everoze

# Saving Money

## 70 by 30 Implementation Plan

May 2020

*Delivering the*

***Climate Action Plan***

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## DISCLAIMER



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## ABBREVIATIONS

| | | | |
|---|---|---|---|
| AEP | Annual Energy Production | OPEX | Operational Expenditure |
| IWEA | Irish Wind Energy Association | DUoS | Distribution Use of System |
| LCOE | Levelised Cost of Energy | TUoS | Transmission Use of System |
| WACC | Weighted Average Cost of Capital | TLAF | Transmission Loss Adjustment Factor |
| CAPEX | Capital Expenditure | DLAF | Distribution Loss Adjustment Factor |
| RVs | Rateable Values | ARV | Annual Rate on Valuation |

# FOREWORD

Wind energy has led Ireland's efforts to tackle climate change. It currently saves more $CO_2$ emissions each year in Ireland than all other forms of renewable energy combined and in 2018 avoided €432 million in fossil fuel imports.

Like many other countries wind energy in Ireland required financial support over the last two decades (i.e. REFIT) but, in return, wind energy has driven down the price of electricity on the wholesale market.

Energy experts Baringa calculated that wind energy is currently reducing the wholesale price of electricity each year by approximately 20 per cent, which is almost €400 million per year[1]. When all costs and savings are accounted for, Baringa concluded that wind energy in Ireland has only cost €1 per person per year since 2000. In return, the consumer is getting a third of electricity from wind energy which is now saving more than 3 million tonnes of $CO_2$ annually.

This story can get even better. Over the last 20 years the price of wind energy has been falling steadily. Wind farms in the Nordic countries are selling power at prices as low as €30/MWh[2] while in Spain, Germany, Turkey and Poland[3] prices have fallen to €40/MWh.

To put this in context, the average annual price on Ireland's wholesale electricity market over the last 10 years ranged from €45-65/MWh, so we have now entered an era where wind energy could potentially be cheaper as well as greener[4].

But whether our industry achieves this is not solely up to us.

In the next two to three years the Irish Government will face an array of policy choices that can cut – or drive up – the price of wind-generated electricity. Government Ministers, officials in various departments and other policymakers will soon decide whether Ireland's homes are powered with some of the most, or the least, expensive electricity in global markets.

Baringa calculated previously that if onshore wind in Ireland can be delivered at €60/MWh, on average, between 2020 and 2030, then the 70 per cent renewable electricity target set out in the Climate Action Plan will actually be cost neutral for the consumer[5]. If we can achieve prices under €60/MWh then Ireland's electricity consumers will be saving money.

A key driver of falling prices in other countries was the move by policymakers from renewable electricity 'tariffs' to 'auctions'. The REFIT scheme was tariff based, which meant that every wind farm got the same fixed price for its electricity, typically around €80/MWh.

However, in an auction, each wind farm bids a price and only the projects that offer the best value make it into the support scheme. The competitive bidding environment in auctions has driven down the price of renewable electricity in other countries over the last decade and, as expected, Ireland will hold our first auction in July 2020[6].

Auctions have put price front and centre for renewable electricity in Ireland, but they are only part of the picture. Prices will only fall if wind projects can provide their power at the best possible price. IWEA commissioned this work by Everoze to examine a series of scenarios and policy choices available to the Government that will reduce or increase the cost for consumers of electricity generated by wind power.

It is clear from the analysis that policymakers will have a huge influence over the cost of wind energy in the coming decade. If all the potential savings are implemented then onshore wind in Ireland could absolutely match the record lows in other EU countries of approximately €40/MWh. This requires taller turbines, 30-year consents, a more efficient

[1] https://www.iwea.com/images/files/baringa-wind-for-a-euro-report-january-2019.pdf

[2] https://iwea.com/images/Article_files/10._14.30_Cathrine_Torvestad.pdf

[3] https://www.linkedin.com/posts/giles-dickson-98607229_energy-renewableenergy-coal-activity-6621332388104548352-ddci

[4] https://www.iwea.com/images/files/iwea-cheaper-and-greener-final-report.pdf

[5] https://www.iwea.com/images/files/70by30-report-final.pdf

[6] http://www.eirgridgroup.com/site-files/library/EirGrid/RESS1-AT-RESS-1-Auction-Timetable-171219.pdf

planning system, lower balancing costs in the electricity market, smarter grid connections, reforms to grid charges, and capital allowances.

To achieve this, we have developed ten ‘cost saving’ policy choices demonstrating how policymakers can facilitate a 46.5 per cent drop in onshore wind costs.

But there is another possibility. The Government can also make a series of decisions that will, perhaps unwittingly, drive up the cost of onshore wind energy in Ireland. If this is the road taken, a country with some of the best wind resources in the world may end up paying some of the highest prices.

The most immediate decision is the proposed noise limits in the draft Wind Energy Development Guidelines, potentially the most extreme in Europe, which will require wind farms to switch off if they create a noise louder than the hum from your kitchen fridge.

With such extraordinary noise limits wind farms will need to be turned off much more often than in the past, which will increase the cost of producing renewable electricity.

Another immediate concern is the ongoing revaluation being carried out by the Valuation Office, which is increasing the commercial rates for a wind farm by 200-300 per cent. Longer-term, likely increases in constraints and curtailment on the electricity grid will also add costs to wind energy development, as like the noise limits, these will require wind farms to switch off more and more when the wind is blowing. When combined these measures could increase onshore wind prices by 34 per cent which would increase costs to ~€100/MWh for onshore wind in Ireland.

So, if all savings are applied, Ireland will become a world-leader in low-cost wind energy and potentially reach levels of €40/MWh, but if the wrong choices are made, if all the additional costs are imposed, Irish electricity consumers will see the impact on their bills every month.

Under the new auction system, the ultimate beneficiary of lower onshore wind prices will be the electricity consumer. If wind farms can offer lower prices into the auction, then the Irish electricity consumer will pay less on the PSO and, if onshore wind can offer prices lower than the electricity market, wind farms could potentially be paying money back to the electricity consumer.

International energy experts Pöyry calculated that for every €10/MWh reduction in wind energy in the auctions, the Irish electricity consumer will save ~€1.5 billion.

Although this study is focused on onshore wind, many of the potential savings and costs are applicable to other forms of renewable electricity also, particularly offshore wind and solar, which are also central to the Government’s plans for 70 per cent renewable electricity by 2030.

In this study, Everoze has shown that it is policymakers, not industry; Ministers and officials, not wind farm developers and operators, who will decide whether onshore wind in Ireland is at €40/MWh or €100/MWh. Those decisions are theirs, and theirs alone, to make and we hope this study will ensure the choices they make are informed and focused on delivering renewable electricity at the lowest possible cost to the consumer.

Dr. David Connolly

CEO, IWEA

## Policy Choices to Reduce the Cost of Onshore Wind in Ireland

| Name | Description | Lead Stakeholders | Most Affected | Others Impacted^ | Cost Impact |
|---|---|---|---|---|---|
| **1. Tip Heights** | Ensure that taller wind turbines can be accommodated in the revised Wind Energy Development Guidelines | DHPLG, DCCAE, Communities, Local Authorities, An Bord Pleanála | All Consumers receive savings via the PSO due to lower RESS bid prices. | | -27 per cent -€20.3/MWh |
| **2. Noise Limits** | Ensure the revised Wind Energy Development Guidelines do not include extreme noise limits | DHPLG, DCCAE, Communities, Local Authorities, An Bord Pleanála | All Consumers pay additional costs via the PSO due to higher RESS bid prices. | | +11.4 per cent +€8.6/MWh |
| **3. Life Extension** | Grant planning for wind farms for 30 years | Local Authorities, An Bord Pleanála, DHPLG | All Consumers. | Offshore Wind; Solar | -10 per cent -€7.5/MWh |
| **4. Simplified Planning** | a) Enhanced community engagement; b) Implement regional planning for wind energy; c) Improve SID engagement and decision timelines in An Bord Pleanála; d) Facilitate grid consenting in parallel to wind farm consenting. | a) Wind farm developers; b) DHPLG & Regional Authorities (via REPDF); c) An Bord Pleanála & DHPLG; d) DHPLG & CRU to facilitate grid installations on public roads | All Consumers. Some savings should be allocated to additional resources in Regional Authorities & ABP. | Offshore Wind | -1.5 per cent -€1.1/MWh |
| **5a. Curtailment** | Continuation of the DS3 program to ensure enough system services (reserve, inertia, reactive power, and ramping) can be provided, ideally by zero-carbon services, to increase SNSP to 95 per cent and eliminate 'Min Gen'. Create more flexibility on the Irish grid via interconnection and Demand Side Management/storage. | CRU to provide enough resources via PR5 and EirGrid/ESBN to implement, particularly via continuation of DS3, more interconnection and flexible technologies. | All Consumers. Some savings should be allocated to EirGrid, ESBN & industry to invest in new solutions required. | Offshore Wind; Solar | +10 per cent +€7.5/MWh |
| **5b. Constraints** | Progress grid reinforcements based on future development along with alternative network solutions using best-in-class community engagement. Streamline EirGrid's 'six-step' process and create a Grid Capacity Advisory Council. | CRU to provide enough resources via Price Review 5 and EirGrid to design/consent based on future outlook. ESBN to build the grid once a clear need is demonstrated. | | Offshore Wind; Solar | +8 per cent +€6/MWh |
| **6. Grid Charges** | Provide fixed grid charges (DLAF, TLAF, DuOS and TuOS) before financial close of a wind farm and allocate future cost changes to new connections and/or to be socialised. | CRU to review grid charges methodology. | All Consumers will benefit from lower capital costs. Reform of grid charges should otherwise be cost neutral. | Offshore Wind; Solar | -3 per cent -€2.3/MWh |

| | | | | | |
|---|---|---|---|---|---|
| **7. Grid Connections*** | More contestability for grid connections, sufficient grid offers and alignment of grid offer process with RESS auctions, facilitate hybrid connections by allowing separate legal entities and dynamic sharing of capacity at a single connection point. | CRU via review of Hybrid policy, ECP policy and PR5. EirGrid and ESBN to implement Hybrid and ECP policy with resources/incentives from PR5. | All Consumers. Some savings should be allocated to EirGrid & ESBN for additional resources to deliver. | Offshore Wind; Solar | -1 per cent -€0.8/MWh |
| **8. Balancing Costs** | Create more flexibility on the Irish grid via interconnection and DSM/storage; couple I-SEM to Europe via SIDC (formerly XBID); improve liquidity in the continuous markets by allowing new products and GB access to all intraday markets; avoid excessive system margins. | EirGrid via SEMO and CRU to update the I-SEM design. EirGrid to facilitate more interconnection and flexible technologies. | All Consumers with some savings offset by investment in new solutions. | Offshore Wind; Solar | -3 per cent -€2.3/MWh |
| **9. Commercial Rates** | Reverse recent increase in commercial rates for wind farms so they are maintained at similar levels to those payable by fossil fuel generators. For example, Ireland could decrease the rates payable by wind farms by updating the Valuations Act to exclude the moving parts of a wind turbine which is the case in Northern Ireland. | DHPLG to update the Valuation Act. Valuation Office to implement based on a more transparent and robust valuation scheme for wind farms. | All Consumers. Reduced commercial rates liability will enable wind farms to sell power more cheaply. | Solar | +5 per cent +€3.8/MWh |
| **10. Grid Capital Allowances** | Allow the capital costs associated with grid connections to be included as capital expenditure like roads, turbines and electricity systems when reducing the amount of tax payable, as allowed in the UK. | Department of Finance and the Revenue Commissioners | Lower costs for wind, but tax reductions will need to be collected elsewhere or offset by future growth in wind. | Offshore Wind; Solar | -1 per cent -€0.8/MWh |
| **Total Savings** | | | | | **-46.5** per cent **-€35/MWh** |
| **Total Costs** | | | | | **+34.4** per cent **+€26/MWh** |

