THE VALUE OF SOLAR IN THE REPUBLIC OF IRELAND

A report to Irish Solar Energy Association

FEBRUARY 2021

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Making Future

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AFRY Management Consulting provides leading-edge consulting and advisory services covering the whole value chain in energy, forest and bio-based industries. Our energy practice is the leading provider of strategic, commercial, regulatory and policy advice to European energy markets. Our energy team of over 250 specialists offers unparalleled expertise in the rapidly changing energy markets across Europe, the Middle East, Asia, Africa and the Americas.

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1 Executive Summary

While comparisons of RESS[1] auction bids across different technologies are important, they do not tell the whole story of which renewables technologies are most appropriate to build. Future deployment based purely on auction bids may lead only to further onshore wind being built in Ireland. However, a more balanced mix of new wind and solar leads to: (1) lower societal costs; (2) lower carbon emissions; and (3) more secure system.

Ireland has adopted a 70% renewables penetration target for 2030[2] with further decarbonisation ambition to 2050 in light of the Paris Agreement. In order to stimulate further investment in renewable generation, Ireland has introduced the Renewable Electricity Support Scheme (RESS), a technology neutral two-way Contract-for-Difference (CfD) scheme that is paid for via the Public Service Obligation (PSO). The result of the first RESS auction notwithstanding, it is widely accepted that the levelized cost of solar is higher than that of onshore wind in the all-island Single Electricity Market (SEM). In turn, cost-reflective RESS auction bid prices will generally favour onshore wind, resulting in the view that onshore wind naturally provides the most attractive way to decarbonize the Irish power system.

However, decisions on which renewable technology to build for achieving the renewable penetration targets should not depend on relative auction bids alone. While auction bids are important, they do not tell the whole story. For example, solar and wind projects with the same strike price would not necessarily expect to receive the same level of RESS support, as their respective captured wholesale price may be quite different. This means solar projects with a higher strike price than onshore wind may have the same or lower cost of support. Other aspects to consider are: (1) PSO costs of supporting future renewable capacity under RESS; (2) PSO costs of supporting existing REFIT renewable capacity; (3) costs of meeting electricity demand; (4) level of overall emissions; (5) curtailment and constraint payments; (6) DS3; and (7) network reinforcements.

[1] DECC, Renewable Energy Support Scheme, 20 December 2019.
[2] DECC, Ireland’s National Energy and Climate Plan 2021-2030, 15 June 2020.

This study finds that achieving the 2030 RES-E ambitions through a more balanced mix of new wind and solar leads to a number of benefits to society in the Republic of Ireland when compared to a scenario that relies more heavily on new wind developments alone.

1.1 Lower overall societal costs

This study finds that a more balanced mix of new wind and solar substantially reduces total annual societal costs in Ireland (Exhibit 1.1). That is, a more balanced mix of new wind and solar avoids some of the increases in PSO costs of supporting future and existing renewables that would otherwise occur, which also more than offsets the relatively higher cost of meeting demand. The positive net effect to society is expected to be greater than the levels illustrated in Exhibit 1.1, were the lower levels of balancing costs, constraint payments and network reinforcement costs also quantified[3].

As part of this finding, this study shows that solar can achieve a high strike price in the next auction and still provide lower cost to consumers than onshore wind, even when a more balanced mix of wind and solar is built.

1.2 Lower carbon emissions

This study also shows that a more balanced mix of new wind and solar leads to lower carbon emissions from power generation in Ireland (Exhibit 1.2). By replacing some wind with the same amount of solar in MWh, annual emissions can further reduce by 7% in 2030 and 8% in 2035.The key driver behind this finding is the daytime generation profile of solar displacing more carbon intensive thermal plants.

1.3 A more secure electricity system

This study shows that a more balanced mix of new wind and solar results in significantly lower levels of renewable curtailment in Ireland (Exhibit 1.3). Hence, there will be less need for redispatch of thermal plant to replace curtailed volume, and therefore constraint payments will be lower. This also means there is less balancing to be done, as there will be less reliance on the relatively more variable wind generation.

1.4 Recommendations

This study shows that a more diverse mix of renewable generation would provide improved outcomes. Relying solely on strike price comparisons in next RESS auctions may not allow for this to be realised, and therefore some form of mechanism could be employed to provide a more equitable comparison. For example, as with the first RESS auction (RESS-1), a preference category for solar could be included in future auctions to ensure some solar. The Evaluation Correction Factor (ECF) could also be used in the determination of successful projects, for example by assigning an ECF to solar in RESS auctions below 1.0 to reflect some of the identified benefits.

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[3] Quantifying these elements is outside the scope of this study

Exhibit 1.1 – Annual societal cost differential between the Lower/Higher Solar Ambition and the No Solar Ambition scenario in the Republic of Ireland (€m, real 2019 money)

A more balanced mix of wind and solar substantially reduces societal cost, particularly due to lower costs of supporting future renewables.

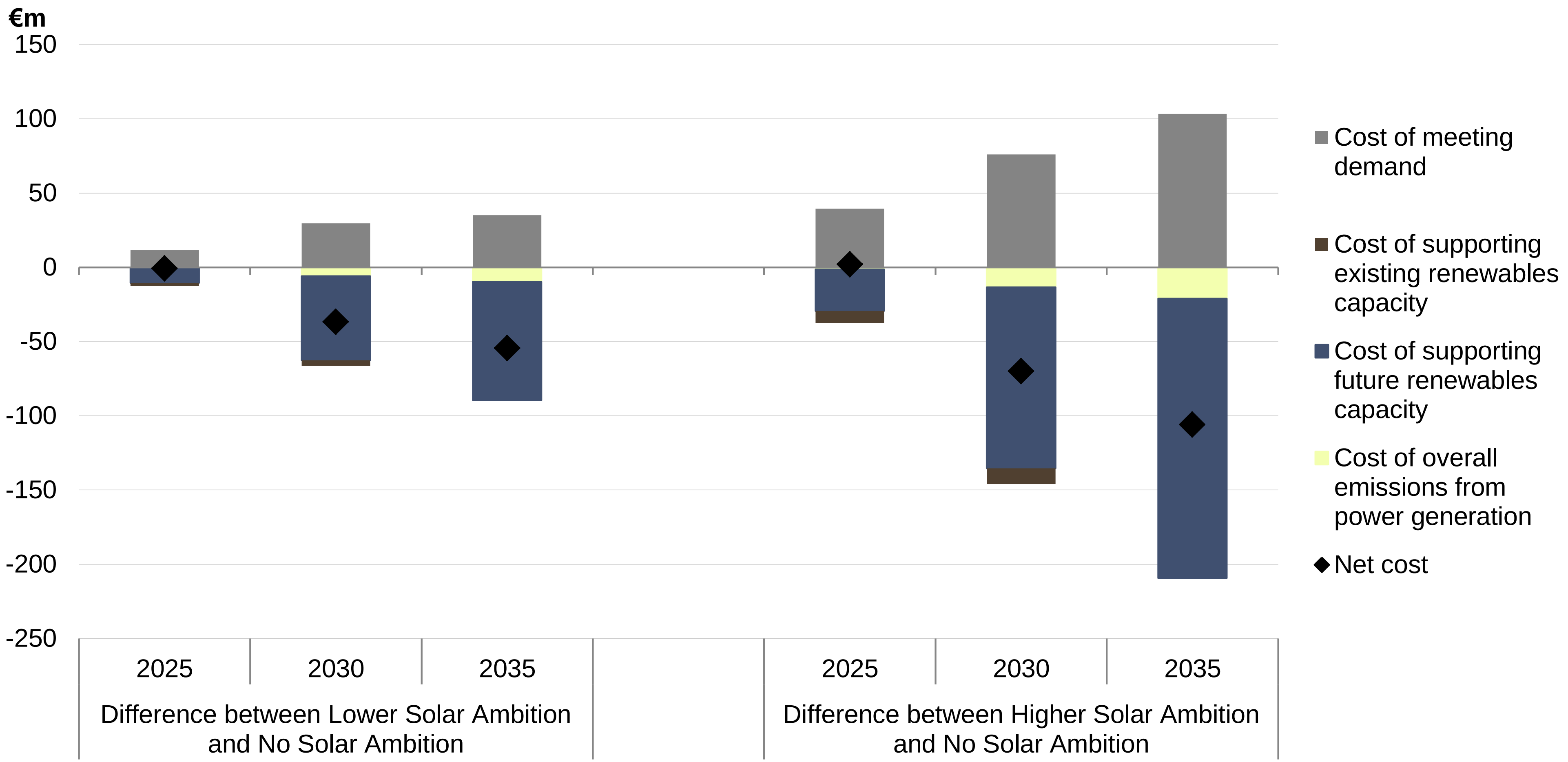


Exhibit 1.2 – Total emissions from the power generation sector by hour of the day in 2030 in the Republic of Ireland (ktCO2)

A more balanced mix of new wind and solar significantly reduces emissions by replacing higher emitting thermal generation across the day.

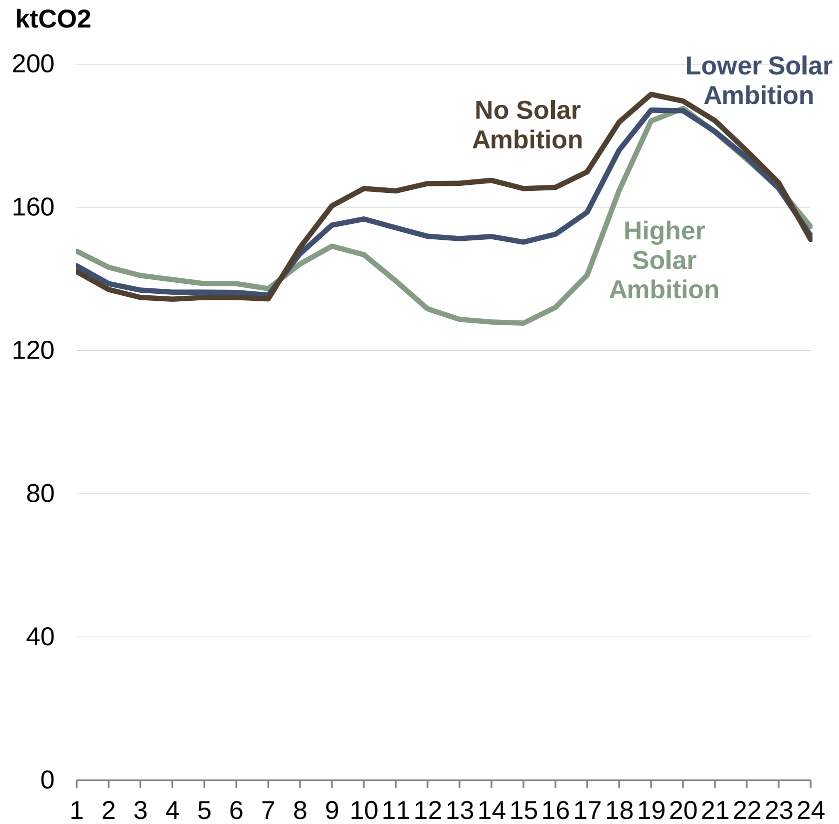
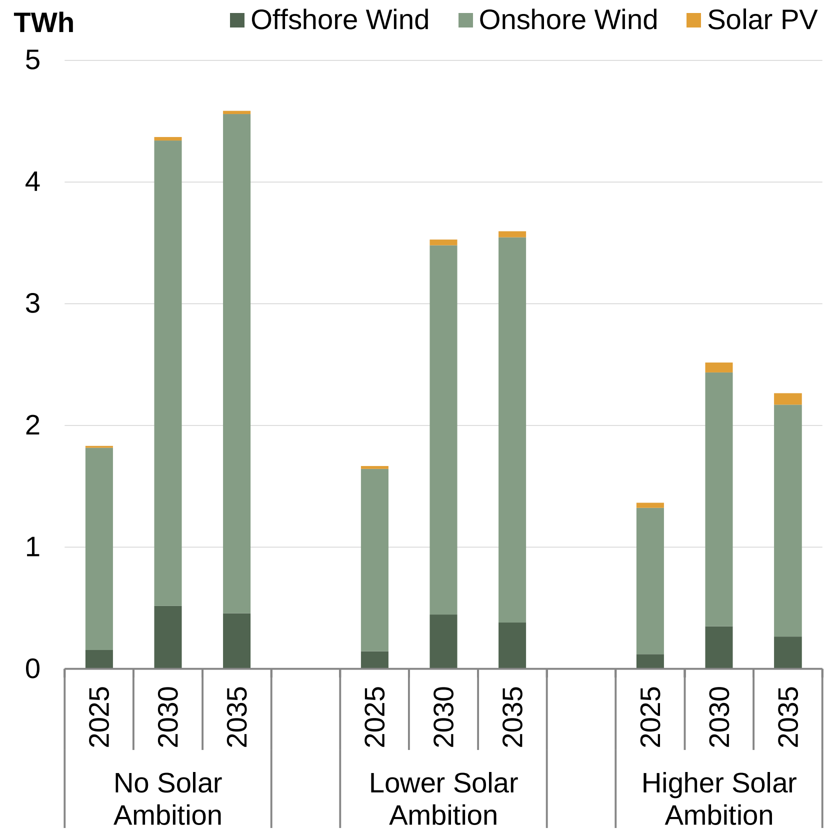


Exhibit 1.3 – Total renewable curtailment in the Republic of Ireland (TWh)

A more balanced mix of wind and solar better reflects the shape of demand, which means system constraints are binding less often.



