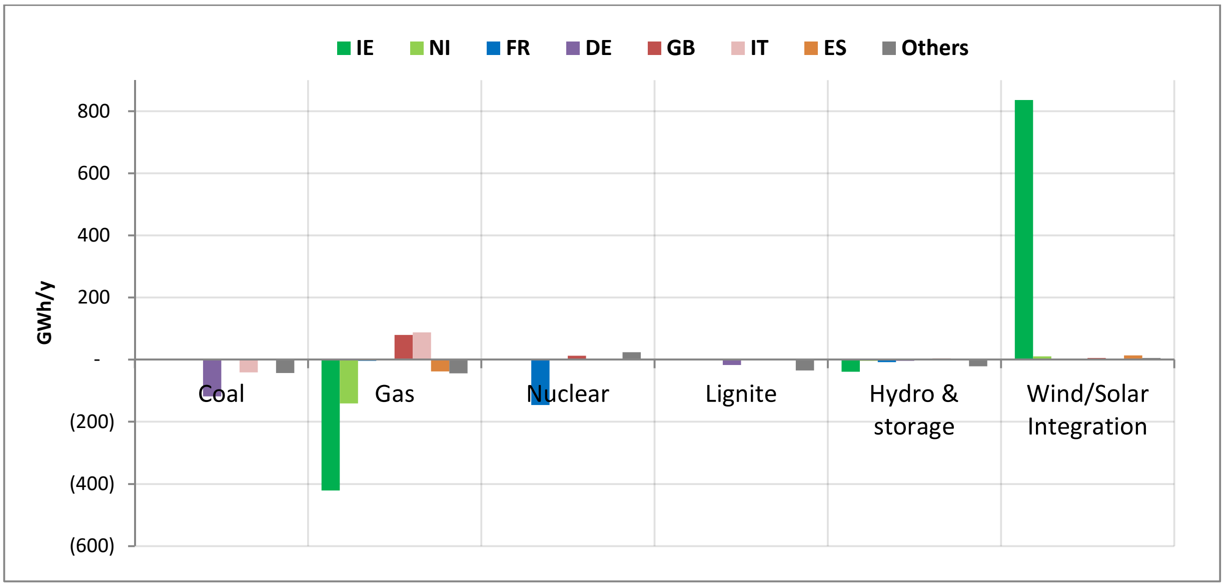


Figure 9: The effect of the Celtic Interconnector on different fuel types for Sustainable Transition

Large increase in wind energy generation

It can easily be seen that the commissioning of the Celtic Interconnector mainly leads to a large increase in wind energy generation (as a result of reduced curtailment) in Ireland along with a reduction of gas generation in Ireland. It can be concluded from this that the economic benefit of the Celtic Interconnector largely results from improved integration of RES in Ireland through the ability to export during periods of high RES generation. It also provides Ireland with access to the competitive continental market which leads to a reduction in higher cost thermal generation in Ireland. Appendix A4.4 gives a more detailed presentation of the projections for installed wind generation in Ireland.

Factors affecting the benefits of Celtic

Therefore, the following parameters should be considered as key factors affecting the benefits of the Celtic Interconnector and this is why an extended sensitivity analysis centred on these three key factors was carried out:

- The installed wind capacity in Ireland, which determines the amount of RES generation to be integrated,
- The fuel (and CO_2 price), which determines the value of each MWh of avoided curtailed energy replacing thermal generation, and
- The capacity of interconnection between Ireland and GB and between GB and the continent, which constitutes an alternative route to integrate Irish RES.

Brexit

France, Ireland and GB are part of an increasingly integrated European market for electricity and gas. The move towards a single market for energy and the Energy Union brings benefits for all Member States such as increased SoS at reduced cost. How Brexit will impact this integrated market and the associated arrangements and regulation is an important consideration when making investment decisions in the energy sector and particularly regarding new interconnection between Ireland and Continental Europe. Given the potential consequences of a possible de-harmonisation of the wholesale electricity markets following Brexit, and the potential for climate and renewable energy regulatory drift between the UK and the EU, Brexit has been incorporated into the sensitivity analysis. A “Hard Brexit” sensitivity was simulated by modelling a decoupling of the GB market with the rest of Europe using the approach set out in Appendix A9.

Other sensitivities

Other sensitivities include using different levels of demand in France and Ireland and different installed capacity of nuclear generation in France. As the PLEXOS and ANTARES modelling tools have the capability to explicitly model the interconnector availability, this was also included in the sensitivity analysis. The complete list of the sensitivities studied across the four scenarios is provided in Appendix A8.

4.3.6 Celtic Benefit Sensitivity Analysis Results

The results of the analysis for each of the sensitivities performed for the SEW benefit of the Celtic Interconnector are presented in *Figure 10* overleaf. The dark grey bars give the average of the four scenarios with the range across the scenarios given by the smaller semi-transparent bars. The average of the four base case reference scenarios is highlighted in green. A detailed table of the resulting NPVs for each scenario and sensitivity is provided in Appendix A8.

These sensitivity results illustrate a number of important points. The first is that the project benefits are robust across the large majority of sensitivities studied. The project benefit is not very sensitive to many of the input assumptions and the benefit shows a significant increase in three of the sensitivities. The Reduced SEM Solar sensitivity was only performed for Distributed Generation as this was the only scenario with a high level of installed solar generation in SEM. The installed level of solar in SEM was reduced from 5 GW to 1 GW. This level of reduction in solar generation without a rebalance of the remaining portfolio causes an increased use of peaking capacity in the reference case without the

Celtic Interconnector. This merit order shift is the reason for the non-intuitive benefit increase in this sensitivity.

The two sensitivities that show a decrease in benefits are the sensitivity with reduced wind in SEM and the sensitivity with an additional 500 MW of interconnection between GB and Ireland. The reduction of benefit in these sensitivities was expected:

- One of the main drivers of this project is the facilitation of RES and in particular the facilitation of increased RES generation in Ireland through increased opportunities to export. It was therefore expected that a large reduction in the level of installed wind capacity in Ireland would lead to reduced benefits. This sensitivity is useful for illustrating the directionality of the impact of installed wind levels, but such a large reduction in the level of installed wind is highly unlikely (see Appendix A4.4 for further discussion on wind projections for Ireland).
- The sensitivity that shows the largest decrease in benefits is the sensitivity with an additional 500 MW of interconnection between Ireland and GB. This sensitivity assumed that Brexit has no impact on market coupling between Ireland and GB. The decrease in benefits for this sensitivity was expected as increased interconnection between Ireland and GB would likely reduce price differentials between Ireland and Continental Europe and the facilitation by the Celtic Interconnector of renewable exports would provide less benefit.

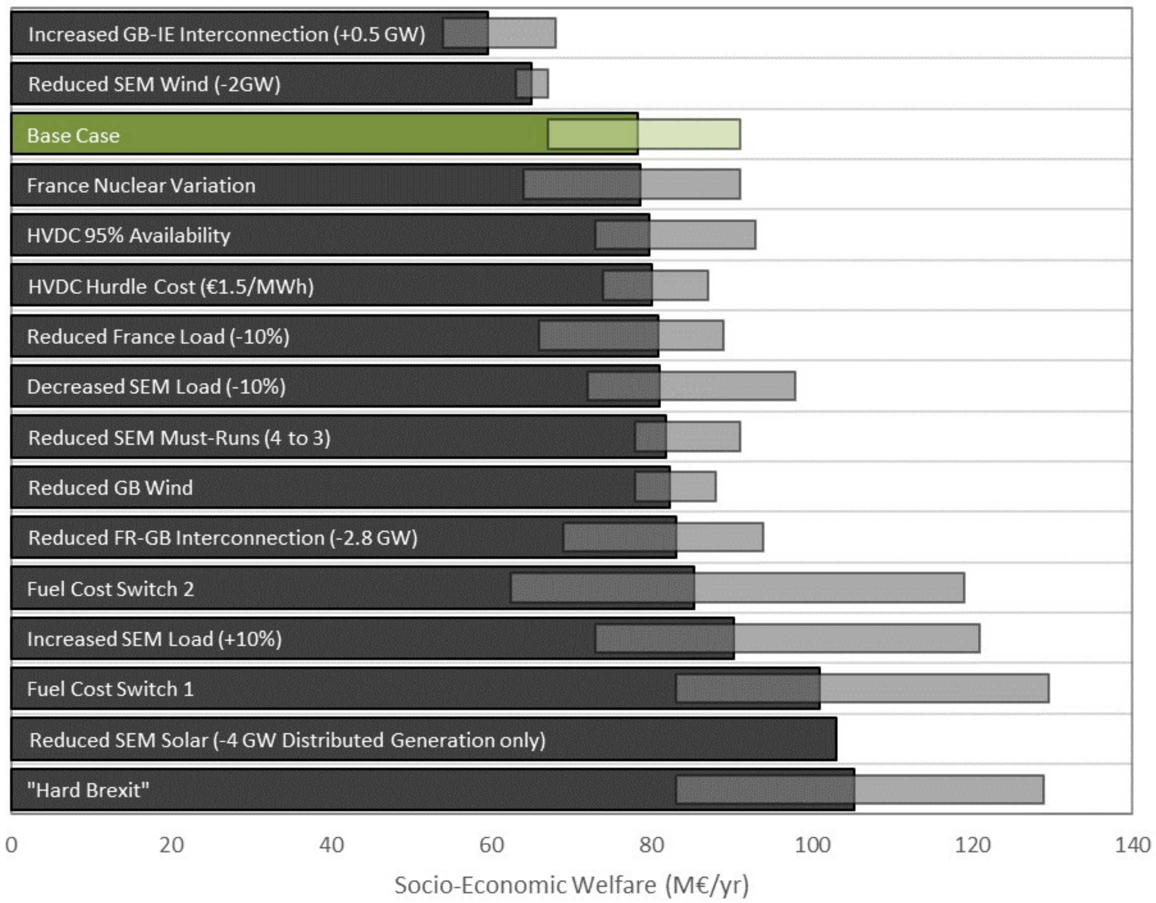


Figure 10: SEW Sensitivity Results

The sensitivity analysis highlights two key points:

- The SEW benefit of the Celtic Interconnector project would be significantly reduced by an increase of the interconnection capacity between Ireland and GB. The analysis shows that this is the main risk for the project benefits;
- Conversely, "Hard Brexit", according to the assumptions used in the analysis, significantly increases the SEW benefit and can be considered as more of an opportunity than a risk for the project benefits.

For the SEM wind sensitivity, the variations of the annual benefits of the Celtic Interconnector at the European scale as a function of the variations in installed wind capacity in SEM is plotted in *Figure 11* (see Appendix 4 for an analysis of SEM wind capacity). The plot confirms that the development of installed wind capacity in Ireland is one of the key factors to the development of interconnection in Ireland to which the Celtic Interconnector economics are directly linked. A similar trend is observed in each of the base case scenarios except for EUCO (due to large generation overcapacities).

As regards the sensitivity performed on nuclear generation in France, it included an increase of 5% of the installed nuclear capacity in the Sustainable Transition and Distributed Generation scenarios along with a decrease of 5% of capacity in the EUCO and Slowest Progress scenarios (reflecting the different starting capacity levels in the two sets of scenarios). Results showed only minor variations in the SEW benefit leading to the conclusion that the SEW benefit of the Celtic Interconnector is not sensitive to the level of installed nuclear capacity in France.

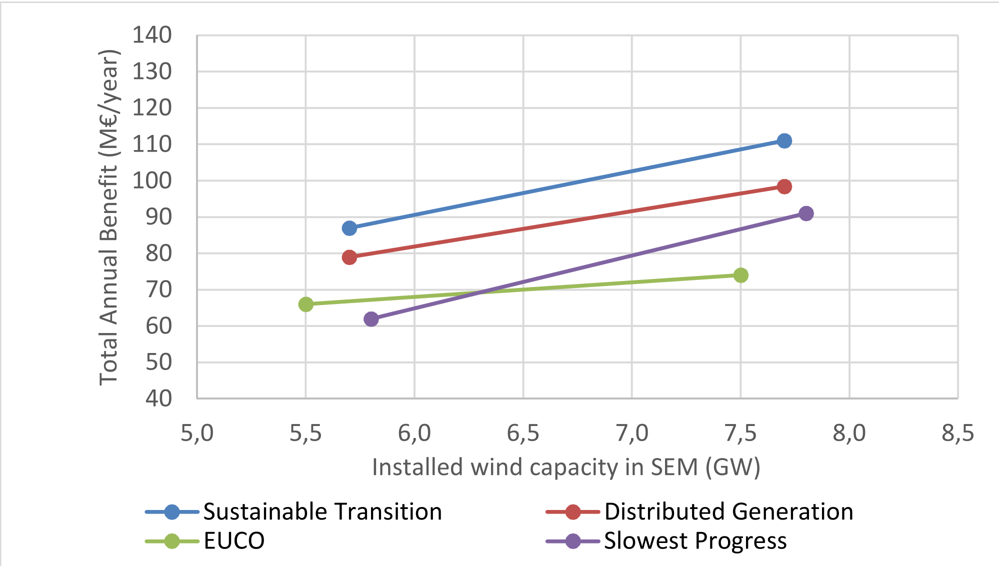


Figure 11: SEW Sensitivity to Wind in SEM

Sensitivities for Security of Supply benefit

Sensitivities have also been performed for the SoS benefit. These sensitivities included the addition of a 5% outage rate on the interconnector and sensitivities that changed the interconnection capacity between Ireland and GB, and France and GB. The sensitivity with the largest impact on the SoS value was the sensitivity with additional interconnection between Ireland and GB. The main reason for the decrease in benefits for that sensitivity is the impact of the additional interconnection on Loss of Load Expectation (LOLE) in Ireland. Across all the base case scenarios and sensitivity analysis results have shown that when both Ireland and France have balanced adequate systems (that is, no significant over-capacity) the Celtic Interconnector has a large and stable SoS capacity benefit.

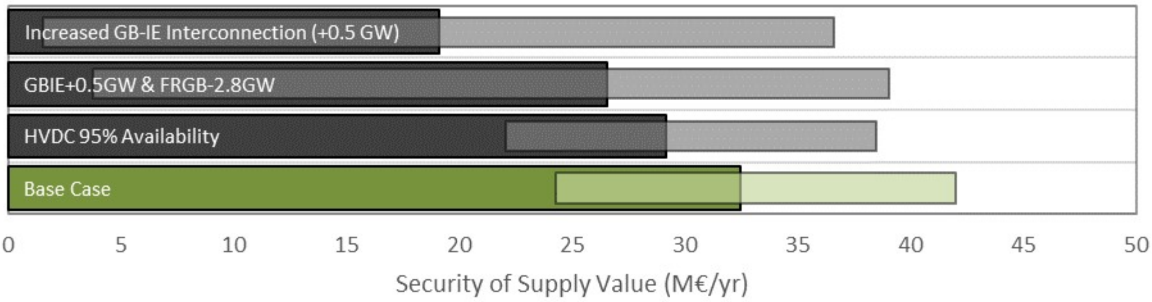


Figure 12: SoS value sensitivities

4.4 Expected Usage of the Celtic Interconnector

This section provides expected flows and usage rates of the Celtic Interconnector for each of the four long-term scenarios.

4.4.1 Expected Flows

The Celtic Interconnector flow duration curves (calculated on the average of ANTARES and PLEXOS results) are presented for each of the long-term scenarios in Figure 13. The values are in the range of +/- 700 MW (the rated capacity of the Celtic Interconnector). The positive values are related to the flows from France to Ireland and negative values are flows from Ireland to France. Sustainable Transition results in an even distribution of flows in both directions. Flows from France to Ireland dominate for EUCO and Slowest Progress and to a lesser degree for Distributed Generation.

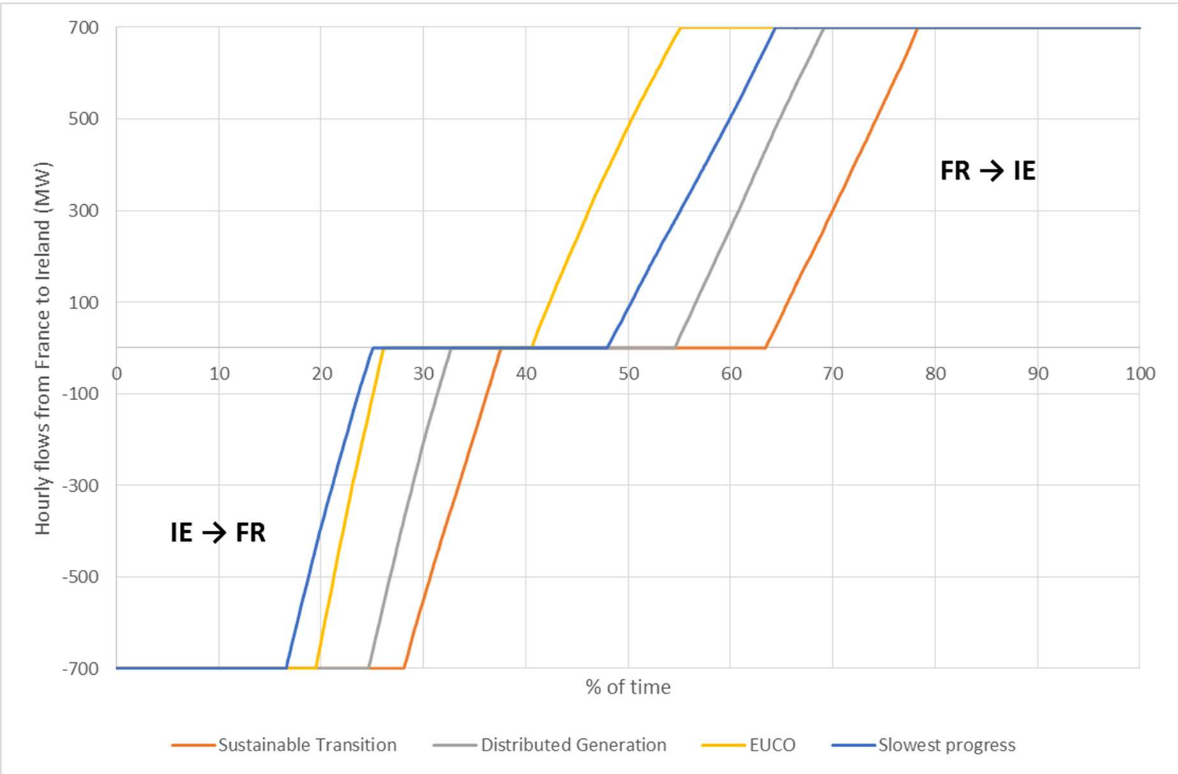


Figure 13: Flow duration curves for the Celtic Interconnector for each of the four scenarios

The flow duration curves are consistent with the observed changes in the Celtic Interconnector economic results across the scenarios. As a significant portion of the benefits of the Celtic Interconnector is driven by avoided curtailed RES generation in Ireland, most of the benefits of the interconnector result from flows from Ireland to France. In all the scenarios there are also benefits resulting from flows from France to Ireland. Most of these benefits are due to thermal substitutions (for example, depending on the merit order of the scenario, gas against coal, lignite against gas, etc.) that do not add significant value. This is why the SEW of Slowest Progress and EUCO with a predominance of flows from France to Ireland is significantly lower than the SEW for Sustainable Transition.

Annual percentage usage rates for the Celtic Interconnector range from 61% (Sustainable Transition), 64% (Slowest Progress), 66% (Distributed Generation) to 74% (EUCO) and are approximately 66% on average across the four scenarios. Those numbers show that the benefits of the project and the usage rate of the interconnector are not correlated. Appendix A7 provides further details on the usage rates of the Celtic Interconnector for each of the scenarios.

4.5 Cost-Benefit Analysis Summary and Discussion

This section has provided the results of the CBA and additional sensitivities (with further detail provided in Appendix A4). The CBA performed within the TYNDP 2018 framework has demonstrated that the Celtic Interconnector will deliver significant benefit to Europe and has a significantly positive European NPV on average across the four scenarios with an appreciable contribution from the SoS adequacy value.

There is a large positive NPV for Ireland, while results indicate that the project entails non-negligible risk for French consumers. There are well-established EU mechanisms designed to facilitate projects with asymmetric benefits for hosting countries that bring benefit to Europe and aid Member States to achieve European policy objectives. These include the CBCA process which is discussed in Section 8.

The results of the sensitivity analysis have shown that the outcome is robust across the majority of sensitivities and the sensitivities that show a reduction in benefits are in-line with expectations. Nevertheless, it should be noted that an increase of interconnection between Ireland and the UK or a delay in the development of wind capacity in SEM pose risks to the project benefits. As these factors influence the economic benefits of the Celtic Interconnector, RTE and EirGrid would plan to re-assess these immediately prior to Final Investment Decision (FID) to check the basic attributes (economic soundness, project costs) and ensure that the project benefits remain attractive.

To achieve national and EU climate and RES policy objectives will require efficient use of energy resources across Europe and mutual support between Member States. The CBA results have highlighted that the Celtic Interconnector will help to facilitate the achievement of these objectives and that in scenarios where national and European policy objectives are achieved the Celtic Interconnector will provide the highest benefit.

5 National Net-Impacts

In the document on *Good Practices for the Treatment of Investment Requests (Recommendation N°5/2015),* ACER recommends that compensations are provided if at least one Member State hosting the project is deemed to have a net-negative impact in at least one of the scenarios deemed plausible by all involved NRAs. In such cases, the aim should be in general to compensate for the net-negative impact in the relevant Member States. According to the Celtic Interconnector CBA, France is deemed to have a negative impact in at least two scenarios out of the four base case scenarios.

In general, countries on which a project has a net-positive impact should provide compensation. Article 12(3) of the TEN-E Regulation states that the investment request shall be submitted after the project promoters consulted TSOs from Member States to which the project provides a significant net-positive impact and ACER recommends that only countries with a net-positive impact exceeding 10% of the sum of net-positive impact accruing to all beneficiary countries should provide compensation.

The aim of this section is to identify the countries on which the project has net-positive impact beyond the 10% threshold.

5.1 Identification of the Countries above the 10% Benefit Threshold

Table 14 lists the countries that benefit from the Celtic Interconnector and the NPV of which are beyond the 10% threshold. The 5% threshold is also presented to show other countries that also see benefit.

Table 14: Identification of countries that benefit from Celtic Interconnector

	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress
Net beneficiary countries over the 10% threshold	Ireland (69.2%) France (11.5%)	Ireland (70.2%)	Ireland (78%)	Ireland (48.2%)
Net beneficiary countries (above 5% threshold)	Spain (5.0%) Sweden (5.9%)	Sweden (8.8%) Germany (5.2%)	Spain (5.7%) Germany (5.3%)	Germany (8.4%) Spain (5.2%) N. Ireland (9.0%)

5.2 Conclusions of the National Net Impacts Analysis

Only two countries are above the 10% threshold: Ireland across the four scenarios and France in the Sustainable Transition scenario. Otherwise, all the other noticeable beneficiary countries remain below this threshold. For Slowest Progress, almost 50% of the net-positive impacts are split between about 15 countries.

The conclusion of this analysis is that there is no need to consult third party TSOs and confirm that France and Ireland are the only two cost-bearers that shall agree on a CBCA (Section 8).

6 Externalities

This section sets out the additional externalities of the Celtic Interconnector that are not quantified or monetised in the CBA. These include the positive externalities of solidarity (including SoS), market integration and sustainability, which is required under EU legislation to be eligible for EU financial assistance (Article 14(2) of TEN-E Regulation).

6.1 Solidarity (including Security of Supply, Market Integration and Sustainability)

A direct physical link between Ireland and continental Europe

The Celtic Interconnector would be the only physical link between Ireland and Continental Europe and it would be the only means of direct trading between Ireland and the Integrated European Electricity Market.

The intention of the EU's Energy Union is to ensure all EU Member States have secure, affordable and climate-friendly energy. **The Celtic Interconnector would allow Ireland directly contribute to, and be part of, the EU's Energy Union.**

Ireland's Electrical Isolation

Ireland is currently considered to be isolated with low levels of electrical interconnection. Ireland is currently below the 10% electricity interconnection target (import capacity over installed generation capacity) set for EU countries for 2020 and 15% for 2030. Ireland is also considered to trigger all three of the European Commission's thresholds proposed to facilitate urgent development of interconnection:

- Average yearly price difference greater than 2 €/MWh between countries or regions (to improve market integration and minimise price differentials),
- Interconnection capacity is less than 30% of peak load (to improve security of supply and ensure electricity demand can be met), and
- Interconnection capacity is less than 30% of installed renewable generation (to enhance sustainability by enabling export potential of excess renewable production).

This is highlighted in the European Commission's "Communication on strengthening Europe's energy networks" as detailed in Figure 14. In this communication the Commission "calls upon Member States to prioritise the development of interconnections with those neighbours that are below any of these thresholds in a spirit of solidarity and cooperation".

This communication also notes that "with the United Kingdom leaving the European Union, Ireland will have 0% interconnection level" relative to the 10% and 15% targets.

Brexit

As an island nation on the periphery of Europe the challenge of SoS resonates with Ireland's citizens. The Celtic Interconnector will bring a new import route for electricity and diversify Ireland's energy supply. It brings geographical and technological diversification through linking Ireland with the French and Continental European electricity system.

An extract from the recent Irish Government publication *National Policy Statement on Electricity interconnection* notes that:

> "Making it a priority to diversify Ireland's international electricity connections will significantly improve the State's security of supply. In the light of the UK's decision to leave the EU, it is

particularly pertinent that Ireland looks to pursue interconnection with at least one EU Member State so that Ireland can participate fully in the delivery of the fully-integrated common electricity market and Energy Union, meet its commitments in that regard, as well as its 2030 renewable energy targets and continue to pursue efficient use of the energy infrastructure available".

Should the UK leave the Internal Energy Market Ireland will become even further isolated. The UK would become decoupled from the EU electricity market making trade less efficient with a knock-on effect on electricity prices in Ireland. Ireland already has one of the highest electricity prices in Europe. During the second half of 2017 Ireland's average consumer electricity price was the fourth highest in the EU at 0.24 €/kWh and was 15% higher than the EU average (Eurostat). The Celtic Interconnector would be Ireland's only direct energy (electricity or gas) connection to another EU Member State.

While the above externalities are difficult to quantify and monitise, and as such are not accounted for in the project's CBA, they are of significance.

Irish Peripherality Means Significant Additional Cost

The Celtic Interconnector provides significant positive externalities for Ireland as outlined above. However, to achieve these and establish a connection from Ireland to another EU Member State requires an interconnector three times longer than one to the UK in order to reach the closest country in continental Europe, France. In addition, Ireland's isolation means that a sub-sea interconnector is required. Such a lack of interconnection between two Continental European countries would be addressed by a 400 kV AC line of, say, 50 km length. **As an approximation therefore one can estimate that to realise this connection and progress towards the targets set by the European Commission, costs in the case of Ireland are 10 times more expensive for Ireland (and in the case of the Celtic Interconnector for France) compared to other EU states, namely much more than 50% of estimated project cost of the Celtic Interconnector (465 M€).**

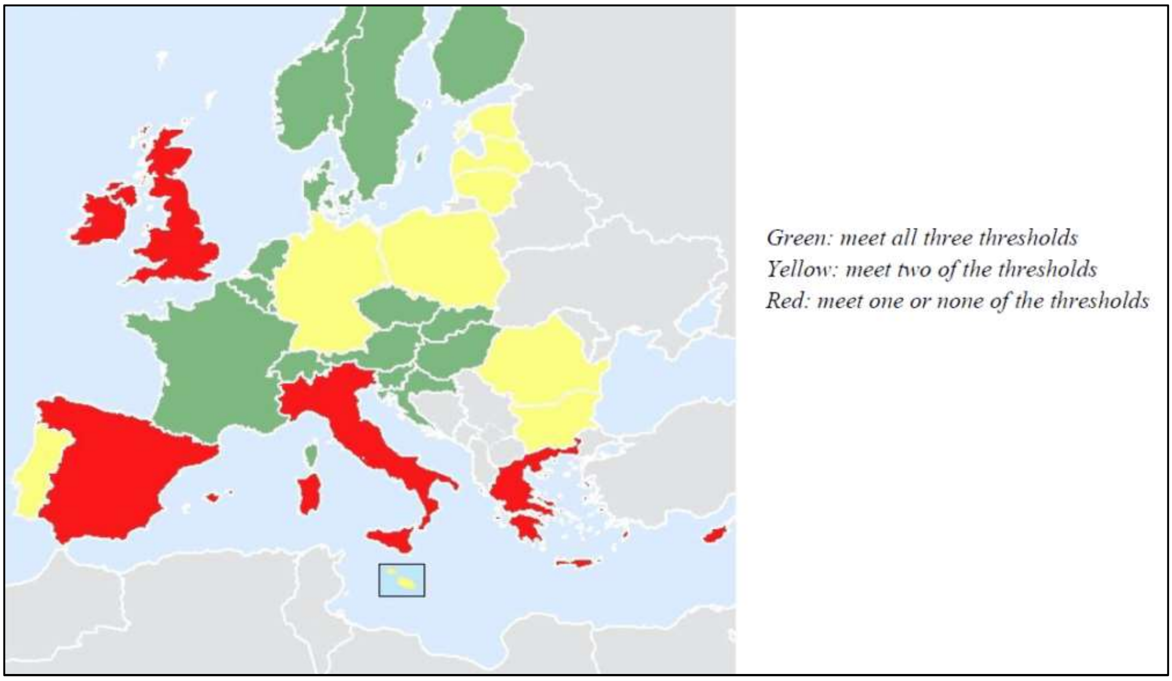


Figure 14: Map indicating how countries score on the three interconnection thresholds. (European Commission's "Communication on strengthening Europe's energy networks"– November 2017)

6.2 Further Externalities regarding Market Integration

As an island system with high RES integration targets the expected impact of RES on market dynamics in Ireland will be particularly pronounced. The Celtic Interconnector would connect the markets of Ireland, the Single Electricity Market (SEM), and France, both of which have different energy mixes and RES generation profiles. An excellent example of the potential of interconnection for improving market integration the Celtic Interconnector would help to reduce price volatility in Ireland and ensure that price differentials between Ireland and other EU Member States are minimised. It would also reduce France's exposure to weather related market impacts. In the context of Brexit the benefits are more pronounced as it will ensure both Ireland and France can benefit from the market-stabilising effects of interconnection discussed above while achieving national climate and RES or generation mix targets.

