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Financial Implications of High Levels of Renewables on the European Power System

D2.5

EU-SysFlex

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ABBREVIATIONS AND ACRONYMS

APE	Automated Plexos Extraction tool
BAU	Business as Usual
CCGT	Combined Cycle Gas Turbine
CE	Continental Europe
CHP	Combined Heat and Power
DSM	Demand-Side Management
DSO	Distribution System Operator
EAC	Equivalent Asset Cost
EFR	Enhanced Frequency Response
EHV	Extra High Voltage
ENTSO-E	European Network of Transmission System Operators for Electricity
EOC	Enhanced Operational Capability
EU	European Union
EV	Electric vehicles
FFR	Fast Frequency Response
HV	High Voltage
LFG	Landfill Gas
MV	Medium Voltage
NI	Northern Ireland
NOPAT	Net Operating Profit After Tax
OCGT	Open Cycle Gas Turbine
PV	Photovoltaic
RES	Renewable Energy Sources
RES-E	Renewable Energy Sources for Electricity
ROCOF	Rate Of Change Of Frequency
ROIC	Return on Invested Capital
SNSP	System Non-Synchronous Penetration
TES	Tomorrow’s Energy Scenarios
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan
UC	Unit Commitment
UCED	Unit Commitment and Economic Dispatch
VRES	Variable Renewable Energy Sources
WP	Work Package
WTG	Wind Turbine Generator
WJMM	Wilmar Joint Market Model

1 EXECUTIVE SUMMARY

The EU-SysFlex project aims to identify large scale deployment of flexible solutions for a European power system with a high share of Renewable Energy Sources (RES). These solutions can include technical options, procurement of system services (both new and existing), operational strategies and market designs. The project results will contribute to enhanced system flexibility, coordinating the use of both existing and new technologies.

Work Package (WP) 2 is the starting point of the project as its goal is to evaluate the challenges, both technical and financial, arising in the future European power system. Task 2.5 provides a comprehensive economical and financial analysis of future power systems which incorporate higher levels of Variable Renewable Energy Sources (vRES). The analysis undertaken in this task builds upon the work carried out in earlier tasks within WP2 in which detailed scenarios and models were developed. These models and scenarios are employed to carry out detailed production cost analysis, in order to assess the impact of increasing shares of variable renewables. In addition, an analysis of generation costs versus forecasted market revenues allows for a study of potential financial gaps that may arise.

It is evident, as the power system is transitioning to accommodating higher levels of renewables, and in particular vRES technologies, which have very low and even zero marginal cost, that market prices and therefore revenues decline for all generating technologies in an energy only market. In particular, revenues for the variable renewable resources themselves decline more rapidly. This is the cannibalisation effect. It is also shown in this report that the investment cost structure is changing, with fixed costs becoming increasingly dominant as the proportion of vRES technologies increases in future generation portfolios. It is apparent that at very high levels of vRES, when market revenues are very low, costs exceed revenues giving rise to significant financial gaps. This is true for many technologies but in particular wind and solar.

It becomes clear from the analysis that with decreasing market prices, existing energy markets do not provide adequate revenues to fund future sustainable generation portfolios. Additional and adequate revenue streams are needed in order to ensure that the required technologies and capabilities are present on the system. Investment in the correct technologies forms an essential role in transitioning towards decarbonisation, while operating power systems with the required safety and security. The results point out that the energy market design needs to be reconsidered, and reflect the new paradigm of the future power systems with high capital investment and intermittent flexible power generation.

Results from the Ireland and Northern Ireland Power System analysis demonstrate that enhanced System Services could provide a revenue stream to improve the financial viability of both vRES and conventional technologies, whilst also providing the the needed incentive to invest in technologies that will allow for mitigation of the technical scarcities identified in WP2.

2 INTRODUCTION

2.1 CONTEXT

The EU-SysFlex project seeks to enable the European power system to utilise efficient, coordinated flexibilities in order to integrate high levels of renewable energy sources and to meet European decarbonisation objectives. One of the primary goals of the project is to examine the European power system with at least 50% of electricity coming from renewable energy sources (RES-E). In order to transition to a decarbonised power system and to reach at least 50% RES-E on a European scale, Europe needs to develop low carbon and renewable technologies. In some countries these low carbon technologies are predominately variable non-synchronous renewable technologies such as wind and solar. In the context of the EU-SysFlex project, high levels of renewable generation are defined as being installed capacities of renewables that succeed in meeting at least 50% of the total annual electricity demand. As hydro power potentials are largely exploited in many regions, and biomass growth is limited by supply constraints, an increasing part of the growth will come from variable non-synchronous renewables [1]. In addition to developments in renewable electricity, there is also a trend towards sector coupling with, for example, increased electrification of heat and transport, which is seen to be an enabler of the power system transition. While this is clearly an advantage and an opportunity, this can also create challenges for the transmission and distribution networks. Distribution networks in particular were not designed for accommodating embedded generation and this can lead to the need for expensive infrastructure investment.

Transitioning from power systems which have traditionally been dominated by large synchronous generating units to systems with high levels of variable non-synchronous renewable technologies has been shown to result in technical challenges for balancing and operating power systems safely and reliably. This is due to the non-synchronous nature of these technologies as well as the variable, distributed and decentralised nature of the underlying resources. Deliverable 2.1 of this Work Package [2] has performed a comprehensive review of the literature and identified a number of key technical scarcities associated with integration of variable non-synchronous generation and the associated displacement of conventional synchronous generation. These scarcities, if not mitigated, may impact the security and stability of the power system of the future.

The advent of non-synchronous renewable generation, and the associated displacement of conventional generation, will result in a need for system services traditionally provided by conventional generation to be provided by different technologies. This is to ensure that there will be sufficient frequency control capabilities across multiple time frames. Displacement of conventional technologies can also lead to a range of instabilities and issues with reactive power control. High levels of variable generation can cause an increase in network congestion, especially when generation is situated far away from load centres. Furthermore, displacement of conventional generation can lead to a lack of system restoration capability and a need for additional system services to provide black start services. In addition, a potential reduction in system adequacy has also been identified as a challenge associated with displacement of conventional generation.

As a consequence of these technical scarcities, there is an increasing need for provision of system services from wind and solar, as well as enhancement of existing technologies to improve capability.

Further to the aforementioned challenges, there is also a trend towards increasing levels of distribution-connected generation capacity and this, coupled with increasing electricity demand, can have a profound impact on distribution networks and the power system as a whole. The need to accommodate increasing levels of renewables at the distribution level, as well the overall power system need to enable distribution-connected resources to provide the needed services, can lead to issues such as network congestion and curtailment. This is because, historically, distribution grids were not designed to operate with bi-directional flows and with the potential for high, simultaneous demand peaks. Expensive grid reinforcements can therefore be required.

In addition to technical challenges that need to be overcome, economic and financial challenges are also anticipated. The present energy market structure was developed for conventional, centralised and high availability plants. It is expected that with increased energy from renewable sources, which have very low (if any) marginal costs that energy market wholesale prices will fall. It is thought that this will be the case even if carbon prices become exceptionally high. Indeed, Hirst (2013) finds that a high carbon price alone does not make wind and solar power competitive at high penetration rates. Lower energy prices in turn reduce the revenues available to generators from which to recoup their costs. This leads to loss of profitability and financial gaps for all generation but particularly for renewables, the cost structure of which is increasingly dominated by capital costs.

2.2 WORK PACKAGE 2 AND TASK 2.5 WITHIN EU-SYSFLEX

Work Package (WP) 2 forms a crucial starting point for the EU-SysFlex project. WP2 performs detailed technical power system simulations of the European power system with high levels of renewable generation as well as high levels of electrification. The main objective is the assessment of technical shortfalls of the pan-European power system with high levels of renewables.

The first deliverable of WP2 was completed as part of Task 2.1 - D2.1 - State-of-the-Art Literature Review of System Scarcities at High Levels of Renewable Generation [2]. Deliverable 2.1 divided the technical scarcities from the literature into a number of categories; frequency stability, voltage stability, rotor angle stability, network congestion and system restoration. These are the technical scarcities and challenges that are being assessed in Task 2.4. To enable this assessment, it was first necessary to develop scenarios and models. Thus, Task 2.2 defined a set of pragmatic and ambitious scenarios for renewable and low carbon generation deployment in Europe [3], while Task 2.3 developed detailed models to simulate technical scarcities on the European system. Task 2.4 employs the scenarios and the models to perform detailed simulations to determine the technical shortfalls of future power systems. T2.5 completes the picture by performing techno-economic analysis using production cost modelling to assess, among other things, the levels of revenues available to fund large scale deployment of renewables.

One of the anticipated changes will be to system operating costs and consequently this task seeks to assess the savings in production costs that can arise as a result of increased variable renewables with lower marginal costs. Another key objective of this task is to identify and quantify how financial gaps will arise for certain technologies. Due to falling energy market prices, energy markets alone are insufficient for incentivising the required investment in power system capability that is needed at high levels of variable renewables. This task will also determine how system services could be beneficial in providing an additional revenue stream for new and existing technologies. Analysis is performed for the Continental European power system, the Nordic power system, the Ireland and Northern Ireland power system and a subsection of the European power system around Poland and its neighbouring countries.

The results of Task 2.5 are relevant to Work Package 3 which focusses on Market Design and Regulatory Options for Innovative Services. The results are also beneficial to Work Package 10 which builds on the results of the entire EU-SysFlex project to provide a clear vision and strategy in the form of a roadmap for development and deployment of system services and flexibilities needed by the European power system to support the transition to a decarbonised power system with high levels of renewables.

2.3 GENERAL APPROACH

The general approach employed in this task requires 3 key steps:

1. Performance of production cost simulations (or similar)
2. Determination of potential energy market revenues for generators
3. Calculation of cost incurred by generators.

Using these three steps, Financial Gap Analysis can be performed. In the context of this report, Financial Gap Analysis is used for assessing financial feasibility of technologies in future power systems. The financial gaps are assessed by determining the gaps that exist between potential energy revenues and costs. An illustration of the general approach is provided in Figure 1.

The production cost simulations, which are the dominant type of simulations performed, permit analyses of the changes to a) energy markets and b) system operation. Furthermore, some of the key outcomes of the production cost simulation are the revenues from selling electricity in competitive electricity markets for individual generators. Other revenues, such as those from providing system services (e.g. reserves) are not included in the financial gap calculation. In parallel, costs incurred by generators are also forecasted. These include capital costs and fixed annual costs. These costs have been obtained from publically available sources for each region. Production costs, such a fuel costs, are extracted from the production cost simulation results. A comparison of revenues with costs facilitates an investigation into financial gaps which may arise for certain technologies.

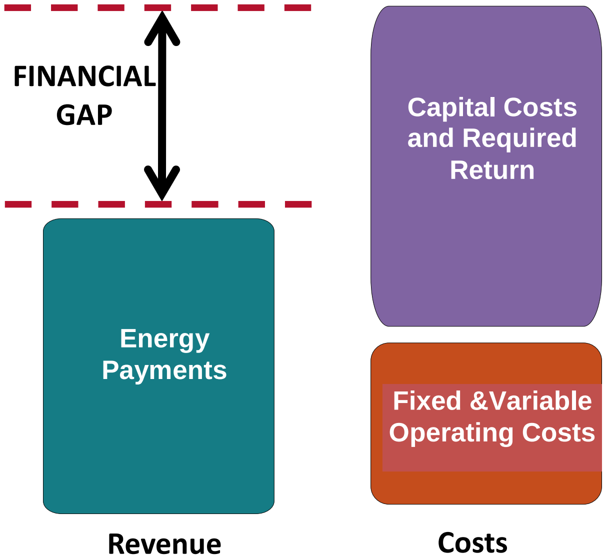

FIGURE 1: GRAPHICAL OVERVIEW OF THE GENERAL APPROACH

2.4 OUTLINE OF THE REPORT

The remainder of this report is structured as follows:

- Chapter 3 outlines the various scenarios and Network Sensitivities that are being examined by each partner. The scenarios and Network Sensitivities are those that were developed as part of Task 2.2. Detail on the models and methodologies that are being employed by each partner are also provided. The chapter concludes with a summary and comparison of the models and analysis.
- Chapter 4 explores the outcomes of employing the scenarios and models as discussed in Chapter 2. The technical implications of adding large shares of vRES into the Continental European power system, the Nordic power system and the Ireland and Northern Ireland power system are presented and discussed.
- Chapter 4 presents the details of the financial analysis that has been conducted for the Continental European power system, the Nordic power system and the Ireland and Northern Ireland power system. The impact of renewables on energy prices and the consequently effect on revenues available from the energy market is discussed.
- Chapter 5 outlines the evaluation of system services analysis that was completed for the Ireland and Northern Ireland power system. The evidence from Chapter 3 and Chapter 4 indicates the need for sufficient revenue streams to support the transition to power systems with high levels of renewables. This chapter illustrated that system services can be part of an effective and plausible revenue stream for Ireland and Northern Ireland, and potentially beyond.
- Chapter 6 makes suggestions for future work that would enhanced the analysis and concludes the report.

3 OVERVIEW OF SCENARIOS, MODELS AND METHODOLOGIES

As outlined in the Task 2.2 deliverable [3], two categories of scenarios are being utilised in EU-SysFlex to study the 2030 power system, Core Scenarios and Network Sensitivities:

Core Scenarios – These are the central scenarios which will define the installed generation capacities by fuel type, demand, interconnection and storage portfolios to be used. These scenarios will be used to produce total annual energy demand as well as total annual energy production by source and fuel type. These scenarios will be used throughout the project for technical and production cost simulations on a pan-European basis.

Network Sensitivities – These are sensitivities which examine various parts of the European network in 2030 and will vary the capacities and locations of demand, generation, interconnection or storage in order to examine various scenarios in specific countries of the European power system. These sensitivities will be used to assess more specific technical scarcities in certain parts of the European system.

The two chosen Core Scenarios are **Energy Transition** and **Renewable Ambition**, which have a percentage of electricity from renewable energy sources (RES-E) with respect to overall demand of 52% and 66%, respectively, on a pan-European basis. A short summary of each scenario is provided below. In addition, various Network Sensitivities have been developed which seek to stress particular parts of the European network in order to examine further technical scarcities in greater detail. These Network Sensitivities are used to investigate more onerous or more ambitious generation and demand portfolios for specific areas and countries. The Network Sensitivities are focused on the areas of the European power system which will undergo increased analysis and simulations. Therefore, the areas which were primarily chosen for Network Sensitivities are the Ireland and Northern Ireland power system and a sub-network of the Continental European power system centred on the Polish network. Additionally, a further sensitivity for the Nordic system has been developed.

3.1 CONTINENTAL EUROPE

The aim of the analysis for the Continental power system is to determine the impact of variable renewables on the power system and on market revenues for various generating technologies. The ultimate objective is to determine if there are sufficient revenues available in the energy market to drive the transition to high – levels of renewables.

3.1.1 SCENARIOS FOR CONTINENTAL EUROPE

Following a review of a wide range of scenarios, two Core Scenarios for the project EU-SysFlex were constructed in 2018 as part of WP2, Task 2.2 [3]. These scenarios are based on the European Commission's EU Reference Scenario 2016 [4] as they meet all of the criteria that were set out by the project. The EU Reference Scenarios from 2016 are official scenarios for the European Commission, and were prepared by national experts across all

EU countries. It sets out a trajectory from 2020 to 2050, based on the European policy framework as of December 2014, with defined scenarios every five years. They integrate all of the European policies and directives, and meet the 2020 renewable energy targets set by the European Commission. In addition, they assume the successful implementation of the EU ETS and meet the CO_2 reduction targets for the projected years. This ties in well with the EU-SysFlex project as the project was funded from the competitive Low-Carbon Energy call. The scenarios developed in the EU Reference Scenario 2016 are the result of a series of interlinked models combining technical and economic methods that have been peer-reviewed and/or have been used for numerous publications in peer-reviewed journals. They set out generation, demand, storage and interconnection portfolios which will be used in the development of EU-SysFlex scenarios. An overview of the EU-SysFlex scenarios is presented in Table 1.

Given the time horizon under consideration in the EU-SysFlex project, the 2030 scenario from the European Commission's EU Reference Scenario 2016 was used as the basis for the first EU-SysFlex scenario. This scenario was adapted for the purposes of the EU-SysFlex project and is called **Energy Transition**. For the second scenario, the European Commission's EU Reference Scenario 2016 with the most ambitious RES penetration was chosen. This was the European Commission's EU Reference Scenario for 2050, and the new EU-SysFlex scenario for 2030 which is derived from it is called **Renewable Ambition**.

It is important that there is a direct relationship and coherence between harmonized scenarios to allow for an easy and direct comparison between the two 2030 Core Scenarios. The **Energy Transition** scenario is 65.5% carbon-free for the EU-28 countries. This includes 25% of energy produced from non-synchronous vRES sources (wind and solar generation). The **Renewable Ambition** scenario assumes 73.1% of generation comes from carbon-free sources, with 36% from non-synchronous vRES sources in the EU-28 countries. While, these figures are the average EU-28 percentages, they can be much higher for some individual member states. The percentages of RES as a proportion of demand across Europe for the two scenarios are 52% for the **Energy Transition** scenario and 66% for the **Renewable Ambition** scenario. The share of carbon-free generation by country is given in Figure 2.

TABLE 1: OVERVIEW OF THE ENERGY TRANSITION AND RENEWABLE AMBITION SCENARIOS

EU 28 + CH + NO	Energy Transition	Renewable Ambition
Overall Demand	3262 TWh	3741 TWh
Overall Renewable Energy Sources	1713 TWh	2469 TWh
Overall Variable RES	859 TWh	1441 TWh
Part of demand covered by RES	52.5%	66.0%

The RES projections from the EU Reference Scenarios 2016, taken as the basis for the EU-SysFlex Scenarios, stem from consultations with Member States and integrate their projection trajectories of the RES shares by sector as expressed in the respective National Renewable Energy Action Plans (NREAPs). The framework integrates known direct RES feed-in tariffs and other RES enabling policies, such as priority access, grid development and streamlined authorisation procedures. The binding targets on RES for 2020 (20% share of gross final energy consumption from RES by 2020 and 10% of the transport sectors gross final energy consumption from RES by

2020) are assumed to be achieved. Beyond 2020, the RES development continues despite the fact that direct incentives are phased out because:

- Some RES technologies are becoming economically competitive;
- The carbon price is increasing through the ETS scheme; and
- The extension of the grid and the improvement in market balancing allow for higher RES penetration.

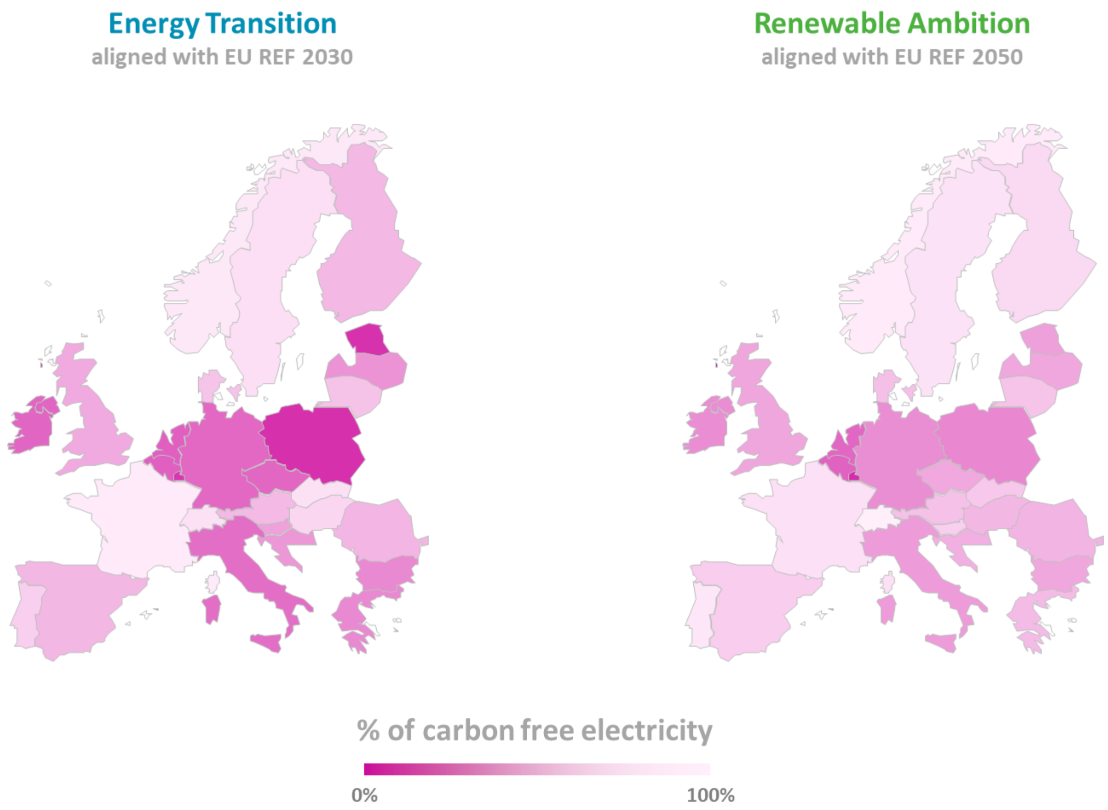

FIGURE 2: SHARE OF CARBON-FREE ELECTRICITY FOR ENERGY TRANSITION (LEFT) AND RENEWABLE AMBITION (RIGHT)

The **Energy Transition** scenario has a share of RES-E of 52% of the electricity demand, and the **Renewable Ambition** scenario has a share of 66%. While these figures are the average percentages for all countries modelled as part of the EU-SysFlex scenarios, the percentage of RES-E is higher for some individual countries and lower for others. Table 2 provides a summary of the renewable generation production, electricity demand and RES-E levels seen for all countries modelled in the two EU-SysFlex scenarios for 2030.

Both Core scenarios already include some storage through pumped hydro stations at the European level, some demand-response through the shaping of the demand of electric vehicles and flexibility through favourable assumptions for interconnections between countries.

In addition to the percentage of RES-E in the two Core Scenarios, the percentage of variable non-synchronous renewable resources is of particular interest to the EU-SysFlex project. Table 3 provides a summary of the carbon-free generation and non-synchronous variable renewable generation for each of the European country considered in the EU-SysFlex scenarios. This is further illustrated in Figure 3, which demonstrates the increase in non-synchronous vRES for each European country between the **Energy Transition** and **Renewable Ambition** scenarios.

TABLE 2: PERCENTAGES OF RENEWABLE ENERGY PRODUCTION IN THE ENERGY TRANSITION AND RENEWABLE AMBITION SCENARIOS AS A PERCENTAGE OF DEMAND

	Energy Transition			Renewable Ambition		
Country	RES production (TWh_e)	Demand (TWh_e)	%RES	RES production (TWh_e)	Demand (TWh_e)	%RES
AT	62	73	85%	73	83	88%
BE	29	89	32%	41	108	37%
CH	45	61	74%	74	56	132%
CZ	9	66	14%	16	79	21%
DE	267	559	48%	385	580	66%
DK	29	36	80%	35	44	80%
ES	163	257	63%	282	291	97%
FI	43	84	51%	50	96	52%
FR	211	469	45%	362	548	66%
HU	3	39	8%	9	47	19%
IE	14	28	48%	21	34	63%
IT	148	314	47%	273	395	69%
LU	1	8	12%	2	12	14%
NL	50	116	43%	67	133	50%
NO	155	117	132%	160	110	145%
PL	40	168	24%	71	202	35%
PT	42	48	88%	50	51	98%
SE	113	144	78%	133	166	80%
SK	7	31	21%	10	34	31%
UK	176	356	49%	201	438	46%
Total	**1607**	**3063**	**52%**	**2315**	**3507**	**66%**

TABLE 3: CHARACTERISTICS OF THE EU-SYSFLEX SCENARIOS FOR THE 28 MEMBER STATES, SWITZERLAND AND NORWAY, FOR CARBON-FREE ELECTRICITY AND VARIABLE NON-SYNCHRONOUS RENEWABLE ENERGY AS PART OF THE ELECTRICITY PRODUCTION.

	Energy Transition				Renewable Ambition			
Country	% carbon - free	% vRES	vRES of which % Wind	vRES of which % Solar	% carbon - free	% vRES	vRES of which % Wind	vRES of which % Solar
EU-28	**65**	**24**	**72**	**28**	**73**	**35**	**70**	**30**
AT	78	17	75	25	81	23	75	25
BE	40	32	83	17	41	33	84	16
BG	57	18	63	37	70	23	57	43
HR	64	16	56	44	73	31	46	54
CH	94	13	26	74	100	18	27	73
CY	29	26	32	68	41	38	33	67
CZ	43	4	28	72	70	5	38	62
DK	81	58	96	4	80	58	97	3
EE	21	11	100	0	67	42	100	0
FI	77	8	100	0	91	8	100	0
FR	98	20	67	33	94	38	69	31
DE	44	31	68	32	60	43	70	30
GR	57	46	63	37	78	66	58	42
HU	90	2	90	10	77	9	85	15
IE	42	36	100	0	59	49	100	0
IT	46	21	49	51	65	36	41	59
LV	61	9	100	0	70	19	100	0
LT	81	6	93	7	82	14	97	3
LU	22	14	81	19	18	13	87	13
MT	13	13	-	100	22	20	13	87
NL	40	24	85	15	43	29	88	12
NO	97	10	100	-	99	12	96	4
PL	20	11	100	0	57	18	99	1
PT	87	41	79	21	96	52	71	29
RO	76	21	83	17	75	25	74	26
SK	94	2	4	96	84	4	23	77
SI	67	6	29	71	87	6	31	69
ES	77	42	60	40	86	71	54	46
SE	93	13	100	0	94	14	100	0
UK	71	26	91	9	70	28	93	7

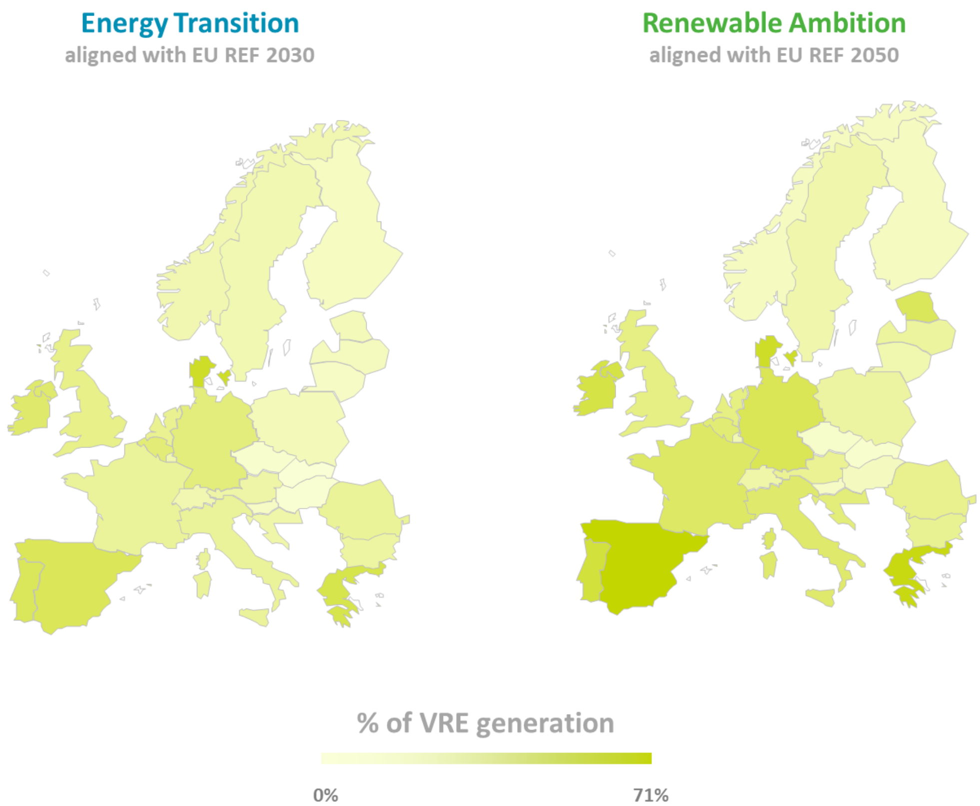

FIGURE 3: SHARE OF VARIABLE NON SYNCHRONOUS RENEWABLE GENERATION (WIND AND SOLAR) FOR POWER GENERATION FOR ENERGY TRANSITION (LEFT) AND RENEWABLE AMBITION (RIGHT)

The EU-SysFlex scenarios allow us to identify 2 main decarbonisation strategies:

- **Decarbonisation based on a power generation mix with a high share of vRES, i.e. wind and solar energies:** Wind and solar technologies are replacing fossil sources such as coal or gas, as shown in Figure 4. The share of variable renewables (vRES) in these systems can be very high. Spain, Greece, Denmark, Portugal and Ireland reach a share of vRES higher or equal to almost 50% in the **Renewable Ambition** scenario. Portugal has the characteristics to couple a large share of variable renewables with a large share of hydro, allowing it to reach a carbon-free level of 96%. In Spain, the carbon-free share reaches 71%, split almost equally between solar and wind, and the 14% share of gas subsides as the share of biomass and hydro remains relatively small. The generation split for Greece is similar to that of Spain. Denmark and Ireland are relying almost exclusively on wind generation as well as biomass to lower the share of fossil generation, typically coal or gas fired power plants. Belgium, Estonia, Germany, the Netherlands, and to some extent Italy, rely on a high share of vRES to lower the carbon intensity of their power generation mix. Biomass plays an important role for Denmark, Estonia and Belgium.
- **Decarbonisation based on a power generation mix of variable renewable energies in conjunction with CO_2-free dispatchable energies:** Wind and solar energies are combined with other carbon-free technologies, renewable or nuclear, to replace non carbon-free energies such as coal or gas as shown in Figure 5. Generally, the power mix of the countries of Figure 5 have a low carbon intensity in **Renewable Ambition**, upwards of 57% carbon-free, with 5 countries being upwards of 90% carbon-free and more

than half being upwards of 80% carbon-free. These countries rely on a combination of hydroelectricity where available, biomass and nuclear energies, along with wind and solar. The choice of dispatchable energies depends mainly on their local resources.

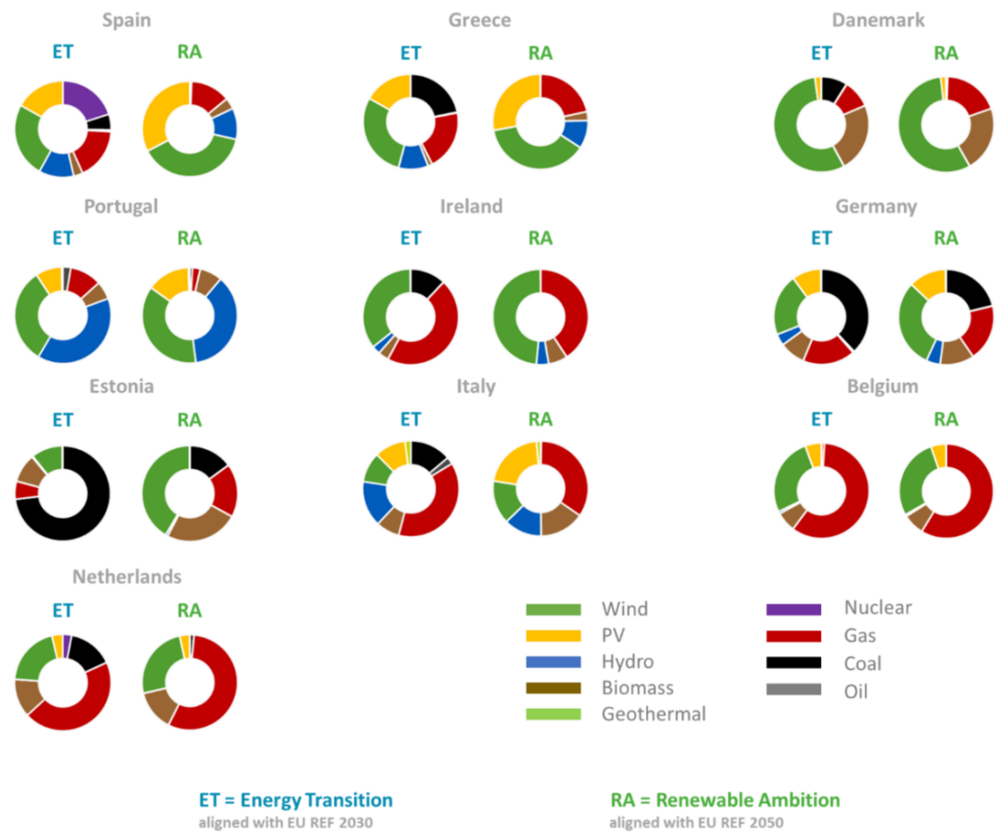

FIGURE 4: COMPARISON OF TOTAL ANNUAL POWER PRODUCTION BY FUEL TYPE FOR ENERGY TRANSITION AND RENEWABLE AMBITION FOR ALL COUNTRIES RELYING PREDOMINANTLY ON VARIABLE RENEWABLE ENERGIES

Additional sensitivities are developed for Task 2.5 to assess the impact of varying shares of vRES in the European power system. One of the main differences between **Energy Transition** and **Renewable Ambition** is the decommissioning of a large share of coal-fired plants at the European level, the highest carbon emitting sources. In particular, the less carbon intensive mix from **Renewable Ambition** as well as the demand and the CO_2 price of €90/tCO_2 are taken as a reference. The gas plants, CCGT and OCGT, are then adjusted so that each sensitivity meets a reliability target level of 3 hours per year per country on average on the 165 climate and outage scenarios[1], so as to provide adequate level of service to consumers. Gas peaking plants ensure flexibility of the power system needed to compensate for vRES in this part of the work. Other solutions (e.g. batteries,…) will be considered in Task 2.6. Four shares of vRES[2] are considered: 23%, 34%, 45% and 55%. 23% vRES share is the share from **Energy Transition** and 34% from **Renewable Ambition**. 45% and 55% vRES shares additional trajectories were created to account for even higher levels of vRES and analyse subsequent issues.

[2] These shares are computed with respect to European production and differ slightly (less than 2%) from the ones computed above using the given net demand from the EU Reference scenarios.

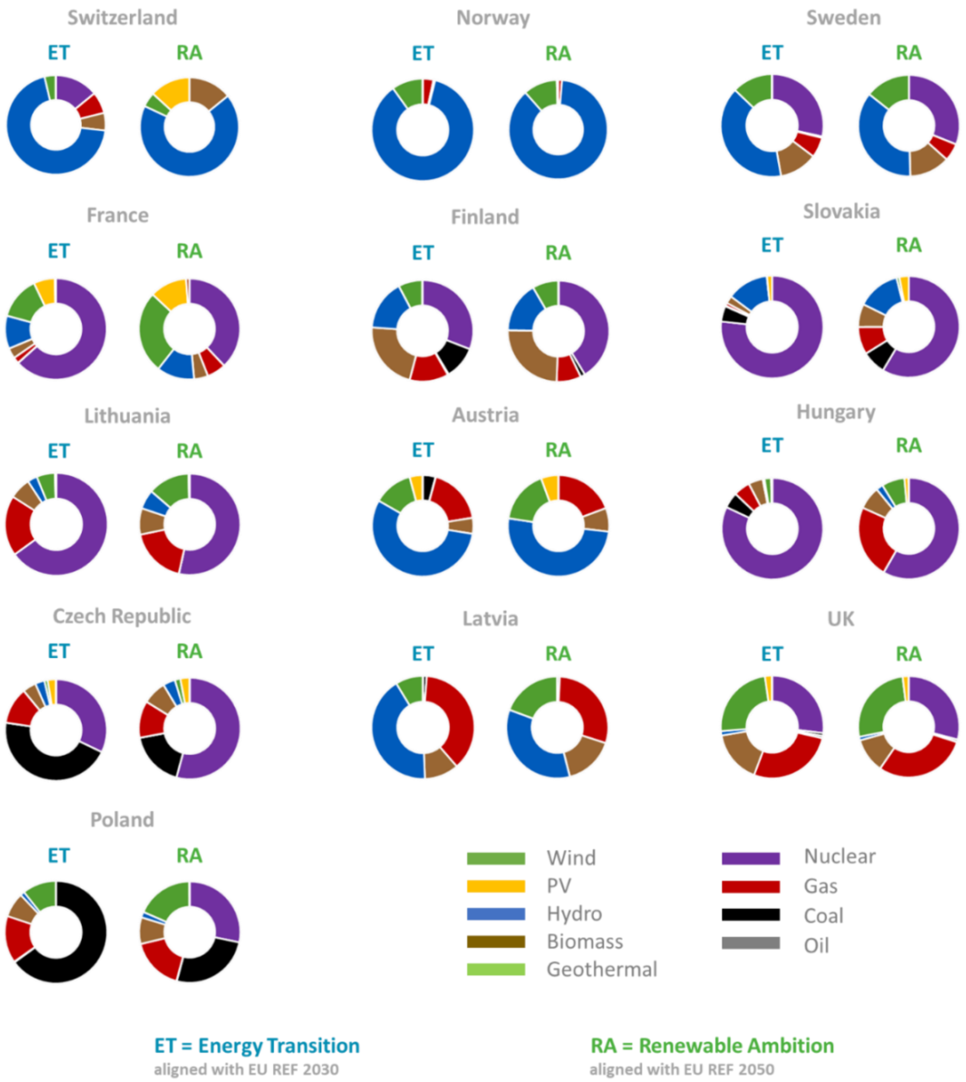

FIGURE 5 : COMPARISON OF TOTAL ANNUAL POWER GENERATION BY FUEL TYPE FOR ENERGY TRANSITION AND RENEWABLE AMBITION FOR ALL COUNTRIES RELYING ON CARBON-FREE, DISPATCHABLE TECHNOLOGIES IN CONJUNCTION WITH VARIABLE NON SYNCHRONOUS RENEWABLE GENERATION

3.1.2 CONTINENTAL POWER SYSTEM MODEL

The European power system is simulated using CONTINENTAL, an EDF state-of-the-art Unit Commitment software suite, which was used for the study on integrating 60% Renewable Energy into the European System [5]. This suite is an integrated electric generation and transmission market simulation system. It balances electricity supply and demand over the medium-term, on numerous scenarios reflecting the uncertainty, for a set of interconnected zones, minimising the overall production cost. Figure 6 shows the different steps of the CONTINENTAL model, as well as the breadth of input and output data.

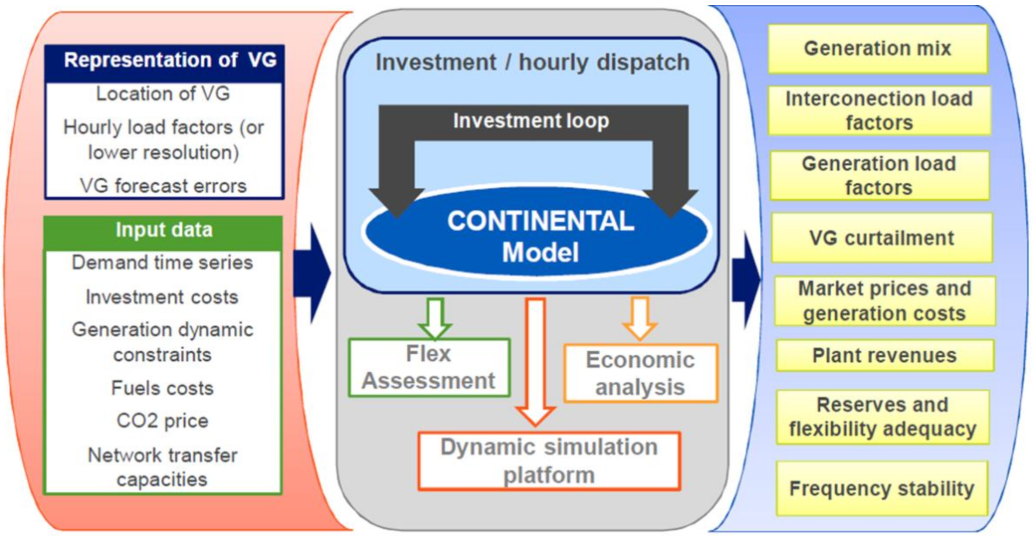

FIGURE 6: SOFTWARE SUITE WITH AN INVESTMENT LOOP AND A UNIT COMMITMENT MODEL

An investment loop ensures that the power system that is modelled does not have excessive hours of unserved energy, and enhances the generation mix if needed in the most cost-effective way. The Unit Commitment model then proceeds in two steps:

1. First, it determines the strategy for using hydraulic stocks (water placement), by calculating “water values" for each period and stock level and for each scenario, using a dynamic stochastic programming method. These water values will then be assimilated to variable costs.
2. It then calculates the electric generation program by zone minimising the overall cost of the system. When activated, it also respects the various constraints of the power system: supply-demand balance at each hour, maximum interconnection capacities, dynamic constraints related to the flexibility of thermal units (minimum power, start-up costs, minimum on/off time, etc.), and constraints related to the primary and secondary reserve services.

CONTINENTAL processes data on an hourly basis, for example solar or wind generation, and accounts for uncertainty coming from weather patterns using a set of over 50 climate years, which are projections into the future of historical data. The CONTINENTAL model also requires data for conventional plants such as technical characteristics of thermal units (efficiency range, variable costs, planned and forced outage rate, start-up cost, minimum on/off time, etc.), interconnection capacities, number of electric vehicles (for demand), commodity prices. The Unit Commitment software optimizes the hourly generation of thermal plants as well as hydraulics, and indicates the number of hours of unserved energy in the system. The geographical perimeter includes 20 countries: Austria, Belgium, The Czech Republic, Denmark, Finland, France, Germany, Hungary, Ireland, Italy, Luxembourg, The Netherlands, Norway, Poland, Portugal, Slovakia, Spain, Sweden, Switzerland, and the United Kingdom.