2 Introduction

This study has been commissioned by the Irish Solar Energy Association (ISEA) to assess some of the potential 'hidden' benefits of solar to Irish society.

2.1 Background

Ireland has adopted a 70% renewables penetration target for 2030, with Northern Ireland likely to introduce its own targets in 2021. In order to stimulate investment in renewable generation, Ireland has introduced the Renewable Electricity Support Scheme (RESS), a technology neutral two-way Contract-for-Difference (CfD) scheme that is paid for via the Public Service Obligation (PSO). The result of the first RESS auction notwithstanding, it is widely accepted that the Levelized Cost of Electricity (LCOE) of solar in the all-island Single Electricity Market (SEM) is higher than that of onshore wind[4]. In turn, cost-reflective RESS auction bid prices will generally favour onshore wind, resulting in the view that onshore wind naturally provides the most attractive way to decarbonise the Irish power system.

While respective auction bids are important, auction bids do not tell the whole story of which renewables technologies are most appropriate to build. The following subsections discuss the 'hidden' benefits to society that should also be considered, namely impacts on:

- PSO costs of supporting future renewables capacity;
- PSO costs of supporting existing renewables capacity;
- costs of meeting electricity demand;
- overall level of carbon emissions;
- constraint payments; and
- the DS3 programme and network reinforcements.

2.1.1 PSO costs of supporting future renewables capacity

Rather than only looking at the respective CfD strike price that may be expected from solar or wind projects competing in the RESS auctions, the total PSO cost of supporting these renewable projects should be considered. Besides strike prices, the other aspect to consider is the capture prices, as

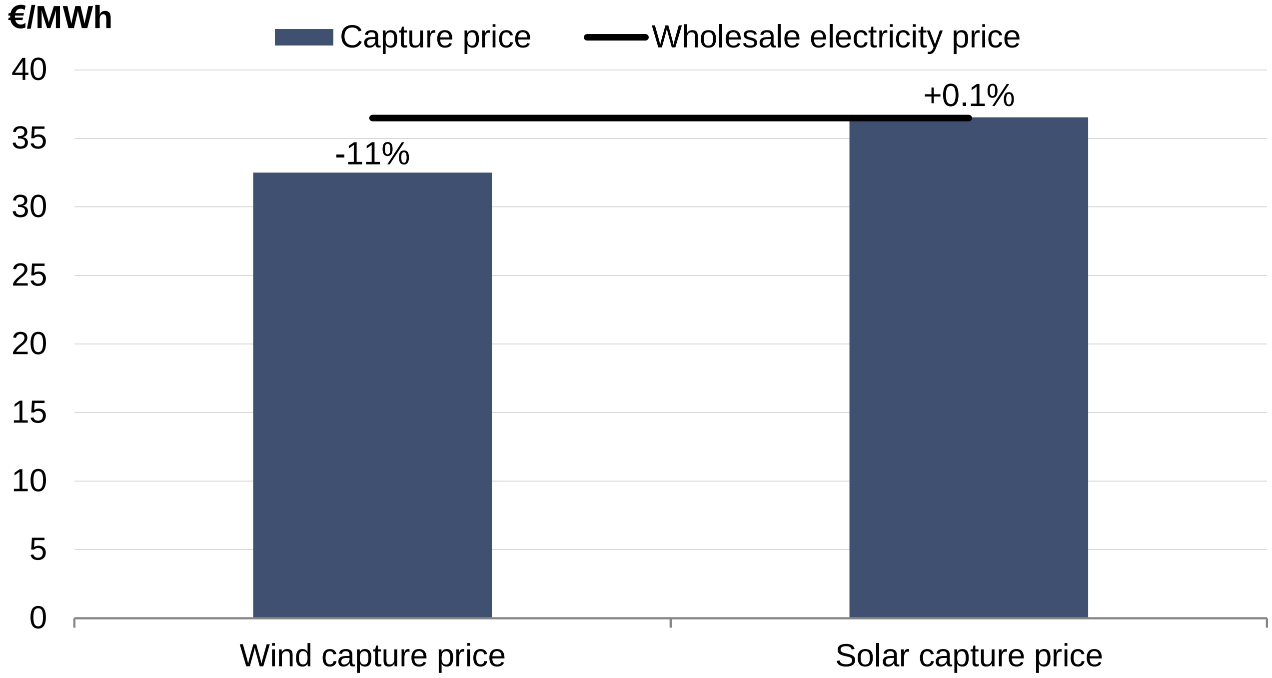
[4] BEIS, Electricity Generation Costs 2020, August 2020.

the cost of support is determined by the difference between the respective capture price[5] and strike price.

Capture prices for wind and solar are not expected to be the same in the Irish market, as shown in Exhibit 2.1. Due to the high level of wind already on the system and the typical hours when wind generation is high (often overnight when demand is low), hourly power prices tend to be low when wind generation is high. By contrast, because there is very little solar on the system and solar generates during the day when demand tends to be higher, hourly power prices tend also to be higher when solar generation occurs.

Exhibit 2.1 – Capture prices for wind and solar in the SEM in 2020 (€/MWh, nominal money)

While average solar capture prices were at the same level as average baseload prices through 2020, average wind cannibalisation was more than 10% in 2020.



Notes: This is based on metered generation from December 2019 to November 2020.

If a renewables penetration of 70% is to be reached by increasing already high levels of wind capacity even further, the likely downward impact on wholesale prices captured by RESS-supported wind will be significant.

For the purposes of this study, we looked at a range of future outcomes of wind and solar in the SEM, spanning both Northern Ireland and the Republic of Ireland, to assess how these may affect these capture prices for future supported renewables, and thereby the PSO cost of these renewables in the Republic of Ireland.

5 Capture prices refers to the average price a generator expects to receive from the wholesale market, as determined by their hourly generation profile and the hourly profile of prices in the market.

2.1.2 PSO costs of supporting existing renewables capacity

The second key aspect is the PSO costs of payments to existing REFIT-supported renewable projects.

Due to their very low marginal cost of production, increasing levels of renewables leads to downward pressure on wholesale electricity prices. Delivering a renewables penetration of 70% by relying substantially on further wind capacity alone would increase this downward price impact even further when compared to a more balanced deployment, and the downward impact on capture prices for REFIT-supported wind will also be significant. Mitigation of the reduction in wholesale and wind capture prices would help to reduce the PSO costs of supporting REFIT-supported wind.

2.1.3 Costs of meeting electricity demand

As Ireland increases its renewables penetration, electricity prices will see significant downward pressure, and thereby the costs of satisfying electricity demand at wholesale electricity prices.

Due to the complementary nature of wind and solar[6], wholesale electricity prices are not expected to decline as much in scenarios that reflect a greater proportion of solar generation than when only wind would be added to the system. This is because wind and solar typically generate at different times; wind generation usually is highest during the night and in the winter, whereas solar generation only happens during the day and is highest in the summer.

2.1.4 Level of carbon emissions from power generation

The third aspect considered relates to the overall level of emissions from power generation in Ireland. An increase in the renewable penetration to 70% will greatly reduce carbon emissions from current levels (c. 40%) However, this report shows that adding a more balanced mix of wind and solar capacity has the potential to reduce carbon emissions by more than by solely adding more wind capacity. Wind often generates when demand is already relatively low (e.g. overnight), and adding further wind generation at these times tends to displace relatively more efficient thermal generation. In contrast, solar generation will often more readily displace less efficient, and therefore higher emitting, thermal generation during the day, when levels of demand are high and the required thermal generation is therefore higher.

With the cost of carbon emissions under the EU ETS already above €30/tCO2 and expected to rise further, this could represent a significant advantage that is not captured solely by comparing auction strike prices.

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[6] Heide, Dominik, et al. "Seasonal optimal mix of wind and solar power in a future, highly renewable Europe." Renewable Energy 35.11, 2010.

2.1.5 Curtailment and constraint payments

The relatively isolated nature of the all-island system combined with already high levels of renewables penetration makes curtailment a major issue in the SEM. The SEM currently has a 65% system non-synchronous penetration (SNSP) limit; this limit means that no more than 65% of system demand in any period can be met by non-synchronous generation, which today generally refers to wind, solar and generation imported on the interconnectors.[7]

When renewable generation is curtailed, an amount of thermal generation must be redispatched to compensate for the reduction, occasionally at significant cost. These costs, known as constraint payments, are projected to be €286m for 2020/21[8].

Increasing the renewables penetration by adding increasing amounts of wind generation to the system will increase curtailment significantly, and potentially by more than if a mix of wind and solar were added. Scenarios resulting in 70% renewable penetration in 2030 which reflect a higher level of solar generation would lead to lower curtailment, and thus be expected to mitigate the level of constraint payments in the future.

2.1.6 DS3 and network reinforcements

Besides the aspects addressed above, there are more potential benefits to society of having a blend of new wind and solar. In this study, we will also discuss in a qualitative basis how DS3 and network reinforcements may be affected by the choice of future renewable deployment.

2.2 Structure of this report

The remainder of this report is structured so that Section 3 describes the methodology, particularly the approach to assessing the value of solar. Section 4 discusses the results of this study. Last, Section 5 ends with concluding remarks of this study.

Besides that, Annex A and Annex B provide further information on key scenario inputs and AFRY's proprietary power market model, BID3, respectively.

2.3 Conventions

- all monetary values quoted in this report are in euro in real 2019 prices, unless otherwise stated; and
- annual data relates to calendar years running from 1 January to 31 December, unless otherwise identified.

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[7] Note that a trial of 70% SNSP limit has commenced in January 2021.
[8] SEM-Committee, Imperfections Charge October 2020 – September 2021 and Reforecast Report October 2018 – September 2019, 27 August 2020.

2.3.1 Sources

Unless otherwise attributed the source for all tables, figures and charts is AFRY Management Consulting.

3 Methodology

This chapter sets out the approach to assessing the value of the various impacts of solar generation on the society in the Republic of Ireland as outlined above, which is done by means of a counterfactual analysis. The chapter also briefly touches upon key scenario inputs and BID3, which is AFRY's proprietary power market model.

3.1 Approach to assessing the value of solar

This study uses counterfactual analysis to investigate the potential value of solar's 'hidden' benefits to the society in the Republic of Ireland. The basis of this analysis is to posit a counterfactual scenario of what the power system would look like if all incremental renewables generation to 2035 were wind and how outcomes would compare if a range of outcomes on the levels of solar and wind were developed instead.

All scenarios modelled in this study result in an overall renewable penetration of 70% by 2030 in the SEM, and differ only in the volume of solar and wind capacity deployed to achieve this. By keeping all other variables constant, the impact of building varying outcomes of wind and solar rather than solely wind is isolated.

3.1.1 Scenarios modelled in the study

This study considers three alternative scenarios for the make-up of the SEM. Under each of these scenarios, the overall level of renewable penetration in 2030 is 70% in the SEM (i.e. in both Northern Ireland and the Republic of Ireland), however the make-up of the scenarios differ as follows:

1. **No Solar Ambition (NSA)**, which represents a counterfactual scenario without any further new solar beyond current levels[9];
2. **Lower Solar Ambition (LSA)**, which assumes a total of 2.5GW solar is installed in the SEM by 2030; and

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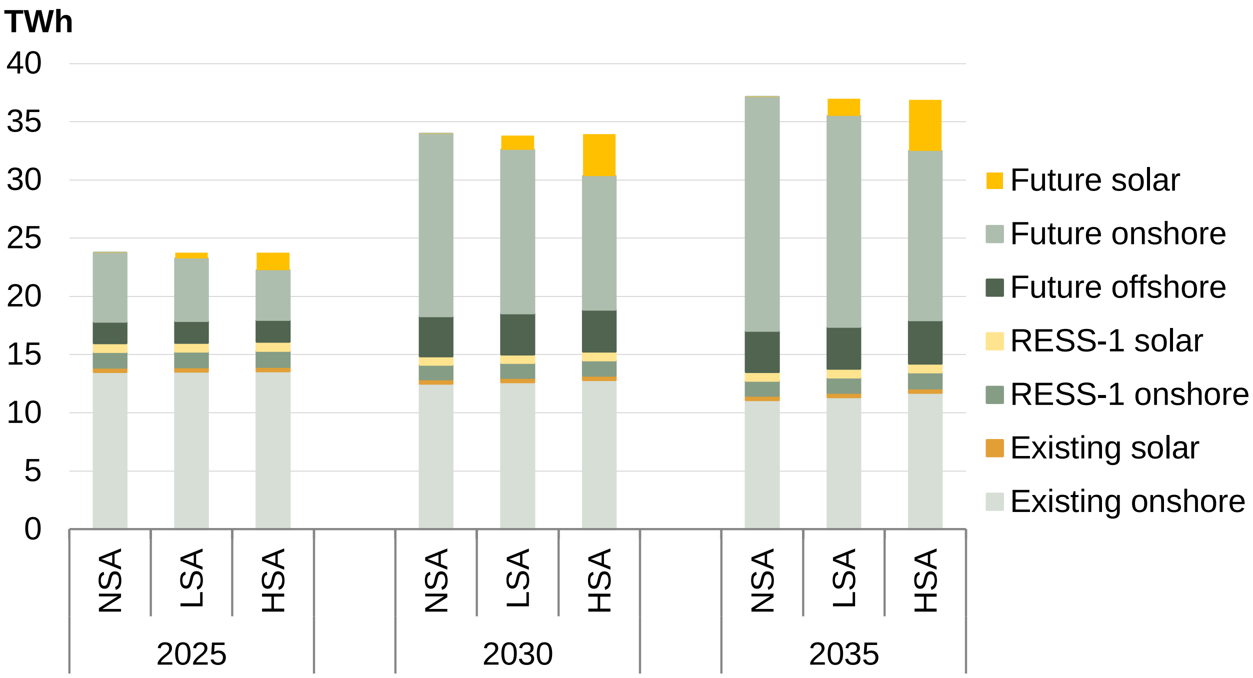
9 This scenario includes the 796.3MW solar awarded contracts through RESS-1 auction on 4 August 2020.