The SEM on the Island of Ireland is undergoing a major transformation to comply with the European Target Model for Electricity which was a development of the Third Energy Package. One of the primary objectives of the new I-SEM market design is to ensure the optimal use of interconnection though the market coupling discussed above. The **Celtic Interconnector will help to ensure that the benefits of this transformation are maximised and that consumers in Ireland can continue to benefit from, and contribute to, the market coupling objectives of EU Member States.**

6.3 Further Externalities regarding Security of Supply in Europe

The Celtic Interconnector will contribute to the SoS of France and Ireland during peak hours but also in any other contingency situation where adequacy is at risk. As regards France, given the crucial role it plays in the European Power System because of the size of its own system, and the consequences that would result from a major failure affecting this**, it can be said that the Celtic Interconnector would have a noticeable positive impact on the resilience of the European Power System.**

6.4 Further Externalities regarding Sustainability

The Celtic Interconnector is a facilitator of Ireland's transition to a low carbon future by reducing the curtailment of RES generation and the need for subsidies to support RES development. At the same time the Celtic Interconnector represents a significant opportunity to allow the exploitation of the vast RES reservoir, which is available in Ireland, by continental Europe to assist in the achievement of the long-term goal of the EU Energy Union.

These goals, including reductions in subsidies required for RES development and the opportunity for Ireland to increase its level of RES beyond the somewhat conservative assumed 2030 levels and to export green energy are not factored into the CBA.

The estimated cost savings from the Sustainable Transition scenario are highest with an NPV estimated at 350 M€. As there is less curtailment of RES generation so more reductions in Green House Gases (GHG) will be achieved from a lower number of installations, reducing the number of new RES plants required to meet the targets set. In addition, there will be also be displacement of generation from other fuel sources, particularly thermal generation, again supporting the wider goal of achieving significant reduction in the level of GHGs.

Computing the difference between the NPV estimates for Sustainable Transition (350 M€) and the average of the other possible scenarios determined by ENTSO-E and the European Commission (25 M€) is one way of approximating the value of achieving the goals of EU policy through the Sustainable Transition scenario. **This would mean that the value of the Celtic Interconnector in terms of implementation of the EU policy can be monetised at 325 M€ based on the NPVs calculated in the CBA.**

7 Project Business Plan

7.1 Celtic Costs and Revenues

As requested by the NRAs, project business plans along with the calculation of the Internal Rate of Return (IRR) of the project have been carried out from the French and Irish points of view. The business plans provided in the Investment Request rely on the assumption that the Celtic Interconnector would be operated completely as a commercial interconnector, effectively a merchant line, and therefore not included in the national Regulated Asset Base (RAB). The plans make it possible to check whether the benefits expected from such a project outweigh the total costs incurred by both promoters.

They account for the following:

- Revenues derived from the project, separating the CRs and the others,
- Cost of replacement of the assets according to their lifespan and the duration of the business plan,
- Costs for O&M, and
- Losses on the HVDC line, financial charges (assuming 1% inflation), depreciation and taxes.

As the RTE business plan spans 45 years, the refurbishment of the converter stations that occurs at the end of their useful lifespan (25 years) must be accounted for. The corresponding costs are included in the project costs. The replacement of power electronics and of the control system for the French converter stations is assessed to be about M€ completed 25 years after the commissioning date.

The EirGrid business plan only spans 25 years and hence does not include for any additional costs for the refurbishment of the converter.

The values of the losses and CRs are interpolated between 2025 and 2030, using the average of the four base case scenarios.

The Financial NPV and IRR of the project using the average of the base case scenarios are presented in the following table:

Table 15: Financial NPV and Internal Rate of Return

	EirGrid	RTE
FNPV (M€)	-137	-147
FIRR	-5.7%	-4.7%

7.1.1 Conclusions on the Commercial Viability of the Celtic Interconnector

Despite the positive outcome from the economic CBA, results of which are presented in Sections 4 and 5 and the positive nature of the externalities which are detailed in Section 6 for both EirGrid and RTE (accounting for all the SEW benefits), the business plans for the Celtic Interconnector show significantly negative FNPV and FIRR that provide clear evidence of the non-commercial viability of the project.

This confirms that the Celtic Interconnector fulfils one of the major requirements for qualification for CEF funding for Works in that, despite its economic and other benefits, it is not commercially viable.

7.2 CEF Grant Eligibility

To be eligible for funding under the CEF a project must first achieve designation as a PCI. The Celtic Interconnector has been a PCI since the publication of the first list of PCIs in 2013. The Celtic Interconnector is a PCI and so is eligible for grants for works providing it meets all of the criteria specified in Article 14 (2) of the TEN-E Regulation. Article 14 (2) (c) specifies one of the eligibility criteria for CEF Energy grants for Works Actions is that the project is NOT commercially viable, that is that the market cannot fully finance the project. Article 14 (2) also specifies that the project specific CBA of the PCI must also demonstrate the existence of significant positive externalities and that the project must have received a CBCA decision. Both the CBA and the CBCA need to be standalone documents.

Proposals which meet the eligibility criteria and formal requirements specified are evaluated on the basis of the criteria defined in the relevant work programme and call texts. Essentially, these relate to maturity, quality, cross-border dimension, positive externalities, the need to overcome financial obstacles, stimulating effect of the CEF financial assistance, priority and urgency, and complementarity with other actions financed by the CEF.

EirGrid and RTE, the joint promoters of the Celtic Interconnector Project, intend to apply for grant funding from the CEF on the basis that the project meets all of the foregoing criteria. In addition, as demonstrated in Section 7.1 of this document the project is not commercially viable in that the market cannot finance it as is clear from the financial assessment carried out. Based on the foregoing analysis as detailed in the previous sections, EirGrid and RTE consider that there is more than adequate justification for the Project Promoters to apply for CEF grant funding of 50% of the estimated project cost of the Celtic Interconnector.

The needs of Ireland in terms of interconnection development for improving market integration are very significant as noted in Section 6.1. These needs can be appreciated by considering the criteria set by the Commission Expert Group on electricity interconnection targets. Ireland meets none of the three thresholds defined by the experts and is characterised by:

- A price differential with other Member States which exceeds the 2 €/MWh a year threshold defined by the Experts,
- Electrical interconnection below 10% which would be further decreased after Brexit.

The gaps in price differential and in interconnection are such that the development of interconnection between Ireland and another Member State must be urgently investigated.

The CBA carried out by RTE and EirGrid gives clear evidence that the Celtic Interconnector is vital strategic infrastructure to ensure Ireland can reach the RES development targets, and on a much wider basis to ensure Europe's targets in terms of sustainability can be achieved. As noted in Section 6.4 the Celtic Interconnector's contribution to sustainability has been estimated at 325 M€.

Following the CBA methodology validated by ACER and applied by ENTSO-E in the framework of the TYNDP 2018, the Celtic Interconnector will be beneficial for all European consumers. In that respect considering a range of contrasted futures (as predicted by the scenarios used in the analysis) in terms of installed wind capacity in Ireland, it can be seen that the benefits provided by the project significantly outweigh the related costs.

Moreover, the Celtic Interconnector may contribute to SoS in France and Ireland during the peak hours where the power system adequacy is at most risk. As regards France, given its significance in the European Power System, and the dramatic consequences that a major failure in France would have on the European Power System, it can be said that the Celtic Interconnector may have a major positive impact on the resilience of the European Power System.

Ireland has two options for the development of electricity interconnection: connecting to GB or connecting to Continental Europe. These options are far from being similar in terms of actual potential for enhanced market integration. Within the framework of Brexit, the Celtic Interconnector would be a major contributor not only to European SoS as previously mentioned but will also make a major contribution to the unity of the European Energy Union. For this reason, the Celtic Interconnector is very similar to the synchronisation project of the Baltic States with the European Power System that was crucial to complete the integration of the European energy market and which was strongly supported by the European Commission.

However, achieving this strategic contribution to European energy unity is cost intensive. As detailed in Section 6.1, constructing the Celtic Interconnector is ten times more expensive than constructing a similar project that could be implemented on Continental Europe between two neighbouring countries because of the remoteness and insularity of Ireland.

This extra cost can be estimated as between 800 and 900 M€ and has significant financial impact on both of the host Member States proposing to complete the Celtic Interconnector because the project is not commercially viable as demonstrated in Section 7.1.

- As regards France, the Celtic Interconnector has negative impacts on French consumers (NPV = -85 M€ on average of the base case) and significantly negative in the scenario proposed by EC (-235 M€) while the project is commercially non-viable for RTE (-147 M€ on average). The impact of the Celtic Interconnector on tariffs by itself may appear low.
- As regards Ireland, the project is commercially non-viable for EirGrid (-137 M€ on average). The investment cost will be a burden through transmission tariffs on a relatively small number of consumers in comparison with the number of consumers in other Member States. Moreover, paying for the Celtic Interconnector will reduce the benefits expected by Irish consumers in terms of electricity price reduction. These consumers already experience electricity prices that are one of the highest in Europe. The financial charge induced by Ireland's electricity interconnectors (EWIC and the Celtic Interconnector) would reach 15% of the tariffs and is far beyond the cost paid by consumers in other Member States.

As a consequence, EirGrid and RTE consider that it is justifiable that the Celtic Interconnector should benefit from substantial financial support from the European Union. The support that is necessary is estimated at 50 % of the project cost, namely 465 M€, corresponding to the 50 % theoretical limit of CEF funding which can be achieved. (The extra costs that will be incurred by the promoting TSOs are estimated beyond this value). This amount includes grant funding previously allocated for studies in the framework of CEF funds (about 7 M€).

Such a grant amount would constitute a concrete expression of solidarity in energy security for a project which deserves to be considered a flagship project for the European Energy Union given its location, its ambition and its potential contribution to that European Energy Union.

7.3 Financing Strategy

Both EirGrid and RTE will require funding for construction as well as longer-term funding over the life of the project.

The amount to be financed by both EirGrid and RTE depends on two key assumptions:

i. The grant amount from the EU, and

ii. The amount to be self-financed by EirGrid and RTE.

EirGrid and RTE have made a proposal as part of the CBCA on the appropriate division of grant funding based on the benefits estimated using the scenarios from TYNDP 2018 and Slowest Progress.

The Boards of EirGrid and RTE have not yet decided on the appropriate amount of self-financing (debt and/or equity) for their respective shares of the Celtic Interconnector. This will depend to some extent on the level of the EU Grant Aid available.

As RTE is financed at a corporate level, the Celtic Interconnector will be financed together with RTE's other investments most likely through an EIB loan. RTE has historically had access to a large number of sources of finance, particularly in the capital markets. It also has a global EIB facility. Given the scale of its overall operations the Celtic Interconnector would form a small part of RTE's general corporate financing requirements.

It would be commonplace to source both construction and term funding at the same time and EirGrid may follow this practice. The overall amount to be financed by EirGrid will cater for capital costs, interest during construction, any cost overruns and the financing of Debt Service Reserve and Maintenance Reserve Accounts.

When construction is complete and the Celtic Interconnector has completed its commissioning phase, EirGrid will convert its construction loan into a term loan for a period in the order of 20 to 25 years. In its modelling of the Celtic Interconnector, EirGrid has assumed a 5-year period for its construction loan and a 20-year Term Loan.

The debt financing of the Celtic Interconnector is likely to follow EirGrid's usual financing procedures and will be put out to a competitive process. The European Investment Bank (EIB), as a long-term supporter of EirGrid, has indicated its interest in the Celtic Interconnector project, as have a number of international banks and bond investors.

There are a number of long-term financing options potentially available to EirGrid. Generically these are:

- Bank Debt Project Finance,
- Bank Debt Project Finance, with up to 50% provided by EIB,
- Private Placement with Institutions, and
- Project Bond (Private Placement) with Credit Enhancement from the EIB.

It is important to recall that, for EirGrid as well as for RTE, the EIB is limited by its own statutes to financing 50% of the cost of any project, when it is a lender.

7.4 Potential Financing Solution

7.4.1 Illustrative Scenario

The scenario outlined in this section shows the financial arrangement envisaged by the Project Promoters wherein a Grant of 50% is assumed and a direct CBCA contribution is not envisaged. The balance of funding will be provided by the Promoters as either debt finance and/or equity.

Table 16: Financing

Financing sources	RTE (M€)	EirGrid (M€)
1. CEF-Energy financing	232.5	232.5
2. Promoter's own resources Loan and/or Equity	232.5	232.5
TOTAL	465	465

7.5 Impact on Regulatory Asset Base

The impact of the Celtic Interconnector on the RAB will be the accounting value of the Celtic Interconnector as attributed to RTE and as, and if, attributed to EirGrid and shown in the files which are included in the Tariff Impact in Appendix A11. The amount attributed to work in progress during the construction period will also form part of the RAB for RTE.

The regulatory treatment which will govern RTE's investment in the Celtic Interconnector is expected to be the same as that which has previously governed all of RTE's investments which are added to its RAB.

EirGrid also assumes that the Celtic Interconnector will be treated on a WACC RAB basis and added to EirGrid's RAB.

When considering the best regulatory framework to apply in this instance EirGrid looked at two models currently used for regulated interconnectors in Europe, (i) WACC*RAB model and (ii) Cap and Floor model.

EirGrid's financial advisors carried out an analysis of its ability to finance the project based on both of the models. In both instances a number of assumptions were made with regard to certainty provided by CRU, including that the RAB and WACC would not be reviewed until the initial debt has been repaid and that there would be a zero floor on inflation.

The financial analysis found that the WACC*RAB model is flexible and offers a viable option towards financing the project for EirGrid provided that the asset life is aligned with the tenor of the debt and that the WACC is fixed for the same period, with 25 years being the assumed life of the asset. Additionally, the application of the Cap Floor framework raises some concerns as by its nature it would require EirGrid to seek to maximise interconnector revenues in a manner which may raise conflicts with its duties as TSO.

Given the findings of the analysis, coupled with the inappropriateness of the alternative models, EirGrid recommends the usage of the WACC*RAB model as the regulatory framework for the Celtic Interconnector.

7.6 Impact on the Network Tariffs

The French and Irish network tariffs mechanisms are presented in Appendix A10 along with the implementation of those mechanisms from which are appraised the effect of constructing the Celtic Interconnector on the national network tariffs.

With regard to the Celtic Interconnector, the impact of the project inclusion in the network tariffs of France and Ireland will be 0.2% and 2.9% respectively, based on the promoters' business plans implementing the national regulatory schemes presented in Appendix A10.

The impact of the Celtic Interconnector on the RTE RAB is 1.2%. The different nature of the EirGrid business means a comparable calculation is not appropriate. However, the overall impact on network tariffs has been set out.

8 Cross Border Cost Allocation

The CBA conducted at national level shows that 35% of the benefits for the hosting countries accrue to France and 65% to Ireland. Assuming an equal sharing of costs and CR between EirGrid and RTE, the NPV for France is negative in two of the four scenarios considered in the CBA assessment and negative on average as outlined in Section 4. EirGrid and RTE therefore agree on the need for a CBCA decision.

In accordance with ACER guidelines, EirGrid and RTE have agreed a proposal for CBCA to be considered by the NRAs.

8.1 Key Points for CBCA

The following key points informed the agreement of the CBCA proposal:

1. Based on the roughly even geographical distribution of the project infrastructure, the infrastructure is to be owned 50:50 by EirGrid and RTE with a corresponding targeted 50:50 sharing of costs and 50:50 sharing of CRs.
2. The ACER guidelines for CBCA state that compensation for a hosting country should only be provided if there is a net negative impact for that country. The proposed CBCA should therefore seek to “neutralise” the net-negative impact. EirGrid and RTE agree that this may include neutralising a fair and logical level of risk around a net-negative NPV.
3. Subject to achieving point 2, any additional upsides should be used to rebalance any difference in net investment and bring consistency with point 1.

8.2 Maximum Investment Cost for France

Figure 15 presents the project’s average NPV (over the four base case scenarios) for France and Ireland, depending on the investment cost borne by RTE and EirGrid respectively. It can be seen that the maximum investment cost that can be borne by France without resulting in a negative NPV is 360 M€ (38.8% of the project cost of 930 M€). It should be noted that this number is a very optimistic assessment of the maximum cost bearable by French consumers as it does not account for any risk likely to affect France and can result in extreme situations with very low NPV (lower than -235 M€).

Figure 15: CAPEX break-even point based on the average of the four base case scenarios

8.3 Cross Border Cost Allocation Proposal

As detailed in Section 7.2, EirGrid and RTE intend to apply for financial support from the European Commission in the form of a grant through the CEF. It is currently EirGrid and RTE's intention to apply for a grant at 50% of the overall project cost estimate. As such the following CBCA proposal includes the allocation of a potential grant:

Costs Sharing:

- Project cost to be split 50:50 (including any cost over-run or underspend),
- O&M costs to be split 50:50 (details to be defined).

Grant Sharing:

- Grant of 50% of the estimated project cost to be applied for (that is, 465 M€),
- The first 232.5 M€ shared 65% to RTE and 35% to EirGrid,
- Above 232.5 M€, each M€ shared 35% to RTE and 65% to EirGrid,
- Note: percentages based on benefits (net of losses) split of 65% Ireland, 35% France.

Revenue Sharing:

- CR to be shared 50:50 up to a yearly cumulative threshold representing the CR expected in the CBA,
- Any CR in excess of the yearly cumulative threshold to be provided to EirGrid until any difference in net investment following the allocation of the grant is removed,
- Once difference is removed, CR is shared 50:50,
- The yearly cumulative threshold amount is calculated as:
    - Estimated average yearly CR added year-on-year to give yearly cumulative CR,
    - Estimated average yearly CR calculated as the sum of CR estimated for each year over 25 year period divided by 25:
        - CR between 2025 and 2030 linearly interpolated from 2025 and 2030 revenue value,
        - CR after 2030 equal to 2030 revenue value,
    - CR in 2025 and 2030 is calculated as the annual sum of: hourly price spreads between France and Ireland (in absolute value) x 700MW x 95% corrected for losses x 95%. Uses weighted average of the nine climate year results from ANTARES and PLEXOS.

Appendix A1 Complementary Technical Information

A1.1 Technical Description of the Project

A1.1.1 Feasibility Phase

During the Feasibility Phase of the project (2014-2016) several studies were undertaken to confirm the availability of feasible offshore and onshore routes between Ireland and France for the installation of a HVDC interconnector. These studies were carried out following the identification of connection points in Ireland and France that had the potential to accommodate the import and export of 700MW between both countries. The Knockraha substation in East Cork and the Great Island substation in West Wexford were identified in Ireland based on their connectivity in the Irish transmission grid and their location along the south coast of Ireland. The La Martyre substation in Brittany was identified in France.

Offshore

A landfall identification study was carried out in 2014, with a range of feasible landfall locations being identified in Ireland and in France. In Ireland, the landfall options were located in the south (East Cork) and in the south-east (West Wexford). Following the landfall identification, an offshore route investigation was conducted to identify and assess viable offshore route options between the landfall points on the south coast of Ireland and the landfall points on the north-west coast of France. The study considered matters including the shortest reasonable route between the two countries and potential engineering and environmental constraints.

Based on a constraints analysis of the routes identified, the two preferred marine routes were from the East Cork area to North Brittany in France, laid out in Figure 16 below as Route 1 and 2. One of these routes runs inside UK territorial waters (UK TWs) while the other runs outside. Route 2 below runs outside UK TWs and, while not the shortest route, it was considered the best performing route. This is because it is least constrained overall and avoids UK TWs, which could introduce additional time during the consenting phase and enduring cost to the project.

Figure 16: Marine routes identified

A detailed marine survey of Route 2 was undertaken in 2014 and 2015 to:

- Develop the offshore route,
- To assess the seabed conditions and any technical constraints associated with cable laying, and
- To provide a basis for cost estimation.

A survey of the marine environment and benthic habitats along the route was also carried out. The marine survey confirmed that the chosen route was feasible, with generally favourable conditions for cable installation. The main findings of the marine survey can be summarised as follows:

- No major constraints identified along the route,
- Maximum water depth of 110-115m with majority of the route between 90-100m,
- Majority of the route consists of gravely sands and sandy gravels with 75% of the route containing a sediment layer of 1m or less,
- Sections of clay, silt, chalk and sandstone also recorded with outcrops of rock recorded along small portions of the route, which was predominantly recorded at both Irish and French nearshore approaches,
- A large variance of marine habitats were encountered along the route, however there was no evidence of any particularly sensitive habitats recorded,
- The benthic sampling and reporting provides a good quality basis for future Environmental Impact Assessment Studies.

These studies were complemented by shipping, fishing and burial assessment studies to identify the density of maritime traffic along the cable route and to determine the optimal burial depth for the proposed cable beneath the seabed. These studies combined the results of all of the previous marine studies along with risk based quantification along the entire route. The main findings of these studies were as follows:

- The probability that a vessel would drag anchor over the cable route is estimated as very low,
- Recommended minimum burial depth of 0.6m – 1.2m for majority of route,
- Estimated requirement for additional protection along 50-80km of originally surveyed route.

Further investigation of some of the challenging areas, particularly the nearshore approaches and boulder areas in the route mid-section, is currently being carried out through additional marine surveys and engineering studies as part of the current phase. The findings of these additional studies may result in minor route optimisation and a reduced requirement for additional protection, with the potential for a refinement of the capital cost estimates.

Onshore

Onshore studies were carried out in both Ireland and France in order to identify feasible options to connect from each of the landfall points to a range of converter station site locations and onwards to each of the connection points.

Ireland

In Ireland, a high-level project scoping study including a high-level environmental appraisal of the converter station, onshore routing and landfall area options was carried out under the following headings:

- Ecology, including screening for Appropriate Assessment,
- Cultural Heritage,
- Hydrology and Hydrogeology,
- Soils and Geology,

- Human Beings,
- Landscape and Visual Impact,
- Infrastructure and Utilities.

The report concluded that there were a range of feasible AC and DC circuit routes for each of the project elements in both the East Cork and West Wexford study areas, and provided an outline design of a proposed converter station and the identification of feasible converter station location areas and associated constraints analysis.

Network studies were also carried out to assess the potential impact of a 700MW interconnector on the transmission system when it was connected at either the East Cork or West Wexford connection points. This clearly identified the East Cork connection point as outperforming the West Wexford option.

Following a consultation with stakeholders during the second half of 2017, the Knockraha substation in East Cork was selected as the preferred connection point in Ireland for the Celtic Interconnector.

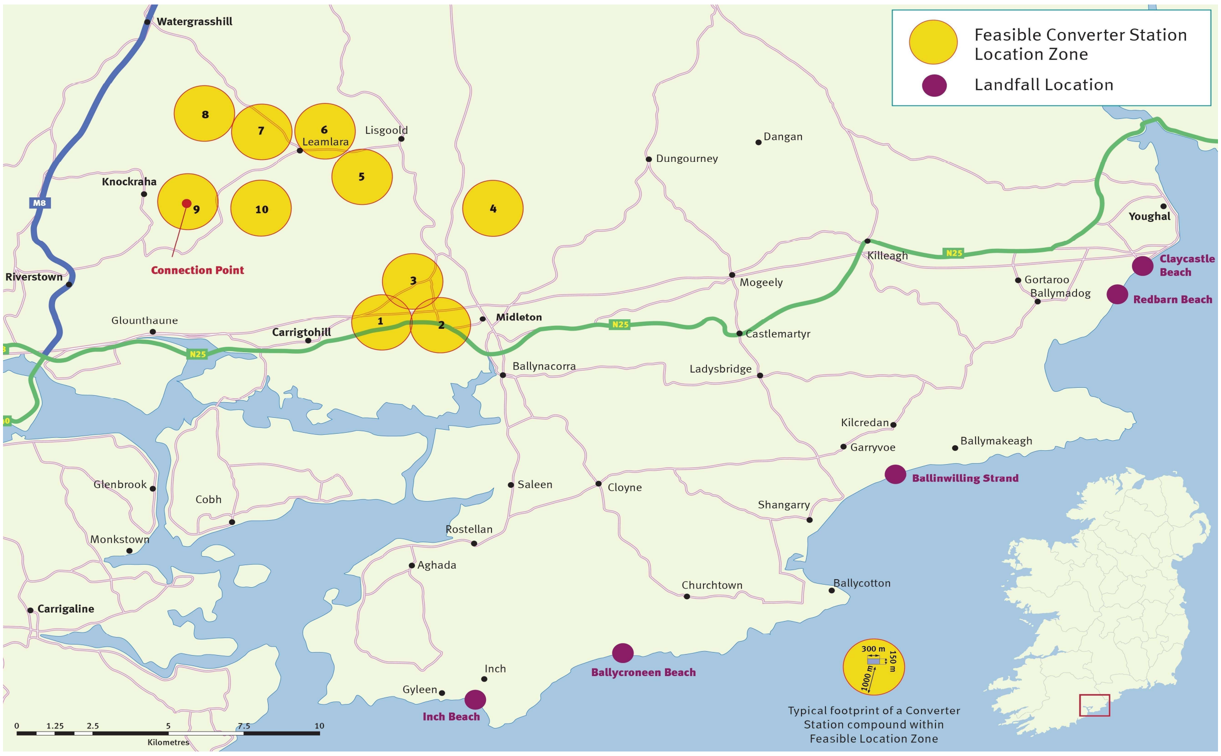


Figure 17: Feasible Converter Station Location Zones and Short List of Landfall Locations in East Cork

France

As in Ireland, a feasibility study was conducted to assess the key issues from an environmental and societal perspective.

The possible landfall locations are a determining factor for the realisation of the project. Potential landfall sites were assessed according to multiple criteria, including marine approach conditions (geology, meteorological conditions and uses) and terrestrial accessibility.

The feasibility study also identified favourable sites for the installation of the converter station. Feasible land routes between the potential landfall sites and converter station sites were investigated and evaluated in relation to the constraints, in particular the crossing of the Elorn Valley.

The different options for the landfall site, the converter station location and the route of the underground cable will be presented and discussed during the consultation with project stakeholders. The various network studies carried out have also shown that the connection to La Martyre substation did not generate any constraint on the network in Brittany.

A1.2 Assessment of the Availability Rate of the Celtic Interconnector

A1.2.1 Overall Approach

In order to calculate the link overall availability rate, the failure rate associated with each component of the link separately was first calculated – namely the HVDC/HVAC converters, the land cable in France and Ireland, and the marine cable – and then the global rate was assessed using basic probability laws.

While the proposed methodology considered the so-called SKM model (Sinclair Knight Merz)[7] which has been used by the Ofgem (GB regulator) since 2013 and has been recently updated by Gutteridge Haskins Davey (GHD)[8], the intention of this assessment is to present the inherent limitations of this model, in particular for the submarine aspects, and to develop a more rational calculation for that specific component of the project.

A1.2.2 Converter Stations

While the previously mentioned models have tried and calculated failure rates for the various components of a HVAC/HVDC converter station, it is our view that this approach can be improved. Indeed, the availability rate of 320kV HVDC/HVAC converters is likely to be a contractual requirement as for all previous RTE HVDC projects.

Nowadays, VSC suppliers accept to commit to a 99.5% availability rate for the system (2 converters). In addition, the planned maintenance operations are estimated to represent about 1% unavailability.

Consequently, the overall unavailability rate estimated for the Celtic converter stations is:

$$\boxed{\tau_{Converters} = 1.5\%}$$

A1.2.3 Underground Cables

The SKM model is based on a significant database established by the International Council on Large Electric Systems (CIGRE)[9] from thousands of kilometres of underground cables (UGC) data. While this model could certainly be improved (more recent data, distinction between voltages levels, consideration of cables proven reliability – that is, passed tests, etc.), it seems to be a robust one and the best model available to be used for underground projects.

