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Working Paper No. 725

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The impact of planning and regulatory delays for major energy infrastructure

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Abstract: Effective planning and regulatory processes ensure orderly energy systems. Often, decisions are not made within mandated time frames or discrete consent processes are infrequent. Where multiple consent processes exist in sequence, a given delay may be compounded. These factors can negatively affect system costs and, ultimately, consumer welfare. This paper uses an Irish case study to quantify these effects utilising a power system model, which is a generation and transmission expansion modelling tool designed to determine optimal investments in generation and transmission infrastructures. We show that delays have meaningful impacts on electricity prices, system emissions, infrastructure investment and system operating costs. While impacts converge once all planning has been completed, deviations occur in the intervening period. Absent a delay, our case study shows that wholesale electricity prices are up to c.10% lower for a given year, while CO_2 emissions are up to 3.4% lower. Efficient regulation is therefore important to maximise consumer welfare and minimise cumulative emissions. There is a clear case for undertaking an overarching review of the entire regulatory process, particularly the interface between processes.

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1 Introduction

Climate policy in many jurisdictions earmarks a rapid expansion in the share of renewable energy. In practice this will entail construction of large-scale energy infrastructures, including but not limited to on- and off-shore wind farms, solar farms, hydrogen electrolyzers and bio-refineries. Supporting infrastructural investment will also be required, especially in the electricity sector, including transmission/interconnection lines, sub-stations, and battery storage. Developers of large-scale energy projects face a series of hurdles in advancing their projects. The key hurdles relate to consents on planning and network access (electricity or gas), and subsidy support where applicable, though the intricacies may differ across countries. There is an enduring perception that the time-frames associated with planning and regulatory processes related to major infrastructure are excessive (Owens, 1985; Marshall and Cowell, 2016). Unquestionably, planning and regulatory processes are critical to ensure orderly systems that are beneficial to society but planning and regulatory delays for renewable energy projects are routine in many countries across the Americas, Africa, Asia and Europe (Bayer et al., 2018a,b; Huenteler et al., 2018). The impact attributed to such delays varies from projects being completed behind schedule or abandoned altogether, to under performance in renewable power generation, and to large financial losses for investors (Metaxas and Tsinisizelis, 2013; Huenteler et al., 2018; Bayer, 2018; Bayer et al., 2018a,b). What constitutes a ‘delay’ or whether planning and regulatory time-frames are excessive requires precise definition (Marshall and Cowell, 2016) but in the context of climate policy and the urgency related to carbon emission reduction targets, it is important to assess whether delays are inherent in planning and regulatory approval processes and to what extent such delays are substantially impeding the delivery of national emission targets.

While delays can occur for a myriad of reasons, two particular manifestations of delay are considered here. The first simply relates to decisions not being made within mandated time-frames. In many instances there are specified time-frames in which decisions related to new energy infrastructure should be made. Citing just one example, Metaxas and Tsinisizelis (2013) note delays up to 2 years in Greece. The second manifestation of delay relates to the structure or cycle within which decisions are made, particularly if consent is allocated according to a discrete process and the cycle has a low frequency. If decisions on consents or ‘gates’¹ to submit for consent occur on a monthly basis, and one cycle is missed, the delay to the next cycle is relatively short at one month. Where the cycle frequency is yearly, the length of delay is substantially longer or undetermined if no regular cycle is specified. Cycle length can create an additional delay when there are multiple, interacting regulatory processes. Renewable energy projects usually require multiple consents (e.g. planning, network access, subsidy support). If consent applications occur in sequence (e.g., grid application is conditional on planning consent) a delay in one stage can lead to misalignment at a second stage, further amplifying the delay.

¹ In some jurisdictions, such as Ireland, consent is given for the development of renewable energy infrastructure on a grouped basis. Each tranche of development is referred to as a ‘gate’.