3. **Higher Solar Ambition (HSA)**, which assumes a total of 5GW solar is installed in the SEM by 2030.

The three scenarios differ only by generation capacity mix, as demonstrated in Exhibit 3.1.

Exhibit 3.1 – Wind and solar generation mix per scenario (TWh)



Notes: In all three scenarios, RESS-1 capacity is expected to develop as planned and 1GW of offshore wind capacity is expected by 2030.

The capacities set out above are not forecasts of future renewables capacity. They are designed to provide an appropriate and relatively conservative set of assumptions intended to answer the question about the hidden value of solar. The selected capacities are a product of a number of constraining assumptions (e.g. meeting rather than surpassing demand). If other use cases accelerate (e.g. offshore wind being utilised for hydrogen, or greater demand for electrification than this model contains), then the overall technology mix may look very different but the dynamics brought out by this analysis would be expected to hold true (i.e. the value of some diversification of renewable capacity provided by solar).

3.1.2 Calculating PSO costs of supporting future renewables capacity

The cost in any given hour for supporting all future RESS-supported capacity (incl. RESS-1) in Ireland can be estimated as the sum of the payments from and to the supported renewable generators for each onshore wind, offshore wind and solar technologies.

For a given technology in a given hour, the cost / (benefit) to the PSO Levy from RESS supported capacity (i.e. the payments to / (from) the generators) will be equal to the CfD strike price minus the prevailing hourly wholesale price multiplied by the metered generation (i.e. net of curtailment) of the technology.

This is then summed across all hours in a year to give the costs relating to each technology. Aggregating across all of the technologies gives the total RESS cost in a year, which can be compared between the three scenarios for the years in question and between onshore wind and solar PV.

3.1.2.1 CfD strike prices

The CfD strike price is an assumption that has a significant impact on the overall results of the analysis, which is discussed in Annex A.4. The strike prices for RESS-1 naturally apply to the RESS-1 capacity; the average strike price of RESS-1 and 2025 apply to capacity built up to and including 2025; the average strike price for 2025 and 2030 applies to capacity built between 2026 and 2030; and the average strike price for 2030 and 2035 applies to capacity built to 2035.

Given the importance of the choice of strike prices on the outcome of these results, two more extreme approaches are also investigated:

- **Rapid Cost Change** – assumes the strike price for each year are specifically used for all future capacity in the given year (e.g. 2030 strike prices are used for all future capacity built up to 2030).
- **No Cost Change** – assumes the strike prices remains at 2025 levels.

3.1.3 Calculating PSO costs of supporting existing renewables capacity

The cost to the PSO Levy of supporting REFIT-supported onshore wind is the difference between Total Market Revenue (TMR) and Total REFIT Payment (TRP) provided TRP is larger than TMR over the course of a year:

- TMR includes energy market revenues, capacity payments and constraint payments, although for the purposes of this study the latter two will be considered to be zero.
- TRP is calculated as the product of metered generation and the sum of the Technology Reference Price and Balancing Payment. In this study, all REFIT capacity follows the rules of REFIT2 and REFIT3. A reference price of €70/MWh and a balancing payment of €9.90/MWh have been assumed for wind in real 2019 money.

Thus, the annual PSO cost for supporting REFIT onshore wind can be estimated as the difference between the technology-specific wholesale capture price and the sum of the Technology Reference Price and Balancing Payment multiplied by the metered generation (i.e. net of curtailment) of the technology.

3.1.4 Calculating costs of meeting electricity demand

Combining modelled hourly wholesale electricity prices and hourly electricity demand in Ireland creates the overall cost of Irish electricity demand on an hourly level. This hourly cost can be aggregated by year and can subsequently be compared between the scenarios. The assumed demand is presented in Annex A.

3.1.5 Calculating level of carbon emissions

Because our modelling generates an hourly dispatch schedule and also requires plant efficiencies, we can calculate hourly carbon emissions by applying known emissions factors to the fuel projected to be consumed by all thermal plant in Ireland.

This can be represented as both the carbon intensity of generation as well as the absolute volume of carbon emissions, with differences between the scenarios derived thence. Furthermore, multiplying the absolute volume of carbon emissions by the assumed future carbon price[10] provides a cost for these emissions.

3.1.6 Calculating curtailment

AFRY's balancing market modelling captures the balancing actions by the TSO, under which the TSOs instruct plants to move away from their expected generation level, or final physical notifications in order to:

- maintain the supply and demand balance in the market as a whole ('energy actions'); and
- ensure that the system is secure (i.e. address system issues that would still exist even if the market had perfectly balanced) by addressing system operator constraints ('non-energy actions'), which result in a net zero energy change to the system.

The level of curtailment depends heavily on the (developments of the) system constraints, particularly the SNSP limit. This study assumes that system constraints will improve in line with expectations by EirGrid and SONI. These assumptions are presented in Annex A.5.

The total cost of constraint payments is fundamentally driven by the volume of redispatch generation required and the price of the redispatch actions. A material driver of the volume of redispatch actions is the extent of curtailment of intermittent renewables generation. When wind and/or solar generation are curtailed, synchronous, typically thermal, generation must be redispatched to compensate for the reduction. Therefore, the level of curtailment of all renewables is directionally an important driver of the level of constraint payments in each scenario.[11]

3.2 Key scenario inputs

Besides the generation mix, key scenario inputs do not differ per scenario and have been taken from publicly available third party sources, such as

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[10] Future carbon prices are informed by National Grid's 2020 Future Energy Scenarios, as described in more detail in Annex A.
[11] It is beyond the scope of this study to assess the specific redispatch costs associated with the different levels if curtailment seen in the modelled scenarios.

EirGrid, BEIS and National Grid. More information on these key inputs can be found in Annex A.

3.3 BID3 POWER MARKET MODEL

AFRY's proprietary power market modelling software, BID3, is used to model the ex-ante and balancing markets of the SEM. It provides a simulation of all the major power market metrics on an hourly basis, such as electricity prices, dispatch and redispatch of power plants and flows across interconnectors. Annex B provides a brief description of BID3 and how it has been used to obtain the required outputs for this analysis.

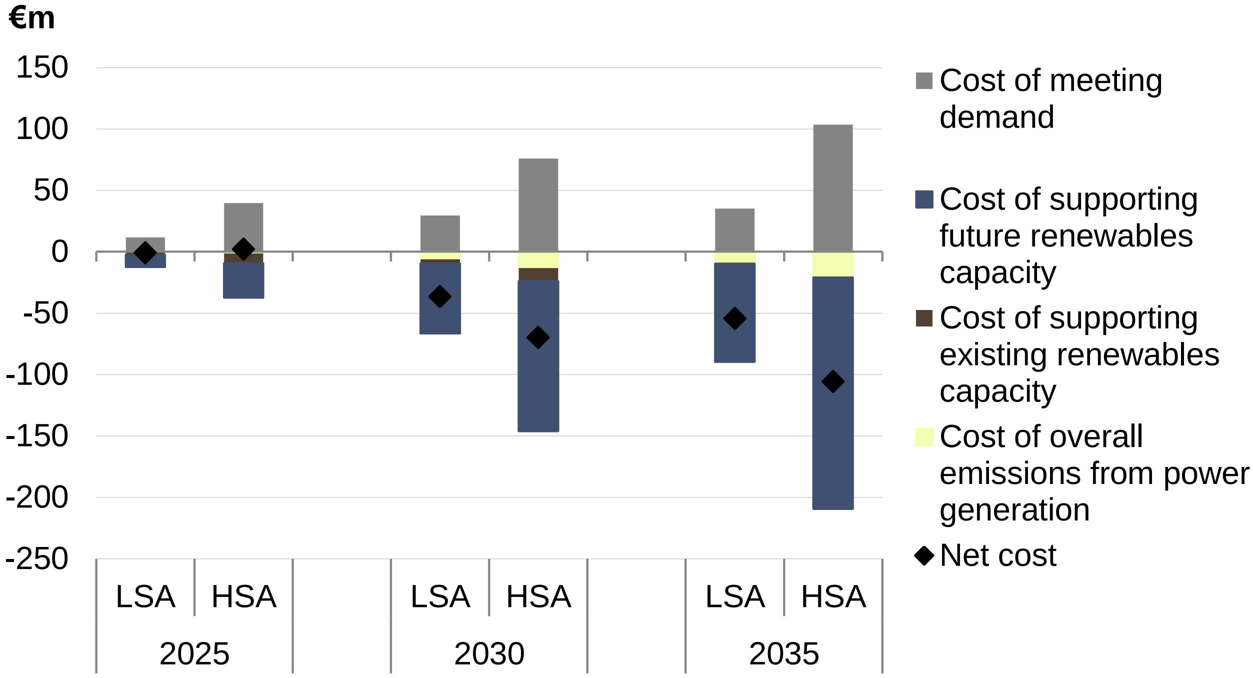
4 Results

In this chapter, we find that a more balanced mix of new wind and solar leads to: (1) a reduction in the increase of PSO costs for supporting both future and existing renewables; (2) higher costs of meeting electricity demand; (3) lower overall carbon emissions; (4) reduction in curtailment and thereby constraint payments; and (5) a more secure system

When a mix of new solar and wind is added to the system, net annual societal costs could reduce by as much as €106 million in 2035 in comparison to when only new wind is added (Exhibit 4.1).

Exhibit 4.1 – Annual societal cost differential between the Lower/Higher Solar Ambition and the No Solar Ambition scenario in Ireland (€m, real 2019 money)

Adding a mix of new wind and solar may reduce annual societal costs substantially.



Notes: The cost of emissions from the power sector reflects the cost based on the assumed carbon prices in this study; however, the cost of emissions could have been greater if it would have been based on the social cost of emissions. In addition, the cost of supporting existing renewables is shown until 2030, as REFIT support lasts until the early 2030s.

The subsequent sections will go into more detail of each of the components shown in the stack above, and will discuss how different mixes of wind and solar affect constraint payments, the DS3 programme and network reinforcements.

4.1 PSO costs of supporting future renewables capacity

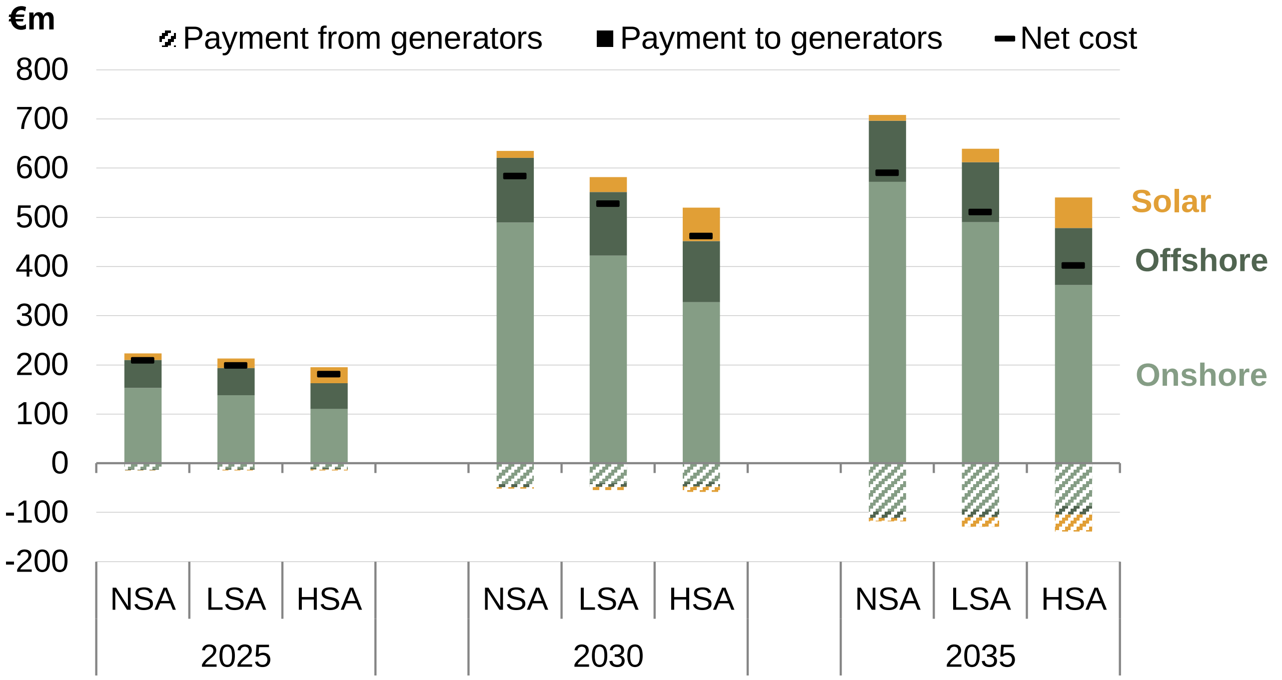
The PSO cost of future renewable capacity in the Republic of Ireland is presented in Exhibit 4.2.