^The analysis was originally based on onshore wind, but there are a number of policies that will potentially benefit offshore wind and solar also, which are also central to the Irish government's plans for 2030.

*This does not account for the cost of uncertainty due to grid delivery. For example, if renewable electricity auctions include 'cliff edge' deadlines then this will create additional risk for a project, particularly in relation to the timelines for grid delivery. This will be an additional cost to consider and was beyond the scope of the analysis here.

# 1. EXECUTIVE SUMMARY

The cost of electricity generated by onshore wind farms in Ireland has fallen since the first REFIT projects were installed in 2006 and continues to fall. In addition to various technical and commercial factors, it is clear that policy and regulation are key to driving down the cost of electricity from onshore wind.

The right policy choices can accelerate falling prices but, at the same time, making the wrong choices can push the cost of electricity from onshore wind up, not down.

To support previous strategic studies on cost of energy trajectories in Ireland, IWEA has identified a series of policy choices facing the Government today and in the next two to three years.

IWEA commissioned Everoze to assess the impact of these choices on the cost of electricity generated by onshore wind in Ireland. A straightforward discounted cash flow model has been used to evaluate the discrete impact of each policy scenario on overall LCOE.

The scenarios modelled in this report are summarised below, grouped under three broad themes:

1. **Planning and Environment**
    - Increasing turbine tip heights to provide access to better wind resources and the latest turbine technology.
    - Applying some of the most extreme noise limits known to industry to wind farm development as proposed in the draft Wind Energy Development Guidelines.
    - Increasing a wind farm's operating life.
    - Designing a more streamlined and predictable planning system.
2. **Grid Development and Reform**
    - Rising levels of constraint and curtailment, collectively known as dispatch-down.
    - Reforming the system of charges[7] imposed on wind farms.
    - Improving the development of grid connections, giving increased contestability, better standard requirements and promoting hybrid connections.
    - Reducing balancing costs in Ireland's electricity market (I-SEM) through appropriate regulation, allowing volatility and encouraging storage.
3. **Tax Policy Reform**
    - Increasing business rates for wind farms arising from the ongoing Ireland-wide revaluation.
    - Including grid connection costs as capital allowances in the same manner as other capital expenditure.

The results of the modelling exercise, presented graphically below, show that the choices for policymakers that would cut the cost of wind energy by the greatest amount are:

- Increasing turbine tip height;
- Extending the operating life of wind farms;
- Reform balancing costs in the electricity market; and
- Reform of system charging.

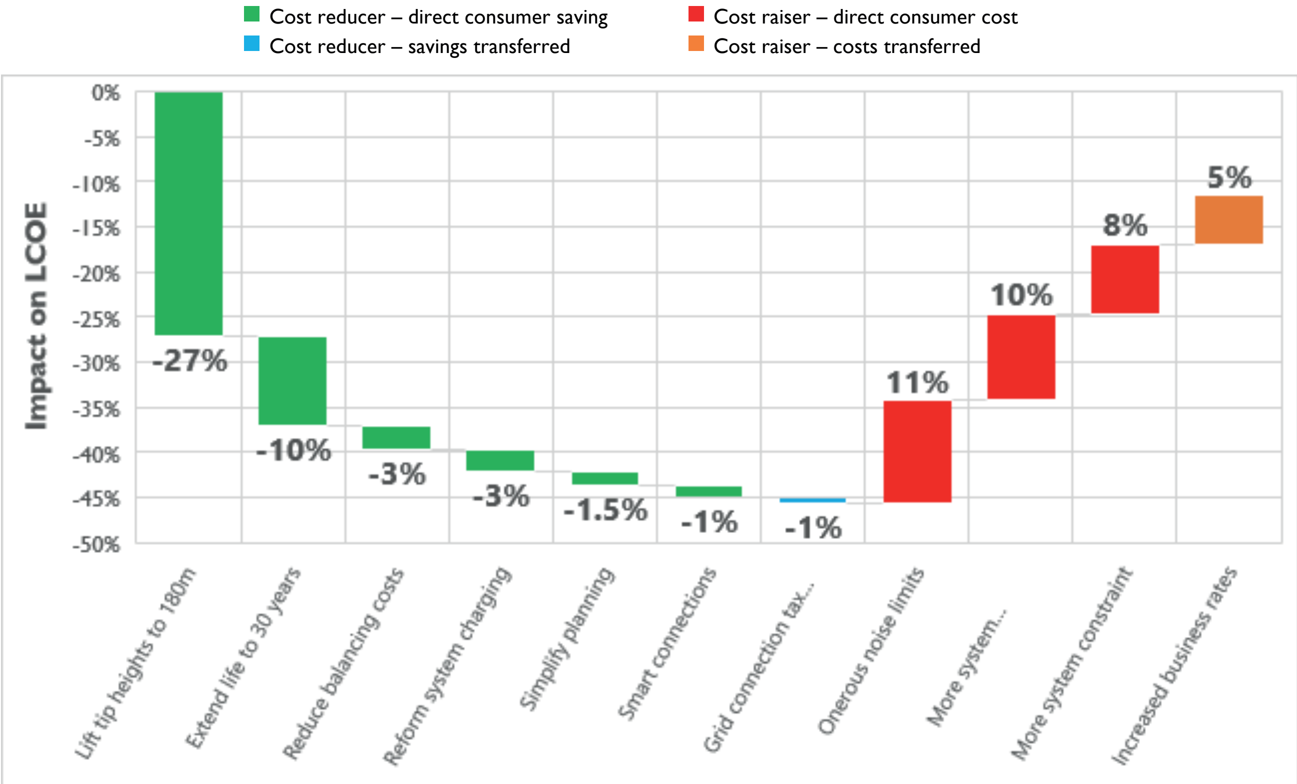
All of these would deliver measurable, identifiable, direct savings to the Irish electricity consumer. More modest savings could be realised from simplification of the planning consent process and a smarter approach to grid connections while additional savings are also possible from reforming the tax treatment of grid connection costs.

On the other hand, the cost of onshore wind will increase significantly in the short term if the extreme noise limits contained in the proposed Wind Energy Development Guidelines are implemented. This will mean higher bills for the electricity consumer.

[7]System operators providing fixed loss factors (DLAF and TLAF) and use of system charges (DUoS and TUoS).

Further short-term cost increases would result if commercial rates continue to rise for wind farms under the ongoing revaluation.

Over the longer-term, there is a further risk of significant price rises from delays to the reinforcement of the electrical grid (resulting in increased constraints) or failure to build on the success of the DS3 programme (resulting in increased curtailment), both of which would push up the price of electricity in Ireland.




Our analysis shows just how significant the role of Irish policymakers will be in supporting the development of onshore wind energy at the best possible price for the consumer.

It also makes clear that the Government has a major role to play in supporting industry to achieve the Climate Action Plan's target to meet 15 per cent of electricity demand from renewable sources contracted through Corporate PPAs.[8] The choices made by policymakers will determine the price wind farms can offer the large energy users who are the potential customers for such agreements. The more prices can be reduced, the stronger the likelihood of achieving that target.

However, the wrong policy choices can increase costs and wipe out the savings that may be obtained from other efforts. Therefore, a measured approach, that is mindful of the consequences for cost of energy, needs to be taken if continued cost reductions are to be achieved.

An important caveat to this study is that levelised cost should not be confused with bid prices or strike prices. It must be emphasised that this analysis provides only an assessment of the relative impact of policy scenarios on overall LCOE for a notional base case site.

It is not an attempt to prejudge any derivation of bid price or strike prices that may be put forward as part of the upcoming RESS auction process. There are many technical and commercial factors that will influence the bid price that is appropriate for an individual project and this report does not seek to define the bounds of such factors.

By putting a price tag on various policy levers that are available to government Everoze hopes that this report will help prioritise efforts on future policy changes across all stakeholders such as IWEA, EirGrid, ESB Networks, CRU, An Bord Pleanála, Valuation Office, DCCAE, DHPLG, and DPER.

[8] https://www.dccae.gov.ie/documents/Climate%20Action%20Plan%202019.pdf

# 2. INTRODUCTION

## 2.1 CONTEXT AND OBJECTIVES

The cost of electricity generated by onshore wind farms has fallen since the first REFIT projects were installed in 2006 and continues to fall. Advances in turbine technology, improvements in yield assessment, better project design and streamlining of supply chains have combined to allow new projects to deliver electricity to the Irish consumer more economically than ever before.

The wind industry in Ireland is rightly proud of their achievements and recognises that there is more that could be done to deliver wind generated electricity even more cheaply and so further lead Ireland's transition to a low-carbon economy.

Policy and regulation are key to reducing cost. The right policies can reduce the price of electricity; however, if the wrong choices are made we will see the cost of electricity from onshore wind rise, not fall.

