Working Paper No. 647

December 2019

Capacity-constrained renewable power generation development in light of storage cost uncertainty

Desta Fitiwi, Muireann Á. Lynch, Valentin Bertsch*

Abstract: The development of sustainable energy sources and their enabling infrastructures are often met by public opposition, resulting in lengthy planning processes. One proposed means of reducing public opposition is constraining the capacity of renewable energy projects onshore, leading to more small-scale, decentralised and possibly community-driven developments. This work computes the effects of same by performing a medium- and long-term generation expansion planning exercise considering two renewable development cases, in which renewable power expansion is spatially constrained to certain degrees, under high and low storage cost regimes. We employ an appropriately designed optimisation model, accounting for network effects, which are largely neglected in previous studies. We apply our study to the future Irish power system under a range of demand and policy scenarios. Irrespective of storage costs, the unconstrained portfolio is marginally cheaper than the constrained one. However, there are substantial differences in the final generation expansion portfolios. The network reinforcement requirements are also greater under the unconstrained approach. Lower storage costs only slightly mitigate the costs of capacity constraints but significantly alter the spatial distribution of generation investments. The differential in costs between the unconstrained and constrained cases increases non-linearly with renewable generation targets.

Keyword(s): Generation expansion planning; electricity generation mix; renewable integration; constrained energy expansion; community energy; public acceptance

**Corresponding Author:muireann.Lynch@esri.ie*

Acknowledgements: Desta Fitiwi acknowledges funding from Science Foundation Ireland (SFI) under the SFI Strategic Partnership Programme Grant number SFI/15/SPP/E3125. Muireann Lynch acknowledges funding from the ESRI's Energy Policy Research Centre. The opinions, findings and conclusions or recommendations expressed in this material are those of the authors and do not necessarily reflect the views of the Science Foundation Ireland. We are grateful to ESRI seminar participants for useful comments and to EirGrid for providing much of the data necessary to complete this study, along with invaluable insights and advice.

1 Introduction

Concerns over climate change among other factors have led to a paradigm shift in the electricity generation sector [30], [19]. Traditionally, electricity has been produced centrally and transported over longer distances via transmission and distribution lines before it reaches the end-of-the-pipe consumers. Such a centralised power generation approach proves economic due to the potential to exploit economies of scale. As a result, generation expansion planning has, for the most part, been framed in this context. However, in the last decade or so, there has been a growing pressure to integrate increased levels of electricity generation from renewable energy sources (RES). Variable renewable power production sources, such as wind and photovoltaic solar (PV), are characterised by the dispersed availability of primary energy resources and the low energy intensity of these energy sources compared to conventional ones. This means their development is space-intensive. In the presence of strong public support, large-scale renewable power development may prove least-cost, but a much reinforced power system network may be required as an enabling mechanism for same [13]. However, renewable developments have been hindered in many cases due to public opposition to energy infrastructure projects. This phenomenon has been noted in various jurisdictions throughout the literature, for example by [31, 2, 41, 7, 14, 3, 15]. Reference [33] provides a survey-based comparison of public acceptance of renewable development and attitudes towards energy autonomy in three countries.

Various measures have been proposed and implemented in an effort to overcome public opposition to energy infrastructure projects, including financial compensation [17], part-ownership of the assets [1] or more stringent regulations, for example by increasing required set-back distances [4]. Highlighting the fact that regions can increase their energy self-sufficiency via locally-sourced energy has also gained traction as a potential mechanism for reducing public opposition to energy infrastructure, see for example [11, 16]. In line with this, the so-called energy democracy is emerging as a notable social movement in energy supply and demand [5, 8]. Over the coming years, communities, municipalities and even ordinary citizens are generally expected to have greater control of decisions in sustainable energy transition [37].

As noted above, economies of scale dictate that community-level, small-scale renewable development is likely to prove more costly than centrally-planned large-scale developments [27]. However, continuously falling costs of renewable technologies and storage systems may render local power production and use economically viable [23] and, if network reinforcements can be avoided may be preferable from a systems perspective. A renewable power development that constrains the installed capacity at any given onshore location may have unintended effects on existing power systems [39], for example on voltage issues. However, these can be resolved by proper planning and execution, accounting for network effects. This provides the primary motivation for the current work.

This paper performs a case study of the future Irish power system under both a constrained and an unconstrained onshore renewable development. The unconstrained case corresponds to a renewable power development motivated by cost minimisation only, while the constrained case represents a development that evolves under community-owned and led small-scale power developments, where there is opposition to large-scale renewable power projects. As such, the constrained scenario includes extra constraints on the location and installed capacity of renewable power. It should be noted that the use of "unconstrained" here is in relative terms and indicates that large-scale investments in onshore wind farms are not precluded by the optimisation. In fact, the maximum installed capacity at each candidate transmission node is capped in the unconstrained approach, but at a considerably higher level compared to the constrained approach.

The Irish power system provides a particularly interesting case study due to its high current and planned levels of renewable power, as well as its limited interconnection to other power systems. Ireland has also made poor progress towards meeting its climate and renewable energy targets, which have prompted new and demanding policy targets for the year 2030 and beyond. In particular, the Irish Government's 2019 Climate Action Plan [20] targets 70% of electricity to be generated by renewables in 2030. Sustainable energy communities are expected to play a key role in achieving this target, with the Action Plan aiming to increase the number of sustainable energy communities to 1500. However, the mechanisms that enable community-driven energy infrastructure developments are not properly identified. Furthermore, the costs and benefits and/or any associated side-effects of constrained power development must be quantified to resolve policy dilemmas [28] and facilitate evidence-based decisions. Developing the future energy system in a constrained rather than an unconstrained manner may prove more costly, but policy makers may judge that the cost is justified if public opposition is indeed reduced.