PSO costs for supporting future renewable capacity rapidly increase when only new wind is added to the system (i.e. the NSA scenario). The main reason for this is because further adding more wind to the system to achieve a renewables penetration of 70% results in substantially increased cannibalisation of wind capture prices. Much lower capture prices therefore result in higher levels of support being paid. This is particularly the case because of the high level of wind already on the system, and because the hours when wind generation are high are often when demand is low (e.g. overnight). Consequently, wholesale electricity prices tend to be low at times when wind is generating, and this issue would evidently increase further by only building more wind.

In contrast, both the LSA and HSA scenarios avoid some of the increase in PSO costs. This stems from the fact that a more balanced mix of new wind and solar avoids the more rapid decline in wind capture prices seen when only new wind would be built.

Exhibit 4.2 – PSO cost of supporting future renewables (€m, real 2019 money)

A more balanced mix of new wind and solar mitigates the material increase in PSO costs.



To further support the above, the two underlying drivers of these support costs are shown below, namely the average strike prices across the portfolio of future renewables (Exhibit 4.3) and the capture prices of the future renewables (Exhibit 4.4). The unit cost of supporting future renewable generation is essentially the difference between these two values.

The average strike prices across the portfolio of future solar are higher than onshore wind, although this difference becomes smaller over time. These average strike prices are a cumulative representation that reflects the year when it is assumed capacity starts receiving support. The underlying annual strike prices have been set out in Annex A.4. The average strike prices of solar remain higher than onshore wind principally due to the high annual strike prices of solar in the early years.

However, by choosing the renewable technology based on the RESS strike price alone, one neglects that wind and solar capture prices are different. The difference in wind and solar capture prices increase over time, although this difference is reduced when more solar is built.

As a side note, onshore wind capture prices are higher with a more balanced mix of wind and solar. Naturally, this is a benefit for onshore wind projects that do not or no longer receive support.

Exhibit 4.3 – Average strike prices across the portfolio of future renewables (€/MWh, real 2019 money)

The average strike price of the solar portfolio is higher than onshore wind, although this difference becomes smaller over time.

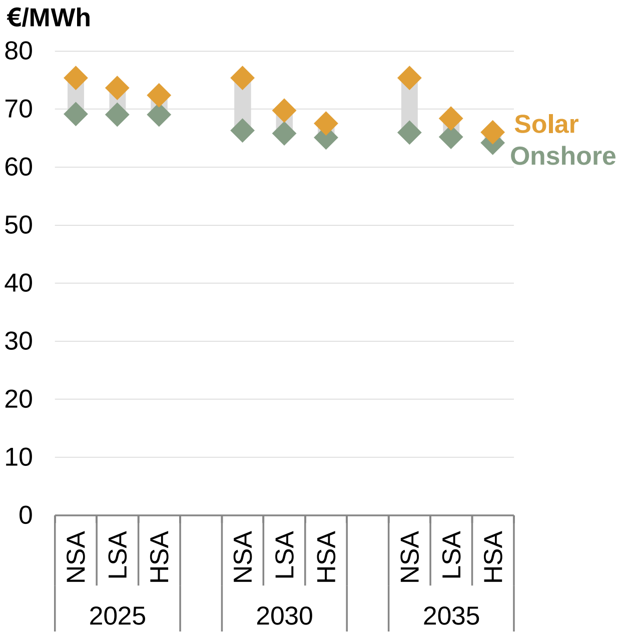
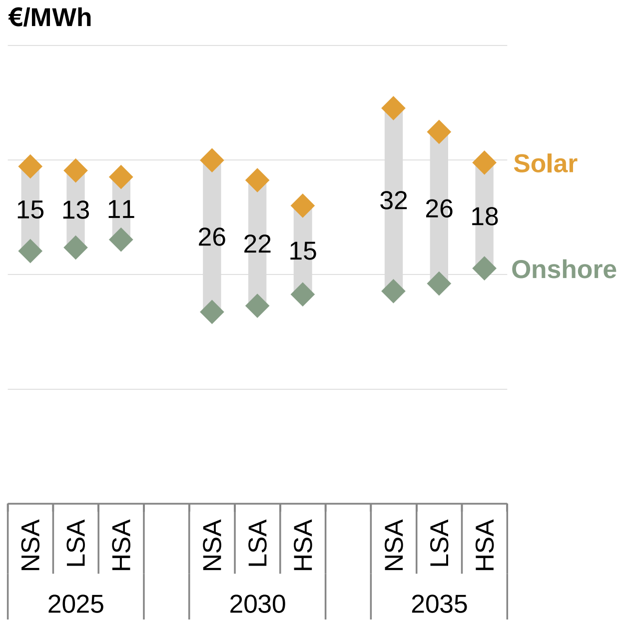


Exhibit 4.4 – Annual capture prices of supported future renewables (€/MWh, real 2019 money)

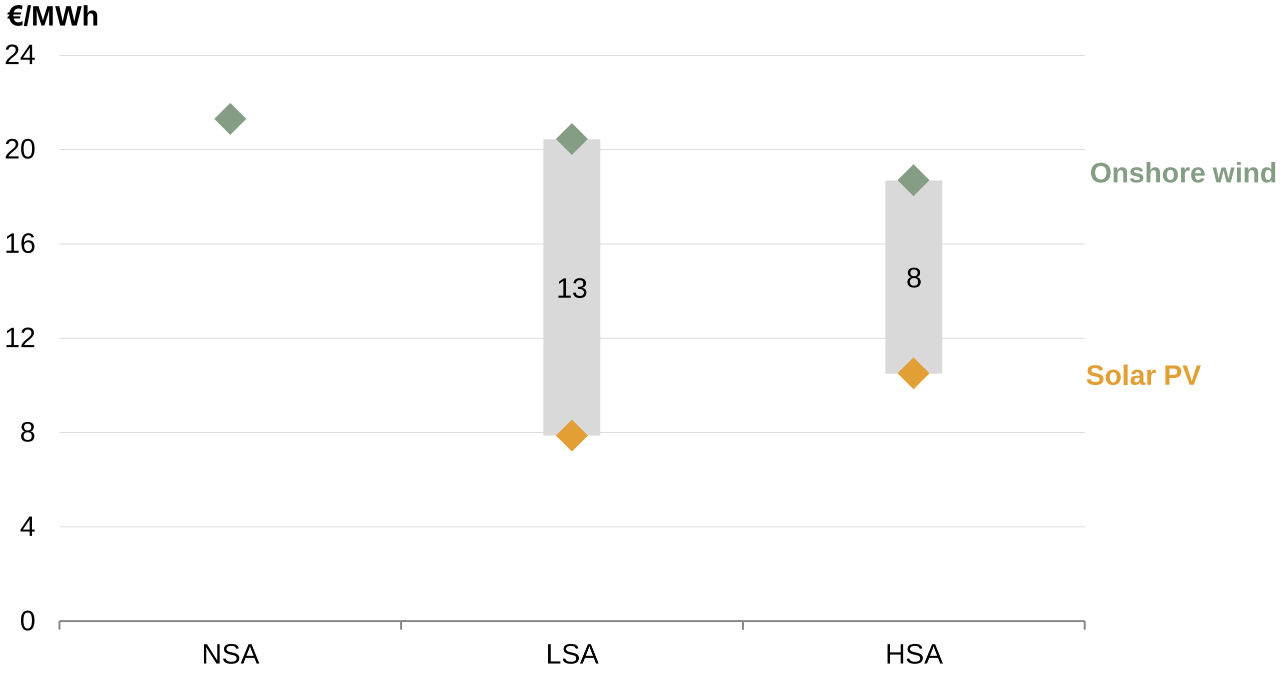
The difference in wind and solar capture prices increase over time, although much more limited when more solar is built.



Based on the strike prices and the capture prices, the support cost can be considered per unit of generation, shown in Exhibit 4.5. This demonstrates that solar can achieve a high strike price in the next auction and still provide lower cost to consumers than onshore wind, even under the HSA scenario. For example, if the ambition is to reach 2.5GW of solar in the SEM by 2030, in order for the support cost per MWh of solar to be equal to that of onshore wind, the strike price of solar can be €13/MWh higher than the assumed strike price used in this study. This chart also shows that there is still a spread of €8/MWh between the support costs of onshore wind and solar under the HSA scenario, which indicates that even more solar capacity may provide further overall benefits to society.

Exhibit 4.5 – Discounted support cost per unit of generation over the supported period for the forthcoming auction (€/MWh, real 2019 money)

Solar can achieve a high strike price in the next auction and still provide lower cost to consumers than onshore wind, even under the HSA scenario.



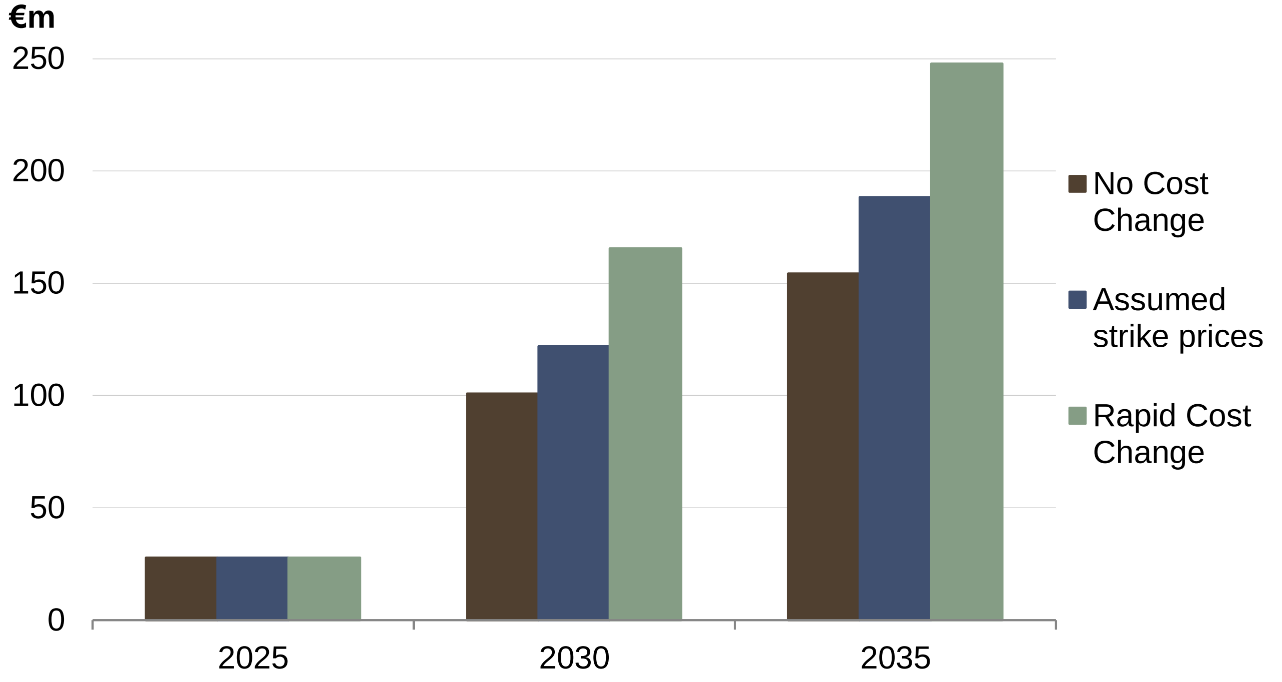
Notes: The assumed hurdle rates are 4.2% for wind and 5.0% for solar PV in accordance with the underlying LCOE assumptions from the 2020 Generation Cost Update by BEIS.

4.1.1 Sensitivity – assuming different strike prices

Because the strike prices are a key input assumption with material uncertainty, we have also assessed what happens to the PSO cost for future renewable capacity when different strike prices are assumed. Exhibit 4.6 compares the differential in PSO costs of future renewable capacity between the HSA scenario and the LSA scenario. For each year, the assumed strike prices are compared with two additional sets of strike prices: No Cost Change (NCC); and Rapid Cost Change (RCC). Further details on NCC and RCC can be found in Section 3.1.2.1.