The findings of the *Economic analysis to underpin a new renewable electricity support scheme in Ireland* (DCCAE, May 2017) and *70 by 30, A 70* per cent *renewable electricity vision for Ireland in 2030* (Baringa, October 2018) studies mapped out a cost reduction trajectory for Irish onshore wind. The *70 by 30* study defined the price point (€60/MWh LCOE) at which onshore wind reaches parity with fossil fuel generation, meaning that electricity from wind power can be generated at no net-cost to the Irish consumer.

While these studies provided valuable macro-economic context for renewable electricity, they did not explicitly identify how policymakers can help to achieve the desired objective of cutting energy costs or how they might undermine it.

The Irish Wind Energy Association ("IWEA") has commissioned Everoze Partners Limited ("Everoze") to assess the sensitivity of the cost of electricity generated by onshore wind in Ireland to various policy scenarios.

The objective of this study is to aid the development of energy policy by putting a price on the various choices and options available to the Government. Only by understanding how a decision can increase or reduce the cost of electricity can informed choices be made.

## 2.2 ABOUT EVEROZE

Everoze is an employee-owned renewables, storage and energy flexibility consultancy. Our unique strength is bridging the gap between the technical and the commercial. We are a team of over 50 consultants who are flexible, experienced and interdisciplinary, working closely with our clients to make projects, companies and technologies futureproof and financeable.

Everoze is a leading provider of independent technical due diligence in the onshore wind sector in Ireland, having advised many of the leading players in the renewables investment community on over 50 individual wind farms over the past 4 years.

Everoze is experienced in the field of techno-economic modelling of a range of technology types, as evidenced by the following publicly available strategic studies:

- *Onshore Wind in Scotland: opportunities for reducing costs and enhancing value*, August 2016
- *Batteries: beyond the spin*, October 2017
- *Cracking the Code: a guide to energy storage revenue streams and how to derisk them*, July 2016
- *Swarm Governance: flying to a future of domestic energy-as-a-service*, June 2019

In addition to the above studies, Colin Morgan, a founding partner at Everoze, chaired the Renewable UK onshore wind cost reduction task force, which produced the influential *Onshore Wind Cost Reduction Taskforce Report* in April 2015.

# 3. MODELLING METHODOLOGY

## 3.1 MODELLED SCENARIOS

In collaboration with IWEA, Everoze has developed the following 10 scenarios that have formed the basis of the LCOE sensitivity testing described in this report. These scenarios fall under three broad themes of:

- Planning and Environment;
- Grid development and reform; and
- Tax policy reform.

Further details of each scenario are given in Sections 4, 5, and 6.

| Group | No. | Title | Scenario description |
|---|---|---|---|
| Planning and Environment | 1 | Tip heights | Assesses the impact of increased Annual Energy Production (AEP) realised through increasing tip heights from 125m to 150m or 180m. |
| | 2 | Noise | Assesses the impact of AEP reduction due to extreme noise emission regulations. |
| | 3 | Life extension | Assesses the impact of increasing wind farm operating life from 20 years to 25 years or 30 years. |
| | 4 | Simplified planning | Assesses the impact of reduced development costs as a result of more readily obtained planning consent. |
| Grid development and reform | 5 | Constraint and Curtailment | Assesses the impact of increased constraint and curtailment losses. |
| | 6 | System charging reform | Assesses the impact of fixed loss factors (TLAF) and charges (DUoS & TUoS), allowing reduced Weighted Average Cost of Capital (WACC). |
| | 7 | Smart connections | Assesses the impact of reduction in grid connection costs through increased contestability, improved standard requirements and promotion of hybrid connections. |
| | 8 | Balancing cost reform | Assesses the impact of reducing balancing costs in the wholesale electricity market through appropriate regulation, allowing volatility and encouraging flexible technologies such as interconnection and storage. |
| Tax policy reform | 9 | Business rates reform | Assesses the impact of the proposed increase in commercial rates for onshore wind farms. |
| | 10 | Grid capital allowances | Assesses the impact of adjusting the tax treatment of grid connection costs. |

TABLE 1: LCOE SCENARIO SUMMARY

## 3.2 MODELLING APPROACH

Everoze has used a discounted cash flow model to evaluate the discrete impact of each policy scenario on overall LCOE. This is a spreadsheet tool that is typically used to model key assumptions about a particular business (i.e. lifetime, revenue, CAPEX, and OPEX) and determine the return on the capital invested. In the context of this study, the same model can be used in reverse to evaluate the cost of energy associated with a fixed cost of capital.

For each of the scenarios listed in Section 3.1 the impact on the following project cost drivers, relative to a base case set of conditions, has been estimated:

- WACC – Weighted average cost of capital;
- AEP – Annual energy production;
- Operating life;
- CAPEX – Capital expenditure associated with development and construction;
- OPEX – Operational expenditure associated with the operation of the wind farm.

Details of the adjustments made to each of the input variables are presented in Appendix 1.

The base case used as the starting point of the analysis has been derived from the DCCAE 2017 economic analysis and is intended to represent a reasonably typical REFIT2 project[9]. The key parameters of the base case are as follows:

- LCOE of €75.00 per MWh;
- Nine 2 MW wind turbines with 90m hub height and 125m tip height;
- 20-year operating life;
- 7.7 m/s hub height wind speed, with an associated capacity factor of 36.2 per cent, or 57,100 MWh per annum;
- CAPEX and OPEX on a € per MW basis, based on the DCCAE 2017 study, bolstered by industry experience;
- WACC of 6.6 per cent.

To support the overall base case assumptions, Everoze has also undertaken an analysis of recent wind farm projects in Ireland to evaluate the breakdown of CAPEX across a number of cost line items including turbine supply, civil balance of plant (CBoP), electrical balance of plant (EBoP), grid connection, development costs (DEVEX), and financing costs.

A similar analysis has also been undertaken for OPEX to assess the relative contribution of technical costs (such as turbine maintenance and asset management), and non-technical costs (such as balancing costs, use of system costs, lease costs and business rates).

With these CAPEX and OPEX distribution profiles in hand, as shown graphically below, the impact of a change in one cost component on the overall CAPEX or OPEX allocation can be evaluated. For example, it can clearly be seen that a 10 per cent change in turbine supply cost will have a greater impact on overall CAPEX than a 10 per cent increase in EBoP cost.

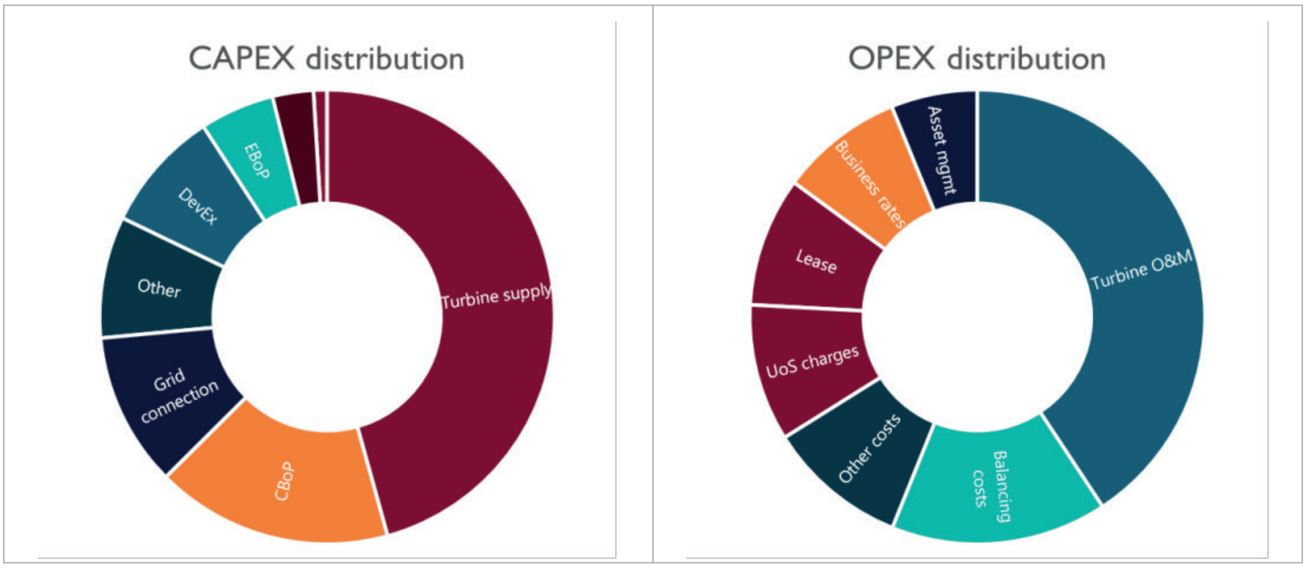



FIGURE 1: CAPEX AND OPEX DISTRIBUTIONS

It must be emphasised that this analysis provides only an assessment of the relative impact of policy scenarios on overall LCOE for a notional base case site. It is not an attempt to prejudge any derivation of bid price or strike prices that may be put forward as part of the upcoming RESS auction process. There are many technical and commercial factors that will influence the bid price that is appropriate for an individual project and this report does not seek to define the bounds of such factors.

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[9] Typical REFIT2 project is based on Everoze's experience acting as technical advisor to REFIT2 wind farm acquisition and project financing transactions.

# 4. PLANNING AND ENVIRONMENT

Everoze has analysed a total of six scenarios that fall under the theme of planning and environment related policy interventions. The LCOE impact of each scenario is presented graphically in the table below. Subsequent subsections provide further background on the rationale and approach for each scenario.

| Scenario 1a | Scenario 1b | Scenario 2 | Scenario 3a | Scenario 3b | Scenario 4 |
|---|---|---|---|---|---|
| **Tip height up to 150m** | **Tip height up to 180m** | **Increased noise curtailment** | **25-year life extension** | **30-year life extension** | **Simplified planning** |
| -12% | -27% | +11.4% | -6.2% | -10.0% | -1.5% |

TABLE 2: PLANNING AND ENVIRONMENT PRICE TAG SUMMARY

## 4.1 SCENARIO 1: TIP HEIGHTS

Turbine tip height, which is the distance from the bottom of the turbine tower to the uppermost limit of the rotor, is usually explicitly constrained by planning consents granted to wind farms. As modern turbines have grown, so too have tip heights also increased.

While permitted tip heights in Ireland are increasing, they have only recently begun to exceed a level of around 125m. In this respect Ireland is a laggard behind other markets across Europe – for example, tip heights in Scandinavian countries often exceed 200m, a key factor in reducing costs to ~€30/MWh in these countries[10].