Hence, policy makers require quantitative results that calculate the extra long run costs of constraining RES capacities onshore. Furthermore, the feasibility of this approach, considering metrics such as system security and transmission congestion, should be identified. In order to investigate these questions, we perform a Generation Expansion Planning (GEP) exercise using the Electricity Network and Generation INvEstment (ENGINE) model, partly described in [12]. The exercise determines the least-cost generation capacity expansion, while respecting a number of technical and policy constraints, under both unconstrained and constrained renewable power expansion portfolios. The results indicate that the total costs of a constrained renewable expansion are greater than, but close to, those of an unconstrained approach, but that the generation portfolio is significantly different. Furthermore, the differential between the costs of the two expansions are sensitive to policy parameters such as renewable power targets, as well as the future cost of battery energy storage.

The remainder of this paper is structured as follows. A description of the methodology and the cases under consideration is provided in section 2. Section 3 presents relevant information regarding data and assumptions made during the analysis. Section 4 presents the results, and includes a broader discussion. Section 5 concludes.

2 Problem Formulation

2.1 Modelling approach and associated terminologies

This modelling approach takes the form of Generation Expansion Planning (GEP), where the optimal generation capacity investments are determined, in a least cost manner, while satisfying demand and technical constraints. The optimal operation of the generation assets is also determined. The model considers n potential future scenarios, each with a specific probability, which represent a realisation of the relevant sources of long-term uncertainty such as demand growth, carbon prices and fuel prices. The demand growth projections are primarily driven by different potential growth rates of data centres in Ireland, as projected by the System Operator, EirGrid [10]. Each scenario has a collection of hourly realisations of demand and renewable energy availability, chosen to form a realistic representation of operational situations that may arise under each scenario trajectory.

The problem itself is formulated as a multi-stage stochastic optimisation, i.e. the planning horizon is divided into multiple decision periods and accounts for the various potential scenarios. The model solves for optimal values of all control variables at each decision period, considering all potential future scenarios and the probability of same. This generates one optimal solution for the probability-weighted combination of all scenarios. The multi-stage and multi-scenario GEP modelling framework, and the expansion solution structure, is discussed in detail in [12].

2.2 Formulation of the unconstrained and constrained cases

The main focus of this paper is the consideration of two renewable energy development cases: unconstrained and constrained. The unconstrained case assumes that renewable developments are determined by a social planner, and therefore installs generation capacity in the optimal locations from a system cost perspective, up to a maximum capacity of 400 MW of onshore wind power at any given transmission node. The constrained case assumes that onshore wind development is driven by local communities who object to large-scale renewable development, and so generation capacity investments face a far lower maximum installed capacity, that of the peak demand at each transmission node. For both cases, up to 700 MW of offshore wind capacity (along the coast) or thermal generation can be connected per candidate transmission node. The RES-E targets for both cases are identical.

We also differentiate between the two cases regarding their treatment of installations of battery energy storage systems. EirGrid's projections for battery storage installations range between 100 MW and 1700 MW by 2030 [10]. We use these figures as the basis for our storage installations. In the unconstrained case, we assume battery energy storage facilities of 30 MW/120 MWh ratings [29, 38, 25, 26, 22]. In contrast, the constrained case assumes that regional self-sufficiency is a motivating factor in generation investment decisions, and so we restrict the capacity of battery storage investments to a 7.5 MW/30 MWh rating, leading to a greater geographical dispersion of same. No more than four storage systems of each type can be built at each RES candidate node, or demand node, shown in Figure 1.

Table 1 summarises the main differences between the two cases.

Table 1: Underlying assumptions of each RES development case

Cases	*Variations*		
	Storage deployment	*Wind onshore*	*Solar PV*
Unconstrained	Unlimited capacity	$\leq$ 400 MW per transmission node	$\leq$ 50 MW per transmission node
Constrained	Limited capacity	$\leq$ Peak demand at each transmission node	$\leq$ min {50 MW; Peak demand at each transmission node}

The optimal location of renewable power generation assets depends on a number of technical, spatial and environmental factors, such as demand, electrical connectivity and proximity to primary energy resources, as well as socio-economic factors. In order to ensure that renewable power expansion is not unrealistically concentrated in one or two geographical regions, we impose a maximum installed capacity at a regional level that can be feasibly built by 2030. This maximum is based on existing and planned levels of installed capacity and scaled up according to population density and available space in the regions in question. The resulting maximum wind installations per region are shown in Table 2. The table also shows the number of demand nodes as well as the percentage share of demand of each region.

3 Data and Assumptions

The analysis is performed using the 2017 power system of the island of Ireland, described in detail in [12]. The system includes a transmission network aggregated at 110 kV or higher for the whole island. Data and further details of this system can be found in [9].