[7] Model and calculation spreadsheet can be found respectively at :
- https://www.ofgem.gov.uk/ofgem-publications/59247/skm-report-calculating-target-availability-figures-hvdc-interconnectors.pdf and
- https://www.ofgem.gov.uk/ofgem-publications/59248/skm-model-target-availability-model-hvdc-interconnectors.xlsx

[8] Report for Ofgem – Target Availability Figures for HVDC Interconnectors - Update , 66/10798/001 | ii (August 2016)

[9] CIGRE Brochure 379 Update on Service Experience for HV Underground and Submarine Cable Systems (2009)

Table 17: SKM model failure rates for UGC

Cable Type	External Failures (fail./yr/cct.km)			Internal Failures (fail./yr/cct.km)			MTTR (days)	
	High	Low	Average	High	Low	Average	Average	High
AC Onshore XLPE Cable	0.00087	0.000435	0.00058	0.00045	0.000225	0.0003	20	30
HVDC Onshore XLPE Cable	0.00087	0.000435	0.00058	0.00045	0.000225	0.0003	20	30
HVDC Onshore MIND Cable	0.00087	0.000435	0.00058	0.00045	0.000225	0.0003	40	65

While the exact ratio between HVAC and HVDC land circuits lengths is not known yet, the overall land part of the Celtic Interconnector will entail approximately 75 km of UGC (considering both the French and Irish side). Since the SKM model presents identical failure rates for AC and DC (and for XLPE and MI) the final design will not impact the availability calculation.

Considering RTE's high standards with regards to UGC cable rating, design and testing as well as the intention of monitoring the Celtic Interconnector UGC thermal status thanks to fibre optic being deployed along with the power cables, the internal failure rate has been chosen. For the external failure rate, the average rate has been used.

The model defines an average repair time for UGC failure of 20 days. Thus, the SKM model gives us following UGC overall unavailability rate:

$$\boxed{\tau_{UGC} = 0{,}33\%}$$

A1.2.4 Submarine Cables

A similar type of failure rates calculated on the basis of submarine projects data is given by the SKM model for underwater cables (UWC):

Table 18: SKM model failure rates for UWC

Cable Type	External Failures (fail./yr/cct.km)			Internal Failures (fail./yr/cct.km)			MTTR (days)	
	High	Low	Average	High	Low	Average	Average	High
AC subsea XLPE Cable	0.000315	0.0001575	0.00021	0.000405	0.0002025	0.00027	65	90
HVDC subsea XLPE Cable	0.000315	0.0001575	0.00021	0.000405	0.0002025	0.00027	65	90
HVDC subsea MIND Cable	0.000315	0.0001575	0.00021	0.000405	0.0002025	0.00027	65	90

The degree of reliability of those numbers is questionable. Indeed, the amount of submarine projects data is, by nature, much more limited than underground projects. As an illustration, there is currently no known internal failure on XLPE HVDC UWC (which is the anticipated cable technology for the Celtic Interconnector).

However, for internal failure rate, it is considered there is no better approach than the CIGRE based rates, that is, an average rate of 0.00027 fail./year/cct.km.

With regards to external failures, the installation techniques of submarine cables have drastically improved in recent decades, with a significant impact on the protection level. Consequently, it is very debatable to use SKM rates which are based on a majority of projects where cables were simply laid on the seabed with no or poor protection. Nowadays, as acknowledged in the GHD report:

> "*a risk assessment of the full cable route is undertaken to inform the suitable burial depth to mitigate damage by third parties. This would suggest that the failure rate would improve further as the submarine cable should be appropriately protected for the full route length*".

In addition, external threats for submarine cables vary significantly from one area to another, depending on the local anthropogenic activities. This means the external risk profiles of submarine projects are usually not comparable. In fact, for a given project, the risk profile may even present a very heterogeneous aspect along the route. Thus, using a constant external failure rate per kilometre is not appropriate and the RTE recommendation is to adopt an in-depth analysis of the project specifics.

To assess the external failure rate for the Celtic Interconnector, one shall first take into account that **a robust cable routeing process** has been conducted, so the cable route avoids any area presenting an unacceptable level of risk, such as dredged areas. Consequently fishing and shipping risks will be the only credible factors to consider for assessing external failure.

Besides, **the link will be protected along 100% of the submarine route.** While the main approach will be to bury the cables, external protection (for example, rock placement) will be systematically used in case burial is deemed impossible or proven insufficient.

As detailed by the Carbon Trust Association[10], cables being buried at more than 50 cm in the seabed can be considered safe from fishing activities. The Celtic Interconnector cables will always be buried deeper than 50 cm or protected with rock to achieve a better level protection. Consequently, shipping activities constitute the predominant threat for the link.

To define an appropriate level of protection (that is, depth of burial) from shipping activities, the marine traffic in the area has been studied over a 15 year period and the various risks associated (that is, anchoring or foundering) have been modelled using a state-of-the-art methodology[11], taking into account local water depth conditions and proximity from shores (indeed, vessels do not drop anchor when far from any obstacle and/or when water depth is beyond 80-100 m).

Figure 18 - Celtic shipping Risk Profile

It is interesting to note that the risk is high in the nearshore areas, where the marine activity is important and in the close vicinity of the navigation corridors that are used by cargos to travel along the Channel. However, the main part of the route presents a negligible risk, and consequently the overall risk has been assessed to 4.1 x 10^{-4} failure/year. For the sake of a comparison, the same model applied on the IFA2 Interconnector has led to an overall risk of 5.89 x 10^{-3} failure/year while the length of the route is only 205 km.

The shipping risk has been likewise quantified for different vessel categories (that is, different anchor sizes and weight).

[10] Carbon Trust | Cable Burial Risk Assessment Methodology: Guidance for the Preparation of Cable Burial Depth of Lowering Specification (2016)
[11] Anatec Limited | Celtic Interconnector - Shipping and Fishing Cable Risk Assessment (2016)

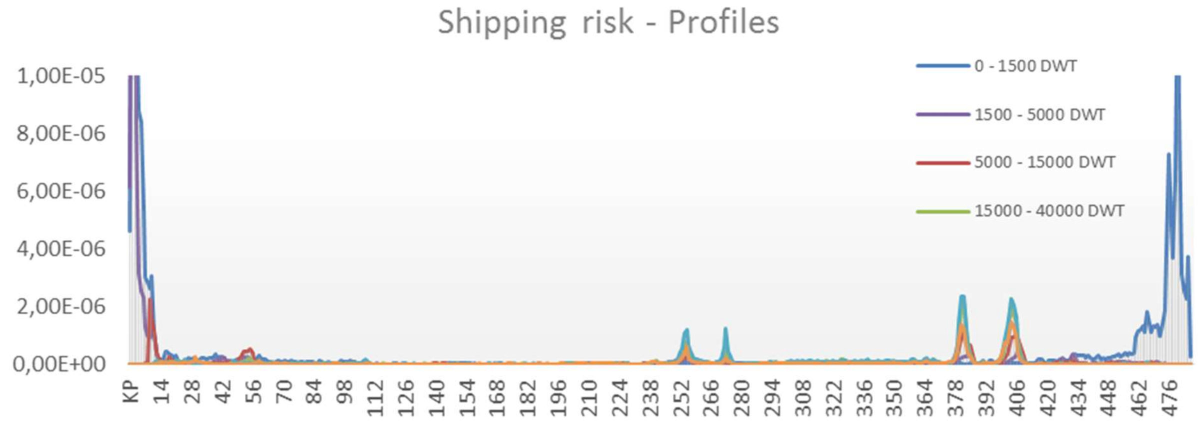


Figure 19- Shipping Risk profile per anchor weight categories

Considering ground conditions (sediment thickness, bedrock hardness) and the potential penetration of different anchors, an optimum burial depth has been calculated for each section of the route to achieve an acceptable level of protection at a reasonable installation cost. This exercise has been undertaken by three external consultants – DNV GL, 4COffshore and Wood Group – to guarantee the robustness of the protection strategy.

The resulting burial depth – which varies from 0.7m to 3m – enables the achievement of a theoretical residual overall risk of 2.15 x 10^{-4} failure/year.

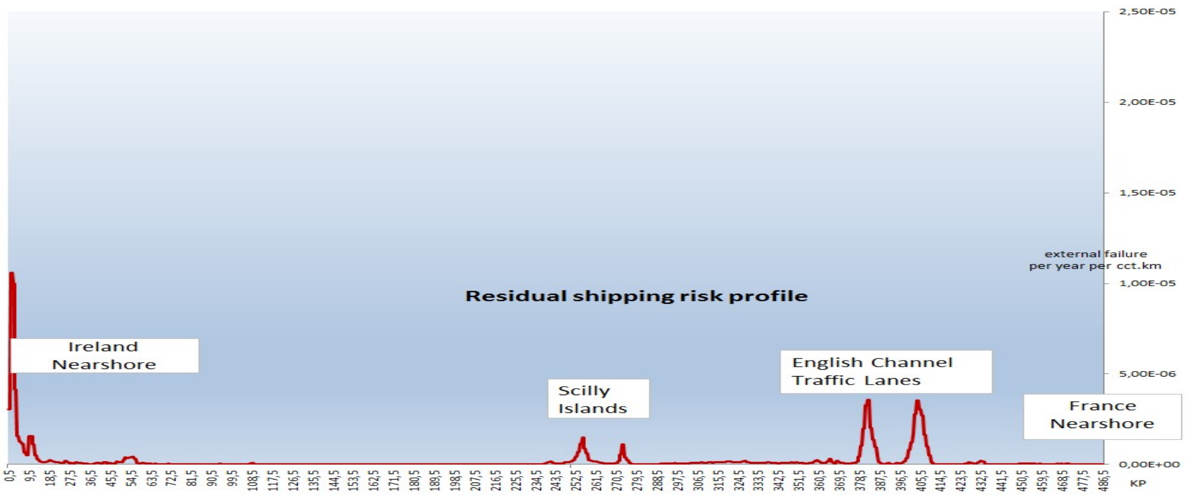


Figure 20 - Celtic Remedial Risk profile

Using the external and internal failure rates developed previously, the overall unavailability rate of the submarine part of the interconnector has been calculated considering a repair time of 90 days, to reflect on the experienced duration for IFA2000 offshore repair in 2017.

τ_{UWC} = 3.27%

A1.2.5 Overall Availability Rate

For calculation purpose, we will define:

- A = UGC internal failure event,
- A' = UGC external failure event,
- B = UWC internal failure event,

- B' = UWC external failure event,
- C = Converters failure event,
- and p(A), p(A'), p(B), p(B') and p(C) the associated probabilities.

The event E= System failure is then defined by:

$\mathrm{E} = \mathrm{A} \cup \mathrm{A}' \cup \mathrm{B} \cup \mathrm{B}' \cup \mathrm{C}$ and $\mathrm{p(E)} = \mathrm{p}(\mathrm{A} \cup \mathrm{A}' \cup \mathrm{B} \cup \mathrm{B}' \cup \mathrm{C})$

Those events are not strictly incompatibles (for example, it is possible to have an external fault on the submarine cable while the converters are out of service) but the probabilities associated with cumulative faults are negligible. Therefore, we will assume that:

$\mathrm{p(E)} = \mathrm{p(A)} + \mathrm{p(A')} + \mathrm{p(B)} + \mathrm{p(B')} + \mathrm{p(C)} = \tau_{Converters+}\ \tau_{UGC+}\ \tau_{UWC}$

This leads to an overall assessment of a system failure event:

$$\mathrm{p(E)} = 5.0274\%$$

τ_{Celtic} = 5.0274%

In conclusion, the Celtic Interconnector availability rate is estimated to be 95 %

A1.3 Assessment of Risk Factors for Implementation Plan

The main risk factors have been outlined in Table 19 below for each of the remaining phases of the project.

Table 19 - Key risk factors for implementation plan

Project Phase	Risk Description	Potential Impact	Mitigation Measures
DDC			
DDC			
DDC			
Construction			
Construction			
Construction			

Appendix A2 Celtic Interconnector Costs Analysis

A2.1 Project Cost Uncertainty

As experience shows, all uncertainties relating to cost estimates are unlikely to simply add up. The project cost of 930 M€ takes into account the price variations observed within similar contracts and covers the whole scope of the project: cable supply, converter station supply, and land and marine installation operations.

The project cost takes into account the difficulties assessed along the route and includes for example the costs for route preparation (pre-lay survey, UXO detection campaign, boulder clearance, HDDs, 3rd party crossings preparation etc.). In addition it should be noted that a certain element of contingency regarding marine operations has been taken into account such as weather downtime during cable laying operations and protection operations.

The risk analysis characterises the downward opportunities and the upward risks regarding the cost assessment of 930 M€.

Table 20: Project Cost Uncertainties (values in M€)

Cost Item	Specific Risk	Downward Opportunity (M€)	Sub-Total (M€)	Upward Risk (M€)	Sub-Total (M€)	Risk Mitigation Measures
Marine Installation						
Cable Supply						
Land Cable Installation						
Converter Stations						
Other Costs						

Total Uncertainty	**-110**	**140**	

A2.2 Cost Efficiency

The efficiency and coherency of the expected costs for the main assets of the projects, cables and converter stations, can be assessed by comparison with public data from contract awards of recent similar interconnections and with the results of recent tender submissions for a similar project.

The budget considers M€/km of cable and M€ for each bipolar converter station (700 MW).

Regarding cable systems, with the public information on the awards of NSN Link, NordLink, Borwin 3 and IFA2 the reference cost would be between 0.57 and 0.79 M€/km with mean value of 0.68 M€/km. The price for each kilometre significantly depends on the total length of the interconnectors. The longer the route of the cable, the higher the cost reductions that will be expected from the cable providers during the procurement negotiations.

Regarding VSC converter stations, public information includes projects in Sweden, Spain, France, Italy, UK, Norway, Denmark, Belgium and Germany. The range would be between 60 and 140 M€ for voltage level of 320kV, and between 170 and 300 M€ for 525 kV. It should be noted that public information on submarine interconnectors in 525 kV technology generally provides the global cost of the project. The cost of the converters can only be an estimation that is derived from an assessment of the cable cost.

A2.3 Project Cost Schedule

The schedule of the project expenditures (that is, expenditures likely to be included in the RABs) is as follows:

Table 21: CAPEX Schedule (values in M€)

CAPEX total	Feasibility phase	IDPC phase 2017-2018	2019	2020	2021	2022	2023	2024	2025	2026
930	11	7	5	5	6	50	160	310	286	90

All the economics calculations proposed in this document (NPV calculations) are carried out on the basis of this cost schedule.

A2.3.1 Decommissioning Process

According to present French law and the coming amendments related to off-shore windfarms connection, there is no requirement for mandatory decommissioning of submarine cables (the main part of the assets) at the end of their technical lives.

The only requirement for the TSOs at the end of the "public field occupation" concession is to carry out environmental studies to assess the impacts, negative or positive, resulting from the decommissioning process. According to the outcomes of these studies, a decision will then be taken to engage decommissioning or not. It turns out very often that the devices used for protecting the submarine cables have become habitats for marine mammals, hence the decommissioning may have huge negative environmental impacts.

For the portion of the project in Ireland and in Irish TWs, decommissioning will be carried out to meet the requirements of all applicable legislation.

A2.3.2 Assessment of Operation and Maintenance costs

The O&M cost retained for the Celtic Interconnector is 8.4 M€/year. This figure has been assessed considering other HVDC systems developed by RTE and EirGrid, and accounts for the:

- cost of repair of the breakdowns affecting the cables,
- cost of the preventive, curative and adaptive maintenance of the submarine cable system, including the recurrent maintenance expenses and excluding labour costs and possible taxes,
- cost of the preventive and curative maintenance of converter stations, and
- Insofar as the discounting method considers a null residual value, the replacement of the power electronic devices has not been annualised.

Appendix A3 Impact on the French and Irish power systems

A3.1 Grid Transfer Capacity

A3.1.1 Impacts on the grid transfer capacity in France

Since the completion of the “Brittany security meshed network” (an underground 225 kV line between the Plaine Haute substation in the North of Brittany and the Calan Substation in the South), the studies concerning the transmission network in Britany carried out in the framework of the various long term scenarios of the French Adequacy Outlook issued since 2012 have given evidence of the absence of congestions in this network. The same studies have also shown that the selected development strategy which consists in connecting the interconnector to the La Martyre 400 kV substation does not generate any additional congestion, even in the situation where power flows are oriented to Ireland during peak hours. The latest computations carried out with the scenarios of the French 2017 Adequacy Outlook have confirmed this diagnosis. The assumption accounted for in the studies cover the whole provisions mentioned in the “Electric Pact” for Brittany, including the Landivisiau CCGT commissioning.

The following graphs show the flow distribution on the transmission network in Brittany during a cold spell with a probability of one in ten years considering the higher growth demand scenario in 2035 in the absence of any RES generation in this area. In such a situation, in case of maximal import from Ireland, it can be seen that there is enough margin left on the lines. The major part of the power flow in the Celtic Interconnector is provided by the network in the south of Brittany which is particularly strong. The most constraining incident is the 400 kV DOMLOUP-PLAINE HAUTE line tripping, in the North of Brittany which result in no congestion, thanks to the “Brittany security meshed network” CALAN-MUR DE BRETAGNE-PLAINE HAUTE that enables mutual help between the North and South of Brittany.

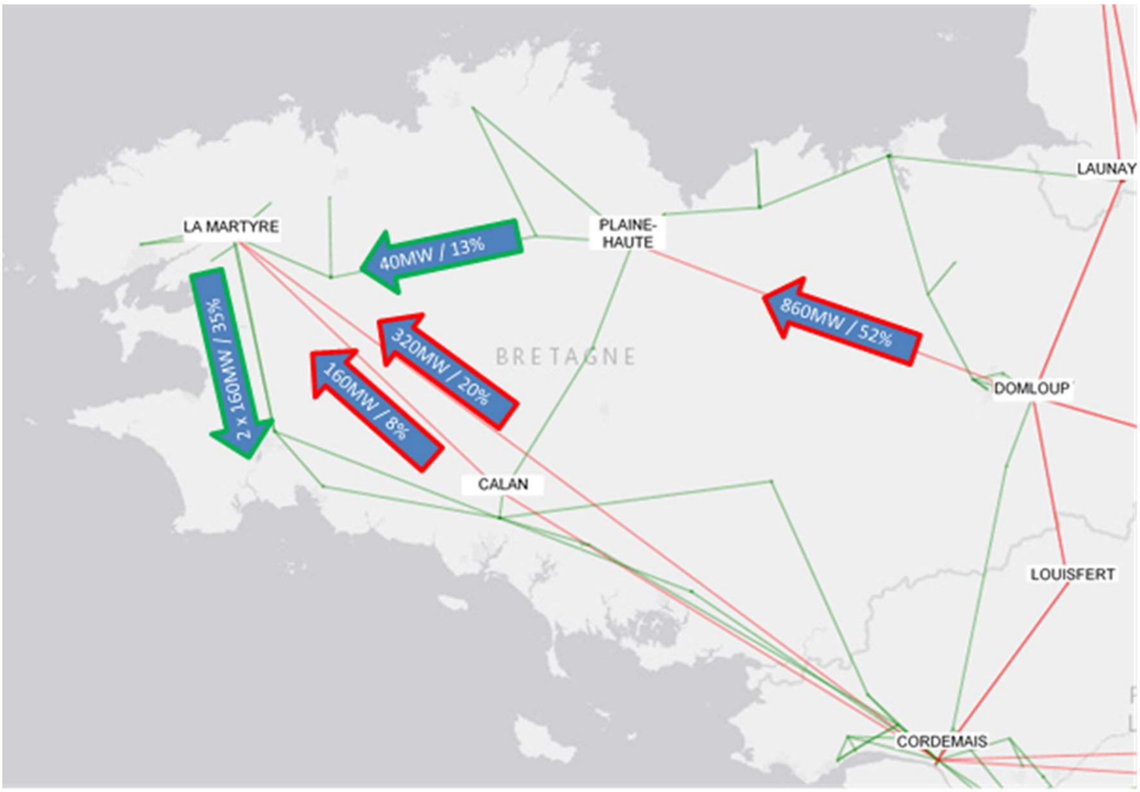


Figure 21: Power flows in MW and load rate in % of the various transmission lines in Brittany during a cold spell – French Bilan Prévisionnel Higher growth scenario 2035 time horizon – without the Celtic Interconnector.

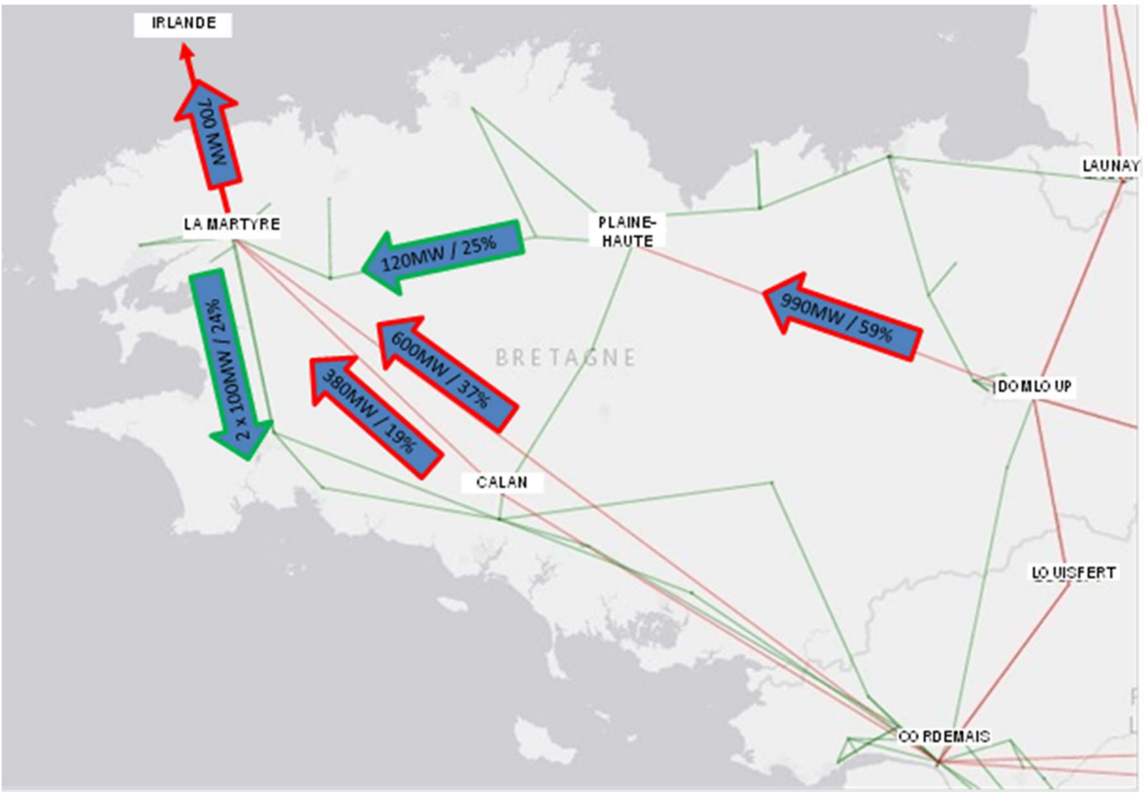


Figure 22: Power flows in MW and load rate in % of the various transmission lines in Brittany during a cold spell – French Bilan Prévisionnel Higher growth scenario 2035 time horizon – with the Celtic Interconnector.

The only congestions likely to affect the network in Britany in the long run are related to voltage profile issues during cold spells, because of the numerous uncertainties concerning the installed generation in this area. These include: peaking plants obsolescence, foreseen shutdown of coal fired power plants in the mid-term in France, and future use of nuclear power plants. The main features of those situations are their low likelihood, but critical outcomes (voltage collapse).

Robustness voltage analysis focusing on this area across various long term scenarios highlights that it is necessary to combine several unfavourable key factors to get a risky situation from the voltage stability point of view, for example, a cold spell in the western part of France combined with a N-1 situation (line or power plant tripping) in a situation of export from France to Ireland.

When crosschecking the probabilities of those various factors and analysing the forecasts of the net demand in Brittany and the time-series of the cross-border exchanges described in the long-term scenarios, it can be seen that the number of hours during which the risk of voltage collapse might lead to a reduction in the exchanges to Ireland is almost negligible.

Impact of Celtic Interconnector on the network beyond Brittany

Network studies carried out on the latest long term scenarios made it possible to detect and identify several areas in the western part of France where the network is potentially vulnerable. They are detailed in the following map. The map highlights the lines that could be congested in N-1 situations (line tripping) in certain scenarios of demand, generation and cross-border exchanges.

This map highlights the main congested areas at stake in Normandy – South of Paris and in Atlantic facade already mentioned in the French NDP 2016 as well as the underlying 225 kV networks, particularly in Normandy and the Vendée.

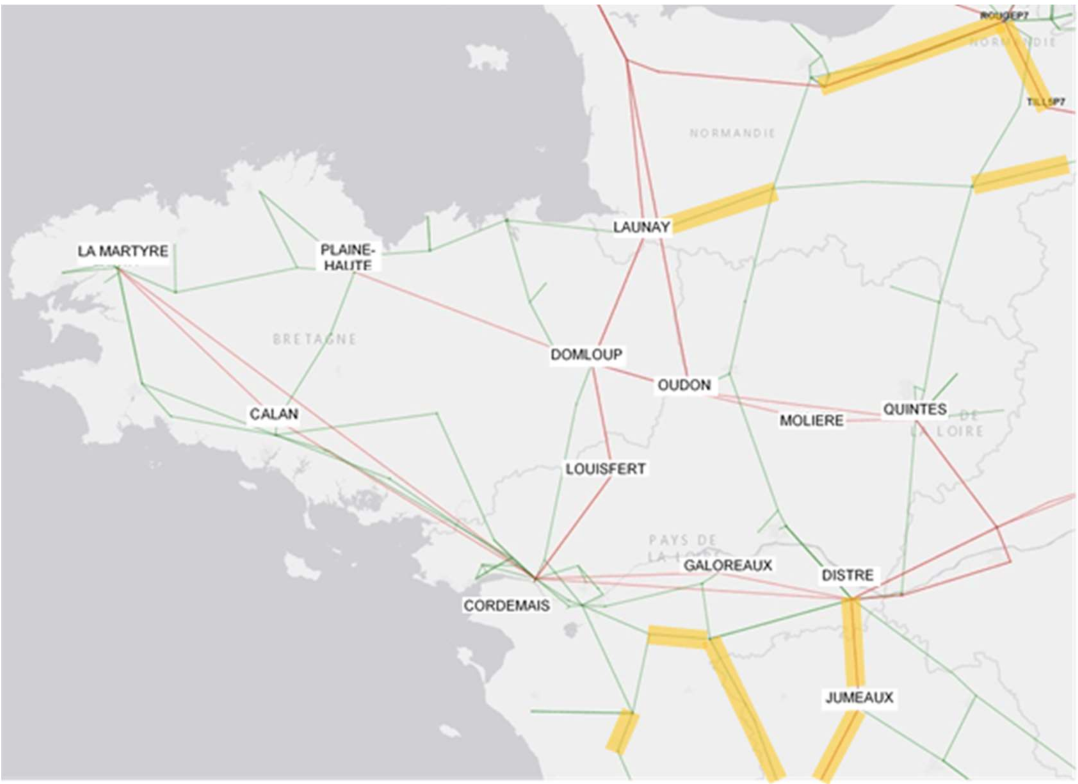


Figure 23: 400kV and 225kV congested lines in various studied long term scenarios

Those areas are regularly the object of comprehensive studies for specifying the best strategy according to the possible futures (for example, modification of the network topology, suppression of the ampacity limits in the substations, flexible solutions to dynamically improve the ampacities of the line or operate the interaction between the 400 kV network and the underlying 225 kV one, building new lines). The frequency and the level of these congestions are highly depend on the numerous possible changes in the energy mix in one area and by definition are highly uncertain.

The plots hereunder detail the “load rates” duration curve corresponding to some of the congested lines presented on the map in two long-term contrasted scenarios:

- The Volt scenario which foresees a strong RES development along with a limited nuclear decommissioning scheme in France and an intensive development of interconnection,
- The Ampère scenario which foresees an intensive RES development and a relatively important nuclear decommissioning scheme in France associated with a high development of interconnection.

For each of those scenarios that assume that the Celtic Interconnector is included in the network in 2030, a sensitivity analysis without the Celtic Interconnector was carried out for appraising the consequences. In both scenarios, the coal-fired plants in Cordemais are considered as decommissioned.