The purpose of this paper is to examine the impact of planning and regulatory delays on the development of renewable energy infrastructure. In the first instance, we illustrate how the operation of the planning and regulatory regime can impinge on delivery of new energy infrastructure. We show how relatively minor adjustments in procedures, especially on cycle frequency, can substantially improve delivery schedules for new infrastructure. The direct impact of delays are usually borne by investors but are difficult to quantify, as verifiable data are generally not publicly available. A second aspect of this paper is to illustrate the impact of delays on the power system. While individual energy infrastructure projects have private investor benefits, they also impact on the wider power system, including contributing to carbon emissions targets. We illustrate the impact of planning and regulatory delays on power system costs, electricity prices, as well as contribution to carbon emission budgets.

2 Literature

A viewpoint widely held is that planning and regulatory processes associated with large-scale energy infrastructure are inefficient (Salvador et al., 2018; Cowell and Owens, 2006; Bayer et al., 2018a; Bayer, 2018; Bayer et al., 2018b; Huenteler et al., 2018). Delays occur across many jurisdictions with several comparative analyses seeking to identify approaches to streamline the speed, coordination, and clarity of consenting processes (Salvador et al., 2018; Ramos et al., 2021; O’Hanlon and Cummins, 2020). Among the research recommendations are the integration of project consenting, a so-called ‘One-Stop-Shop’; and reducing decision-making time-frames, which could be feasible by processing different consenting phases simultaneously. There is a view that planning and regulatory processes for renewable energy infrastructure projects favours, in terms of the power dynamic between stakeholders, large developers and that additional protocols need to be developed to assess wider stakeholder impacts (Rydin et al., 2018; Rydin, 2020).

Marshall and Cowell (2016, p. 1844) take an opposing view on the issue of delays, saying that evidence of delay is often ‘limited, ambiguous and selective’ and more fundamentally that ‘delay’ is never defined. They suggest that efforts to accelerate planning and regulatory time-frames tend to redistribute time between processes and actors rather than reduce overall decision times.

While delays can arise at all stages of the approval process, several papers isolate grid connection delays as a common theme (Metaxas and Tsinisizelis, 2013; Huenteler et al., 2018; Bayer et al., 2018b,a). Huenteler et al. (2018) find that the gap between actual performance and technical potential in China compared to the United States is significantly driven by delays in grid connection. Bayer et al. (2018b) find that grid connection delays are a central cause of project delays in Brazil, France, Italy and South Africa.

Quantification of the length or cost of delay is difficult to ascertain. Whereas Marshall and Cowell (2016) examine planning and consent delays within large-scale infrastructure projects in the UK, similar

analysis of renewable energy projects either in the UK or elsewhere are difficult to find. Much of the relevant information, if publicly available, is not easily accessible as it is often held across multiple public agencies and not collated. While several studies cite examples of extreme delay, cancelled projects or percentages of projects behind schedule, systematic assessments of the costs attributable to delays are missing.

Assessments of the benefits of integrating renewable energy generation within the power system literature are more common (e.g., Min et al., 2018; Micheli et al., 2020; Koecklin et al., 2021; Lynch and Curtis, 2016). The power system benefits of renewable energy integration represent one approach to measuring the opportunity cost of planning and regulatory delays. The impact of new renewable generation (or its delay) on a power system depends on the characteristics of the power system (e.g., extant generation plant, share of renewables, transmission infrastructure, etc.). Consequently, the analysis requires counterfactual modelling of generation capacity expansion versus a baseline no-delays scenario. Koecklin et al. (2021) undertake a comparable analysis to assess the impact of public opposition to renewable electricity generation, finding that additional investment and operational costs associated with public acceptance constraints for new energy infrastructure increase baseline power system costs by 5–6%.

3 Methods

The first component of the quantitative analysis entails outlining the planning and regulatory system of Irish renewable energy projects, and consequently defining what constitutes a delay for the purpose of this analysis. We first consider the impact that delay may have on power system development from a theoretical perspective to provide general insight. To quantify these effects, we then undertake a case study based on the development of new renewable generation capacity within the Irish power system. The second component utilises a power system model of the Irish electricity system to analyse the impact of a number of delay scenarios (based on the preceding section) on various metrics, including power systems costs and carbon emissions.