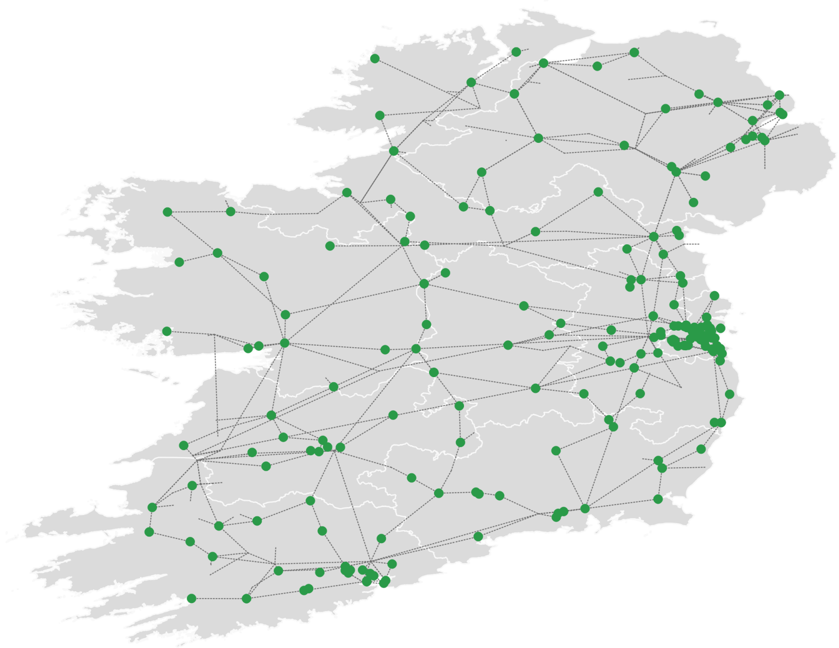


Figure 1: Candidate connection nodes of renewable and storage investment

Table 2: Maximum onshore wind capacity and demand share by region

Region	ξ_{reg}(MW)	Number of demand nodes	Demand share (%)
Mideast	289	23	9
Midland	1096	5	2
West	742	15	7
Midwest	316	14	6
Southeast	674	15	6
Southwest	736	29	10
Border	905	16	6
Northern Ireland	450	27	20
Dublin	0	45	34

The planning horizon is 12 years, with three decision stages at the years 2020, 2025 and 2030. We assume carbon prices of 20, 25 and 30 €/tCO_2 for 2020, 2025 and 2030, respectively, in line with the carbon price projections in [36]. We assume a 55% renewable target for 2030 as the base case, which is 15% higher than the 2020 RES-E target, with an intermediate RES-E target of 47% for 2025. However, we also consider RES-E targets up to 70% as a sensitivity analysis, in line with the recently updated Irish government's plan. Investments in new thermal power plants, including carbon capture and storage (CCS), are assumed to be in brown fields. A retirement plan of existing thermal generation assets is assumed to be a policy decision. Hence, the model does not provide endogenous decommissioning of existing old, inefficient power plants. Previous work has found, however, that this retirement is cost-optimal [12].

A 75% system non-synchronous penetration (SNSP) limit, defined as the ratio of generation from variable renewable power sources plus HVDC imports to demand plus HVDC exports, is imposed[1]. We do not include interconnection in our analysis as we are particularly interested in examining the impacts of renewable generation in an isolated system. It is however important to note that while some of our results may find that the SNSP is almost equivalent to the percentage of demand met by renewable generation, in reality total power generation can be greater (less) than the total electricity demand, with the surplus (deficit) being exported (imported).

To ensure problem tractability, integer constraints related to storage investments (due to lumpiness) are relaxed. This means the optimal storage builds can be fractions of the above nameplate capacities. As battery-based storage systems tend to be modular in nature (similar to wind and solar PV power production technologies), this assumption is not unreasonable. Further assumptions for storage include a 90% round-trip efficiency, a 10 year lifetime and an 80% depth of discharge (DoD) [40, 32, 29]. Additional parameter assumptions regarding generator and storage technologies are presented in Table 8.

To account for uncertainty in storage costs, two different overnight costs of installing 1 MW of storage are assumed: 1 M€and 0.6 M€, with 5 and 10% cost reductions anticipated by 2025 and 2030, respectively. These cases are designated as *High Storage Cost* and *Low Storage Cost*, respectively. Thus, there are four total cases considered: *unconstrained* and *constrained*, each with *high* and *low* storage cost assumptions. It should be noted that the unconstrained and constrained cases closely resemble large-scale and small-scale approaches for developing renewables onshore, respectively. As such, in the following sections, these terms are interchangeably used.

Table 3: Considered cases and their distinguishing features

Cases	RES installation	Storage cost
1	Unconstrained/ Large-scale	High
2	Unconstrained/ Large-scale	Low
3	Constrained/ Small-scale	High
4	Constrained/ Small-scale	Low

4 Results and Discussion

4.1 Total system costs

In the first instance, we examine the total system costs under all four cases. The lowest net present value (NPV) is the unconstrained case with low storage cost, which is as expected, at least weakly. This is because any solution arrived at by the constrained case can be

[1]Further definition and derivation of the SNSP limit can be found in the All-Island TSO Facilitation of Renewables Studies [35].

arrived at by the unconstrained case while the reverse does not necessarily hold, and the lower cost associated with storage investment obviously reduces costs.