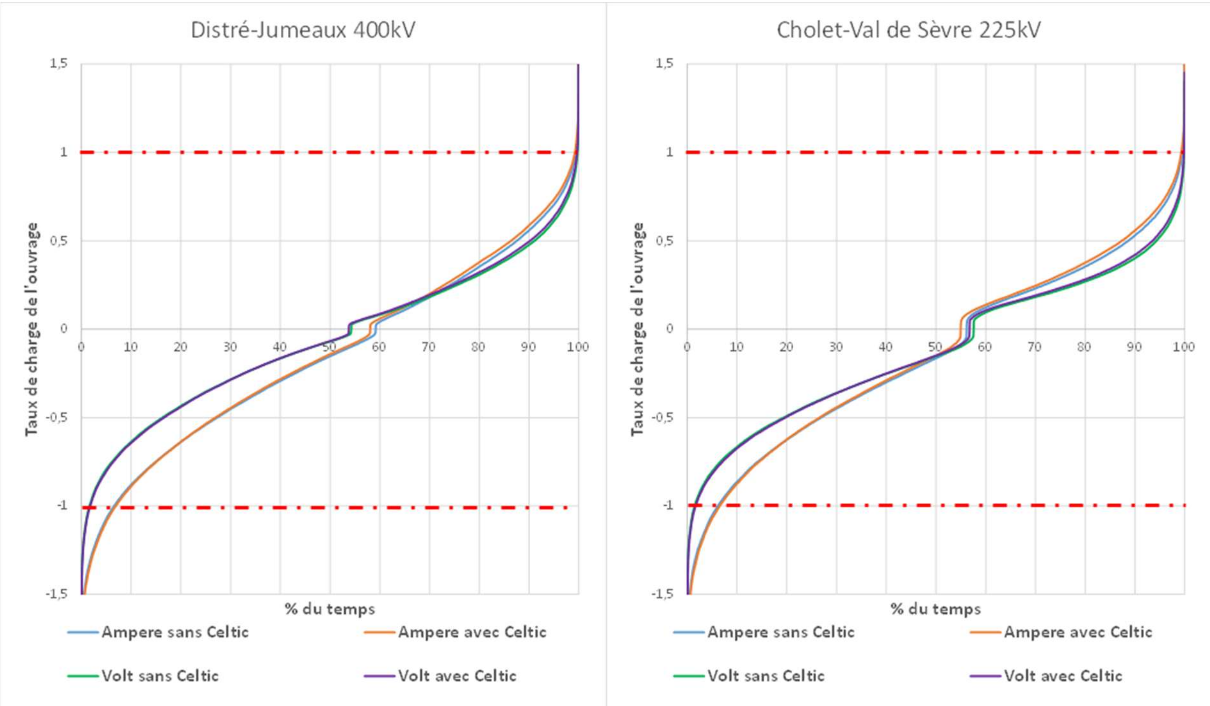


Figure 24: “load rate” duration curves in the “ Volt” and “Ampere” scenarios in 2030, with and without the Celtic Interconnector, Normandy – South of Paris area and 225 kV underlying network

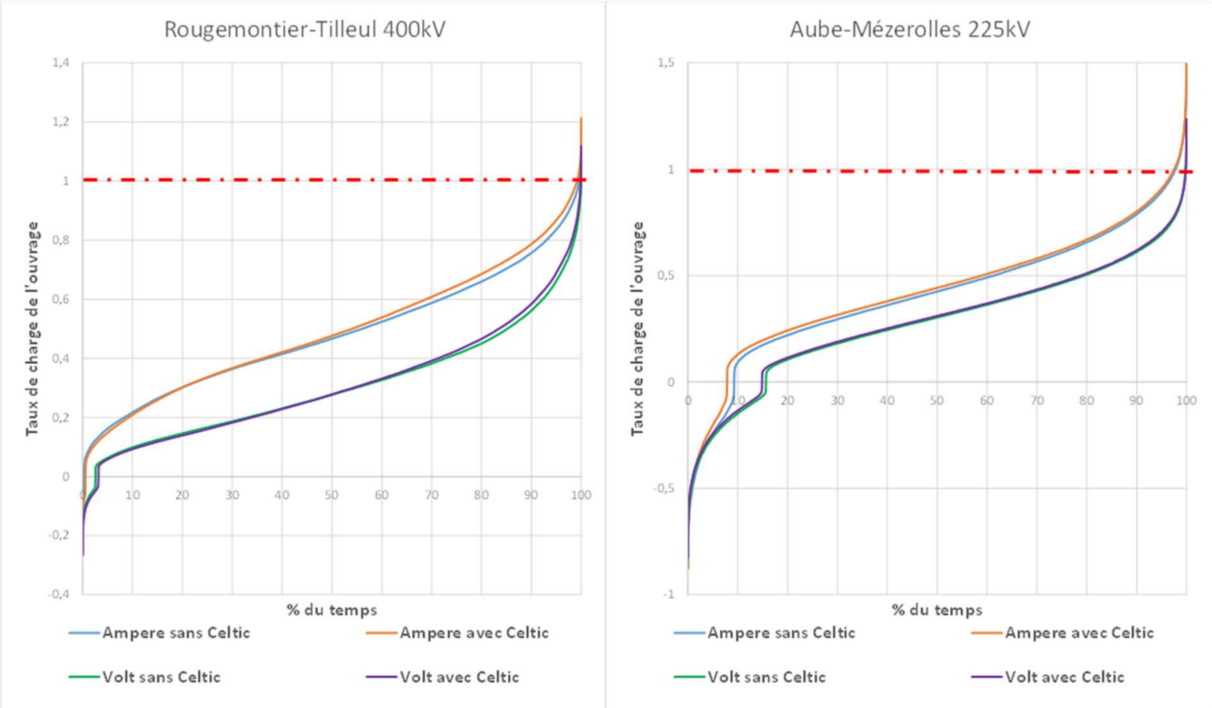


Figure 25: "load rate" duration curves in the "Volt" and "Ampere" scenarios in 2030, with and without the Celtic Interconnector, Normandy – South of Paris area and 225 kV underlying network

The following observations can be made:

- There is no significant long-term congestion identified in the "Volt" scenario in the study area,
- In the "Ampère" scenario, congestion occurs on the main lines of Normandy – South of Paris and the Atlantic Facade and on the 225kV underlying network,
- The Celtic Interconnector project is not a cause of these constraints and has a negligible impact on them.

Hence, the Celtic Interconnector has no major impacts on the congestions on the transmission network in the study area. These are the foreseen changes taken as a whole that might cause the need for network reinforcement.

It should be noted that this need is highly uncertain given that the changes are themselves highly uncertain.

The Celtic Interconnector has a low impact on these congestions. It will not, therefore, be an efficient means of mitigating or solving these issues. It can be said that the interconnection capacity between France and Ireland will not be affected by the identified congestions.

A3.1.2 Impacts on the grid transfer capacity in Ireland

As of 17th October 2017, EirGrid was directed by the CRU to commence processing any electricity interconnector applications that had received PCI status. An analysis was carried out to determine any additional transmission network needs that would be driven by the connection of the Celtic Interconnector to the Irish System. The general principles and assumptions set out here were applied in all of the studies.

General Assumptions

1. Network cases were derived from the latest generation and network database release (November 2017) used for the compilation of the 2017 Ten Year Transmission Forecast Statement. These cases have undergone rigorous examination and have been deemed appropriate for use of studying interconnection on the southern coast of Ireland.
2. PSSE software was used to run these studies (v33).
3. This study does not include an assessment of the shallow connection options or costs of the interconnector applicants.

Study Year

The study year chosen was 2025 for both the Standard Access PSSE Analysis and the 8760 Analysis. This was considered an appropriate year to assess the long term impacts for further interconnection on the transmission system. A 'five years out' analysis was not considered necessary since the key difference between 2025 and 2030 cases is organic load growth, which was not deemed likely to have considerable impact on the study results.

Demand

Standard Access PSSE Analysis

Winter Peak and Summer Peak demand scenarios were considered. Summer Valley was not considered in this study as this was not considered an excessively onerous scenario as observed in previous pre-feasibility studies. Generally, summer night valley issues materialise as voltage control issues. The introduction of new interconnection would provide voltage support both as a generation source and a demand and in general result in a flattening of the load curve meaning the summer night valley case will improve.

The demand levels used in the study are in line with the All-Island Ten Year Transmission Forecast Statement 2017 (TYTFS). However, there has been large interest in new data centre demand connections in the Dublin area within the last year. To take account of this, additional demand totalling approximately 1067MVA has been included in Dublin, above the demand levels specified in the TYTFS for this study. This represented the latest estimate of contracted demand.

8760 Analysis

All hours during the 2025 year were considered through the 8760 Analysis. The demand levels used in the 8760 phase of the study were in line with the assumptions in the 2017 Tomorrow's Energy Scenario Steady Evolution scenario. This scenario includes 840MVA of demand connections in the Dublin area, which also aligns with a medium ramp rate assumption for the full 1067MVA of contracted demand.

Network

Two study cases were examined in both the Standard Access PSSE Analysis and the 8760 Analysis. Network assumptions for both analysis phases were the same.

- **Base Study Case** – No Additional Interconnection
- **Study Case** – Celtic Interconnector (700MW) at Knockraha 220kV station

The following network reinforcements were applied to the study cases:

- The following network reinforcements which make up the Grid Link 'Regional Solution':
  - Series compensation was added to three of the existing 400 kV circuits by changing their reactances to the compensated values shown below;

Table 22: Assumed Reactance Values on the 400kV Network Following Series Compensation

Circuit	Uncompensated X (pu)	Compensated X (pu)
Oldstreet-Woodland 400kV	0.0278	0.008
Dunstown-Laois 400kV	0.01	0.003
Moneypoint-Laois 400kV	0.0378	0.01134

  - A Moneypoint- Kilpaddoge 400 kV cable was added plus one 400/220 kV transformer at Kilpaddoge;
  - Great Island-Kilkenny 110 kV was uprated to a 430 mm2 @80°C ACSR conductor;
  - Great Island-Wexford 110 kV was uprated to a 430 mm2 @80°C ACSR conductor.
- A reinforcement to strengthen the Dunstown-Woodland corridor. It had been identified in numerous previous studies, including the Grid Link review and Dublin studies, that a 400 kV connection is required between Dunstown and Woodland stations. Solution options are currently under investigation. A preferred solution option has not yet been finalised. A solution option was therefore chosen to represent this reinforcement. This consisted of:
  - Turning-in of the Gorman-Maynooth 220kV circuit into Woodland 220 kV station;
  - Up-voltaging the Woodland to Maynooth section of the Gorman-Maynooth 220 kV circuit to 400 kV;
  - Up-voltaging Dunstown-Maynooth 220 kV circuit 1 to 400 kV.
- A 100 MVAr STATCOM was added at Ballynahulla 110 kV bus.
- A 100 MVAr STATCOM was added at Ballyvouskill110 kV bus.
- A 30 MVAr STATCOM was added at Thurles 110 kV bus.
- A 50 MVAr reactor was added at Knockanure 220 kV bus.
- A 30 MVAr STATCOM was added at Cauteen 110 kV bus. This is not an approved project; however, the requirement for some reactive support at this node is under consideration.

Generation

The assumed generation portfolio is in line with the assumptions in the Generation Capacity Statement 2017-2026[12].

Dispatch

Standard Access PSSE Analysis

The two dispatches represent simultaneous import or export on all available interconnectors. These dispatches are applied to all study cases. The dispatches are described as follows:

- Import on all interconnectors (low wind)
- Export on all interconnectors (high wind)

[12] http://www.eirgridgroup.com/site-files/library/EirGrid/4289_EirGrid_GenCapStatement_v9_web.pdf

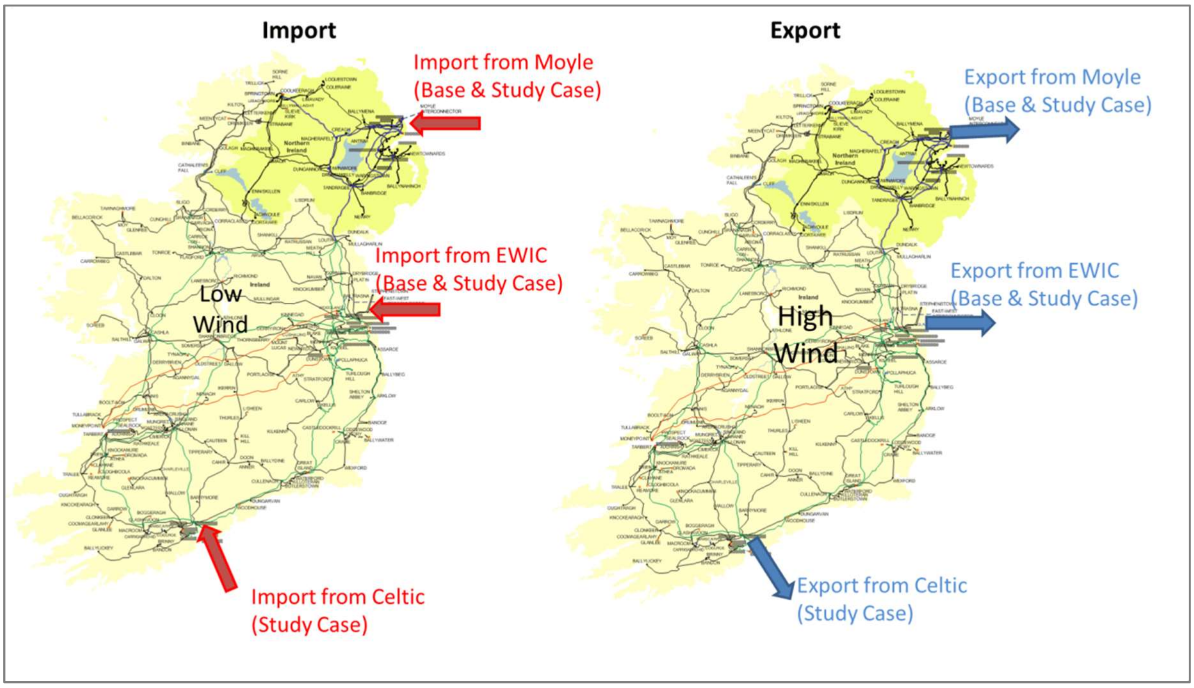


Figure 26: Visual Representation of Dispatches considered for Study Cases

For each dispatch, the system non-synchronous penetration (SNSP) was calculated in order to ensure that it remained below 75% in accordance with the future SNSP target as set out by the DS3 programme. The two dispatches that were considered are summarised in the figure above. In each case, once the interconnection and wind levels were set, the conventional generation was then dispatched to meet the remaining demand based on merit order.

Table 23: Dispatches Considered for Study Cases

Base Study Case - No Additional Interconnection						
		SNSP	**EWIC (MW)**	**Moyle (MW)**	**Celtic (MW)**	**Wind MW AI (MW)**
Import	SP	16%	500	500	0	0
	WP	13%	500	500	0	0
Export	SP	69%	-500	-500	0	5296
	WP	70%	-500	-500	0	6350
Study Case - Celtic 700 MW Interconnector at Knockraha						
		SNSP	**EWIC (MW)**	**Moyle (MW)**	**Celtic (MW)**	**Wind MW AI (MW)**
Import	SP	27%	500	500	700	0
	WP	22%	500	500	700	0
Export	SP	71%	-500	-500	-700	5481
	WP	69%	-500	-500	-700	6493

A number of sensitivities were carried out with varying amount of wind. This ensured that a full suite of onerous yet realistic issues were identified. The details of these wind level sensitivities were defined as the studies were carried out.

Wheeling scenarios were not considered during the Standard Access PSSE Analysis phase of this study. These scenarios were omitted from this analysis for two reasons:

- The likelihood of wheeling scenarios occurred in the market models infrequently. Wheeling flows from France to GB would likely cause further network congestion, however it was noted to occur for approximately. 1% of the year.
- Wheeling between France and GB would provide benefits to other jurisdictions. It is therefore envisaged that through guidelines on cross-border allocation, there would be mechanisms in place to ensure that the cost of transmission reinforcements which may be required on the Irish system would not be borne by the Irish TUoS customer

8760 Analysis

A modified dispatch from the Tomorrow Energy Scenario's Steady Evolution scenario was used to examine the probability of the occurrence of the issues identified in the PSSE Phase of this project. Steady Evolution base dispatch assumes that the Celtic Interconnector is part of the system portfolio (Study Case). Therefore the following change was applied to represent the Base Study Case.

- Remove Celtic Interconnector (Base Study Case)

Reserve

It was assumed that the primary operating reserve being carried by traditional means would not exceed current levels. With the introduction of the Celtic Interconnector there may be occasions in which the LSI will increase to 700 MW. It was envisaged that the increased level of reserve would be provided for by DS3 system service contracts using new technologies like batteries. Therefore, the current trend in conventional generation portfolio dispatched was not altered to cater for the increased levels demand in line with future expectation.

Maintenance and N-G-1 scenarios considered

A number of maintenance and N-G-1 scenarios were considered in this analysis. See below for generators and planned outages that were examined.

Table 24: Generator Outages considered

Great Island
Aghada
Whitegate
Huntstown
Poolbeg
Moneypoint

Table 25: Maintenance Scenarios considered

Arklow - Carrickmines 220 kV Ckt 1	Inchicore-Irishtown 220 kV
Arklow - Lodgewood 220 kV Ckt 1	Killonan - Shannonbridge 220 kV Ckt 1
Ballyvouskil - Ballynahulla 220 kV Ckt 1	Killpadogue - Moneypoint 220 kV Ckt 1
Ballyvouskil - Clashavoon 220 kV Ckt 1	Kilpaddoge - Moneypoint 400 kV Ckt 1
Butlerstown Circuit 110 kV	Kilpaddoge - Moneypoint 400 kV Ckt 2
Carrickmines- Irishtown 220 kV	Knockanure - Ballynahulla 220 kV Ckt 1
Carrickmines- Poolbeg 220 kV	Knockanure - Killpadogue 220 kV Ckt 1
Clashavoon - Knockraha 220 kV Ckt 1	Knockanure - Killpadogue 220 kV Ckt 2
Cullenagh - Great Island 220 kV Ckt 1	Knockraha - Killonan 220 kV Ckt 1
Cullenagh - Knockraha 220 kV Ckt 1	Knockraha- Aghada 220 kV Ckt1
Dunstown - Kellis 220 kV Ckt 1	Knockraha- Aghada 220 kV Ckt2
Dunstown - Laois 400 kV Ckt 1	Knockraha-Raffeen 220 kV
Dunstown - Woodland 400 kV Ckt 1	Laois - Moneypoint 400 kV Ckt 1
Dunstown- Carrickmines 220 kV	Maynooth - Shannonbridge 220 kV Ckt 1
Great Island - Lodgewood 220 kV Ckt 1	Moneypoint - Oldstreet 400 kV Ckt 1
Great Island- Kellis 220 kV Ckt 1	Oldstreet - Woodland 400 kV Ckt 1
Great Island Transformers 220/110 kV	

Solution Costing Assumptions

Table 26: Summary Table of Assumed Solution Costings to Network Needs Driven by the Connection of the Celtic Interconnector

Celtic: Conceivable Solution Costings				
Network Need	**Solution Option**	**Justification for Solution Choice**	**Conceivable Cost**	**Assumptions**
Cahir-Barrymore 110kV Circuit	Uprate the existing Barrymore- Cahir 110kV circuit to 110kV 430 mm2 ACSR @ 80°C	Assume uprate of the Cahir - Barrymore circuit to 110kV 430 mm2 ACSR @ 80°C is a technical solution The existing circuit has two sections. The first section Cahir- Barrymore is a 200ACSR line. The second circuit section, Barrymore - Knockraha is a 300 ACSR line. Uprate of the Cahir - Barrymore section alone is sufficient		Title: SC Woodpole 200/300mm2 ACSR to 430mm2 ACSR
				Assumed TSO Costs
Kilbarry 110kV Station Work	Replace the bay conductor at existing Kilbarry 110kV station	Assume replacement of bay conductor at Kilbarry and along with the new Kilbarry station configuration The double circuit between Marina and Kilbarry is limited by the bay conductors at Kilbarry, at 98 MVA. The double circuit is then limited by the 300 ACSR line at 102 MVA, which has a 110% overload capability.		Title: 110kV Bay Uprate [Conductor uprate only]
				Assumed TSO Costs
Bandon-Dunmanway 110kV Station Work	Replace the busbar conductor at Bandon and the bay conductor at Dunmanway.	Assume replacement of busbar conductor at Bandon and bay conductor at Dunmanway The circuit between Bandon and Dunmanway is limited by the bay and busbar conductors previously mentioned, at 98 MVA. The circuit is then limited by the 200 ACSR line at 104 MVA, which has a 110% overload capability.		Title: Full Busbar Uprate to 2500A Tubular Busbar in existing Single Busbar Outage Station)
				Title: 110kV Bay Uprate [Conductor uprate only]
				Title: Install New Lightening Monopole 110/220 kV (by quantity 1)
				Assumed TSO Costs
Total			**15.7 M€**	

Ireland Network Study Conclusions

The results of this analysis have shown that there are a number of independent network needs driven by the interconnector connection. The network solutions required are relatively minor in relation to the scale of the applicant, and consist of a number of 110kV network solutions.

The growth of load/ Data Centres in the Dublin area, connection of offshore wind and generation in the south will impact flows on the south east to Dublin 220kV corridor. Alternative solutions to these issues may be determined once the Framework for Developing the Grid is applied and other transmission drivers are considered.

The network solutions identified arising from the development of the Celtic Interconnector are largely independent of the development of any other interconnector applicant currently being processed by EirGrid. A separate analysis has been undertaken in relation to the case whereby two interconnectors connect to the South of Ireland:

- A HVDC link from Knockraha 220kV station to France, and
- A HVDC link from Great Island 220kV station to Great Britain.

The results have shown that the network solutions required for each interconnector are largely independent of each other. Some additional network issues arise for the connection of the two interconnectors. However, these can be manged by dispatching generation or implementing relatively minor reinforcement solutions. Significant additional reinforcements were not identified.

A3.2 System Operation

This section outlines the impact of the Celtic Interconnector on system operational costs and in particular it possibly becoming the new LSI/LSO on the Irish transmission system.

Summary:

- The Celtic Interconnector would provide services to assist with the operation of the transmission system, for example, black start, voltage support, dynamic frequency response.
- EirGrid has undertaken a suite of frequency and transient stability studies to assess the operational impact of a generic 750MW interconnector on the system. Mitigation measures for identified issues demonstrate implementable solutions within the timeframe associated with the development of the Celtic Interconnector. There are no foreseen operational issues with enabling 750MW import or export.
- The Celtic Interconnector would increase the LSI and LSO on the system to 700 MW, from 500 MW currently set by Moyle or EWIC.
- Loss of the LSO can be managed by the TSO operating a prudent Over Frequency Generation Shedding Scheme (OFGSS). However, Operating Reserves of 75% of the LSI are required to ensure system stability in the event of the loss of the LSI.
- A cost-based assessment of providing 150 MW of Operating Reserves (75% of increase in LSI) can be made using a Life Cycle Cost Analysis of a suitable technology provider such as Battery Energy Storage.
- It is likely that offshore windfarms would also increase the LSI in the future. It is also likely that batteries would provide other system benefits.
- Attributing 25-50% of the cost of providing these reserves to the Celtic Interconnector equates to a cost range of 1.4 M€ to 2.8 M€ a year.

Current Operating Regime

The Ireland and Northern Ireland power system today operates with an LSI and LSO of 500 MW. In both instances, this level is set by the two interconnectors on the island, the Moyle interconnector and EWIC. The LSI is set when either of the interconnectors is importing 500 MW of power from the GB power system, and the LSO is set when either of the interconnectors is exporting 500 MW to the GB power system.

The interaction between the requirement for System Services and the LSI is set as a result of the TSOs rules on operating reserves. At present the TSOs require a certain percentage of operating reserves which is governed by the LSI at any given moment in time. The current operating reserve levels are set as:

Table 27 Current operating reserve levels

Category	All-Island Requirement (% of LSI)
Primary Operating Reserve	75%
Secondary Operating Reserve	75%
Tertiary Operating Reserve 1	100%
Tertiary Operating Reserve 2	100%

There are currently no System Services requirements which are set by the LSO on the system. Any over-frequency event which would occur on the system as a result of the loss of the LSO is managed through the OFGSS in Ireland and Northern Ireland. The OFGSS is currently comprised of primarily wind generation.

It is likely any future increase in LSO, and thus any increased risk to the system, could be managed through prudent altering of the existing OFGSS. However, any future increase in LSI on the system is likely to lead to an increase requirement for operating reserves.

Future Operating Regime

It is difficult to accurately quantify the contribution of the increased LSI directly to future System Services requirements. The current System Services arrangements only extend to 2024 and there has been no decision beyond that point in time on the future of System Services. This makes forecasting increased System Service requirements, and thus System Services costs directly attributable to an increased LSI, impossible beyond 2024.

The TSOs are working to approximate the future levels of System Services requirements and valuation in 2030 through the EU-SysFlex project. The results of this analysis come to light in late 2019 or early 2020.

As a result, it is very difficult to equate any future System Services costs to an increased LSI given the current conditions.

However, one possible cost-based method of approximating the increased System Services requirements would be to take the existing operational reserves ruleset and identify the overall increased MW reserve capability needed to maintain the current standards. This additional MW reserve capability requirement could then be costed against a suitable new service provider to offer this service.

In the case of the Celtic Interconnector, the LSI would increase from 500 MW to 700 MW. This increases the Primary Operating Reserve requirement by up to 150 MW based on the current operating schemes. However, this requirement may decrease in future depending on the future development of the transmission system and the generation and demand portfolio. A suitable technology to provide the required fast-acting operating reserves would be Battery Energy Storage.

Lifecycle Cost Analysis of a 150 MW battery

The costs associated with this battery should be discounted against any further future generators or interconnectors which exceed the existing 500 MW LSI threshold. This provides an estimate to the possible costs associated with meeting the increased operating reserve requirement.

Possible additional increases to Largest Single Infeed

In addition to the proposed Celtic Interconnector, approximately 5.6 GW of offshore wind farms have applied to connect to the electricity system. The EirGrid Group Tomorrow's Energy Scenario has identified a range of trajectories for offshore wind in Ireland with 3 GW projected for a Low Carbon

Living Scenario in 2030. Economies of scale are vital in offshore wind developments and in countries like Ireland with centralised auctions (where transmission is provided partly or in full), project sizes are likely to exceed 500MW (current LSI), at sizes designed to standardise processes and bring down the cost of expensive offshore transmission platforms.

Advances in windfarm technology have led some industry analysts to predict that 12 MW turbines could be in place in the mid-2020s while others have already assumed 13-15 MW turbines in recent successful auctions for offshore windfarm auction.

The capacity of the possible installations to be connected to the Ireland electricity system when the Celtic Interconnector is projected to be commissioned includes between 1 to 4 offshore facilities of a comparable size to the Celtic Interconnector at 700 MW.

On this basis, the requirement for additional Primary Operating Reserve can be estimated as split between the Celtic Interconnector and one of the additional offshore wind farms of comparable size. On a proportional basis therefore the Celtic Interconnector would be responsible for 25-50% of the increase of 150 MW over the current maximum requirement of Primary Operating Reserve as specified by the TSO regime.

Provision of Primary Operating Reserve

The cost of providing 150 MW of Primary Operating Reserve can be approximated using the cost of a 150 MW Battery Energy Storage device. Predicted prices for the benchmark capital costs for a fully installed energy storage system are estimated by several sources including a Bloomberg New Energy Finance survey. As industry players commission larger manufacturing plants, economies of scale remain an important driver of lithium-ion battery price reductions. By 2025, benchmark capital costs for a fully-installed energy storage system are predicted to be 303 € per MW. When annualised over 10 years, using a rate of 4% over 10 years which is a reasonable assumed battery life this cost comes to approximately 5.6 M€. Attributing 25-50% of the cost of providing these reserves to the Celtic Interconnector equates to a cost range of 1.4 M€ to 2.8 M€ a year.

Appendix A4 Cost-Benefit Analysis Methodology

Derived from ENTSO-E CBA 2.0 Methodology documentation, which has undergone public consultation and been reviewed by ACER and the European Commission and the associated 2nd ENTSO-E Guideline for Cost-Benefit Analysis of Grid Development Projects [13].

A4.1 ENTSO-E TYNDP 2018 CBA Assessment Framework

The assessment framework of a project is a combined cost-benefit and multi-criteria assessment, complying with Article 11 and Appendixes IV and V of the TEN-E Regulation. The selected criteria enable an appreciation of project benefits in terms of EU network objectives:

- They ensure the development of a single European grid to permit the EU climate policy and sustainability objectives (RES, energy efficiency, CO_2);
- They guarantee security of supply;
    - They complete the internal energy market, especially through a contribution to increased socio-economic welfare ;
    - They ensure technical resilience of the system,
- They provide a measurement of project costs and feasibility (especially environmental and social viability).
- The indicators used are as simple and robust as possible. This leads to simplified methodologies for some indicators.

The figure below shows the main categories group and the indicators used in the CBA of projects for TYNDP 2018.