Even if strike prices remain at 2025 levels (i.e. NCC), future renewable capacity has a much lower PSO cost when a mix of new solar and wind is added to the system. In fact, even in the case of No Cost Change, the finding holds that a more balanced mix of wind and solar leads to an overall decrease in societal costs.

Exhibit 4.6 – Difference in PSO costs of future capacity between the Higher Solar Ambition and No Solar Ambition with strike price sensitivities (€m, real 2019 money)

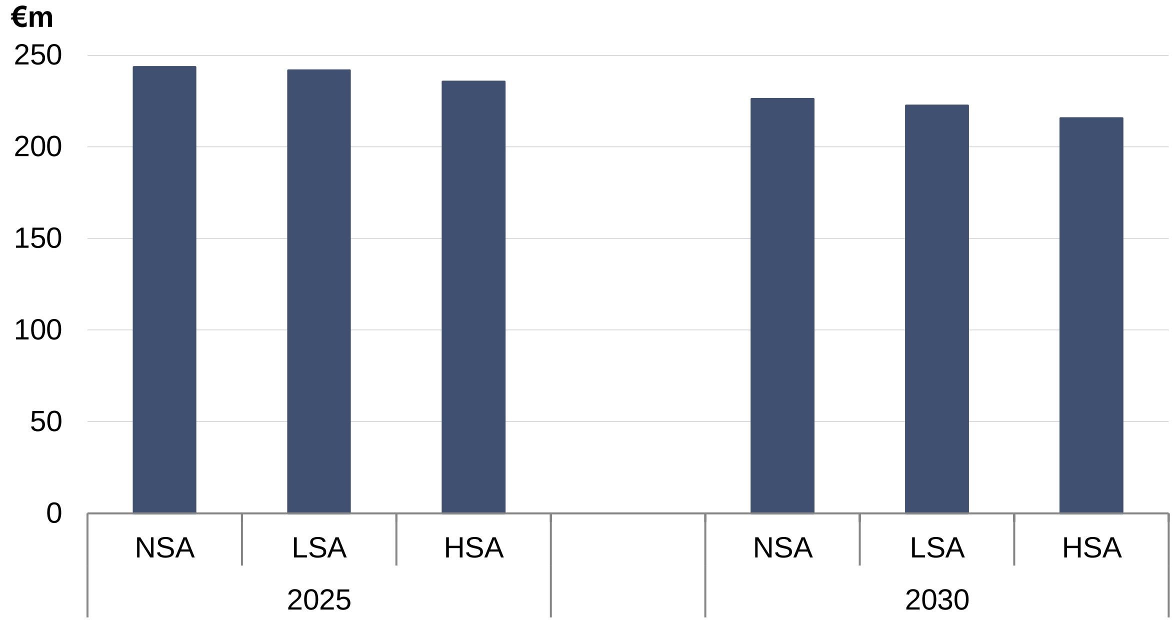


4.2 PSO costs of supporting existing renewables capacity

Projections for the PSO costs of payments to REFIT-supported renewables are shown in Exhibit 4.7. Naturally, the PSO costs of supporting existing renewables are also affected by the choice of renewables built in the future, as this affects the resulting level of wholesale prices. Similar to PSO costs for future renewable capacity, REFIT-supported renewables have a higher PSO cost per MWh when only wind is built to achieve a renewable penetration of 70%, as a consequence of the higher rate of wind cannibalisation.

Exhibit 4.7 – PSO cost of supporting existing renewables (€m, real 2019 money)

PSO costs of REFIT-supported renewables reduce by as much as 5% in 2030 by supplementing wind with more solar.



4.3 Costs of meeting electricity demand

To understand the cost of satisfying electricity demand at wholesale electricity prices, the wholesale electricity prices projections for the SEM (Exhibit 4.8) should be investigated as well as the cost of electricity demand in the Republic of Ireland itself (Exhibit 4.9).

In all scenarios modelled for this study, wholesale electricity prices tend to follow a very similar path. From 2025 to 2030 in all scenarios, the renewable penetration increases from 55% to 70% pushing down the wholesale electricity prices, albeit the impact is somewhat mitigated by increasing carbon and fuel prices. From 2025 to 2035 in all scenarios, the carbon price continues to rise, whilst renewable penetration remains at 70%, resulting in an increase in the wholesale electricity price.

A more balanced mix of wind and solar better reflects the shape in demand, which generally results in higher wholesale prices. Under the NSA scenario, wholesale prices are particularly often depressed at times of high wind generation (often overnight when demand is low). In contrary, under the NSA and even more so under the HSA scenario, the solar PV generates during the day when demand tends to be relatively high. As such, solar generation replaces generators that are higher up in the merit order, and consequently solar generation will not depress the electricity price as much as wind does. In other words, solar is not the marginal price setting technology very often and is not expected to become so unless much greater volumes of solar are added to the system.

Naturally, as electricity prices are higher when a mix of new solar and wind are added to the system than when only new wind is added, the cost of meeting electricity demand is also higher. However, overall this increase in cost of meeting electricity demand is more than offset by the avoided increase in support cost for renewables, particularly the future renewable capacity (both solar and wind). Furthermore, the higher prices may provide more robust investment signals, especially when the system would also be less reliant on one particular technology in the case when comparing the NSA scenario with the HSA scenario.

Exhibit 4.8 – Wholesale electricity prices in the SEM (€/MWh, real 2019 money)

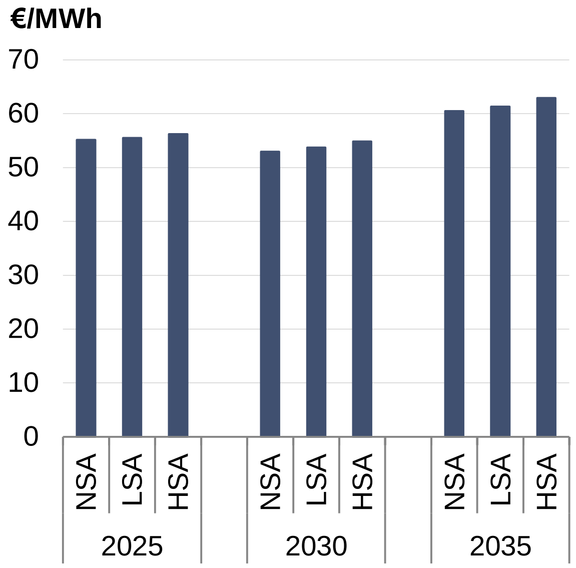
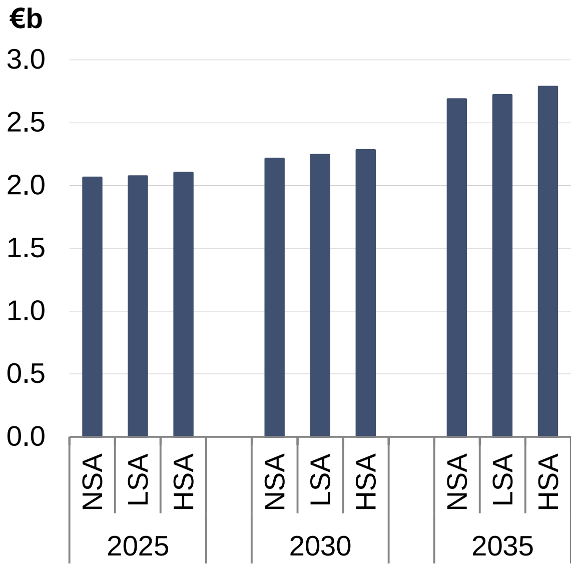


Exhibit 4.9 – Cost of electricity demand in Ireland (€b, real 2019 money)



Notes: As demand increases, the cost of electricity demand also increases in contrary to the decrease in wholesale electricity prices.

4.3.1 Comparing the increase in cost of meeting demand with the decrease in PSO costs of supporting renewables

While higher wholesale prices reduce the PSO costs of supporting future and existing renewables capacity, it also increases the cost of meeting electricity demand. There are two key reasons why there is a net benefit when comparing these components in the HSA over the NSA scenario:

1. From NSA to HSA, future onshore wind is replaced by future solar PV, which is fully considered in the PSO cost assessment. As such, any shift in wholesale prices will be captured in the PSO costs difference. Even at a higher strike price for solar of €90/MWh through to 2035, there would still be a net benefit. While a solar strike price of €90/MWh is extreme, the sensitivity in Section 4.1.1 provides a more realistic range of strike price outcomes and the consequence it has on the associated PSO costs.
2. The HSA scenario is more self-sufficient than the NSA. In comparison to the NSA, the HSA: (1) has less exports and less curtailment (i.e. when wind generation would be setting the price); but (2) also has less imports during the day (i.e. the price is lower when demand is high). As such, the upward impact on total costs of meeting demand is more moderate when weighted by hourly demand.

4.4 Level of carbon emissions from power generation

The total projected carbon emissions from the electricity generation sector by year and by hour of the day in the Republic of Ireland are presented in, Exhibit 4.10 and Exhibit 4.11. Although each scenario reflects the same renewable penetration of 70% (post curtailment), achieving this by adding a mix of solar and wind is more effective in terms of decarbonisation than by only adding new wind to the system. As shown, annual emissions can reduce by as much as 8% by 2035 when comparing the NSA scenario with the HSA scenario. Substituting some new wind with solar significantly reduces emissions, as solar is able to replace thermal generation during the day time, when higher levels of demand mean less efficient thermal generation would otherwise be operating, while night time emissions only slightly increase.

The key driver behind lower emissions from power generation in these scenarios is the complementary nature of wind and solar generation in representing the shape of demand (i.e. the system is more self-sufficient). That is, solar replaces thermal generation during the day when demand is usually high. Thus solar also reduces the need for imports that would be required with wind generation alone. In contrast, the material proportion of new wind generation occurs at times when less thermal generation can be displaced (e.g. overnight). This wind generation ends up being exported or curtailed, particularly because there is already a high level of wind.

Exhibit 4.10 – Total annual emissions from the power generation sector in Ireland ($MtCO_2$)

Annual emissions can reduce by as much as 8% by 2035 when comparing the NSA scenario with the HSA scenario.

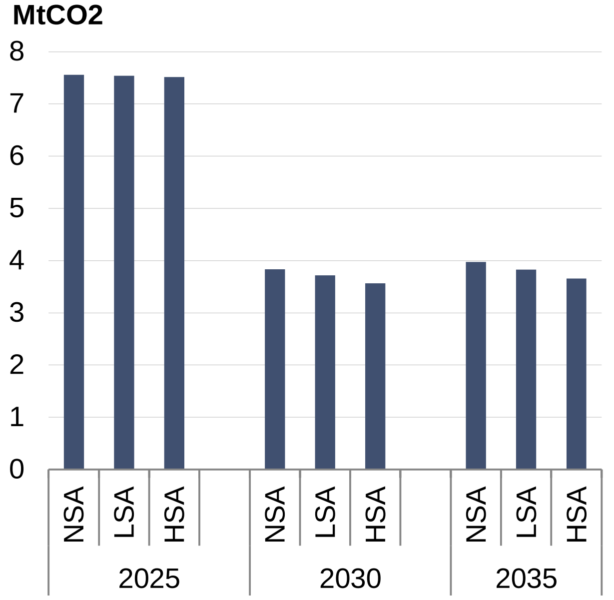
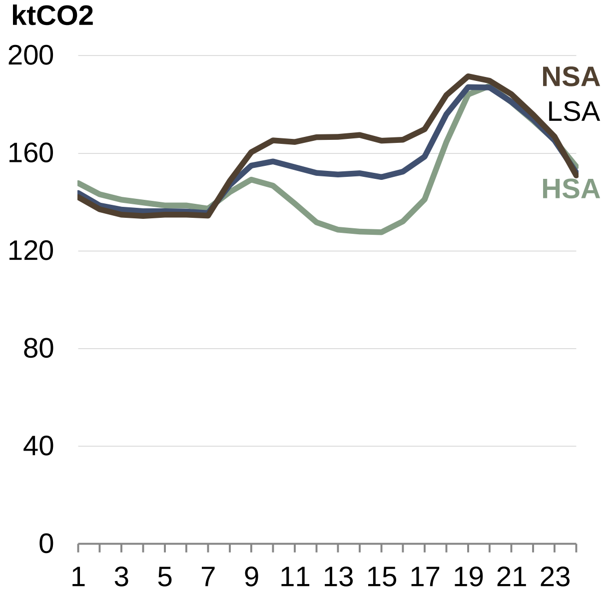


Exhibit 4.11 – Total emissions from the power generation sector by hour of the day in Ireland in 2030 (ktCO2)

A more balanced mix of wind and solar significantly reduces emissions by replacing day time thermal, while night time emissions only slightly increase.



4.5 Curtailment and constraint payments

Exhibit 4.12 and Exhibit 4.13 present curtailment projections for onshore wind, offshore wind and solar PV as a percentage of available resource and in TWh, respectively across the modelled scenarios in the Republic of Ireland.