The results for the total annual power production by fuel type for **Energy Transition** and **Renewable Ambition** obtained with the modelling approach presented above is shown in Figure 7 and Figure 8. These graphs were produced from averaging the hourly production for each country by fuel type over the 165 year-long simulations representing different climatic conditions and plant outages. The main output of this detailed modelling of the European power system is production schedules at an hourly resolution for a large range of climate years and plant outages. This allows the EU-SysFlex project to carry out state-of-the-art technical and economic studies of a system with a large amount of variable renewables, so as to make key contributions to the final flexibility roadmap of the EU-SysFlex project.

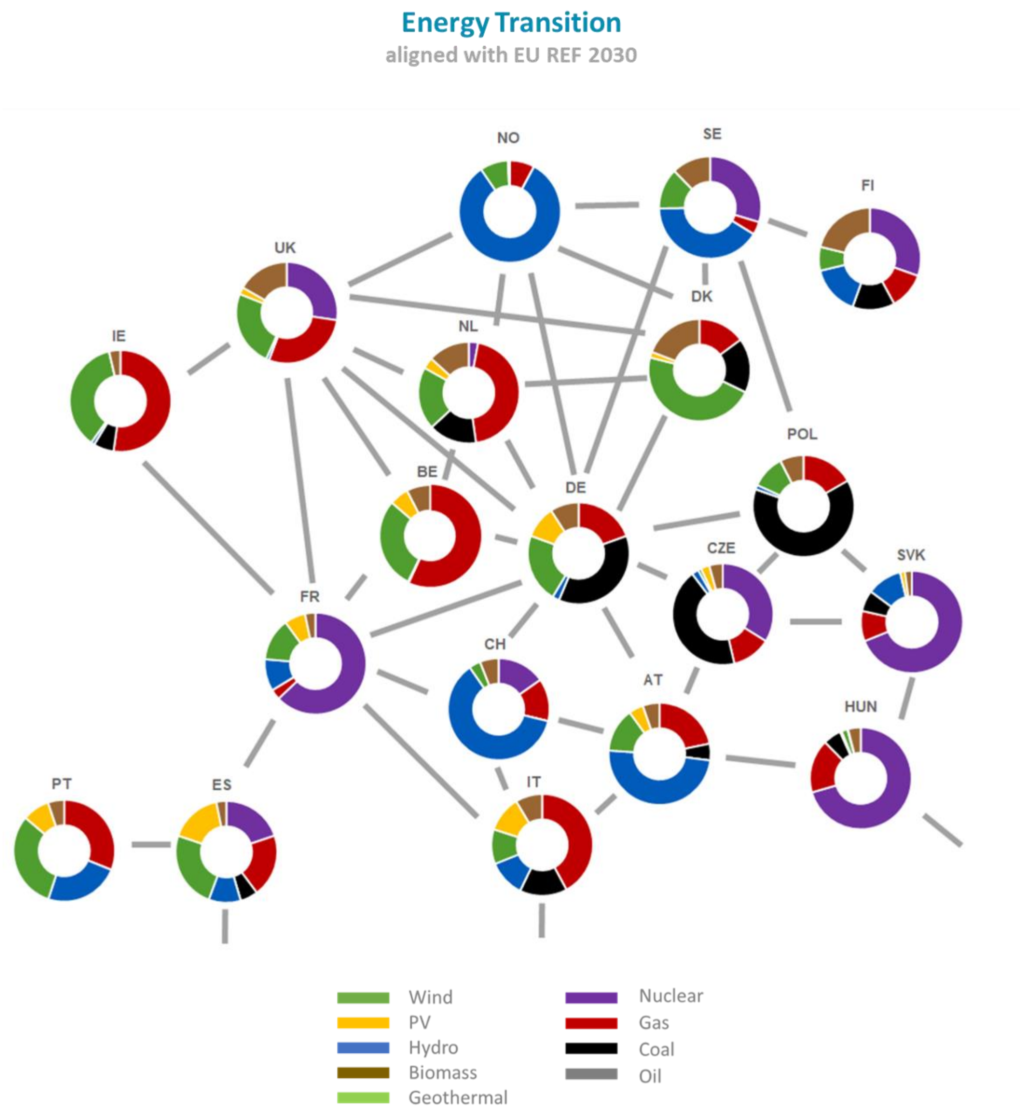

FIGURE 7: TOTAL ANNUAL POWER PRODUCTION FOR THE ENERGY TRANSITION SCENARIO

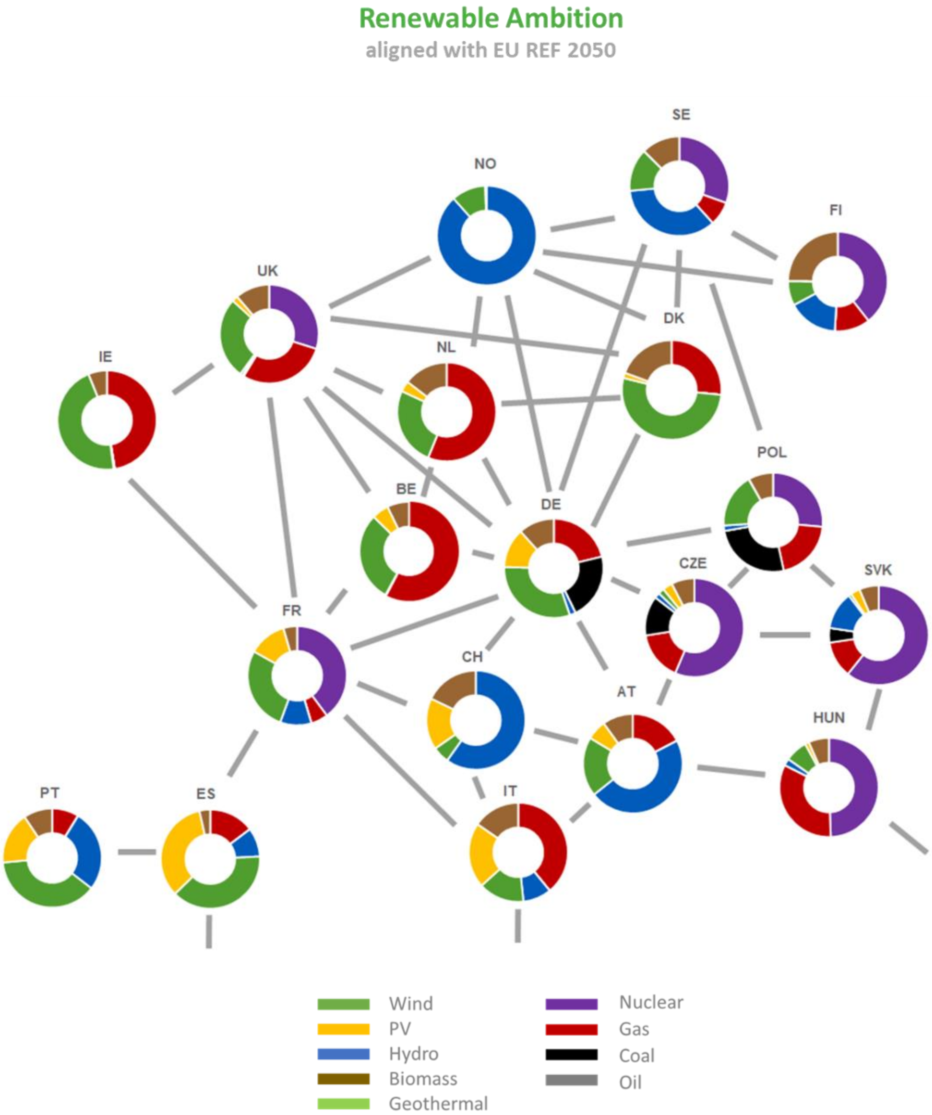

FIGURE 8: TOTAL ANNUAL POWER PRODUCTION FOR RENEWABLE AMBITION

3.2 SUB-NETWORK OF THE EUROPEAN POWER SYSTEM

The area of the Continental power system around Poland, including some of the surrounding countries (Germany, Austria, Czech Republic, Slovakia and Hungary) is also being investigated as part of the analysis in WP2. This is referred to as the Sub-Network of the European Power System. There are two Network Sensitivities – **Going Green** and **Distributed Renewables** for this region of study. These Network Sensitivities are being used in conjunction with the two Core Scenarios.

The two Network Sensitivities assume more installed capacity of wind and PV generation in Poland than in either of the two Core Scenarios. Both Network Sensitivities have 19,860 MW of wind generation, 3,500 MW of which is offshore, and 3,260 MW of solar PV capacity.

The main difference between **Going Green** and **Distributed Renewables** lies in the assumed location of the renewable resources. For **Going Green** it is assumed that 83% of the installed renewable generation capacity is at the EHV and 110 kV network level, with the remaining 17% of installed generation capacity at the MV and LV networks. The **Distributed Renewables** Network Sensitivity on the other hand assumes the same values of installed capacity as in the **Going Green** scenario but with 40% installed at 110 KV and above and the remaining 60% installed below 110 KV, in the distribution network[3].

3.2.1 MODEL FOR THE SUB-NETWORK OF THE EUROPEAN POWER SYSTEM

The aim of the analysis for the sub-network of the European power system is to compare the costs of grid investment with the costs of system services provision for the mitigation of voltage stability issues, identified in Task 2.4. This type of analysis differs considerably from the analysis being conducted for the wider pan-European power system. Consequently, the models employed for this part of the analysis differ from those discussed in Section 3.1.2.

The model for the Continental power system described above in Section 3.1.2 (the CONTINENTAL model) does not contain details of the network. Therefore, while the model above is ideal for simulating generation commitment and dispatch schedules, and consequently for performing cost and revenue analysis, it is not possible to employ it to perform analysis of reactive power and voltage stability. Consequently, a detailed network model is required in WP2 more generally to supplement, enhance and complement the commitment and dispatch models and analysis.

As it was not possible to model the entire transmission network of the Continental power system, the sub-network around Poland was instead chosen. The aforementioned Network Sensitivities for the sub-network of the European Power System were created for implementation in this detailed model. This detailed model is described in considerable detail in EU-SysFlex Deliverable D2.3 [6], while the primary output of that model and the associated analysis is presented in EU-SysFlex Deliverable D2.4.

The sub-network model distinguishes different areas of the network covered by three levels of modelling complexity and this is depicted in Figure 9:

- A detailed representation of the transmission 400 kV and 220 kV (EHV) and sub-transmission 110 kV (HV) power grid in Poland
- A simplified representation of the neighbouring countries (aggregation of lines in parallel, busbars, power plants)
- Equivalent models for Western and Southern Europe countries which are part of CE power system.

[3] It may be noticed that, for the Going Green scenario, the ratio of installed capacity of renewables above and below 110 kV differs slightly from the ratio proposed in the original D2.2 Report (EU-SysFlex Scenarios and Network Sensitivities). The change stems from analysis that is taking place in Task 2.4 where it was found that it was necessary to adjust the ratios to ensure convergence of the load flow calculations.

FIGURE 9: SCOPE OF INTEREST FOR CONTINENTAL EUROPEAN POWER SYSTEM VOLTAGE STUDIES

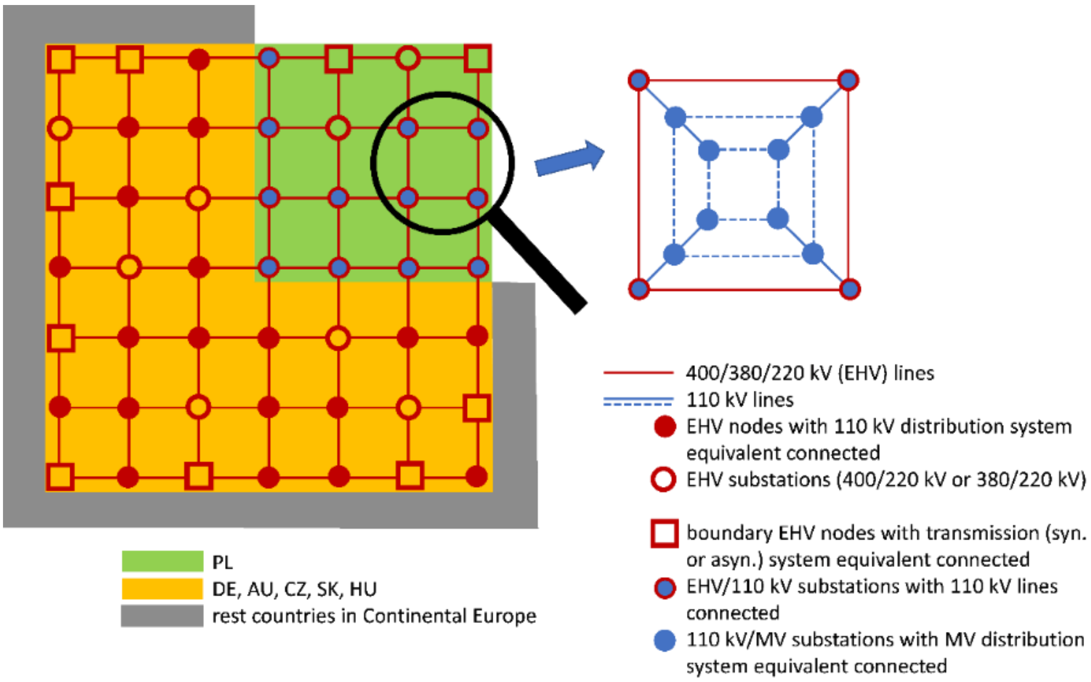

FIGURE 10: SIMPLIFIED MODELLING SCHEME FOR SPECIFIC AREAS IN THE SCOPE OF THE POWER SYSTEM IN CONTINENTAL EUROPE

3.2.2 EVALUATION METHODOLOGY

As mentioned in the previous section, the aim of the analysis for the sub-network of the European power system is to compare the costs of grid investment with the costs of system services provision for the mitigation of voltage stability issues. This required close collaboration with Task 2.4. As part of Task 2.4, it was identified that there is a significant increase in voltage fluctuations as levels of renewable generation increase. It was also found that the associated reactive power deficiencies arose solely on the distribution grid. In order to mitigate these deficiencies two key mechanisms were identified. The first mechanism comprises investment in grid assets, namely capacitive and inductive shunts, by system operators. The second solution entails procurement of system services from grid users. For the second option, it was found through analysis conducted as part of Task 2.4 that increasing the rated power of inverters in wind turbines to a value of 0.2 MVA/1 MVar was sufficient to address the reactive power deficiencies.

These two investment scenarios[4] are summarised below:

- Business as Usual (BAU) – This scenario assumes that reactive power requirements are met through grid investment by System Operators. This entails investment in capacitive and inductive shunts. The additional requirements for this scenario were derived as part of analysis in Task 2.4 and are summarised in Table 4 below. Only investments in capacitor banks and shunt reactors were considered as they were simplest technologies providing the necessary reactive power requirements as identified in Task 2.4.
- Enhanced Services (ES) – This scenario assumes reactive power requirements are met through procurement of system services from grid users and that provision of such services is achieved through increasing the rated power of inverters in wind turbines. This is due to the fact that it has been shown in Task 2.4 that the inherent capabilities of the existing distribution-connected wind turbines would not be sufficient to resolve the identified issues with voltage stability.

TABLE 4: ADDITIONAL CAPACITIVE AND INDUCTIVE SHUNTS REQUIRED FOR BAU SCENARIO – RESULTS FROM TASK 2.4 OF EU-SYSFLEX

	Additional Inductive Shunts [MVAR]	Additional Capacitive Shunts [MVAR]
Energy Transition	2504	1309
Going Green	1914	1625
Distributed Renewables	1591	730

For the BAU case, the costs for the inductive and capacitive shunts were based on information the e-Highways 2050 project [7]. The quoted costs include delivery and assembly, but exclude all civil and structural works. Therefore, an additional allowance has been made for ancillary works bringing the assumed costs up to about €3 million/MVAR, ± 30% and €5.75 million/MVAR, ± 30% for inductive and capacitive shunts, respectively. These

[4] It should be noted that using a combination of the two approaches above is also a possibility, but for the purposes of this analysis the two are considered separately.

ranges in value represent the variance in costs associated with additional construction works and ancillary equipment.

For the ES case, it was assumed that a doubling of reactive power capabilities relative to the existing distribution-connected wind turbine capabilities was required. It was calculated that an increase in the rated power of inverters with a ratio of up to 0.2 MVA/1 MVar was needed. The costs associated with this for a future power system in 2030, are based on costs published by the Joint Reseach Centre of the European Commission [8], with learning rates [9] and installation costs also factored into the analysis. A variance of ± 15% is applied to capture the variances in cost associated with construction works and ancillary equipment.

3.3 NORDIC POWER SYSTEM

The aim of the analysis for the Nordic power system is to determine the impact of variable renewables on the power system and on market revenues for various generating technologies. The ultimate objective is to determine if there are sufficient revenues available in the energy market to drive the transition to high–levels of renewables. The model for the Nordic power system includes Sweden, Finland, Norway and Denmark. Zonal resolution is used (9 zones as in Figure 11). The zones follow the bidding zones of the Nordic day-ahead power market except in a few cases, for which one or more bidding zones have been combined for computational reasons.

Production cost simulations of the Nordic region were linked with the CONTINENTAL model by matching hourly interconnector flows. These data were exchanged on country level for Norway, Sweden and Denmark (as opposed to zonal resolution). No flow data was defined between Finland and the continental system. For the purpose of the simulation the flows were converted into zonal resolution by assigning them to the NO_S, SE_M, DK1 and DK2 zones. The DK1 zone was assigned a fixed share of 60 %, and DK2 40 %, of the flow between Denmark and the rest of the continental European system.

3.3.1 ENERGY SYSTEM SCENARIOS

Similar to Continental Europe, the core EU-SysFlex Scenarios (**Energy Transition** and **Renewable Ambition**) for the Nordic system are built based on the EU Reference Scenarios 2016. In addition, a Network Sensitivity has been created in order to further stress the Nordic power system and to explore a potential situation in 2030 where there are much higher levels of Solar PV. This Network Sensitivity is called **High Solar**. The reason for including the High Solar scenario is the very low PV capacity in Finland, Sweden and Norway in the EU-SysFlex Scenarios. For example in the **Energy Transition** scenario, 26 MW was assumed in Finland, whereas the existing capacity in the beginning of 2019 was 120 MW. The **High Solar** scenario also assumes somewhat larger heat pump capacities in district heat generation, compared to **Energy Transition**. Otherwise, the scenario is identical to **Energy Transition**.

We should note that the scenarios do not differ much in terms of vRES share in the Nordic region. The share of vRES in **Energy Transition** scenario is 12 % and in **Renewable Ambition** 15 %. In Nordic countries, nuclear power and hydro power contribute significantly to decarbonisation. For additional detail on these scenarios, the reader is directed to the EU-SysFlex D2.2 report [3]

The analysis in this task is focused on the year 2030 and consequently we study the profitability of new investments in 2030. This requires that generation costs in 2030 must be forecasted. This introduces uncertainty, which is considered by introducing three different cost scenarios. Generation costs include the parameters $C_{inv,g}$, $C_{omf,g}$ and $C_{omv,g}$.

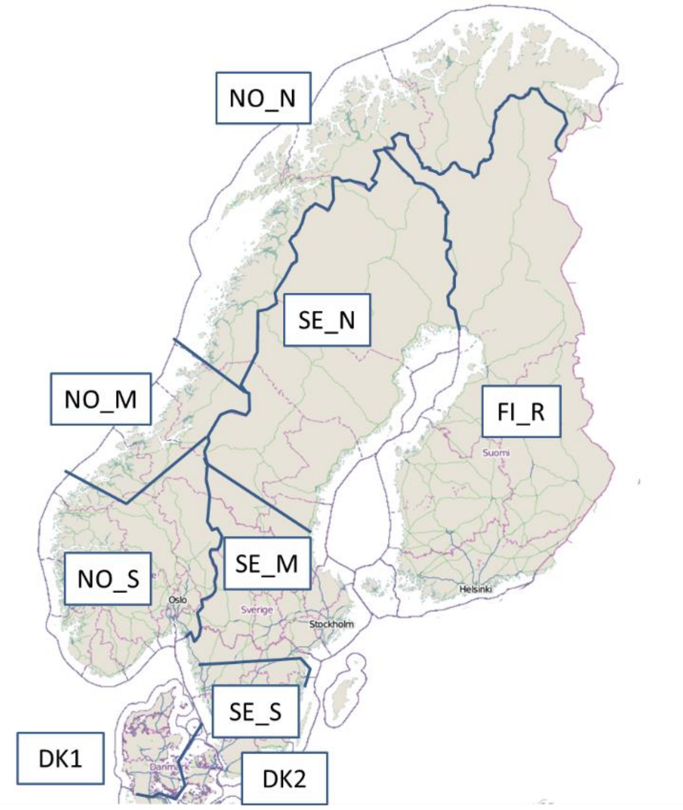

FIGURE 11: MODEL ZONES FOR THE NORDIC SYSTEM

3.3.2 COST SCENARIOS

Average wind power park and solar PV plant investment cost vary by country. This is for several reasons. Labour costs of installation and grid connection costs vary by country. Incentives targeting investment costs – such as tax credits, grants and rebates – usually result in relatively higher system prices, such as in Australia and the United States [10]. We have thus decided to use different investment cost for each of the modelled systems (in this case the Nordic system). The same decision was made for the operation and maintenance costs. However, clear cost differences could not be seen between the Nordic countries, especially when forecasted costs for 2030 were considered. Table 5 shows the forecasted costs. The estimate for wind power concerns onshore wind power.

Offshore wind power is expected to remain more expensive in 2030, although a certain amount of capacity could be available at an average production cost of €50 /MWh [11]. The estimate of solar PV concerns utility-scale ground-mounted installations.

TABLE 5: WIND AND SOLAR POWER INVESTMENT AND OPERATION AND MAINTENANCE COST

Technology	Cost Scenario	Investment Cost $C_{inv,g}$ (€/kW)	Fixed Operation and Maintenance Cost $C_{omf,g}$ (€/kW/a)	Economic Lifetime (years)
Wind	low	1040	17.6	32
Wind	base	1150	23	28
Wind	high	1300	30	25
Solar PV	low	510	6.5	32
Solar PV	base	600	10	28
Solar PV	high	700	12	25

The estimates are based on CEPA (2017), [12], [13] and [14]. The first two references list forecasts to 2030, whereas the last two concern the current situation. Salvage value of the installations at the end of their lifetime was considered to be equal to their decommissioning cost.

For the purposes of converting the investment costs into costs per MWh electricity produced, the cost of capital or discount rate is needed. Cost of capital needed for the investment is often divided into costs of different forms of financing, such as debt and equity financing, which are then summed together, taking into account the “tax shield” effect of debt, i.e. the possibility to get rebates of the corporate tax. The cost of equity financing depends on the perceived riskiness of the investment, considering also the correlation with the risks of other investment opportunities. The cost of debt financing depends on the general interest rate level of the economy and transaction costs. However, in different references it is often not specified how the cost of capital has been calculated and terminology is vague.

In the Eurozone, interest rates for lending are currently historically low. The interest rates in 2030 and beyond cannot be predicted. The assumption was made that the interest rates do not significantly increase from current levels and current published cost of capital estimates can be thus used. For example [15] estimates the “unlevered discount rate” for onshore wind as 5.5 %. The authors in [14] mention that the real interest rate for RES power plant investments has been approximately 4–5 % in 2010’s. IRENA [16] has used a much higher cost of capital 7.5 %. In this analysis we ended up using the range of costs shown in Table 6. The same cost of capital was applied to all generation technologies.

TABLE 6: COST OF CAPITAL FOR GENERATION PLANT INVESTMENTS

Cost Scenario	Discount Rate
Low	4 %
Base	5 %
High	7 %

3.3.3 NORDIC POWER SYSTEM MODEL

As mentioned in D2.2 [3], in order to supplement and complement the scenarios developed and modelled in the EDF Continental model, scenarios for the Nordic power system will be studied in more detail using the WILMAR joint market model. WILMAR is a unit commitment and economic dispatch model, which can take advantage of stochastic wind and solar power forecasts and simultaneously optimize resources for power, heat and reserve markets [17]. The model was used for production cost analysis and financial gap analysis for RES. The model was run using year 2011 weather and consumption data. A single year was simulated because of the large running time (approximately 20 hours per scenario) of the simulation.

In addition, the Stossch (Stochastic Storage Scheduler) dispatch model was used in tandem with the WILMAR model to produce more accurate long-term plans especially for hydro reservoirs. As hydro power accounts for approximately 50% of the electrical energy consumed in the **Energy Transition** scenario and Nordic hydro reservoirs are large, inclusion of the long term planning is crucial. The Stossch model plans the future operation of hydro reservoirs, other storages and power plants by taking advantage of N_s different historical years, selected from the period 1980–2001, as different stochastic scenarios. At the time of planning, it is assumed that any of the stochastic scenarios may be realized, thus precautions must be taken to e.g. avoid overexploiting of hydro reservoirs. In this analysis N_s = 8 was used as a balance between accuracy and computational burden. Figure 12 shows the architecture of the combined Wilmar JMM and Stossch models.

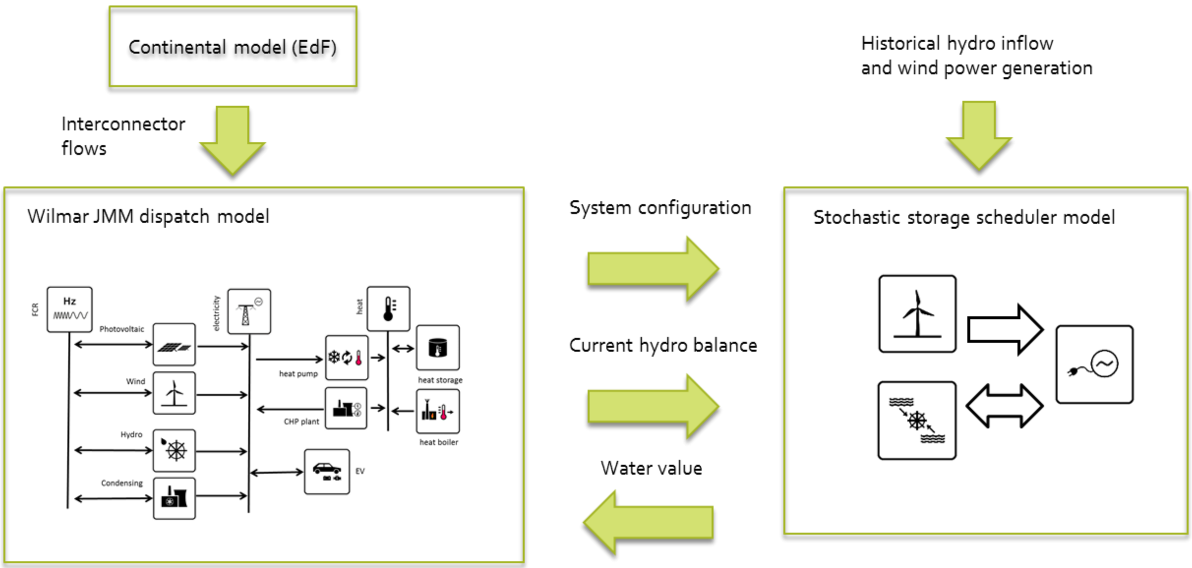

FIGURE 12: STRUCTURE OF THE UNIT COMMITMENT AND ECONOMIC DISPATCH MODEL FOR THE NORDIC SYSTEM.

3.3.4 FINANCIAL GAP CALCULATION METHOD

Calculation of the financial gap is performed by subtracting costs, C_g, from market revenues, R_g. Here the index g refers to the generation type. Furthermore the calculation is region-specific. Annual revenue is calculated by:

$$\mathrm{R}_g = \sum_t (p_t - \kappa) P_{g,t} \tag{1}$$

where p_t is the market price at time t and $P_{g,t}$ is the production of generation type g at time t. κ is the grid input tariff. For simplicity the grid input tariff was considered zero because of the complexity of grid tariffs in different countries. For example in Sweden the TSO grid tariffs vary by grid node and may be either positive or negative. In Finland the TSO grid input tariff is positive and independent of the grid node.

The analysis is to a degree simplified because the lifetime of investments is generally longer than 20 years, during which time the market prices can change. Here only one year of hourly data is used for p_t. In case of deterministically decreasing output such as in the case of solar PV, the net present value of revenues is first calculated. In a second step, this is converted into an annualized value. In other words the following equation is solved:

$$\frac{(1+\lambda)^T - 1}{\lambda(1+\lambda)^T} \mathrm{R}_g = \frac{\alpha(1+\alpha)^T}{(1+\alpha)^T - 1} \sum_t (p_t - \kappa) P_{g,t} \tag{2}$$

where λ is the cost of capital and α is the relative annual degradation. Here α=0.005 was used [12]. Annual costs are given by the following equation [18] :

$$\mathrm{C}_g = \mathrm{K}_g \left(\mathrm{C}_{inv,g} \frac{\lambda(1+\lambda)^T}{(1+\lambda)^T - 1} + \mathrm{C}_{omf,g} \right) + \sum_t \mathrm{C}_{omv,g} P_{g,t} \tag{3}$$

where K_g is the capacity of generation type g, $C_{inv,g}$ is the relative (per capacity) investment cost, T is the economic lifetime, $C_{omf,g}$ is the relative (per capacity) fixed operation and maintenance cost and $C_{omv,g}$ is the per unit variable operation and maintenance cost. $C_{omv,g}$ for solar PV was considered to be zero. For wind power it is slightly positive but for example Danish Energy Agency includes the variable cost in the fixed cost $C_{omf,g}$. In this analysis the variable cost was also included in $C_{omf,g}$.

We define the market value factor of production type g the same way as [19]:

$$\nu_g \stackrel{\text{def}}{=} \frac{\sum_t (p_t - \kappa) P_{g,t}}{\frac{1}{T} \sum_{t=1}^{T} (p_t - \kappa) \sum_{t=1}^{T} P_{g,t}} \tag{4}$$

In other words, the market value factor is the ratio of market revenues to the market revenue which would be obtained if the average market price was always received. Due to the variability of vRES and the mismatch with electricity demand, these production types tend to receive on the average lower electricity prices, thus leading to ν values below 1 [20]. Market value factor will be explored in more detail in Chapter 4.

3.4 IRELAND AND NORTHERN IRELAND POWER SYSTEM

Like the analysis for Continental Europe and for the Nordic power system, the aim of the analysis for the Ireland and Northern Ireland power system is to determine the impact of variable renewables on the power system and on market revenues for various generating technologies. The ultimate objective is to determine if there are sufficient revenues available in the energy market alone to drive the transition to high levels of renewables. In addition to this, there is an additional objective for the studies for Ireland and Northern Ireland: the evaluation of system services in 2030.

The Ireland and Northern Ireland power system is a synchronous system with limited HVDC interconnection to Great Britain. For 2019 Total Energy Requirement (TER) for Ireland and Northern Ireland was approximately 39.9TWh. Wind is the dominant source of variable renewable generation on the island and reached installed levels of over 5GW in 2019 [21]. At present, there is a significant surplus of generation plant available. However, this surplus is expected to be eroded in the coming decade by the growth in demand (particularly data centres) and expected fossil-fired plant closures (e.g. due to emissions restrictions) creating a need for new generation [21]. The power system in Ireland and Northern Ireland is currently undergoing a period of transformation and change as increased renewable generation is added to the generation portfolio in order to meet ambitious Government targets.

For Northern Ireland, the United Kingdom's Committee on Climate Change recently advised that it is necessary, feasible and cost-effective for the UK to set a target of net-zero Green House Gas (GHG) emissions by 2050. The Climate Change Act 2008 (2050 Target Amendment) Order 2019 came into effect on the 27 June 2019. The revised legally binding target towards net zero emissions covers all sectors of the economy. This update to the Order demonstrates the UK's and Northern Ireland's commitment to targeting a challenging ambition in line with the requirements of the Paris Agreement.

The Irish Government has set ambitious targets in its Climate Action Plan [22]; this states that for the electricity sector CO_2 emissions should be reduced by up to 55% by 2030. This ambition is needed to honour the Paris Agreement and represents a significant change for the electricity industry. It is an opportunity to create a sustainable electricity system that will meet the needs for the next generation. It is also stated that, as part of this plan, the following is required:

- Delivery of an early and complete phase-out of coal- and peat-fired electricity generation in Ireland
- Increase in electricity generated from renewable sources in Ireland to 70%, indicatively comprised of:

1. at least 3.5 GW of offshore renewable energy
2. up to 1.5 GW of grid-scale solar energy
3. up to 8.2 GW total of increased onshore wind capacity

3.4.1 NETWORK SENSITIVITIES FOR IRELAND AND NORTHERN IRELAND

The Network Sensitivities for Ireland and Northern Ireland were leveraged from work completed as part of Tomorrow's Energy Scenarios 2017 [23]. Each of these Network Sensitivities has its own specific storyline based on potential economic, energy policy, and technical as well as consumer behaviour developments. Across the three Network Sensitivities for EU-SysFlex, the installed renewable generation capacities for the Ireland and Northern Ireland power system vary between 9,000 MW and 15,000 MW by 2030. Thus, the Network Sensitivities for Ireland and Northern Ireland project much higher installed capacities of variable renewable generation than the EU Reference Scenario 2016 scenarios, which have approximately 6500 MW and 8300 MW of renewable generation for **Energy Transition** and **Renewable Ambition**, respectively. Consequently, the more ambitious scenarios from the Tomorrow's Energy Scenarios 2017 for Ireland plus the tailored TYNDP 2018 scenarios for Northern Ireland are the ideal sensitivities to utilise in order to stress the power system of Ireland and Northern Ireland and to identify technical scarcities and gaps in the financial mechanisms. The generation portfolios corresponding to the three Network Sensitivities are detailed in Table 7. For additional detail on these scenarios, the reader is directed to the EU-SysFlex D2.2 report [3].

TABLE 7: IRELAND AND NORTHERN IRELAND PORTFOLIOS

Installed Capacity by Fuel Type (MW_e)	IE and NI Network Sensitivities		
	Steady Evolution	Low Carbon Living	Consumer Action
Solids	-	-	-
Gas	5657	5207	5657
Distillate Oil or Heavy Fuel Oil	389	273	273
Conventional Fuel Generation	6096	5530	5980
Wind (Onshore)	6678	7040	6922
Wind (Offshore)	700	3000	1000
Wind-Total	7378	10040	7922
Hydro	237	237	237
Biomass/LFG (including Biomass CHP)	487	847	528
Solar PV	900	3916	2916
Ocean (Wave/Tidal)	50	98	73
Renewable Generation	9052	15188	11725
Pumped Storage	292	652	292
Small Scale Battery Storage	200	500	800
Large Scale Battery Storage	350	1300	500
DSM	500	750	1000
DC Interconnection	1650	2150	1650
Conventional CHP or waste	290	309	318

3.4.2 PRODUCTION COST SIMULATION MODEL FOR IRELAND AND NORTHERN IRELAND

PLEXOS is a widely utilised tool for Unit Commitment and Economic Dispatch problems, both within industry and in academia. UCED is an hourly cost minimisation problem. The algorithm in PLEXOS determines the least cost manner in which to schedule generation to meet demand for each hour of the simulation, whilst being subject to a number of operating constraints. As part of Task 2.3, EirGrid and SONI created many UCED models for the Ireland and Northern Ireland power system in PLEXOS. These models correspond to the various scenarios and Network Sensitivities (**Steady Evolution**, **Consumer Action** and **Low Carbon Living**) which have been detailed in D2.2 of EU-SysFlex [3].

Each conventional generator in Ireland and Northern Ireland is modelled individually in PLEXOS utilising both technical and commercial data. The data required to fully model a conventional generator includes parameters such as: maximum capacity, minimum stable level, heat rates, ramp rates, minimum up and down times, start times, start costs and variable operational and maintenance costs. The fuel prices for the conventional plant are based on the ENTSO-E Ten-Year Network Development Plan [24] fuel prices, which are consistent with the fuel prices utilised to develop the scenarios in Task 2.2. Hydro generation is modelled with similar constraints to the conventional plants; however, there is an additional constraint on the hydro generation units. This is a daily energy limit constraint and represents the hydrological constraints that exist for run-of-river hydro generating units. Pumped hydro energy storage is modelled in PLEXOS in such a way so as to reflect how it is operated in reality on the Ireland and Northern Ireland power system. Historical 2015 available wind power time series with an annual wind power data capacity factor in Ireland of 34% is utilised in the Network Sensitivities. The historical 2015 solar data for Ireland and Northern Ireland is employed for solar PV time series.

For the three Ireland and Northern Ireland Network Sensitivities, there is an annual profile for residential and commercial load. In addition, large industrial customers, heat pumps and electric vehicles are modelled individually. Demand side units are also modelled in PLEXOS for the Ireland and Northern Ireland Network Sensitivities. The units are modelled as negative generators, capable of reducing demand for a maximum of a few hours per day.

Inter-market HVDC interconnector flows are a fixed input to the unit commitment model. The sources of the interconnector flows are the TYNDP 2018 models for the specific Network Sensitivities. The interconnectors are modelled as generators and loads to reflect import and export respectively and the interconnectors are capable of providing reserve, when such requirements are specified in the simulations. While flows are fixed on the interconnectors, counter trading of exports is permitted to ensure that no loss of load events occur.

The Automated Plexos Extraction tool (APE) is a Python based tool that has been developed for quick and efficient extraction of outputs from PLEXOS. APE extracts the PLEXOS .csv files and creates a Microsoft Excel spreadsheet output detailing the hourly commitments and dispatches for each plant for each hour of simulated year.

From the hourly dispatches, capacity factors for all generation types are calculated as the share of annual energy output of the maximum theoretical annual output, i.e. in hourly time resolution, as shown in Equation 5 below.

$$capacity\ factor = \frac{\sum_{t=1}^{8760} Generation_t}{Installed\ capacity\ \times 8760\ hours} \tag{5}$$

APE also has functionality for calculating a number of key metrics. These metrics include the RES-E level for the simulation year, the max potential Rate of Change of Frequency (RoCoF) for each hour, the inertia level for each hour of the simulation and the SNSP level for each hour. Together, PLEXOS and APE produce a wide variety of results and outputs including the least cost dispatches for all units for each hour of the simulation period as well as the total system operating costs. Additionally, the model indicates total net demand, taking IC flows and storage into account. Furthermore, the tools determine the level of renewable curtailment or dispatch down levels.

3.4.3 OPERATIONAL POLICY ASSUMPTIONS FOR THE IRELAND & NORTHERN IRELAND POWER SYSTEM

In order to evaluate the production costs, it is necessary to consider models with and without adequate provision of system services to facilitate high vRES levels. Where system services provision is adequate many operational constraints present in today's policies can be relaxed. The two most significant constraints when operating the transmission system in Ireland and Northern Ireland power system at present are System Non-Synchronous Penetration (SNSP) and maximum instantaneous Rate of Change of Frequency (RoCoF).

The SNSP formula can be defined as follows [25] in Equation 6:

$$SNSP(\%) = \frac{Non - Synchronous\ Generation + Net\ Interconnector\ Imports}{Demand + Net\ Interconnector\ Exports} \text{ x } 100 \tag{6}$$

A constraint is included explicitly in the PLEXOS model to calculate SNSP and limit the SNSP. The current SNSP limit on the Ireland and Northern Ireland power system is 65%, with a goal of reaching 75% by 2020. By 2030 it is envisaged that this SNSP limit will be either increased to approximately 90% or will be completely removed.

A second constraint which is explicitly implemented into PLEXOS is a Rate of Change of Frequency (RoCoF) constraint which calculates the maximum instantaneous RoCoF which would be seen on the system for the loss of any infeed on the system. The N-1 RoCoF constraint is calculated as in Equation 7:

$$RoCoF\ = \frac{f^{nom}.\max\{p_t\}}{2.(System\ Inertia)} \tag{7}$$

where f^{nom} is the nominal frequency (i.e. 50Hz) and $\max\{p_t\}$ is the largest potential contingency at time *t.* The current RoCoF limit on the Ireland and Northern Ireland power system is 0.5 Hz/s measured over a 500ms timeframe. This is to be increased to 1 Hz/s in 2020. It is highly unlikely that the RoCoF limit on the Irish power system will be increased above 1Hz/s by 2030. Thus, the 1Hz/s RoCoF, as will be discussed later, is included in all simulations apart from, of course, the unconstrained market run. The ability to implement this RoCoF constraint in PLEXOS allows for the scheduling of sufficient inertia on the power system to ensure the maximum instantaneous RoCoF limit is not breached.

In addition, at present for system stability reasons, current operational policy requires that a minimum number of large conventional generating units are online at all times [26]. In order to accommodate greater levels of non-synchronous renewable generation, the minimum number of units constraint will have to be lowered. This, however, will expose a number of technical scarcities that will need to be surmounted, scarcities which are being investigated in Task 2.4.

Analyses of production costs are performed for the Network Sensitivities with varying wind levels. In addition, three key cases relating to operational policies are described below:

- 2030 Market Run (MARUN): This is a case set up to simulate the energy only market. There are no system operating constraints incorporated into the model. It is these simulations that are used to perform the financial analysis.
- 2030 Business as Usual (BAU): This represents 2020 operational policies including a maximum SNSP limit of 75% and a RoCoF limit of 1Hz/s. In addition it is required that a minimum of 7 large synchronous generator units are online at all times and in specific geographical locations. There are also operating reserve requirement constraints included in the model.
- 2030 Enhanced Operational Capabilities (EOC): It is assumed that the technical scarcities can be mitigated through provision of system services and that these services are provided by the range of different technologies in the portfolio. These services are modelled by assuming enhanced operational capability of the power system. This enhanced operational capability is modelled by removing the 75% SNSP limit as well as the requirement that a minimum number of large synchronous generators must be online in each time period. The RoCoF limit of 1 Hz/s is not removed as it is not envisaged that this will change in the near future. The operating reserve requirements continue to be included in the model; findings from Task 2.1 and analysis from Task 2.4 show that there will continue to be a significant requirement for carrying additional capacity in the form of operating reserves and in many cases this requirement will actually increase.