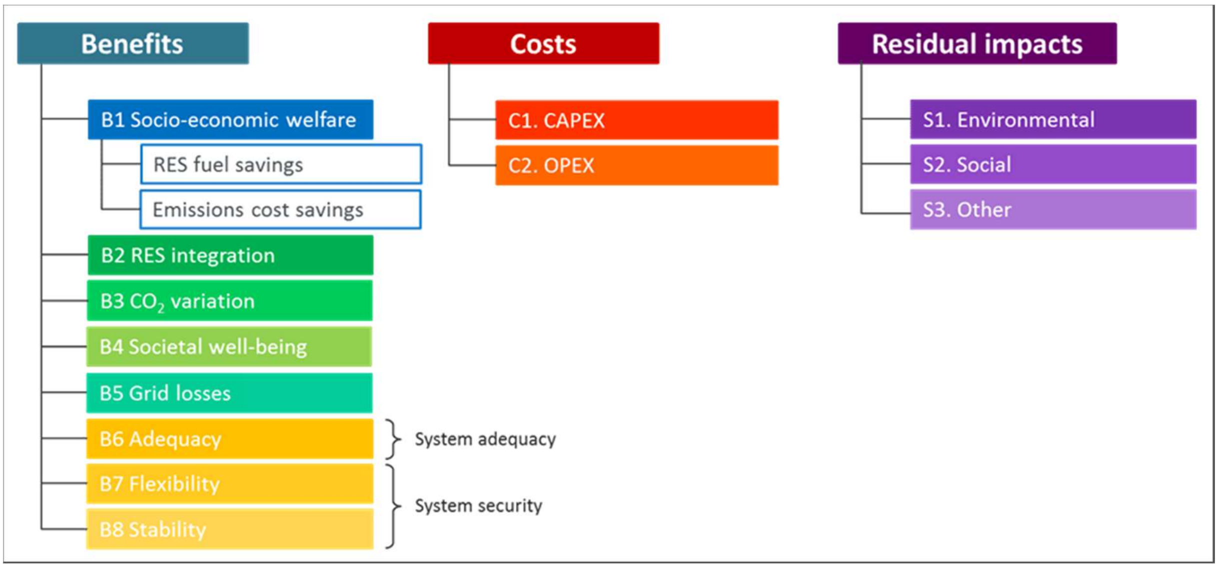


Figure 27: ENTSO-E TYNDP 2018 assessment indicators

A4.1.1 CBA Assessment Indicators

The main CBA assessment indicators for the Celtic Interconnector project are listed below:

Socio-Economic Welfare: SEW or market integration is characterised by the ability of a project to reduce congestion and provide fuel cost savings. It thus provides an increase in transmission capacity

[13] 2nd ENTSO-E Guideline for Cost Benefit Analysis of Grid Development Projects

that makes it possible to increase commercial exchanges, so that electricity markets can trade power in a more economically efficient manner. This benefit indicator is expressed in millions of euro a year.

Security of Supply Adequacy (SoS): SoS is assessed as the adequacy to meet demand which characterises the project's impact on the ability of a power system to provide an adequate supply of electricity to meet demand over an extended period of time. Variability of climatic effects on demand and renewable energy sources production is taken into account. This benefit is expressed in millions of euro a year.

As stated in CBA 2.0 interconnectors are also likely to provide benefits as regards SoS through mutual support between interconnected countries. To assess this benefit (benefit B6 of CBA 2.0) also known as Capacity Value, EirGrid and RTE have applied a methodology that was jointly developed by RTE, EirGrid and ELIA (the Belgian TSO). This methodology has now also been incorporated into TYNDP 2018. The methodology is detailed below and is also described in the appendices of ENTSO-E's TYNDP 2018 report.

Variation in Grid Losses: Variation in grid losses in the transmission grid is the cost of compensating for thermal losses in the power system due to the project. It is an indicator of energy efficiency and expressed as a cost in millions of euro a year.

RES Integration: Contribution to RES integration is defined as the ability of the system to allow the connection of new RES generation, unlock existing and future "renewable" generation, and minimising curtailment of electricity produced from RES. RES integration is one of the EU 20-20-20 targets. This benefit indicator is expressed in MWh a year and is not included in the NPV calculations.

Variation in CO_2 Emissions: Variation in CO_2 emissions represents the change in CO_2 emissions in the power system due to the project. It is a consequence of changes in generation dispatch and unlocking renewable potential. The aim to reduce CO_2 emissions is explicitly included as one of the EU 20-20-20 targets and is therefore displayed as a separate indicator. This benefit indicator is expressed in k tonne a year and is not included in the NPV calculations.

A4.2 Security of Supply Adequacy Benefit Methodology

A new interconnector is likely to provide benefits related to SoS by enabling the pooling of the risk of load-shedding between the interconnected countries as well as optimising the build-out and usage of peaking plant capacity, provided that the countries are not short of supply at the same time.

The following table details the correlation factors between three countries (France, Ireland and GB) worked out for various climatic time series from the TYNDP 2018 scenarios.

Demand			Wind Generation			Solar Generation			Residual Load		
	IE	GB		IE	GB		IE	GB		IE	GB
FR	0.61	0.76	FR	0.34	0.46	FR	0.90	0.94	FR	0.17	0.58
IE		0.92	IE		0.72	IE		0.95	IE		0.61

Figure 28: Correlation factors for demand, wind generation, solar generation and residual load for France, Ireland and Great Britain.

The analysis of those corelation factors between demand, installed solar and wind generation in France and Ireland shows that the net demand (demand less variable renewable generation) for various climatic years are very loosely correlated and this indicates that there is significant potential for mutual back-up.

Detailed simulations were carried out in the framework of TYNDP 2018. The methodology for assessing the SoS benefit relies on the calculation of the Non Supplied Energy plus a sanity check to ensure no over-estimation of the value. The principles and steps used are set out in this section[14].

A4.2.1 Introduction to the methodology

This section describes the methodology used to calculate the SoS benefit (B6 from ENTSO-E CBA guidelines) of the Celtic Interconnector project. The approach calculates the Expected Energy Not Served (EENS) savings due to the project and monetises the saving using the VoLL. It allows for separate and complementary SEW and SoS savings assessments and is consistent with the Welfare Loss monetisation calculation specified in the ENTSO-E CBA guidelines. The approach is also consistent with the ongoing development of CBA 3.0.

The methodology has been applied to all scenarios using the ANTARES and PLEXOS market/adequacy modelling tools. It incorporates adequacy assessment approaches that have been developed and extensively tested in the ENTSO-E MAF[15]. This alignment with the MAF approach means that there is an alignment between the implicit value being assigned to interconnectors in ENTSO-E adequacy assessments and the value calculated here using this method

A4.2.2 Background to the methodology

There are a number of potential approaches to generation adequacy assessments. These include deterministic, probabilistic and Monte-Carlo. The MAF utilises a Monte Carlo approach as it is considered to be the "state of the art technique to represent probabilistic variables such as climate data and unplanned outages in electricity market models". This adequacy assessment approach is favoured by the European Commission[16].

When performing adequacy assessments it is important to model a large number of potential demand and generation availability scenarios. Demand scenarios are modelled using the regional demand profiles associated with the 34 climate year demand dataset developed for the TYNDP (and MAF). These profiles include examples of expected demand in each region during extreme weather events. A wide range of generation availability scenarios is modelled by simulating multiple forced outage patterns. Variations in the availability of renewable resources such as hydro, wind and solar are captured by using the associated resource profiles for each climate year. Network availability may also be modelled through outage patterns. The demand and renewable profiles for each climate year have already been prepared for the TYNDP and applying them in an approach similar to the MAF simulates a wide range of demand and generation availability scenarios, which inherently includes some high-impact low-probability events.

When assessing the generation adequacy benefit of interconnectors, one of the key factors is to assess how simultaneous stress periods occur in the interconnected regions. Where an interconnector connects two regions which are unlikely to face coincident stress periods, it will have a larger benefit than an interconnector between two regions where periods of coincident stress are likely. Stress events in a region are usually driven by high demand and low generation availability and are appropriately modelled using this probabilistic approach.

[14] The methodology is also described in the appendices of the TYNDP 2018 report.
[15] Mid-Term Adequacy Forecast 2017 Edition
[16] Identification of Appropriate Generation and System Adequacy Standards for the Internal Electricity Market

A4.2.3 Methodology Steps

This section gives some details for each of the steps involved in the methodology.

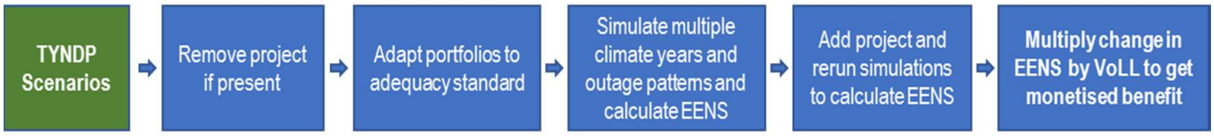


Figure 29: Project Security of Supply Monetization Methodology steps

- The full ENTSO-E 34 climate year demand and renewable generation dataset is incorporated into the models used for the SEW calculations. They are also set up to model multiple forced outage patterns.

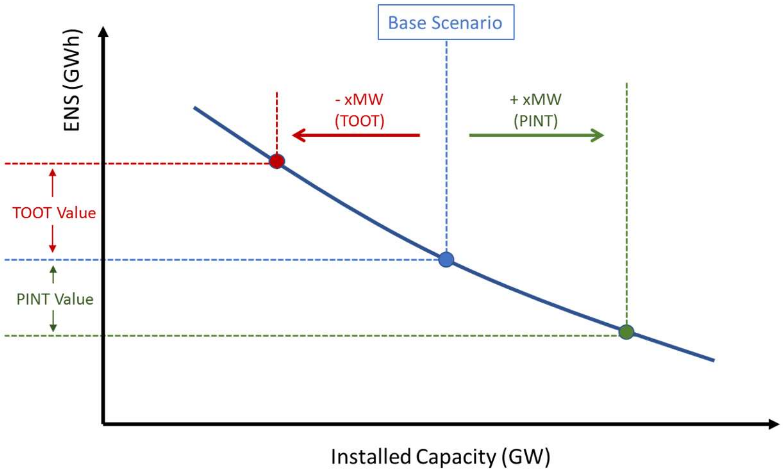


Figure 30: Illustration of the variance of EENS with Installed Capacity and the TOOT vs PINT approaches.

- As the relationship between EENS and installed capacity in a region is non-linear (see figure above), the security-of-supply benefit of a project will depend on the initial level of LOLE in each region. As has been observed in previous TYNDP studies, if a region has a large generation surplus, the addition of extra generation or interconnector capacity brings little additional security-of-supply benefit. On the other hand, if a country initially has a too high LOLE that would not be accepted by the country, the assessment of the EENS saved could be biased because of the sensitivity it has to initial LOLE.

  Given the above, it is preferable to bring the interconnected regions to a predefined generation adequacy standard prior to the benefit assessment[17]. If regions have a defined LOLE adequacy standard this is used and if no defined standard is available for a region 3 hours has been be used.

  The portfolio adaption (adequacy fine-tune) was required because when a full adequacy assessment was performed on the TYNDP scenarios, countries were not at their respective adequacy standards. During the TYNDP scenario development process for Sustainable Transition and Distributed Generation a process was performed to remove un-profitable generation which limited the amount of over-capacity in those scenarios. However, this was a limited check and not a full adequacy assessment. When a full adequacy assessment using 34 climate years and multiple forced outage patterns was performed, it showed that countries

[17] The underlying assumption is that the peak generation fleet would have dynamically adapted and reached the standard, but that the current scenario building process does not fully take this aspect into account

were not at their adequacy standard in those scenarios and that there was very significant over-capacity in EUCO.

Bringing the interconnected regions to an adequacy standard has been achieved by the removal/addition of peaking generators (for example, light oil) in the region. As these are peaking units, this adjustment should have little impact on the SEW. Tests were performed to confirm this. In any case the adjustment is just for adequacy studies and has no impact on the SEW calculations.

- Once any adaptations have been made, the assessment simulations can be performed. A simulation of each of the 34 climate years with multiple forced outage patterns is performed. The average annual EENS value from all the simulations is used as the measure of EENS without the project.

- The project is then added and the simulations are re-run for the same climate years and forced outage patterns. Again, the average annual EENS value from all these simulations is used as the measure of EENS with the project.

- The change in the EENS caused by the addition of the project is calculated using the results of the previous two steps. The change in EENS (MWh) is multiplied by VoLL (€/MWh) to give the monetized security of supply value of the project. To align with national values, the VoLL used for France was 13,000 €/MWh and 11,000 €/MWh for SEM.

- A sanity check is performed to account for the fact that maybe, instead of decreasing EENS, the project would lead to decreasing peak power plant capacity. The project effectively avoids these peak power plants investments[18], which can be monetised through avoided investment cost. An iterative approach is used to evaluate the quantity of peaking capacity that would be required to achieve the same level of SoS benefit (LOLE/EENS reduction) as achieved by the project being assessed. The value used for the annualized cost of a peaking unit in both countries was set at 40,000 €/MW/Yr. This is used as a cap for the capacity value of the project.

- The minimum value between the monetised EENS saved and the avoided peak generation cost is used as the final reported SoS value for the project.

A4.3 Cost-Benefit Analysis Scenarios

A4.3.1 Choice of the planning scenarios

The planning scenarios are defined to represent future developments of the energy system. The essence of scenario analysis is to come up with plausible pictures of the future. Scenarios are means to approach the uncertainties and the interaction between these uncertainties.

Scenarios shall at least represent the European Union's electricity system level and be adapted in more detail at a regional level. They shall reflect European Union and national legislations in force at the date of analysis.

[18] Third countries may be impacted by the project, but we assume that, when adding the peak power plants to the two countries, the impact on third countries is at least as good as the project's impact.

A4.3.2 Contents of the planning scenarios

Planning scenarios are a coherent, comprehensive and internally consistent description of a plausible future (in general composed of several time horizons) built on the imagined interaction of economic key parameters (including economic growth, fuel prices, CO_2 prices, etc.). A planning scenario is characterized by a:

- Generation portfolio (power installation forecast, type of generation, etc.),
- Demand forecast (impact of efficiency measures, rate of growth, shape of demand curve, etc.), and
- Exchange patterns with the systems outside the studied region.

A scenario may be based on trends and/or local specificities (bottom-up scenarios) or energy policy targets and/or global optimisation.

A4.3.3 TYNDP 2018 scenarios detailed description

Sustainable Transition 2030:

Sustainable Transition seeks a quick and economically sustainable CO_2 reduction by replacing coal and lignite with gas in the power sector. Gas also displaces some oil usage in heavy transport and shipping. The electrification of heat and transport develops at a slower pace than other scenarios. In this scenario, reaching the EU goal (80-95% CO_2 reduction in 2050) requires rapid development during the 2040s to be achieved through increased technological adoption or evolution.

Gas-fired power generation flourishes due to relatively cheap global gas prices and strong growth of bio-methane. A regulatory framework in place decreases the use of coal-fired power stations. Gas-fired generation provides the necessary flexibility to balance renewables in the power system.

There is a decrease in CO_2 emissions since much coal-fired base load power generation retires or is out of merit due to a reasonably high ETS, carbon prices and governmental policies.

Depending on national policies, there could still be room for a minimum number of new units but overall the number of nuclear plants in Europe is decreasing. Carbon capture and storage represents a viable option in industries for those processes characterised by high load factors. An efficient electricity market and strong price signals ensure necessary investment to peaking power generation, with gas being the preferred fuel.

Overall, electricity demand stagnates or grows moderately. Use of gaseous fuels increases for transport and power generation, but slightly decreases for heating.

Distributed Generation 2030:

Distributed Generation places prosumers at the centre. It represents a more decentralised development with focus on end user technologies. Smart technology and dual fuel appliances such as hybrid heat pumps allow consumers to switch energy depending on market conditions. Electric vehicles see their highest penetration with PV and batteries widespread in buildings. These developments lead to high levels of demand side response available. Biomethane growth is strong as connections to distribution systems grow utilising local feedstocks.

Small-scale generation technologies costs have been rapidly declining. Technologies such as solar offer a non-subsidised option for ‘prosumers’ in most parts of Europe. Major advances in batteries enable ‘prosumers’ to balance their own electricity consumption within a day. Nuclear mostly depends on country specific policies. P2G becomes a commercially viable technology for the production of green gas. Technological leaps in small-scale generation challenge large-scale power generation, pressurising the profitability of traditional power plants. System adequacy is maintained through a centralised mechanism that retains enough peaking capacity, district heating CHP are suitable for both heating and electricity adequacy. The scenario has a strong Emissions Trading Scheme (ETS) which favours gas before coal in the power market, and an increasing share of bio fuels. There is a strong EU climate policy in place, the decreasing cost of small-scale generation technologies drives down the cost of climate action. As solar yields are higher in Southern Europe, investments are likely to be higher in these regions, in comparison to Northern Europe. Electricity demand flexibility has substantially increased, both in residential and industrial solutions, helping electric power adequacy. However, wintertime with high heating needs and low solar availability remains a challenge, since batteries cannot be used for seasonal storage.

Yearly electricity demand has increased in the heating and transport sectors, overall electricity demand growth has reduced in the residential sector due to ‘prosumer’ behaviour, high efficiency goods and building efficiency measures. Demand responds well to market prices, the daily electricity demand profile is evened out, the effect is that peak electricity demand is reduced in this scenario.

EUCO 2030:

As part of the European Commission’s (EC) impact assessment work in 2016, EUCO 30 was a core policy scenario, created using the PRIMES model and the EU Reference Scenario 2016 as a starting point. The scenario models the achievement of the 2030 climate and energy targets as agreed by the European Council in 2014, but including an energy efficiency target of 30%. It was prepared by a consortium led by E3Mlab, hosted at the National Technical University of Athens (NTUA), and including the International Institute for Applied System Analysis (IIASA). Upon assessment from the European Commission, although no scenario offered a direct comparison, it was determined that Global Climate Action was the closest representation in terms of the parameters that define the scenario. As a result, the scenario created using the input data from EUCO has replaced Global Climate Action for 2030 within the TYNDP framework. However, the diverse methodologies used for deriving the scenarios may lead to differences in the continuity between this scenario and those that have been internally developed. The ENTSOs will further collaborate with the EC to improve the overall consistency shown within the Scenario Report.

Slowest Progress TYNDP 2016 Vision 1 (NRA scenario):

The perspective of TYNDP 2016 Vision 1 (also called “Slowest Progress”) is a scenario where no common European decision regarding how to reach the CO2-emission reductions has been reached. Each country has its own policy and methodology for CO_2, RES and system adequacy. Economic conditions are unfavourable, but there is still modest economic growth. This results in a limitation on willingness to invest in either high carbon or low carbon emitting sources due to investment risks, low CO_2 prices and lack of aligned support measures. Consequently older power plants are kept online rather than being replaced if they are needed in order to maintain adequacy. The situation varies across countries. The absence of a strong European framework is a barrier to the introduction of fundamental new market designs that benefit from R&D developments resulting in parallel, loosely coordinated national R&D expenditure and cost inefficiencies. Carbon pricing remains at such a level that base-load electricity production based on hard coal is preferred to gas in the market.

In Slowest Progress there are no major breakthroughs in energy efficiency developments such as large scale deployment of micro-cogeneration or heat pumps nor minimum requirements for new appliances and new buildings due to a lack of strong political and regulatory policy. There are also no major developments of the usage of electricity for transport such as large scale introduction of electric plug-in vehicles or heating/cooling. A modest economic growth brings a modest electricity demand increase. Also demand response potential that would allow partial shifting of the daily load in response to the available supply remains largely untapped.

The future generation mix is determined by national policy schemes that are established without coordination at a European level. Due to a lack of joint framework and joint decision to reduce emissions, the generation mix in 2030, on a European level, fails to be on track for the realization of the energy roadmap 2050 and no additional policies are implemented after 2020 to stimulate the commissioning of additional RES except locally due to local subsidy schemes. Adequacy is handled on a National basis. Some countries may require complete adequacy while others may depend on neighbouring countries. Very little new thermal capacity will come online except in the case for subsidized production or adequacy required peak capacity. New CO_2-emitters risk being closed down after 2030 in order to reach the 2050 target; hence the financial risk is substantial and old units are kept online instead of replacing them. Nuclear power is a national issue. In some countries nuclear power is regarded as a clean and affordable source of electricity and new units are brought online before 2030.

In order to be able to simulate multiple climate years the demand profiles from Sustainable transition were scaled to the match the peak demand levels for Slowest Progress and the resulting profiles were used in the analysis.

A4.3.4 TYNDP 2018 fuel and carbon prices

Table 28 gives the fuel and carbon prices used in each of the four scenarios.

Table 28 TYNDP 2018 fuel and carbon prices

	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress
Nuclear (€/GJ)	0.47	0.47	0.47	0.46
Lignite (€/GJ)	1.1	1.1	2.3	1.1
Hard Coal (€/GJ)	2.7	2.7	4.3	3.0
Gas (€/GJ)	8.8	8.8	6.9	9.5
Light Oil (€/GJ)	21.8	21.8	20.5	17.3
Heavy Oil (€/GJ)	17.9	17.9	14.6	13.7
Oil Shale (€/GJ)	2.3	2.3	2.3	2.3
CO_2 Price (€/ton)	84.3	50.0	27.0	17.0

A4.4 Expected Evolution of the Generation Mixes

A4.4.1 Evolution of generation mix in Ireland

Ireland has signed up to the Paris COP21 Agreement which requires us to move to a low carbon energy system by 2050. As part of Ireland's renewable energy target of 16% of its final energy requirement to be achieved by 2020, Ireland has committed to ensure that 40% of electricity will be generated from renewable sources.

Following on from 2020, the TYNDP 2018 scenarios Sustainable Transition, Distributed Generation and European Commission’s EUCO scenario are designed to ensure that Ireland is on a trajectory to achieve a low-carbon energy system by 2050. The fourth scenario used in the assessment, Slowest Progress, targets to only continue to maintain the 2020 renewable targets of 40% of electricity from renewable sources out to 2030. For Ireland we consider the Sustainable Transition scenario to be the more likely.

Biofuels, hydro and solar energy will make an important contribution to these targets however, it is expected that these targets will be achieved largely through the use of wind powered generation and reduction in generation capacities of gas, coal, peat and other non-RES sources.

Non-renewables currently account for over 90% of total energy consumption. This will fall to 84% in 2020 if we reach Ireland's binding EU targets for renewables. Reducing GHG emissions from the energy system by 80-95% by 2050 will require that the electricity system play a much greater role than now in the energy system and will have to contribute to the decarbonisation of transport and heating/cooling. Non-renewable energy sources will make a progressively smaller contribution to our energy mix over the course of the energy transition. In the short to medium-term, driven by carbon pricing, the mix of non-renewables will shift from more carbon-intensive fuels, like peat and coal, to lower-carbon fuels like natural gas. By 2050, fossil fuels will be largely replaced by renewable energy sources.

Solar generation has become more economically viable and there are indications that the Government will provide subsidies for a small capacity of utility scale solar farms. Due to its relatively low generation output (average 11% capacity factor), solar generation remains relatively expensive. Solar generation will likely play a part in meeting future targets but to a lesser extent than wind generation. The Celtic interconnector will provide key infrastructure support which will support this development of wind generation.

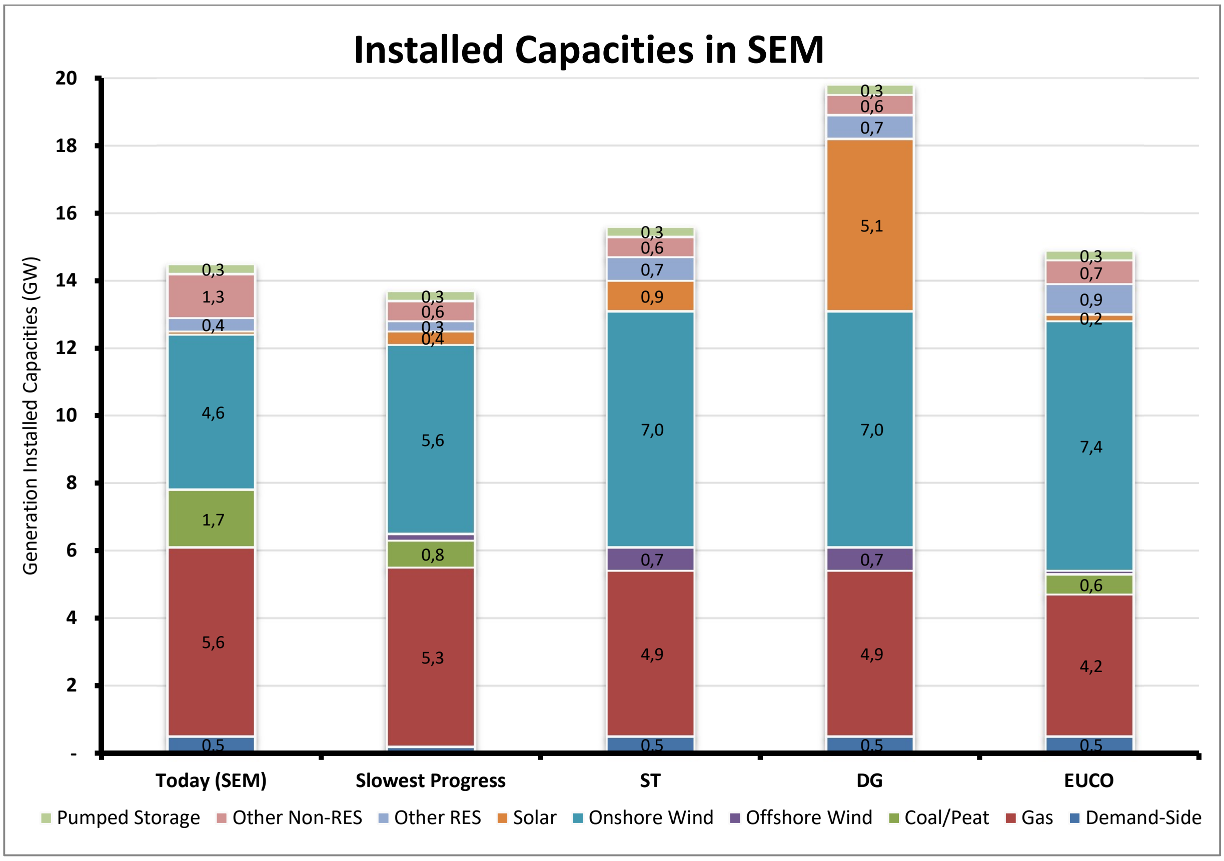


Figure 31 Evolution of Installed Capacities in SEM

SEM Wind Generation:

Recent average annual wind generation installation per year across Ireland and Northern Ireland between 2013 and 2018 has been significant and has exceeded 430 MW. Figure 32 shows both historic SEM island wind capacity installation and projected TYNDP scenario wind capacity. Historic installed wind capacity was all onshore generation, but it is likely that offshore wind generation will need to have a role in meeting 2030 projections.

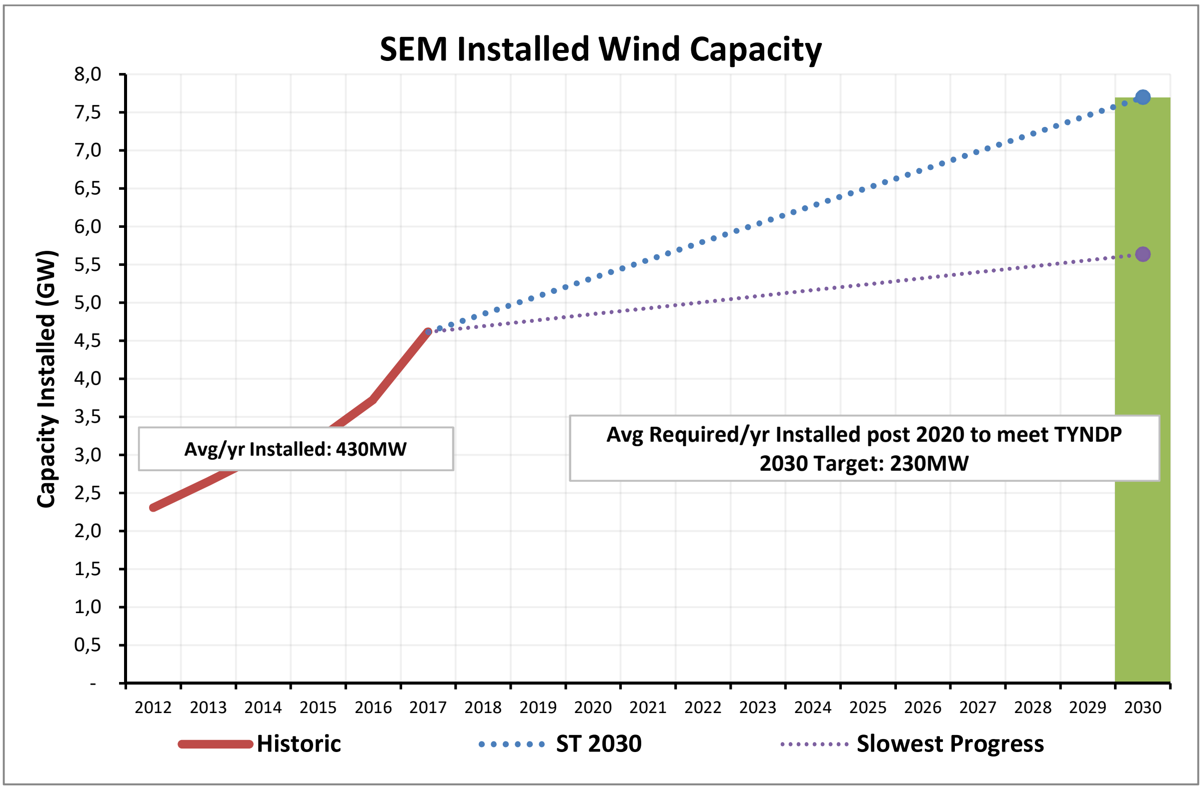


Figure 32 SEM Wind Capacity Installation 2012 to 2030

EirGrid's Ireland future planning scenario process "Tomorrow's Energy Scenarios" (TES), in line with the TYNDP scenarios, envisage continued increases in wind generation. The TES scenarios project a SEM installed wind generation capacity range from 7.7 to 11.2 GW.