In all scenarios, curtailment for each technology broadly follows a similar trend. Onshore wind curtailment increases from 2025 to 2030 following an increase in renewable penetration from 55% to 70%, and remains at broadly the same level from 2030 to 2050 as the onshore wind penetration remains the same. Offshore wind curtailment also increases from 2025 to 2030 following an increase in renewable penetration from 55% to 70%, but declines from 2030 to 2035 because the relative offshore wind penetration declines. Solar curtailment only increases slightly, which simply reflects the moderate level of solar on the system relative to wind.

Comparing scenarios, it is evident that wind and solar generation profiles work in a complementary fashion, in the sense that adding a mix of new wind and solar leads to lower level of curtailment than when only new wind is added to the system. This is because a more balanced mix of wind and solar better reflects the shape of demand, which means system constraints are binding less often. More specifically, the solar displaces day-time thermal generation when demand is high, whereas wind typically generates most during low demand periods (e.g. overnight) when thermal cannot be displaced due to system constraints.

Given that less redispatch is required when curtailment is lower, constraint payments are also expected to be lower when a more balanced mix of new wind and solar is added to the system.

Exhibit 4.12 – Renewable curtailment in Ireland (% of available resource)

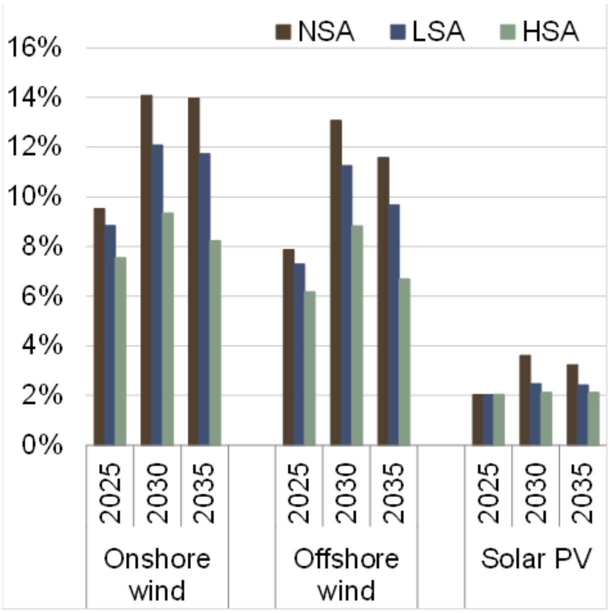
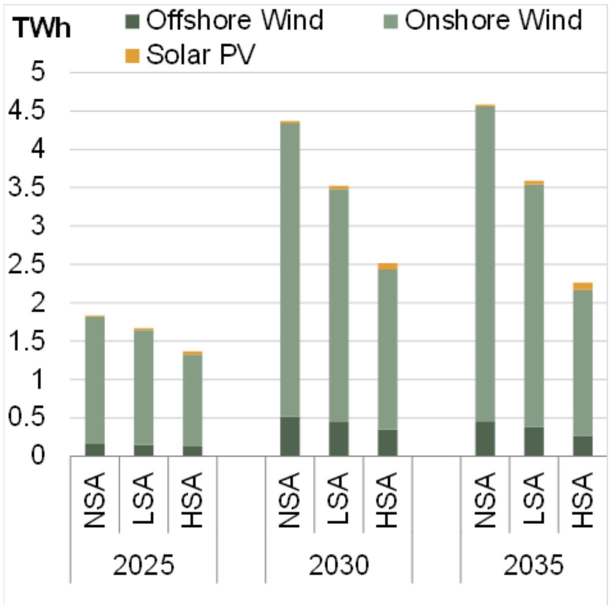


Exhibit 4.13 – Renewable curtailment in Ireland (TWh)



4.6 Other qualitative aspects considered

Besides the aspects discussed above, there are other aspects that are out of the scope of this study to quantify, but are worthy of note.

4.6.1 The DS3 programme

In order to achieve a renewable penetration of 70% by 2030, improvements to the system are required. This is where the DS3(+) programme comes in[12], to Deliver a Secure and Sustainable Electricity System; increasing reliability and predictability. However, there are a number of uncertainties around these system improvements. For example, whether these system improvements are technically feasible, whether RoCoF has to increase again and whether more interconnection is required.

Given that there is such a strong reliance on the uncertain improvements to system constraints in order to deliver the growth in renewable penetration, any chance to remove pressure from the reliance on these improvements should be taken into consideration.

Section 4.5 describes that a more balanced mix of wind and solar can reduce curtailment and that this more balanced mix better reflects the shape of demand. In other words, by means of more efficient use of the complementary nature of wind and solar, a more balanced mix of wind and solar may make the system more reliable, relieving some pressure from the DS3+ programme.

Furthermore, with a more balanced mix of wind and solar, the ancillary services (i.e. DS3 System Services) will also have more volume available from thermal generation, particularly balancing products. The reason for this is because solar would displace the thermal generation during the day, which can now be used as reliable sources for ancillary services.

Moreover, solar generation is easier to predict than wind generation given that wind generation is much more variable than solar. As wind is the primary source of electricity generation, the system is heavily reliant on the predictions of wind generation. As such, a more balanced mix of wind and solar means less reliance on wind forecasts, and the system may also require less balancing. Hence, the system becomes more secure when a mix of new wind and solar is added to the system rather than only adding new wind to the system.

4.6.2 Network reinforcements

The need for deep transmission reinforcements is fundamentally driven by the distance of new power generation units from the existing grid. Depending on where future wind and solar developments take place, there is potential for a mix of wind and solar to require fewer costly transmission reinforcements than if solely wind generation is developed. That is, if wind and solar are built in the same region, there will be less imports to that

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[12] EirGrid, DS3 programme, 2011 and ongoing.

region due to the complementary nature of wind and solar. This would even be more the case if wind and solar would be co-located.

5 Conclusions

For Irish policy makers, by choosing the renewable technology based on the RESS strike price alone, important aspects are neglected. Furthermore, pursuing the 2030 renewable ambitions by procuring a balance of new wind and solar to leverage the complementary nature of wind and solar generation seems to appear as a win-win for all stakeholders. This study showed that a more balanced mix of new wind and solar leads to: (1) overall lower societal costs; (2) lower carbon emissions; and (3) a more secure system.

Deciding which renewable technology to build for achieving the renewable penetration targets should not depend on auction bids alone. While auction bids are important, they do not tell the whole story. Other aspects to consider are: (1) PSO costs of supporting future renewables capacity; (2) PSO costs of existing REFIT capacity; (3) costs of electricity demand; (4) emissions; (5) constraint payments; (6) DS3; and (7) network reinforcements.

A more balanced blend of new wind and new solar results in lower societal costs

This study showed that a more balanced mix of new wind and solar substantially reduces annual societal costs in Ireland. That is, a more balanced mix of new wind and solar avoids material increases in PSO costs of supporting future and existing renewables that would otherwise occur, which also more than offsets the relatively higher cost of meeting demand.

As part of this finding, this study showed that solar can achieve a high strike price in the next auction and still provide lower cost to consumers than onshore wind, even when a more balanced mix of wind and solar is built.

A more balanced blend of new wind and new solar results in lower carbon emissions

This study also showed that a more balanced mix of new wind and solar leads to lower carbon emissions from power generation in Ireland. By replacing some wind with the same amount of solar in MWh, annual emissions can further reduce by 7% in 2030 and 8% in 2035.The key driver behind this finding is the daytime generation profile of solar displacing more carbon intensive thermal plants.

A more balanced blend of new wind and new solar results in a more secure system

Finally, this study showed that a more balanced mix of new wind and solar results in significantly lower levels of renewable curtailment in Ireland. Hence, there will be less need for redispatch, and therefore constraint payments will be lower. This also means there is less balancing to be done, as there will be less reliance on the more variable wind generation.

Discussion

The findings in this study are the result of modelling of alternative scenarios with assumptions based on third party sources. If these key input assumptions would differ, they could have an impact on the overall level of benefits identified in the study, although it is expected that the key conclusion of the benefit of some diversification would hold. The potential impact of changes to the key input assumptions are addressed in Annex A.6, which covers fuel and carbon prices; electricity demand growth; RESS auction bid prices; and improvements to operational system constraints.

Recommendations

While this study does not seek to answer the question of determining the optimal future generation mix, the analysis illustrates that a more diverse mix of renewable generation would provide improved outcomes. Relying solely on strike price comparisons in the forthcoming RESS auctions may not allow for this to be realised, and therefore some form of mechanism could be employed to provide a more equitable comparison.

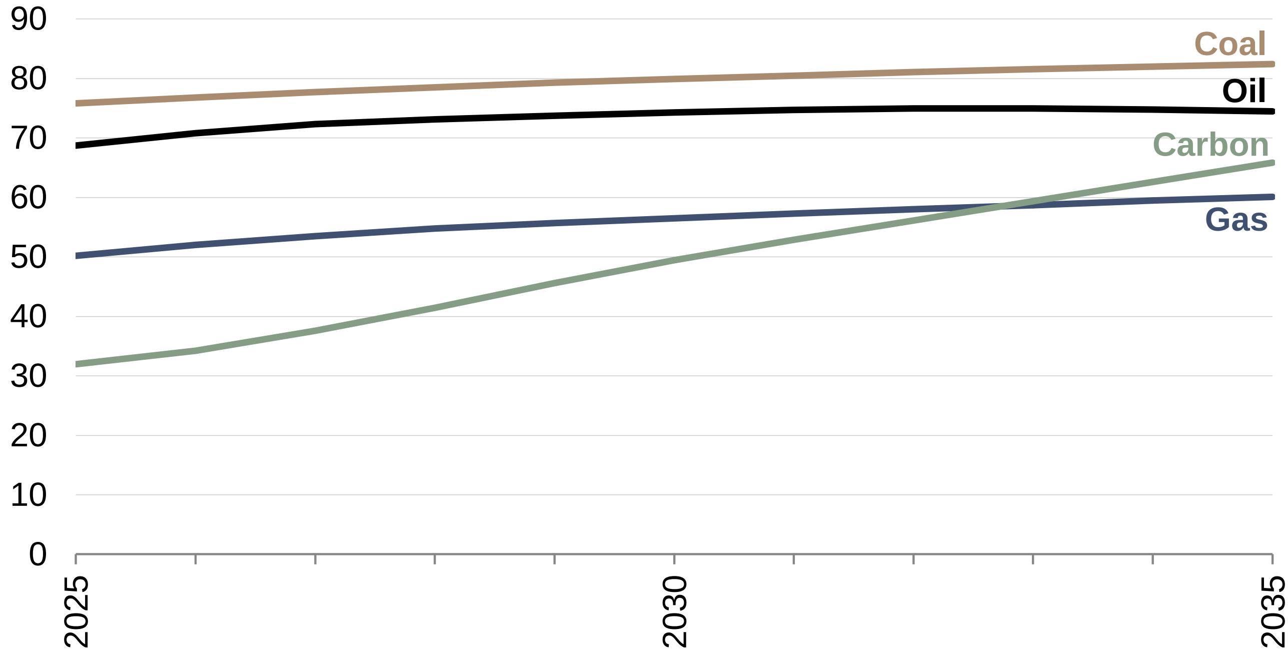
For example, as with the first RESS auction (RESS-1), a preference category for solar could be included in future auctions to ensure some solar is procured in order to capture some of the benefits. Alternatively, setting the Evaluation Correction Factor (ECF) for solar below 1.0 could be another way to capture some of the benefits, in the determination of successful projects based on resulting Deemed Offer Prices (i.e. project-specific offer price multiplied by technology-specific ECF).

Annex A Key inputs

A.1 Fuel and carbon prices

Fuel and carbon prices have been taken from National Grid's 2020 Future Energy Scenarios study using the Base case (Exhibit A.1)[13].