3.1 Irish planning and regulatory framework

The regulatory framework for renewable energy in Ireland has been described previously by Ramos et al. (2021) and O’Hanlon and Cummins (2020) as part of comparative analyses with the frameworks in France, Portugal, Spain, and the UK. Salvador et al. (2018) also undertakes a similar comparative analysis for The Netherlands, Spain, Germany, Denmark and the UK. In Ireland there are between 3 and 5 major regulatory hurdles for the development of renewable energy projects, depending on the nature of the project. Planning permission, grid connection, and authorisation to construct a plant/generate electricity are relevant to most projects. The majority of renewable projects will also seek financial support under the government’s Renewable Electricity Support Scheme (RESS). A foreshore licence or lease is also required for projects based in marine waters. The consent process is largely sequential and summarised

in Table 1. Beyond the detail necessary for the current analysis, O’Hanlon and Cummins (2020) includes a summary of the steps within each authorisation process.

Large-scale renewable energy projects can be classified as Strategic Infrastructure Development, which comprises projects of strategic economic or social importance to Ireland. An Bord Pleanála (the Irish planning board) is the competent authority for consenting of Strategic Infrastructure Development and the legislated time-frame for decisions is within 18 weeks of the last day for making submissions or observations on the application.

Grid connection authorisation is regulated by the Commission for Regulation of Utilities under its Enduring Connection Policy (ECP) and administered jointly by EirGrid, the transmission system operator, and by ESB Networks, the network owner. Applications under the ECP are submitted in September, formed into batches between October and December based on published guidelines for prioritisation, and the batches are processed between January and December in the following year (CRU, 2020a). Applications for grid connection must be in receipt of valid planning permission (with the exception of community-led projects, though they need planning permission to receive a connection offer).

A submission for authorisation to construct generation capacity must be in receipt of valid planning permission and have either a grid connection agreement or proof of application for a connection agreement (CRU, 2020c). This means that the authorisation to construct can occur in parallel with the grid connection process subject to the grid connection application proceeding first. The critical path in any project development will likely include the grid connection phase but not authorisation to construct. Applications for a licence to generate electricity must have planning permission and a grid connection agreement for the associated generation station (CRU, 2020b).

Applications for financial support under RESS are required to have planning permission and either a grid connection agreement or be processed as eligible to receive a valid grid connection offer under the ECP scheme described above (DECC, 2021c).

The Maritime Area Planning Act (2021) establishes a new planning regime for the maritime area, which is intended to streamline the consenting process for off-shore renewable energy projects.

3.2 Theoretical outline

We first consider the impact of planning delay from a theoretical perspective to provide general insight. We define T as the total time (in months) for a project to be energised. Given the sequential nature of the application process, T is the sum of PP , defined as the total time to obtain planning permission, GC , defined as the time to obtain a grid connection and $RESS$, defined as the time to gain a RESS contract (equation (1))

Table 1: Regulatory hurdles for renewable energy projects

Authorisation	Public Body	Authorisation cycle	Decision timeframe
Planning permission	Local Authority/ An Bord Pleanála	Continuous	18 weeks
Grid connection	EirGrid/ ESB Networks	Yearly (September)	12-15 months
Licence to generate/ authorisation to construct	Commission for Regulation of Utilities (CRU)	Continuous	12-16 weeks
Renewable Electricity Support Scheme (RESS)	Department of Environment, Climate and Communications (DECC)	Yearly (March)	3 months
Foreshore licence/ lease	Department of Housing, Local Government and Heritage	Continuous	18 weeks

$$T = PP + GC + RESS \quad (1)$$

We subdivide GC into GC_{apply} , the time spent waiting to apply for a grid connection, and $GC_{approve}$, the time spent waiting for the grid connection to be approved. We subdivide $RESS$ into $RESS_{apply}$ and $RESS_{approve}$ in a similar manner. Thus, the total time T is

$$T = PP + GC_{apply} + GC_{approve} + RESS_{apply} + RESS_{approve} \quad (2)$$

Because grid application gates close in September each year, GC_{apply} is given by equation 3:

$$GC_{apply} = (24 - (3 + month_{pp})) \text{ mod } 12 \quad (3)$$

where $month_{pp} = 1$ in January, 2 in February and so on and corresponds to the month in which planning permission was granted.