To reach 7.7 GW requires a yearly increase after 2020 of 230 MW, which is smaller than the recent rate of installation of over 430MW per year (assuming 2020 target of approximately 5.4 GW achieved). The Celtic Interconnector will play an essential role in facilitating RES generation growth in Ireland.

ENTSO-E TYNDP 2018 scenarios project SEM wind generation exceeding 7.5 GW across each of its 2030 scenarios with onshore wind remaining the main area of generation capacity growth. Table 29 shows SEM capacity today and the SEM wind projections for the scenarios used in this Investment Request.

Table 29: Forecasted installed wind capacities for each scenario studied

	SEM Today	Best Estimate 2025	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress
Onshore Wind (GW)	4.6	6.3	7.0	7.0	7.4	5.6
Offshore Wind (GW)	0	0	0.7	0.7	0.1	0.2

The new Irish Renewable Energy Support Scheme 2018

The new Renewable Energy Support Scheme (RESS) was published on July 24th 2018 and sets out Ireland's ambitions to tackle climate change and to have a low carbon economy. The Scheme will provide for a renewable electricity (RES-E) ambition of up to 55% by 2030, or an additional 11-12 GWh of energy. The new RESS will deliver Ireland's contribution towards the new EU 32% RES-E target for 2030, as agreed between the European Commission, European Parliament and European Council in June 2018. RESS auctions will be designed in line with trajectory targets identified in Ireland's National Climate and Energy Plan. Also central to this scheme are increased community ownership and partnership, and the provision for enhanced renewable technology diversity, all within a cost effective competitive framework.

A new auction system is introduced, where different types of energy will bid for State support. This marks a shift from guaranteed fixed prices for renewable generators, to a more market-oriented mechanism where the cost of support will be determined by competitive bidding between renewable generators. RESS auctions will be held at frequent intervals throughout the lifetime of the scheme, which will allow Ireland to take advantage of falling technology costs. By not auctioning all the required capacity at once, higher costs will not be 'locked in' for consumers for the duration of the scheme. The first auction is planned to take place in 2019, with planning permission, grid connection secured and submission of bid bond as criteria for participation. It is proposed that the scheme be funded through the Public Service Obligation Levy.

Table 30: RESS Auctions

	Auction Capacity (GWh)	Auction Year	Delivery Year (end of)	Single Technology Cap
RESS 1	1,000	2019	2020	No
RESS 2	3,000	2020	2022	Yes
RESS 3	3,000	2021	2025	tbc
RESS 4	4,000	2023	2027	tbc
RESS 5 (possible)	2,500	2025	2030	tbc

A4.4.2 Evolution of generation mix in France

TYNDP 2018 Sustainable Transition data was collected from European TSOs. In France, it is a scenario compliant with the 2015 French Sustainable Transition scenario. In particular, the chosen assumptions show a decreasing nuclear fleet (38 GW at 2030) combined with a development of RES (wind and solar generation specifically). Those evolutions permit reaching the target of 50% of nuclear share and 40% of RES in the French mix.
Distributed Generation and EUCO were adapted on the French side according to the corresponding story lines. Distributed Generation is characterized by an intensive increase of PV while EUCO keeps nuclear generation at 60 GW as well as conventional generation. The scenario proposed by the NRAs is consistent with TYNDP 2016 Vision 1 "Slowest Progress".

In France, the evolution for wind and solar generation in TYNDP 2018 are shown in the following Figure 33.

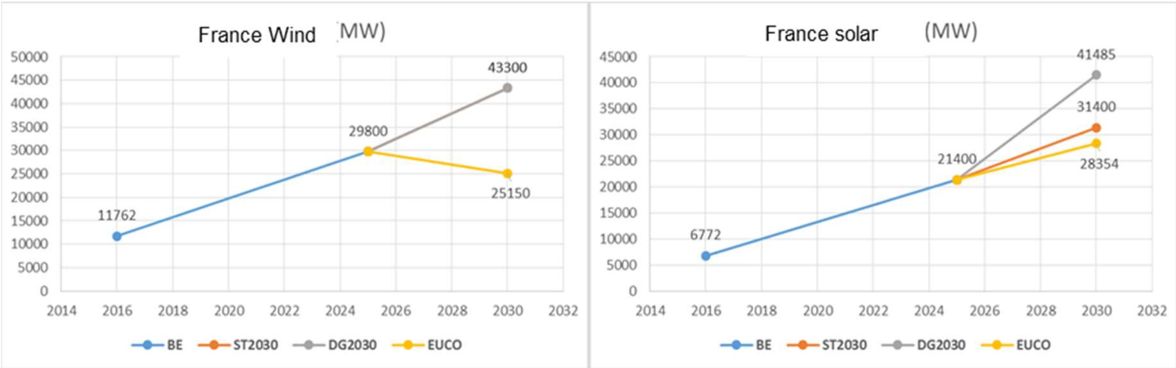


Figure 33: The forecasted evolution of wind and solar generation for France based on TYNDP 2018 scenarios

It results in the following mixes at the 2030 horizon across the base case scenarios studied in the framework of the Celtic Interconnector CBA.

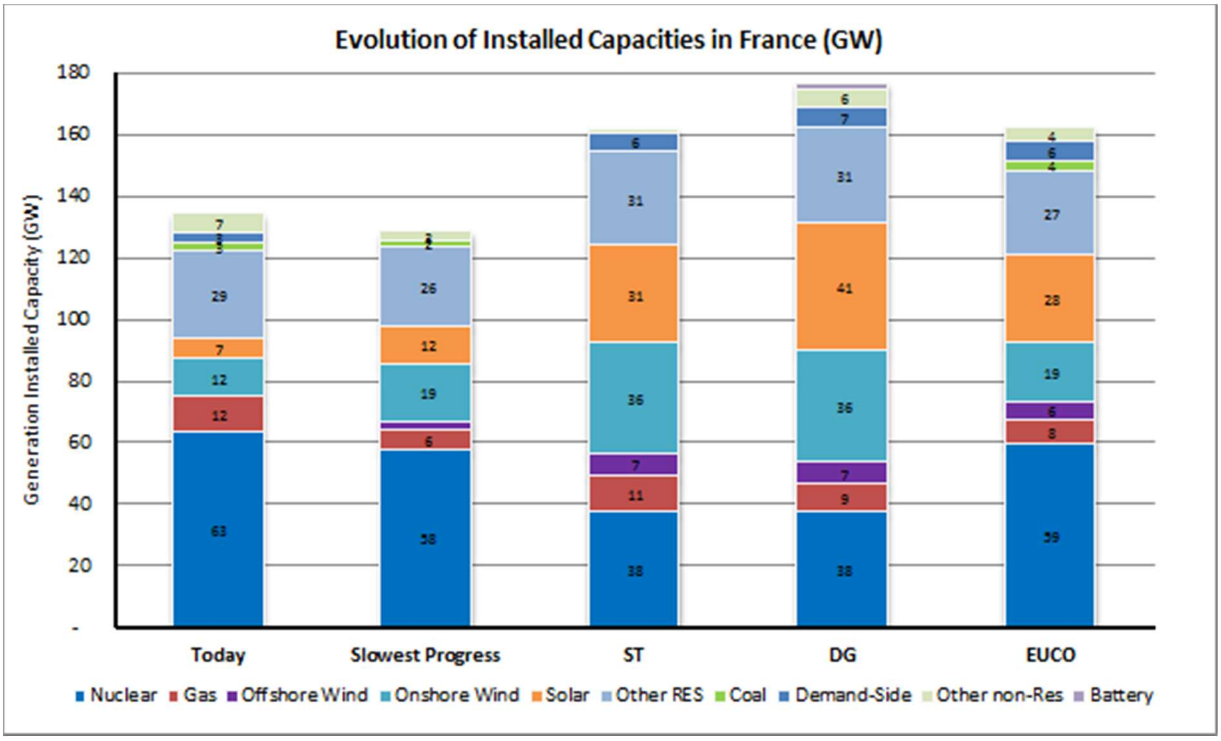


Figure 34: Forecast evolution of installed generation capacities in France

Appendix A5 Comparison of TYNDP 2018 Results and Celtic CBA Results

As discussed in Section 4 the values used for the base case and sensitivities results in this investment request are the **average of the results** of the PLEXOS and ANTARES modelling tools used by EirGrid and RTE respectively. A third TSO modelling tool was used for some of the indicators in the TYNDP 2018 project sheets, but was not used for the additional scenario and sensitivities that have been studied for this investment request. The average of the results from the PLEXOS and ANTARES modelling tools are used throughout this document so as to ensure consistency across all scenarios and sensitivities.

Within the framework of the TYNDP there is a process in ENTSO-E to ensure alignment across all the modelling tools used in the CBA assessments. While small differences in results are to be expected, checks are performed to ensure each modelling tool is consistent. Table *31* compares the Celtic Interconnector CBA assessment indicators used in this Investment Request and the values that are included in the project sheets of TYNDP 2018.

Table 31: Comparison of the TYNDP 2018 project sheet results and the PLEXOS and ANTARES averages

		Sustainable Transition	Distributed Generation	EUCO	
SEW (M€/year)	TYNDP 2018	89	82	77	
	Antares/Plexos	91	82	76	
Losses (M€/year)	TYNDP 2018	-20	-21	-22	
	Antares/Plexos	-22	-22	-26	
SoS (M€/year)	TYNDP 2018	52	39	20	
	Antares/Plexos	42	38	24	
Variation in CO_2 emissions (kT/year)	TYNDP 2018	-428	-154	-651	
	Antares/Plexos	-475	-178	-605	
RES integration [GWh/year]	TYNDP 2018	896	916	851	
	Antares/Plexos	871	884	811	
					Average
NPV (M€)	TYNDP 2018	440	230	-20	215
	Antares/Plexos	350	220	-15	185

It can be seen that the SEW results from both analysis along with losses numbers are very close for each of the scenarios.

The main differences are in the SoS value assessment results. The results for TYNDP 2018 and the results used in this Investment Request are both calculated based on the methodology set out in Appendix A4.2 and the appendices of the TYNDP 2018 report. The results calculated for this Investment Request uses the refined sanity check approach specified in the methodology. This more detailed approach, along with the use of country specific VoLL helps to ensure that the SoS value results presented in this document are the best reflection of the expected SoS benefit of the Celtic Interconnector.

The average of the 2030 NPVs shows reasonable consistency (difference of €30 M) between the TYNDP 2018 values and the values used in this Investment Request. **This comparison also confirms that using the average of the PLEXOS and ANTARES results throughout this document is appropriate and does not overstate the project benefits.**

Appendix A6 Surplus Analysis

The total surplus approach is a commonly accepted proxy for calculating the variation in SEW. This approach compares the producer and consumer surpluses for both bidding areas, as well as the CR between them, with and without the project.

The following charts present the project gross benefits (fuel savings) by country resulting from the surplus analysis and its breakdown in producer, consumer surplus and CR across the four scenarios. Values are the weighted-average of 9 climate years and based on the average of the results from the PLEXOS and ANTARES modelling tools.

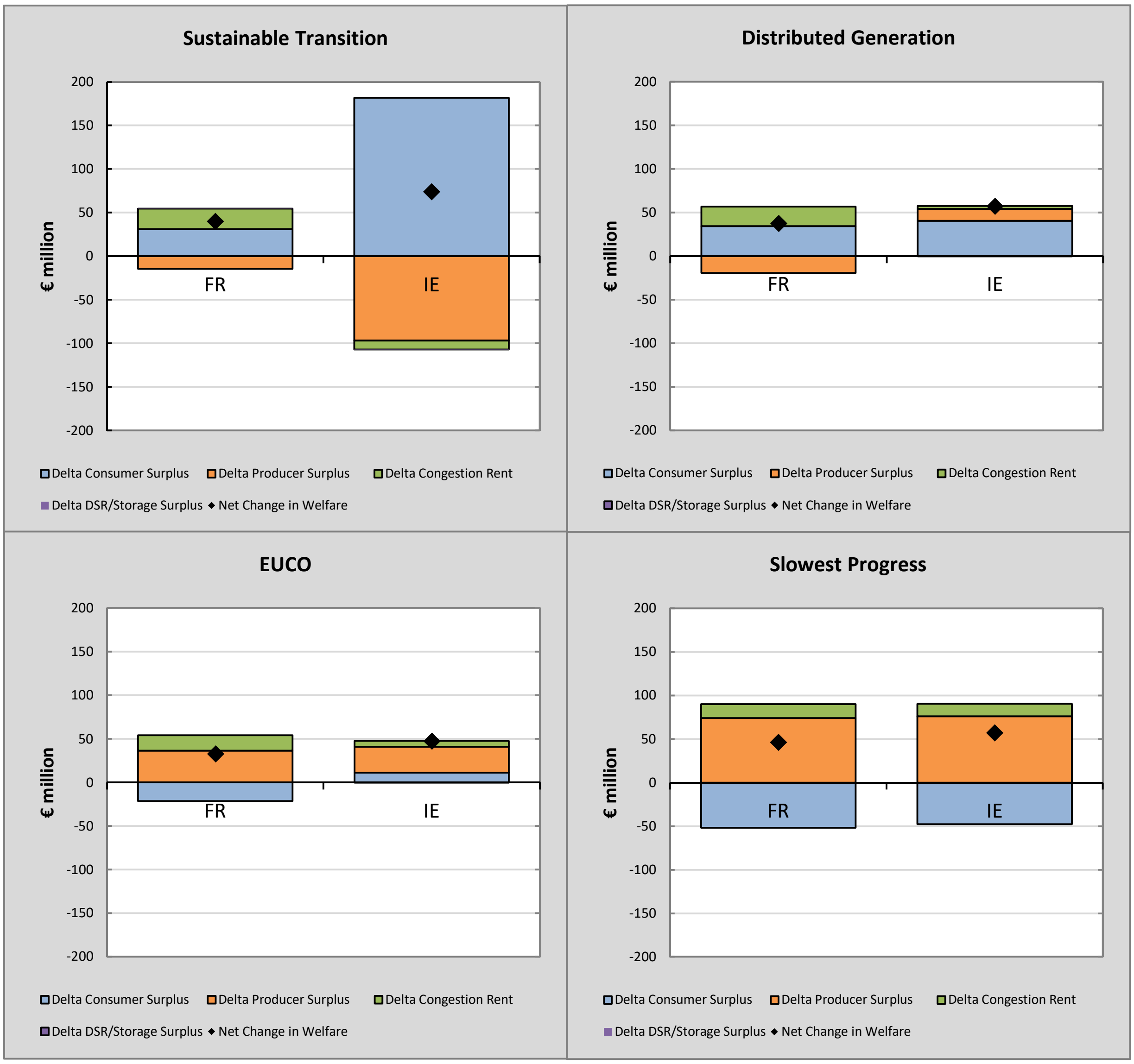


Figure 35: Surplus splits for Sustainable Transition, Distributed Generation, EUCO and Slowest Progress

The charts highlight that the surplus splits between stakeholders vary across the base case scenarios. The following table presents the average of the four base case scenarios.

Table 32: Surplus analysis based on the average of the four scenarios

M€	France	Ireland
Consumer	-2	47
Producer	19	6
Congestion Rent	20	4
DSR/Storage	0	0
Total	**37**	**55**

- In Ireland, the consumer surplus is significantly positive and amounts to 85 % of the overall economic surplus.
- In France, the distribution of surplus between stakeholders is mainly in favour of the producers and TSOs (congestion rent).

A sensitivity analysis was carried out to assess the sensitivity of the SEW to the key factors of the Celtic Interconnector economics which are the wind installed generation in Ireland and the interconnection capacity between Ireland and GB. A sensitivity analysis was also completed for appraising the changes in the surplus values induced by the same factors. The results are detailed in the following tables:

Table 33: Surplus analysis for base case and increased IE-GB interconnection and SEM wind sensitivities

	France			Ireland		
M€	Base Case	Increased GB-IE (+0.5 GW)	SEM Wind	Base Case	Increased GB-IE (+0.5 GW)	SEM Wind
Consumer	-2	-20	-33	47	-38	69
Producer	19	42	53	6	83	-15
Rents	20	11	14	4	-10	-2
Total	**37**	**33**	**34**	**55**	**35**	**53**

The two sensitivities do not have a notable impact on the overall surplus by country except for Ireland for the sensitivity with the additional 500 MW of interconnection between Ireland and GB. By contrast, their impact on the surplus split is noticeable.

- In Ireland, the consumer surplus can be heavily eroded where the interconnection capacity between Ireland and GB is increased.
- In France, regardless of the considered key-factor, the producer surplus increases at the expense of CR and consumer surplus.

Appendix A7 Interconnector Usage Rates

Usage rates of the Celtic Interconnector have been calculated using the flow results for each of the four base case scenarios.

Table 34 shows the situation with and without the Celtic Interconnector and makes it possible to assess the consequences of its commissioning on the other Irish interconnections and on the interconnections between GB and France (global use of the available interconnection capacity on a border – the calculation by individual interconnector is not possible).

It can be seen from the table that usage rates for the Celtic Interconnector range from 61% (Sustainable Transition) to 74% (EUCO) and is approximately 66% on average across the four scenarios. The highest usage rate corresponds to the EUCO scenario while this scenario corresponds to the lowest NPV.

The Celtic Interconnector has some impact on the usage rate of the interconnection between GB and Ireland reducing it from 64% to 52% on average across the four scenarios.

Table 34: Interconnector usage rates for each of the four base case scenarios

	Sustainable transition 2030				Distributed Generation 2030				EUCO 2030				Slowest Progress			
	FR-IE	GB-IE 0.5GW	FR-GB 6.8 GW	IE-NI 1.25GW	FR-IE	GB-IE 0.5GW	FR-GB 6.8 GW	IE-NI 1.25GW	FR-IE	GB-IE 0.5GW	FR-GB 6.8 GW	IE-NI 1.25GW	FR-IE	GB-IE 0.5GW	FR-GB 6.8 GW	IE-NI 1.25GW
TYNDP Reference Network	0%	64%	43%	10%	0%	70%	44%	10%	0%	74%	53%	15%	0%	48%	51%	15%
TYNDP Network +Celtic	61%	52%	42%	8%	66%	57%	43%	9%	74%	57%	52%	12%	64%	41%	50%	19%

The same usage rate calculation was carried out assuming the commissioning of a new 500 MW interconnector project between GB and Ireland leading to a total interconnection capacity of 1000 MW between the two countries.

Table 35: Interconnector usage rates for the increased GB-IE interconnection sensitivity

	Sustainable transition 2030				Distributed Generation 2030				EUCO 2030				Slowest Progress			
	FR-IE	GB-IE 1.0GW	FR-GB 6.8 GW	IE-NI 1.25GW	FR-IE	GB-IE 1.0GW	FR-GB 6.8 GW	IE-NI 1.25GW	FR-IE	GB-IE 1.0GW	FR-GB 6.8 GW	IE-NI 1.25GW	FR-IE	GB-IE 1.0GW	FR-GB 6.8 GW	IE-NI 1.25GW
Ref. Network +0.5GW GB-IE	0%	55%	43%	8%	0%	61%	45%	8%	0%	65%	53%	12%	0%	76%	51%	13%
Ref. Network +0.5GW GB-IE +Celtic	58%	44%	42%	7%	62%	49%	43%	7%	72%	47%	51%	12%	62%	67%	50%	17%

As can be seen from *Table 35*, the usage rate of the Celtic Interconnector is only slightly reduced compared to the base case. For both of the cases above, the Celtic Interconnector has little impact on the usage rate of IE-NI interconnection or FR-GB interconnection.

Appendix A8 CBA Sensitivity Analysis

The following table lists and gives a short description of each of the sensitivities carried out for the results presented in this Investment Request.

Table 36: List and description of each of the sensitivities

	Sensitivity	Sensitivity Analysis description	Scenarios
1	Increased GB-IE Interconnection	Building of GB-IE Interconnection: +0.5GW capacity increase between Great Britain and Ireland	All scenarios
2	Reduced FR-GB Interconnection	Reduction of -2.8GW interconnection capacity between France and Great Britain	All scenarios
3	Increased GB-IE and reduced GB-FR Interconnection	+0.5GW capacity increase between Great Britain and Ireland plus reduction of -2.8GW interconnection capacity between France and Great Britain	Sustainable Transition, Distributed Generation, EUCO
4	Reduced SEM Wind	Reduction of SEM wind installed for Sustainable Transition, Distributed Generation, EUCO: 7.7GW to 5.7 GW (BE 2025 wind installed generation); Slowest Progress: increase of installed wind SEM generation from 5.9 GW to 6.9 GW	All scenarios
5	SEM Load Increase	Load SEM increase by 10%	All scenarios
6	SEM Load Decrease	Load SEM decrease by 10%	Sustainable Transition, Distributed Generation, Slowest Progress
7	French Nuclear Variation	Nuclear France increased/decreased installed capacity: EUCO and Slowest Progress -5 GW; Sustainable Transition and Distributed Generation +5 GW	All scenarios
8	Reduced SEM Solar	Reduction of solar generation in scenario DG2030 only from 5 GW to 1 GW installed capacities for SEM of scenario Sustainable Transition (1 GW)	Distributed Generation Only
9	HVDC Hurdle Cost Increase	Hurdle Cost Interconnection 1.5 €/MWh on HVDCs GB-Continent, GB-Scandinavia, GB-SEM, FR-SEM	Sustainable Transition, Distributed Generation, EUCO
10	HVDC 95% Availability	Forced outage rate 5% on all HVDCs interconnectors GB-continent, GB-Scandinavia, GB-SEM, FR-SEM (in that case, SEW is not modulated with the 0.95 availability rate factor)	Sustainable Transition, Distributed Generation, EUCO
11	Reduced GB Wind	Reduction of installed wind generation in GB from 38 GW (Sustainable Transition, Distributed Generation, EUCO) to 32 GW (BE 2025)	Sustainable Transition, Distributed Generation, EUCO
12	Reduced SEM Must Run Units	Reduction of the number of must-run units (CCGT) in Ireland :one less unit (-1)	All scenarios
13	French Load Reduced	Load in France reduced to 420 TWh/y	All scenarios
14	Hard Brexit	Hard Brexit (see description in appendix A9)	All scenarios
15	Fuel Cost Switch 1	Distributed Generation fuel costs in Sustainable Transition Sustainable Transition fuel costs in Distributed Generation, EUCO	Sustainable Transition, Distributed Generation, EUCO
16	Fuel Cost Switch 2	EUCO fuel costs in Sustainable Transition and Distributed Generation Distributed Generation fuel costs in EUCO	Sustainable Transition, Distributed Generation, EUCO

Table 37 gives the NPV results for Europe across the each of CBA base case scenarios and sensitivities. The cells in green correspond to a positive NPV at the European level and the cells in red correspond to a negative NPV.

Table 37: NPV results for each of the sensitivities

NPV at a European Level (M€)	Sustainable Transition	Distributed Generation	EUCO	Slowest Progress
Base Case	350	220	-15	-130
Increased GB-IE Interconnection +0.5GW	65	-135	-390	-410
Reduced FR-GB Interconnection -2.8GW	380	215	65	-105
Increased GB-IE & Reduced GB-FR Interconnection	170	50	-325	
Reduced SEM Wind – BE2025 targets	115	30	-90	150
SEM Load Increase +10%	620	325	95	-65
SEM Load Decrease -10%	315	170		-75
French Nuclear Variability +/-5GW	350	200	0	-150
Reduced SEM Solar -5GW		455		
HVDC Hurdle Cost Increase 1.5 €/MWh	315	190	-40	
HVDC 95% Availability	400	140	-25	
Reduced GB Wind – BE2025 Targets	325	215	5	
Reduced SEM -1 Must Run Units	345	185	-5	-15
French Load Reduced	330	225	85	-135
Hard Brexit	735	580	295	25
Fuel Costs Switch 1	380	235	410	
Fuel Costs Switch 2	265	90	370	

In line with the results presented in Section 4, Sustainable Transition and Distributed Generation are the scenarios that show the highest benefits and resulting NPVs. NPV remains positive for all of the sensitivities on these scenarios except for the sensitivity with increased interconnection between GB and Ireland in Distributed Generation.

Again in line with the results presented in Section 4, EUCO and Slowest Progress show lower benefits and there are negative NPVs for many of the sensitivities on these scenarios. However, the benefits increase in some sensitivities and this can result in positive NPVs for EUCO and Slowest Progress. For example, when the fuel prices of EUCO are changed to match those of Distributed Generation or Sustainable Transition it results in much higher benefits and positive NPVs.

The SEM wind sensitivity illustrates the impact of wind on the Celtic Interconnector benefits. For the three ENTSO-E scenarios this sensitivity is a reduction of the level of wind in SEM and this sensitivity results in lower benefits and NPVs in those scenarios. As there is a low level of SEM in Slowest Progress the SEM wind sensitivity is actually a small increase in installed capacity for that scenario. As a result this sensitivity gives higher benefits and NPVs for the Slowest Progress.

The “Hard Brexit” sensitivity also results in positive NPVs across all scenarios. This sensitivity highlights the major positive impact a de-harmonisation of the retail electricity markets between GB and Ireland and GB and the Continent have on the Celtic Interconnector benefits.

The impacts of Brexit on the Celtic Interconnector economics are presented in the next appendix.

Appendix A9 Brexit Sensitivity Analysis

This section aims to detail the impacts of Brexit on the Celtic Interconnector economics at the European level as well as for France and Ireland.

A9.1 Assumptions

RTE and EirGrid implemented a Brexit scenario for each of the TYNDP 2018 scenarios according to the following assumptions:

a) Soft Brexit Scenario Modelling:

The "Soft Brexit" scenario is modelled as a limitation of the interconnection capacities between France and GB because Brexit is not thought likely to provide a framework favourable to develop interconnection capacity. Consequently, it assumes that there will not be any other new interconnection between France and GB after Eleclink (1000 MW) and IFA2 (1000 MW) have been built.

Accounting for the IFA2000 existing interconnector, the overall FR-GB interconnection capacity is limited to 4000 MW.

b) Hard Brexit Scenario Modelling:

The proposed modelling of the "Hard Brexit" scenario considers three aspects of the potential impact of Brexit:

I. An overall decrease of the interconnection between GB and Continental Europe and not only restricted to the border between France and GB:

- FR-GB capacity interconnection is still limited to 4000 MW
- the interconnector between Germany and GB (1400 MW) is removed
- No additional interconnection capacities between GB and Ireland
- Note: GB - Norway interconnectors are kept because Norway is not part of EU as well as Viking Link project between GB and Denmark. Taking out these interconnectors would only reinforce the conclusions.

II. A partial de-optimisation of the electricity trading between GB and the continental Europe due to a market decoupling likely to occur.

RTE and EirGrid modelled a decoupling of the GB market with the rest of Europe according to the following approach, similar to the one used in Artelys study[19] on the impact of Brexit on interconnection projects between France and GB:

A first simulation was done for the GB market as still coupled with the rest of Europe (9 climatic years in the simulations);

- From this simulation, the average flows of the 9 climatic years on the different links between GB and Continental Europe were calculated at an hourly step;
- A new simulation was performed in which the capacities of all the interconnectors between GB and Continental Europe were split into two parts:

[19] https://www.cre.fr/en/content/download/17042/209401

- one part corresponding to half the capacity, optimised by the market model for each hour,
- the other part regarded as fixed and equal to 50% of the average flow calculated before.

III. Economic background in Great Britain

Owing to the uncertainty on the evolution of demand and generation mix in GB following Brexit, the TYNDP 2018 assumptions for GB in each scenario have not been changed for these sensitivities.

A9.2 Results for the Celtic Interconnector Economics

On the basis of those assumptions, Brexit was simulated for the four scenarios and NPV recalculated. The results are detailed in the following table.

Table 38: NPV results for BREXIT sensitivities

M€	Sensitivity "Soft Brexit"			Sensitivity "Hard Brexit"			Base Case		
	Europe	NPV IE	NPV Fr	Europe	NPV IE	NPV Fr	Europe	NPV IE	NPV Fr
Sustainable Transition	380	470	115	735	700	365	350	420	70
Distributed Generation	215	270	85	580	390	305	220	260	15
EUCO	65	295	-125	295	380	-45	-15	215	-235
Slowest Progress	-105	125	-75	25	170	-80	-130	145	-180
Average	140	290	0	410	410	135	105	260	-85

Both “Soft” and “Hard Brexit” result in an increase in SEW benefits (SoS not assessed) of the Celtic Interconnector and the Celtic Interconnector NPV (overall and national) and to a particularly high extent in case of “Hard Brexit”.

The combination of interconnectors between GB and Ireland with the interconnectors between GB and Continental Europe represents a bypass to a direct link between Ireland and Continental Europe. This is likely to decrease the economics of the Celtic Interconnector as shown in the CBA sensitivity analysis.