Exhibit A.1 – Fuel and carbon prices (Gas (NBP) in p/therm; carbon (EU ETS) in €/tCO$_2$; oil (Brent) in $/bbl; coal (ARA CIF) in $/tonne; all in real 2019 money)

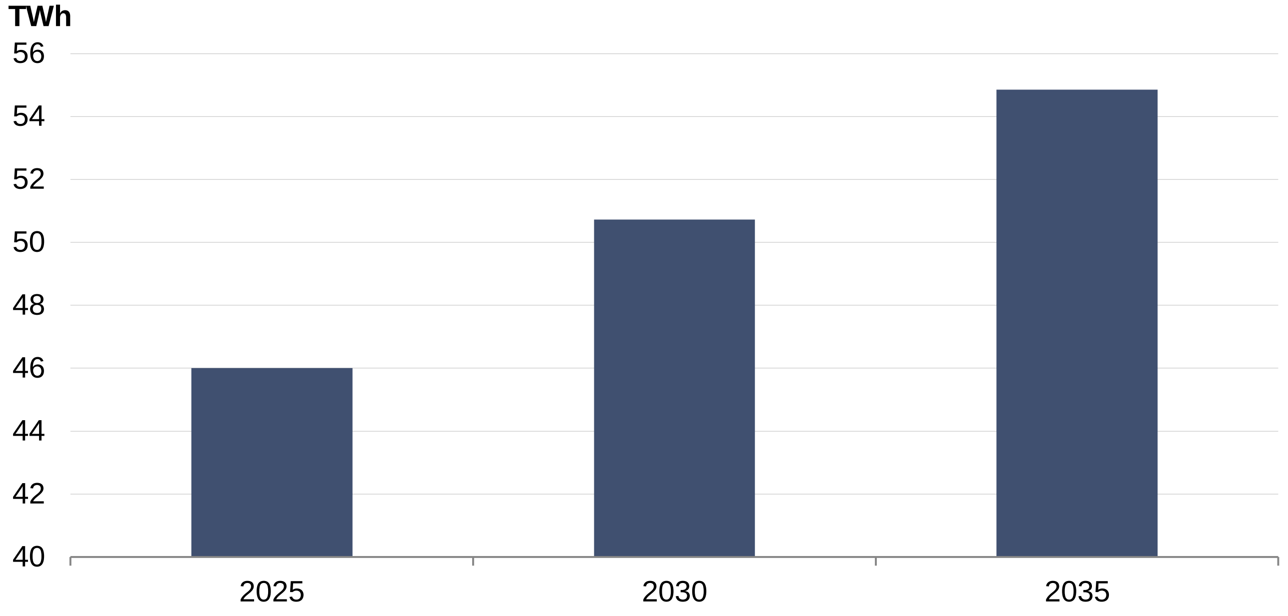


[13] National Grid, Future Energy Scenarios 2020, July 2020.

A.2 Demand

Annual demand has been taken from EirGrid's 2020-29 Generation Capacity Statement using the Median scenario[14] and 2019 Tomorrow's Energy Scenarios using the Centralized Energy scenario[15], and is shown in Exhibit A.2.

Exhibit A.2 – Annual electricity demand in the SEM (TWh)



[14] EirGrid, All Island Generation Capacity Statement 2020-2029, August 2020.
[15] EirGrid/SONI, Tomorrow's Energy Scenarios, 2020.

A.3 Capacity and generation mix

The capacity mix is the key differentiator of this study. The development of new renewable capacity has specifically been constructed to reflect three pathways to a renewable penetration of 70% by 2030. The capacity mix and generation mix are shown per scenario in Exhibit A.3 and Exhibit A.4, respectively.

Exhibit A.3 – The capacity mix in the SEM for the three scenarios (GW)

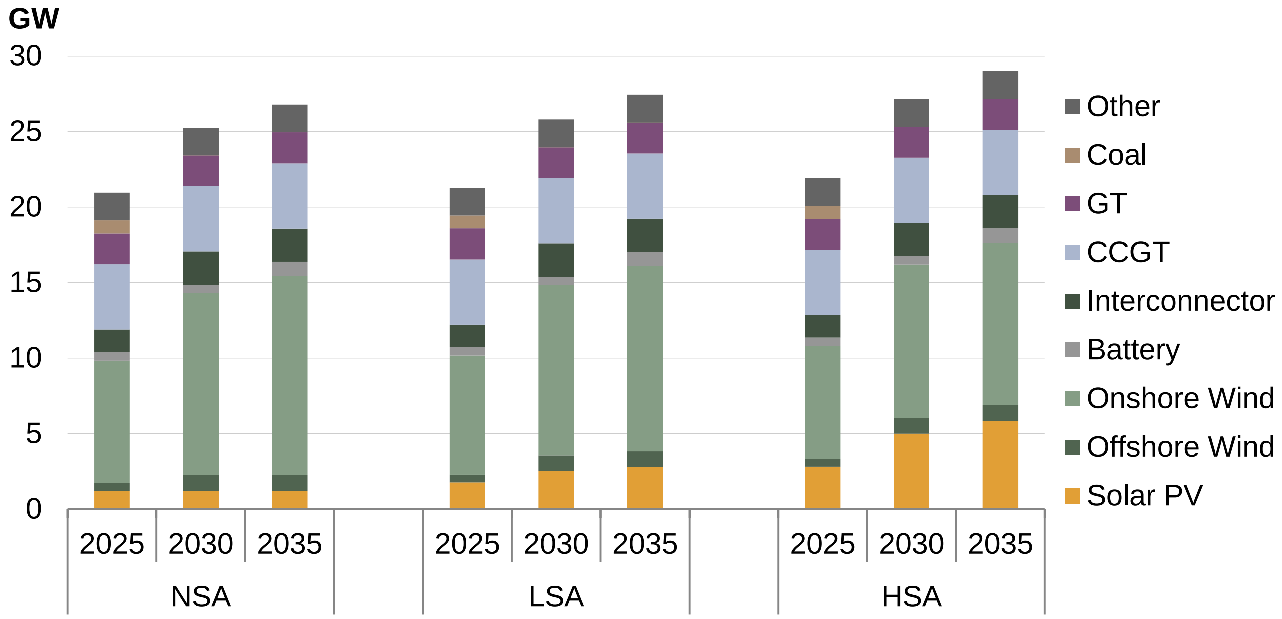
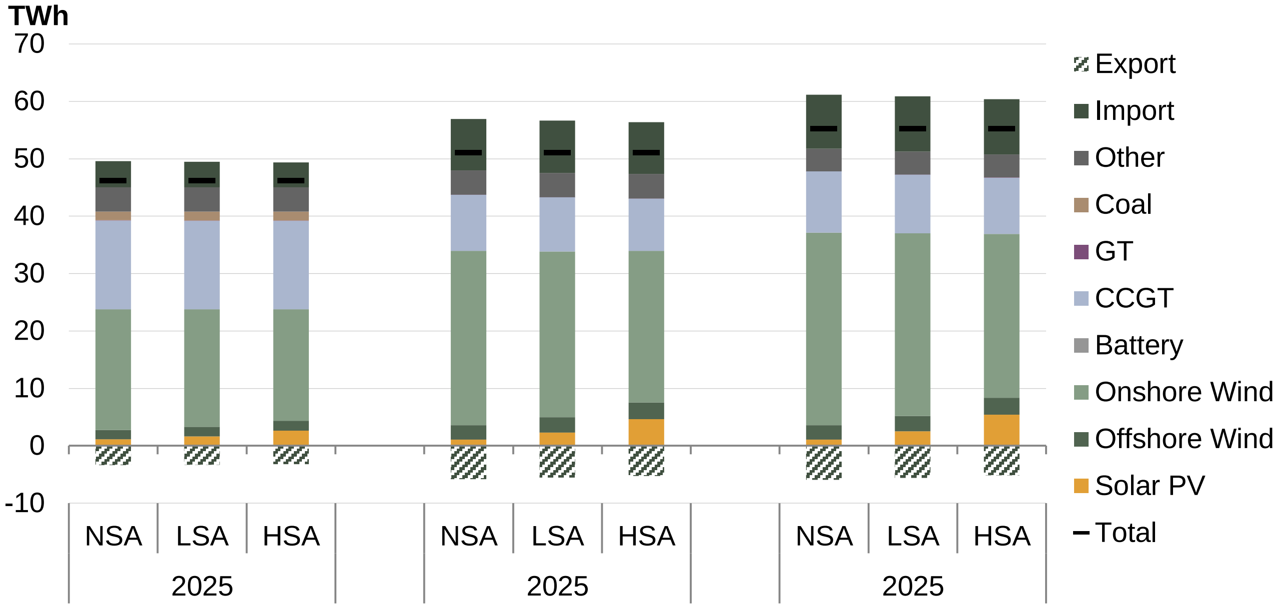


Exhibit A.4 – Generation mix in the SEM for the three scenarios (TWh)



Notes: In all three scenarios, RESS-1 capacity is expected to develop as planned and 1GW of offshore wind capacity is expected by 2030.

A.4 Strike prices

In order to calculate strike prices, a set of LCOE input assumptions have been combined with the modelled curtailment output. While LCOE is presented hereafter, the curtailment results can be found in Section 4.3.1.

A.4.1 LCOE per technology

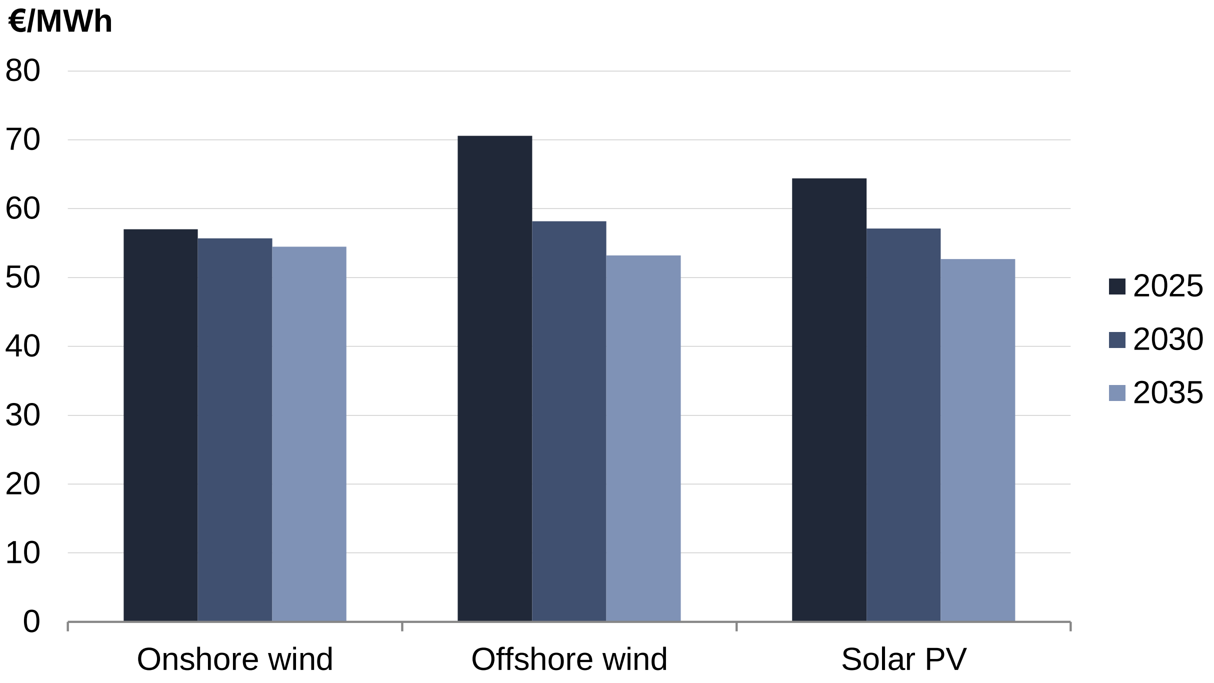
The LCOE per renewable technology have been derived from BEIS' 2020 Electricity Generation Cost report using the Central scenario[16], and are shown in Exhibit A.5. To reflect Irish market conditions (i.e. to account for the difference between the market in GB and the SEM), LCOEs have been multiplied by 1.1 for wind and by 1.3 for solar.

A.4.2 Strike prices per technology

The technology-specific strike prices vary per scenario and reflect the cost of a new entrant, as shown in Exhibit A.6. They are based on the assumed LCOE and the modelled curtailment (see results Section 4.3.1).

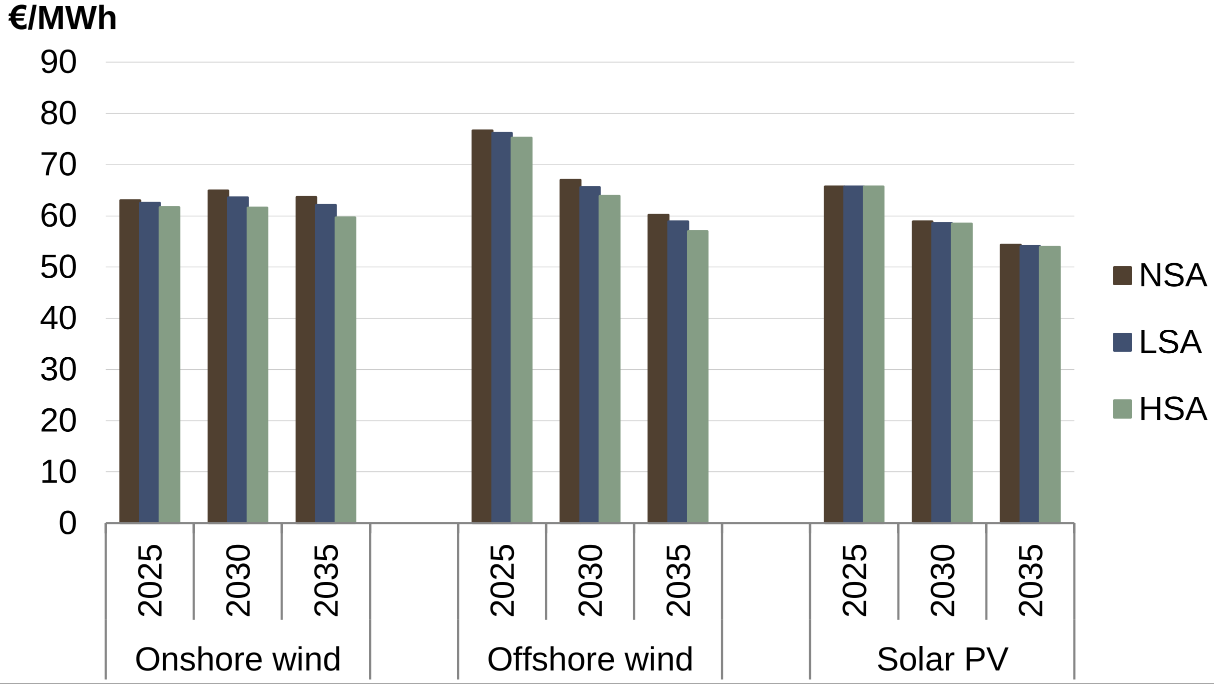
While solar curtailment does not deviate much between the scenarios, wind curtailment is highest when only new wind is built and lowest when a mix of new wind and solar is built. Consequently, strike prices also deviate per scenario for wind, while strike prices for solar remain very similar.