Similarly, because the application deadline for RESS support is in March, $RESS_{apply}$ is given by equation 4:

$$RESS_{apply} = (24 - (9 + month_{gc})) \text{ mod } 12 \quad (4)$$

where $month_{gc}$ maps to the integers 1-12 as before but in this case corresponds to the month in which the grid connection was secured.

These expressions can be substituted into equation 2 above, yielding:

$$T = PP + (21 - month_{pp}) \bmod 12 + GC_{approve} + (15 - month_{gc}) \bmod 12 + RESS_{approve} \quad (5)$$

More generally, if the number of grid connection application gates and RESS application gates per year are given by g_{GC} and g_{RESS} respectively, the total time for the project to be energised is given by equation 6:

$$T = PP + (21 + month_{pp}) \bmod \frac{12}{g_{GC}} + GC_{approve} + (15 - month_{gc}) \bmod \frac{12}{g_{RESS}} + RESS_{approve} \quad (6)$$

It is trivial to show that the equation increases in PP , $GC_{approve}$ and $RESS_{approve}$ and decreases in g_{GC} and g_{RESS} . Therefore, increasing the number of application gates for both grid connection and RESS per year would decrease the total delay in a given project coming onstream. Furthermore, relaxing the requirement for grid connection approval in order to be eligible to apply for RESS allows the equation to become

$$T = PP + \max[(21 + month_{pp}) \bmod \frac{12}{g_{GC}}, (15 - month_{gc}) \bmod \frac{12}{g_{RESS}}] + \max[GC_{approve}, RESS_{approve}] \quad (7)$$

Finally, allowing for simultaneous application for planning permission, grid connection and RESS support yields

$$T = \max[(21 + month_{pp}) \bmod \frac{12}{g_{GC}}, (15 - month_{gc}) \bmod \frac{12}{g_{RESS}}] + \max[GC_{approve}, RESS_{approve}, PP] \quad (8)$$

The expected reduction on the time spent for a project to be energised under the various options (increasing number of gates vs allowing simultaneous applications for various stages of the process) depends on the expected duration of each stage. The above equations cannot be solved analytically, as modular and max functions are discontinuous and so not differentiable. Therefore, we perform a numerical simulation exercise to determine the cost of delays from a power system point of view, focusing on various metrics of concern to policy makers such as total costs, electricity prices and carbon emissions. The following subsection details this exercise for the power system of the island of Ireland.

3.3 Delay scenarios

It is practically challenging to collate a representative sample of historical time-lines for consents on renewable energy projects. Instead we track hypothetical projects through the planning and regulatory

framework outlined above. For simplicity we assume all applications are approved, i.e., we only track successful projects. We consider a number of scenarios. The scenarios include a Status Quo baseline similar to the current framework and several variants.

We assume that 2000MW of capacity enters the planning and regulatory cycle in year 1, 500MW in each quarter. We initiate projects at An Bord Pleanála stage where the rule on decisions is 18 weeks. Based on the most recent annual report, the average time taken to dispose Strategic Infrastructure cases is 37 weeks (ABP, 2021, Table 2). No additional information on the distribution of decision duration is reported. Employing the empirical or three-sigma rule that for a normal distribution almost all observed data fall within three standard deviations of the mean, and further assuming that 97.5% of cases take longer than 18 weeks, the implied standard deviation of decision duration is 9.5 weeks. From this we can assume that 13.5% of cases are 0–3 months late, 68% are 3–6 months late, and that 16% are 6–9 months late.

With planning permission received, the next stage we consider is grid connection, the gate for which is the month of September, i.e., all planning permissions received prior to end of quarter 3 are eligible to apply. On the basis of duration of planning decisions described earlier 12.5MW will be eligible to apply for grid connection in year 1, quarter 3 (Y1Q3), 1487.5MW in Y2Q3, and 500MW in Y3Q3, as reported in the ‘Status Quo’ scenario in Table 2. In practice energy projects are not divisible but assumed so here for convenience. As noted earlier, grid connection applications are formed into batches between October and December and the batches are processed between January and December in the following year. We assume that one-third of the capacity is processed in each of the quarters, Q2–Q4.