If the probability of congested situations in interconnection with GB increases, it directly results in a significant increase of Celtic Interconnector benefits. An increase in the probability of congested situations – as just described –might occur either because of:

- a reduction of the physical interconnection capacities between GB and Ireland, or
- a combination of such a reduction and a de-optimised use of the existing capacities.

Given the assumptions made in this study, it is clear that Brexit is much more an opportunity than a risk for the Celtic Interconnector project.

Appendix A10 Network Tariffs

A10.1 Description of the National Tariff Models

A10.1.1 Irish transmission tariff model

The revenues required to operate and develop the transmission system in Ireland are determined through the setting of 5 year ex ante revenue controls by the CRU following analysis of proposals brought by EirGrid, in its capacity as TSO, and ESB Networks, in its capacity as Transmission Asset Owner (TAO). The current Revenue Control, PR4, runs from 1 January 2016 to 31 December 2020.

Additionally, there is an annual ex ante process to make adjustments to the revenues for tariff setting purposes, with updated information for pass through elements and any new requirements, along with an ex post correction for the difference between what was actually required in the previous year versus what was collected through tariffs.

The revenue controls cover all aspects of what is required to develop the transmission system including, O&M costs, returns and depreciation for capital invested in the network and in non-network investments etc. All revenues categorised as being related to the development or operation of the transmission system are recovered via the Transmission Use of System Tariffs (TUoS). These tariffs are set by reference to a forecast demand provided by EirGrid to the CRU each year.

EirGrid is incentivised to achieve efficiency targets for its internal operating costs under a price-cap regulation framework. In relation to capital investments, these are included on a RAB and EirGrid is entitled to a return on the closing RAB at 31 December each year at the prevailing WACC, currently 4.95%. EirGrid is also entitled to returns for the financial risk it takes on in managing a number of cash flows including the imperfections revenues and the overall TUoS pot, in addition to having a number of performance target incentives.

At this time the only interconnector operating in Ireland is EWIC. EWIC has its own specific regulatory framework set out in CER/12/149. Under this framework all costs associated with EWIC are paid for by the TUoS customer. Costs are offset by income from CRs and provision of ancillary services. The capital costs associated with EWIC do not therefore appear in EirGrid's RAB. In relation to the Celtic Interconnector, and as set out in Section 7.5, it is EirGrid's assumption that EirGrid's investment in the Celtic Interconnector will be added to the RAB over an appropriate time frame consistent with the tenor of the funding in relation to the project.

A10.1.2 French transmission tariff model

Investments in the transmission network are approved by the CRE based on socio-economic analyses which rely, for interconnections, on SEW for the community at the European level, such as those provided by the European TYNDP process.

The current regulation (TURPE5 decision), determines a cost coverage scheme for the power transmission system based on capital remuneration for net asset value of all assets, under construction or in operation, depreciation coverage, and operational costs (for example, costs to compensate losses, O&M costs, etc.) coverage. TURPE5 entered into force on the 1st August 2017 for 4 years, with cost coverage since January 1st, 2017. French Law provides that the French regulator has to cover the costs of an efficient operator (Article L341-2 of Code de l'Energie).

Capital remuneration

The investments are included in the RAB on the 1st of January following commissioning, and remunerated with a 6.125ç% rate (regulated WACC), including financial costs of the debt, corporate tax, shareholder pay-out and retained earnings. The investments are depreciated each year in accordance with the accounting lifetime, up to 45 years for cables. Assets under construction are remunerated with a 3.7% rate. The investments included in the RAB are net of any granted subvention.

Operational costs

RTE's overall OPEX (that includes interconnectors' O&M costs) are mainly subject to an overall "R × (1 + CPI – X)" regulation (RTE's allowed OPEX amount is revalued according to a retail price index, but is subject to a productivity factor). OPEX such as purchases of energy to compensate electric losses are subject to a specific regulation.

Specificities for interconnections

A specific incentive regulation for interconnection investments is in force in France: a share of the net SEW value for the community provided by the investment is given back to RTE, after a regulator decision including also a bonus/ penalties system for meeting the targeted costs and the targeted use of the asset. The resulted remuneration rate cannot be, in any case, less than regulated WACC minus 1%.

According to Regulation (EC) No 714/2009, auction revenues (from the French shares of all interconnectors) are used to maintain or increase interconnection capacities through network investments. This means that, as long as RTE's overall auction revenues are lower than RTE's CAPEX dedicated to maintaining or improving European exchange capacities (which is the case), auctions revenues reduce the national transmission tariffs.

In practice both (tariffs and auction revenues) cover interconnections costs with additional (or respectively smaller) auction revenues offset by tariff decrease (or respectively increase).

A10.2 Assessment of Impact on the National Transmission Tariffs

A10.2.1 Impact on tariffs in Ireland

Assumptions

Total Cost of project		930
Project cost financed by EirGrid	50%	465
Asset Lifetime	25	465
Debt financing	55%	
Debt rate IE	4.90%	
WACC IE	7.05%	
Managed assets rate	0.00%	
Corporate tax IE	12.50%	
Price index	2.00%	

	O&M	4
	Average Losses IE	10
	Valve Renewal	0
2026	Congestion Income	18
2027	Congestion Income	20
2028	Congestion Income	23
2029	Congestion Income	26
2030	Congestion Income	29

CAPEX Schedule	
2018	-18
2019	-5
2020	-5
2021	-6
2022	-50
2023	-160
2024	-310
2025	-286
2026	-90

Losses IE			
ST	10.6	Average	9.7
DG	9.0		
EUCO	7.9		
V1	11.2		

Average pricing impact over the life of the asset	2.9%

			CAPEX	Assets basis			Capital charges				OPEX		Revenues				
	Year	Price index	EirGrid Investment	Assets under construction	RAB	Managed assets	Financial charge	Regulatory Return	Regulatory return on managed assets	Depreciation	O&M	Losses	Congestion income	Other revenues	Total revenues	Operating charges	EBITDA
N-8	2018	1.00	-9	9			0	0						0	0	0	0
N-7	2019	1.02	-3	12			0	0						0	0	0	0
N-6	2020	1.04	-3	14			0	0						0	0	0	0
N-5	2021	1.06	-3	17			0	0						0	0	0	0
N-4	2022	1.08	-25	42			-1	0						0	0	0	0
N-3	2023	1.10	-80	122			-3	0						0	0	0	0
N-2	2024	1.13	-155	277			-7	0						0	0	0	0
N-1	2025	1.15	-143	420			-11	0						0	0	0	0
N	2026	1.17	-45		465	465	-13	33	0	-19	-4	-8	18	46	64	-12	51
N+1	2027	1.20			446	446	-12	31	0	-19	-5	-10	24	41	65	-15	50
N+2	2028	1.22			428	428	-12	30	0	-19	-5	-11	28	36	65	-16	49
N+3	2029	1.24			409	409	-11	29	0	-19	-5	-12	32	32	64	-17	47
N+4	2030	1.27			391	391	-11	28	0	-19	-5	-12	37	27	64	-18	46
N+5	2031	1.29			372	372	-10	26	0	-19	-5	-13	37	25	63	-18	45
N+6	2032	1.32			353	353	-10	25	0	-19	-6	-13	38	24	62	-18	44
N+7	2033	1.35			335	335	-9	24	0	-19	-6	-13	39	22	61	-19	42
N+8	2034	1.37			316	316	-9	22	0	-19	-6	-13	40	20	60	-19	41
N+9	2035	1.40			298	298	-8	21	0	-19	-6	-14	40	19	59	-19	40
N+10	2036	1.43			279	279	-8	20	0	-19	-6	-14	41	17	58	-20	38
N+11	2037	1.46			260	260	-7	18	0	-19	-6	-14	42	15	57	-20	37
N+12	2038	1.49			242	242	-7	17	0	-19	-6	-14	43	13	56	-21	36
N+13	2039	1.52			223	223	-6	16	0	-19	-6	-15	44	12	55	-21	34
N+14	2040	1.55			205	205	-6	14	0	-19	-6	-15	45	10	54	-21	33
N+15	2041	1.58			186	186	-5	13	0	-19	-7	-15	46	8	54	-22	32
N+16	2042	1.61			167	167	-5	12	0	-19	-7	-16	46	6	53	-22	30
N+17	2043	1.64			149	149	-4	10	0	-19	-7	-16	47	4	52	-23	29
N+18	2044	1.67			130	130	-4	9	0	-19	-7	-16	48	3	51	-23	28
N+19	2045	1.71			112	112	-3	8	0	-19	-7	-17	49	1	50	-24	26
N+20	2046	1.74			93	93	-3	7	0	-19	-7	-17	50	-1	49	-24	25
N+21	2047	1.78			74	74	-2	5	0	-19	-7	-17	51	-3	48	-25	24
N+22	2048	1.81			56	56	-2	4	0	-19	-8	-18	52	-5	48	-25	23
N+23	2049	1.85			37	37	-1	3	0	-19	-8	-18	53	-6	47	-26	21
N+24	2050	1.88			19	19	-1	1	0	-19	-8	-18	54	-8	46	-26	20

A10.2.2 Impact on tariffs in France

The impact of the Celtic Interconnector on the French transmission tariffs is appraised through a Business Plan over the technical life span of the project where the revenues are those provided by the tariffs according to the regulatory scheme in force and where the congestions revenues are redistributed to the French customers.

ASSUMPTIONS

Total cost of project		930
Project cost financed by	50%	465
Cables lifetime	45	325
Substations lifetime	25	140
valves	20	80
Debt financing	60%	
Debt rate FR	3.70%	
WACC FR	6.125%	
Managed assets rate	2.821%	
Corporate tax FR	34.43%	
Price index	2.00%	

	O&M	4
	Average Losses	15
	Valve Renewal	80
2026	Congestion income	18
2027	Congestion income	20
2028	Congestion income	23
2029	Congestion income	26
2030	Congestion income	29

Losses FR			
ST	12	Average	15
DG	12		
EUCO	16		
V1	19		

CAPEX Schedule	
2018	-18
2019	-5
2020	-5
2021	-6
2022	-50
2023	-160
2024	-310
2025	-286
2026	-90

Impact tarifaire moyen sur la durée de vie de l'actif	0.2%

			CAPEX	Assets basis			Capital charges				OPEX		Revenues					
	Year	Price Index	RTE Investment	Assets under construction	RAB	Managed assets	Financial charge	Regulatory Return	Regulatory return on managed assets	Depreciation	O&M	Losses	Incentive	Congestion income	Other revenues	Total revenues	Operating charges	EBITDA
N-8	2018		-9	9			0	0							0	0	0	0
N-7	2019		-3	12			0	0							0	0	0	0
N-6	2020		-3	14			0	1							1	1	0	1
N-5	2021		-3	17			0	1							1	1	0	1
N-4	2022		-25	42			-1	2							2	2	0	2
N-3	2023		-80	122			-3	5							5	5	0	5
N-2	2024		-155	277			-6	10							10	10	0	10
N-1	2025		-143	420			-9	16							16	16	0	16
N	2026	1.00	-45		465	465	-10	28	0	-13	-4	-10	0	18	38	55	-14	41
N+1	2027	1.02			452	452	-10	28	0	-13	-4	-11	0	21	35	56	-15	41
N+2	2028	1.04			439	439	-10	27	0	-13	-4	-13	0	24	33	57	-17	40
N+3	2029	1.06			427	427	-9	26	0	-13	-4	-14	0	28	30	58	-19	39
N+4	2030	1.08			414	414	-9	25	0	-13	-5	-16	0	31	27	59	-21	38
N+5	2031	1.10			401	401	-9	25	0	-13	-5	-16	0	32	26	58	-21	37
N+6	2032	1.13			388	388	-9	24	0	-13	-5	-17	0	33	25	58	-21	37
N+7	2033	1.15			375	375	-8	23	0	-13	-5	-17	0	33	24	58	-22	36
N+8	2034	1.17			362	362	-8	22	0	-13	-5	-17	0	34	23	57	-22	35
N+9	2035	1.20			350	350	-8	21	0	-13	-5	-18	0	35	22	57	-23	34
N+10	2036	1.22			337	337	-7	21	0	-13	-5	-18	0	35	21	57	-23	33
N+11	2037	1.24			324	324	-7	20	0	-13	-5	-18		36	20	56	-24	33
N+12	2038	1.27			311	311	-7	19	0	-13	-5	-19		37	19	56	-24	32
N+13	2039	1.29			298	298	-7	18	0	-13	-5	-19		37	18	56	-25	31
N+14	2040	1.32			285	285	-6	17	0	-13	-6	-19		38	17	55	-25	30
N+15	2041	1.35			273	273	-6	17	0	-13	-6	-20		39	16	55	-26	30
N+16	2042	1.37			260	260	-6	16	0	-13	-6	-20		40	15	55	-26	29
N+17	2043	1.40			247	247	-5	15	0	-13	-6	-21		40	14	55	-27	28
N+18	2044	1.43			234	234	-5	14	0	-13	-6	-21		41	13	54	-27	27
N+19	2045	1.46			221	221	-5	14	0	-13	-6	-22		42	12	54	-28	26
N+20	2046	1.49			209	209	-5	13	0	-13	-6	-22		43	11	54	-28	26
N+21	2047	1.52			196	196	-4	12	0	-13	-6	-22		44	10	54	-29	25
N+22	2048	1.55			183	183	-4	11	0	-13	-6	-23		45	9	53	-29	24
N+23	2049	1.58			170	170	-4	10	0	-13	-7	-23		46	8	53	-30	23
N+24	2050	1.61	-80		237	237	-5	15	0	-13	-7	-24		46	11	58	-31	27
N+25	2051	1.64			224	224	-5	14	0	-11	-7	-24		47	9	56	-31	25
N+26	2052	1.67			213	213	-5	13	0	-11	-7	-25		48	8	56	-32	24
N+27	2053	1.71			202	202	-4	12	0	-11	-7	-25		49	7	56	-32	24
N+28	2054	1.74			191	191	-4	12	0	-11	-7	-26		50	6	56	-33	23
N+29	2055	1.78			180	180	-4	11	0	-11	-7	-26		51	5	56	-34	22
N+30	2056	1.81			168	168	-4	10	0	-11	-8	-27		52	4	56	-34	22
N+31	2057	1.85			157	157	-3	10	0	-11	-8	-27		53	3	56	-35	21
N+32	2058	1.88			146	146	-3	9	0	-11	-8	-28		54	2	56	-36	20
N+33	2059	1.92			135	135	-3	8	0	-11	-8	-28		56	0	56	-36	19
N+34	2060	1.96			123	123	-3	8	0	-11	-8	-29		57	-1	56	-37	19
N+35	2061	2.00			112	112	-2	7	0	-11	-8	-30		58	-2	56	-38	18
N+36	2062	2.04			101	101	-2	6	0	-11	-9	-30		59	-3	56	-39	17
N+37	2063	2.08			90	90	-2	5	0	-11	-9	-31		60	-4	56	-39	17
N+38	2064	2.12			79	79	-2	5	0	-11	-9	-31		61	-5	56	-40	16
N+39	2065	2.16			67	67	-1	4	0	-11	-9	-32		63	-6	56	-41	15
N+40	2066	2.21			56	56	-1	3	0	-11	-9	-33		64	-7	57	-42	15
N+41	2067	2.25			45	45	-1	3	0	-11	-9	-33		65	-8	57	-43	14
N+42	2068	2.30			34	34	-1	2	0	-11	-10	-34		66	-9	57	-44	13
N+43	2069	2.34			22	22	0	1	0	-11	-10	-35		68	-11	57	-44	13
N+44	2070	2.39			11	11	0	1	0	-11	-10	-35		69	-12	57	-45	12
N+45	2071	2.44			0	0	0	0	0	0	-10	-36		70	-24	46	-46	0

Appendix A11 Celtic Business Plans (Merchant line)

A11.1 Celtic Interconnector Business Plan – EirGrid

CELTIC Project Business Plan - EirGrid only

	Costs	Lifetime
Total EirGrid Cost	465 M€	
Asset Value	465 M€	25
O&M	4 M€	
Losses IE	10 M€	

Congestion Rent	18 M€	2026
Congestion Rent	20 M€	2027
Congestion Rent	23 M€	2028
Congestion Rent	26 M€	2029
Congestion Rent	29 M€	2030

Debt financing	55%
Debt rate IE	1.00%
Corporate tax IE	12.50%
Discount rate	5.00%

FNPV	-137 M€
FIRR	-5.71%

Year		Capital Expenditure	Remaining principal	Congestion Rent	O&M	Losses	EBITDA	Total Depreciation	EBIT	Financial charge	Result before taxes	Tax	Net result
N-8	2018	-9.0	9							0.0	0	0	0
N-7	2019	-2.5	12							-0.1	0	0	0
N-6	2020	-2.5	14							-0.1	0	0	0
N-5	2021	-3.0	17							-0.1	0	0	0
N-4	2022	-25.0	42							-0.2	0	0	0
N-3	2023	-80.0	122							-0.7	-1	0	-1
N-2	2024	-155.0	277							-1.5	-2	0	-2
N-1	2025	-143.0	420							-2.3	-2	0	-2
N	2026	-45.0	465	18	-4	-8	5	-19	-13	-2.6	-16	0	-16
N+1	2027		446	20	-4	-8	8	-19	-11	-2.5	-13	0	-13
N+2	2028		428	23	-4	-9	10	-19	-8	-2.4	-11	0	-11
N+3	2029		409	26	-4	-9	13	-19	-6	-2.3	-8	0	-8
N+4	2030		391	29	-4	-10	15	-19	-4	-2.1	-6	0	-6
N+5	2031		372	29	-4	-10	15	-19	-4	-2.0	-6	0	-6
N+6	2032		353	29	-4	-10	15	-19	-4	-1.9	-6	0	-6
N+7	2033		335	29	-4	-10	15	-19	-4	-1.8	-5	0	-5
N+8	2034		316	29	-4	-10	15	-19	-4	-1.7	-5	0	-5
N+9	2035		298	29	-4	-10	15	-19	-4	-1.6	-5	0	-5
N+10	2036		279	29	-4	-10	15	-19	-4	-1.5	-5	0	-5
N+11	2037		260	29	-4	-10	15	-19	-4	-1.4	-5	0	-5
N+12	2038		242	29	-4	-10	15	-19	-4	-1.3	-5	0	-5
N+13	2039		223	29	-4	-10	15	-19	-4	-1.2	-5	0	-5
N+14	2040		205	29	-4	-10	15	-19	-4	-1.1	-5	0	-5
N+15	2041		186	29	-4	-10	15	-19	-4	-1.0	-5	0	-5
N+16	2042		167	29	-4	-10	15	-19	-4	-0.9	-5	0	-5
N+17	2043		149	29	-4	-10	15	-19	-4	-0.8	-4	0	-4
N+18	2044		130	29	-4	-10	15	-19	-4	-0.7	-4	0	-4
N+19	2045		112	29	-4	-10	15	-19	-4	-0.6	-4	0	-4
N+20	2046		93	29	-4	-10	15	-19	-4	-0.5	-4	0	-4
N+21	2047		74	29	-4	-10	15	-19	-4	-0.4	-4	0	-4
N+22	2048		56	29	-4	-10	15	-19	-4	-0.3	-4	0	-4
N+23	2049		37	29	-4	-10	15	-19	-4	-0.2	-4	0	-4
N+24	2050		19	29	-4	-10	15	-19	-4	-0.1	-4	0	-4

A11.2 Celtic Interconnector Business Plan – RTE

CELTIC Project Business Plan - RTE only

	Costs	Lifetime
Total RTE Cost	465 M€	
Cables	325 M€	45
Substations	140 M€	25
O&M	4 M€	
Losses FR	15 M€	
Valve Renewal	80 M€	20

Congestion Rent	18 M€	2026
Congestion Rent	20 M€	2027
Congestion Rent	23 M€	2028
Congestion Rent	26 M€	2029
Congestion Rent	29 M€	2030

Debt financing	60%
Debt rate FR	1.00%
Corporate tax FR	34.43%
Discount rate	6.00%
FNPV	-147 M€
FIRR	-4.71%

Year		Capital Expenditure	Remaining principal	Congestion income	O&M	Losses	EBITDA	Total Depreciation	EBIT	Financial charge	Result before taxes	Tax	Net result
N-8	2018	-9	9							-0.1	0	0	0
N-7	2019	-3	12							-0.1	0	0	0
N-6	2020	-3	14							-0.1	0	0	0
N-5	2021	-3	17							-0.1	0	0	0
N-4	2022	-25	42							-0.3	0	0	0
N-3	2023	-80	122							-0.7	-1	0	-1
N-2	2024	-155	277							-1.7	-2	0	-2
N-1	2025	-143	420							-2.5	-3	0	-3
N	2026	-45	465	18	-4	-15	-1	-13	-14	-2.8	-17	0	-17
N+1	2027		452	20	-4	-15	1	-13	-11	-2.7	-14	0	-14
N+2	2028		439	23	-4	-15	4	-13	-9	-2.6	-11	0	-11
N+3	2029		427	26	-4	-15	7	-13	-6	-2.6	-8	0	-8
N+4	2030		414	29	-4	-15	10	-13	-3	-2.5	-5	0	-5
N+5	2031		401	29	-4	-15	10	-13	-3	-2.4	-5	0	-5
N+6	2032		388	29	-4	-15	10	-13	-3	-2.3	-5	0	-5
N+7	2033		375	29	-4	-15	10	-13	-3	-2.3	-5	0	-5
N+8	2034		362	29	-4	-15	10	-13	-3	-2.2	-5	0	-5
N+9	2035		350	29	-4	-15	10	-13	-3	-2.1	-5	0	-5
N+10	2036		337	29	-4	-15	10	-13	-3	-2.0	-5	0	-5
N+11	2037		324	29	-4	-15	10	-13	-3	-1.9	-5	0	-5
N+12	2038		311	29	-4	-15	10	-13	-3	-1.9	-5	0	-5
N+13	2039		298	29	-4	-15	10	-13	-3	-1.8	-5	0	-5
N+14	2040		285	29	-4	-15	10	-13	-3	-1.7	-5	0	-5
N+15	2041		273	29	-4	-15	10	-13	-3	-1.6	-5	0	-5
N+16	2042		260	29	-4	-15	10	-13	-3	-1.6	-4	0	-4
N+17	2043		247	29	-4	-15	10	-13	-3	-1.5	-4	0	-4
N+18	2044		234	29	-4	-15	10	-13	-3	-1.4	-4	0	-4
N+19	2045		221	29	-4	-15	10	-13	-3	-1.3	-4	0	-4
N+20	2046		209	29	-4	-15	10	-13	-3	-1.3	-4	0	-4
N+21	2047		196	29	-4	-15	10	-13	-3	-1.2	-4	0	-4
N+22	2048		183	29	-4	-15	10	-13	-3	-1.1	-4	0	-4
N+23	2049		170	29	-4	-15	10	-13	-3	-1.0	-4	0	-4
N+24	2050		157	29	-4	-15	10	-13	-3	-0.9	-4	0	-4
N+25	2051	-80	224	29	-4	-15	10	-11	-1	-1.3	-3	0	-3
N+26	2052		213	29	-4	-15	10	-11	-1	-1.3	-3	0	-3
N+27	2053		202	29	-4	-15	10	-11	-1	-1.2	-3	0	-3
N+28	2054		191	29	-4	-15	10	-11	-1	-1.1	-2	0	-2
N+29	2055		180	29	-4	-15	10	-11	-1	-1.1	-2	0	-2
N+30	2056		168	29	-4	-15	10	-11	-1	-1.0	-2	0	-2
N+31	2057		157	29	-4	-15	10	-11	-1	-0.9	-2	0	-2
N+32	2058		146	29	-4	-15	10	-11	-1	-0.9	-2	0	-2
N+33	2059		135	29	-4	-15	10	-11	-1	-0.8	-2	0	-2
N+34	2060		123	29	-4	-15	10	-11	-1	-0.7	-2	0	-2
N+35	2061		112	29	-4	-15	10	-11	-1	-0.7	-2	0	-2
N+36	2062		101	29	-4	-15	10	-11	-1	-0.6	-2	0	-2
N+37	2063		90	29	-4	-15	10	-11	-1	-0.5	-2	0	-2
N+38	2064		79	29	-4	-15	10	-11	-1	-0.5	-2	0	-2
N+39	2065		67	29	-4	-15	10	-11	-1	-0.4	-2	0	-2
N+40	2066		56	29	-4	-15	10	-11	-1	-0.3	-2	0	-2
N+41	2067		45	29	-4	-15	10	-11	-1	-0.3	-2	0	-2
N+42	2068		34	29	-4	-15	10	-11	-1	-0.2	-2	0	-2
N+43	2069		22	29	-4	-15	10	-11	-1	-0.1	-1	0	-1
N+44	2070		11	29	-4	-15	10	-11	-1	-0.1	-1	0	-1

Appendix A12 CRU Specific Section

Celtic Interconnector Project

Investment Request File

Appendix to address CRU-specific questions

7th September 2018

Introduction

This appendix contains analysis that has been requested by the CRU. It will be included in EirGrid's Investment Request submission to CRU, but is not required for RTE's Investment Request submission to CRE. This appendix focuses on:

1. Impact on wholesale markets and competition in Ireland,
2. The distributional impact on the gas customer in Ireland, and
3. An additional sensitivity study on batteries as requested by CRU.

A12.1 Impact on Wholesale Markets and Competition in Ireland

This section provides a quantitative analysis of the impact of the Celtic Interconnector on the functioning of wholesale markets and competition in Ireland. The results here are based on the methodology and model simulations used in TYNDP 2018 and the main Investment Request document.

A12.1.1 Impact on Wholesale Market Prices

Interconnection increases competition in the European internal market for electricity, and this helps to ensure the most efficient use of energy resources. As an Island system on the periphery of Europe, interconnection with Europe is particularly important to Ireland.

The Celtic Interconnector will facilitate exports from Ireland during periods of high RES generation. This will reduce curtailment levels, and help to ensure that the benefits from investment in RES are maximised.

The Celtic Interconnector also provides Ireland with direct access to the continental market which will tend to reduce prices during periods of low RES generation and reduce price volatility. The TYNDP 2018 models show that at peak load times, where previously expensive generation would be required to meet Irish demand, the Celtic Interconnector allows for cheaper EU generation merit order plant to meet this demand. This can reduce the hourly market price depending on demand level and plant availability.

As shown in Table 39, the Celtic Interconnector reduces the average market prices in Ireland for the three TYNDP 2018 scenarios and there is an increase in the Slowest Progress scenario. The variation in results across the scenarios is due to differences in generation mix and fuel prices in the scenarios.

Table 39: Changes in load-weighted average market prices in Ireland due to the Celtic Interconnector

2030 Scenario	Without Celtic (€/MWh)	With Celtic (€/MWh)	Difference (€/MWh)
Sustainable Transition	83.7	78.3	-5.3
Distributed Generation	65.4	64.6	-0.7
EUCO	61.8	60.7	-1.1
Slowest Progress	55.8	57.9	2.1

The TYNDP CBA methodology uses Short-Run Marginal Costs (SRMC) to represent generator bidding, and marginal pricing to forecast future electricity prices. This follows marginal-cost theory which predicts that in a competitive market, prices will be set by the cost of the next cheapest available MW. In systems with high penetration of low-cost RES, during periods of RES curtailment this can lead to sustained periods of zero-pricing (or very low pricing) meaning that generators running during these periods do not receive revenue. As this will make it more difficult for generation to recover costs in the market, high levels of curtailment and zero-pricing can lead to:

- Increases in subsidy payments,
- Lack of efficient investment signals, and
- High market volatility.

Results show that the Celtic Interconnector will significantly reduce curtailment and the frequency of unsustainable zero-price periods.

Figure 36 shows the impact of the Celtic Interconnector on the different market price levels in Ireland and is based on the average of the four scenarios. As the Celtic Interconnector reduces curtailment in all of the scenarios there is also a reduction in zero-price periods in all of the scenarios. There is an increase in the frequency of moderate prices and a reduction in the frequency of high prices as the Celtic Interconnector enables Ireland to import lower cost generation from the continent during periods of low RES generation. This general pattern is the same across all scenarios, but as there is over-capacity and low fuel prices in the Slowest Progress scenario there are no high-price periods in Ireland in the basecase scenario without the Celtic Interconnector. This is why the average price increases in that scenario.

This impact on prices illustrates the positive effect the Celtic Interconnector will have on the electricity market in Ireland. It will lead to lower average prices, reduce price volatility and also improve market sustainability.