While there are several valid reasons for limiting tip heights for new developments, such as managing visual impact, minimising such limitations would enable Ireland's wind resource to be captured more efficiently and, as a consequence, at a lower cost.

There is a trend towards permitting of greater tip heights, which will provide benefits in terms of cost of energy, for the reasons set out below.

### 4.1.1 Increasing tip heights gives improved wind conditions

Wind speeds close to the ground are lower than wind speeds at higher heights – this is what is termed "wind shear". Another property of wind shear is that wind speeds over a given vertical distance are increasingly similar the further above ground one is. The consequence of these two physical properties is that the energy yield of a wind turbine generally increases with increased tip height. Depending on the model of turbine a height increase of 20 per cent can provide a 180 per cent increase in power capacity.

While this effect has an upper limit, since structural considerations mean that unlimited tower height is neither feasible nor desirable, it is correct to say that wind turbines being installed in Ireland today are at the lower end of the available hub height range.

In Everoze's experience, the wind conditions on Irish wind farm sites developed in recent years have been more benign than the conditions that the chosen turbines are designed for. This "over-engineering" is in part a consequence of tip height restrictions, which constrain the tower height and prevent the deployment of the turbines in their optimum configuration. If tip heights could be higher then the turbines could be installed on taller towers, producing additional energy at minimal cost.

[10] https://iwea.com/images/Article_files/10._14.30_Cathrine_Torvestad.pdf

### 4.1.2 Increasing tip heights allows deployment of the latest technology

The product range of all major turbine manufacturers is subject to ongoing development. A consistent trend across manufacturers has been towards turbines with larger MW capacity, larger rotor diameters, and higher hub heights. Deploying higher capacity turbines will increase annual energy output from a given wind farm, and the increase in energy yield will offset any increase in the turbine cost, resulting in a reduction in cost per MWh.

The latest generation of turbines also tend to have several other beneficial features such as more sophisticated electrical characteristics to better support the grid, monitoring equipment to eliminate shadow flicker and improved noise control modes.

Current tip height restrictions that are commonly seen in Ireland will prevent the very latest generation of turbines from being widely deployed. This may result in a very limited market of turbines for projects to choose from. Using older turbine models also poses an operational and maintenance risk. Both factors will lead to increased costs for Irish wind farms.

### 4.1.3 Modelled scenarios and results

For the purposes of this LCOE modelling study, Everoze has investigated the impact of increasing the tip height from the base case value of 125m to two higher values that both increase the available wind resource, and permit deployment of larger turbines. The key inputs to the scenarios considered are summarized in the table below.

| TIP HEIGHT | TURBINE CAPACITY | HUB HEIGHT | ROTOR DIAMETER | HUB HEIGHT WIND SPEED |
|---|---|---|---|---|
| 125m | 2 MW | 80 m | 90m | 7.7 m/s |
| 150m | 4.2 MW | 91.5 m | 117m | 7.9 m/s |
| 180m | 5.6 MW | 105 m | 150m | 8.1 m/s |

TABLE 3: TIP HEIGHT SCENARIO KEY ASSUMPTIONS

The wind speeds for the 150m and 180m scenarios have been derived by applying a power law wind shear profile to the 125m base case wind speed, assuming a shear exponent ($\alpha$) of 0.2.

For each of the tip height scenarios, Everoze has estimated annual energy production that could be achieved from a nine-turbine layout by running a basic wind flow and energy computational model. The model was based on the assumption of no complex terrain or forestry. Whilst this is unlikely to be representative of a real site, it is a reasonable approach for assessing the relative impact on LCOE, which is the focus of this study.

In addition to the estimation of energy production, the CAPEX and OPEX assumptions have been adjusted to reflect expected cost savings, on a € per MW basis, that can be achieved via deployment of larger capacity turbines. Whilst the absolute cost of a larger turbine will be greater than a smaller machine, there is an economy of scale that will result in the capital cost of turbines and their foundations reducing on a € per MW basis. Similar economies of scale also apply to the operational costs associated with maintaining larger turbines.

**Result: The results of modelling the tip height scenarios show that significant cost reductions can be realised by increasing tip height to access better wind resource and to allow larger more cost-efficient turbine models to be deployed, with LCOE reductions of 12** per cent **and 27** per cent **from the 150m and 180m scenarios respectively.**

## 4.2 SCENARIO 2: NOISE

Wind farms in Ireland are frequently constructed in proximity to neighbouring dwellings. In order to ensure that people are not subjected to unacceptable levels of noise from the wind farm, planning consents usually define the acceptable noise levels at neighbouring properties.

Historically, noise limits for wind farms in Ireland have been based on the limits proposed in the 2006 version of the Irish Wind Energy Development Guidelines, which were typically 43 dB(A) at night and 45 dB(A) during the day[11].

In 2017, the government proposed a 'Preferred Draft Approach' (PDA) for the new Wind Energy Development Guidelines which indicated that there would be much stricter noise limits in the future, equating to a maximum noise limit of 35-43 dB(A) at all times, day or night, but linked to the background noise that exists during these times:

"*…proposing a relative rated noise limit of 5dB(A) above existing background noise within the range of 35 to 43dB(A) for both day and night, with 43dB(A) being the maximum noise limit permitted*"[12].

Implementing these stricter limits will increase the need to turn off wind turbines in order to comply with more onerous noise limits. Based on the noise limits suggested in the PDA, IWEA members have estimated the likely impact of the proposed noise limits on a series of sample wind farm sites.

The noise curtailment analysis was carried out by modelling ten different wind farms from several different IWEA members. The types of wind farm assessed were a mix of existing operational sites and pre-planning 'green field' wind farm sites.

Due to the commercial sensitivity of the data gathered, the results were anonymised, and the average curtailment levels were deduced. For each site, the assessment compared the curtailment levels of a wind farm when the 2006 Wind Energy Development Guidelines noise criteria were applied to them, and those when the proposed limits in the PDA were applied.

Across the ten different sites the additional curtailment due to the stricter noise limits in the PDA varied from a low of 1.6 per cent to a high of 20 per cent. The average was 9.5 per cent, so in this analysis, it is assumed that the more onerous noise limits will typically increase the curtailment from an Irish wind farm by approximately 10 per cent.

**Result: Modelling this assumption shows that significant LCOE increases of over 11 per cent would result from an additional 10 per cent of curtailment.**

After this analysis was completed, the Irish Government published the draft Wind Energy Development Guidelines for consultation[13]. As expected, the new noise limits aligned in general with those proposed in the PDA at 35-43 dB(A), but importantly there are other proposals in the methodology for applying these noise limits which would increase the curtailment levels of a wind farm even further than envisaged in the PDA.

Therefore, the analysis above should be considered a conservative estimate of the impact of the new noise limits proposed in the new Wind Energy Development Guidelines.

## 4.3 SCENARIO 3: LIFE EXTENSION

The duration of a wind farms' operating life is constrained primarily by planning consent and technical considerations.

Planning consents for onshore wind farms in Ireland will include conditions that limit the permitted operational life of the project. This consented period often commences on first export of electricity from the wind farm and usually permits an operating period of either 20 or 25 years. Decommissioning of the project is required after the end of this period. In the past, it was unusual in Ireland to see consent for operating periods longer than 25 years.

In addition to planning constraints, wind turbines are generally designed in accordance with the IEC-61400-1 international design standard. Implicit within this design standard is an assumption of a 20-year operating life and therefore it can be said that turbines have a "design life" of 20 years beginning upon completion of turbine construction.

The design life of a wind turbine is driven by the frequency and magnitude of repeated structural loads, which are themselves induced by the wind conditions that the turbine experiences on a given site. This fatigue loading is affected not only by average wind speed, but also wind turbulence, wind shear, air density and temperature. The operational behaviour of the turbine is also relevant.

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[11] https://www.opr.ie/wp-content/uploads/2019/08/2006-Wind-Energy-Development-1.pdf

[12] https://www.housing.gov.ie/planning/guidelines/wind-energy/coveney-and-naughten-announce-key-development-review-wind-energy-development-guidelines

[13] https://www.housing.gov.ie/guidelines/wind-energy/public-consultation-revised-wind-energy-development-guidelines

As part of the IEC design standard a series of pre-defined wind condition parameters, or "classes", are used to design turbines that are capable of withstanding conditions at the limit of the applicable design class. Thus, a turbine model may be referred to as a "Class 1A" turbine, or a "Class IIB" turbine.

It is normal for the climatic conditions on a specific site to be evaluated as part of the wind farm development process, usually via a series of site measurements. It is often the case that some climatic condition parameters are less onerous than the limits of the applicable design class and this presents a potential opportunity for the operating life of a project to be extended without compromising the structural integrity of the turbines.

The impact of increasing operating life on the present value of a wind farm is already well known in the wind industry. Considering how best to extend the life of a wind farm through asset-sweating, refurbishment, re-planting or other means is of increasing commercial interest. This is particularly true in markets where energy price support mechanisms are being removed and projects are more exposed to merchant pricing risk.

For the purposes of this LCOE modelling study, Everoze has evaluated the impact of increasing the operating life from a base case of 20 years to 25 years and 30 years, for which some wind farms in Ireland are now obtaining consent.

Extending the operating life of a wind farm, while technically feasible in principle, is not cost-free as it is likely that turbine O&M costs will increase in later years to reflect the additional maintenance effort required to keep an ageing asset operating efficiently. Within the LCOE model Everoze has assumed that turbine O&M costs step up relative to the base case by 10 per cent in years 21-25 and by 15 per cent in years 26-30.

**Result: The results of the modelled scenarios shows that the additional revenue realised from extending the operating life of a project outweighs the additional O&M costs, with LCOE reductions of 6.2 per cent and 10 per cent for the 25 and 30-year scenarios respectively.**

## 4.4 SCENARIO 4: SIMPLIFIED PLANNING

Obtaining planning consent for an onshore wind farm is a time-consuming and costly exercise. A robust planning process is an important part of responsible development, but there is significant potential to streamline the current system. IWEA has identified the following areas where simplification of the planning process could be achieved:

- Improved spatial planning to identify areas that are suitable for wind energy development on a regional level;
- A clearer and more interactive pre-application SID (Strategic Infrastructure Development) process that enables fatal flaws to be identified pre-planning;
- Reduced An Bord Pleanála decision timelines; and
- Enable grid connections to be designed and consented in parallel with the main wind farm consent.

Addressing these areas would prevent the planning process from being unnecessarily protracted and would enable the associated development costs to be reduced.