Exhibit A.5 – LCOE per technology in Ireland (€/MWh, real 2019 money)



[16] BEIS, Electricity Generation Costs 2020, August 2020.

Exhibit A.6 – Strike prices (€/MWh, real 2019 money)



A.5 System constraints

System constraints for 2025 and 2030 have been taken from EirGrid's 2019 Tomorrow's Energy Scenarios using the Centralized Energy scenario[15]. 2035 assumes the same assumptions as 2030. The system constraints are summarised in Exhibit A.7.

Exhibit A.7 – System constraints

	2025	2030	2035
SNSP limit (%)	80%	95%	95%
Inertia limit (GWs)	15	None	None
RoCoF limit (Hz/s)	1	1	1
Limit on reserve from non-synchronous sources	No	No	No
Reduction in the minimum generation output of large generating units	Yes	Yes	Yes
Inertia from non-generation resources	No	Yes	Yes
Jurisdictional reserve requirement	No	No	No
Minimum number of conventional units in the Republic of Ireland	3	2	2
Minimum number of conventional units in Northern Ireland	2	2	2

A.6 Potential impact of changing key inputs

The table below includes some qualitative commentary on how the findings of this study may be expected to change, with changes in the key input assumptions used for the scenarios.

Exhibit A.8 – Potential impact on the findings when input changes

Input change	Potential impact on the findings
Higher fuel and carbon prices	This could result in relatively higher benefits with a more balanced mix of wind and solar. That is, thermal generation will set a higher electricity price, which solar generation will likely capture more often than wind. As such, the increase in the difference in capture prices between wind and solar may widen, leading to greater reduction of support costs for renewables with a more balanced mix of wind and solar.
Higher electricity demand	This could result in greater impact on both societal costs and emissions, in scenarios reflecting a more balanced mix of wind and solar. In this event, solar generation would occur at times when higher merit order generation is otherwise generating, which means solar generation would capture higher prices and would displace higher emitting thermal generation.
Higher solar strike prices (or lower for wind)	This would reduce the impact on societal costs in scenarios reflecting a more balanced mix of wind and solar. However, as discussed in, Section 4.1 the study indicates: (1) how much higher solar strike prices could be before support costs per unit of solar generation would be equal to that for onshore wind; and (2) that the lower societal costs would still persist when strike prices of solar remain high.
Less improvements to the system constraints	Were system constraints to be addressed more slowly than anticipated, it is expected this would result in a greater impact on curtailment and emissions between the NSA and the HSA scenario. That is, the system constraints (e.g. the SNSP limit) would be binding more often, particularly at times when demand tends to be lower, which will affect wind generation more than solar generation. This also means that solar generation can more easily displace higher emitting thermal generation than wind generation.

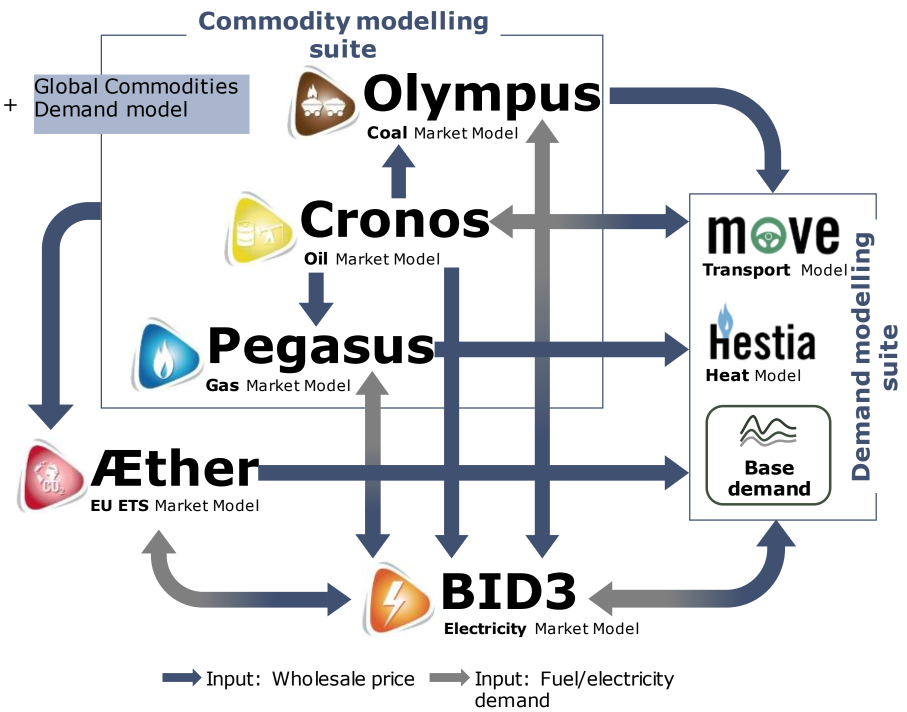
Notes: If the input change would be reversed, the potential impact on the findings could also be interpreted in reverse.

Annex B BID3 Power Market Model

B.1 What is the role of BID3 in AFRY's energy system?

AFRY Management Consulting has been providing energy market participants and lenders with long-term price projections for more than two decades. We produce our projections using a set of in-house market models, running in an interdependent and iterative manner to ensure consistency between related sectors. Accordingly, we have created commodity market models for oil, coal, gas, carbon, and electricity supported by models for demand in the transport and heat sector (Exhibit B.1). As part of the modelling ecosystem, BID3 is AFRY's proprietary power market modelling software.

Exhibit B.1 – OVERVIEW OF THE AFRY MODELLING ECOSYSTEM



B.2 How does BID3 work?

BID3 provides a simulation of all the major power market metrics on an hourly basis electricity prices, dispatch of power plants and flows across interconnectors. An overview of BID3 has been displayed in Exhibit B.2.

In some markets (e.g. GB and the SEM) we extend our regular Day Ahead Market modelling into the balancing timeframe (Exhibit B.3). The resulting outputs allow us to assess a range of factors, such as curtailment, imbalance costs and the DS3 System Services expenditure.

For the purposes of this study, hourly wind and solar curtailment are particularly critical redispatch outputs. That is, curtailment is currently not compensated in the SEM. Without this, a true picture of the PSO Levy costs is not possible.

Exhibit B.2 – Overview of BID3

BID3 is AFRY's proprietary power market modelling software used to model the European markets.

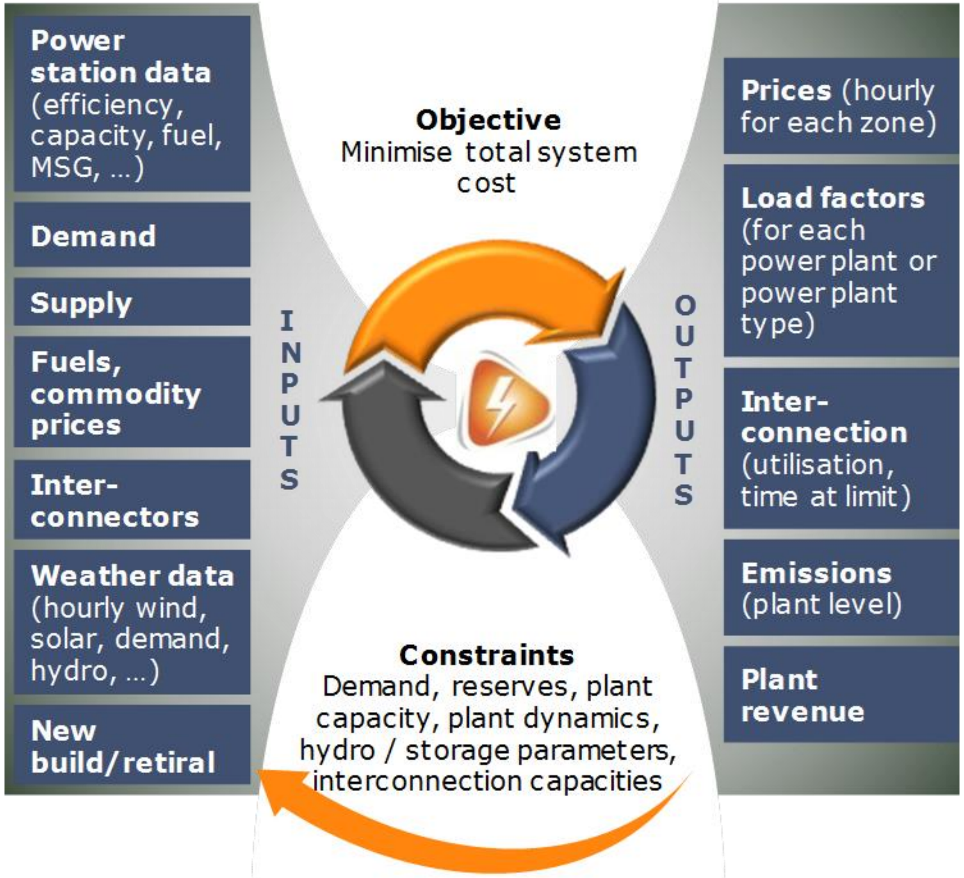


Exhibit B.3 – Redispatch modelling in BID3

We model the Irish Balancing Market at hourly resolution to reflect the impact system constraints can have on the economics of renewables.

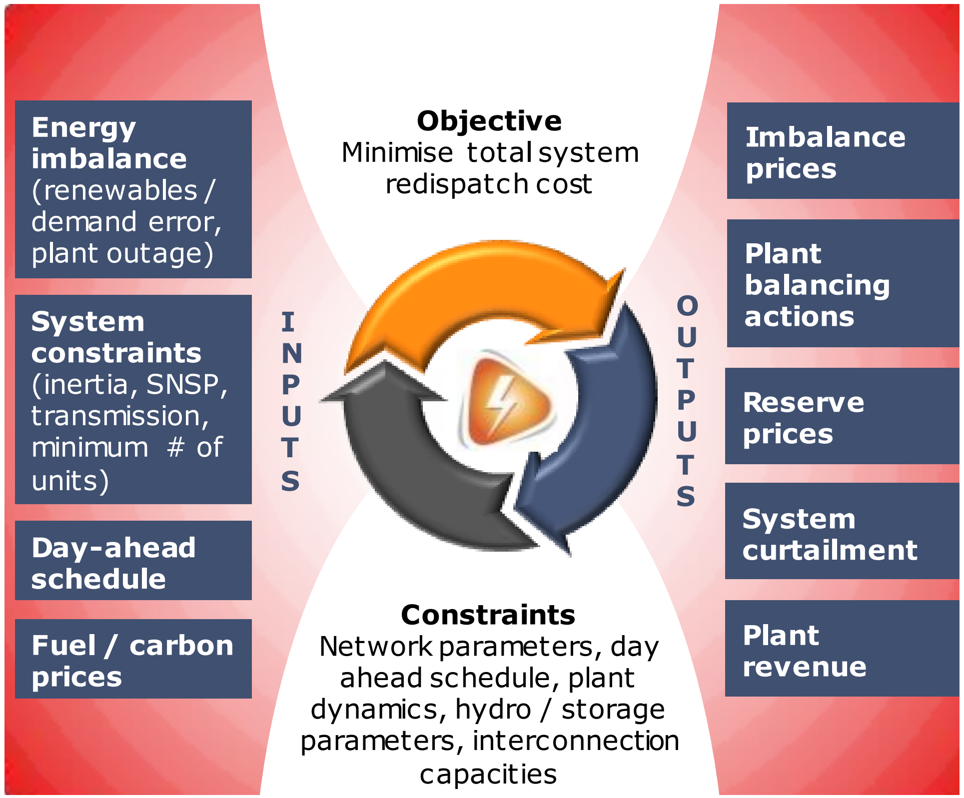


TABLE OF EXHIBITS

Quality control

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Version	Date	Comments
100	February 2021	Initial release
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300	February 2021	Minor correction

ÅF and Pöyry have come together as AFRY. We don’t care much about making history.

We care about making future.

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