This information is summarised below in Table 8:

TABLE 8: SUMMARY OF CASES FOR EXAMINATION IN THE PRODUCTION COST SIMULATIONS

Case	SNSP Limit	RoCoF Limit	Operating Reserve	Min. Units
2030 Market Run (MARUN)	-	-	-	-
2030 Business as Usual (BAU)	75%	1 Hz/s	Yes	7
2030 Enhanced Operating Capability (EOC)	-	1 Hz/s	Yes	-

3.4.4 FINANCIAL GAP CALCULATION METHODOLOGY AND ASSUMPTIONS FOR THE IRELAND AND NORTHERN IRELAND POWER SYSTEM

The specific approach adopted to determine the financial gaps for the Ireland and Northern Ireland requires the revenue outputs from the PLEXOS production cost simulations. The energy revenue is determined from PLEXOS using market model runs (or MARUN). Revenue per generator for a particular interval can be calculated as the product of the system marginal price per interval and the corresponding generator MW output for that interval. The revenue is determined for every hour in the year 2030.

The revenues available are compared with fixed, variable and capital costs to determine if there is a financial gap or missing money. For energy and service providers, capital costs represent the total installed cost including grid connection and development. Capital costs typically include items such as Engineering, Procurement and Construction (EPC) contract price and timeframe, Site procurement costs, Electrical interconnection costs, Financing Fees, insurance, among others. In order to determine the capital costs borne for individual technologies on a per MW basis, a blend of publically available data is utilised.

For new technologies, the Department of Communications Climate Action and Environment has published a report entitled, “Economic Analysis for a Renewable Electricity Support Scheme in Ireland” [27]. This report contains €/kW capital costs for a range of technologies including, wind, solar, geothermal, ocean, hydro, waste to energy and bio energy. There are three scenarios listed, high medium and low, and we study cases with all three scenarios (see Table 9 below). The World Economic Outlook figures are also considered. These are especially useful when studying results across all regions studied within this task.

In order to estimate the annual capital costs for technologies for the year 2030, a formula for Equivalent Annual Cost (EAC) is employed. This takes into account a discount rate and expected lifetime of a unit (t) to capture the capital costs accrued in the year 2030. The equation for EAC is as follows:

$$EAC = \frac{Invested\ Capital\ \times Discount\ rate}{1-(1+Discount\ rate)^{-t}} \tag{8}$$

TABLE 9: COSTS USED IN FINANCIAL MODELLING FOR IRELAND AND NORTHERN IRELAND [17]

Technology	Cost Scenario	Capital Costs (€\kW)	Fixed Costs (€\kW)
Onshore Wind	High	1811	68
	Medium	1413	49
	Low	1120	34
Offshore Wind	High	3803	110
	Medium	2836	89
	Low	1823	58
Solar	High	3803	110
	Medium	2836	89
	Low	1823	58

The discount rate is the interest rate used to determine the present value of future cash flows in standard discounted cash flow analysis. Many companies calculate their weighted average cost of capital (WACC) and use it as their discount rate when budgeting for a new project [28].

TABLE 10: DISCOUNT RATES USED IN FINANCIAL MODELLING OF IRELAND AND NORTHERN IRELAND POWER SYSTEM

Case	Discount Rate
High	5%
Medium	4%
Low	3%

Additionally, the Regulatory Authorities (RAs) in Ireland and Northern Ireland publish a report on the financial performance of generators in the Ireland and Northern Ireland electricity market [29]. These reports provide aggregated information on the financial performance of generators in the Ireland and Northern Ireland electricity market as a whole, as well as breakdowns by generation fuel source and generation type. The purpose of these reports is to enhance transparency around generator remuneration in the SEM while respecting individual generator commercial sensitivity by presenting aggregated information only. For existing units in SEM, capital costs accrued are based on information published in these reports. Existing technology types for which this information is used include, thermal, hydro, pumped storage and some wind.

In order to determine operational running costs for individual generators, the total generation cost is extracted from PLEXOS; this cost includes start costs as well as fuel and emission costs. The fuel prices for the conventional plant are based on the ENTSO-E Ten-Year Network Development Plan (TYNDP) [24] fuel prices, which are consistent with the fuel prices utilised to develop the scenarios in Task 2.2. In addition for wind, from the Generator Financial Performance report, fuel related operating costs were included for wind.

Statutory corporation tax rates of 12.5% [30] in Ireland and 17% in Northern Ireland [31] are employed for new units. For existing units, tax information provided in Generator Financial Performance Reports published by the RAs is used.

Net Operating Profit after Tax (NOPAT) for each unit is determined based on Revenue minus cost items as categorised above. The formula for NOPAT used is as follows:

$$NOPAT\ = Revenue - Production\ Cost - EAC - Annual\ Fixed\ Costs - Tax\ \&\ Interest \tag{9}$$

This formula is used for new units. For existing technologies, depreciation costs from the Generator Financial Performance Reports are used instead of Equivalent Annual Costs.

The return on invested capital (ROIC) is the percentage amount that a company is making for every percentage point over the cost of capital. More specifically, the return on investment capital is the percentage return that a company makes over its invested capital. The equation for ROIC is as follows:

$$ROIC = \frac{NOPAT}{Invested\ Capital} \tag{10}$$

For a particular study year, this formula is adapted to be:

$$ROIC = \frac{NOPAT}{Equivalent\ Annual\ Cost} \tag{11}$$

For the purposes of these studies, a ROIC of between 5 and 10 % has been assumed. This aligns with trends reported in industry [32]. The concept of a 'Required ROIC' can be used as a means to extract any financial gaps that exist and make investment in particular technologies infeasible. Ideally technologies should face no financial gaps (i.e. 0 gap) and NOPAT/EAC should yield sufficient returns for financial viability. However for certain technologies, there may be no NOPAT or it is so small it does not allow for investment. In cases such as this, the required ROIC can be defined as follows:

$$Required\ ROIC = \frac{(NOPAT + Gap)}{EAC} \tag{12}$$

The Gap represents a financial shortfall and is based on the difference between what NOPAT should be to yield sufficient return and the actual outturn NOPAT. Using simple manipulation of formula, the financial gap can be expressed as:

$$Gap = Required\ ROIC \times EAC\ - NOPAT \tag{13}$$

3.4.5 EVALUATION OF SYSTEM SERVICES METHODOLOGY FOR THE IRELAND AND NOTHERN IRELAND POWER SYSTEM

This part of the analysis relies on the production cost outputs from PLEXOS and focuses on determining on the financial benefit (or value) which can be achieved by enhanced operational capability and system services. In developing the methodology for the Ireland and Northern Ireland system, an approach utilised as part of an earlier study conducted by EirGrid in 2012 [33] is employed. That analysis showed that investment in enhanced operational capability of the transmission system and provision of system services from alternative sources to conventional plant is a key factor in reducing wind curtailment and consequently allowing increased variable renewables on the transmission system without compromising system security. That particular approach involved two evaluation methodologies and these are being employed here and relies on the 2030 Business as Usual (BAU) case and the 2030 Enhanced Operating Capability (EOC) case discussed in Section 3.4.3.

1. The first methodology assumes that windfarms will only build, and thus renewable targets will only be met, if the curtailment (or dispatch down) levels are low enough. Crucially, it is assumed that system services are required in order to ensure that the curtailment levels are sufficiently low. In order to determine the benefit associated with system services the change in production costs between a Business As Usual case without additional renewables investment and a case with additional renewables investment as well as Enhanced Operational Capability, which is used to model system services.

2. The second methodology of the methodology assumes that renewable investment will be realised irrespective of curtailment levels. The introduction of system services (through the Enhanced Operational Capability) results in a reduction in system dispatch balancing costs and therefore the value of adopting system services is the dispatch balancing cost savings between the Business As Usual case and the Enhanced Operational Capability case, without a change in renewable levels.

It could be seen that the first methodology represents an overestimation of the value as consideration of the capital cost of investing in renewables is required. Additionally, it could be argued that the second methodology is an underestimation of the benefit of system services as it suggests that the build of new renewables is not linked at all with the introduction of system services.

The EirGrid 2012 study noted that a range of external factors that could also be considered in determining the value of system services. These external factors, or externalities, include emissions trading benefits and potential reduced penalties for not meeting binding RES targets. Additionally, consideration could also be given to the benefits associated with the ability of the power system to support sector coupling, notably electrification of heat and transport. No such consideration was given in the 2012 study [33]. However, in this report, in Chapter 6, an effort is made to estimate the potential value that could be assigned to the decarbonisation of a portion of the heat and transport sector in Ireland and Northern Ireland.

3.5 SUMMARY OF ANALYSIS, MODELS AND METHODOLOGIES

Though the aims of all the different models and methodologies presented above are all broadly similar[5], there are some differences between the models and there are some parts of the analysis which are complementary, but distinct. Table 11 provides a summary of the study aims and models to put the results which follow in Chapter 3 and Chapter 4 into context and to allow for a comparison.

TABLE 11: OVERVIEW OF THE STUDIES AND MODELS BEING EMPLOYED IN TASK 2.5

Power System under Analysis	Aim of Analysis	Model	Analysis Type	Outcomes
Continental Power System	Determination of the impact of renewables on the power system and on market revenues. Understanding of the financial gaps.	UC/ED	Production cost and financial gap analysis	Total production costs, curtailment levels, carbon emission reductions, revenues, market value factors, financial gaps.
	Comparison of costs of grid investment and costs of providing system services for mitigating voltage scarcities.	Network model	Voltage stability analysis and cost comparison	Costs associated with mitigating voltage issues using grid investment, costs associated with procuring enhanced system services.
Nordic Power System	Determination the impact of renewables on the power system and on market revenues. Understanding of the financial gaps.	UC/ED	Production cost and financial gap analysis	Total production costs, revenues, market value factors, financial gaps.
All-Island Power System of Ireland and Northern Ireland	Determination of the impact of renewables on the power system and on market revenues. Understanding of the financial gaps. Understanding of the advantages of moving to an enhanced operating regime. Determination of the value of System Services.	UC/ED	Production cost and financial gap analysis.	Total production costs, curtailment levels, carbon emission reductions, revenues, market value factors, financial gaps system services value.

[5] i.e. determination of the impact of variable renewables on the power system and on market revenues and financial gaps etc.

4 PRODUCTION COST ANALYSIS: HOW THE POWER SYSTEM IS TRANSFORMED BY VARIABLE RES

This section will look at the outcomes of employing the scenarios and models as discussed in Chapter 2. The implications of adding large shares of variable RES into the Continental European power system, the Nordic power system and the Ireland and Norther Ireland Power System are introduced and discussed.

This section is structured as follows: results and key messages from the pan-European power system analysis, followed by the results from the specific system analysis, including some case studies of particular regions. A summary of all the findings concludes this Chapter.

4.1 DEVELOPING VARIABLE RES HAS A SMALL IMPACT ON THE NEED FOR CONVENTIONAL PLANTS

In this section, we take **Renewable Ambition** as a reference with a vRES share of 34% for the European power system and we modify the share of vRES. A sensitivity is performed with a vRES share of 23% which corresponds to the share of vRES in **Energy Transition**. However, the rest of the generation mix is different than **Energy Transition**. Two more sensitivities with 45% and 55% variables RES shares are added. To construct the three sensitivities, CCGT and peaking plants are adjusted economically for each vRES share so that there is at most 3 hour of loss of load per country in Europe and adequate level of service is provided to consumers. Therefore, CCGT and peaking plants will cover their costs[6] by construction for the European power system. In Section 5 on market revenues and costs analysis, the gap analysis for the Continental System will, as a consequence, not be performed on CCGT and peaking plants but only on RES.

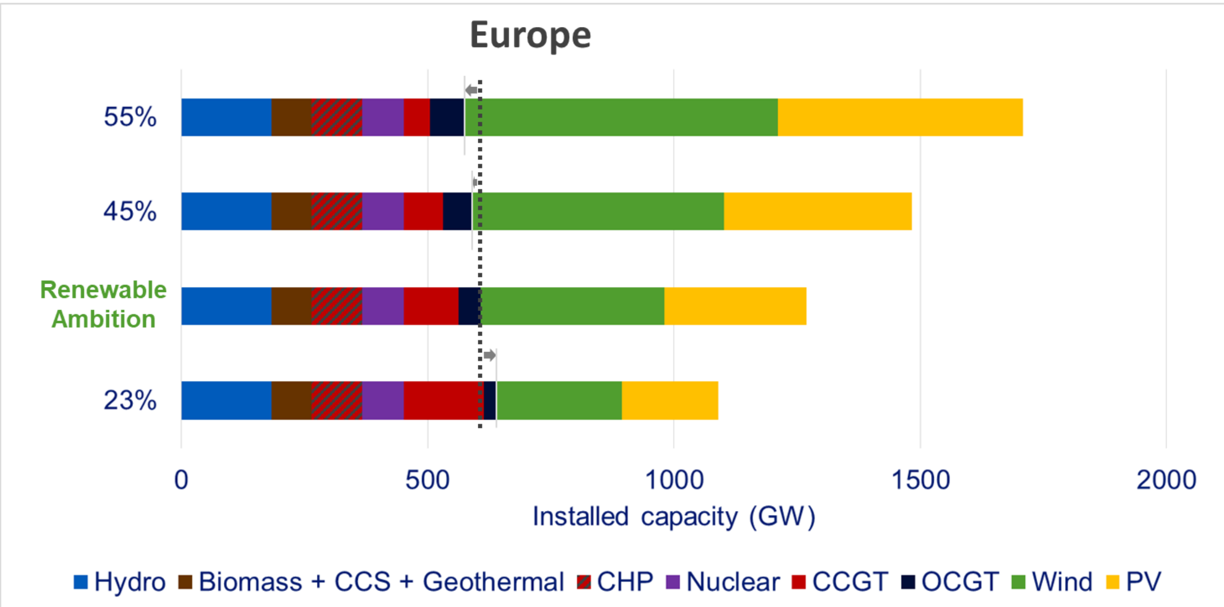

FIGURE 13: INSTALLED CAPACITY BY TECHNOLOGY DEPENDING ON THE VRES SHARE IN THE EUROPEAN SYSTEM

[6] Assuming that the marginal price of the system is very high during loss of load hours (€20 000 /MWh).

Figure 13 shows the installed capacity by technology for each vRES share. The installed capacity of conventional plants decreases with the integration of more vRES. However, the decrease in capacity is small relative to the capacity of vRES installed. The decrease in gas plants (CGGT+OCGT) between a vRES share of 55% and **Renewable Ambition** with a vRES share of 34% is around 35GW European-wide. This is to be compared with a combined additional installation of wind and solar of 470GW. From 23% vRES share to the **Renewable Ambition** share, the ratio of newly installed vRES compared to decommissioned gas plants is 1-to-6, but it sharply increases for higher shares of vRES. This is because vRES production, in particular solar production, is often not available at peaking time.

Developing vRES has a small impact on the need for conventional plants. Additional vRES capacity does reduce the installed capacity for gas plants but not on a 1-to-1 ratio. The ratio is close to 1GW of decommissioned gas plants for 6GW of newly installed wind and solar in the beginning but increases sharply for higher shares of vRES.

4.2 THE NEED FOR PEAKING PLANTS IS INCREASING WITH VARIABLE RES SHARE

The European-wide installed capacity for CCGT and OCGT is detailed in Figure 14. The installed capacity of CCGTs (red) drops by about 60GW when the vRES share increases from 34 % to 55 %. However, at the same time, the installed capacity for OCGT (black) increases by 25GW. This leads to a ratio of 1-to-2.5. At high vRES shares, peaking plants supplement vRES when there is no wind or sun. The total running time for thermal plants does not allow for a larger installed capacity of CCGTs to cover their costs, and therefore, peaking plants with lower investment costs but higher CO_2 emissions make it possible to offer an adequate level of service to customers at a lower price. The CO_2 price of 90 €/tCO_2 from **Renewable Ambition** is quite high compared to current levels but not sufficient to tilt the economics towards a larger number of less carbon intensive CCGTs.

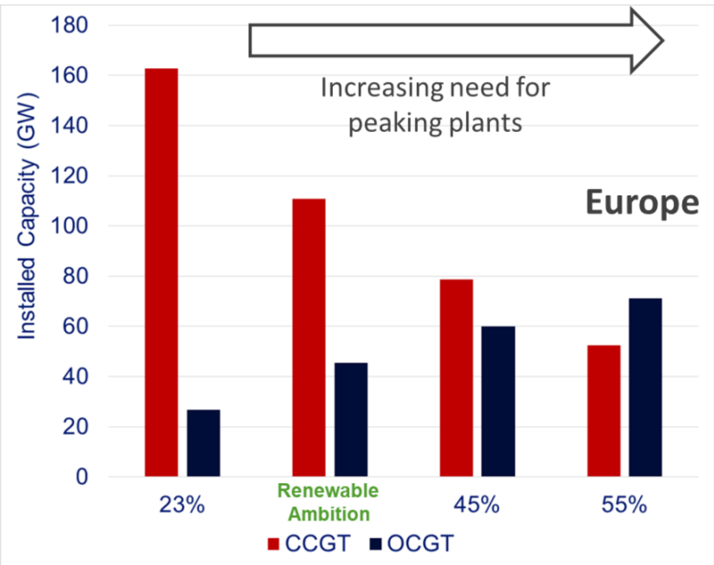

FIGURE 14: INSTALLED CAPACITY FOR CCGT AND OCGT DEPENDING ON THE VRES SHARE IN THE EUROPEAN POWER SYSTEM

The need for peaking plants (OCGT) is increasing with vRES shares as the need for CCGT is decreasing with a ratio of 1 to 2.5.

4.3 LOAD FACTORS FOR CCGT ARE DECREASING SHARPLY WHEN VARIABLE RES SHARE INCREASES

Figure 15 shows the European-wide load factors for CCGT (red) and OCGT (black) for different vRES shares. The load factors for CCGT are decreasing sharply when the vRES share increases. It plummets from 57 % to 16 % when the vRES share increases from 23 % to 55 %. At the same time, the load factor for the peaking plants is multiplied by more than 2 and increases from 1 % to 2.5 %.

This result underlines the fact that it will be harder for CCGT to balance economics in a power system with a large share of vRES. Also, because peaking plants have higher CO_2 emissions than CCGT plants, it is expected that CO_2 emissions reductions will taper off as the share of vRES increases. This will be shown in Section 4.5.

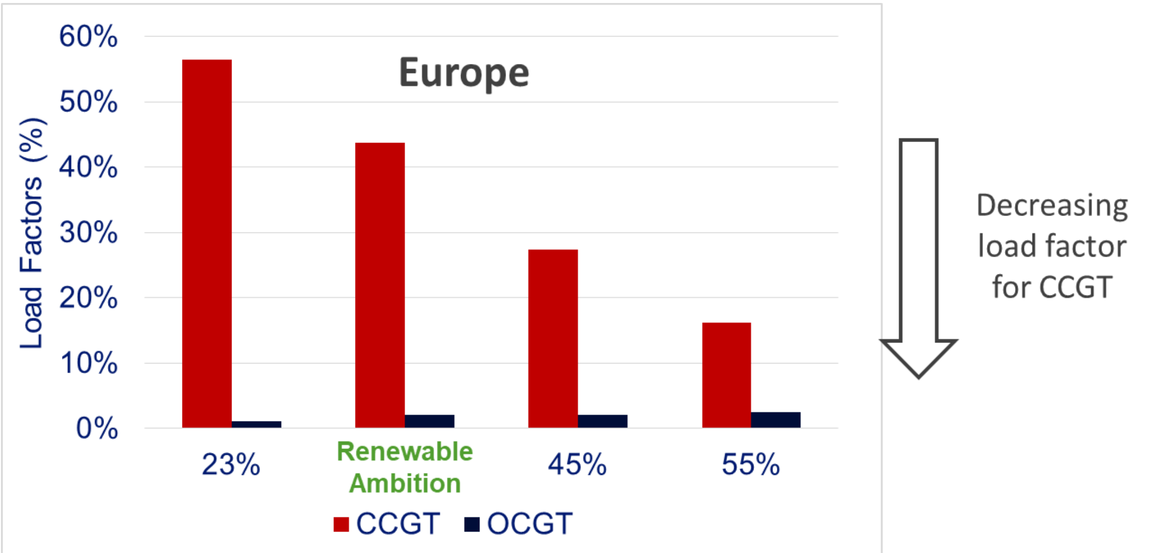

FIGURE 15: LOAD FACTORS FOR CCGT (RED) AND OCGT (BLACK) DEPENDING ON THE VRES SHARE

Load factors decrease sharply for CCGT while load factors for peaking plants are multiplied by 2.

4.4 TIMES WITH VARIABLE RES GENERATION EXCEEDING DEMAND INCREASE SHARPLY

The load factor could also be smaller for vRES without additional levers such as storage, exports or demand shifting. Figure 16 shows the share of vRES production that is curtailed depending on the vRES share in the European power system. At 23% vRES, there is almost no curtailment while more than 10% of the production is curtailed at 55% vRES.The hours of curtailment correspond to hours where RES production exceeds demand and storage through pumping hydro stations available in **Renewable Ambition** are not able to store the energy. Interconnections assumptions are favourable and allow to pool RES production and customer demand at a

European level. An example is given in Section 4.6. Indeed inside a country or a zone, there might be congestions that could potentially lead to more curtailment if not addressed.

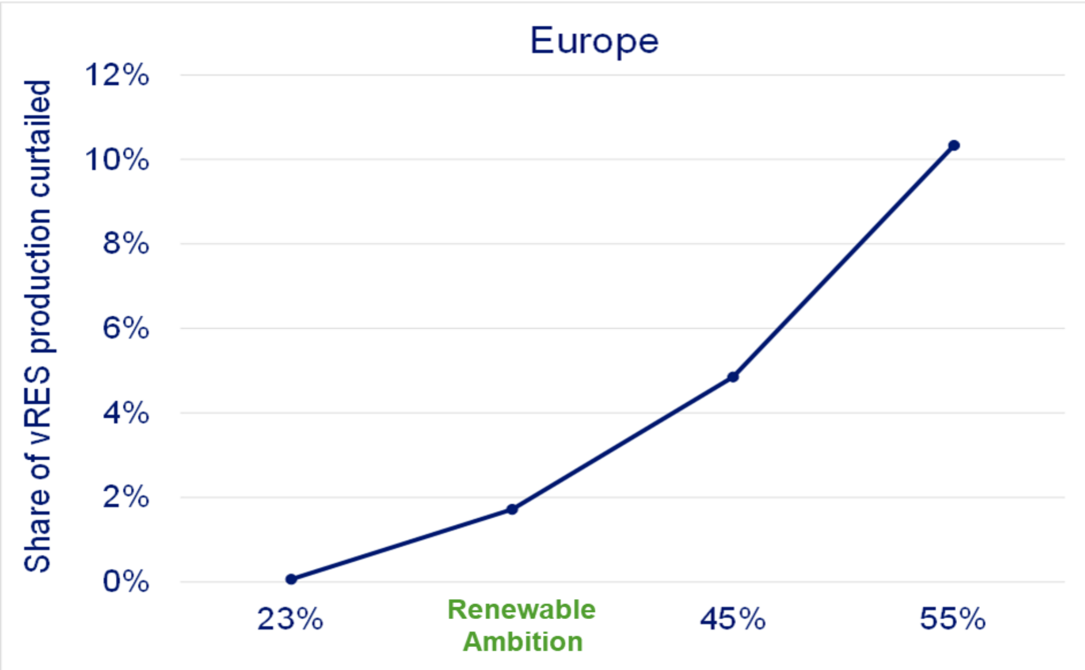

FIGURE 16: SHARE OF VRES PRODUCTION THAT IS CURTAILED DEPENDING ON VRES SHARE IN EUROPEAN POWER SYSTEM.

The number of hours when RES production exceeds demand increases sharply.

4.5 THE REDUCTION OF DIRECT CO_2 EMISSIONS BY ADDING VRES IS SLOWING DOWN WHEN THE POWER SYSTEM IS ALREADY LOW CARBON

A significant benefit of renewables and a significant positive impact that they have on the power system relates to carbon emission reduction. Simply adding additional renewable capacity succeeds in displacing carbon intensive fossil fuel generation.

This section discusses the CO_2 emissions analysis performed using the EU-SysFlex scenarios and sensitivities. The change in CO_2 emissions is illustrated in Figure 17. The EU-SysFlex scenarios are 2030 **Energy Transition** and 2050 **Renewable Ambition**. The differences between the two scenarios are multi-fold.

The first difference is that the share of vRES changes from 23% to 34%. However, there are additional first order drivers. In particular, the CO_2 prices are different. The CO_2 price increases from €27/tCO_2 in 2030 **Energy Transition** to €90/tCO_2 in 2050 **Renewable Ambition**, thereby yielding different, usually less carbon intensive, generation mixes in each European country. One of the main differences between the two scenarios is the decommissioning of a large share of coal-fired plants at the European level. This accounts for 84 gCO_2/kWh of the CO_2 intensity reduction between 2030 **Energy Transition** and the 2050 23% vRES share sensitivity. The sensitivity has the same 23% variable share of RES than 2030 **Energy Transition** but is based on the same mix than 2050 **Renewable Ambition** completed with CCGT and peaking plants to meet the loss of load criteria. Therefore, the 2050 23% vRES sensitivity is less carbon intensive. Adding vRES while adjusting for loss of load criteria with CCGT and OCGT decreases the CO_2 intensity of the electricity produced as shown in Figure 17. However, the slope tapers off as the vRES increases because of a higher capacity in peaking plants. Between a vRES share of 45% and 55%, the difference is 8g CO_2/kWh.

Computing the total cost difference[7] between the two power systems, the cost of avoided CO_2 is €480/ton which emphasizes the message from the IEA on deep decarbonisation (Source: WEO 2019). There is no single or simple solution to reach deep decarbonisation. The most efficient way to lower CO_2 emissions is to pool carbon-free technologies together in all sectors of economy in a drastic way.

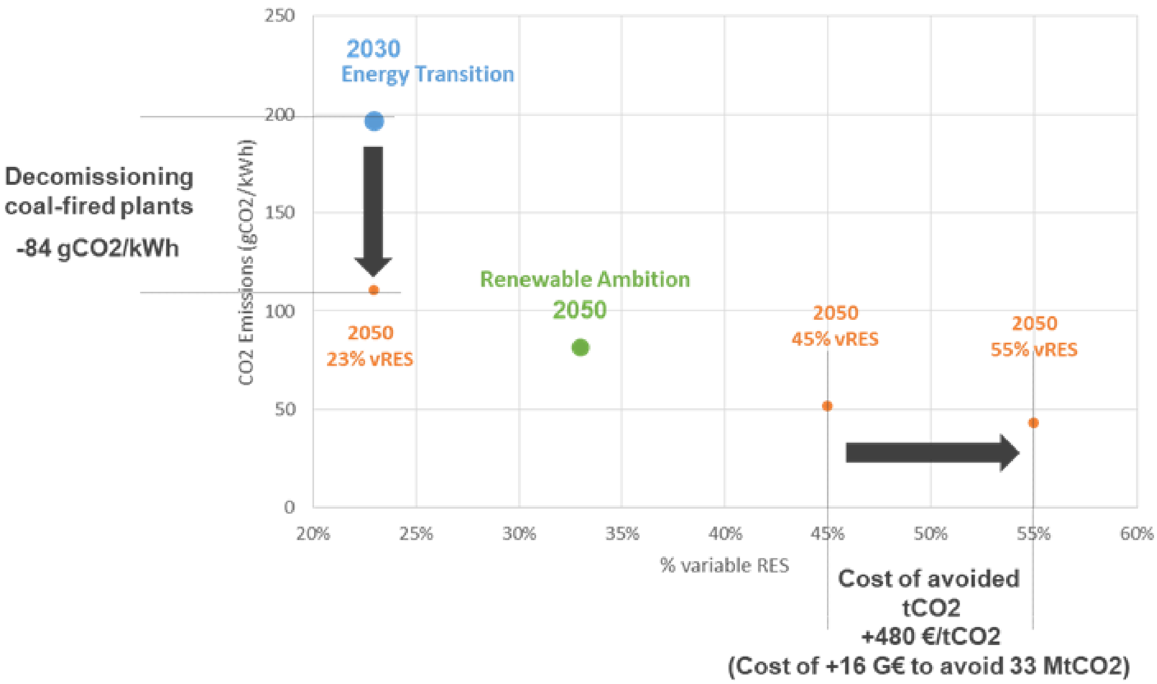

FIGURE 17: DIRECT CO_2 EMISSIONS PER KWH[8] DEPENDING ON THE VRES SHARE IN THE EUROPEAN SYSTEM

The reduction of direct CO_2 emissions by adding only vRES is tapering off when the power system is already low carbon.

[7] The total cost difference between the two systems takes into account the difference in CAPEX from new investments in vRES and peaking plants as well as avoided investments in conventional plants and reductions in operating costs.
[8] From the EU-Reference scenarios, the 2020 figure for carbon emissions for the power sector is around 260 gCO_2/kWh.

4.6 SYSTEM SPECIFIC FINDINGS – CONTINENTAL EUROPEAN POWER SYSTEM : CASE STUDY OF GERMANY

This section presents two distinct examples which illustrate some of the potential issues associated with curtailment and a loss of load. These examples are shown for Germany which has a 66% share of vRES in the 2030 scenario and are based on the analysis of the European simulation model.

Case Study 1: Curtailment

Figure 18 shows power generation by technology, associated marginal costs and imports/exports for Germany on a two-week period in the spring (for one of 165 climate & outage scenarios). On the graph, periods of large vRES generation (green for wind and yellow for solar) illustrated in purple are alternating with periods of low vRES generation, in particular low wind generation, circled in turquoise. By convention in this graph, the curtailment is hashed and is materialized on solar generation first, as solar generation is the technology highest on the graph.

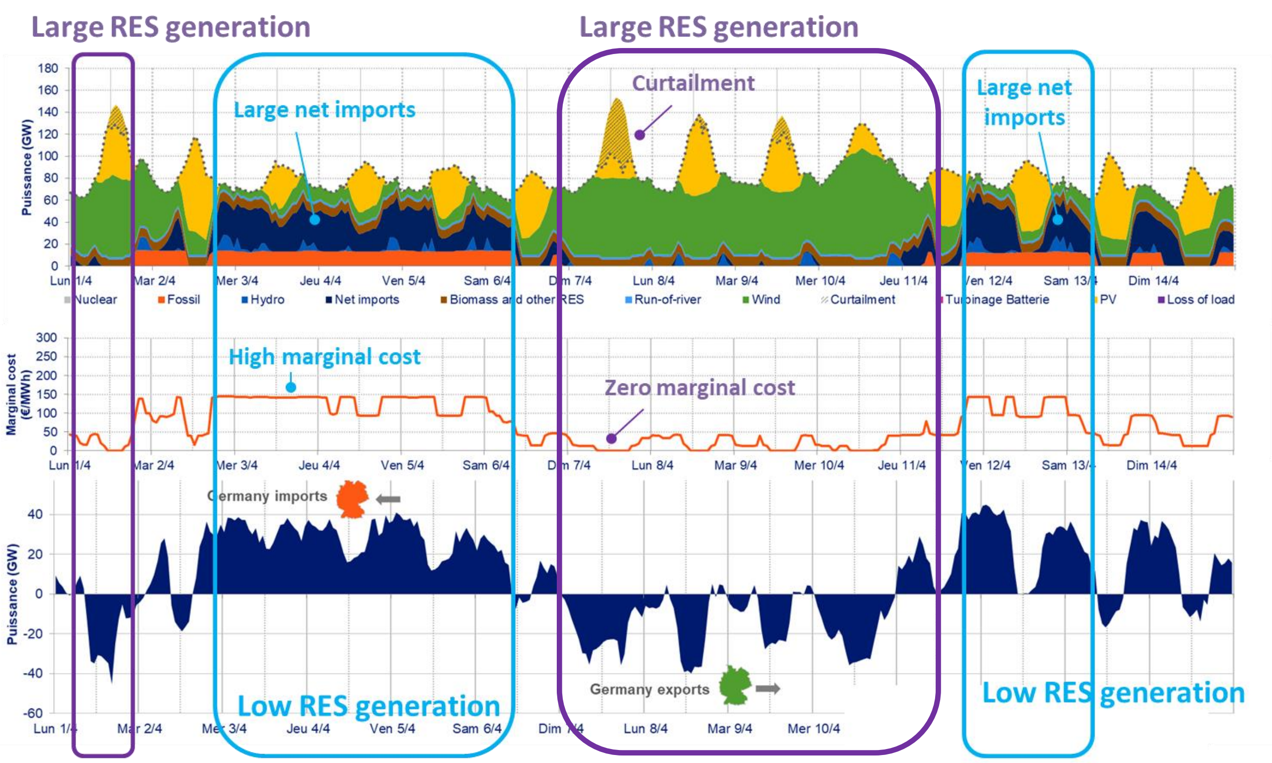

FIGURE 18: POWER GENERATION BY TECHNOLOGY, MARGINAL COSTS AND IMPORTS/EXPORTS FOR A CURTAILMENT EPISODE

In the middle of the day, on days with large wind generation, generation exceeds demand in Germany despite close to 40GW of exports to its neighbours, as shown on the bottom-most graph. The curtailed generation (hashed) can reach 20GW or even 60 GW on some days. At the same time, marginal costs drop to zero in the middle of the day, and remain moderate during the entire day.

When wind production is low, fossil-fired plants (orange) and hydro (medium blue) are started but their installed capacity, and therefore generation is modest, relative to the demand to be addressed. Germany must then heavily rely on its neighbours with levels of imports (dark blue) that reach 40GW. 40GW represents roughly half of the German interior demand on these days. At the same time, the marginal costs are high and remain high for the entire period where there is little wind.

Case Study 2: Loss of Load

Figure 19 shows power generation by technology, associated marginal costs and imports/exports for Germany on a two-week period in the winter. This example exhibits hours of loss of load, which are shown in purple on the graph. By design, investments in CCGT and OCGT have been made so that there is at most 3 hour of loss of load on average for the 55 different climate years taken into account.

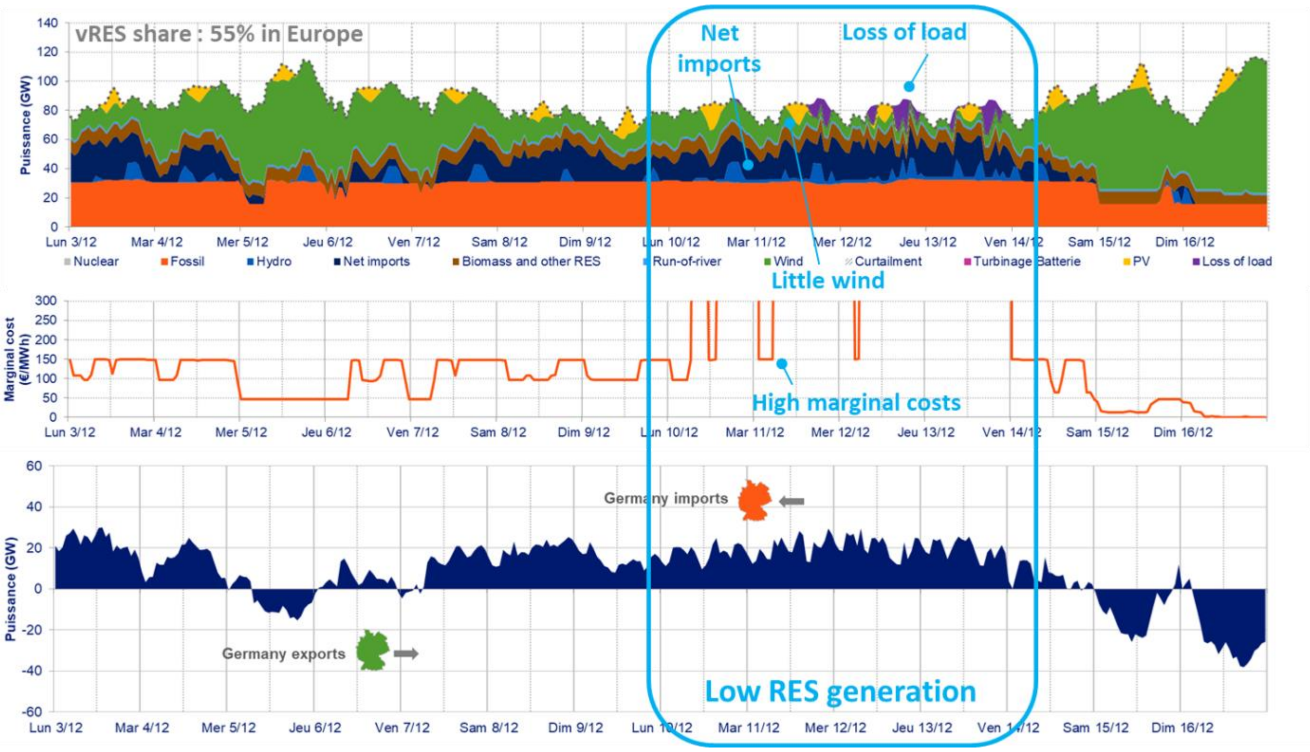

FIGURE 19: POWER GENERATION BY TECHNOLOGY, MARGINAL COSTS AND IMPORTS/EXPORTS FOR A LOSS OF LOAD EPISODE

In early December, the generation of solar (yellow) is low. Fossil-fired plants (orange) are on and produce close to their maximum capacity for the entire two-week period. When the wind generation is very high but the demand is low, i.e. week-end of the 15/12 and 16/12, exports are high and fossil-fired plants production can be dispatched-down. At the same time, marginal costs drop to close to zero. When both wind production and demand are high, i.e. Wednesday 5/12, a small volume of German production is exported towards its neighbours, and the marginal costs are moderate.

The graph shows several episodes where there is little wind. On Monday 3/12, and the days between the 8/12 and the 14/12, Germany must rely steadily on imports (dark blue) from its neighbours for about 25% to 34% of its demand. In the beginning of the period, neighbours can supply adequate generation, and marginal costs are high but there are no loss of load hours. In the period circled in turquoise, the situation is very tight; there is missing generation (purple) to fulfil the German demand and consequently marginal costs are increasing.

It is clear from this case study that high levels of variable renewables create challenges for scheduling of generating units to continuously meet supply and demand. These examples highlight the importance of interconnection and and also illustrate how curtailment measures can be required.

Curtailment and Loss of Load can be more difficult to manage at high levels of vRES, especially during times when RES generation is low for short durations.

Furthermore, in Germany, there is a rapid increase in the number of generating units connecting at the distribution level. While this is true of many distribution grids in Europe, the focus here is on Germany as a specific case study. In general, and as is the case in Germany, distribution grids were not designed for operation with high levels of embedded generation, the possible simultaneity of their operation and the likelihood of new peak loads. These high levels of embedded generation are leading to congestion at both the transmission and distribution level. One of the mechanisms for reducing congestion is curtailment. The main challenge with curtailment in Germany lies in the fact that RES generators are currently fully remunerated for any energy that is curtailed. This leads to curtailment costs in Germany of over €600 million per annum at present [34].

Moreover, curtailment measures alone are far from sufficient in counteracting grid congestion in distribution and transmission grids caused by high levels of renewables. RES curtailment levels in Germany can be as high as 6,000 GWh, while redispatch levels can be as high as 20,000 GWh per annum [34]. Consequently additional expensive redispatch measures within the grids are necessary every day to ensure secure grid operation, leading to further costs. It has been estimated that curtailment and redispatch measures could exceed €1.5 billion per annum [34]. When these costs are combined with the high costs of network investment that are already taking place in Germany, it is clear that there is a considerable challenge. It is proposed that there is significant value in mechanisms and solutions that can reduce congestion and curtailment, both now and in the future. As part of this project, some guiding principles that could be employed to mitigate the impact of curtailment and congestion in Germany are outlined in section 6.1.2

Congestion and curtailment measures in Germany are increasingly expensive but vital to ensure secure grid operation.

4.7 SYSTEM SPECIFIC FINDINGS - NORDIC POWER SYSTEM

The capacity factors of gas plants have been analysed with higher RES capacity in the Nordic system. For the entire pan-European power system it was found that capacity factors of CCGT plants decrease sharply when RES capacity increases. In the Nordic system this can be analysed by comparing the **Energy Transition** and **High Solar** scenarios. Interestingly, it is seen that a similar effect does not take place in the Nordic system when the increased RES consists of solar power. This can be explained by the seasonal differences in the operation of solar PV and gas condensing plants. In the Nordic systems gas-fired plants are used as peaking plants, i.e. during the coldest time of the year. Thus it is natural that increased solar PV does not have much influence on their operation. However, a decrease can be seen in the capacity factors of biomass CHP plants. Figure 20 also shows that the capacity factors of gas plants increase in the **Renewable Ambition** scenario. This is because gas plants make up the energy deficit caused by the phase-out of coal plants and increased overall electricity demand.

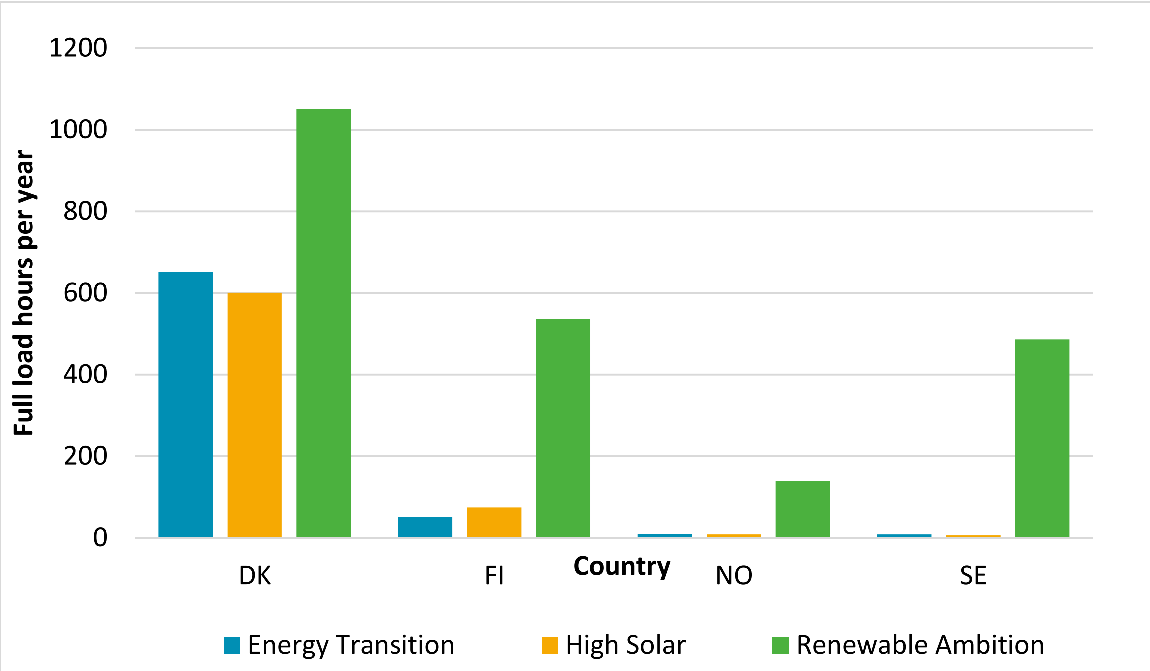

FIGURE 20: CAPACITY FACTORS OF GAS CONDENSING (CCGT AND OCGT) PLANTS IN DIFFERENT SCENARIOS IN THE NORDIC SYSTEM.