In addition to a general streamlining of the planning process, the policy choices that IWEA is suggesting would also reduce the uncertainty in the planning process and enable developers to identify successful projects at an earlier stage.

Weeding out unsuccessful sites earlier will prevent unnecessary cost and would reduce the overall failure rate of the development process. Since the cost of energy realised from successful projects needs to cover the underlying costs of development, including some recovery of DEVEX spent on unsuccessful sites, improving the success rate of the development process would allow a reduction in LCOE.

**Result: Based on feedback from members IWEA has estimated that the four policy innovations described below could collectively give a 28 per cent reduction in DEVEX which in turn would mean a 2.4 per cent reduction in overall CAPEX for a given project. Running this scenario through the cost model shows an LCOE reduction of 1.5 per cent.**

The following sections give a high-level description of the policy innovations proposed by IWEA in relation to the planning process.

### 4.4.1 Reduce pre-planning attrition

The spatial planning and identification of suitable areas for wind energy development has, to date, been the responsibility of local authorities, typically achieved through their County Development Plans or specific Renewable Energy Strategy documents.

Many revisions or variations to County Development Plans have been made or attempted because of issues arising from individual planning applications. This has created confusion in national policy and an inconsistent planning environment across the country. In many cases intervention by the Minister of Housing, Planning and Local Government has been required to restore alignment between local and national policy.

The Department of Communications, Climate Actions and Environment (DCCAE) is currently preparing a Renewable Electricity and Policy Development Framework (REPDF) for the guidance of An Bord Pleanála, planning authorities, other statutory authorities, the general public and persons seeking development consent for largescale onshore renewable electricity projects.

IWEA believes it is necessary to carry out spatial planning for renewable energy on a national and regional basis, rather than at the local authority level as has been the case to-date. To complement the REPDF currently being prepared by DCCAE, IWEA urges that the preparation of Regional Renewable Energy Strategies be accelerated and prioritised by the three Regional Assemblies.

A regional approach could be used to strategically designate areas within each region for the development of wind energy. This would help address some of the significant planning contradictions, particularly the inconsistent inter-county approaches taken to designating areas as suitable for wind energy.

By implementing a robust spatial planning approach and defining "areas of search" within each region that are identified as suitable for wind development, this will reduce the number of sites that are developed to a planning consent stage only to fail to obtain consent.

Based on feedback from IWEA members, developers currently assume a development failure rate of 33 per cent – in other words, one out of every three sites for which they seek planning consent will not proceed to construction. Implementing a consistent regional planning approach, as described above, is estimated by IWEA members to have the potential to reduce the failure rate to 15 per cent.

### 4.4.2 Improve SID success rates

Wind energy projects with a proposed capacity of 50MW or greater must apply to An Bord Pleanála for planning permission via the Strategic Infrastructure Development (SID) process. The success rate of SID wind farm applications and decision timeframes have both improved in recent years. However, there remains significant room for improvement in how the SID application process is structured, particularly with regards to the "pre-determination" stage.

It can regularly take more than 12 months to determine whether a project can be classed as SID, a necessary step before an application for planning permission can be even submitted. Many subsequent SID applications have been refused for reasons that could and should have been identified much earlier in the process. Applicants, planning authorities, An Bord Pleanála and third parties, all expend significant time and resources on such applications which, if unsuccessful, do nothing to help deliver strategic national infrastructure.

In IWEA's view, the process of determining and confirming whether a proposed project constitutes SID should be greatly simplified. A formal and meaningful pre-application consultation process for SID projects, akin to that in place for Strategic Housing Development (SHD) applications, would be a sensible way to support the development of strategic infrastructure projects. Such a process is proving very effective in the SHD (Strategic Housing Development) process by identifying material issues in early stage discussions and providing applicants an opportunity to address those issues pre-application.

Based on feedback from IWEA members developers currently see a failure rate of SID applications of around 62 per cent. With a clearer and more interactive pre-application SID process that enables fatal flaws to be identified pre-planning, IWEA expects the failure rate at SID application stage could fall to 25 per cent. This would enable costs associated with unsuitable sites to be minimised.

### 4.4.3 Reduce ABP decision timelines

An Bord Pleanála currently has a statutory objective to decide or dispose of appeals within 18 weeks. However, where the Board does not consider it possible or appropriate to reach a decision within 18 weeks (e.g. because of delays arising from the holding of an oral hearing), it informs the parties of the reasons for this and shall state when it intends to make the decision.

An IWEA analysis of wind farm appeals decided by An Bord Pleanála between 2017 and mid-2019 determined the average period that appeals were under consideration by An Bord Pleanála was 66 weeks. An analysis of appeals for wind farm grid connections decided by An Bord Pleanála between 2018 and mid-2019 found that a decision, on average, took a further 67 weeks.

These average periods for appeals on wind farms and their associated grid connections are far in excess of the 18-week statutory objective period, and three times the average period for all appeals decided by An Bord Pleanála in 2018.

IWEA believes that the statutory objective period of 18 weeks for An Bord Pleanála to decide on appeals should become a statutory decision period. A similar approach was introduced for SHD applications submitted directly to An Bord Pleanála and the Board has proven its ability to meet these statutory deadlines when assigned the necessary resources to do so.

### 4.4.4 Consenting of shallow connection assets

IWEA has identified several issues with the consenting of grid connection works for wind farms, or "shallow connection assets" as they are otherwise known.

At a high level, the current approach to consenting of wind farms and their connection assets often requires a sequential approach by first obtaining planning permission for the wind farm, then negotiating a connection offer and finally obtaining consent for the wind farm grid connection.

Based on the historical performance of local authorities, An Bord Pleanála, ESB Networks and EirGrid, the overall process can take up to six years. Ongoing development costs are incurred throughout this consenting period. Streamlining and reducing the time required for completion of the consent process would reduce DEVEX and therefore the cost of energy.

IWEA aims to increase the proportion of projects that consent their grid connection in parallel with the wind farm from 20 per cent to 80 per cent, through the following principle policy changes:

1. Enable parallel consenting of wind farms and grid connections by improving strategic development of grid connection assets; and
2. Streamline the consenting of grid connections, particularly in relation to consent from landowners along public road corridors.

The key issues underlying these objectives are further summarised below.

**1. Parallel consenting of wind farms and grid connections**

As a result of changes to long-standing custom and practice in relation to wind farm grid connections, a separate planning permission application for grid connections is now often required after planning permission for the wind farm has already been secured.

IWEA estimates that in the case of 80 per cent of wind farm projects in recent years, a separate and subsequent planning permission was required for the wind farm's grid connection, after planning permission had already been secured for the actual wind farm.

Under current policy, projects are not able to apply for a grid connection offer until they have first received planning for the main facility. Grid connection applications from various projects are then batched together. EirGrid and ESB Networks choose a connection method for each batch, considering grid policy and creating sub-groups that share certain assets where such an approach is deemed the most efficient approach.

Based on an IWEA analysis of timelines for wind farm and grid connection consents and grid connection offers, the average overall timeline for obtaining consent for the wind farm, negotiating a connection offer and obtaining consent for the wind farm grid connection can run to more than six years, roughly broken down as follows:

- **Wind farm consent:** The average time for local authorities to decide on wind farm planning applications stands at 38 weeks. As noted in the preceding section, the average time for An Bord Pleanála to conclude on wind farm planning appeals is a further 66 weeks. The total average wind farm consent time stands at 104 weeks, or two years.

- **Grid connection offer:** The average time for development of a connection offer is approximately two years. Developers do not officially learn the likely connection method until mid-way through the offer process. Only after the developer receives and accepts a connection offer do the system operators start to wayleave and permit the non-contestable parts of the connection.
- **Grid connection consent:** The average time for local authorities to decide on grid connection planning applications stands at 45 weeks. The average time for An Bord Pleanála to conclude on grid connection planning appeals is a further 67 weeks. The total average wind farm consent time stands at 112 weeks, or two years and two months.

The main drawback of this process is the requirement to complete each step before being able to commence work on the next. If it was possible to know the grid connection method during the early development stage, then the grid planning permission could run in parallel, reducing the time taken by a third. Also, delayed knowledge of the grid connection method means developers cannot know the overall cost of their project (of which grid connection is the third largest component), and so cannot engage in early auction or Corporate PPA development.

To enable a more strategic approach to grid development a project development support office should be created across both system operators in Ireland, ESB Networks and EirGrid. The role of this office would be to progress the design and consenting of grid connections in parallel with the wind farm consenting process, which would significantly reduce the overall consenting timeline.

**2. Routing of utility services on public roads**

Wind farm grid connections are often routed along public roads.

If planning permission is required for any development the consent of the landowner is required where the applicant is not the owner of the land. Powers are available under the Electricity Acts, Gas Acts, Water Services Acts and other legislation giving statutory bodies or utility providers the right to carry out works to provide utility services, without landowner consent, once planning permission is secured.

Amendments could be made to the Planning and Development Regulations 2001 which would remove the need for landowner consent as a pre-requisite to a planning application for utilities in public roads.

# 5. GRID DEVELOPMENT AND REFORM

Everoze has analysed a total of five scenarios that fall under the theme of grid development and reform related policy interventions. The LCOE impact of each scenario is presented graphically in the table below. Subsequent subsections provide further background on the rationale and approach for each scenario.

| Scenario 5a | Scenario 5b | Scenario 6 | Scenario 7 | Scenario 8 |
|---|---|---|---|---|
| **Increased curtailment** | **Increased constraint** | **System charging reform** | **Smart connections** | **Balancing cost reform** |
| +10% | +8% | -3% | -1% | -3% |

TABLE 4: GRID DEVELOPMENT AND REFORM PRICE TAG SUMMARY

## 5.1 SCENARIO 5: CURTAILMENT AND CONSTRAINT

Renewable generation in the Single Electricity Market (SEM) has benefitted to date from "priority of dispatch". Priority of dispatch is where a generator, in this case a wind farm, is given priority over other generators, such as those using fossil fuels, so that the power they provide is chosen first to meet electricity demand without having to compete commercially.

However, there are times when it is not possible to accommodate all priority dispatch generation while maintaining the safe and secure operation of the electricity network. Limits on priority dispatch can be imposed due to both local network and system-wide network security issues. Such events result in renewable generators reducing output to below their maximum available level. These reductions are referred to as 'dispatch-down' of renewable generation.