Figure 2 compares the expected NPV of each case relative to the unconstrained case with high storage costs. A lower storage cost in the unconstrained case decreases total NPV by 1%, while the constrained case with high storage costs is 3% more expensive than the unconstrained case with high storage costs. In fact, the cost differential between the unconstrained approach and the constrained one is about 3%, for both storage costs. This provides a useful metric for policy makers - a constrained approach may be preferable if policy-makers determine the benefits to be greater than 3% of cumulative system costs. The difference in total costs between the various cases is driven primarily by events that take place in 2030, with little divergence in costs seen between the cases before then.

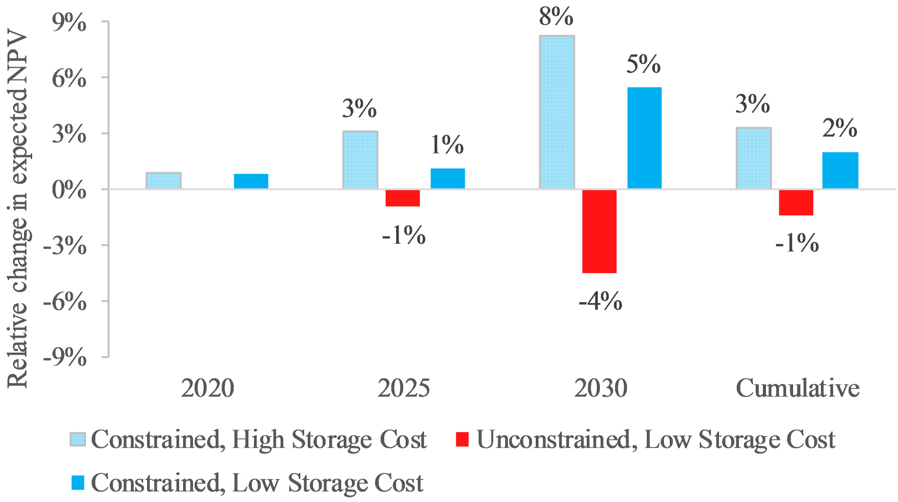


Figure 2: Changes in expected NPV relative to the "Unconstrained with high storage cost" case

Table 4 gives a breakdown of the costs in each case. Focusing on the year 2030, the main driver of the divergence in costs between the unconstrained and constrained cases is capacity investment. The expected energy not served (EENS) is similar for both cases, suggesting that the constrained approach allows the same level of reliability to be met, but with a higher total installed capacity cost. Some trends in the EENS are however visible, e.g. EENS tends to increase in the intermediate year but decreases in 2030, partly thanks to the substantial investments in storage. The low storage cost cases see much lower EENS compared to the respective high storage cost cases. Generally, storage decreases total investment costs, particularly for the constrained case, and reduces EENS costs. Therefore, investing in storage substantially increases system reliability.

4.2 Generation capacity mix

Figure 3 shows the optimal mixes of new installed power generation capacity for each case, under high and low storage investment costs. Only a few power production technologies feature in the optimal solution: solar PV, CCGTs, onshore and offshore wind. In particular, the assumption of a 20% cost reduction in the installation cost of carbon capture and storage (CCS) technology by 2030 is not sufficient to justify investment in the same, at the assumed carbon price levels.

Several results are of note here. The constrained case sees slightly lower total installed capacity than the unconstrained one, both under high and low storage costs. This is because the limits on onshore wind installations increase investment in offshore wind and storage. Offshore wind has a higher capacity factor than onshore wind, and the increased storage reduces curtailment, increasing the effective capacity factor even further. The

Table 4: A breakdown of the system-wide NPV for each portfolio and planning stage (in M€)

		High Storage Cost		Low Storage Cost	
Year	Cost components	Unconstrained	Constrained	Unconstrained	Constrained
2020	Investment	133	142	133	142
	Emissions	311	313	311	313
	EENS	0	0	0	0
	Variable	1426	1432	1426	1432
2025	Investment	197	240	200	223
	Emissions	195	194	192	193
	EENS	5	3	3	1
	Variable	1036	1040	1025	1034
2030	Investment	192	258	146	229
	Emissions	142	143	142	142
	EENS	4	3	0	0
	Variable	673	689	674	692
	Cumulative	4314	4457	4252	4401

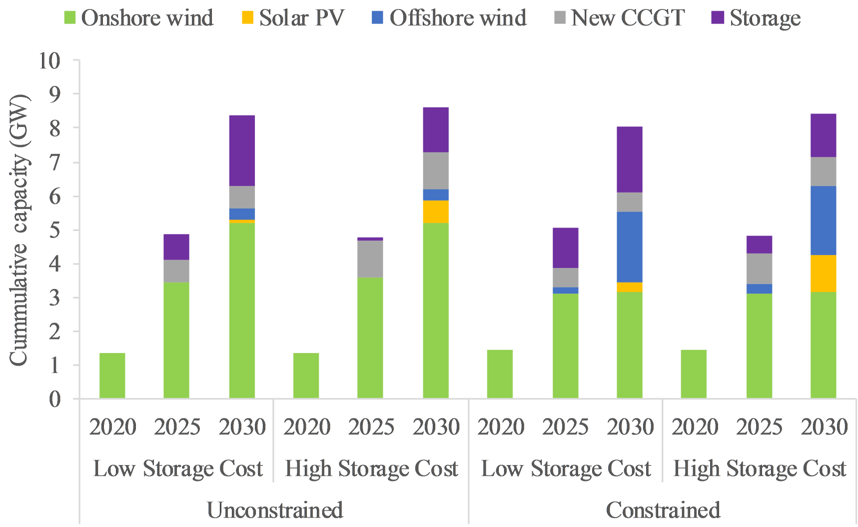


Figure 3: Optimal mix of new investments along the planning horizon

unconstrained case sees low levels of both offshore wind and solar, with investment in both occurring in 2030 only. The higher capacity costs observed in the constrained cases in Table 4 are due to greater investment in the higher-cost generation technologies of offshore wind and storage. In terms of space requirement, the optimal onshore wind installation in the unconstrained case requires roughly twice as much space as the constrained case.