The next stage we consider is the RESS auction application. We assume that applications to the CRU for either authorisation to construct or licence to generate are not in the critical path so we do not explicitly consider either here. The closing date for the most recent RESS auction is the end of Q1, with auction results announced at end of Q2 (EirGrid, 2021b). On the basis of grid connection offer conditions, developers need time to prepare their auction bids to the RESS auction. We allow a 6-month lead-time to prepare auction bids, which means that projects with grid connection offers in Q3 will be both eligible and capable of bidding in the RESS auction in the following Q1. Capacity entering bids in the RESS auction is as follows: Y3Q1, 8.3MW; Y4Q1, 995.8MW; Y5Q1, 829.2MW; Y6Q1, 166.7MW.

The RESS auction results are announced in Q3 and for simplicity we assume a 12–15-month project build time post RESS auction. The first full calendar year when the capacity is energised is as follows: Y5, 8.3MW; Y6, 995.8MW; Y7, 829.2MW; and Y8, 166.7MW. These figures are reported in Table 2, as the Status Quo scenario. The lower half of Table 2 reports the cumulative capacity energised by percent. For example, of the 2000MW that applied for planning permission in year 1, 50% is energised by year 6, 92% by year 7 and 100% by year 8.

A number of variants of the Status Quo scenario are also reported in Table 2. In scenario ‘ABP#1’ we assume that the mean time to dispose of planning permission cases falls from 37 to 25 weeks. In

Table 2: Capacity (MW) energised by year and scenario

	Status Quo	ABP#1	ABP#2	GridOffer	Hybrid	RESS	Combined
Y4	0.0	0.0	0.0	0.0	12.5	0.0	0.0
Y5	8.3	8.3	333.3	8.3	1487.5	12.5	1166.7
Y6	995.8	1109.2	1166.7	1162.5	500.0	1487.5	833.3
Y7	829.2	772.5	500.0	829.2		500.0	
Y8	166.7	110.0					
Total	2000	2000	2000	2000	2000	2000	2000
Y4	0%	0%	0%	0%	<1%	0%	0%
Y5	<1%	<1%	17%	<1%	75%	<1%	58%
Y6	50%	56%	75%	59%	100%	75%	100%
Y7	92%	95%	100%	100%	100%	100%	100%
Y8	100%	100%	100%	100%	100%	100%	100%

‘ABP#2’ we assume that all cases are decided within the mandated 18 weeks. In the ‘GridOffer’ scenario we assume that the number of gates to submit for a grid offer (which we designated as g_{GC} above) increases from one to two per year, at the end of Q1 and Q3. The ‘Hybrid’ scenario reflects a policy discussion currently underway that would facilitate sharing an existing thermal generation plant’s grid connection with a renewable energy project (DECC, 2021b). Under a hybrid grid connection, when a renewable generation resource is available it would utilise the existing thermal grid connection point to the maximum level possible, under priority dispatch. When the renewable generation resource available is less than the grid connection capacity the thermal generator, if dispatched, would avail of the remaining export capacity. In the context of the scenarios developed here, the ‘Hybrid’ option allows the application for a grid offer to be by-passed, allowing for projects to move directly from planning permissions to submitting bids to the RESS auction. In the ‘RESS’ scenario we assume that there are two RESS auction gates per annum (designated as g_{RESS} above), also occurring at the end of Q1 and Q3. The ‘Combined’ scenario implements the ABP#2, GridOffer, and RESS scenarios simultaneously.

In the lower half of Table 2 it is easy to see the relative speed at which projects progress through the entire regulatory process across scenarios. For example, in year 6 100% of projects are energised in the Hybrid and Combined scenarios, compared to 75% in the ABP#2 and RESS scenarios, and compared to approximately half in the remaining three scenarios. In the case of the Hybrid and Combined scenarios, projects are fully energised at least two years earlier than in the Status Quo scenario. The Hybrid scenario is potentially applicable in limited circumstances, as it assumes co-location of renewable and thermal generation grid connections. While adding extra application gates substantially reduces the duration of the consenting process, it is the sequential nature of the regulatory process that contributes most to the lengthy approval process.