4.8 SYSTEM SPECIFIC FINDINGS - IRELAND AND NORTHERN IRELAND POWER SYSTEM

4.8.1 DIRECT CARBON EMISSIONS REDUCTION

As discussed above, one of the significant benefits of renewables and a significant positive impact that they have on the power system relates to carbon emission reduction. Adding additional renewable capacity is a key to displacing carbon intensive fossil fuel generation. This is depicted in Figure 21 which shows that increasing the installed capacity of wind (with all other parameters remaining the same) on the Ireland and Northern Ireland power system results in a reduction in total CO_2 emissions. For example, examining the **Low Carbon Living** (LCL) scenario, increasing the installed capacity of wind from 7 GW to 8 GW results in a 9% reduction in direct CO_2 emissions. Further increasing the installed capacity of wind from 8 GW to 10 GW results in a 19% decrease in direct CO_2 emissions. If operational policies can be augmented as a result of introducing system services, additional benefits of increasing wind levels can be realised. Comparing Figure 21 and Figure 22 illustrates that this additional benefit in direct CO_2 reductions is possible for all wind levels and all scenarios. Figure 23 demonstrates that for the **Low Carbon Living** (LCL) scenario the reduction in direct CO_2 emissions from the implementation of enhanced system operational policies (enabled by system services) over and above the BAU case can be as high as 13%.

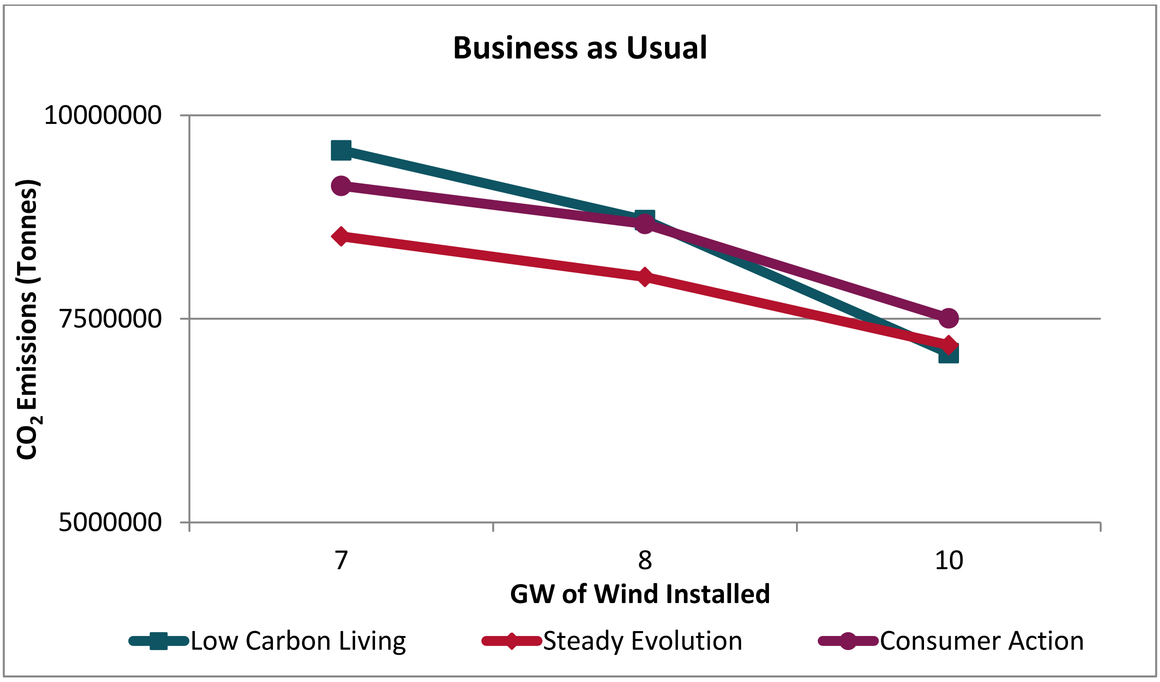

FIGURE 21: DIRECT CARBON EMISSIONS REDUCE AS THE INSTALLED CAPACITY OF WIND INCREASES; EVEN IF NO CHANGES ARE MADE TO OPREATIONAL POLICY

It can clearly be seen that both the transition towards higher levels of renewables and adopting system services and permitting enhanced system operation can have a significant positive impact on total CO_2 emissions. Conversely, the transition towards higher levels of renewables can result in greater curtailment and dispatch-down levels, which is discussed later in the report.

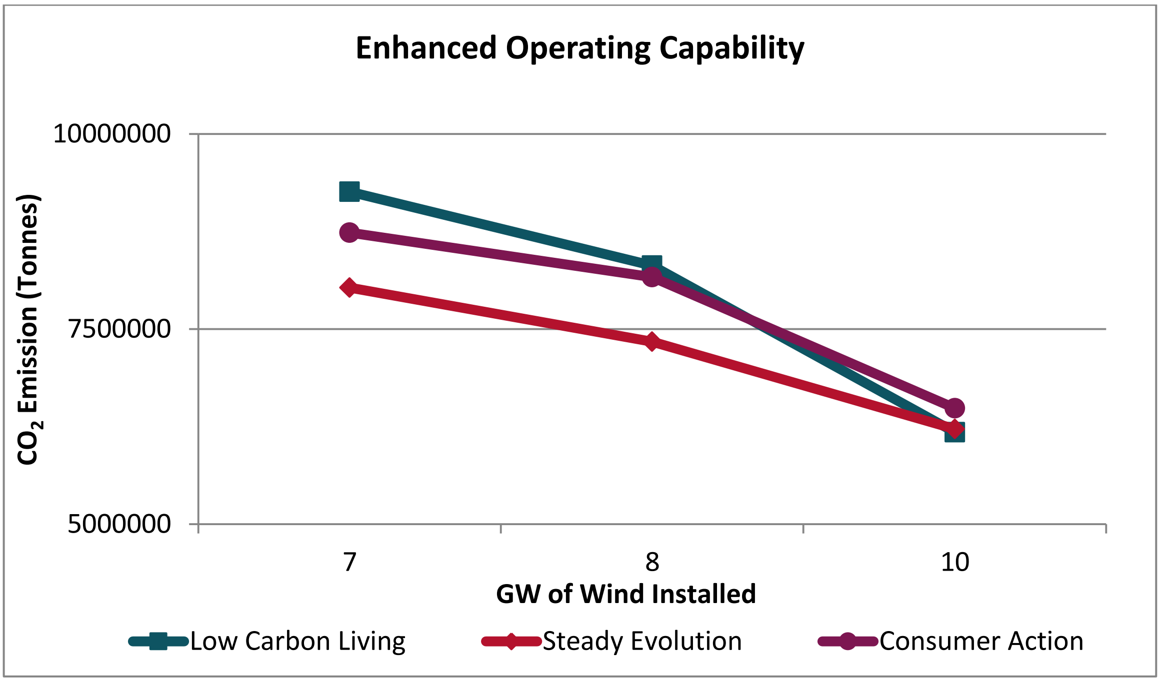

FIGURE 22: GREATER EMISSION REDUCTIONS CAN BE REALISED BY ADOPTING SYSTEM SERVICES

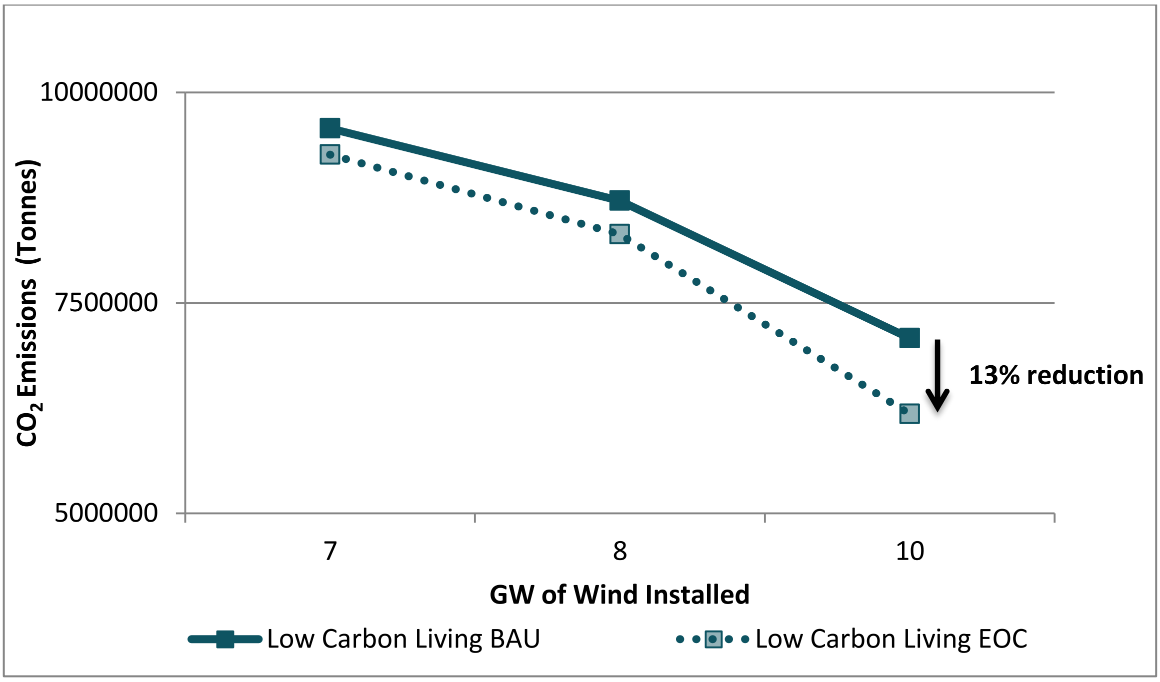

FIGURE 23: COMPARISON OF CO_2 EMISSIONS LOW CARBON LIVING BAU AND LOW CARBON LIVING EOC

For Ireland and Northern Ireland, if power system operational policies can be augmented as a result of introducing system services, the assumed decarbonisation benefits associated with increasing variable renewable levels can be realised.

4.8.2 SYSTEM NON-SYNCHRONOUS PENETRATION

If Business As Usual operational policies are not changed over the next decade, the SNSP limit, as introduced earlier, could be a binding constraint for 25% of the calendar year, as illustrated by the dotted line in Figure 24. In such cases, this would entail dispatch down of renewables during those hours, as a number of large conventional units will need to be committed to keep the SNSP level below the 75% limit, reducing the headroom on the system to accommodate non-synchronous variable renewable generation.

However, by adopting system services, and thus having a portfolio with enhanced operating capability, it may be possible to remove the SNSP limit. This would then enable accommodation of more non-synchronous variable renewables and a reduction in dispatch down (or curtailment), which will be discussed in the next section. Moving to an enhanced operating regime, as a result of having system services, results in a greater than 4% increase in wind production when compared to the BAU case.

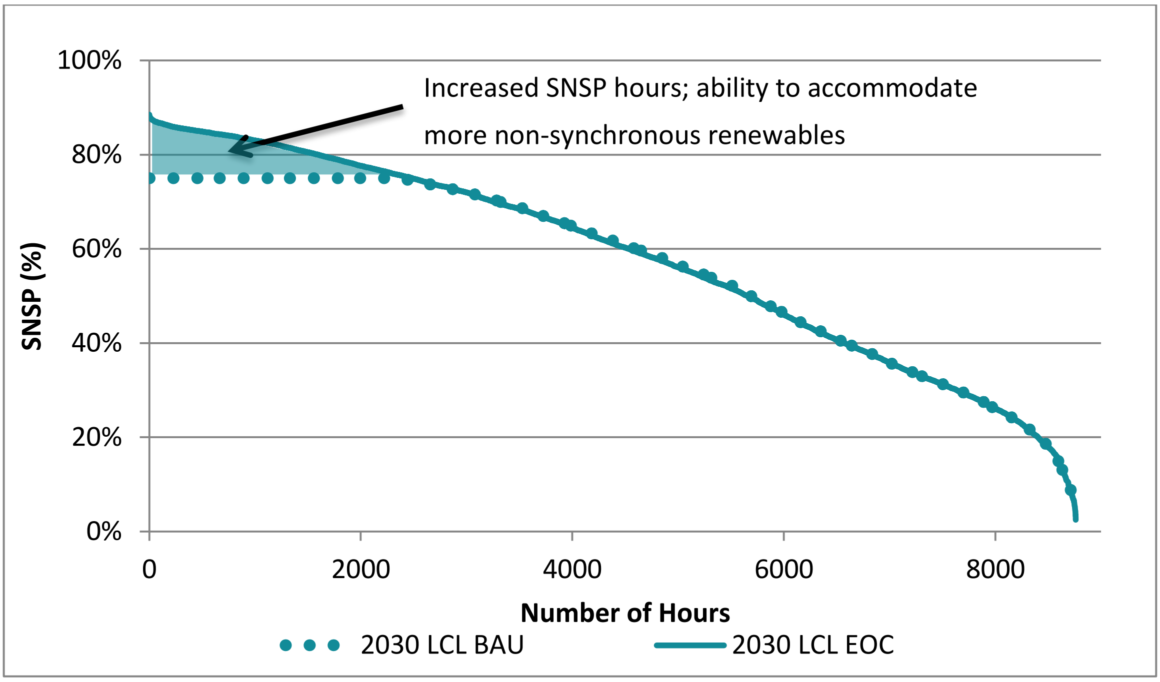

FIGURE 24: LOW CARBON LIVING SNSP DURATION CURVE (BUSINESS AS USUAL -V- ENHANCED OPERATING CAPABILTY)

If Business As Usual operational policies are not changed over the next decade, the SNSP limit, as introduced earlier, could be a binding constraint for a large portion of the year, necessitating curtailment. If power system operational policies can be augmented as a result of introducing system services, it may be possible to remove SNSP constraints, accommodate more renewables and reduce dispatch down levels.

4.8.3 CURTAILMENT & DISPATCH-DOWN

When wind energy is available and has a market position but is not dispatched, this is referred to as dispatch down. Dispatch down can occur for a number of reasons. In Ireland and Northern Ireland, dispatch-down due to overall power system limitations is referred to as curtailment, while dispatch-down due to local network limitations is considered a constraint [35]. A distinction should also be made between dispatch-down due to power system limitations and dispatch-down for energy balance reasons. For example, variable renewable dispatch-down for energy balance reasons is analogous to dispatching down a conventional generator because demand levels have decreased from one interval to the next; there are no system constraints impeding the accommodation of wind generation, only the balance of energy in the market.

Examining the results of the energy market only (MARUN) simulations for the Ireland and Northern Ireland Network Sensitivities, indicates that there is some dispatch-down occurring. This is for energy balance reasons only and cannot be due to system or network constraints, as such constraints are not included in the simulations. As depicted in Figure 25, as wind levels increase so too do dispatch-down levels for energy balance reasons. For each Network Sensitivity the only parameter that has changed is the installed capacity of wind; demand levels remain constant. Therefore it is clear to see that increasing wind capacity would result in excess supply of generation and the consequential need to dispatch-down.

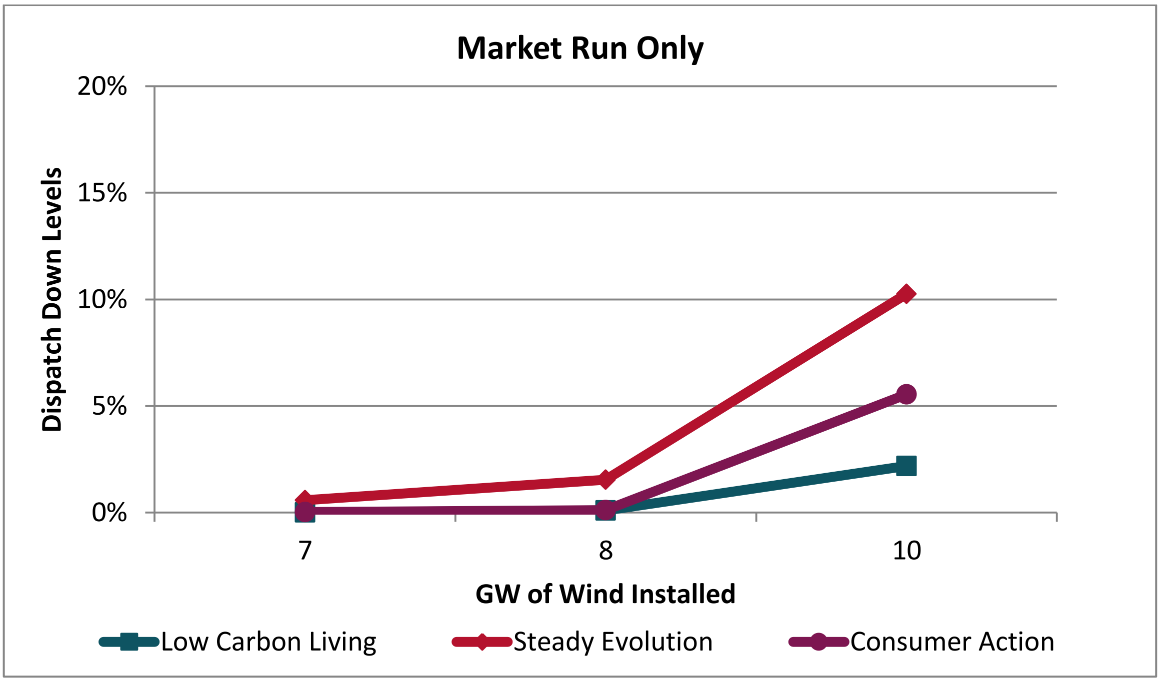

FIGURE 25: RENEWABLE DISPATCH-DOWN LEVELS WITH INCREASING LEVELS OF WIND: DISPATCH-DOWN FOR ENERGY BALANCE REASONS

Considering the Business as Usual simulations, with the required operational constraints, gives an indication of total dispatch down levels, which includes curtailment, or dispatch down due to power system limitations, in conjunction with dispatch down due to energy balance reasons.

Figure 26 illustrates the total dispatch down levels for the **Steady Evolution** (SE) Business as Usual case (red line). By comparing the total dispatch down levels for the **Steady Evolution** (SE) Business as Usual case with the **Steady Evolution** (SE) MARUN case (black line), the individual components of the total dispatch down levels can be seen.

In Figure 27 the increase in dispatch down levels with increasing wind capacity is illustrated for all the Network SensNetwork Sensitivities considered. It is clear to see that continuing with BAU operational constraints and policies whilst also increasing the level of wind, dispatch down levels for renewables will increase, potentially to levels that are unacceptable from the point of view of investment in variable renewable technologies.

However, by adopting system services, it is possible to move towards a more enhanced system operating regime, as described earlier. Doing so permits a reduction in dispatch-down levels and a reduction in carbon emissions because more renewable generation can be accommodated, as well as a reduction in overall system operating costs, which will be discussed in more detail later in this report. Comparing Figure 27 with Figure 28 demonstrates the falling dispatch-down levels by adopting system services and moving towards a portfolio with an enhanced operating capability. Figure 29 shows that the change in the dispatch-down levels that occurs due to the adoption of system services is predominately a reduction in curtailment levels.

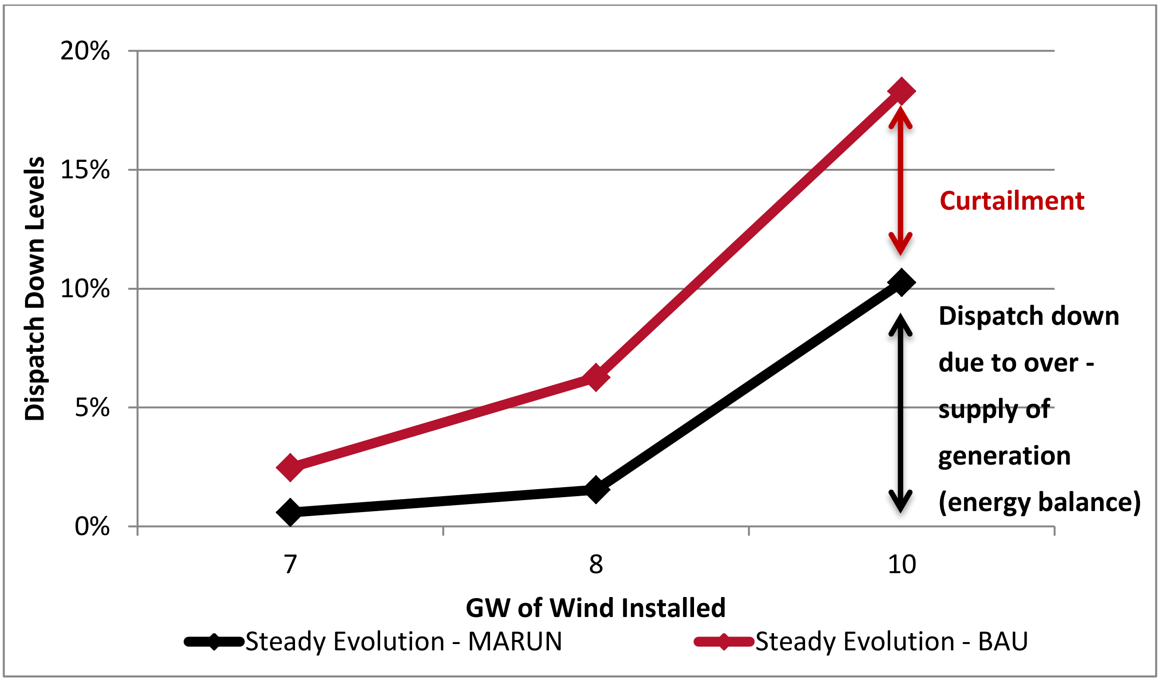

FIGURE 26: COMPARISON OF RENEWABLE DISPATCH-DOWN LEVELS FOR STEADY EVOLUTION: MARKET RUN -V- BUSINESS AS USUAL OPERATING POLICY ASSUMPTIONS

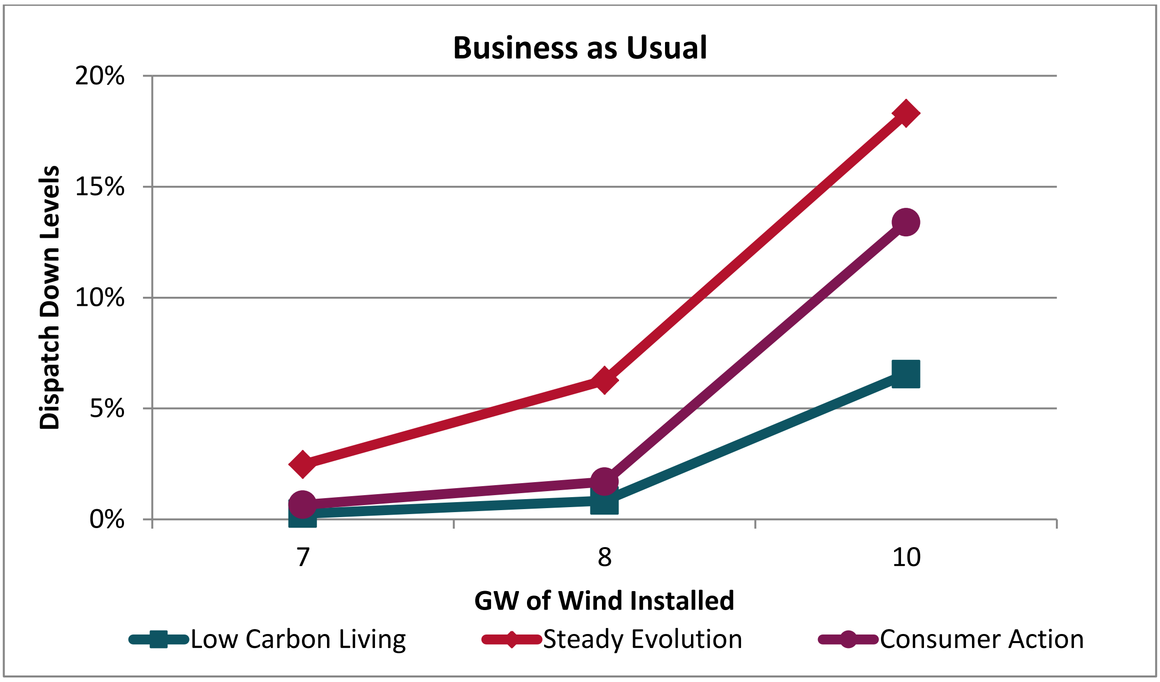

FIGURE 27: RENEWABLE DISPATCH-DOWN LEVELS WITH INCREASING LEVELS OF WIND UNDER BUSINESS AS USUAL OPERATIONAL CONSTRAINT ASSUMPTIONS

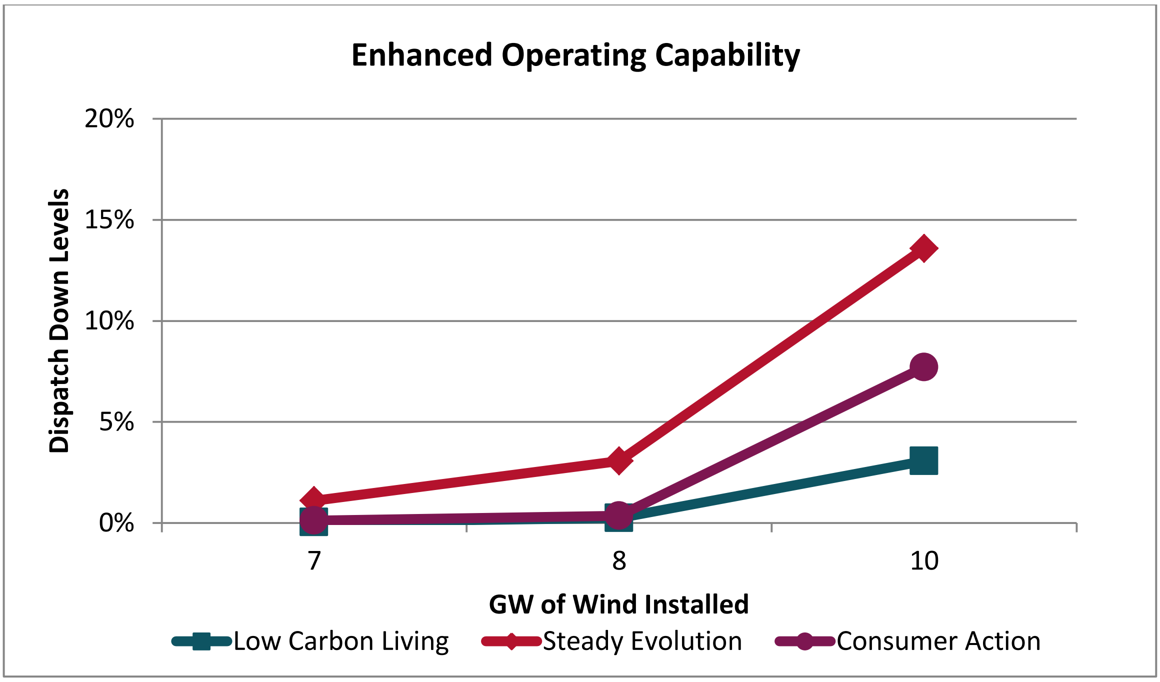

FIGURE 28: RENEWABLE DISPATCH-DOWN LEVELS WITH INCREASING LEVELS OF WIND UNDER ENHANCED OPERATIONAL CAPABILITY ASSUMPTIONS

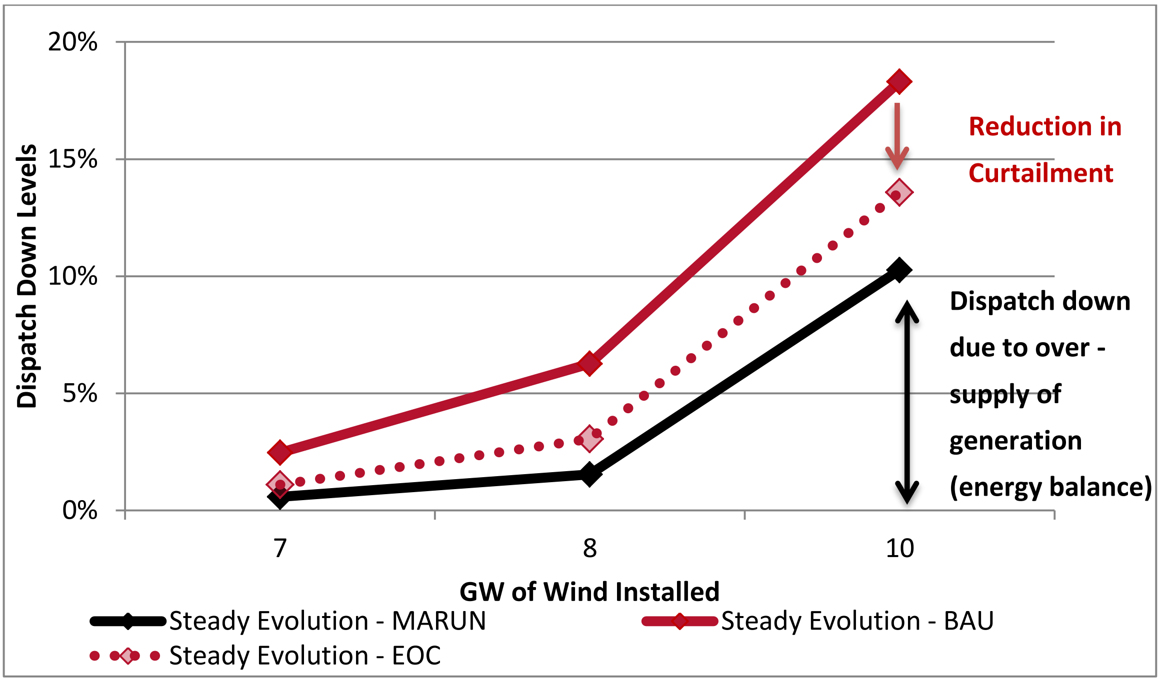

FIGURE 29: RENEWABLE DISPATCH-DOWN LEVELS FOR STEADY EVOLUTION WITH INCREASING LEVELS OF WIND

Increasing the level of renewable generation capacity results in an increase in dispatch-down levels. If power system operational policies can be augmented as a result of introducing system services, dispatch down levels, or specifically the curtailment component of dispatch down levels, can be reduced.

4.8.4 IMPACT OF RENEWABLES ON NET LOAD

Variable renewables can have a considerable impact on the net load profile of the power system. Figure 30 gives an example of the impact wind generation can have on the net load profile for a week on the Ireland and Northern Ireland power system. The regular, repeatable pattern of the load profile is clearly visible from the red line. Wind generation, however, dramatically alters the residual load, or net load, profile in green and the variability of the wind generation from day to day is evident.

According to Huang *et al.* (2018), a ramp event can be considered to be a large or rapid change in power in either direction. They also point out that increases in renewables cause an increase in the variability of the system net load [36]. This concurs with the results from this analysis as considerable net load ramps, both upwards and downwards, are also evident in Figure 30. This net load variability creates challenges for system operation and requires sufficient flexibility and fast acting capability.

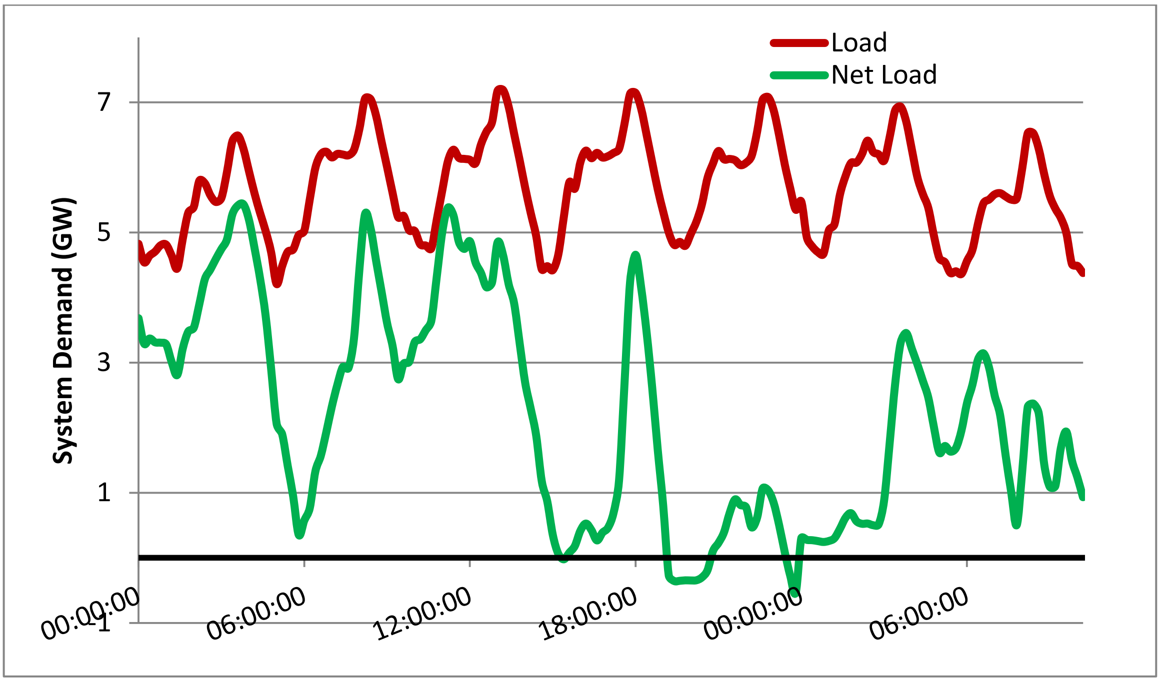

FIGURE 30: EXAMPLE OF THE IMPACT OF RENEWABLES ON NET LOAD (LOAD – WIND GENERATION) FOR STEADY EVOLUTION: MARUN FOR A WINTER WEEK WITH 7 GW OF WIND

It is clear to see how the integration of high levels of variable renewable generation, in this case wind, can have a profound effect on the scheduling of generation and consequently on the capacity factors (discussed in a previous section) of generating units. Simply incorporating additional renewable capacity succeeds in displacing carbon intensive fossil fuel generation such as gas generation. This is illustrated in Figure 31, which shows the residual generation on the system. As can be seen, there is significant variation in operation of the combined cycle gas plants (depicted in red) as scheduled in the energy market from day to day.

The importance of interconnection and storage capacity is also evident in Figure 31, enabling accommodation of high levels of wind generation by balancing supply and demand through exports and through storage of excess energy. Indeed, combining interconnection and storage operation with the net load profile (Figure 32) demonstrates the role they can have on reducing the significant inter-day net load ramps and variability introduced by high levels of wind generation.

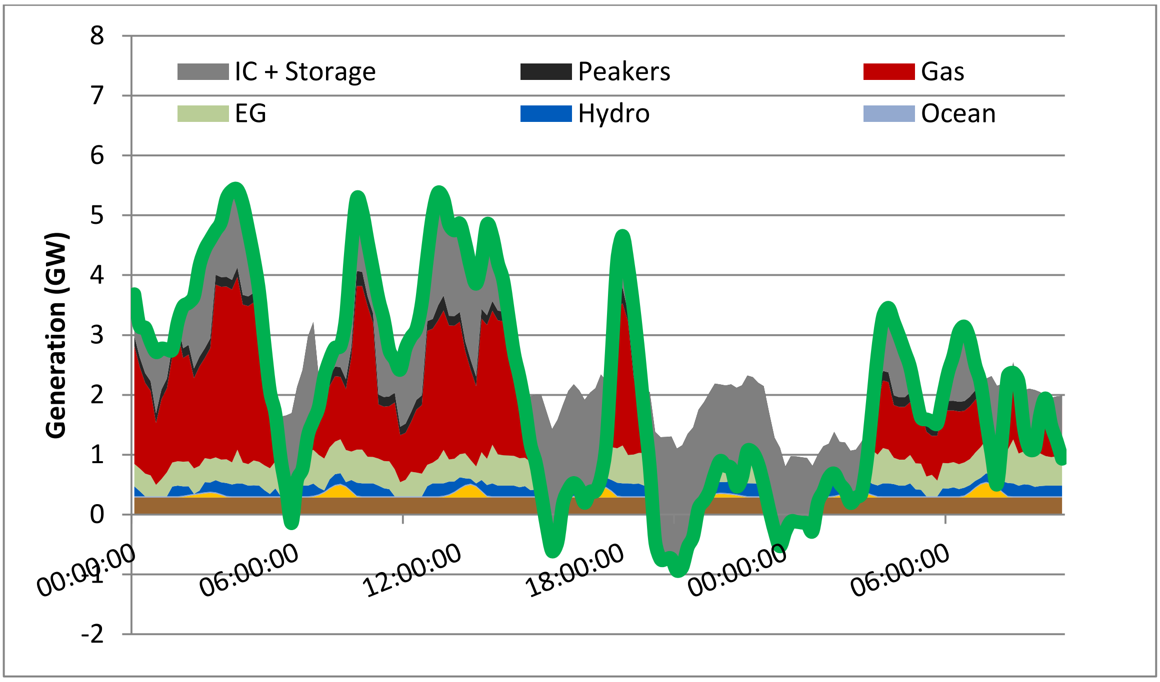

FIGURE 31: EXAMPLE GENERATION SCHEDULE DURING PERIODS OF HIGH WIND VARIABILITY FOR STEADY EVOLUTION: MARUN WITH 7 GW OF WIND[9]

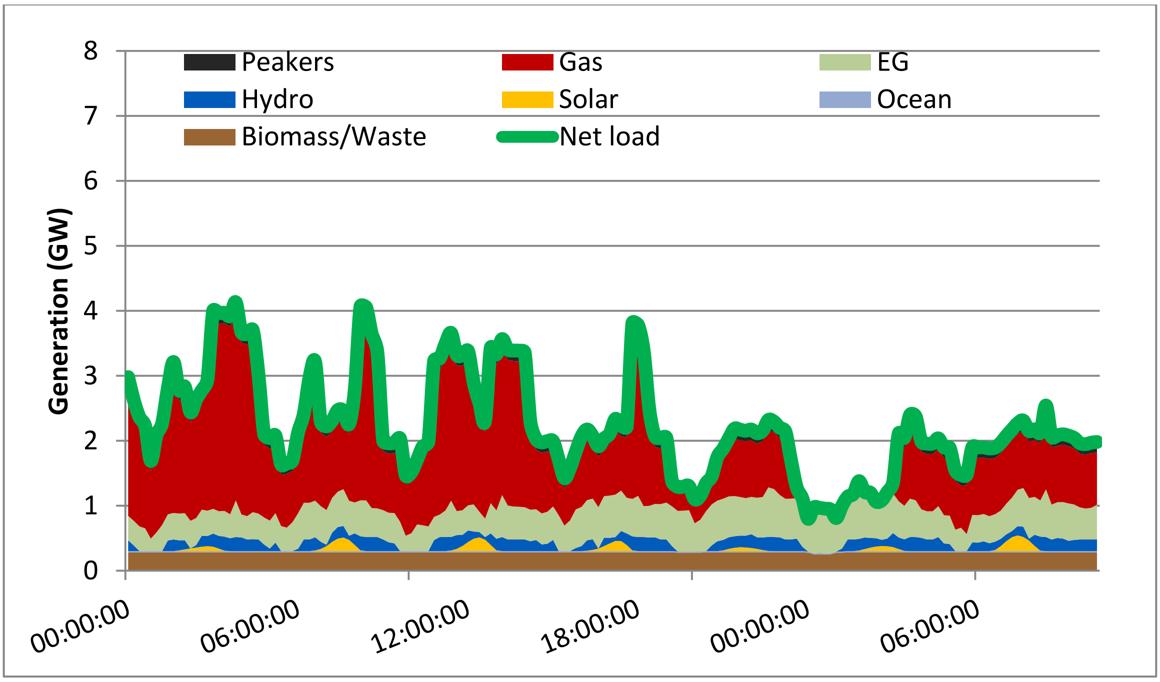

FIGURE 32: EXAMPLE OF GENERATION SCHEDULING DURING PERIODS OF HIGH WIND VARIABILTY WHERE THE NET LOAD ACCOUNTS FOR INTERCONNECTION AND STORAGE OPERATION WITH 7 GW OF WIND

High levels of wind generation have a profound impact on the scheduling of generation and thus have a knock on effect for the capacity factors of the various technologies in the portfolio. Indeed, analysis in Task 2.5 has shown

[9] EG in the graphs stands for embedded generation

that capacity factors for CCGTs are falling as variable renewable capacity increases. This is demonstrated Figure 33.