The cost of storage also has an impact on the capacity portfolio over and above the impact of onshore wind installation limits. Lower storage costs obviously increase storage investments, reducing investment in both solar PV and CCGTs, under both the constrained and the unconstrained expansions. Higher storage investment also decreases the total installed system capacity. Storage deployment reduces investment in new CCGTs by 24% in the constrained - high storage cost case, and 48% in the constrained - low storage cost case. In the unconstrained case, these figures are 4% and 43%, respectively. In installed capacity terms, a 1 MW storage defers investment in new conventional power generation by 1.3 MW and 1.5 MW in the unconstrained and constrained cases with high storage costs, respectively. As storage increases, the amount of new generation capacity deferred increases linearly, which is demonstrated in Figure 4. The impact of storage on capacity expansion is higher under the constrained case than its counterpart: the higher the storage level, the wider the difference between the curves. However, such a pronounced effect may not be solely driven by storage investments, but a composite effect of other issues such as the higher level of offshore wind installations under the constrained case.

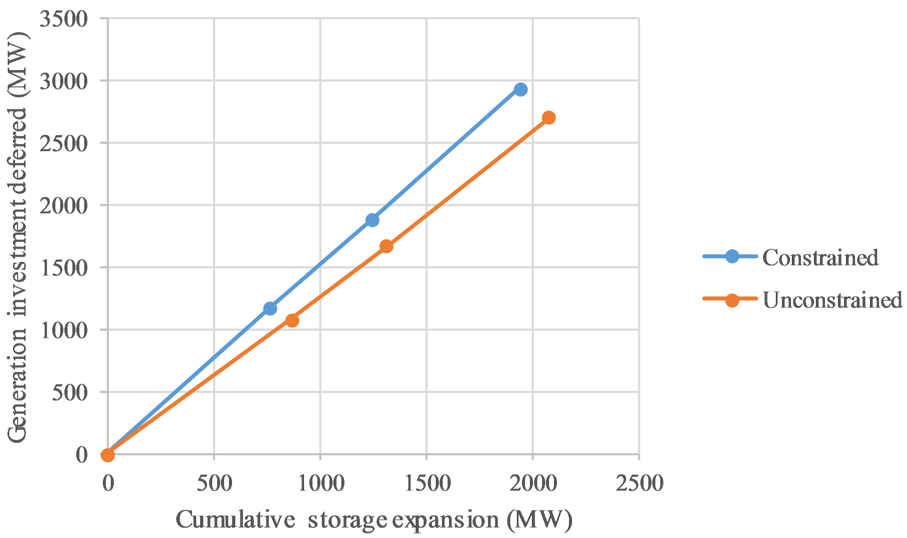
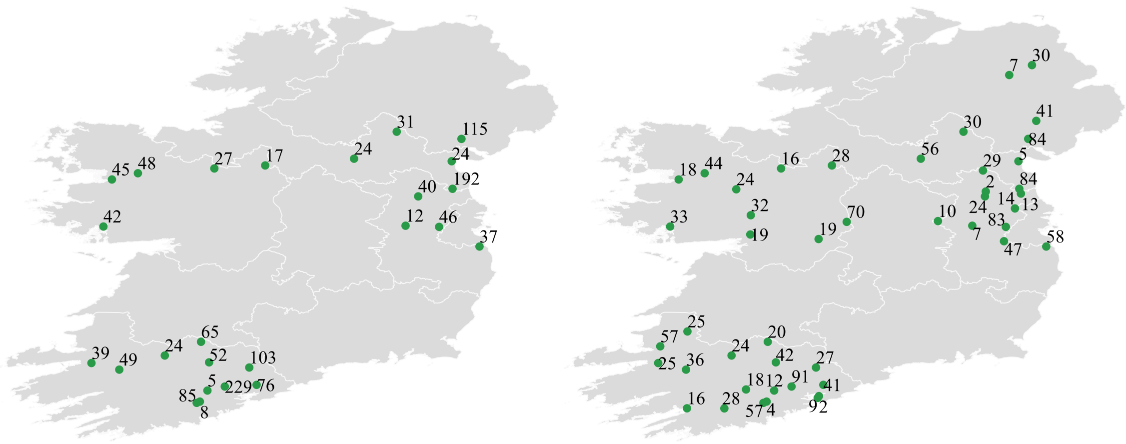