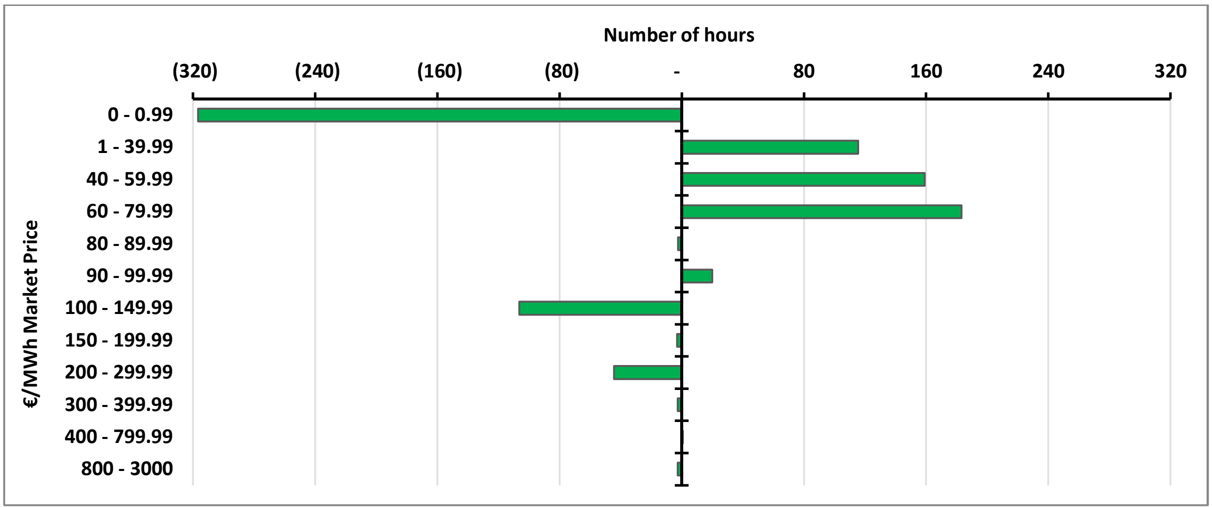


Figure 36: Average impact of the Celtic Interconnector on hourly market prices in Ireland across all 2030 scenarios

A12.1.2 Impact on Ancillary Services and Capacity Markets

The Celtic Interconnector is expected to participate (or facilitate cross-border participation) in the capacity and ancillary service markets in Ireland. As well as participating in these markets, as discussed previously the Celtic Interconnector will facilitate efficient use of other energy sources, improve stability in the energy market and enable an optimal mix of generation, storage and demand side response in Ireland. This will also help to enable competitive and optimal outcomes in the capacity and ancillary service markets and drive value for consumers in Ireland.

A12.1.3 Impact on Generation Types

Figure 37 to Figure 44 give the dispatch and generator market revenue changes for each generation type in Ireland as a result of the Celtic Interconnector for each of the four modelled scenarios.

Effect on RES generation

Table 40 shows that the Celtic Interconnector leads to a large increase in wind energy generation because it reduces curtailment in Ireland. This reduction in RES curtailment will help to ensure that the benefits of national RES policy in Ireland are maximised.

Table 40: The effect of the Celtic Interconnector on RES Integration in Ireland

2030 Scenario	Installed Wind (GW)	Additional RES Generation (GWh)	Curtailment Reduction (%)
Sustainable Transition	6.2	833	2.3%
Distributed Generation	6.2	867	2.2%
EUCO	5.2	711	2.4%
Slowest Progress	5.1	641	2.1%

Effect on peaking generation

The Celtic Interconnector will enable Ireland to import cheaper continental generation instead of utilising expensive distillate units (light oil) in Ireland during periods of low RES generation or low margin. This reduces distillate use in the scenarios by about 11 GWh/year. As shown above, this reduces average prices and price volatility in Ireland.

Effect on gas generation

Gas generation is forecast to increase in all of the scenarios for 2030 relative to current gas generation levels. The Celtic Interconnector tends to reduce gas generation as it facilitates the import of lower cost generation from the continent during periods of low RES generation.

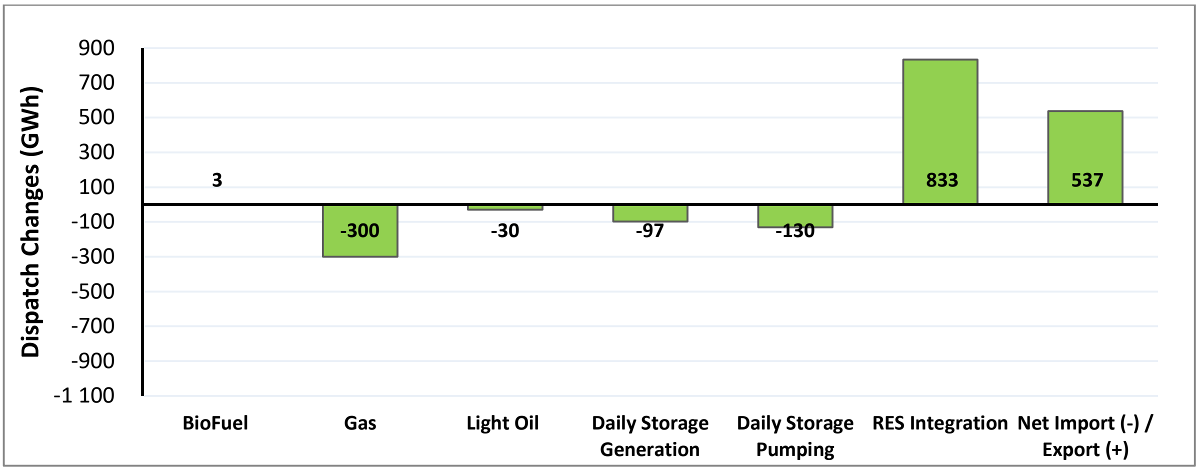


Figure 37: Generator Dispatch Changes for Sustainable Transition

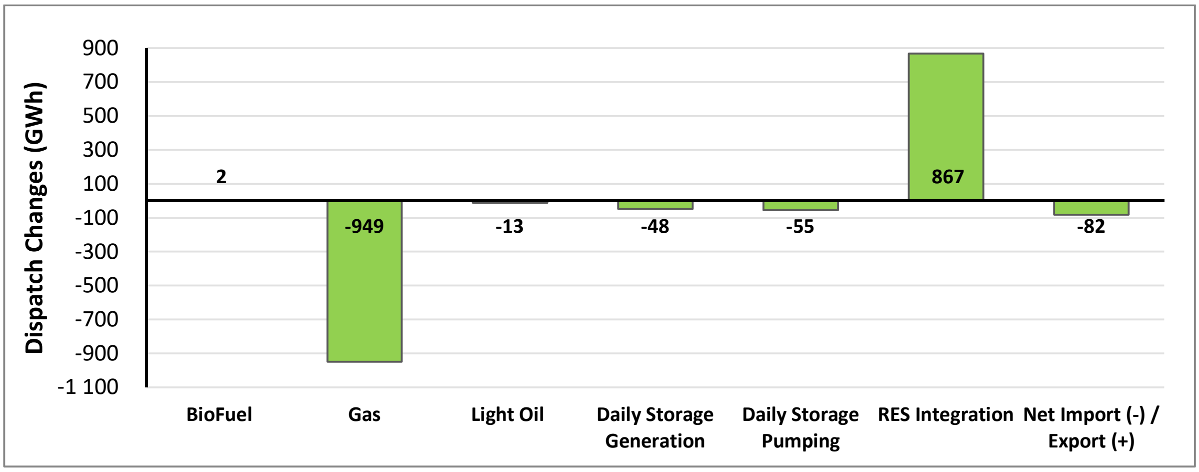


Figure 38: Generator Dispatch Changes for Distributed Generation

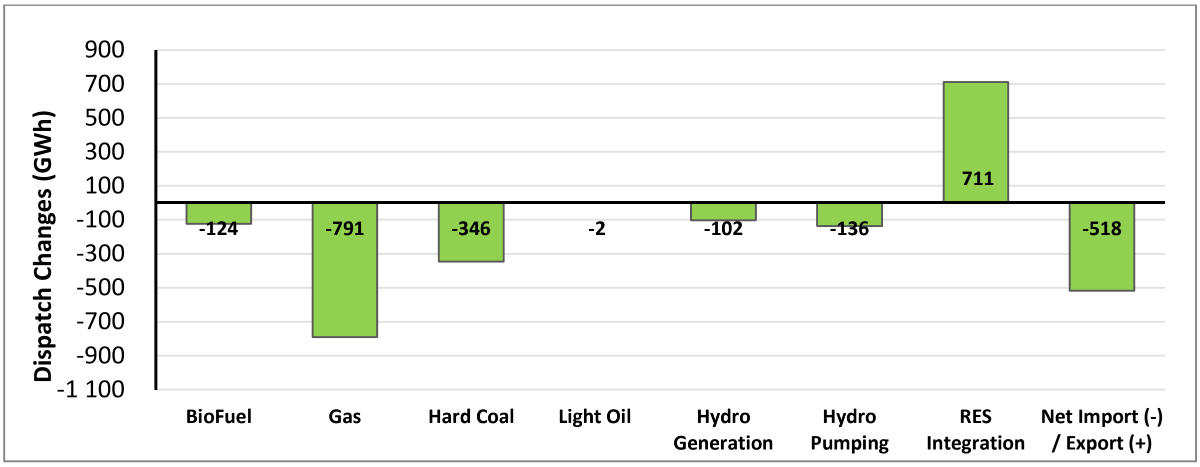


Figure 39: Generator Dispatch Changes for EUCO

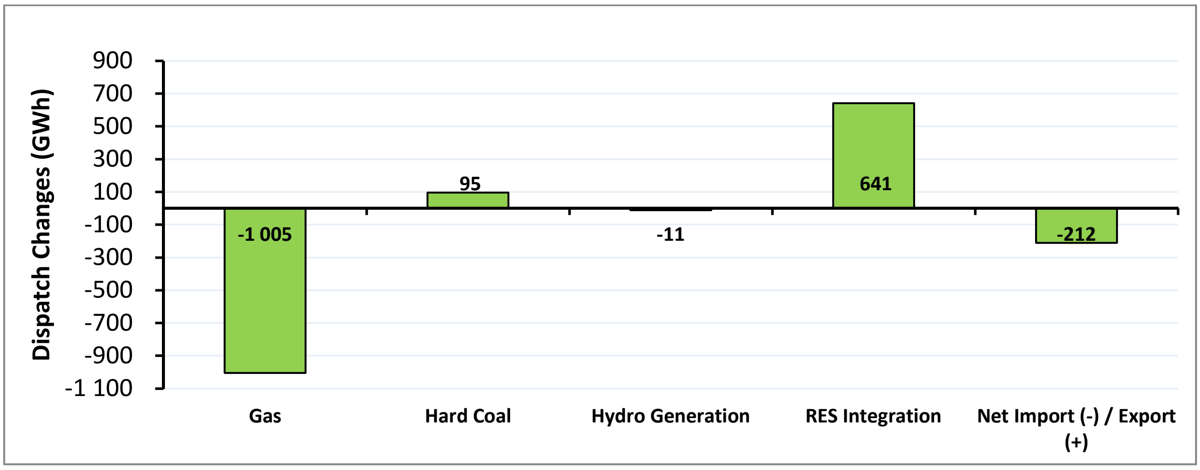


Figure 40: Generator Dispatch Changes for Slowest Progress

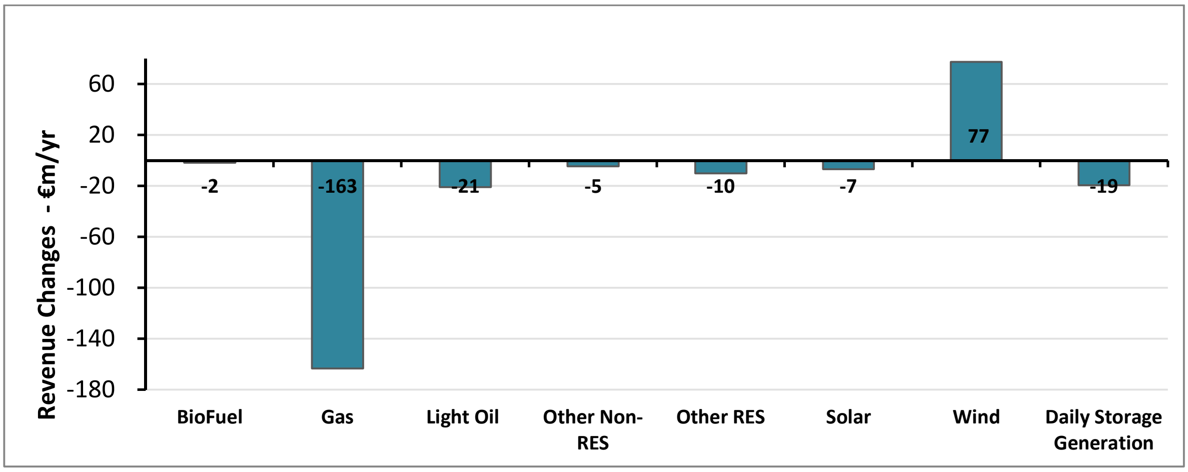


Figure 41: Generator Revenue Changes for Sustainable Transition

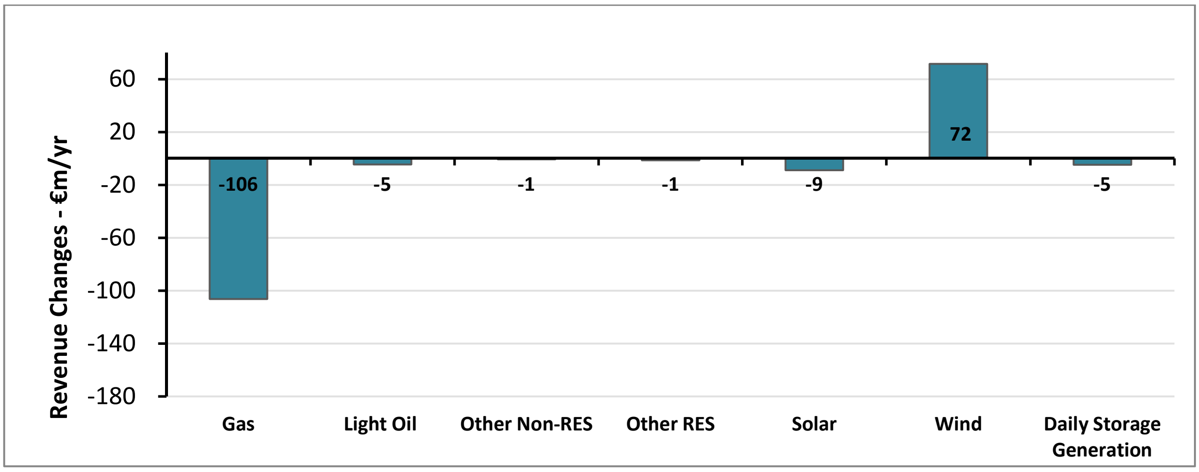


Figure 42: Generator Revenue Changes for Distributed Generation

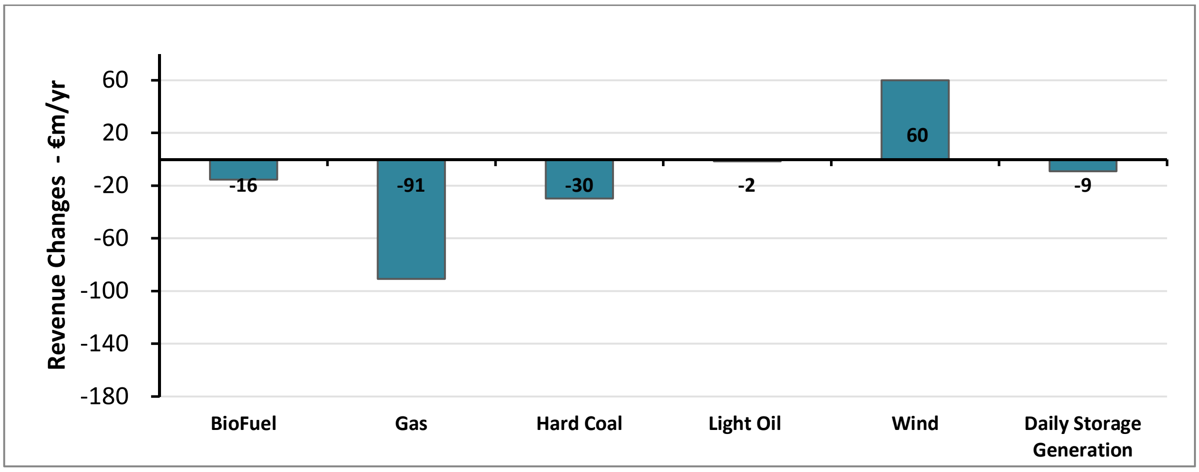


Figure 43: Generator Revenue Changes for EUCO

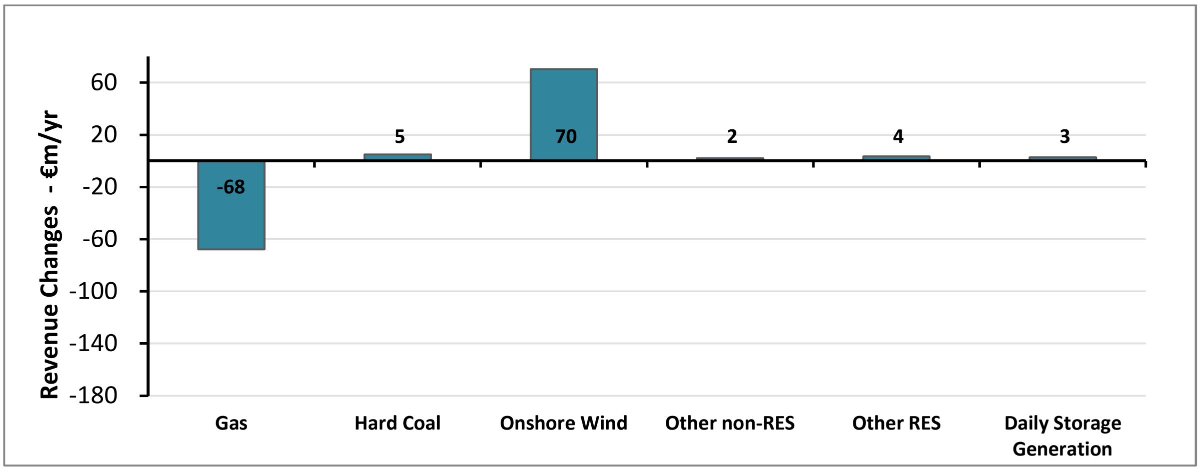


Figure 44: Generator Revenue Changes for Slowest Progress

A12.1.4 Transaction Cost used in the Model to avoid Frictionless Trade

A 0.01 €/MWh hurdle/wheeling cost has been used by ENTSO-E in TYNDP 2018 as a suitable transaction cost within the model simulations. Tests have demonstrated that this hurdle cost of 0.01€/MWh is enough to avoid unrealistic loop flows between regions.

A sensitivity study using a hurdle/wheeling cost of €1.5/MWh was performed to test that the base model €0.01/MWh hurdle cost was satisfactory. The results from this sensitivity analysis shows that there is minimal impact on the SEW for the TYNDP 2018 scenarios. Therefore, the hurdle charge of €0.01/MWh used in the main analysis was set at an appropriate level to avoid frictionless trade. It should be noted also that interconnector losses are also accounted for separately within the CBA methodology.

Table 41: Impact of Hurdle Cost Sensitivity on Project SEW values (PLEXOS & ANTARES average)

€m/year	Base	€1.5/MWh Hurdle Cost Sensitivity	Difference
Sustainable Transition	91	87	-4
Distributed Generation	82	79	-3
EUCO	76	74	-2

**A hurdle cost sensitivity was not carried out for the Slowest Progress scenario*

A12.1.5 Impact on Competition in Ireland

The Celtic Interconnector will improve competition in the wholesale market in Ireland, as it will provide direct access to, and from, the integrated European electricity market.

The Herfindahl Hirschman Index (HHI) is one of the most commonly used market power metrics. It is calculated as the sum of the squares of the shares of the market participants in the relevant market and can vary between 0 and 10,000. The HHI is a measure of overall industry concentration and, as such, is a measure of the ability of a group of market participants to exercise market power together.

Table 42 is based on the values given in the Single Electricity Market Committee decision paper SEM-16-039. The values on the left give the HHI results without the Celtic Interconnector and the values on right give the HHI result when the Celtic Interconnector has been included in the calculation. The reduction in the HHI shows that the Celtic Interconnector will reduce market power and improve competition.

The Celtic Interconnector will increase competition in the energy, capacity and ancillary service markets which will improve market outcomes and deliver value for the consumer.

Table 42: HHI calculation without and with the Celtic Interconnector

	Without Celtic			With Celtic		
	Capacity (MW)	Market Share	HHI Contribution	Capacity (MW)	Market Share	HHI Contribution
ESB PG (Non Wind)	4073	36%	1264	4073	34%	1122
SSE (Non Wind)	1264	11%	122	1264	10%	108
AES	1022	9%	80	1022	8%	71
Viridian Huntstown 1&2	736	6%	41	736	6%	37
NIE PPB	587	5%	26	587	5%	23
BG Energy	444	4%	15	444	4%	13
Tynagh Energy	386	3%	11	386	3%	10
BnM	234	2%	4	234	2%	4
Aughinish	162	1%	2	162	1%	2
Other dispatchable generators	185	2%		185	2%	
Demand Side	235	2%		235	2%	
NI Interconnection	450	4%	15	450	4%	14
IE Interconnecion	500	4%	19	1200	10%	97
Total wind (installed x 0.33)	1179	10%		1179	10%	
Total	**11457**	**100%**	**1600**	**12157**	**100%**	**1501**

A12.2 Distributional Impact on the Gas Customer in Ireland

This section provides an assessment undertaken by EY, at EirGrid's request, based on the results from the analysis detailed in the main Investment request, of the impact of the Celtic Interconnector on the gas customer in Ireland. Gas generation is forecasted to increase in each of the base case scenarios as gas generation replaces other CO_2 emitting thermal generation that is expected to exit the market by 2030.

A12.2.1 Electricity System Costs Reduction

The annual change in net-welfare in Ireland due to the Celtic Interconnector is divided by the total annual electricity generation to get a €/MWh reduction in electricity cost.

The estimated annual net system cost savings will be between €17.8m and €46.6m per year, if a grant of 50% of the project cost is awarded, compared to €3.6m and €32.4m per year without the grant.

A12.2.2 Impact on Electricity Bills

The bill reduction to the average domestic consumer is estimated to be between €2.80 and €5.60 per year if the grant of 50% of the project cost is awarded. This compares to a reduction of between €0.60 and €3.90 a year without the grant. This impact is in addition to the benefit that industry receives from increased productivity.

A12.2.3 Impact on Gas Customer

Estimating the impact on gas bills

Under all of the modelled scenarios, gas usage will increase between now and 2030, regardless of whether the Celtic Interconnector is constructed or not. On this basis the fixed cost of gas network infrastructure will be distributed over the larger number of gas units utilised and so will not increase on a household basis. The introduction of the Celtic Interconnector will lead to a reduction in the total amount of gas required across the system relative to volumes predicted by the TYNDP scenarios for 2030 but not when compared to today's usage.

The reduction in gas-fired generation relative to the base case scenario due to the Celtic Interconnector is expected to be between 2% (Sustainable Transition) and 6% (Distributed Generation and EUCO). According to CSO statistics, 63% of all gas is used for electricity generation. By reducing the amount needed for electricity generation and assuming that the amount needed for business and domestic uses remains the same, a total revised gas requirement can be calculated.

Assuming that the gas network fixed cost of €175m (based on the 2017 Ervia annual report) is spread evenly over all gas users, this would imply a possible cost increase in annual household gas bills of between €0.45 (Sustainable Transition) and €1.38 (Distributed Generation and EUCO) in 2030 relative to the cost which would have been paid if the Celtic Interconnector was not constructed.

A12.2.4 Overall Impact on Households

The CRU estimates that the current average annual domestic gas bill is €780. According to the scenarios provided more gas will be used in 2030, with, or without, the Celtic Interconnector, than is being used today.

With the Celtic Interconnector operating and the consequent reduction in gas usage for electricity production, the price rise possible due to this reduction in gas usage (relative to today) could be between 0.06% and 0.18% of average current gas bills. This is based on the assumption that any increase in cost would be fully passed onto the consumer. As such, this should be considered an estimate of the maximum possible increase, as gas suppliers may seek to absorb some of the additional costs to avoid losing market share.

On this basis it is clear that the impact of the Celtic Interconnector is expected to be small relative to other factors affecting gas bills.

A12.2.5 Review of Historical Impact of Electricity Interconnectors on Gas Networks

Following a review of relevant documents (including the economic case for EWIC), no direct evidence on the impact on gas networks of other similar interconnectors has been found. It was recognised in the determination of the PC3 price control (covering the period 2012-2017) that EWIC may at times "provide a substitute for gas fired generation." However in 2014, the Irish regulator reported that peak volumes on the onshore gas transmission network in 2014/15 would be 13.7% higher than forecast at PC3, although total volumes would be 3.9% lower. It is likely that gas network volumes and charges over this period were influenced by a wide range of factors, including:

- Economic growth,
- Corrib gas production coming on stream,
- Increasing use of renewables, and
- The escalation of the carbon price floor in Great Britain.

A12.3 SEM Battery Sensitivity Study

CRU requested a specific sensitivity study to assess the impact of 700 MW of batteries in Ireland as a potential alternative to the Celtic Interconnector. This section presents the model setup and results of that analysis.

A12.3.1 Model setup and Assumptions

The same scenarios and model set up as were used in the main CBA have been used in this sensitivity analysis. Instead of adding the Celtic Interconnector the effect of adding 700 MW of batteries in Ireland has been analysed for each scenario.

A12.3.2 Battery Sensitivity Results

Table 43 shows that as a potential alternative to the Celtic Interconnector, 700 MW of batteries in Ireland would bring much lower benefits for Ireland and Europe. This applies to both the SEW and RES integration results. It also would provide less security and diversity of supply than direct interconnection with the European market.

Table 43: Comparison of results for an additional 700 MW of batteries and the Celtic Interconnector results

	Europe SEW - €m/year			Ireland SEW - €m/year			Battery Statistics	
	Celtic	+700MW Batteries	Difference	SEW Celtic	SEW Batteries	Difference	Battery Run Hours	Additional RES Integration
Sustainable Transition	91	12	-79	74	27	-47	761 hrs/yr	112 GWh
Distributed Generation	82	15	-67	57	15	-42	769 hrs/yr	126 GWh
EUCO	76	15	-61	47	11	-36	698 hrs/yr	3 GWh
Slowest Progress	66	9	-57	43	10	-33	589 hrs/yr	3 GWh
Average	**79**	**13**	**-66**	**55**	**16**	-39	**704 hrs/yr**	**61 GWh**

The average annual SEW for Ireland from the additional 700 MW of batteries is 16 M€. The average annual SEW for Ireland from the Celtic Interconnector is much higher at 55 M€.

Adding 700 MW of batteries to the Irish system, facilitates on average 61 GWh of RES integration. This compares to between 641 – 867 GWh of additional RES integration facilitated by the Celtic Interconnector in 2030.

When comparing the Celtic Interconnector with a potential alternative of 700 MW of batteries, the Celtic Interconnector has a more beneficial impact on market prices and market sustainability. The additional 700 MW of batteries results in a lower reduction in the number of zero-priced hours compared to Celtic Interconnector as shown in Figure 45 below (this aligns with RES integration results). An additional 700 MW of batteries also lead to a lower reduction in high price periods.

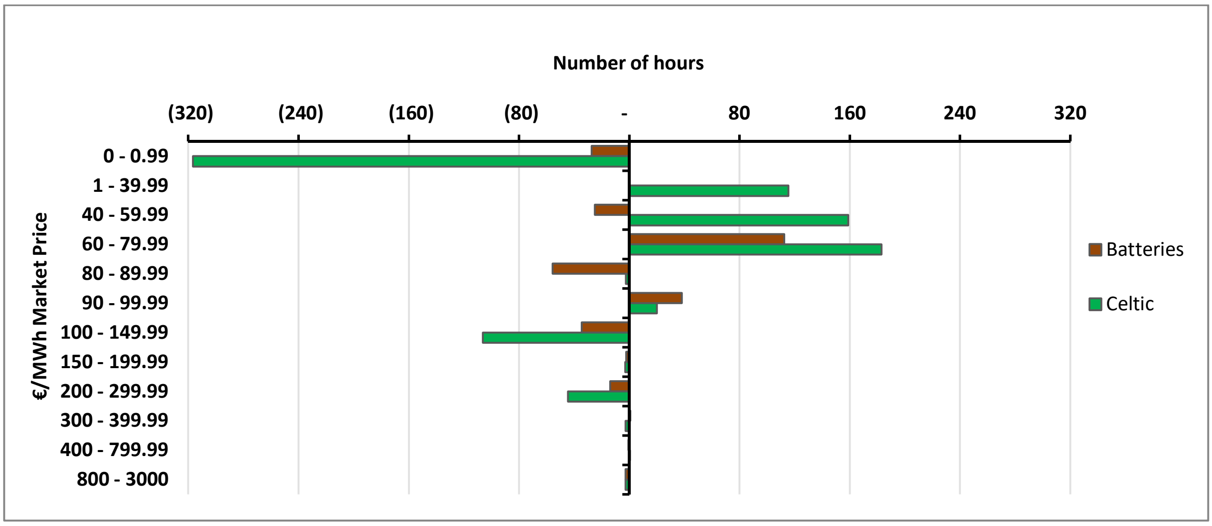


Figure 45: Average impact of hourly market price comparisons for the Celtic Interconnector versus +700MW of Batteries in Ireland