3.4 Power system model

To investigate the power system impacts of regulatory delays we utilise the Electricity Network and Generation INvEstment (ENGINE) model, which is a generation and transmission expansion modelling tool designed to determine optimal investments in generation and transmission infrastructures (Fitiwi et al., 2020a). ENGINE has previously employed scenario analysis to examine several policy questions, including public acceptance of renewable energy investments (Koecklin et al., 2021; Fitiwi et al., 2020b) and the deployment of hydrogen electrolysers on the power system (Longoria et al., 2021).

ENGINE is a multi-stage stochastic joint optimisation model of both generation and transmission expansion planning (GTEP) within the power sector. The ENGINE model incorporates a linearisation of the full AC optimal power flow: Kirchhoff's Current and Voltage laws. These represent the balance of supply and demand and the physical network constraints. The linearisation is important because a full non-linear AC model becomes intractable for a countrywide large-scale analysis. The model includes a realistic representation of power flows and voltage magnitude differences across nodes are incorporated. ENGINE's optimisation occurs in two stages. The first stage optimises investment decision variables, including the quantity, type and location of new generation capacity on the power grid. The locations selected are the nodes that better utilise the new rated generation capacity. The results from the first stage are passed onto the second stage. In the second stage the linearised AC optimal power flow model is solved as an economic-dispatch minimisation problem. Because ENGINE is based on a county-wide real power system, it can provide practical insights to stakeholders on the impact of delays.

The Status Quo and Combined scenarios are simulated in ENGINE to illustrate the power system impacts of delays. The impact of the planning and regulatory framework is assessed across the following metrics: total system cost, CO₂ emissions, marginal electricity price, and transmission system congestion. Where there is an imbalance between electricity demand and supply at any given location on the power system, the transmission system can face congestion. This congestion is relieved by either reinforcing the transmission system or by developing new generation capacity proximate to the demand centre. While there is a single wholesale electricity market price across the island of Ireland, if the market instead featured zonal prices (where prices can vary at different points in the transmission network) transmission system congestion would manifest itself as different prices in different zones. In the context of this modelling exercise, we illustrate any transmission system pressures by examining the ENGINE model's shadow prices at model load nodes, which are effectively the interface of transmission points and substation loads aggregated to 110 kV.

4 Results

Scenario results are reported in Table 3 showing the percentage difference between the Status Quo and Combined scenarios for the system cost, emissions, and price metrics. Total System Costs is the sum of

investment and operation costs, including fuel costs. CO₂ emissions are the emissions from thermal power generation. Marginal electricity price is the demand weighted average price, analogous to wholesale electricity prices within the current electricity market. Given the figures shown in Table 2, the Status Quo and Combined scenarios represent the two extremes of most and least delays to project energisation, respectively, excluding the Hybrid scenario. The reason we do not use the Hybrid scenario is because the total number of renewable energy projects that could operate under a hybrid scenario, by using an existing grid connection, is unknown, and so therefore is the actual delay that could be avoided via the hybrid scenario.

There are no differences across the three metrics in year 4 of the scenario simulations, reflecting the fact that there is no new capacity energised in either scenario in that year, as outlined in Table 2. While there is a small increase in total system costs of 0.3% in Y5 in the Combined relative to the Status Quo scenario, costs are lower in years Y6 and Y7 by at least 3.2%. While this represents a small percentage value, given that it includes total power system investment and operational costs it represents a very large nominal sum. In the Combined scenario the earlier rollout of new renewable generation capacity reduces emissions by 4.2% in Y5 and 3.4% in Y6. Across the three metrics the difference between the Combined and Status Quo scenarios diminishes to zero in Y8, as the two scenarios coincide in Y8 in terms of total new renewable capacity installed. The 0.6% lower total system system costs in Y8 reflects higher investment costs in the Status Quo scenario when the last 166.7MW of capacity is energised. Average electricity prices are almost 10% lower in Y5 and 7% lower in Y6 in the Combined versus Status Quo scenario. This difference reflects a higher reliance on thermal generation in the Status Quo scenario, with the marginal thermal unit driving the shadow price, analogous to wholesale prices in modern electricity markets.