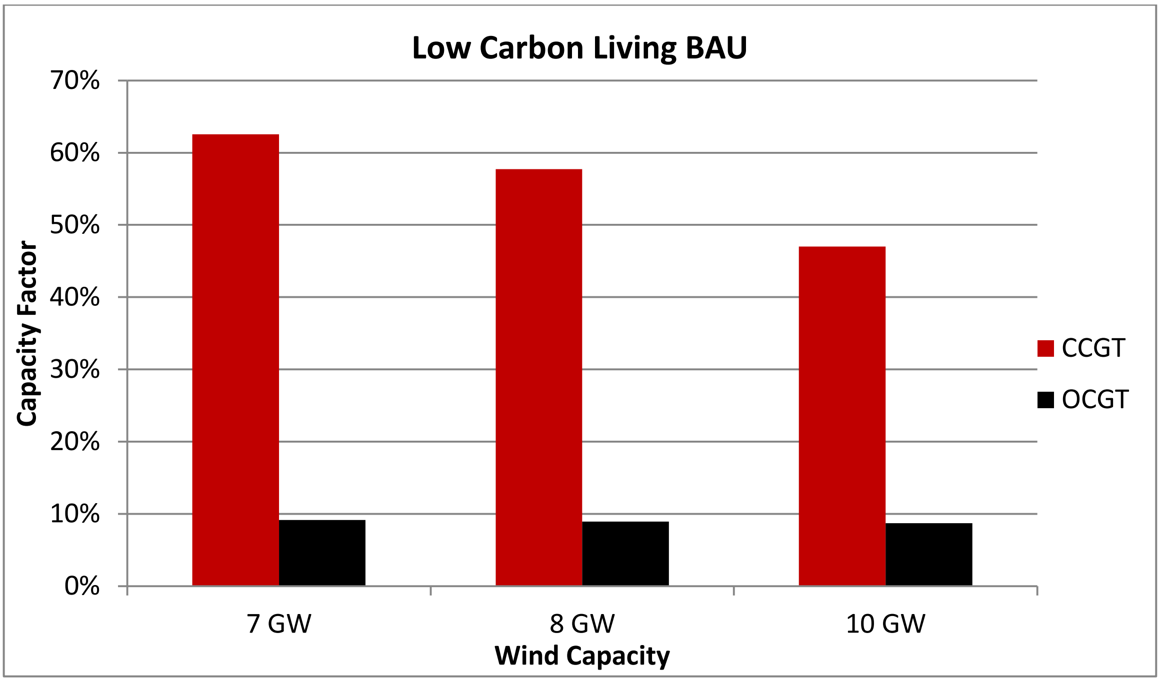

FIGURE 33: CHANGING CAPACITY FACTORS OF CCGTS AND OCGTS AS WIND CAPACITY INCREASES – LOW CARBON LIVING

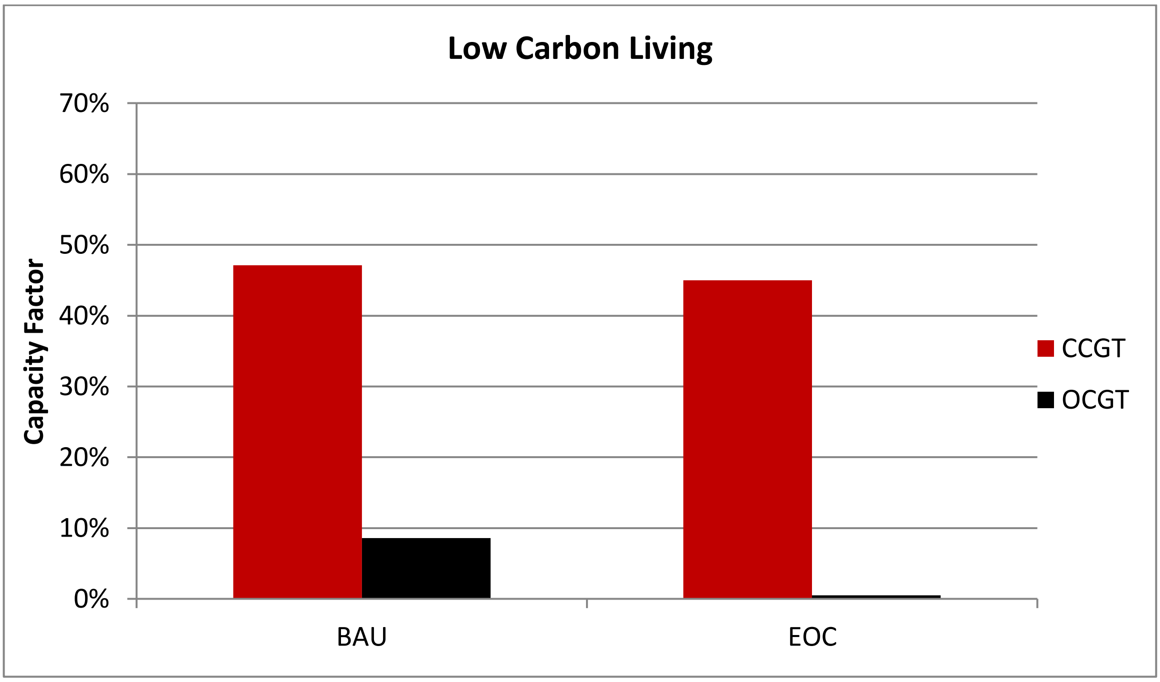

FIGURE 34: IMPACT OF TRANSITIONING TO AN ENHANCED OPERATING REGIME – LOW CARBON LIVING

Conversely, there is a slight increase in the operation of peaking generators. This is unsurprising given the inherent flexibility of open cycle gas turbines (OCGTs), and other peaking plant compared to combined cycle gas turbines. Peaking plants typically have lower min stable levels and shorter minimum up and minimum down times, making them more flexible and less susceptible, and therefore more subject to, cyclical operation, than combined cycle gas turbines or baseload plants.

In general, it is found that there are only minimal changes to the capacity factors of the rest of the generation fleet as wind capacity increases. CCGTs are the biggest changes. In general it appears that OCGTs and other peaking plants either increase in the amount of running they receive or they at least continue to receive the same amount of running. Though, the extent depends on the underlying portfolio and the demand levels.

By transitioning to an enhanced operating regime, there is less of a need for flexible gas/peaking generation as it is being assumed that the requisite system services and flexibility can come from other sources. This is clearly evident in Figure 34 where the capacity factor of OCGTs falls off sharply between the BAU case and the EOC case.

Variable renewables have a considerable impact on the net load profile of the power system and consequently on the capacity factors of CCGTs and OCGTs. There is a need for greater flexibility in the power system. By transitioning to an enhanced operating regime, as shown in the Ireland and Northern Ireland case, there could be less of a need for flexible gas/peaking generation if the requisite system services and flexibility can come from other sources.

4.9 SUMMARY OF KEY FINDINGS

Developing variable RES has a small impact on the need for conventional capacity in terms of generation adequacy. As power systems transition to having portfolios with higher levels of vRES, the capacity of vRES that is required to displace conventional capacity, and still maintain the same level of generation adequacy, increases dramatically. This is a result of the variable nature of these resources and the fact that renewable generation may not coincide with peak demand times. It should be noted, however, that although a portfolio may be sufficient from the point of view of generation adequacy and having sufficient capacity to meet peak demand, there is no guarantee that the portfolio also has the requisite fast responding capability that has been shown in Task 2.1 and confirmed in T2.4 to be vital for secure power system operation.

It has been shown that for the Network Sensitivities studied, based on the cost assumptions that have been made, the need for peaking plants in terms of ensuring generation adequacy increases with vRES share. Peaking plants have, in general, lower investment costs compared to other conventional units. This means that generation adequacy levels can be maintained at cheaper costs. Furthermore, it has been seen that the capacity factors for peaking plants such as OCGTs are also increasing. This indicates that system operation is fundamentally changing with higher levels of vRES where high net load ramps are possible and more flexible, fast responding units are a necessity. It was stated in [37] that "*in an energy-only market with high shares of renewables, capital intensive conventional generators must cover the cost of their capacity with reduced load factors*". This certainly appears to be the case in the analysis presented here. More detailed discussion on the impact of this reduced running on revenues is discussed in detail in the next chapter.

The addition of vRES leads to a drop in load factors for some technologies, particularly CCGTs. This has been shown for the Pan-European system, as well the Ireland and Northern Ireland power system. A similar trend is not seen in the Nordic power system however. This is a result of that fact that CCGTs predominately operate during the winter in the Nordic countries. Consequently, increasing the level of vRES, especially solar which operates during the summer, has limited impact on CCGT operation.

While it is being seen that there is an increasing need for fast, flexible plants, it has been shown that if OCGTs are relied upon for providing the required flexibility at high penetrations of variable renewable, that the potential carbon emission reduction benefits from the renewables may be impacted and could taper off at high levels of renewables. Even when a high carbon price is assumed, there is insufficient incentive to shift away from the carbon intensive OCGTs, for the cost assumptions made here.

It has been shown for Ireland and Northern Ireland, however, that implementing an enhanced system operating regime could result in less of a need for flexible gas/peaking generation and capacity factors for OCGTs fall. This is as result of the fact that the requisite system services, capability and flexibility could come from other non-conventional sources, such as storage, demand-side participation and renewable generation. Additionally, at least for the Ireland and Northern Ireland power system, implementing an enhanced operating regime through the adoption of innovative system services results in greater decarbonisation benefits that those associated with increasing variable renewable generation capacity alone. Future work should consider how the introduction of flexibility and system services on the pan-European power system could assist with the drive towards decarbonisation by 2050.

Unsurprisingly, as the power system transitions towards higher levels of vRES penetration, the times when vRES generation exceeds demand increase. One of the mechanisms to deal with it is curtailment.

A distinction can be made between curtailment and dispatch-down[10], however. If power system operational policies can be augmented as a result of introducing system services, it has been shown for the Ireland and Northern Ireland case, that dispatch down levels, or specifically the curtailment component of dispatch down levels, can be reduced.

For Continental Europe, a case study for Germany shows high levels of curtailment as soon as the vRES production is high, reaching an annual average of 10%. There is also a rapid increase in the number of generating

10 Dispatch-down refers to the amount of wind energy that is available but cannot be accommodated. Dispatch-down due to overall power system limitations is referred to as curtailment, while dispatch-down due to local network limitations is considered a constraint [19]. A distinction should also be made between dispatch-down due to power system limitations and dispatch-down for energy balance reasons. For example, variable renewable dispatch-down for energy balance reasons is analogous to dispatching down a conventional generator because demand levels have decreased from one interval to the next; there are no system constraints impeding the accommodation of wind generation, only the balance of energy in the market.

units connecting at the distribution level. These high levels of embedded generation are leading to congestions at both the transmission and distribution level. Today in Germany, curtailment is a good mechanism to manage congestios. The main challenge lies in the fact that RES generators in Germany are currently fully remunerated for any energy that is curtailed, at a considerable cost.

Renewables have a profound effect on the operation of the power system, which in turn manifests in the energy market and the financial environment. This impact is explored in the next Chapter.

5 FINANCIAL CALCULATIONS

This section looks at costs and revenues in the energy market for the European and Nordic power systems as well as the Ireland and Northern Ireland power system. The findings of this section are that cost structure will change and will be overwhelmingly dominated by fixed investment costs, while energy market revenues are decreasing sharply for RES and conventional plants. This raises the question of the appropriate market design to compensate producers adequately and promote the investments needed by the European power system to provide quality service to customers.

5.1 INVESTMENT COSTS WILL MAKE UP THE OVERWHELMING SHARE

This section looks at the fixed (O&M and investments costs) and variable costs (i.e. mostly fuel and CO_2 costs) for the European power system with different shares of vRES. The costs are computed using O&M and investment costs assumptions coming from WEO (2018) and RTE (2017) as well as the different installed capacities and results from simulations.

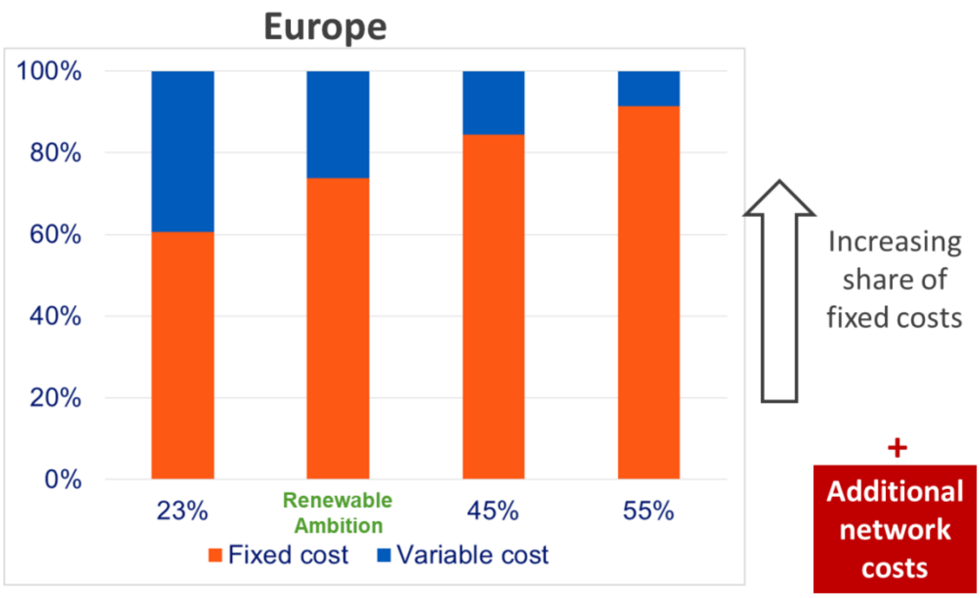

FIGURE 35: DISTRIBUTION BETWEEN FIXED AND VARIABLE COSTS DEPENDING ON THE SHARE OF VRES.

Figure 35 represents the share of fixed costs in orange and variable costs associated to fuel and exploitation in blue for the European power system. It shows the impact of vRES penetration on the structure of total generation costs (fixed and variable costs), excluding necessary network reinforcement, interconnections, or smart technologies deployment costs that are not assessed here. At a share of 23% vRES, the cost structure is split 40% for variable costs and 60% ratio for fixed costs. The share of fixed costs increases steadily with the share of vRES, as an increasing volume of production becomes renewable, thereby having zero or close to zero variable cost. With a share of 55% of vRES, 92% of the total cost comes from fixed costs, to which significant network reinforcement costs would most likely need to be added.

One of the main implications of a power system mainly composed by capital-intensive technologies and high share of fixed cost is its sensitivity to risk issues. Indeed, if risks are not well allocated between different actors, this may imply higher capital cost and investment disincentives and distortions. This raises the question of the appropriate market design to address the shift of system cost structure, properly share the risks and promote necessary investments. Currently, the main source of revenues comes from the energy market which is likely to be very risky and inadequate in particular during **Energy Transition**. WP3 of the EU-SysFlex project is tackling the question of market design enhancement.

With an increasing share of vRES in the power system, the cost structure shifts towards being overwhelmingly dominated by fixed costs. New market designs will need to properly share risks and compensate for capital-intensive and long-term investments, which will also satisfy flexibility needs.

5.2 AVERAGE MARGINAL COSTS ARE DECREASING AS VARIABLE RES SHARE INCREASES

This section looks at the impact of vRES on marginal costs in the European power system. System marginal costs can be interpreted as electricity prices, under the assumption of perfect competition with an energy-only market vision, and thereby give an overview of the trend of the revenues that can be expected by producers with this type of market design.

Hourly system marginal costs are obtained with the detailed optimization model described in section 3.1.2. They are computed for each country in Europe, taking into account interconnection constraints, for close to 165 annual combined climate and outage scenarios and have been capped to 3 hours of loss of load[11]. In all sensitivities, the CO_2 price is kept constant at €90/tCO_2, like in **Renewable Ambition**.

Figure 36 shows in orange the marginal cost for Germany as a function of vRES in the European power system and in blue the share of hours where the marginal cost is zero. The yearly average system marginal cost for Germany (Orange) drops sharply from €95/MWh to €55/MWh as the share of vRES in the European system increases. This represents a 45% loss of value and it is directly linked to the increase of the numbers of hours where the marginal cost is zero as shown in blue in Figure 36. In **Renewable Ambition** (34% vRES), there are very few hours in the year where the marginal cost is zero. With 55% vRES, the marginal cost is zero roughly 10% of the year, and Figure 39 shows that the drop is most severe at midday. This will have an important impact on the energy revenues of the vRES and conventional plants as will be discussed in the following sections.

[11] In terms of system marginal costs, the output of the optimization model are 8760 hourly values for each country/zone and for analysed climate & outage scenario.

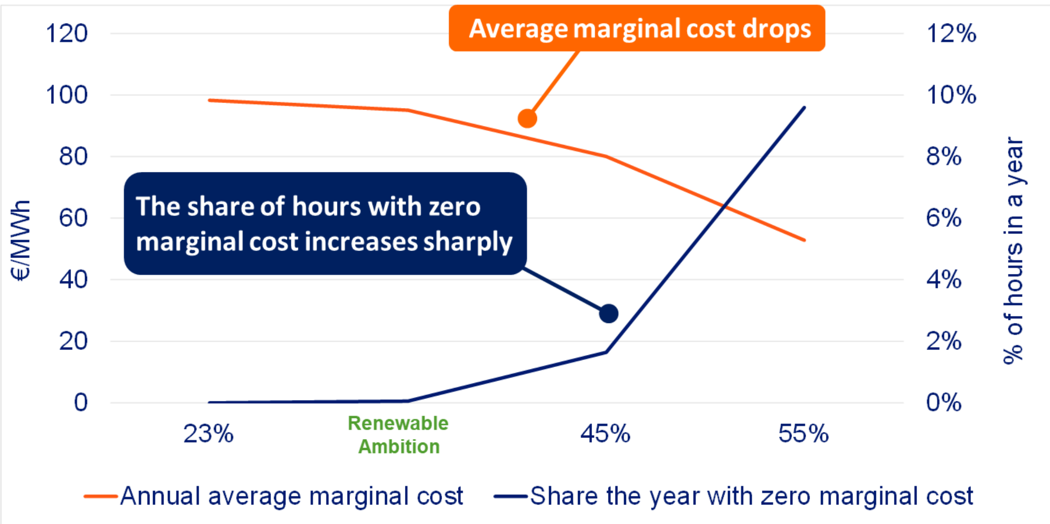

FIGURE 36: AVERAGE MARGINAL COST FOR GERMANY DEPENDING ON VRES SHARES (ORANGE) AND SHARE OF THE YEAR WHERE MARGINAL COST IS ZERO (BLUE)

Average marginal costs drop with an increasing share of vRES. This will translate into deteriorated revenues for all generation plants in an energy-only market environment (no subsidies), that must bear at the same time a higher uncertainty and risk level.

5.3 MARKET VALUE FACTOR DECREASES FOR VARIABLE RES AS THEIR SHARE INCREASES

The economic figures from the previous section call for looking in detail at revenues for RES and whether they can cover their cost in an energy-only market. We consider that vRES are paid at the system marginal cost. We compute the revenue that their production generates on an hourly basis and average it yearly. This is called the average value of a RES technology. Then, we compare it to the yearly average marginal cost of the system. The ratio between the average value of RES and the yearly average marginal cost is called the market value factor for the RES technology considered.

Figure 37 shows the European-wide market value factor for different shares of vRES in the power system and for different vRES technologies. The market value factor drops sharply with increasing share of vRES, in particular for solar. The solar market value factor drops from 93% at a vRES share of 23% to 36% at a vRES share of 55%. This comes from the fact that solar production is concentrated in the middle of the day and leads to a drop of system marginal costs as shown in Figure 36. Wind generation is more spread out during the day, and the market value for onshore (offshore) wind only drops from 97% (98%) at a vRES share of 23% to 76% (81%) at a vRES share of 55%.

This effect has been called the “cannibalization effect” in literature and can be easily explained. A technology is usually said to be mature when its levelised cost of production (LCOE) appears competitive compared with traditional thermal technologies or with a benchmark price for electricity. Joskow (2011) notes however that, for vRES, this comparison is misleading because the variable generation of a RES unit may be statistically biased towards periods when wholesale spot prices are higher or lower than the benchmark. In our approach, we capture this effect since the system marginal costs are outputs of the model and depend on the amount of RES capacity and on their generation patterns. A noticeable contribution of our approach is to reveal a telling pattern for how market value for RES decreases with their deployment.

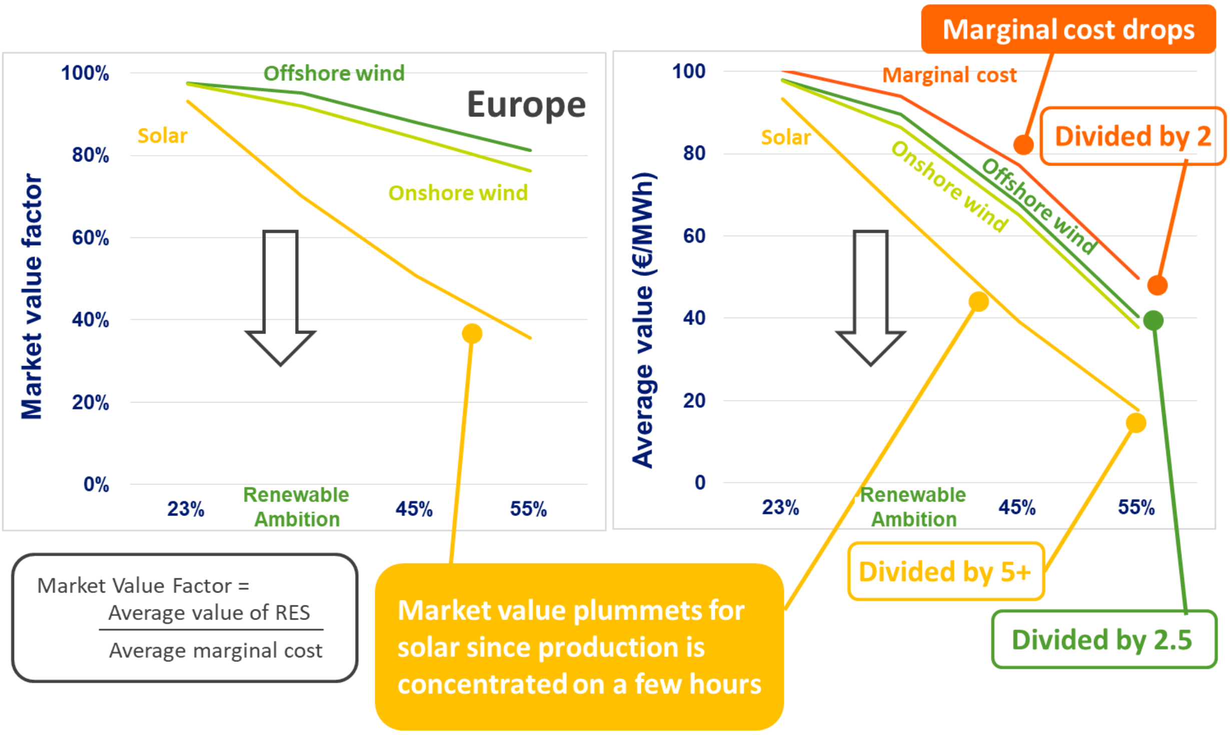

FIGURE 37: MARKET VALUE (LEFT) AND AVERAGE VALUE (RIGHT) FOR SOLAR, ONSHORE WIND AND OFFSHORE WIND DEPENDING ON THE SHARE OF VRES IN THE EUROPEAN POWER SYSTEM.

The average value of RES on the energy market sees a bigger drop than the market value factor since the average marginal costs drops as shown in Section 5.2. The average value of solar is divided by 5, while the wind value is divided by 2.5.

The cannibalization effect is greatest for solar. The value of solar in the energy market is divided by 5 when moving from a scenario with 23% vRES to one with 55% vRES at the European level.

5.4 MARKET REVENUES DO NOT COVER COSTS WITH A CO_2 PRICE AT 90 €/TON FOR VRES SHARES HIGHER THAN 34%

The "cannibalization effect" translates into a difference between the system yearly price and the average revenue of vRES, designated here as "market revenue gap". Figure 38 shows the difference between market revenues (solid line) and costs (dotted line) on average for Europe for each RES technology. A coloured triangle materializes the area for which the market revenues do not cover costs. Costs hypotheses for vRES come from the latest WEO

New Policy Scenario at horizon 2040 and take into account updated prospective costs for RES investment and maintenance costs. The carbon price value for all shares of vRES is €90/tCO_2 from the scenario **Renewable Ambition** and this has a direct impact on the market revenues for RES. For **Renewable Ambition**, there is no need for subsidies for vRES on average, but the 34% of vRES of **Renewable Ambition** is close to the breakeven point[12]. With higher shares of vRES, the need for subsidies becomes larger despite the high carbon price. A lower carbon price would shift the solid curves towards the horizontal axis on the graph, thereby shifting towards the left the breakeven point and increasing the market revenue gap. This would be the case for **Energy Transition** where the CO_2 price of 27€/tCO_2 leads to lower marginal costs than for **Renewable Ambition**.

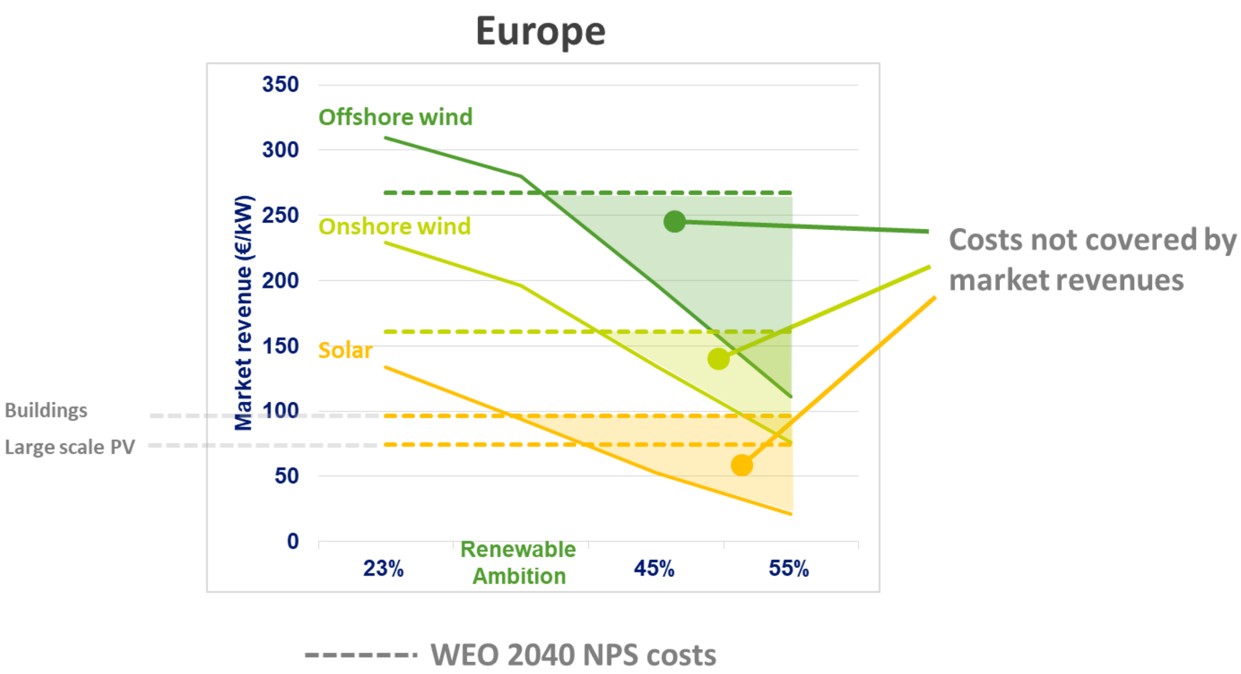

FIGURE 38: ANNUAL MARKET REVENUE AND COSTS DEPENDING ON VRES SHARE

Market revenues do not cover costs with a CO_2 price at €90 /ton when vRES shares become higher than 34%. The market revenue gap is sensitive to the carbon price and increases with lower carbon prices.

5.5 SYSTEM SPECIFIC FINDINGS - CONTINENTAL EUROPE POWER SYSTEM

5.5.1 AVERAGE HOURLY SYSTEM MARGINAL PRICE IN GERMANY

Figure 39 shows an hourly distribution per season of the average marginal cost for Germany. System marginal costs drop for every hour of the day, but they plummet in particular around midday between March and August. In a system with a vRES share of 23%, the average marginal cost at noon is upwards of €90 /MWh (solid orange

[12] The graph is shown with capped prices at 3000€/MWh. Uncapping the prices leads to the same conclusions but the gap is marginally reduced.

line) and it drops to less than €20 /MWh with a vRES share of 55% (dotted orange line). This effect comes from the very concentrated generation of solar and can be seen on summer months as well as on winter months (dotted blue line). After sunset, the difference in marginal costs between the two shares of vRES is reduced. Due to its shape, the resulting curve is called the “Duck curve”.

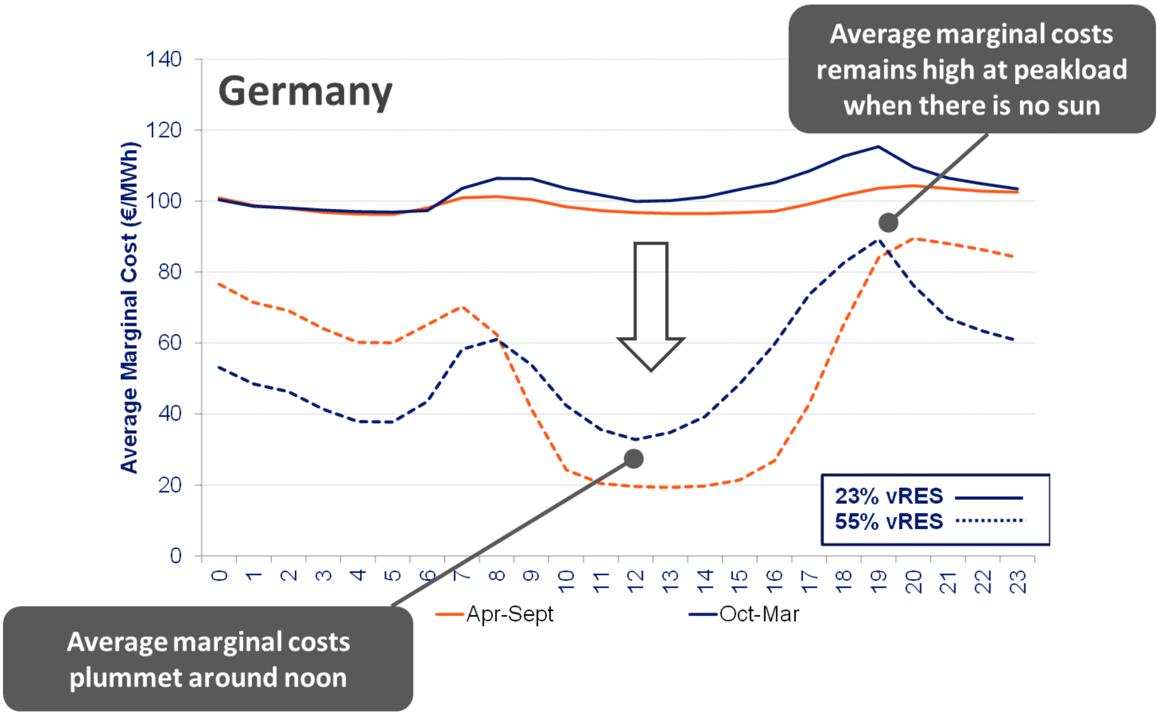

FIGURE 39: AVERAGE HOURLY MARGINAL COST FOR GERMANY BY SEASON (ORANGE – APRIL TO SEPTEMBER AND BLUE – OCTOBER TO MARCH) FOR 23% AND 55% VRES SHARES

5.5.2 EVALUATION OF THE COST OF REACTIVE POWER SERVICES

Based on the investment scenarios described earlier in Section 2.2.1, cost calculations were performed to identify the most economic means to address the voltage stability issues identified in Task 2.4. For convenience, the two investment scenarios are summarised in the Table 12 below:

TABLE 12: INVESTMENT SCENARIOS FOR MITIGATING VOLTAGE STABILITY ISSUES

Investment Scenario	**Assumptions**
Business as Usual (BAU)	System Operators invest in capacitive and inductive shunts to mitigate reactive power deficiencies
Enhanced System Services (ES)	Reactive power deficiencies are addressed through procurement of system services. This is attained primarily through use of power inverters (mostly wind technology).

The overall costs in both scenarios are based on the cost assumptions outlined in section 3.2.2 and the quantities of reactive power deficiencies as identified in Task 2.4 and outlined in Table 4. For the BAU case, this is simply taking the required quantities of capacitive and inductive shunts for each of the three scenarios and multiplying by the referenced unit price for each technology. A similar methodology is used for the ES case.

TABLE 13: INVESTMENT COSTS FOR BAU AND ENHANCED SERVICES INVESTMENT SCENARIOS

Scenario	BAU (millions of €)	ES (millions of €)
Energy Transition	150 (+- 30%)	69 (+15% -15%)
Going Green	151 (+- 30%)	64 (+15% -15%)
Distributed Renewables	90 (+- 30%)	42 (+15% -15%)

It can be observed that costs are lower for the ES scenario. It is also important to note however, that the ES scenario requires private investment by wind turbine owners, and not grid operators'investment. Private investors seek shorter investment timelines and higher returns compared with Grid Operators. Given uncertainty in market conditions, investment in upgrading of inverters could be perceived as risky. It is therefore important to ensure that correct incentives are in place to facilitate required investment in upgrading of inverters in wind turbines. It is also important to note, that for this part of the analysis reactive power is considered in isolation from other system services. In reality, it is more plausible and more efficient that multiple services are assessed, and ultimately procured as a suite of services.

For mitigating voltage stability issues, provision of enhanced system services is less expensive than system operator investment in capacitive and inductive shunts, but implies private investment with sufficient incentive.

5.6 SYSTEM SPECIFIC FINDINGS – NORDIC POWER SYSTEM

5.6.1 AVERAGE MARGINAL COSTS ARE DECREASING AS VRES SHARE INCREASES

For the Nordic system the marginal costs are obtained at zonal resolution as a result of the WJMM UCED model. Although comprehensive tests with different VRES shares were not performed, it is possible to compare the different energy system scenarios. It is seen that the addition of solar PV in the **High Solar** scenario reduces average marginal cost in all countries compared to the **Energy Transition** scenario.

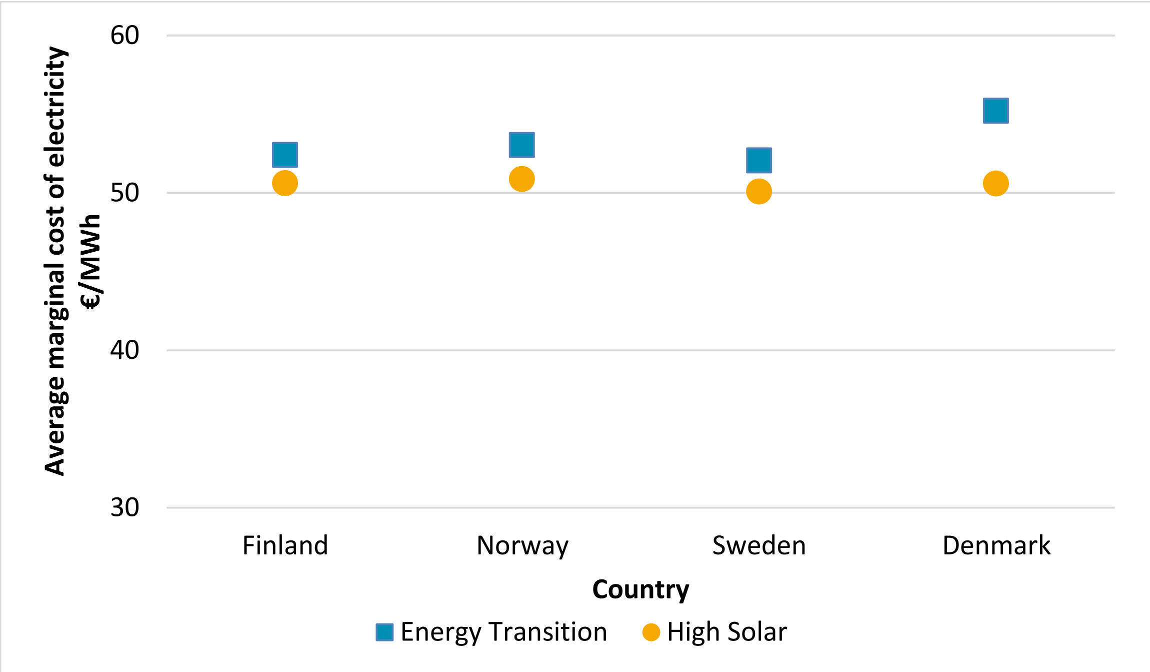

FIGURE 40: AVERAGE MARGINAL COST FOR NORDIC COUNTRIES IN DIFFERENT SCENARIOS

5.6.2 MARKET VALUE FACTOR DECREASES FOR VARIABLE RES AS THEIR SHARE INCREASES

In the Nordic system the decrease of market value factor for solar PV is clearly visible when the **Energy Transition** and **High Solar** scenarios are compared (Figure 41). The **High Solar** scenario increases solar power share of total electricity demand by 3.6 percentage points. It is seen that market value of solar PV drops in all countries. The drop is the largest in Denmark, where the access to balancing hydro power is most limited and where the penetration of variable renewable generation is highest. The market value factor in the **Energy Transition** scenario is also lowest in Denmark because the country manifests the highest capacity of solar PV relative to demand.

The decrease of market value factor is also evident when looking directly at market prices (marginal costs). Figure 42 shows the average marginal cost, grouped by hour of day, in Sweden. A clear depression can be seen around noon when solar PV output is highest.

For wind power the effect is a bit more difficult to analyse using the simulated scenarios. It should be kept in mind that the market value factor is influenced by many things such as the whole generation portfolio, demand patterns, etc., and that changes in VRES share are accompanied by many other changes. In the Nordic system analysis, it is possible to compare the **Energy Transition** and **Renewable Ambition** scenarios whilst bearing in mind that **Renewable Ambition** includes many changes such as changed demand patterns via deployment of EVs. **Renewable Ambition** scenario increases wind power share of total electricity demand by 2.5 percentage points. Even though the change is small, some decrease in the market value factor is visible, as shown by Figure 43. The decrease is somewhat smaller than that of solar power.