Dispatch down events for wind farms can be generally split into two categories:

1. Curtailment - which is the dispatch-down of non-synchronous renewables for system-wide reasons. Curtailment is applied to all controllable wind farms on a pro-rata basis.[14] The majority of wind farms in Ireland are controllable, with only small and/or old projects excluded.
2. Constraint - which is the dispatch-down of selected generators for more localised network reasons. Projects with "firm" network access[15] and which are no longer in a support scheme receive financial compensation for constraint events. Projects with "firm" network access but currently in a support scheme receive constraint compensation but this is netted off against any payment from the scheme so there is no net benefit to the project. Projects with "non-firm" network access do not receive constraint compensation.

[14] Controllable wind farms refers to those which can be operated – or controlled – remotely by the transmission system operator.

[15] The level of "firm" access to the transmission network relates to financial conditions around a generator's output. Firm Access means that if the output on to the grid by a particular generator is changed by the Transmission Operator (known as 'constraint'), then it may be eligible for financial compensation as set out in the Trading & Settlement Code. Firm Access is linked to Associated Transmission Reinforcements – this is where upgrades or new infrastructure are planned by the Transmission System Operator. In advance of Firm Access being available, some generators may opt to connect to the system on a "non-firm" basis. In this instance, if the output of the generator is changed by the Transmission Operator, the generator will not receive financial compensation as set out in the Trading & Settlement Code.

The levels of constraint and curtailment are driven by multiple factors which include the progression of transmission reinforcement works (i.e. upgrades to facilitate the changing generation mix), the build out rate of new generation, growth in demand for electricity and levels of energy export to Britain.

Lack of transmission capacity is likely to be the biggest block to meeting Ireland's 2030 targets. New network infrastructure will be required to deliver the renewable volumes needed for 2030 and beyond. Timelines to reinforce the grid can vary considerably depending on the extent of works required.

The treatment of renewable generators in relation to dispatch down also needs to be re-evaluated due to new energy regulations from Europe, specifically the Clean Energy Package which came into effect on 1 January 2020. These regulations have potentially significant repercussions for new renewable projects which may see greatly elevated levels of dispatch down compared to existing wind farms.

The consequences of the Clean Energy Package are discussed comprehensively in IWEA's position paper on the subject[16] and IWEA is asking for consistent treatment of existing and new renewable generators in relation to dispatch down.

For the purposes of this modelling study, it has been assumed that new renewable projects are treated in the same way as existing generators.

### 5.1.1 Curtailment

The "Delivering a Secure, Sustainable Electricity System" (DS3) programme is an extremely successful initiative that has enabled Ireland to become a world-leader in the integration of renewable electricity onto the grid. The DS3 programme has successfully delivered the tools, policies and system services needed to enable the current SNSP operational limit to be increased to 65 per cent, up from a 50 per cent limit when the programme began in 2011.[17] Further trials to increase SNSP to 70 per cent, and then to 75 per cent, are expected in 2020 and 2021 respectively.

The DS3 programme has so far maintained curtailment at manageable levels of less than 5 per cent[18]. As the volume of renewables connecting to the system continues to grow it is certain that, without developing the DS3 programme and achieving further SNSP increases, curtailment levels will increase substantially. For instance, a report commissioned by the SEAI, *Managing Curtailment in 2030,*[19] estimates that with current system constraints and no new mitigation measures, curtailment levels could increase to 44 per cent which would mean the equivalent of over 21GW of installed onshore wind capacity would be needed for 70 per cent renewable electricity at those levels.

To support the continued minimisation of curtailment, IWEA argues for the following areas of focus within the continuation of the DS3 programme:

- Design of system services including; reserve, inertia, reactive power and ramping. The focus should be on provision of these services by distributed zero-carbon sources such as batteries, demand side management, synchronous condensers and STATCOMs. The recent report *Store, Respond and Save - Cutting two million tonnes of $CO_2$*[20] highlights the benefits of this approach in terms of $CO_2$ reductions from the Irish and Northern Irish power systems, reduced curtailment and reduced operational costs.
- Parallel progress towards higher levels of SNSP and removal of operational constraints.

[16] https://iwea.com/images/files/20191115-iwea-position-paper-on-priority-dispatch-and-compensation-for-constraint-and-curtailment.pdf

[17] The SNSP limit refers to the proportion of electricity demand and exports that can be met through non-synchronous electricity generation, such as wind energy, at any one time. It means that even if wind energy was able to provide more than the current limit of 65 per cent it is not permitted to do so in order to ensure the stability of the system.

[18] http://www.eirgridgroup.com/site-files/library/EirGrid/2019-Qtrly-Wind-Dispatch-Down-Report.pdf

[19] https://www.engineersireland.ie/EngineersIreland/media/SiteMedia/groups/Divisions/biomedical/Managing-Curtailment-in-2030-02-10-2019.pdf?ext=.pdf

[20] https://www.energystorageireland.com/wp-content/uploads/2020/02/Energy-Storage-Ireland-Baringa-Store-Respond-Save-Report.pdf

To assess the sensitivity of LCOE to future curtailment scenarios Everoze has modelled two future curtailment profiles. The "base case" is extracted from the Baringa 70by30 study, assuming 5 per cent energy loss due to curtailment in 2020, rising to 7 per cent in 2025 and holding steady thereafter. The "high-curtailment" case is based on a starting point of 5 per cent energy loss due to curtailment in 2020, ramping up to 25 per cent in 2030, and ramping down to 5 per cent by 2040.

This second scenario is intended to capture what would happen if grid developments that alleviate the root causes of curtailment are delayed. These include:

- Additional interconnection (e.g. Celtic and Greenlink);
- Raising of the SNSP limit;
- Reducing the 'minimum conventional generation' limit; and
- Implementation of additional DS3 services.

EirGrid's current strategy has demonstrated a clear ambition to deliver on these changes by setting a target of 95 per cent SNSP by 2030.

It should be noted that the "high-curtailment" scenario does not necessarily represent an upper limit of curtailment levels that could be experienced. The impact of curtailment could be even larger than the scenario considered here if the solutions required become significantly out of sync with the building of new renewable generation, either through delays to the grid projects or accelerated deployment of new generation.

**Result: Running the "base case" and "high-curtailment" scenarios through the cost model shows a significant LCOE increase of 10 per cent between the two scenarios. This illustrates the importance of maintaining curtailment levels as low as possible.**

### 5.1.2 Constraint

EirGrid's corporate strategy for 2020-25 contains goals to connect 10,000MW of new renewable generation and operate a system with 95 per cent SNSP. However, there is currently a lack of transmission capacity in areas of the country where large numbers of renewable projects are planning to connect, and significant reinforcement of the grid will be required to connect the substantial volumes of additional generation envisaged by EirGrid.

Currently, many existing renewable generators, particularly in the west, north-west and south-west are seeing constraint levels at over 5 per cent due to network limitations. There is a high risk these constraint levels will reach into double figures, for both existing and future projects, if the grid is not reinforced in time for the future pipeline.

EirGrid currently develops grid reinforcement projects via their six-step framework for grid development[21]. Under this process new reinforcements are only commenced once a need to develop the grid has been demonstrated via a signed contract with a new generator or demand customer, which guarantees they will export or import power using the grid at some point in the future. This reactive approach creates the risk that there will be insufficient network capacity to accommodate the volume of renewables needed for 2030.

Furthermore, the new generator is likely to be operational for several years before any grid reinforcement materialises which is likely to result in high constraints being inflicted on the new generator. Under an auction-based system, such as the RESS, this risk will mean higher costs for the consumer as developers price anticipated constraint levels into their RESS bids.

IWEA proposes that EirGrid's reinforcement planning process should be reformed to ensure that sufficient grid capacity is available for projects in the development pipeline. It would enable most projects to connect without delay once they have secured a route to market, while the remainder will only suffer minimal delays. The reforms proposed by IWEA are summarised below:

- EirGrid should progress the design and consent of grid reinforcements based on the strength and certainty of the future renewable energy project pipeline rather than waiting for projects to obtain planning consent and accept connection offers;

[21] http://www.eirgridgroup.com/__uuid/7d658280-91a2-4dbb-b438-ef005a857761/EirGrid-Have-Your-Say_May-2017.pdf

- EirGrid should signal solutions and timelines to address the needs of the grid at an early stage (e.g. via publications such as their System Needs Assessment, Transmission Development Plan and Transmission Forecast Statement) to provide more certainty to participants on future grid development;
- EirGrid/ESBN to investigate alternative network solutions (e.g. smart wires, storage, congestion products) to identify situations where this may prove a cheaper and more efficient outcome than grid reinforcement;
- Streamlining of EirGrid's six-step development framework, to reduce timelines for capital approval of new projects and to give a more focussed delivery of reinforcement projects;
- Establish an all-island Grid Capacity Advisory Council to improve collaboration between EirGrid/SONI, CRU, UR, industry bodies, and other stakeholders, similar to the DS3 Advisory Council;
- Improved community engagement to promote the need for, and benefits of grid development, and how these are linked to renewable energy policies and climate action.

To assess the sensitivity of LCOE to future constraint scenarios Everoze has modelled two future constraint profiles. The "base case" assumes a flat 1 per cent energy loss due to constraint. The "high-constraint" case is based on a starting point of 1 per cent energy loss in 2020, ramping up to 15 per cent in 2030 and back down to 2 per cent by 2040.

Similar to the curtailment scenarios discussed above, the "high-constraint" scenario does not necessarily represent an upper limit of constraints levels that could be experienced and, based on the 2019 figures, is conservative for many projects based on the recent increase in constraints. Delays to local transmission reinforcement projects, or deployment of new generation in areas of grid congestion, could make the impact of constraints for specific projects even worse than the scenario considered here.

**Result: Running the "base case" and "high-constraint" scenarios through the cost model shows a significant LCOE increase of 8 per cent between the two scenarios, which illustrates the importance of continuing the reinforcement of the electricity network in sync with the deployment of new generation.**

## 5.2 SCENARIO 6: GRID CHARGING MECHANISMS REFORM

System charges such as Transmission Use of System (TUoS), Transmission Loss Adjustment Factor (TLAF) and Distribution Loss Adjustment Factor (DLAF) are currently updated annually, with the aim of providing a locational signal that incentivises installation of generation capacity where it is of most benefit to the overall electrical grid.