To illustrate the impacts of transmission system congestion, we examine the average number of hours that the shadow price at demand nodes exceeds a specific threshold price, which we set at the 90th percentile price in year Y4 for the Status Quo scenario. Table 4 reports the percentage difference of the number of hours the electricity price was above the threshold, averaged per node across the 9 regions of the model, for the Combined versus Status Quo scenarios. For example, in the Border region in Y5 there are 5.9% fewer hours where nodal prices are above the 90th percentile threshold. Since these high prices can be used as a metric indicating transmission congestion, under the Combined scenario there is a reduction in congestion across all regions broadly ranging between 4–11% in years Y5 and Y6, which diminishes thereafter as the installed capacities converge in years Y7 and Y8.

Table 3: Combined versus Status Quo scenarios, % differences

	Y4	Y5	Y6	Y7	Y8
Total System Cost	0.0	0.3	-3.2	-3.3	-0.6
CO ₂ Emissions	0.0	-4.2	-3.4	-1.0	0.0
Marginal Electricity Price	0.0	-9.9	-7.3	-0.6	0.0

Table 4: Combined versus Status Quo, Hours above nodal shadow price (90th percentile[†]), % differences

Year	Border	Midland	West	Dublin	Mideast	Midwest	Southeast	Southwest	NI
Y5	-5.9	-6.5	-7.1	-7.8	-11.4	-7.1	-7.3	-4.7	-6.0
Y6	-7.9	-9.0	-8.3	-9.5	-8.8	-6.7	-6.5	-6.5	-5.9
Y7	-1.5	-1.0	-1.6	-1.5	-0.3	-0.9	0.3	-0.3	-0.1
Y8	0.1	0.0	-0.7	-0.3	0.4	2.6	0.5	1.1	0.0

[†] Price threshold set at 90th percentile under Status Quo in Y4.

5 Discussion

The first insight from the paper comes from Table 2, as it illustrates that the design of the regulatory processes can have an immense impact on the pace of infrastructure development. Regulatory processes themselves are critically important both for the integrity of the power system and for wider societal benefit, but Table 2 illustrates how the organisation, as opposed to the content, of the regulatory process can have a large impact on when projects are delivered, with up to two years difference in the scenarios outlined. The changes in regulatory processes outlined in the scenarios are illustrative rather than prescriptive, but the general principle that streamlining regulatory processes can significantly alter the timeline of renewable energy project completion is demonstrated. Given the urgency of climate targets, as well as concerns about energy security, this demonstration of the material impacts of the regulatory process design are of interest to various stakeholders.

Given these results on the impact of delays on the installment of renewable capacity, our second main contribution is the demonstration of the resulting tangible consequences for system costs. These manifest primarily in the form of increased CO₂ emissions and higher electricity prices. The higher emissions associated with regulatory delays is in contrast to the ambition of the Climate Action Plan 2021 (DECC, 2021a), which includes targets of up to 80% of electricity generation using renewable energy by 2030 and 62–81% emissions reduction within the sector. Higher electricity prices impact directly on electricity customers by increasing their energy bills. While the discussion of the impact of rising energy prices often focuses around the residential sector and energy poverty, higher electricity prices also directly affects the competitiveness of Irish business in international markets.

As noted already, the scenarios outlined are intended as illustrative rather than prescriptive. Neither are the scenarios exhaustive in terms of all the steps, and associated potential delays, involved in developing large-scale energy infrastructure projects. For instance, steps and potential delays surrounding project financing or securing site acquisition are not considered. While such steps/delays are not related to the regulatory process they are relevant in terms of the overall time-frames necessary to deliver energy projects.