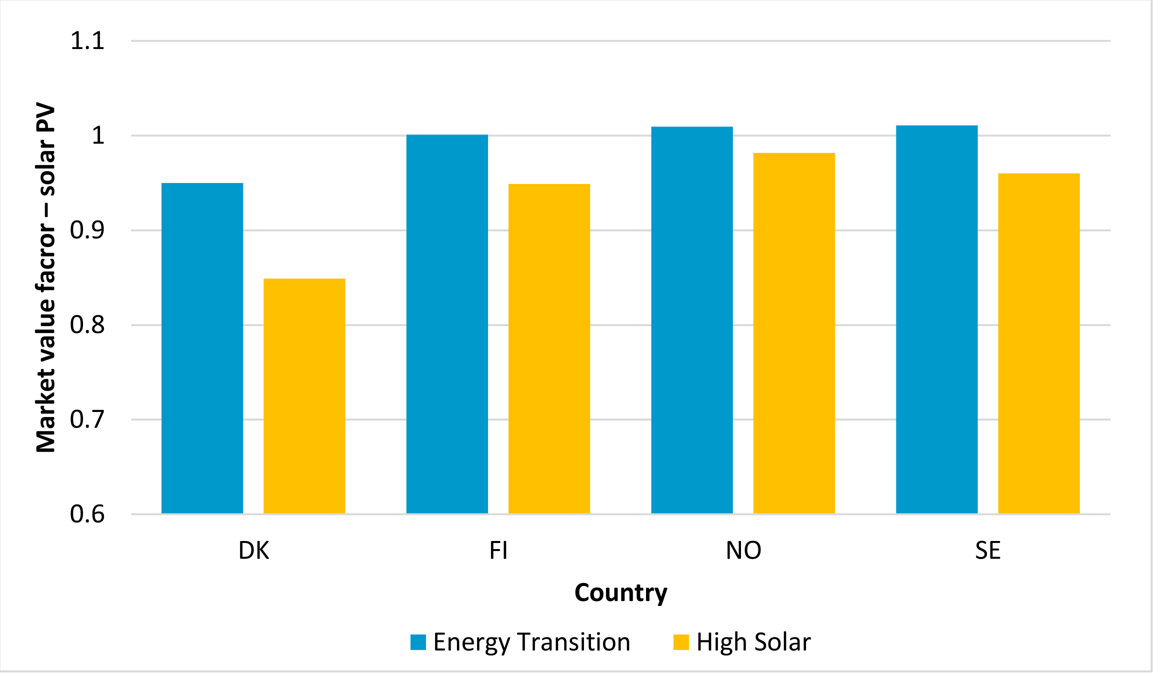

FIGURE 41: MARKET VALUE FACTOR FOR SOLAR PV IN THE NORDIC COUNTRIES

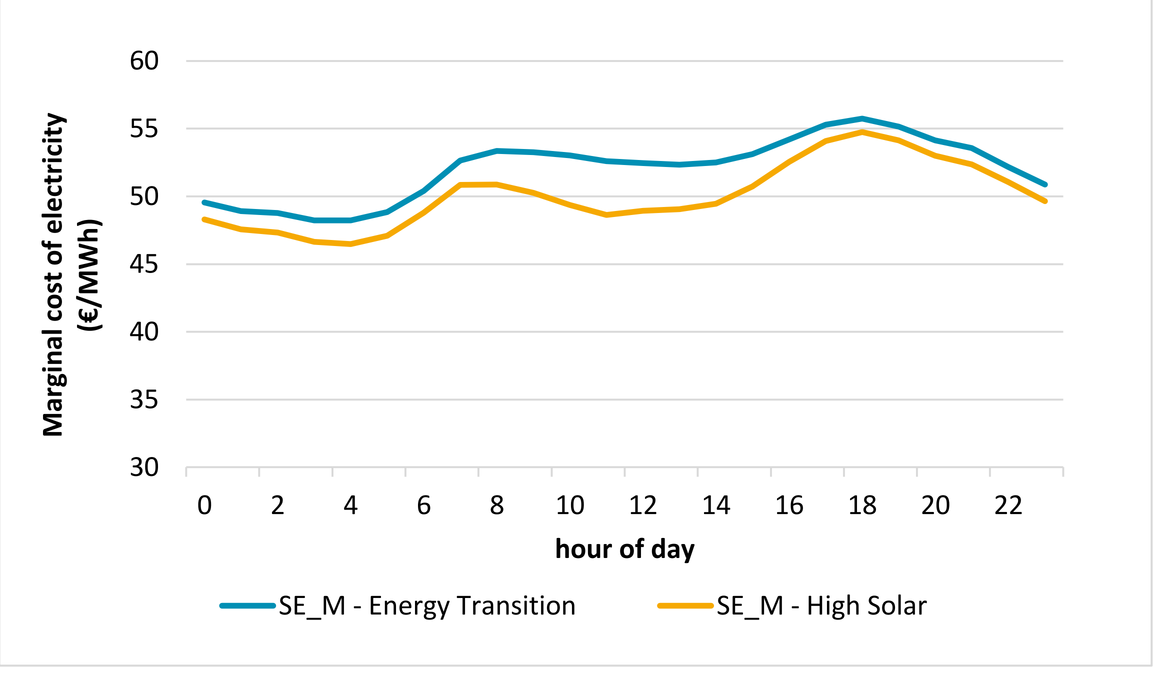

FIGURE 42: DIURNAL PATTERN OF AVERAGE MARGINAL COST OF ELECTRICITY IN SWEDEN

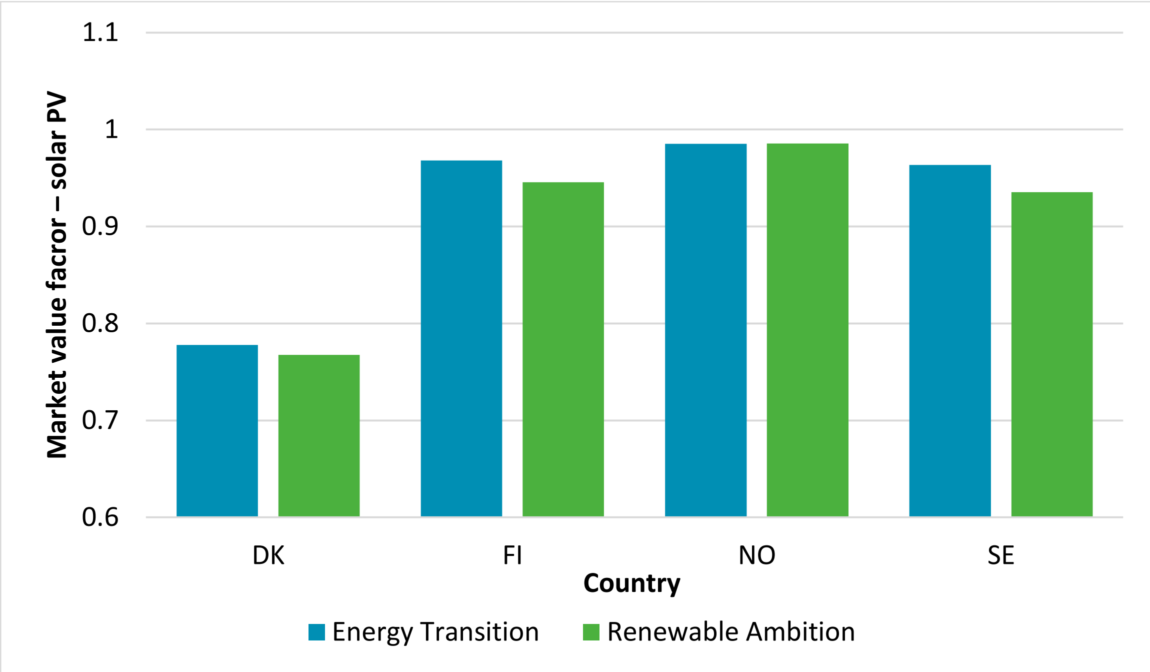

FIGURE 43: MARKET VALUE FACTOR FOR WIND POWER IN THE NORDIC COUNTRIES

5.6.3 WIND POWER CAN COVER ITS COSTS WHILE SOLAR PV EXPERIENCES FINANCIAL GAPS

In this section the results of the financial gap analysis are reviewed. The methodology of the financial gap analysis was explained in Section 0. Here the results are presented as annual "supernormal" profits where the expected return on invested capital has already been deducted. Negative profitability indicates a financial gap.

Figure 44 shows the profitability results per installed capacity for utility-scale solar PV. The different cost scenarios, defined in Section 2.2, have been turned into confidence intervals. It is noted that the confidence intervals are rather wide. In the low cost scenario, solar PV is profitable in all cases, whereas in base cost scenario solar PV is marginally profitable only in the **Renewable Ambition** scenario. This is explained by the higher market prices which were obtained for the **Renewable Ambition** scenario. It is also noted that the small differences between countries are completely masked by the effect of cost uncertainty.

As the profitability was calculated for utility-scale PV, the revenue is based on simulated wholesale market prices. For solar PV which is installed behind the meter, the business case is different, as self-consumption in Nordic countries enjoys a premium compared to selling all production on the wholesale market. However, PV which is installed behind the meter also reduces the market value factor of utility-scale PV.

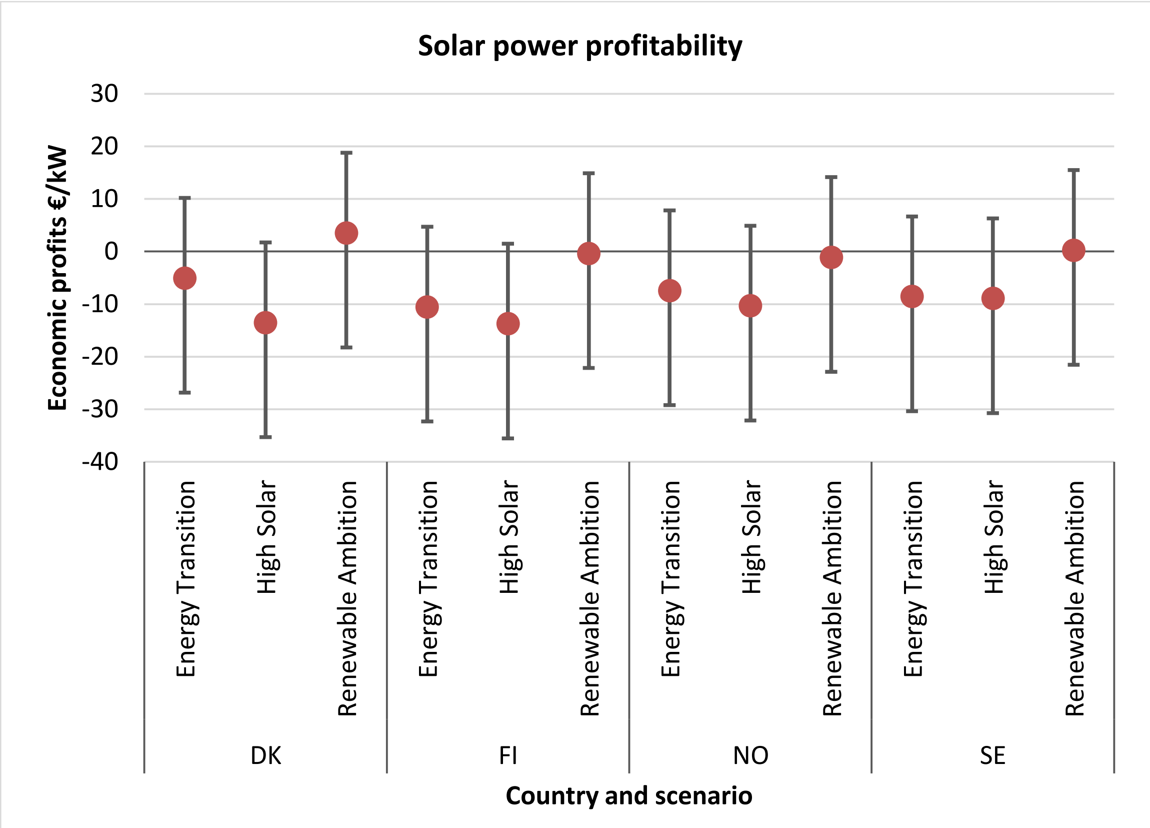

FIGURE 44: PROFITABILITY OF SOLAR PV IN NORDIC COUNTRIES. THE ORDINATE SHOWS THE ANNUAL SUPERNORMAL PROFIT PER INSTALLED CAPACITY. THE ERROR BARS REPRESENT THE CONFIDENCE INTERVAL RESULTING FROM DIFFERENT COST SCENARIOS

Figure 45 shows profitability results per installed capacity for wind power. Overall, the costs and revenues per installed capacity are larger and also the resulting confidence interval is wider. In this case it is also seen that there are clear differences between countries, which are due to the different capacity factors assumed in different countries. The assumed capacity factors for Sweden and Denmark were quite low and higher capacity factors could be achievable. Considering this fact, it could be stated that wind power appears profitable in the base cost scenario and financial gaps are not present. In the high cost scenario small financial gaps seem to be present in the **Energy Transition** and **High Solar** scenarios.

Figure 46 shows profitability results per installed capacity for nuclear power. Depending on the cost scenario, nuclear power may either experience financial gap or not in the **Energy Transition** and **High Solar** scenarios. There is a small difference between Finland and Sweden – Swedish nuclear power must run more time on partial load. Market price level is higher in the **Renewable Ambition** scenario, which leads to a clearly better profitability.

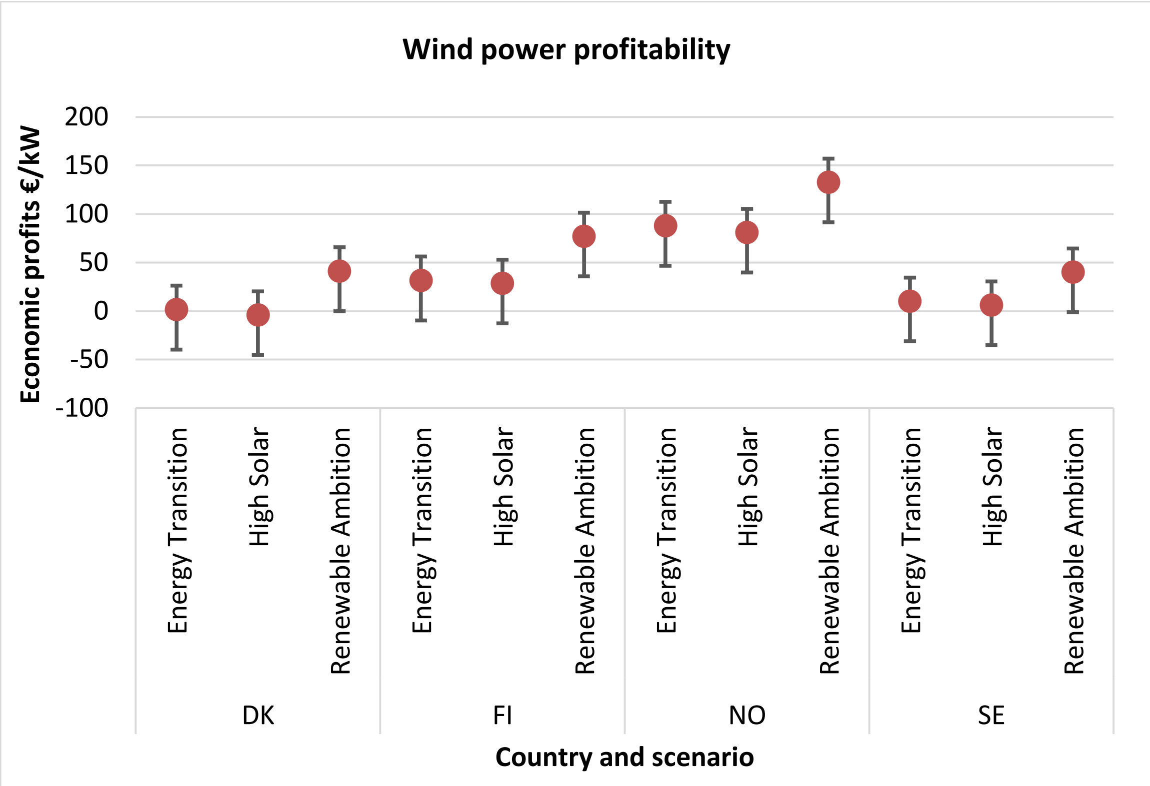

FIGURE 45: PROFITABILITY OF WIND POWER IN NORDIC COUNTRIES.

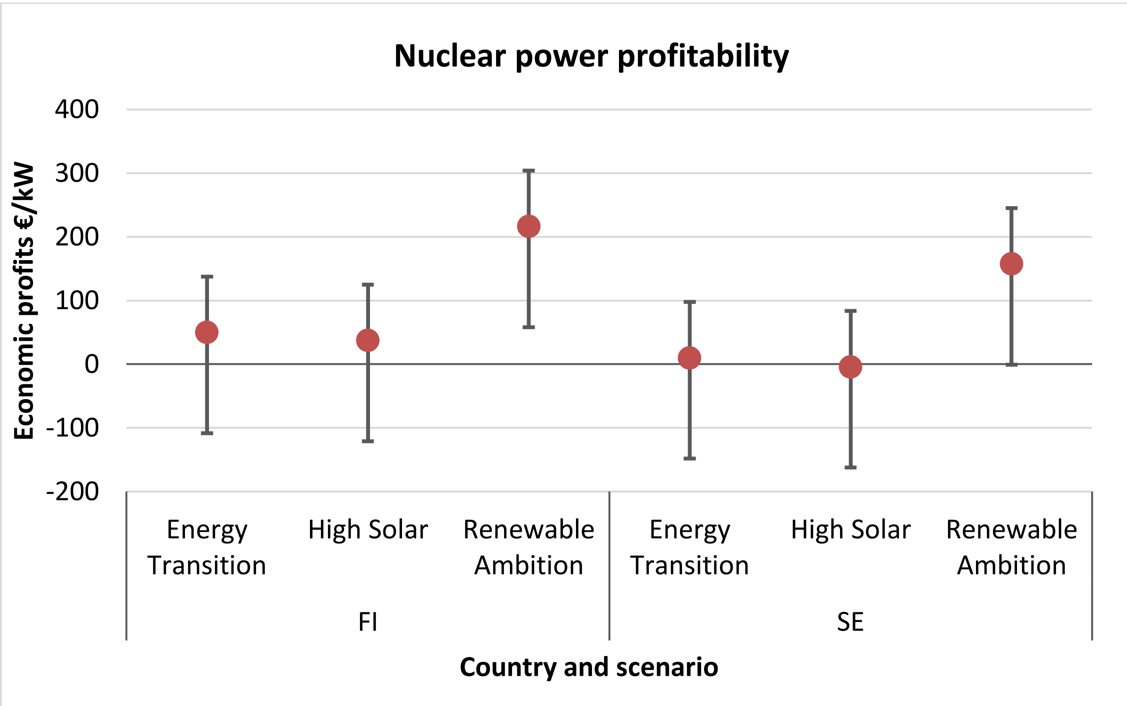

FIGURE 46: PROFITABILITY OF NUCLEAR POWER IN NORDIC COUNTRIES

Utility-scale solar PV is likely to experience financial gaps in Nordic countries. Wind power is likely to thrive on market-based earnings in Norway and Finland. For Sweden and Denmark, only the Renewable Ambition scenario clearly indicates profits.

5.7 SYSTEM SPECIFIC FINDINGS – IRELAND AND NOTHERN IRELAND POWER SYSTEM

The results from the Ireland and Northern Ireland system indicate that significant financial gaps arise across the three Network Sensitivities analysed. In addition to studying the financial gaps for the high, medium and low cost figures published by DCCAE [38], the World Economic Outlook costs [39] are also considered.

5.7.1 SYSTEM PRICES ARE FALLING

It has been well documented in the literature that the transition to a power system with increased levels of renewables is supressing average marginal electricity costs [37]. The results from Task 2.5 for Ireland and Northern Ireland concur with this[13]. Across all the scenarios examined it is found that the integration of high levels of variable renewables can have a very profound downward impact on the average system marginal prices (SMP). Depending on the particular scenario, the specific power system being investigated and the level of renewables being considered, average marginal prices could fall by more than 30%. This is depicted Figure 47 which shows average marginal prices for the power system on the island of Ireland.

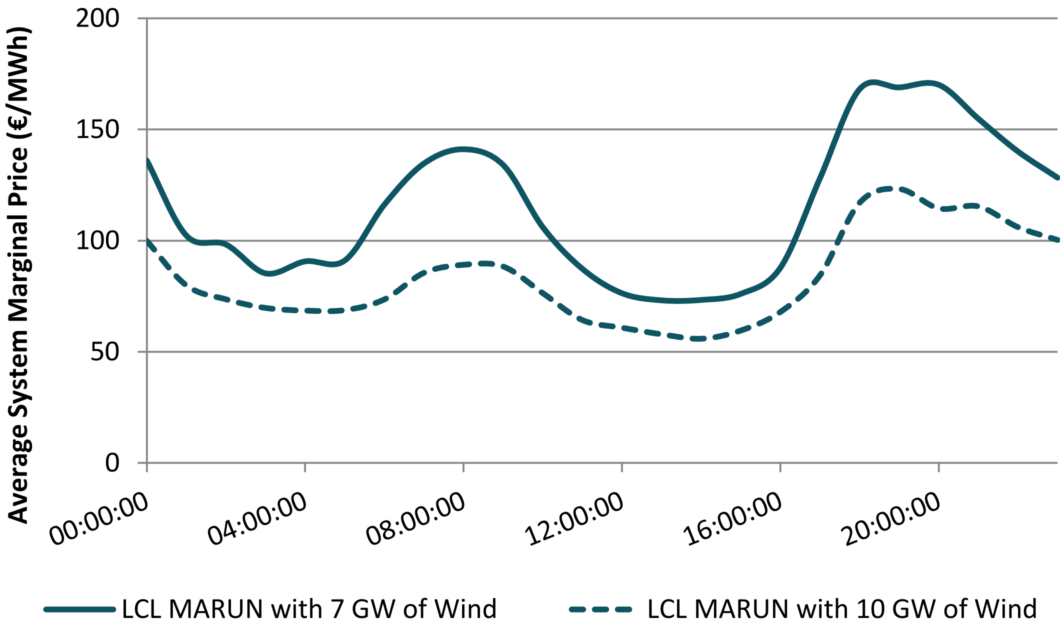

FIGURE 47: COMPARISON OF AVERAGE SYSTEM MARGINAL PRICES FOR THE IRELAND AND NORTHERN IRELAND POWER SYSTEM FOR THE LOW CARBON LIVING SCENARIO IN 2030 WITH VARYING INSTALLED CAPACITIES OF WIND

Additionally, the variability of the profile of the underlying renewable resources can have a considerable impact on the marginal prices. Increasing levels of wind capacity has an impact on the average marginal prices for each hour of the day, unlike solar PV. Increasing solar PV capacity tends to only influence the marginal price between

[13] Note that the system marginal costs from the MARUN (or energy market only simulation) are used to determine the electricity prices for the Ireland and Northern Ireland power system.

the hours of 09:00 and 17:00. This is a result of the fact that the underlying solar resource follows a regular diurnal pattern whereas peak wind generation periods are not restricted to particular hours of the year.

Another impact of increasing levels of renewables on marginal prices is illustrated in Figure 48. As can be seen, increasing the levels of variable renewables results in an increase in the number of hours during the year where the marginal price is 0.

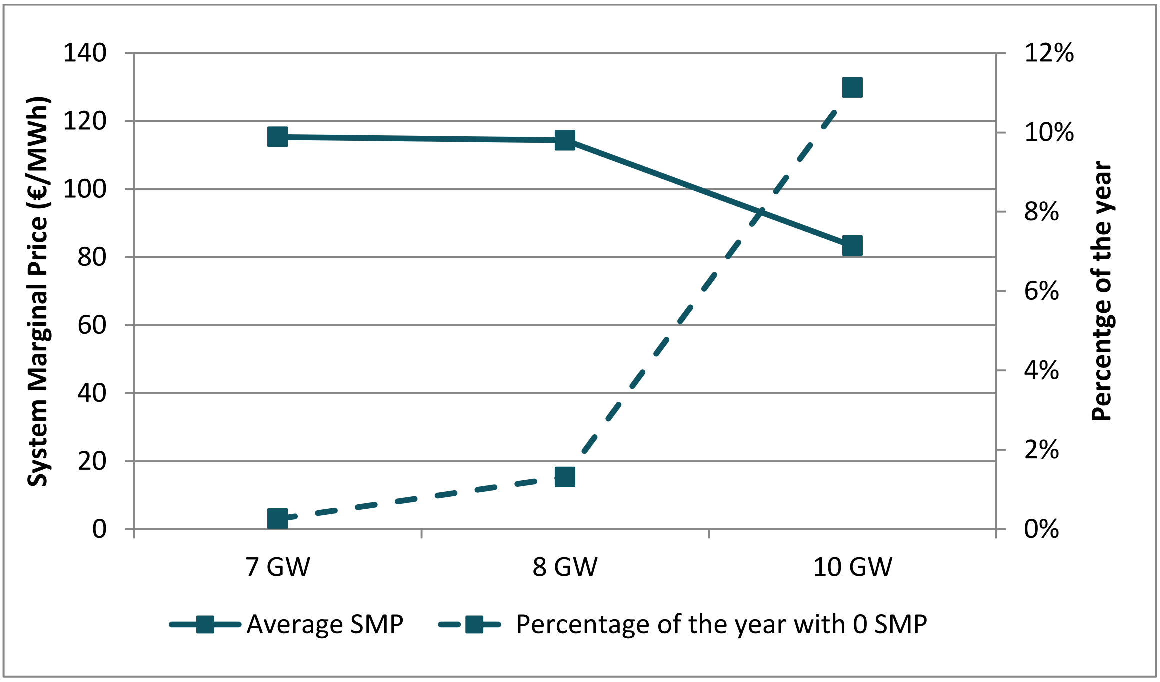

FIGURE 48: FALLING AVERAGE MARGINAL COST AND INCREASING TIME SPENT AT ZERO MARGINAL COST FOR IRELAND AND NORTHERN IRELAND FOR THE LOW CARBON LIVING SCENARIO AND INCREASING WIND INSTALLED CAPACITIES IN 2030

The trends emerging for Ireland and Northern Ireland in terms of falling system marginal prices and the increasing time spent with 0 marginal prices is consistent with the findings presented earlier in this chapter for the broader European power system.

5.7.2 MARKET VALUES ARE FALLING WITH INCREASING LEVELS OF VRES

It was seen for the Continental power system that market value factors decrease with increasing VRES penetration. Similar observations are made on the Irish and Northern Irish power system across the three sensitivities investigated as part of Task 2.5. It can be observed from Figure 49 and Figure 50 that the market value factor decreases significantly with very high levels of installed wind. For the **Consumer Action** (CA) Network Sensitivity the Market Value factor for both on shore and off shore wind increases slightly as installed wind capacity increases from 7GW to 8GW. From a study of the underlying data, this is due to the fact that although the average price received by wind technologies drops, it does not drop as quickly as the average market price.

However, the overall trend is a reduction in the market value of offshore and onshore wind as the levels of variable renewables increases.

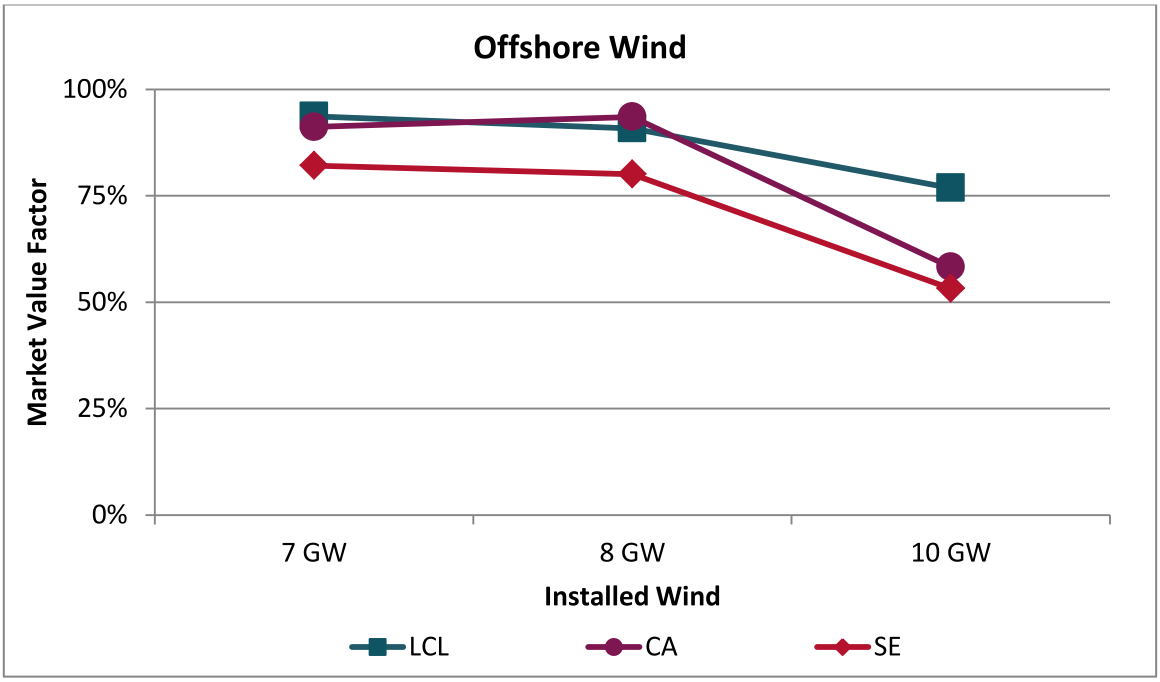

FIGURE 49: MARKET VALUE FACTORS FOR OFFSHORE WIND IN IRELAND AND NORTHERN IRELAND

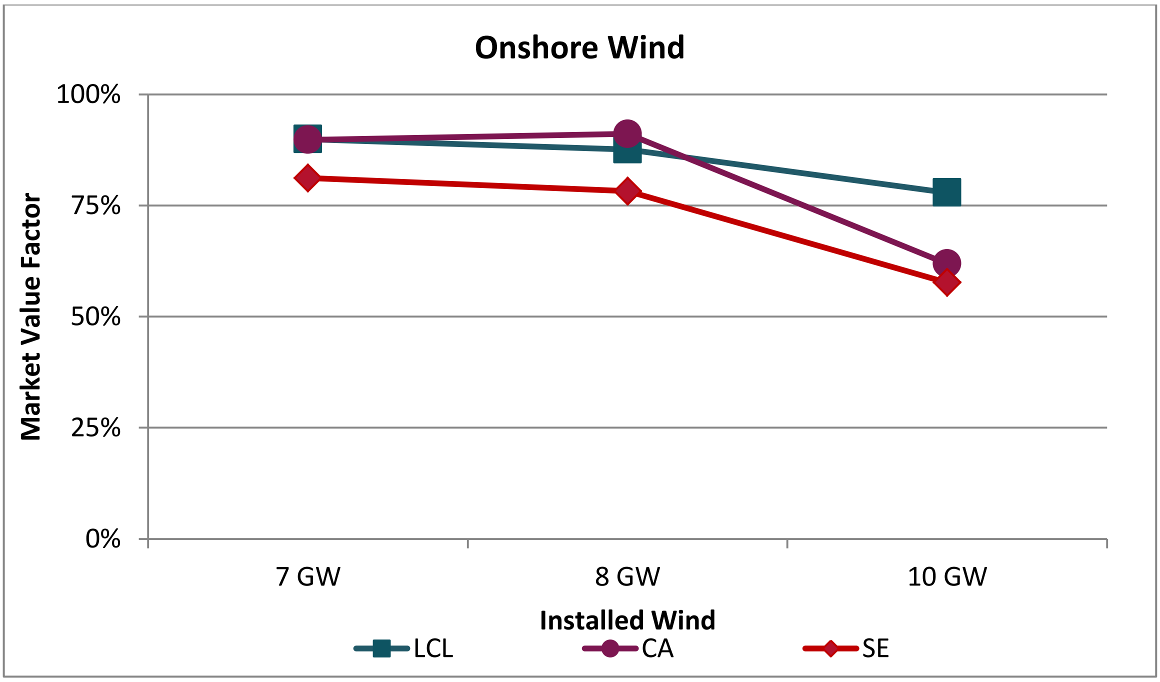

FIGURE 50: MARKET VALUE FACTORS FOR ONSHORE WIND IN IRELAND AND NORTHERN IRELAND

Similarly, it can be observed from Figure 51, that Market Value Factors decrease as the levels of installed solar increase. It can be seen however that the curve does not fall as steeply for solar as it does for wind or solar on the continental system. This is mainly due to both the daily availability of solar and the proportion of solar generation to total vRES generation in Ireland and Northern Ireland.

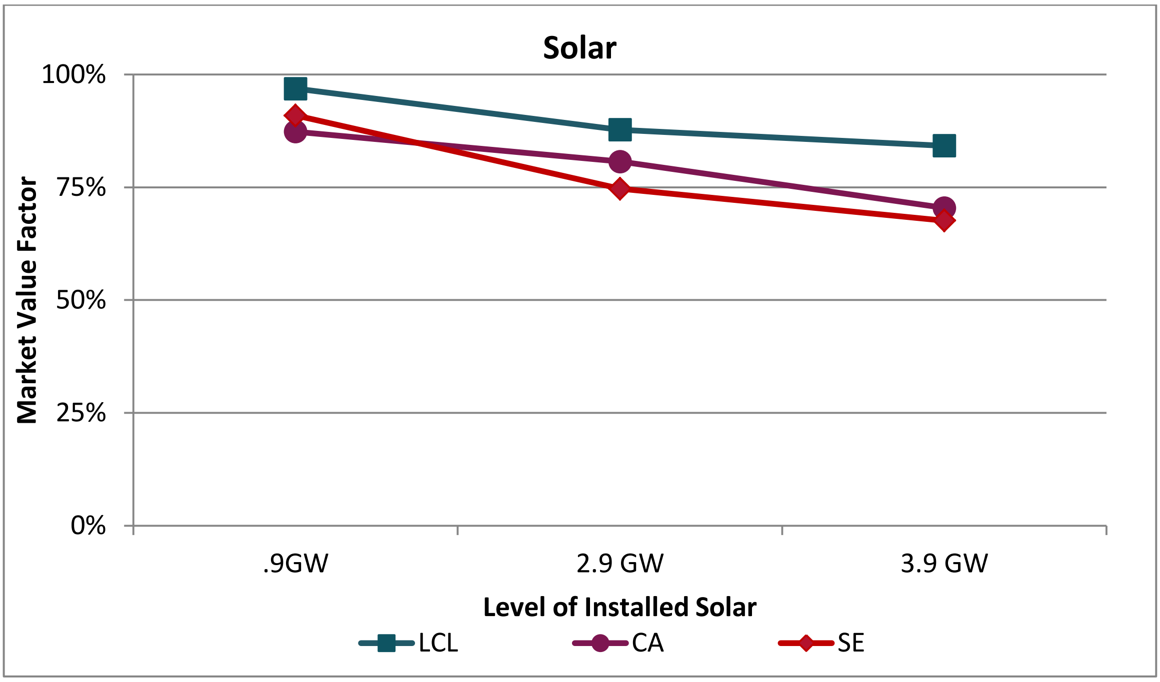

FIGURE 51: MARKET VALUE FACTOR FOR SOLAR IN IRELAND AND NORTHERN IRELAND

From Figure 52, it can be observed that solar generation is only available for a short number of hours throughout the day and that these hours typically coincide with low system marginal prices. This limits the ability of solar to suppress peak system marginal prices. Even though the average price received by solar technologies decreases, average system marginal prices remain high, particularly at peak times when solar generation is not available. This reduces the decline in ratio of system marginal price received by solar to average system price (or the market value factor). Wind however can be available throughout the day and has greater influence in suppressing peak prices, and experiences steeper declines in Market Value Factor as wind levels increase.

In addition, the quantities of solar generation on the Ireland and Northern Ireland system in the various Network Sensitivities make up a smaller share of vRES generation than wind generation. This further reduces the influence of solar generation on system price reduction. For example, in the **Low Carbon Living** (LCL) sensitivity, installed solar capacity is 3.9GW compared to an installed wind capacity of 10 GW. Wind consequently has a greater ability than solar to influence price curves in Ireland and Northern Ireland.

Indeed analysis undertaken by EirGrid and SONI has shown that as wind levels increase and the level of installed solar remains the same, the Market Value Factor for solar can actually begin to increase. This is because although the average system marginal price when solar is generating is decreasing, the average system price decreases more sharply across the day with increasing wind levels. This has the impact of increasing the Market Value Factor for solar as wind levels increase as shown in Figure 53. Such phenomenon is described as a 'correlation effect' by [40]. The average price solar received could be described as having a positive correlation with the average price wind generation receives. Wind is decreasing the average price across the day more rapidly than solar is reducing prices at the middle of the day, giving rise to an increase in Market Value Factor for solar technologies

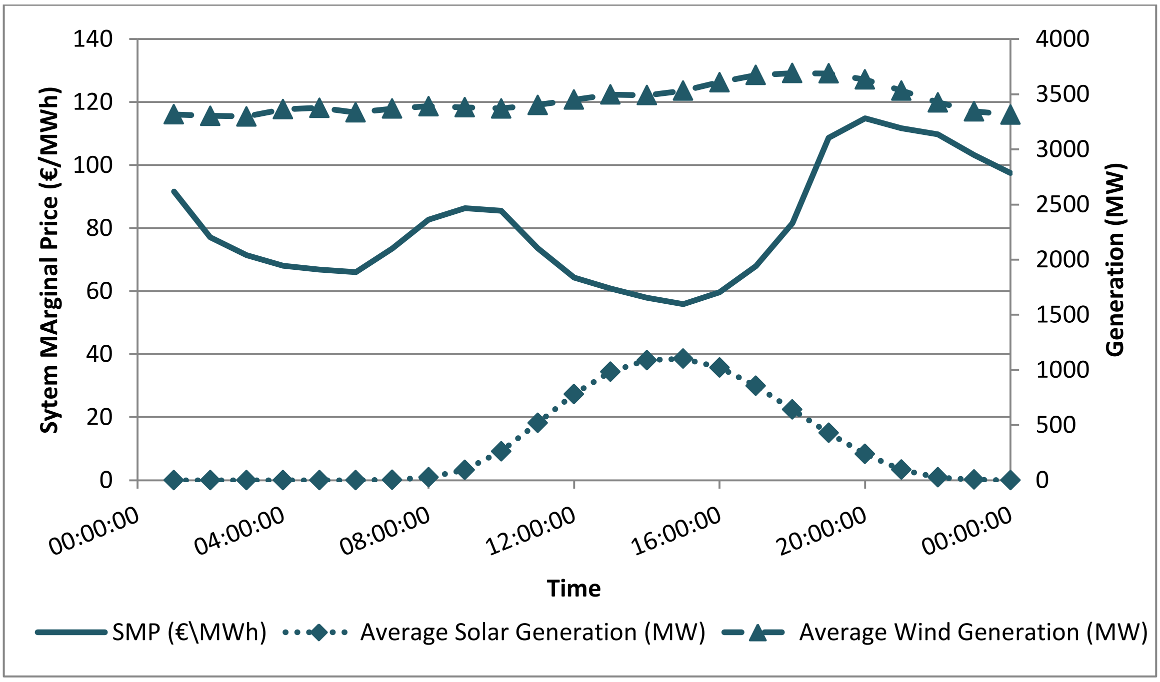

FIGURE 52: AVERAGE SOLAR AND WIND GENERATION VS AVERAGE MARGINAL PRICE

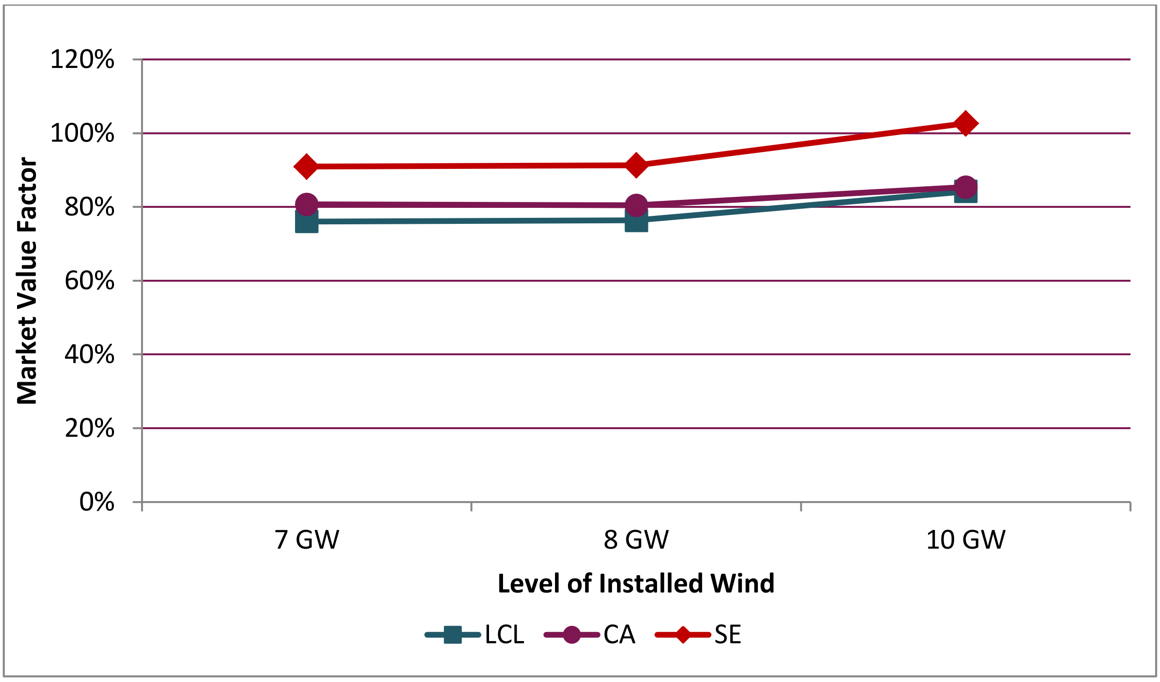

FIGURE 53: MARKET VALUE FACTOR FOR SOLAR WITH INCREASING WIND LEVELS

Although Market Value Factor provides important insight into the profitability of various technologies, the above anomalies highlight the need for deeper insights and alternative metrics to better understand the financial viability of renewable technologies with increasing vRES penetration. It is important to fully comprehend the impact of falling revenues per technology relative to technology specific costs incurred. The next section therefore examines financial gaps that arise for vRES technologies; this is done through analysis of revenues per technology type against technology specific costs.

The trends emerging for Ireland and Northern Ireland in terms of falling system market value factors with increasing levels of variable renewable penetration confirm those observed for Continental Europe.

5.7.3 REVENUES ARE FALLING AND FINANCIAL GAPS ARE APPEARING FOR VRES TECHNOLOGIES

It has been shown in the analysis for Ireland and Northern Ireland that as the levels of installed capacity of variable renewable generation increase, the revenues decrease for most technologies, as a result of falling system marginal prices, as discussed above. This concurs with analysis for the broader European power system presented earlier in this Chapter.

It is worth noting that demand has a significant impact on the levels of revenue available. Although it is noted that the **Low Carbon Living** (LCL) Network Sensitivity has the highest level of installed capacity of variable renewables of any of the sensitivities examined, it also has the high level of system demand. This gives rise to the generators in the **Low Carbon Living** (LCL) Network Sensitivity experiencing higher revenues. On the contrary, the revenues per technology are lowest for the **Steady Evolution** sensitivity which has the lowest demand. Subsequently the **Steady Evolution** (SE) scenario experiences the highest revenues and the lowest financial gaps.

Figure 54 illustrates how market revenues per MW installed for offshore wind decrease with increasing wind levels for each of the three Network Sensitivities used to study the Ireland and Northern Ireland power system. The black dashed line represents the average investment cost being employed in the analysis. As can be seen, the revenues for offshore wind are routinely below the investment cost figure in the vast majority of the sensitivities examined. This leads to considerable financial gaps. From Figure 55 it is evident that offshore wind experiences significant financial gaps, especially at high wind levels, due to the falling revenues.

It is worth noting, that as of October 2019 offshore wind costs have fallen by 32% from the end of 2018 and 12% compared with the first half of 2019 [41]. The reason for this fall in costs is mainly due to a fall in the price of the turbines themselves (7% lower on average globally compared with the end of 2018). It is also noted by IRENA [42], that factors which contribute to off shore wind cost reductions include innovations in wind turbine technology, installation and logistics, economies of scale in O&M (from larger turbine and offshore wind farm clustering) and improved capacity factors from higher hub heights and larger rotor diameters. Based on these developments, the financial gaps for offshore wind may not be as severe as illustrated below. Indeed for the **Low Carbon Living** (LCL) scenario, with 3GW of offshore wind installed, reducing costs by one third results in the financial gap decreasing from approximately €125,000/MW/annum to €55,000/MW/annum.

There are similar trends for onshore wind for the Ireland and Northern Ireland power system as shown below in Figure 56. Unlike offshore wind however which has a relatively high investment cost, onshore wind seems to experience revenues that do not exceed their costs only when the total level of wind installed is exceptionally high. This is clearly depicted in Figure 57, which shows that onshore wind experiences financial gaps for all of the sensitivities studied with the highest level of installed wind generation. It is also evident from Figure 58 that solar technology also experiences financial gaps at very high levels of installed wind.