Once a project is built it cannot relocate and is therefore subjected to significant volatility of charges arising from the annual review process. This volatility of system charges creates uncertainty in the financial model, which further increases the weighted cost of capital (WACC). If charges could be locked in for a longer term at the time of financing (e.g. 15-20 years), with just normal indexation applied, this would result in a reduced risk premium i.e. a reduced WACC.

It is more appropriate for a generator to have fixed grid charges at the time of connection, since individual generators have no control over future changes to grid costs. In contrast, EirGrid, ESBN and, particularly, the CRU have a lot of control over how the grid in Ireland should evolve and hence it is more appropriate if the cost of these future changes are either placed with the systems operators, or with those new generation or demand side connections responsible for the changes, in order to better manage the risk.

Similarly, if the locational aspect could be removed from charging this would also result in reduced risk and more simplified modelling for system operators. The current system penalises infrastructure poor areas through higher locational charges, while arguably the aim should be to support growth in all areas.

IWEA believes the CRU should carry out an independent review of electricity transmission charging and associated connection agreements. This review should include the charging methodology and examine the requirement for a locational element to the charges. Reforming grid charging to bring it into line with the changing requirements of a flexible energy system would reduce the cost burden currently placed on generators and ensure best value for the customer.

**Result: For the purposes of this LCOE modelling study, Everoze has evaluated the impact of reducing WACC from 6.6 per cent to 6.1 per cent. Running this scenario through the cost model shows an LCOE reduction of 3 per cent.**

## 5.3 SCENARIO 7: SMART CONNECTIONS

Grid connections for wind farms in Ireland are currently subject to significant costs with long delivery timelines that are frequently further delayed.

Several different areas have been identified by IWEA where changes could be made, as summarised below, to reduce grid connection costs and timelines. These improvements would cut project costs and introduce better value competition into future energy auctions.

- The CRU and system operators should consider reviewing the contestability of ownership of grid assets to achieve the least cost solution for grid connections. Contestability provides project developers with the opportunity to benefit from competitive tendering for both project costs and project programme for these works, which, for some projects, can represent a significant cost element. This would be similar in principle to the Competitively Appointed Transmission Owner (CATO) concept currently under development in GB[22]. An additional area which could be considered is the splitting of contestable works, with the system operators taking responsibility for the development of projects, and the wind farm developer taking responsibility for construction.
- Separate legal entities should be permitted behind connection points to facilitate hybrid connections. This would allow for the maximisation of existing connections to reduce costs for complementary technologies such as co-located wind and solar, or a renewable project with an energy storage unit or system services providing technology.
- Dynamic sharing of maximum export capacity (MEC) should be allowed so that multiple entities can share MEC to maximise the use of existing grid assets, again to facilitate hybrid connections, resulting in cheaper grid connections for existing and new projects. This would allow for different technologies to maximise the assets at times when they are at their most beneficial, e.g. a high solar MEC allowance during the day, which then moves to a wind farm or energy storage device during the night.
- Improvements should be made to the grid offer process to increase efficiencies and ensure projects can quickly receive a grid offer after achieving consent for their project. This would also benefit auctions by enabling more projects to participate and deliver better prices for consumers through greater competition.
- Consideration should be given to a rollout of smart network optimisation technologies such as dynamic line rating or the use of special protection schemes. Traditionally, conservative underlying connection and grid planning standards have been used to develop the electricity system, but they limit flexibility and inhibit the adoption of "smart" principles by imposing top-down, inflexible requirements. Utilising the existing network to its maximum capability can increase the efficiency of grid connection assets, thus lowering the cost of connections, and overall grid costs for consumers.

It is important to note that the analysis here did not account for the cost of uncertainty due to grid delivery. For example, if renewable electricity auctions include 'cliff edge' deadlines then this will create additional risk for a project, particularly in relation to the timelines for grid delivery. This will be an additional cost to consider and was beyond the scope of the analysis in this study but it means the conclusions below are certainly on the conservative side.

**Result: For the purposes of this LCOE modelling study, Everoze has evaluated the impact of a reduction in CAPEX associated with grid connection of 20 per cent, which results in an overall CAPEX reduction of 2.2 per cent. Running this scenario through the cost model shows an LCOE reduction of 1 per cent.**

## 5.4 SCENARIO 8: BALANCING COST REFORM

The cost of balancing wind generation can vary substantially, with IWEA members advising it ranges from around €1.5/MWh to €4/MWh depending on the design of the electricity market. A key factor they suggest influences this cost is the provision of a deeply liquid continuous market in which changes to forecast generation can be traded out at prices that do not penalise generators. Such a market exists in Europe already in the form of Single Intraday Coupling (SIDC, formerly known as XBID). It is essential that participants on the island of Ireland can access and participate in this market to reduce balancing costs.

[22] https://www.ofgem.gov.uk/system/files/docs/2016/11/quick_guide_to_cato_-_nov_16.pdf

Market access is also key as the I-SEM market is currently only weakly interconnected to the GB market. To improve the ability of participants to access SIDC, IWEA supports the construction of more interconnection and to a more diverse range of locations. The proposed Celtic and Greenlink interconnectors can provide the connectivity, in conjunction with work by SEMO, to incorporate I-SEM into SIDC.

In addition to the improvement of liquidity in the continuous market, which is currently very poor, IWEA sees potential reductions in balancing costs by improving the liquidity in the existing ex-ante auctions. This can be done through expanding the products which can be sold into the existing auctions and by expanding the third intraday market (IDA3) in the wholesale electricity market to allow market access for participants in both Great Britain and Ireland – as the IDA 1 and 2 markets already allow. Whilst the above points have focussed on pre-gate closure markets, the ability to balance on a pan-European basis, as envisaged through the Energy Balancing Guidelines (EBGL), can ensure that where participants are unable to balance their position before gate closure they are not excessively penalised for this, further lowering balancing costs.

Another key driver for lowering balancing costs is improving the flexibility of existing generation assets on the island of Ireland by adding new flexible assets including demand side response and storage[23]. A reduction in the number of large inflexible units required by the system is also important, as is reducing the minimum stable generation of such assets and improving their ramping capability, which has been discussed previously in section 5.1.1.

Another reason for high balancing costs identified by IWEA members is excessive system margins. Under tight system conditions imbalance prices can jump to extreme levels under reserve scarcity pricing, increasing balancing costs. In part this can be mitigated through EBGL, but it is important that policy decisions are taken to ensure a reasonable system margin is maintained, i.e. that there is adequate, but not excessive, generation to meet demand.

Finally, it is important that balancing costs are not unintentionally increased in future by maintaining a full understanding of the effect of system and market policy decisions. In Britain, for example, the move from a dual cash out price to a single cash out price under the Electricity Balancing Significant Code Review (EBSCR) more than halved balancing costs.

I-SEM currently has a single cash out price but IWEA would highlight that policy on cash out pricing needs to be handled with great care to ensure that costs are not unintentionally increased in the future. For example, proposals in a recent SEM Committee consultation on Balancing Market Options[24] could have added €1/MWh to balancing costs if they had been implemented. There is a real risk to changing the cash out calculation methodology without taking the time to fully understand all of the implications for the electricity market of any alteration.

**Result: For the purposes of this LCOE modelling study, Everoze has evaluated the impact of a reduction in OPEX due to balancing costs reducing from €4 per MWh to €1.50 per MWh. Running this scenario through the cost model shows an LCOE reduction of 3 per cent.**

[23] https://iwea.com/images/files/iwea-baringastorerespondsavereport.pdf

[24] https://www.semcommittee.com/sites/semc/files/media-files/SEM-19-024%20Balancing%20Market%20and%20Capacity%20Market%20Options%20Consultation%20Paper.pdf

# 6. TAX POLICY REFORM

Everoze has analysed two scenarios that fall under the theme of tax reform related policy interventions. The LCOE impact of each scenario is presented graphically in the table below. Subsequent subsections provide further background on the rationale and approach for each scenario.

| Scenario 9 | Scenario 10 |
|---|---|
| **Business rates reform** | **Grid capital allowances** |
|   |   |

TABLE 5: TAX POLICY REFORM PRICE TAG SUMMARY

## 6.1 SCENARIO 9: BUSINESS RATES REFORM

The system of business rates for commercial properties in Ireland is based on rateable values (RVs) which are fixed countrywide by the Valuation Office. A county multiplier or 'annual rate on valuation' (ARV) is then applied to the rateable value and the rates are collected by each County Council.

Rateable values in Ireland operated under the old revision system, which had a rental base date of 1988. This system became outdated and it was decided that a modern system of valuation should be applied to commercial properties.

The Valuation Act, 2001, was enacted to govern the revaluation of properties in Ireland. Revaluations have been taking place since 2013. The revaluation in 2019, effective from January 2020, covered counties Cavan, Monaghan, Louth, Meath, Wicklow, Wexford and Tipperary. The revaluation scheduled for 2021, effective from January 2022, will cover Donegal, Mayo, Galway (city and county), Clare, Kerry and Cork (city and county). After this date all of Ireland will have experienced at least one revaluation.

The revaluations are re-establishing the rental value of every property in the country. This poses problems as there is no rental evidence for wind farms, in Ireland or abroad. Rates are being recalculated using a variation of the receipts and expenditure method, which derives RVs from the annual income and costs associated with a project. IWEA has advised that this approach to a wind farm's rates liability primarily depends on the site's RV, each county's specific ARV and the wind farm's capacity factor.

Based on feedback from IWEA, revaluations to date across the country have seen rates payable for wind farms increase by 200-300 per cent with some wind farms now exceeding €20,000/MW in commercial rates under Revaluation 2019. This has resulted in a number of appeals to the Valuation Tribunal, with some of these set to go to the High Court.

IWEA has advised that several factors contribute to the enormous increases in the rates liability of the wind energy sector:

i. The variation of the receipts and expenditure method used by the Valuations Office values wind farm generators at a higher level than fossil fuel generators;
ii. Wind energy generation technology is given no consideration for its high upfront capital costs but lower operating cost per megawatt (MW), unlike fossil fuel generation technology which is given an allowance for the costs of inputs (such as gas or coal);
iii. The method of valuation includes the value of the supports provided under the REFIT, which substantially increases the rates liability of wind farm operators;
iv. All parts of the wind farm are deemed rateable, which is not the case in some other jurisdictions. For example, in Northern Ireland, "plant and machinery" are not rateable. To put the recent rates increases into perspective, IWEA has informed us that Reval2020 in Northern Ireland, which sets out the new values that will be used to calculate rates bills in Northern Ireland from April 2020, has seen an overall reduction for renewables compared

with 2015 levels. Averaged across all projects, the rates valuation for wind farms fell by 37 per cent. The average rate per MW for wind farms in Northern Ireland is now circa £11,000-12,000/MW. This gives operators in Northern Ireland a significant competitive advantage over operators in Ireland, which could see developers choosing to locate in Northern Ireland to improve their chances of obtaining a Corporate PPA.