Possibly the delay of greatest length associated with large-scale energy projects arises in the event of legal challenges to planning permission decisions. Since the planning system is part of the regulatory infrastructure, the time-frame necessary for the legal system to dispose of legal challenges forms part of the regulatory process. Two issues related to legal challenges are relevant in terms of the impact of regulatory delays: the likelihood of a legal challenge arising, and the likely duration of disposing legal cases. Anecdotally, the likelihood of a legal challenge is high with many projects facing local opposition (Bertsch et al., 2017; Koecklin et al., 2021; Harold et al., 2021). The duration of legal cases is also quite long, up to several years, and is within the realm of control of the wider regulatory framework. Given the high likelihood of legal challenge and the extended length of such cases, the extent of power system impacts outlined earlier may be substantially greater in practice.

The 80% renewables target by 2030 in the context of a 42% share in 2020 (SEAI, 2021) is a significant technical and policy challenge, essentially doubling the share of renewables within 10 years. However, electricity demand will not be static over that period, with demand growth to 2030 anticipated between 28% in a median demand scenario and possibly as high as 43% (EirGrid, 2021a). While the nominal target for renewables is that the share will double by 2030, the absolute demand share generated from renewables must increase by 2.5–3 fold. Commensurate with the demand growth, the transmission network may need reinforcement to ensure electricity is distributed reliably. The location of required reinforcement may vary depending on the spatial mix of demand and supply (both renewable and thermal). Additional thermal generation capacity may also be necessary, especially in light of electricity supply challenges as demand grows (EirGrid, 2021a). There is a risk that some of this investment may become redundant once the proposed or delayed renewable capacity comes on-stream, in essence, becoming a stranded asset.

Within the scenarios considered, annual CO₂ emissions converge in the long term and are equal by year 8. (see Table 3). This result could be incorrectly interpreted to suggest that in the longer term project delays have negligible impact on emissions. In practice, cumulative emissions are more important, and increasingly the policy focus will be on carbon budgets rather than on annual emissions performance. Increasing the renewable share of electricity generation as early as possible will assist in adhering to a finite carbon emissions budget. From a policy perspective, the relative cost of achieving ambitious regulatory/planning reform should be considered relative to the next best decarbonisation alternatives. This allows regulatory process reforms to be considered within the context of an efficient decarbonisation trajectory.

The analysis shows that reducing regulatory time-frames leads to a considerable reduction in electricity prices. This is indicative of a strong merit order effect, where zero marginal cost wind (or PV) displaces expensive thermal generation at the margin. While planning delays reduce the merit order effect, they do provide additional time for network planning. Large-scale integration of renewables requires complementary flexible storage, generation and/or demand response, which may not immediately be available.

Future work should consider the costs of delay, considered here, relative to the unintended value of ‘waiting’ for the availability of greater system flexibility.

The Hybrid scenario examined represents a special case and is relevant to a current policy discussion about facilitating shared grid connections between existing thermal generation and new renewable energy projects (DECC, 2021b). Such opportunities may arise only in limited circumstances but, as illustrated in Table 2, would enable much shorter development times within the current regulatory framework. In the context of an expanded share of renewable generation, transmission infrastructure to thermal generation plants would continue to be highly utilised with declining thermal plant capacity factors. The use of hybrid connections may draw concerns around preferential access and competition that may need additional consideration but broadly the approach would facilitate the more efficient deployment of renewable generation capacity.

6 Conclusion

Regulatory processes surrounding new infrastructure development within the power sector is critically important both for the integrity of the power system and wider societal benefit. This paper focuses on the organisation of the regulatory process, not what happens within, or the merits of, that regulatory process. While there may always be debate about what constitutes delay and whether delays are real (Marshall and Cowell, 2016), what is clear is that new energy infrastructure, with the focus here on generation capacity, takes a long time to develop in Ireland. This represents a bottleneck for policy ambition to decarbonise the economy.

There is clear case for undertaking an overarching review of the entire regulatory process, particularly the interface between processes. The analysis above illustrates potential benefits of switching away from the linear sequencing process currently in use. An in depth review can identify how that should be best operationalised and where additional resources may be deployed though work to accelerate regulatory time-frames should be mindful to avoid simply redistributing time between regulatory processes or organisations rather than reducing the entire regulatory time-frame (Marshall and Cowell, 2016).

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