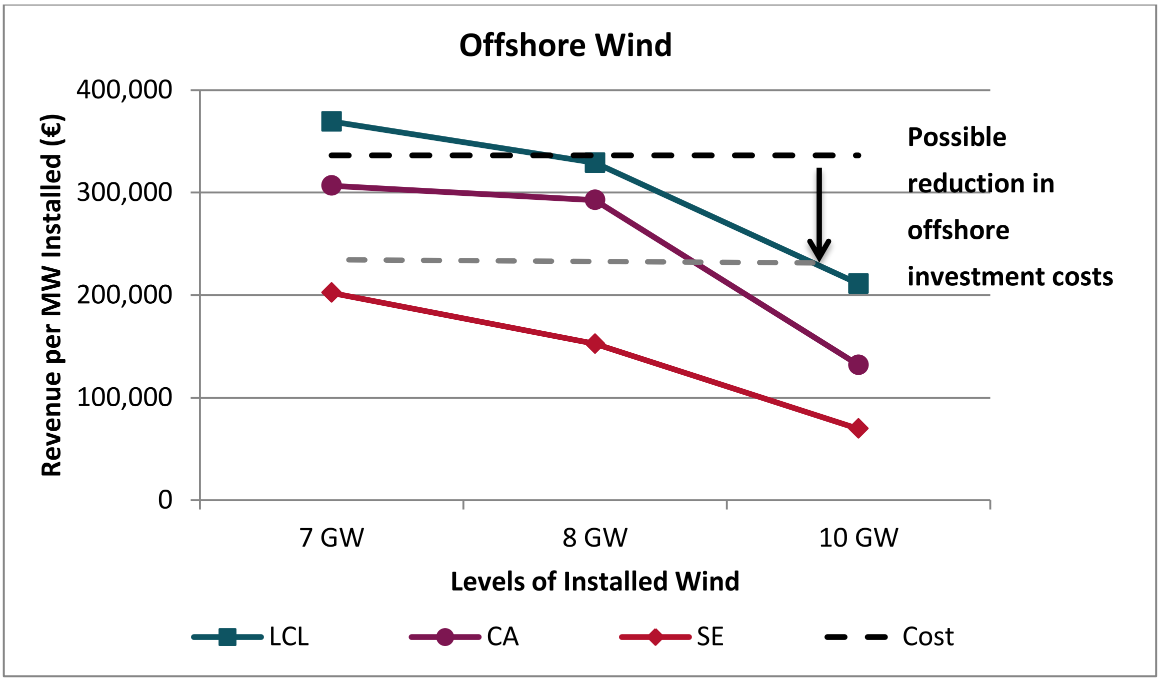

FIGURE 54: REVENUES AND COST FOR OFFSHORE WIND IN IRELAND AND NORTHERN IRELAND

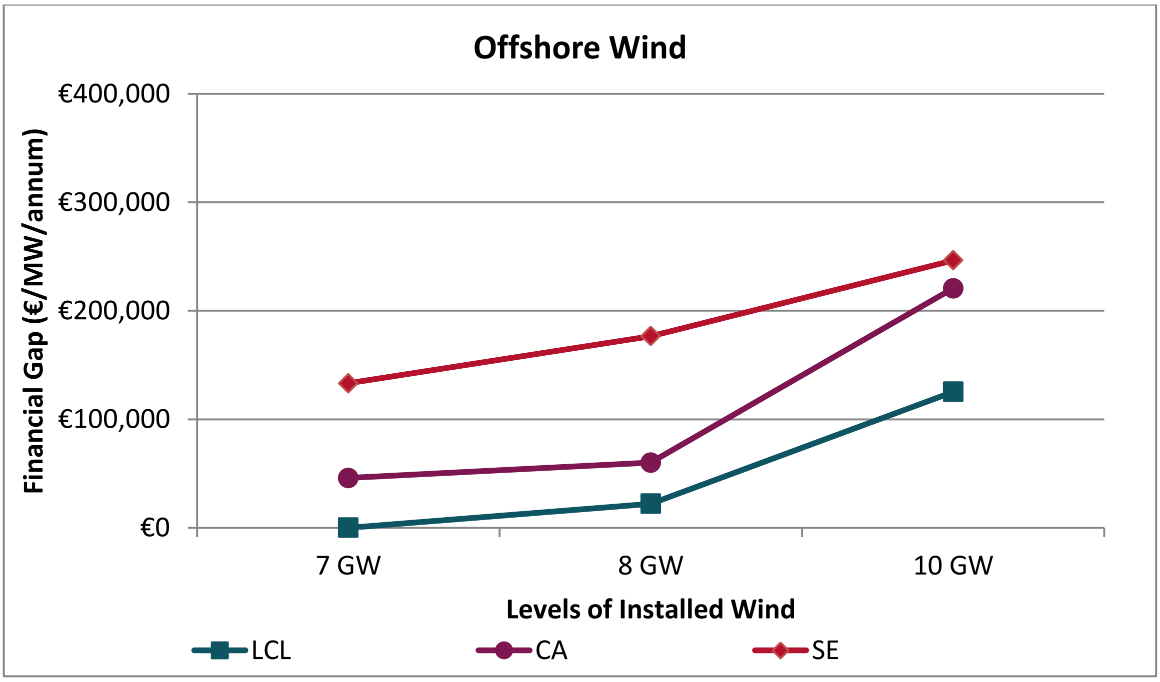

FIGURE 55: FINANCIAL GAPS FOR OFFSHORE WIND IN IRELAND AND NORTHERN IRELAND

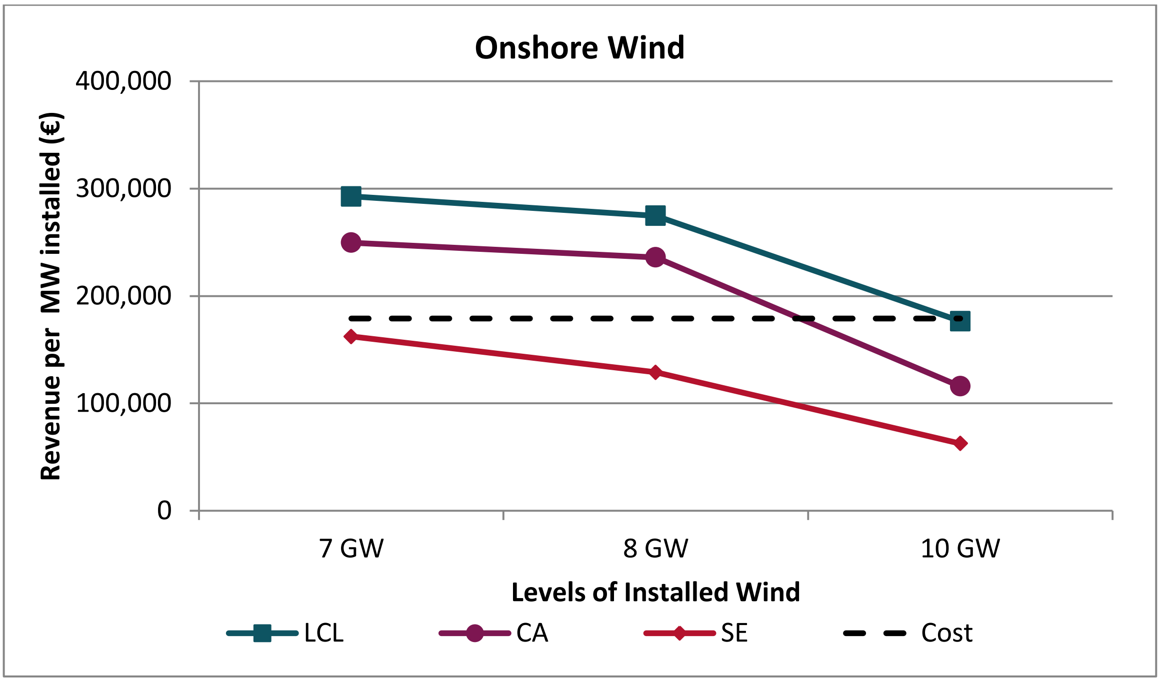

FIGURE 56: REVENUES AND COSTS FOR ONSHORE WIND IN IRELAND AND NORTHERN IRELAND

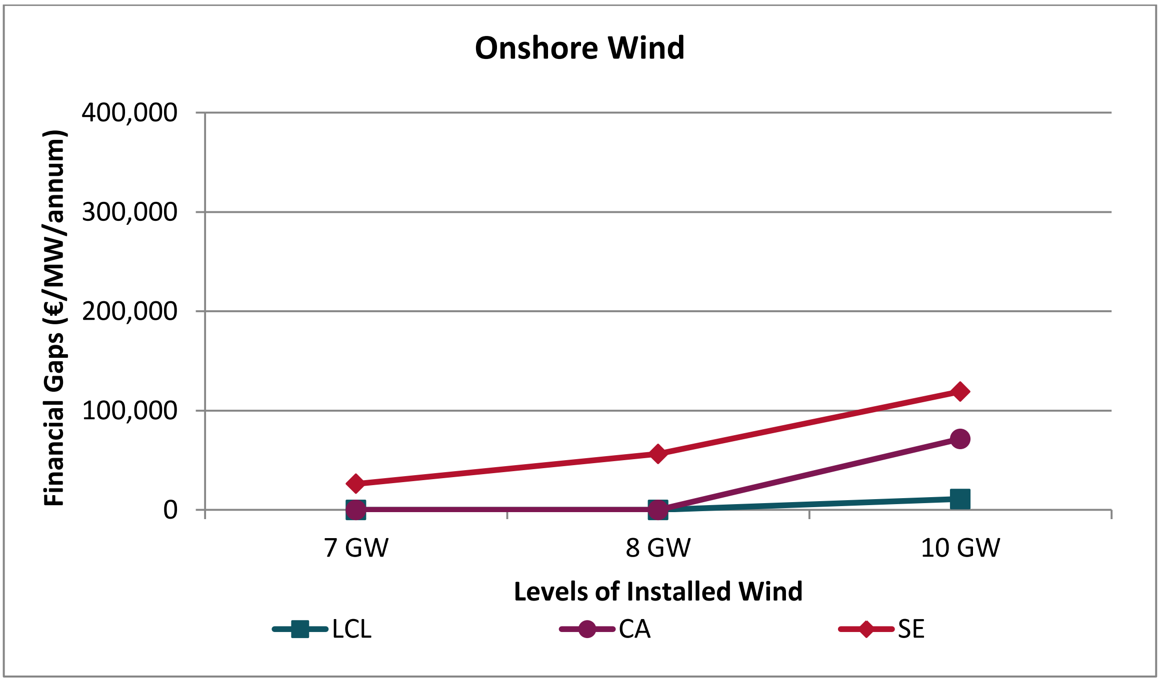

FIGURE 57: FINANCIAL GAPS FOR ONSHORE WIND IN IRELAND AND NORTHERN IRELAND

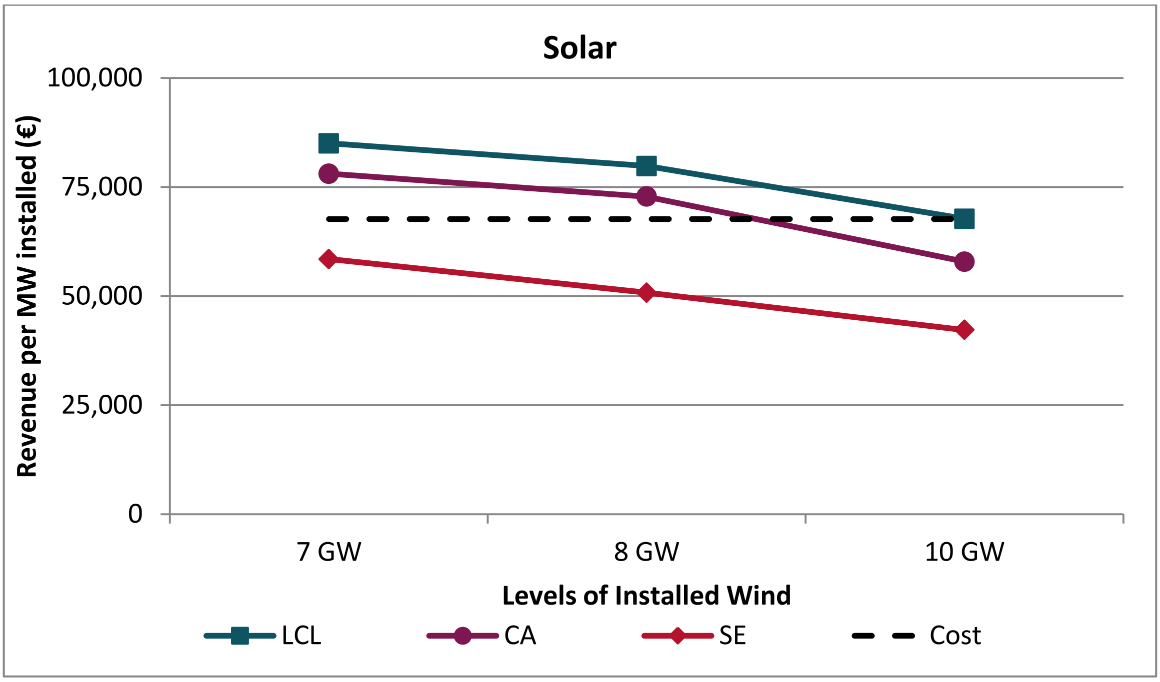

FIGURE 58: REVENUES AND COSTS FOR SOLAR IN IRELAND AND NORTHERN IRELAND

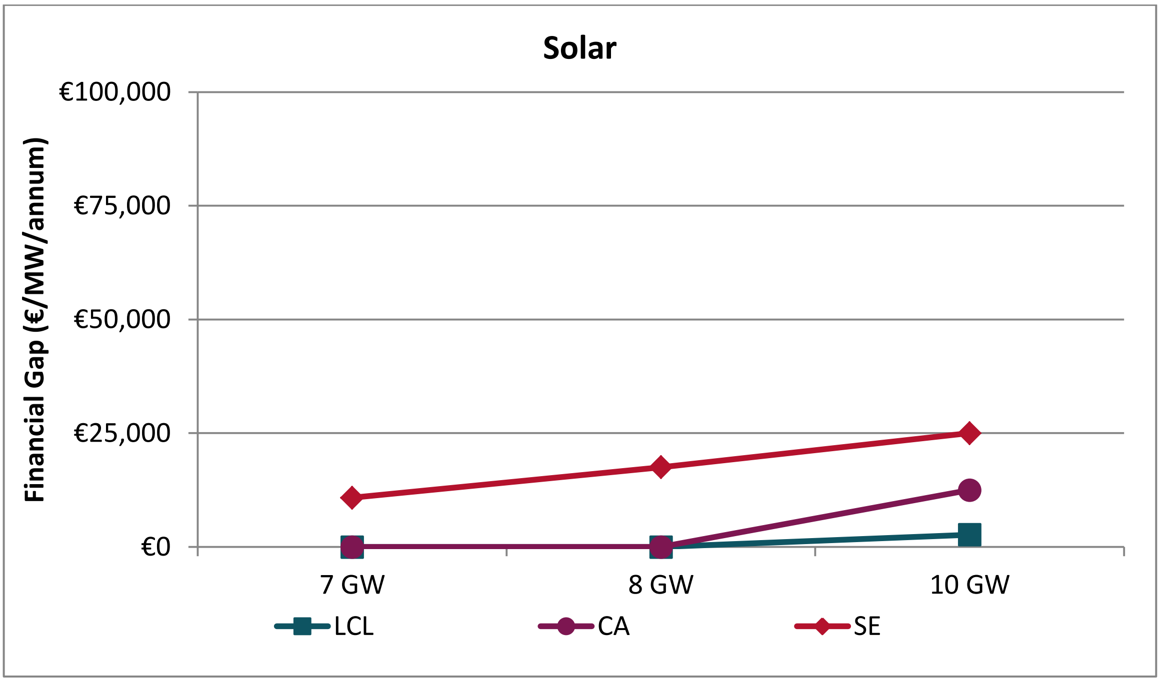

FIGURE 59: FINANCIAL GAPS FOR SOLAR IN IRELAND AND NOTHERN IRELAND

The downward trajectory of revenues leads to significant financial gaps for all variable renewable technologies. The investment cost plays an important role in determining the overall financial gap for each technology.

5.7.4 IN ADDITION TO FINANCIAL GAPS, THERE IS SIGNIFICANT VARIABILITY IN REVENUE

There is also an increase in the variability of market revenue (see Equation X) as VRES levels increase.

$$Variability\ in\ Revenue = \frac{Standard\ Deviation\ of\ Revenue\ earned\ per\ Interval}{Average\ Revenue\ earned\ per\ Interval} \tag{14}$$

This is illustrated in Figure 60 for the **Low Carbon Living** sensitivity. It is shown that as levels of installed wind increase to 10 GW, the standard deviation to average revenue increases sharply, this is due to the volatile and unpredictable nature of renewable technologies at very high levels.

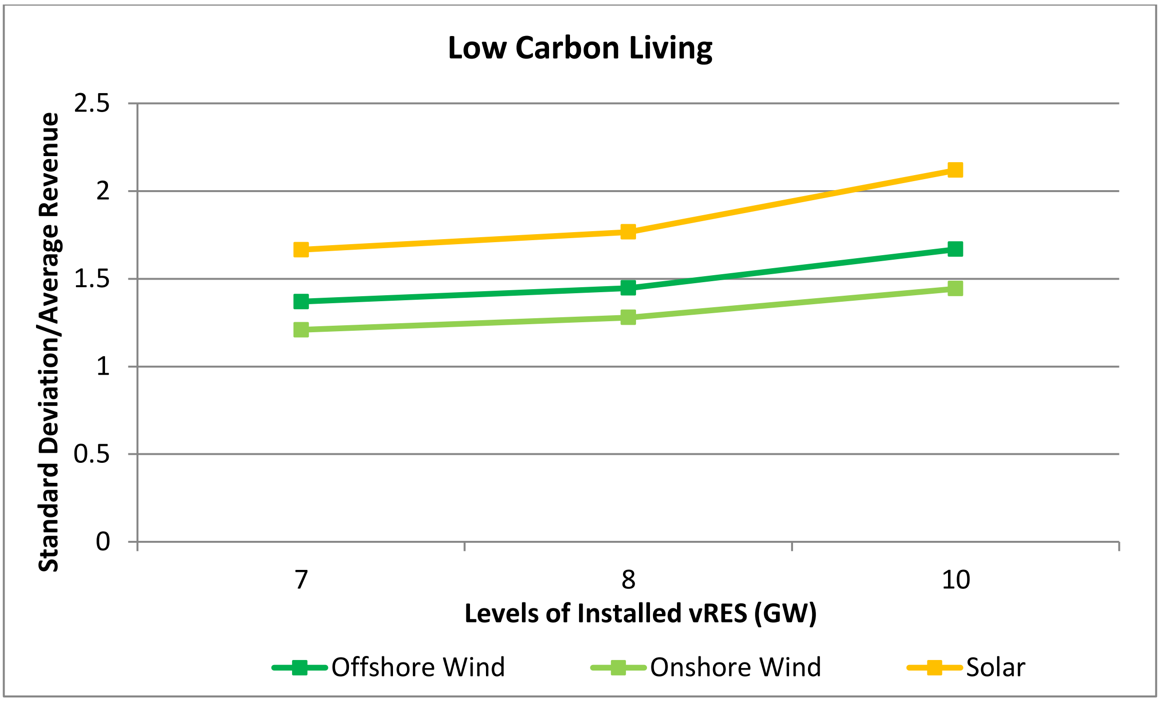

FIGURE 60: VARIABLILITY IN REVENUE FOR THE LOW CARBON LIVING SENSITIVITY

5.7.5 CONVENTIONAL GENERATORS MAY ALSO NOT EARN SUFFICIENT REVENUE

In addition to vRES technologies not earning sufficient revenue, it is evident that existing units including gas units are not earning sufficient revenue, this is shown in Figure 61. For **Low Carbon Living** sensitivity, as levels of installed wind increase from 7GW to 10GW, revenue for gas plant decreases by 50%. From Figure 62 it is evident, that financial gaps for gas generators are more prominent at higher penetrations of installed wind. This is true for all of the Network Sensitivities examined for Ireland and Northern Ireland.

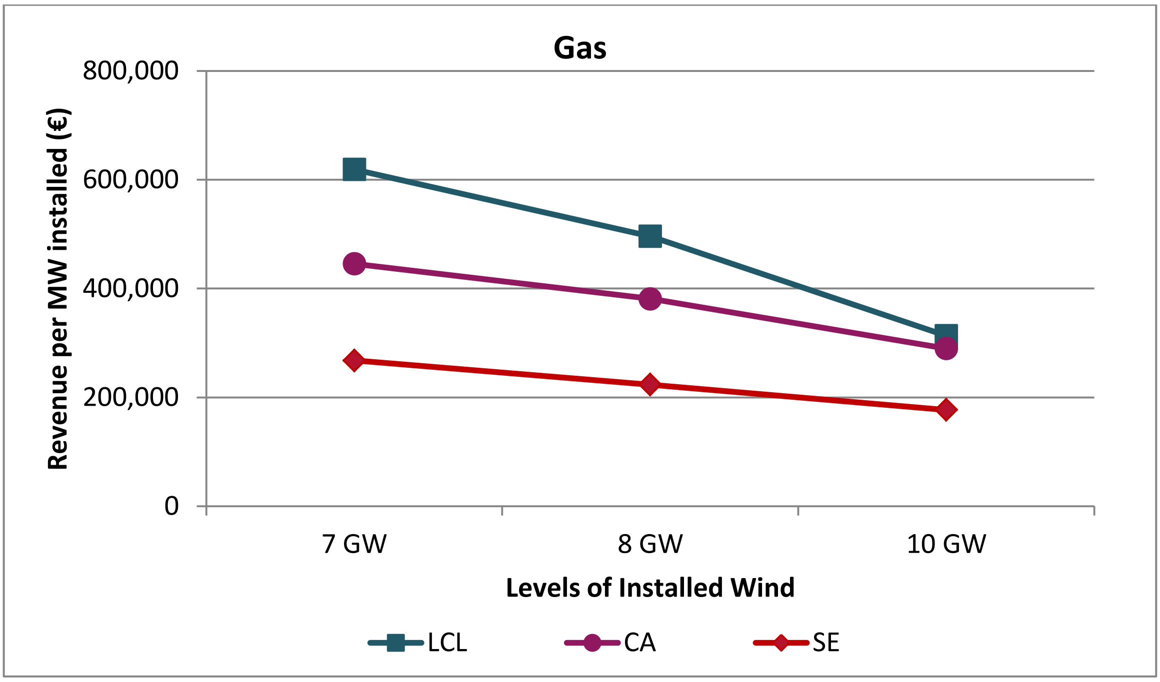

FIGURE 61: REVENUE PER MW INSTALLED FOR GAS UNITS

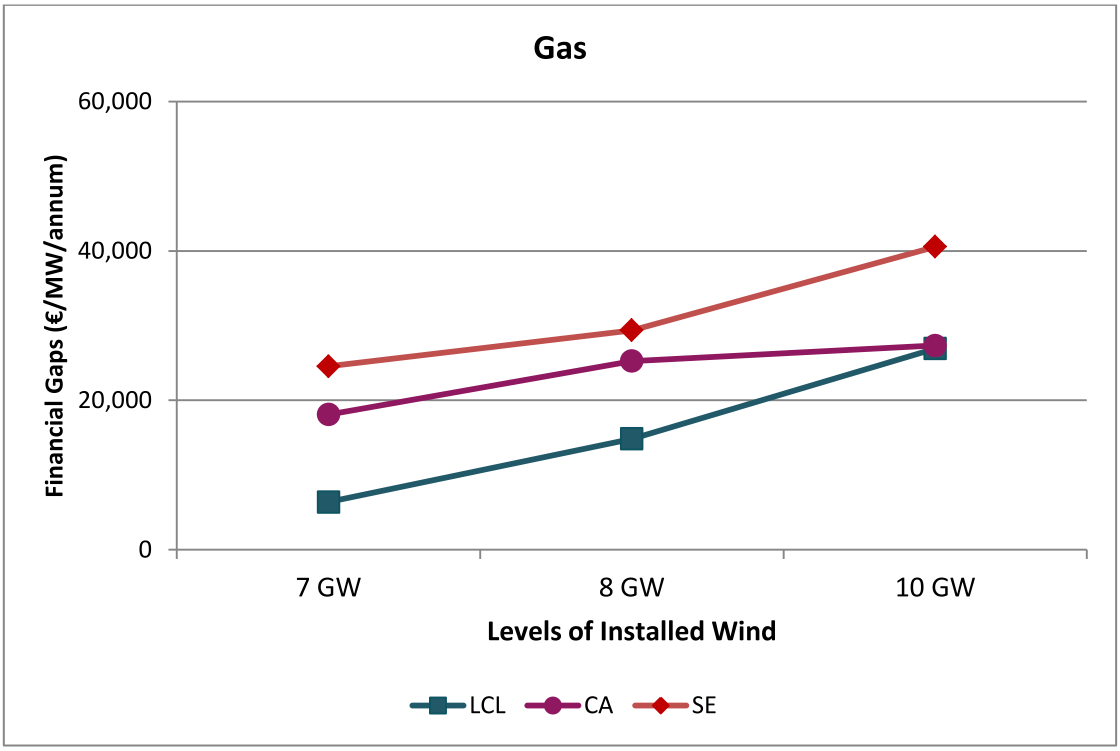

FIGURE 62: FINANCIAL GAPS FOR GAS UNITS IN IRELAND AND NORTHERN IRELAND

5.7.6 EVEN WITH A HIGH CARBON PRICE, FINANCIAL GAPS REMAIN

Figure 63 below illustrates that as carbon prices increase to €90/tonne, there is upward pressure on the average system price. This example is from the **Low Carbon Living** (LCL) Network Sensitivity. This has the effect of increasing revenues and therefore decreasing financial gaps, across the portfolio. However, the financial gaps still remain. The corresponding financial gaps are illustrated in Figure 64, where different assumptions relating to capital and fixed costs are denoted by the high, medium and low cases, as outlined in Table 9, above.

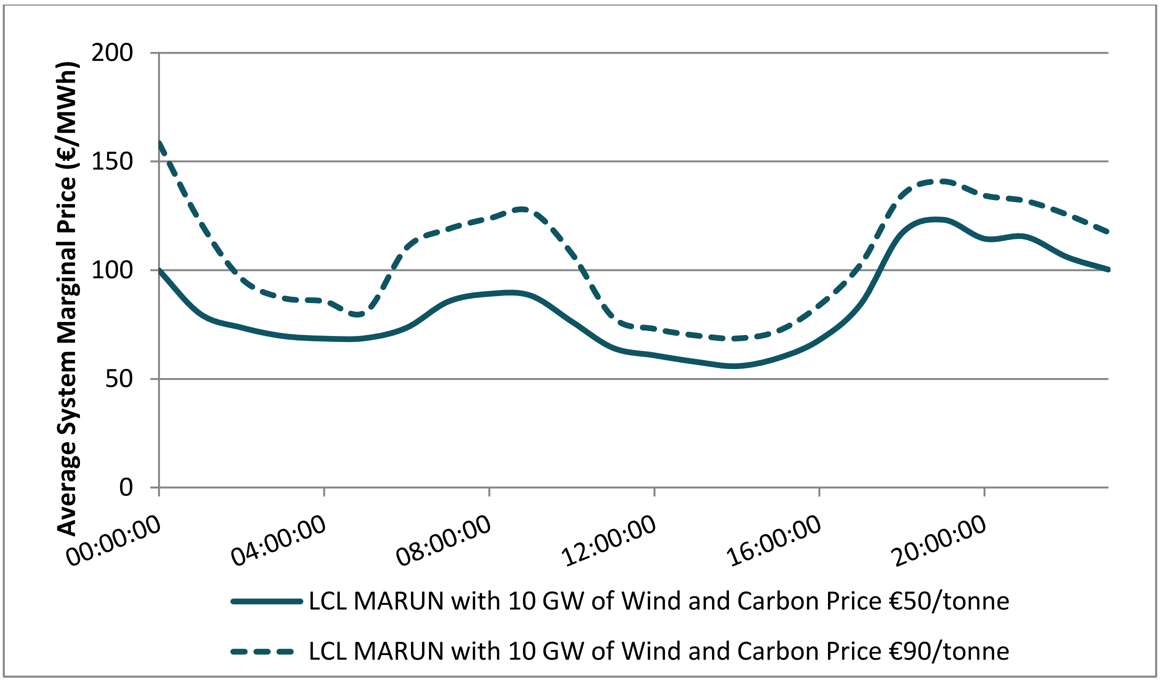

FIGURE 63: IMPACT ON PRICE CURVE WHEN PRICE OF CARBON IS INCREASED TO €90/TONNE

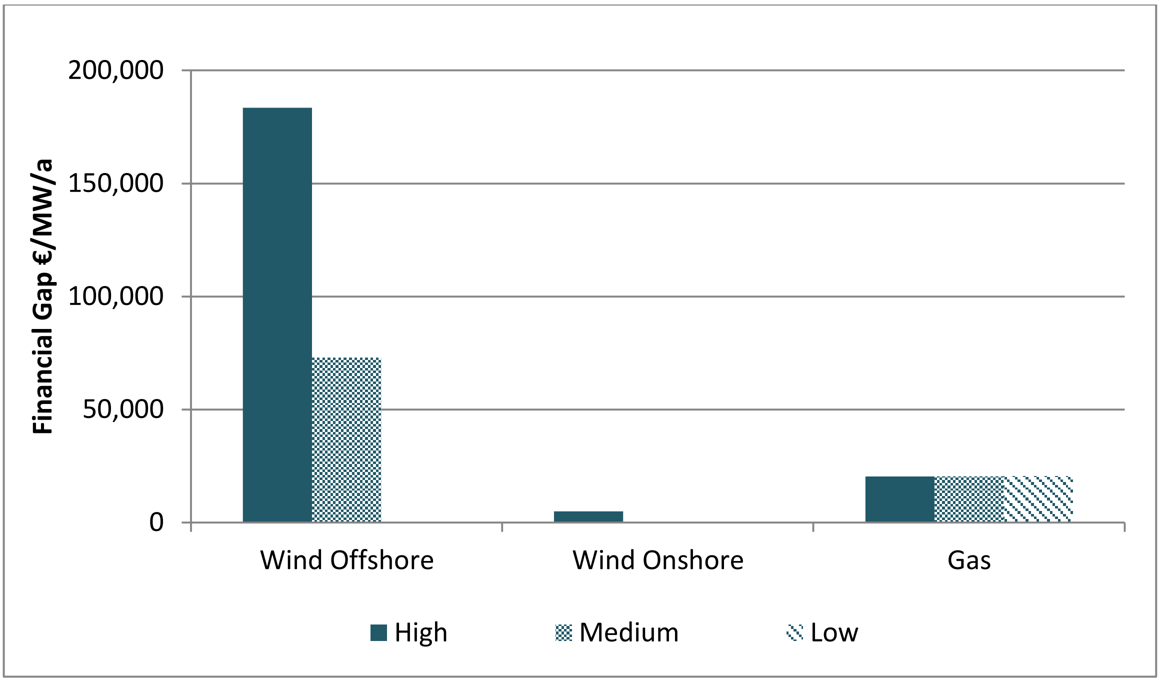

FIGURE 64: FINANCIAL GAPS THAT OCCUR WHEN CARBON PRICE IS €90/TONNE

It is evident that financial gaps are still experienced by wind and gas technologies. This agrees with findings in the literature [1] which show that a high carbon price alone does not make wind and solar power competitive at high penetration rates. It is also evident that gas units still incur financial losses. Indeed it is shown by [42] that high carbon prices significantly increase the cycling costs faced by generators and that these increased cycling costs significantly offset the carbon dioxide reduction benefits of the carbon price.

5.8 SUMMARY OF FINDINGS

In this Chapter, energy market revenues for the high shares of vRES scenarios for all regions were analysed and closely compared with associated costs.

When the UC/ED outcomes are examined, it is seen across the systems studied that the average marginal system prices drop as greater levels of variable renewable generation are integrated into the power systems. This has been well documented in the literature [37]. This is not surprising given the growing dominance of zero marginal cost generation such as wind and solar PV. As the average marginal system prices drop, so too do the revenues that are available. The downward trajectory of revenues leads to significant financial gaps for many technologies. Furthermore, the fact that the financial gaps still persist even with a high carbon price (90€/tCO_2 for Europe and Ireland) indicates that carbon price alone is an insufficient mechanism to drive the decarbonisation agenda.

The increased time spent with zero marginal prices also brings into question the appropriateness of relying on energy market designs that are predicated on the concept of marginal cost based electricity pricing as we transition to power systems with very high shares of renewables. It could also be argued that the end-user is less interested in the price of unit electricity and more concerned with the value or the utility that they can gain from utilising electricity. Perhaps the potential of employing a value-based pricing framework in electricity markets should be considered in earnest. This was out of scope in the analysis completed in this report, but may be an interesting area for future work.

In the context of re-examining electricity market design and potentially considering a value-based framework, the nature of electricity should be to the fore. Historically, electricity would have been considered a commodity as it was not a necessity and could be considered to be excludable. This largely dictated the way electricity markets were designed. Today, however, things are greatly different. In the European Union, access to electricity is considered to be a right and customers should not be disconnected for failing to pay. Therefore electricity is non-excludable. Additionally, having a safe, secure, reliable, adequate and resilient supply of electricity is non-rivalrous; either everyone benefits or no one does. Consequently, in this context, electricity could be considered to be a public good and this should be kept in mind during the transition to a power system with high levels of zero marginal cost renewable generation and in the market design solutions that are being developed.

It has been found that across the Continental European power system and the Nordic power system, utility-scale solar PV is likely to experience significant financial gaps in the future. In Ireland and Northern Ireland, where wind generation is the dominant source of renewable generation in the scenarios, offshore wind experiences significant financial gaps. It should be noted that the investment cost plays an important role in determining the overall financial gap for each technology; if the capital cost of offshore wind can be reduced, the financial gaps for offshore wind in Ireland and Northern Ireland will also fall. This is because for offshore wind and other variable renewable resources cost structures are overwhelmingly dominated by fixed investment costs.

To add to the findings of the calculations, Hogan (2017) argues that wholesale electricity markets (energy only markets) do not reflect the true marginal costs of all the actions required to meet the demand for reliable energy; they typically just reflect the short-run marginal costs. As a result of this failure to properly reflect the marginal cost of balancing services in the energy market clearing price, "*the energy market's ability to remunerate needed investment"* is severely limited. Furthermore, falling energy market prices "*undermine incentives for decentralized investment in generating capacity that can efficiently provide needed system services (e.g. fast response turbines and batteries) as energy prices decline"* [43]. It is also highlighted by Pfeifenberger [44] and Newbery [45], that as a result of price caps that exist in many energy markets, prices can be suppressed during scarcity events with the impact that ancillary services, such as flexibility, ramping , fast frequency response, black start capability, etc. and/or balancing services are inadequately remunerated. All of these issues give rise to a "missing money" problem which broadly concurs with the analysis presented in this chapter.

Hogan also contends that mechanisms to rectify this issue are not as effective as they should be. Capacity markets were designed in the first instance as a mechanism to solve this "missing money problem". Capacity markets or Capacity Remuneration Mechanisms (CRM) by design ensure that there is sufficient generating capacity in the portfolio to reliably meet the peak annual demand (generation adequacy). Capacity markets and CRMs, however, do not ensure that the capacity that is available has the requisite fast-acting capabilities to support the power system. Hogan (2017) argues that capacity remuneration mechanisms provide "*limited scope for valuing capacity resources on the basis of their flexibility".*

It has been argued that in trying to resolve the missing money problem there is a risk of misallocation of money [46], i.e. overcompensation of some resources and under compensation of other resources. Hogan (2017) suggests that this creates the wrong incentives, encouraging investment in a quantity of capacity, in a mix of technologies that may not address the needs of the power system, "*particularly a lower carbon power system".* Hogan (2017) maintains that capacity markets/CRMs placing the same value on all firm capacity and encouraging existing capacity to remain on the system irrespective of its capabilities is a major issue. It was seen in Chapter 3 that ensuring generation adequacy by using the least cost generation technologies can have a detrimental impact on the carbon emission reduction benefit because OCGTs are incentivised, given the cost assumptions that were made. Indeed, according to Hogan (2017), there is consensus that increasing shares of "*variable renewable resources increases the value of flexibility elsewhere in the system*".

The outcomes from this chapter indicate that there will be substantial financial gaps for all generation technologies in future power systems in 2030 and beyond. Consequently, there are concerns regarding the ability of the energy market to compensate producers adequately and promote the investments needed by the European power system to provide quality service to customers. It also brings into question the appropriateness of relying on energy market designs that are predicated on the concept of marginal cost based electricity pricing as we transition to power systems with very high shares of renewables. Perhaps the potential of employing a value-based pricing framework for electricity should be considered in earnest.

As it is clear from the outputs from EU-SysFlex that flexibility and capability in the generation portfolio is a key requirement for future power systems, there is a need to revisit generation remuneration and energy markets. Similarly, it is speculated by Joskow (2019) that the growing dominance of vRES will require new market products and services to ensure an efficient and reliable system [43]. This is where a system services revenue stream is required; to provide the incentives to invest in the correct types of technologies that are needed to support the operation of the power system. These assertions wholeheartedly concur with both the conjecture and the outcomes of the analyses in EU-SysFlex.

6 EVALUATION OF SYSTEM SERVICES FOR THE IRELAND AND NORTHERN IRELAND POWER SYSTEM

As has been illustrated in previous chapters, the impact of the growing dominance of zero marginal cost generation can have a detrimental impact on the revenues of generating technologies, such as gas turbines that are needed to provide vital system services, but also of the renewable resources themselves as a result of the cannibalisation effect. There is increasing evidence that accurate incentives need to be provided to investors to ensure that the future generation portfolio has the capabilities to provide the flexibility and system services necessary to tackle the technical scarcities identified in Task 2.4. Furthermore, the results indicate that a mechanism like enhanced system services can provide an additional revenue stream to cover the lost revenue from the energy market that has been discussed in Chapter 4.

In this section of the report, the potential value of system services in Ireland and Northern Ireland power system is outlined. It must be noted that this evaluation cannot be easily extrapolated to the Continental Europe System, without further detailed analysis. With the use of more ambitious renewables scenarios for the Continental power system, the applicability of the Ireland and Northern Ireland power system results for the pan-Europen power system would become more evident.

6.1 EVALUATION OF SYSTEM AND FLEXIBILITY SERVICES FOR THE ISLAND OF IRELAND

One of the benefits of adopting system services is the ability to accommodate higher levels of renewables, adding flexibility and capability to the system, whilst maintaining secure operation of the power system. Therefore, the primary monetary value of system services could be argued to simply be the reduction in total system operational costs as a result of accommodating greater levels of renewables and displacing carbon–intensive conventional generation.

As per the methodologies outlined earlier in this report, it is necessary to determine the total production costs and total constraint costs associated with the case without system services (BAU) and the case with system services (EOC) in order to determine the reduction in cost that could be achievable. These values are shown in Table 14.

Analysis here would suggest that for the **Low Carbon Living** scenario (LCL), value of system services is €711 million per annum when applying methodology 1, and €179 million when applying methodology 2. The value of €711 million is obtained by comparing the production costs for the BAU case with 7 GW of wind and the EOC case with 10 GW of wind (methodology 1). As discussed earlier, the second methodology does not capture the value associated with the fact that more variable renewable generation can now be accommodated and thus it is a very significant underestimation of the real value of system services.

The analysis presented in Table 14 is repeated for each of the Network Sensitivities and for the different wind level sensitivies. The values of system services calculated using methodology 2 are shown in Figure 65. It can clearly be seen that at high levels of wind generation, the value that is associated with adopting system services increases. Indeed, acccording to Hogan (2017), there is consensus that increasing shares of "*variable renewable* *resources increases the value of flexibility elsewhere in the system*". This concurs with the findings in this report as illustrated in Figure 65. Similarly, it is speculated that the growing dominance of vRES will require new market products and services to ensure an efficient and reliable system [43]. This wholeheartedly concurs with the outcomes of the analysis that is being completed in EU-SysFlex.

TABLE 14: PRODUCTION COST SIMULATION RESULTS FOR LOW CARBON LIVING (LCL) WITH 7 GW OF WIND INSTALLED AND 10 GW OF WIND INSTALLED

Network Sensitivity	Wind Level	Dispatch	Production Costs (m)	Constraint Costs (m)	Curtailment
LCL	7 GW	Market Run	€2,139		0.01%
LCL	7 GW	BAU	€2,200	€54	0.25%
LCL	7 GW	EOC	€2,139	€0	0.03%
LCL	10 GW	Market Run	€1,445	-	2.19%
LCL	10 GW	BAU	€1,668	€223	6.55%
LCL	10 GW	EOC	€1,489	€44	3.06%

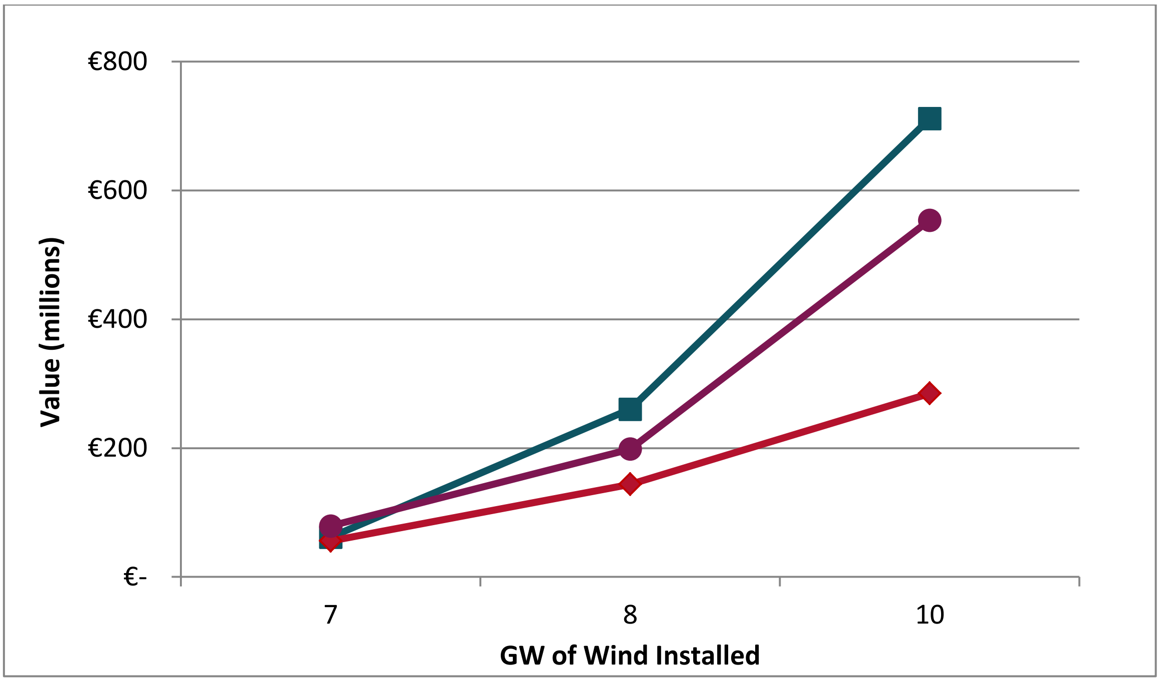

FIGURE 65: VALUE OF SYSTEM SERVICES AS WIND LEVELS INCREASE

6.2 EVALUATION OF SYSTEM AND FLEXIBILITY SERVICES FOR THE ISLAND OF IRELAND: EXTERNALITIES

There are multiple additional benefits or positive externalities that could be incorporated in the evaluation. According to the International Renewable Energy Agency [47] the development of renewable energy will fuel economic growth, create new employment opportunities, enhance human welfare and contribute to a climate-safe future. Energy access plays an important role in analysing welfare. Access to reliable, cost-effective and environmentally sustainable energy can have a multiplier effect on development [47]. Thus the benefits that could be attributed to the integration of renewable energy (and system services as a necessity for integrating high levels of renewables) go far beyond the electrical power system.