Figure 4: Relationship between generation and storage expansions

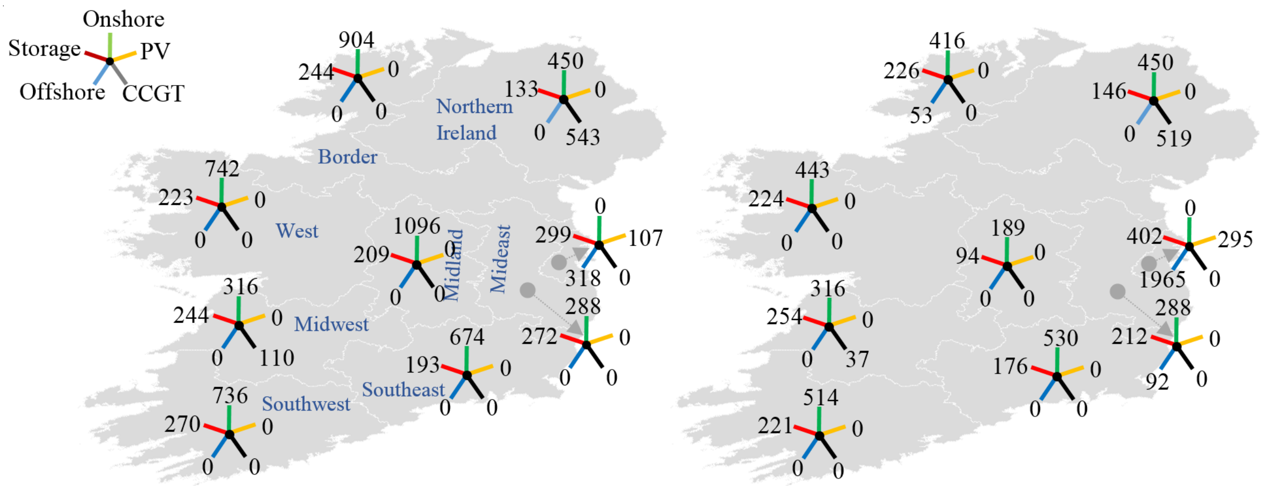
Turning to the spatial distribution, the location of onshore wind developments in 2020 is illustrated in Figure 5. Due to the restrictions of the constrained model, wind turbines are installed in many more geographic locations. The total installed capacity of wind is the same for both cases, but the investment locations vary widely.



(a) Unconstrained (b) Constrained

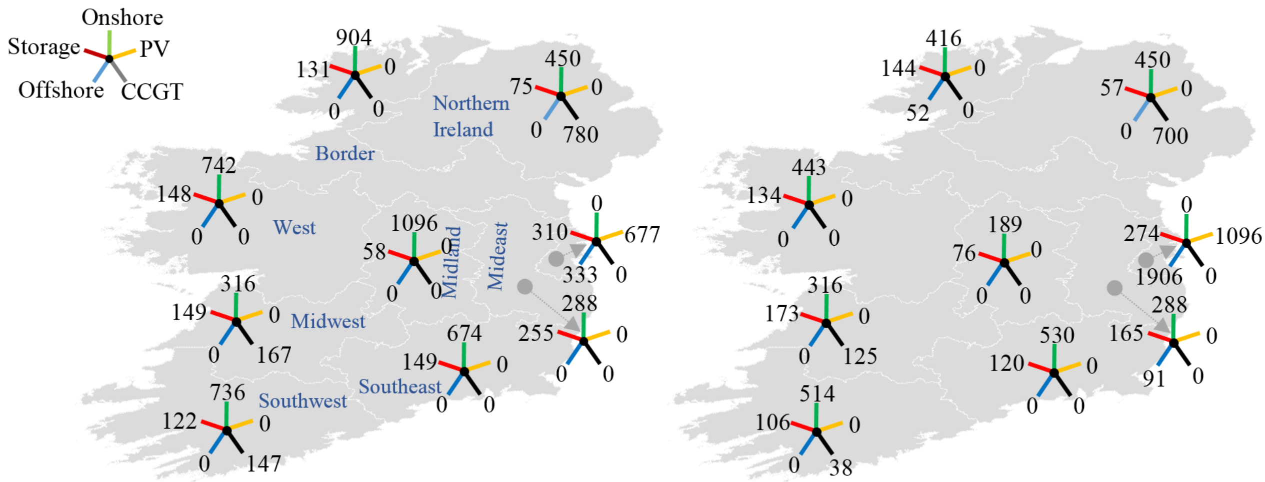
Figure 5: Optimal locations and sizes of onshore wind builds in 2020

Figures 6 and 7 show the total generation capacity investment over the entire horizon of the model at regional levels, under low and high storage costs, respectively.



(a) Unconstrained, Low Storage Cost (b) Constrained, Low Storage Cost

Figure 6: Optimal generation and storage capacity builds by region (MW)



(a) Unconstrained, High Storage Cost (b) Constrained, High Storage Cost

Figure 7: Optimal generation and storage capacity builds by region (MW)

The constrained case leads to a much higher solar PV installation for both high and low storage costs, although the difference is higher under low than high storage cost cases. The location of the solar PV is of interest here. It is installed in the Dublin region, which has the highest demand and the highest network congestion. Both of these effects likely drive the decision to locate solar PV in this area. Interestingly, while the low storage cost case sees higher total investment in storage, this effect is heterogeneous across regions. For example, the midlands see 58 MW of storage with high storage costs and 209 MW of storage with low storage costs under the unconstrained case, while the corresponding storage investments for Dublin are 310 MW and 299 MW, respectively. Generally, high storage costs lead to a much lower storage installation for the whole system. This in turn leads to higher PV investments in the Dublin region, and consequently the majority of the storage investments also take place in this region. In the constrained case, however, every region sees higher storage investment when the storage cost decreases.