Ireland should follow the approach taken in Northern Ireland and reduce the rates liability of wind farms by updating the Valuations Act and exempting “plant and machinery” from being rated.

**Result: For the purposes of this LCOE modelling study, Everoze has evaluated the impact of an increase in OPEX due to business rates increasing from €7k per MW to €21k per MW. Running this scenario through the cost model shows an LCOE increase of 5 per cent.**

## 6.2 SCENARIO 10: GRID CAPITAL ALLOWANCES

IWEA has advised that a company in Ireland can claim certain costs and expenditure against its profits to reduce the amount of tax it pays. Specifically, in Ireland capital allowances can be claimed at a rate of 12.5 per cent over an eight-year period for any capital expenditure. Most elements (roads, turbines, electrical system) of a wind farm are thus eligible for capital allowances.

However, to date, the Irish Revenue has not permitted the grid connection cost to qualify although tax relief on grid connection costs incurred by developers is permitted in Britain. If the grid element of a wind farm was eligible for capital allowances, then the tax cost to the project over the first 8 years would be reduced. Solar farms and offshore wind farms would also be entitled to this allowance, helping to lower the cost of these technologies.

**Result: For the purposes of this LCOE modelling study, Everoze has evaluated the impact of a decrease in CAPEX due to a 12.5 per cent saving in the grid connection portion of the project’s capital cost. Running this scenario through the cost model shows an LCOE decrease of 1 per cent.**

# 7. CONCLUSIONS

The scenarios assessed by Everoze have shown that the following policy interventions, in order of importance, can cut the price of electricity:

- Tip Height;
- Lifetime;
- Balancing costs;
- Grid charging;
- Planning;
- Grid connections;
- Grid connection costs tax reform.

The sum of the reductions delivered by these discrete scenarios is an overall LCOE reduction of 46.5 per cent which is very likely to make onshore wind in Ireland cheaper than fossil fuels[25].

Conversely, Everoze also found that the following policy interventions would, in order of importance, raise the cost of onshore wind:

- Application of extreme noise constraints;
- Increased system curtailment;
- Increased system constraint;
- Increased business rates.

The sum of the increases delivered by these discrete scenarios is an overall LCOE increase of 34 per cent.

The individual scenario results analysed by Everoze are presented graphically, in the form of a waterfall chart below.

[25] https://www.ise.fraunhofer.de/content/dam/ise/en/documents/publications/studies/EN2018_Fraunhofer-ISE_LCOE_Renewable_Energy_Technologies.pdf

https://ens.dk/sites/ens.dk/files/contents/material/file/vejledning_lcoe_calculator.pdf

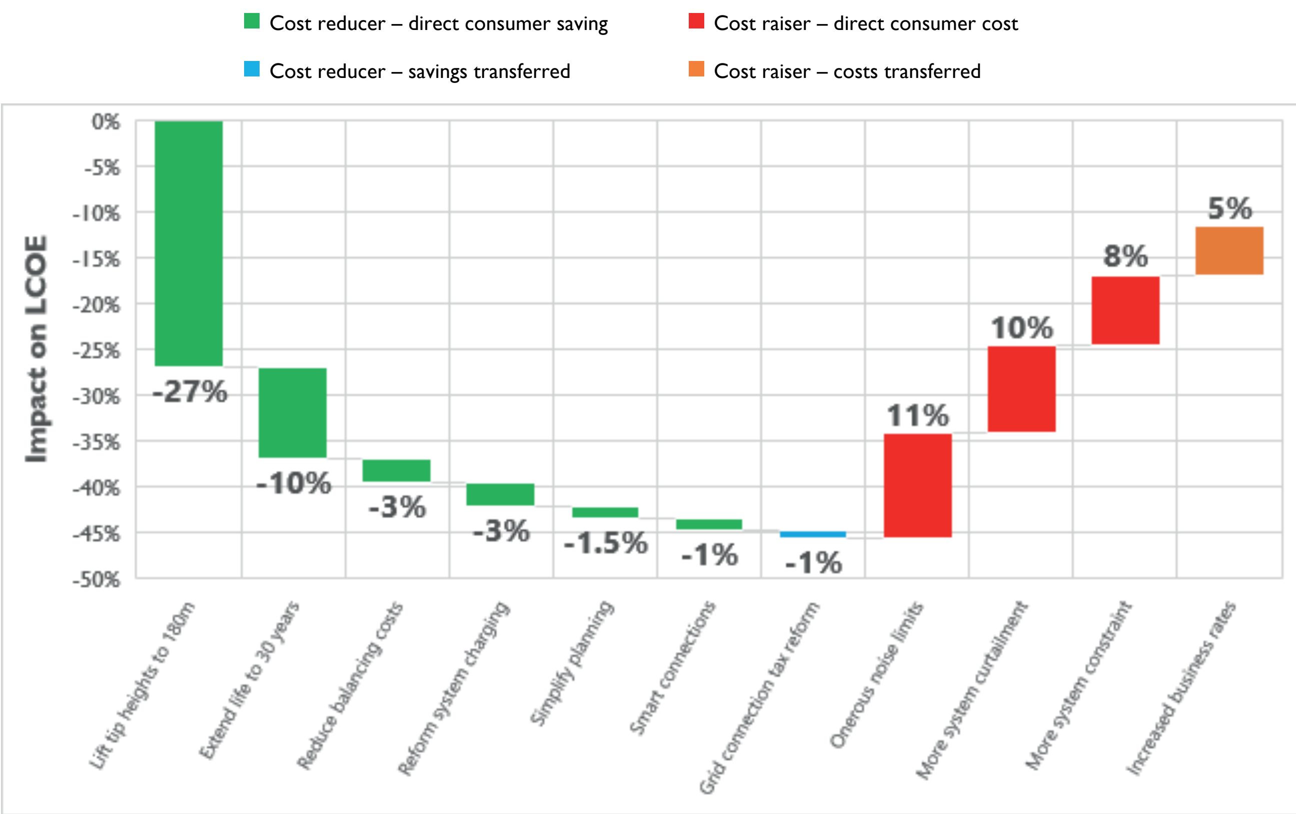


FIGURE 2: LCOE SCENARIO WATERFALL

Our analysis shows just how significant the role of Irish policymakers will be in supporting the development of onshore wind energy at the best possible price for the consumer.

It also makes clear that the Government has a major role to play in supporting industry to achieve the Climate Action Plan's target to meet 15 per cent of electricity demand from renewable sources contracted through Corporate PPAs.[26] The choices made by policymakers will determine the price wind farms can offer the large energy users who are the potential customers for such agreements. The more prices can be reduced, the stronger the likelihood of achieving that target.

However, the wrong policy choices can increase costs and wipe out the savings that may be obtained from other efforts. Therefore, a measured approach, that is mindful of the consequences for cost of energy, needs to be taken if continued cost reductions are to be achieved.

An important caveat to this study is that levelised cost should not be confused with bid prices or strike prices. It must be emphasised that this analysis provides only an assessment of the relative impact of policy scenarios on overall LCOE for a notional base case site.

It is not an attempt to prejudge any derivation of bid price or strike prices that may be put forward as part of the upcoming RESS auction process. There are many technical and commercial factors that will influence the bid price that is appropriate for an individual project and this report does not seek to define the bounds of such factors.

By putting a price tag on various policy levers that are available to government Everoze hopes that this report will help prioritise efforts on future policy changes across all stakeholders such as IWEA, EirGrid, ESB Networks, CRU, An Bord Pleanála, Valuation Office, DCCAE, DHPLG, and DPER.

[26] https://www.dccae.gov.ie/documents/Climate%20Action%20Plan%202019.pdf

# Appendix 1: Scenario assumption register

The table below shows the adjustments made to the base case to evaluate the impact of each policy scenario. Cells that contain a hyphen ("-") indicate no change to that variable relative to the base case.

| Scenario | WACC | AEP | Life | CAPEX | OPEX | LCOE impact |
|---|---|---|---|---|---|---|
| 1.a Tip Heights – 150m | - | Annual MWh increased by 89 per cent | - | Reduced by 19 per cent due to reduced cost per MW of turbines and CBoP | Reduced by 24 per cent due to reduced cost per MW of turbine O&M | -12 per cent |
| 1.b Tip Heights – 180m | - | Annual MWh increased by 212 per cent | - | Reduced by 16 per cent due to reduced cost per MW of turbines and CBoP | Reduced by 27 per cent due to reduced cost per MW of turbine O&M | -27 per cent |
| 2. Noise | - | Reduced by 10 per cent | - | - | - | +11 per cent |
| 3.a Life extension – 25 years | - | - | Increase to 25 years | - | Increased by 10 per cent in years 21 - 25 | -6 per cent |
| 3.b Life extension – 30 years | - | - | Increase to 30 years | - | Increased by 10 per cent in years 21 – 25 and 15 per cent in years 26 - 30 | -10 per cent |
| 4. Simplified planning | - | - | - | Reduced by 2.5 per cent due to reduction in DEVEX | - | -1.5 per cent |
| 5.a Curtailment | - | Adjusted by increased curtailment profile shown in Figure 2 | - | - | - | +10 per cent |
| 5.b Constraint | - | Adjusted by increased constraint profile shown in Figure 3 | - | - | - | +8 per cent |

| Scenario | WACC | AEP | Life | CAPEX | OPEX | LCOE impact |
|---|---|---|---|---|---|---|
| 6. System charging reform | Reduced to 6.1 per cent | - | - | - | - | -3 per cent |
| 7. Smart connections | - | - | - | Reduced by 2.2 per cent due to 20 per cent reduction in grid connection cost element | - | -1 per cent |
| 8. Balancing cost reform | - | - | - | - | Reduced by 9.6 per cent due to balancing costs dropping from €4/MWh to €1.50/MWh | -3 per cent |
| 9. Business rates reform | - | - | - | - | Increased by 17.5 per cent due to tripling of business rates cost component | +5 per cent |
| 10. Grid capital allowances | - | - | - | Reduced by 1.5 per cent due to 12.5 per cent reduction in grid costs | - | -1 per cent |