A preliminary attempt has been made to estimate the value of the externalities associated with system services. This approach aims to put a value on electrification of transport and heat. It is being assumed that the adoption of electric vehicles and of heat pumps is contingent on the transition to greater levels of renewables. As the contention in the EU-SysFlex project is that the transition to higher level of renewables is dependent upon the existence of system services, placing a value on electrification of transport and heat is by extension placing an additional value on system services. The analysis relies on comparing the counterfactual with what is being assumed in the scenarios. This will be further explained in the next sections. A similar analysis was completed for the continental power system and looked at the avoided cost of carbon.

6.2.1 AVOIDED CARBON COSTS DUE TO ELECTRIFICATION OF TRANSPORT

It is being assumed that that there is slow adoption of electric vehicles. By 2030, the level of electric vehicles reached is only at the level predicted in the equivalent 2025 scenario and thus the remainder of these vehicles are petrol cars. For example, for the **Low Carbon Living** Network Sensitivity, rather than having 426,000 electric vehicles in 2030 there are only 163,000 (see Figure 66) and the remaining 263,000 vehicles are petrol.

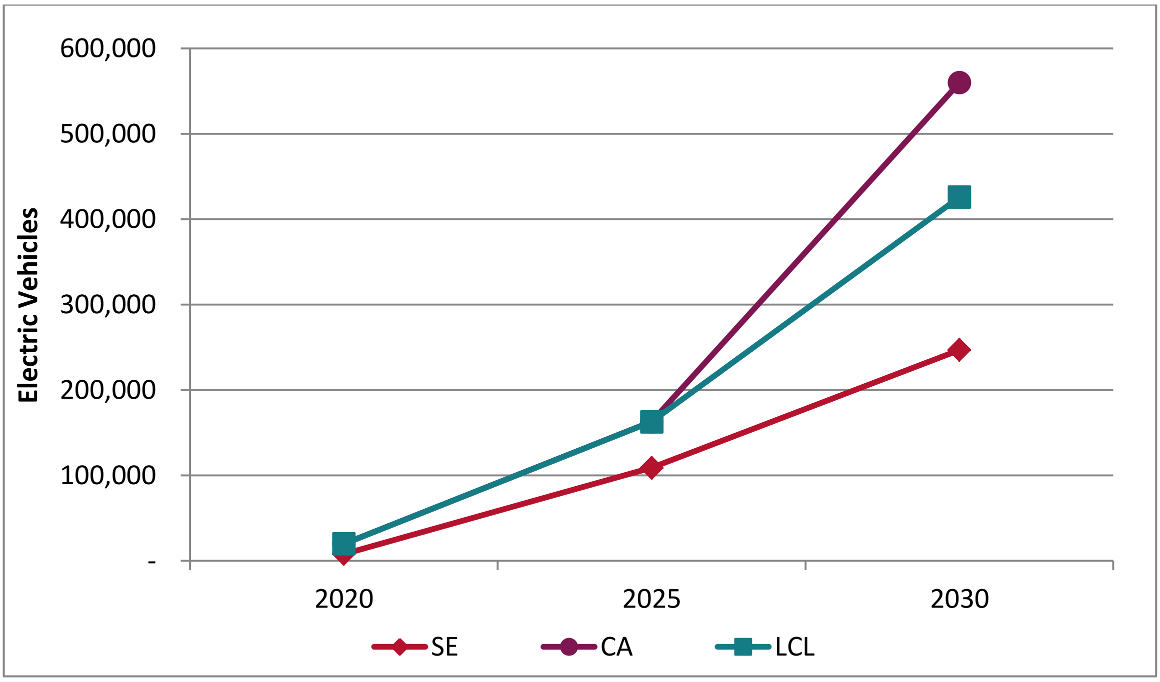

FIGURE 66: ELECTRIC VEHICLE ASSUMPTIONS FOR THE IRELAND AND NORTHERN IRELAND NETWORK SENSITIVITIES

Utilising average specific CO_2 emissions and average annual mileage values from the Sustainable Energy Authority of Ireland [48], estimates can be made of the annual CO_2 emissions and thus the associated CO_2 cost. This CO_2 cost represents the cost savings, and thus the value, that could be attributed to the adoption of electric vehicles, which is assumed to only be possible due to system services. It is found that avoided CO_2 costs vary from scenario to scenario, between €15 million and €43 million with a cost of 50€/tCO2.

TABLE 15: AVOIDED CO_2 DUE TO ELECTRIFICATION OF TRANSPORT

	LCL	CA	SE
#vehicles	263,000	397,000	138,000
km travelled	5,049,600,000	7,622,400,000	2,649,600,000
Tones of CO_2	565,555.20	853,709	296,755
Avoided CO_2 cost (€)	€28 million	€43 million	€15 million

6.2.2 AVOIDED CARBON COSTS DUE TO ELECTRIFICATION OF HEAT

It is being assumed that that there is slow adoption of heat pumps. By 2030, the level of heat pumps reached is only at the level predicted in the equivalent 2025 scenario and thus the remainder of these homes are heated with fossil fuels. For example, for the Low Carbon Living Network Sensitivity, rather than having 279,000 homes with heat pumps in 2030 there are only 194,000 (see Figure 67) and the remaining 85,000 homes are fossil fuel heated.

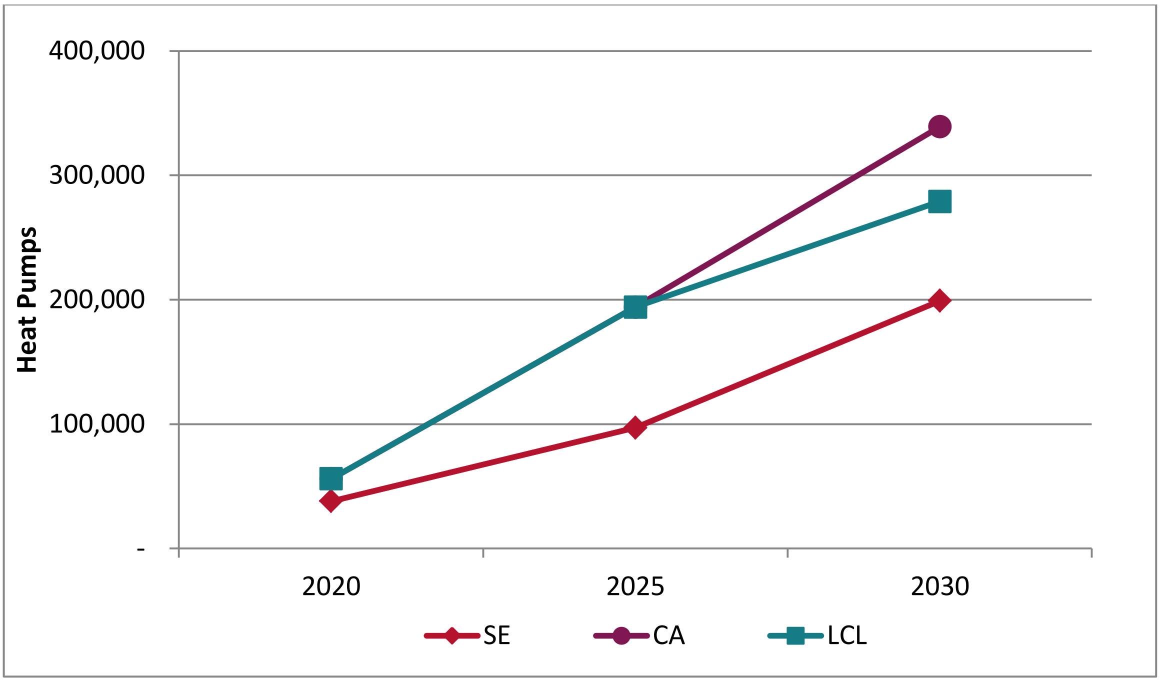

FIGURE 67: HEAT PUMP ASSUMPTIONS FOR THE IRELAND AND NORTHERN IRELAND NETWORK SENSITIVITIES

Utilising the average value for CO_2 emitted for the use of fossil fuels from heating from the Sustainable Energy Authority of Ireland [49], estimates can be made of the annual CO_2 emissions and thus the associated CO_2 cost.

This CO_2 cost represents the cost savings, and thus the value, that could be attributed to the adoption of heat pumps, which is assumed to only be possible due to system services. It is found that avoided CO_2 costs vary from scenario to scenario, between €14 million and €23 million. These figures are the additional value that could be attributed to system services.

TABLE 16: AVOIDED CO_2 DUE TO ELECTRIFICATION OF HEAT

	LCL	CA	SE
#homes	85,000	145,000	102,00
Tones of CO_2	272,000	464,000	326,400
Avoided CO_2 cost (€)	€14 million	€23 million	€16 million

6.3 SYSTEM SERVICES EVALUATION AND FINANCIAL GAPS FOR IRELAND AND NORTHERN IRELAND

Incorporating the additional values (i.e. the avoided cost of carbon) calculated in the previous sections, the value of system services could be estimated to be between €170 million and €750 million, depending on the scenario being considered. The true value, it could be argued, is actually much higher than this. This is because there are many other externalities associated with adopting system services that are not straight forward to capture.

TABLE 17: VALUE OF SYSTEM SERVICES AND FINANCIAL GAPS

	LCL	CA	SE
Financial Gap (millions)	€285 - €1000	€170 - €419	€297 - €594
Value (millions)	€750 +	€600 +	€300 +

There is undoubtedly a positive impact on pollution levels and on environmental impact associated with the displacement of conventional fossil fuel generation by renewable generation. The value to society and to the environment associated with the decarbonisation of the power system is another benefit of system services that has not been captured here but is undoubtedly an important one.

It can be clearly seen from Table 17 that if the value of system services could be assigned to system services payments, the financial gap experience by generators, for the reasons discussed in Chapter 5, can be partly mitigated against.

From the All-Island power system perspective, the only value that is important is the €750 million figure. This is because the particular Network Sensitivity (**Low Carbon Living** (LCL)) and the case examined to determine that value, is the only scenario that meets the Government targets outlined in the Government Action Plan [22] of reaching 70% RES-E by 2030. The additional benefit of system services in this case is that not only do system services provide a revenue stream to overcome the 'missing money' issue at high levels of revenues, but they also provide the needed capability to operate the future power system.

7 DISCUSSION AND CONCLUSIONS

7.1 FURTHER WORK

This report has examined some of the power system impacts as a result of integrating increasing shares of variable RES. The impacts considered are mostly limited to production cost simulation results and financial gap calculations. However, it is acknowledged that there are several other aspects that would be interesting to further investigate. These include an assessment of the needed grid investments, both in transmission and distribution levels. Two pieces of further work indentified in this report include the topic of the cost of congestion and curtailment as well as the evaluation of system services.

7.1.1 FURTHER WORK ON ANALYSIS OF THE COST OF CONGESTION AND CURTAILMENT

As was discussed in the German Case Study in Section 4.6, there is a considerable challenge in Germany, but also arising in Italy and other countries, at present in relation to curtailment and congestion on the distribution network, a challenge which is set to increase in magnitude by 2030. While a number of guiding principles have been proposed in this project in relation to mitigating curtailment and congestion on the distribution network, the effects and associated costs or costs savings of these principles have not been investigated within Task 2.5. Therefore it is recommended that these aspects are comprehensively investigated in follow-up projects. These guiding principles are as follows:

1. **Planning for the use of systems services from generation, load and storage by the distribution grid operators**
   Continuing with today's planning principles could result in sub-optimal operation of the distribution network in a future power system with high penetration of renewables, leading therefore to the need for grid expansion. This is a result of that fact that electrification of heating and transport, in conjunction with other controllable loads and storage, could lead to higher peak demands than currently arise. These effects are particularly visible in urban distribution grids. Taking account of flexibility at the planning stage, however, could alleviate the need for additional grid expansion.

2. **Incorporation of system services provision into operational decisions for generation, loads and storage**
   By using the flexibility of loads and storage, the curtailment of renewable energy systems can be significantly reduced. Utilizing of locally flexibilities in distribution network operation can also lead to national relief for the transmission system operators who benefit from it

These two guiding principles can be used jointly.

To evaluate these principles and to determine the resultant costs and benefits, a resilient and comprehensive data set for the entire European network should be compiled and suitable simulations carried out. Although it was not possible to perform this as part of Task 2.5, it should be noted that a similar study has already been commissioned by Innogy [50][14] for Germany only, dealing with the cost - benefits associated with minimising the effects of grid congestion. The objective was to investigate the extent to which the guiding principles above can lead to a reduction in congestion and curtailment. Special focus was given to quantifying the economic benefit, in the form of network investment deferral, of utilising flexible resources for congestion management in the distribution grid for the year 2035. The German specific results and findings from the report [50] show that system services and operational strategies can reduce congestion, curtailment levels and costs. Planning for the usage of system services can lead to a 55% reduction additional investment needs and to a substantial reduction in congestion and curtailment. The study shows also, that despite the network expansion, these costs will still be significant after 2030.

Future work should consider these guiding principles and determine if they could be as effective on other sub-networks of the pan-European power system.

7.1.2 FURTHER WORK ON THE EVALUATION OF SYSTEM SERVICES

The analysis on the evaluation of system services completed in Task 2.5 and presented in this report relates to the Ireland and Northern Ireland power system only. Consequently, future work could investigate the potential value of system services on the pan-European power system. With the use of more ambitious renewables scenarios for the Continental power system, the applicability of the Ireland and Northern Ireland power system results for the pan-Europen power system would become more evident.

Additionally, the analysis for Ireland and Northern Ireland could be enhanced, by developing and incorporating the value associated with more externalities.

Furthermore, the next step in the analysis would involve determining a) the volumes of specific system and flexibility services required to tackle the issues analysed in Task 2.4 and b) the type and the magnitude of the revenues streams for each of the flexibility services, as well as the corresponding enhancement of the energy market, that would be required to ensure that the required volumes of the system services can be realised.

Some of these issues will be investigated in further work in EU-SysFlex, focusing on the benefits of integrating flexibility solutions tested in the project, and WP3 on the market design enhancement.

[14] on behalf of Innogy: E-Bridge study 2019 “Wirtschaftlicher Vorteil der netzdienlichen Nutzung von Flexibilität in Verteilnetzen“ /„Economic benefits of usage of flexibility in distribution grids”

7.2 CONCLUSIONS

It has been shown in the report that the power system is transformed by the large-scale deployment of vRES, whether it is at the pan-European level , the Nordic level or at the level of the Ireland and Northern Ireland power system. Developing vRES has a small impact on the need for conventional capacity in terms of generation adequacy. As power systems transition to having portfolios with higher levels of vRES, the capacity of vRES required to displace conventional capacity, and still maintain the same level of generation adequacy, increases since variable generation does not always coincide with peak demand time. However, whist a portfolio may be generation adequate, there is no guarantee that the portfolio also has the requisite capability. It has been shown in Task 2.1 that as the share of renewables grows in the system, so too does the need for flexiblilty and capability. If OCGTs and other conventional peaking plants are relied upon for providing the required flexiblilty and capability at high penetrations of variable renewable, the potential carbon emission reduction benefits from the renewables may be impacted and could taper off at high levels of renewables, depending on the generation portfolio. Even when a high carbon price is assumed, there seems to be little incentive to shift away from the carbon intensive OCGTs. This indicates that there is a need for global action to utilise many different mechanisms to lower CO_2 emissions.

For high shares of vRES, it has been demsontrated that the number of hours where vRES generation exceeds demand increases sharply. This could be a major issue for many countries, for example Germany, were curtailment and congestion levels are already significant today. Furthermore, it has been shown in this report that increasing penetrations of vRES generation are creating challenges for power systems and energy markets. It has been illustrated that an energy only market will not provide sufficient revenue in a high variable renewables future to cover investment costs and to ensure that there is sufficient capability to support the power system. The evidence of significant financial gaps, even with high carbon prices, raises the question of the appropriate market design to compensate energy, flexibility and system services providers adequately, and promote the investments needed by the European power system to provide quality service to customers.

There is a need to revisit the available revenue streams available for conventional and renewable generators as there is evidence that energy markets and capacity markets alone are insufficient to incentivise the needed capability in the portfolio. To this end, analysis was completed for the Ireland and Northern Ireland power system to determine the potential value of system services. It was shown that system services could provide a viable revenue stream and enable a reduction of the financial gaps experienced by generators.

Flexibility solutions and system services will be further investigated in T2.6 to see how they can mitigate some of the challenges that the pan-European system power system is facing. The necessary changes required to market design to ensure the deployment of system services is addressed in WP3.

8 COPYRIGHT

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10 ANNEX I: AVERAGE HOURLY MARGINAL COST

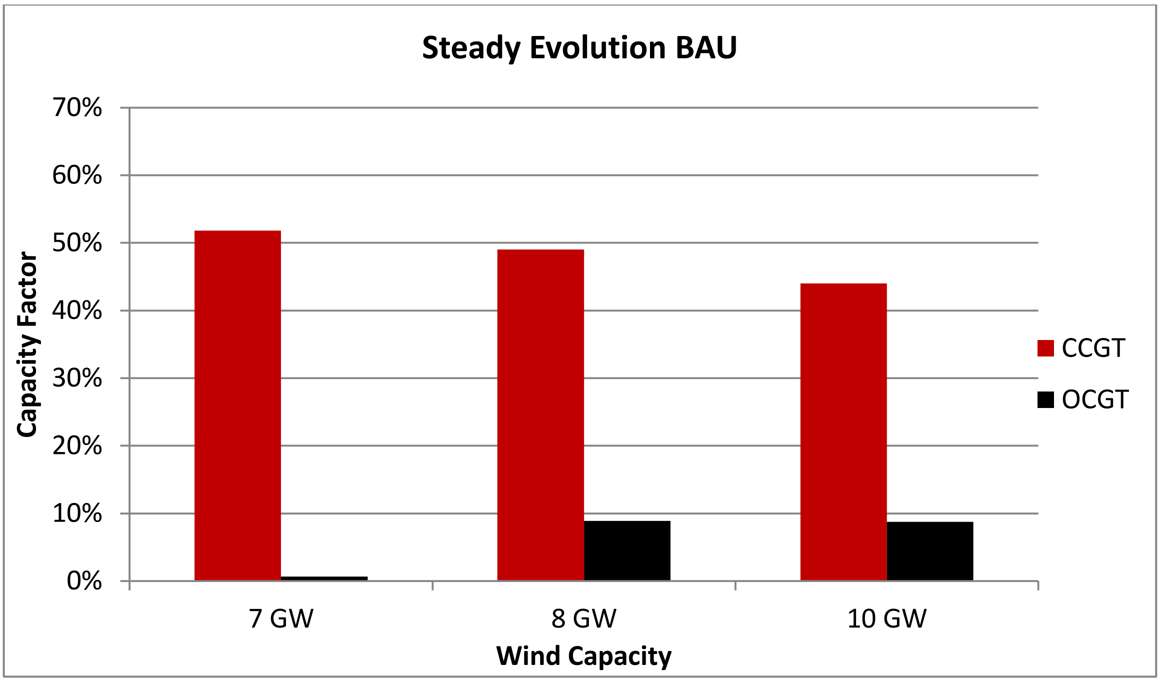

FIGURE 68: CHANGING CAPACITY FACTORS OF CCGTS AND OCGTS AS WIND CAPACITY INCREASES – STEADY EVOLUTION

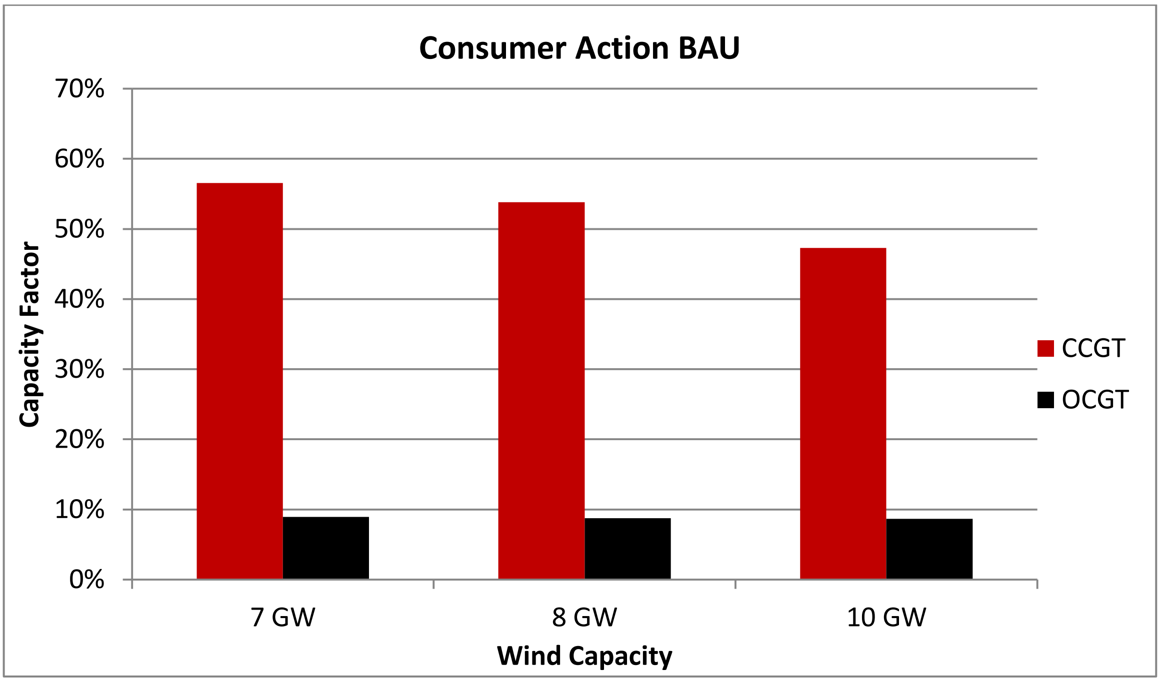

FIGURE 69: CHANGING CAPACITY FACTORS OF CCGTS AND OCGTS AS WIND CAPACITY INCREASES – STEADY EVOLUTION

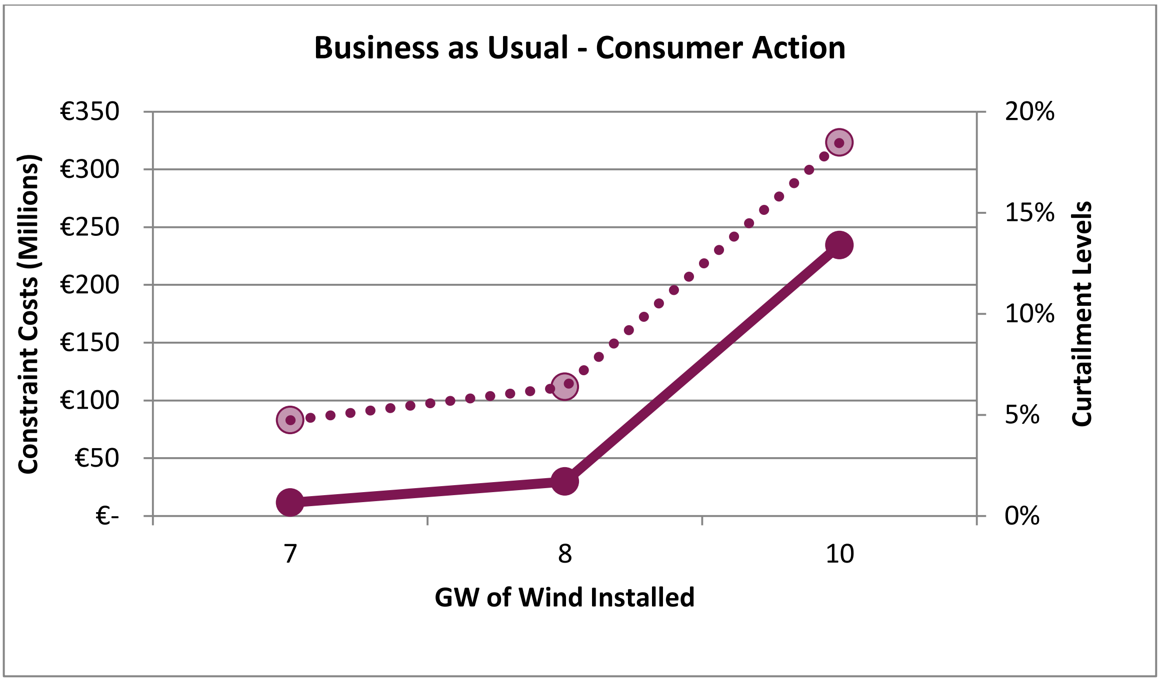

FIGURE 70: CONSTRAINT COSTS AND CURTAILMENT FOR CONSUMER ACTION - BAU CASE

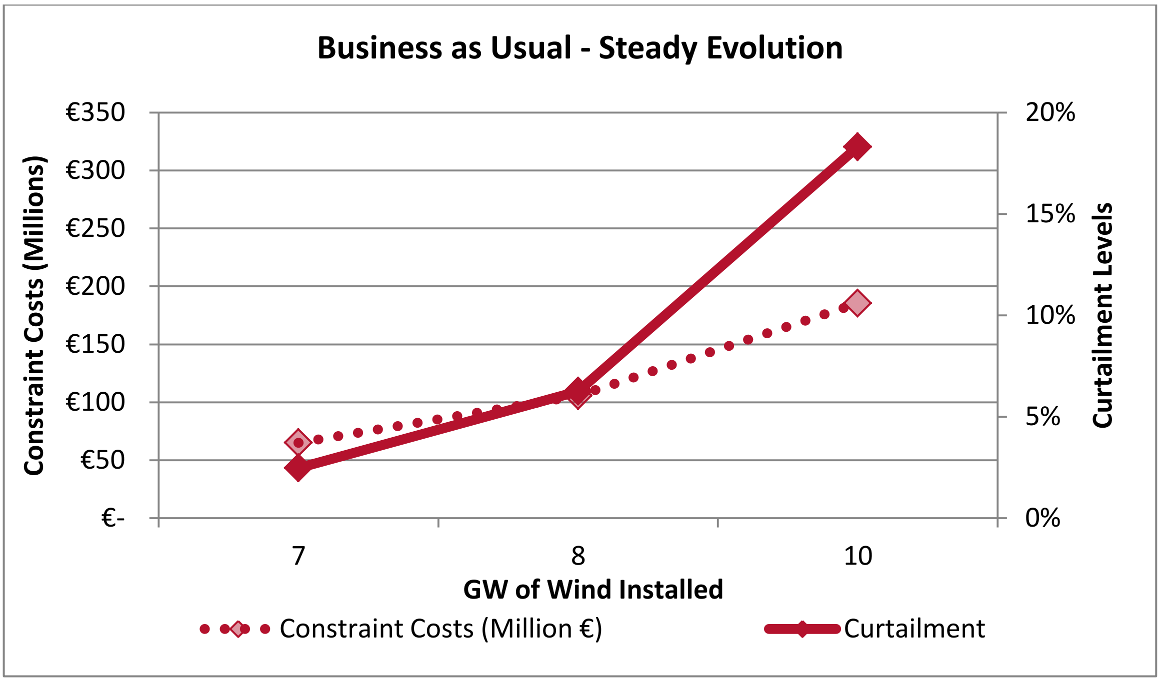

FIGURE 71: CONSTRAINT COSTS AND CURTAILMENT FOR STEADY EVOLUTION - BAU CASE

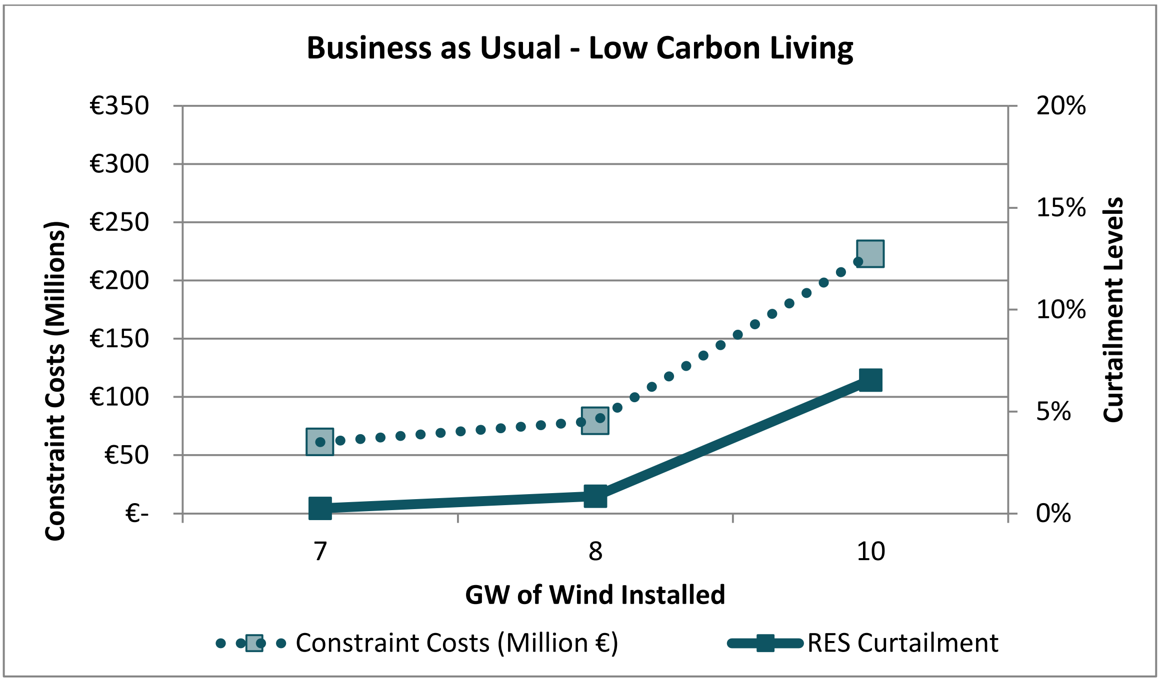

FIGURE 72: CONSTRAINT COSTS AND CURTAILMENT FOR LOW CARBON LIVING - BAU CASE

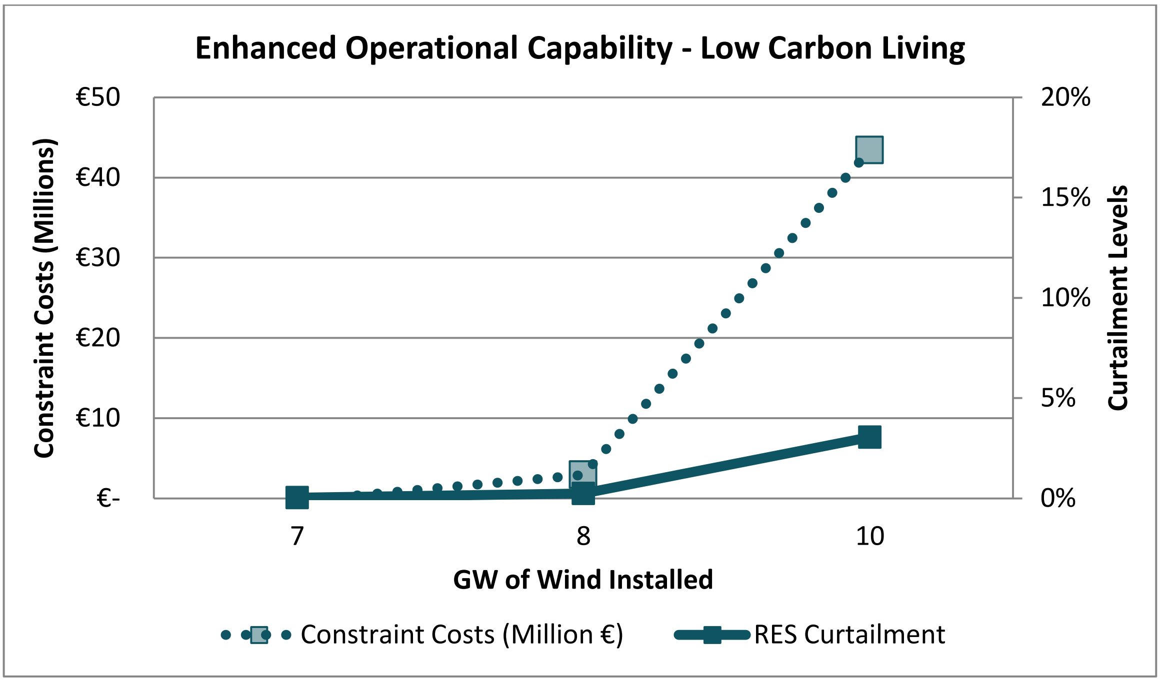

FIGURE 73: CONSTRAINT COSTS AND CURTAILMENT FOR LOW CARBON LIVING - EOC CASE

11 ANNEX II: PRODUCTION COST SIMULATION RESULTS FOR IRELAND AND NORTHERN IRELAND - USED FOR SYSTEM SERVICES EVALUATION

TABLE 18: PRODUCTION COST SIMULATION RESULTS FOR LOW CARBON LIVING (LCL) WITH 7 GW OF WIND INSTALLED AND 8 GW OF WIND INSTALLED

Scenario	Wind Level	Dispatch	Production Costs (m)	Constraint Costs (m)	Curtailment
LCL	7 GW	Market Run	€2,139	-	0.01%
LCL	7 GW	BAU	€2,200	€61	0.25%
LCL	7 GW	EOC	€2,139	€0	0.03%
LCL	8 GW	Market Run	€ 1,937	-	0.10%
LCL	8 GW	BAU	€ 2,016	€79	0.85%
LCL	8 GW	EOC	€ 1,940	€3	0.24%

TABLE 19: PRODUCTION COST SIMULATION RESULTS FOR STEADY EVOLUTION WITH 7 GW OF WIND INSTALLED AND 10 GW OF WIND INSTALLED

Scenario	Wind Level	Dispatch	Production Costs (m)	Constraint Costs (m)	Curtailment
SE	7 GW	Market Run	€1137	-	0.58%
SE	7 GW	BAU	€1202	€65	2.5%
SE	7 GW	EOC	€1146	€9	1.1%
SE	10 GW	Market Run	€843	-	10.2%
SE	10 GW	BAU	€1028	€185	18.3%
SE	10 GW	EOC	€917	€74	13.6%

TABLE 20: PRODUCTION COST SIMULATION RESULTS FOR CONSUMER ACTION WITH 7 GW OF WIND INSTALLED AND 10 GW OF WIND INSTALLED

Scenario	Wind Level	Dispatch	Production Costs (m)	Constraint Costs (m)	Curtailment
CA	7 GW	Market Run	€1962	-	0.58%
CA	7 GW	BAU	€2045	€83	2.5%
CA	7 GW	EOC	€1966	€4	1.1%
CA	10 GW	Market Run	€1377	-	10.2%
CA	10 GW	BAU	€1700	€323	18.3%
CA	10 GW	EOC	€1491	€114	13.6%

12 ANNEX III: VARIABILITY IN RENEWABLE REVENUES FOR IRELAND AND NORTHERN IRELAND

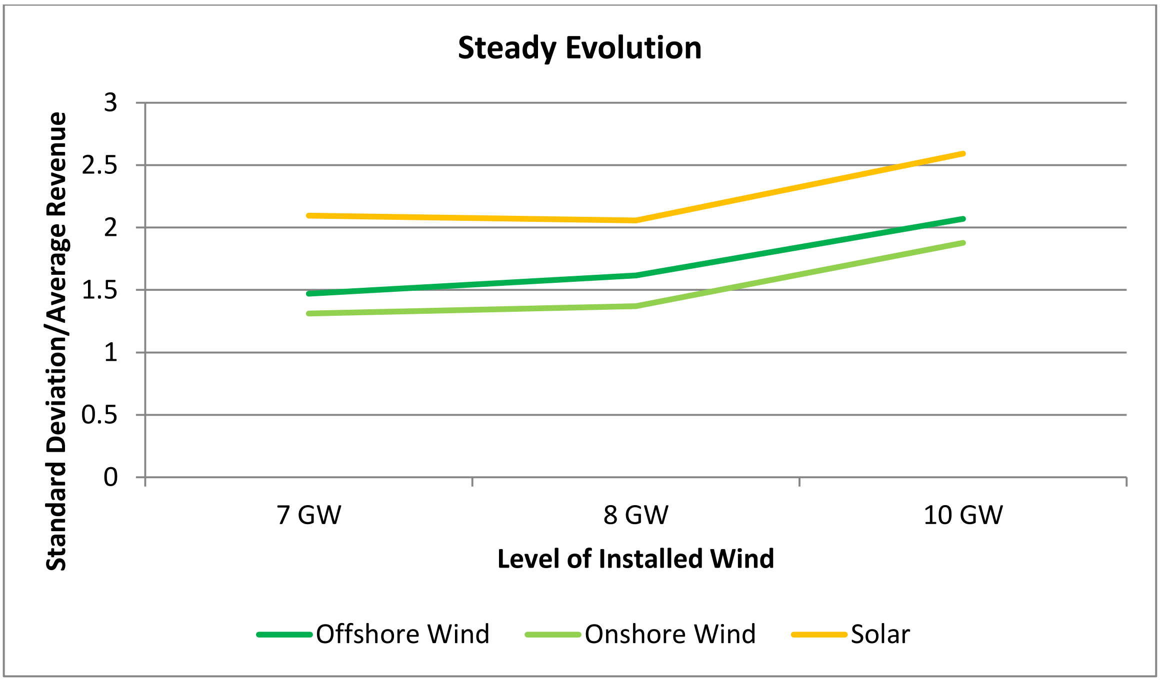

FIGURE 74: VARIABILITY IN REVENUE FOR STEADY EVOLUTION NETWORK SENSITIVITY

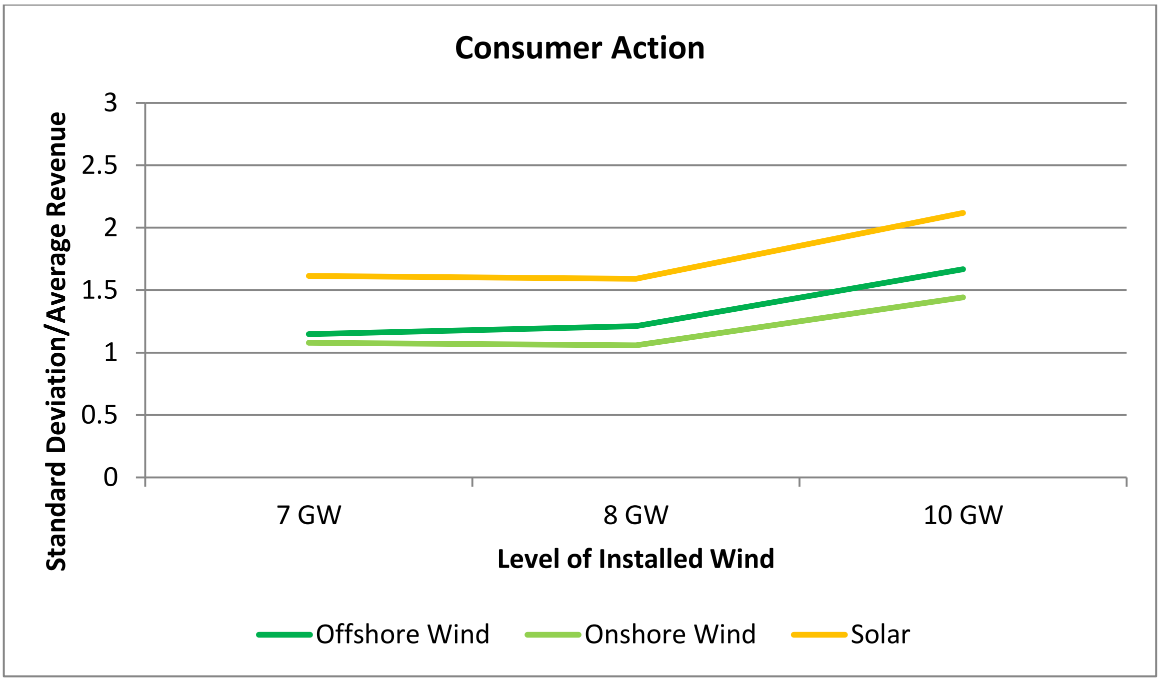

FIGURE 75: VARIABILITY IN REVENUE FOR CONSUMER ACTION NETWORK SENSITIVITY