The trade-off is clear: widespread, small-scale renewable expansion (i.e. the constrained case) halves onshore wind investment, predominantly in rural areas, and leads to an increase in solar PV investment, predominantly in Dublin. These results highlight the importance of spatial modelling as the regional effects of different policies may vary widely even if the system-wide figures are comparable under each policy.

4.3 Energy self-sufficiency and consumption by region

As mentioned in the introduction, the possibility of regions becoming energy self-sufficient has been proposed as a mechanism for reducing public opposition to energy investments. We define energy self-sufficiency as the ratio of electricity consumption at a given transmission node to the energy produced at that node by newly built onshore wind, solar PV and energy storage systems. Existing RES generation is not accounted for in order to ensure comparability between the various scenarios examined. Figure 8 shows the total level of self-sufficiency across the island. Self-sufficiency grows from under 8% in 2020 to about 25% by 2030.

The system-wide energy self-sufficiency levels are comparable under each of the considered cases. However, there is again considerable heterogeneity when the regional figures are considered. Figures 9 and 10 show the spreads in the expected energy self-sufficiency levels within and among regions for all cases. The smaller dots represent the self-sufficiency at a transmission node level while the larger dots show the average self-sufficiency per region. In the unconstrained case, we portray net-exporting nodes (some of which have very low or no demand) as 100% self-sufficient. The percentage of nodes in the Border, Midland,

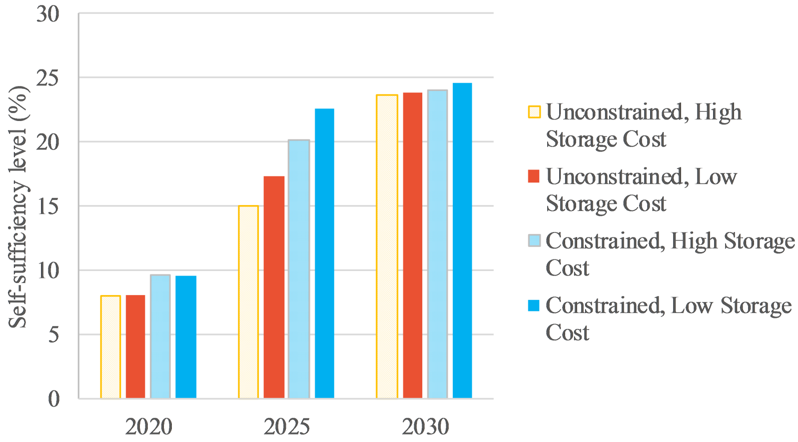
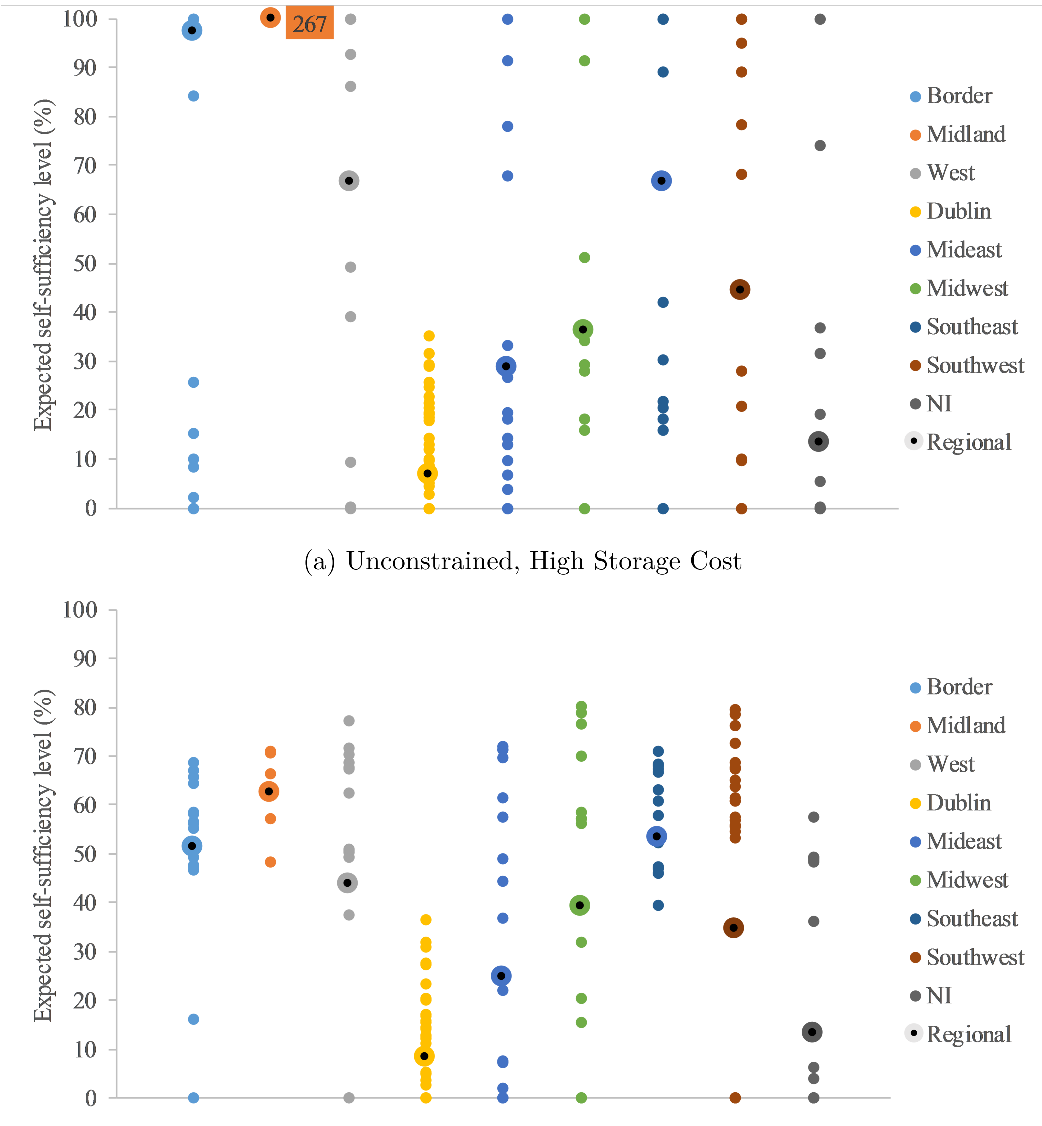


Figure 8: Evolution of expected self-sufficiency level across the island of Ireland under low and high storage costs.

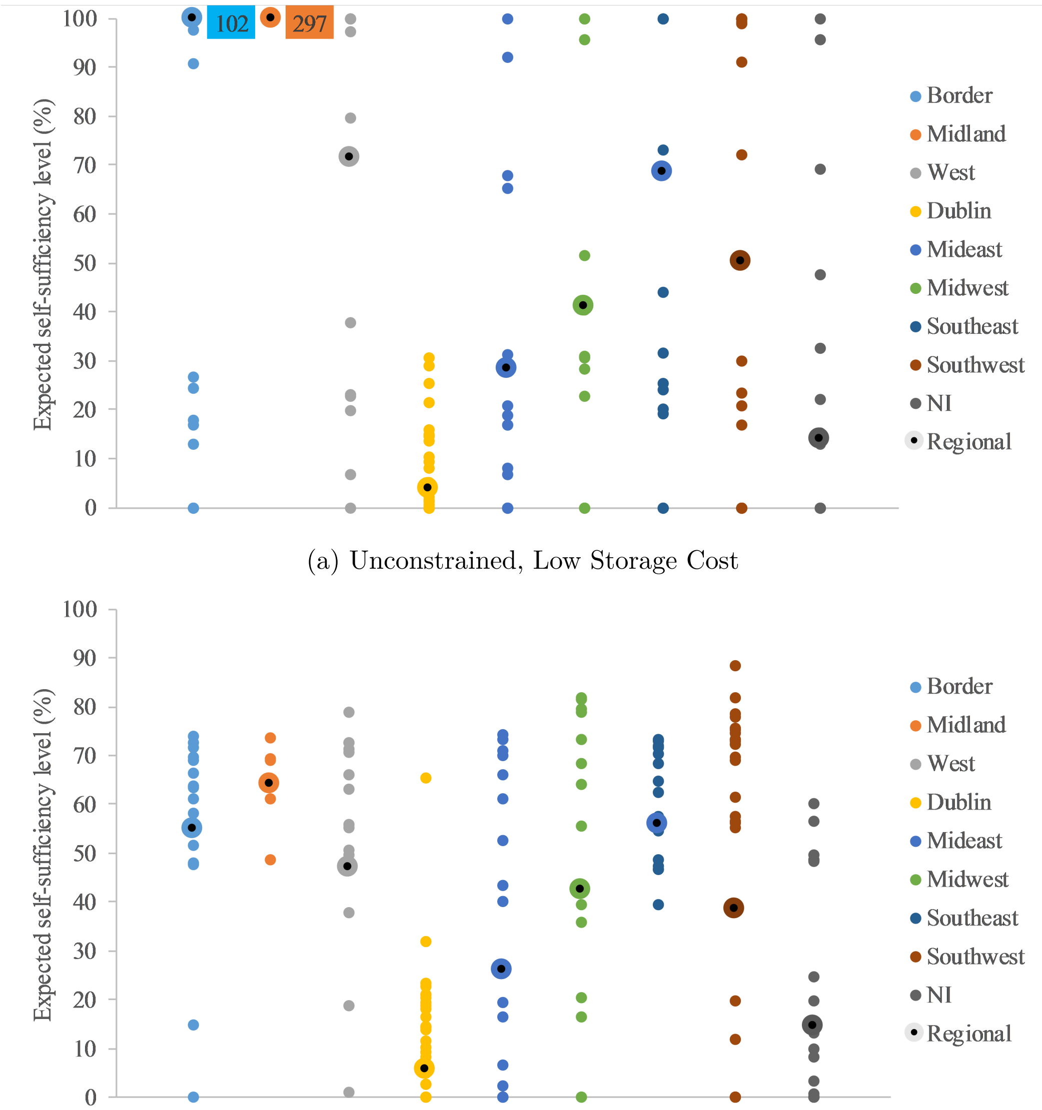
West, Mid-East, Mid-West, South-East, South-West and Northern Ireland regions that are net exporters are 31%, 100%, 47%, 4%, 14%, 27%, 21% and 7%, respectively. Dublin is the only region with no net exporting nodes. Conversely, the constrained case has no exporting nodes in any region, because the cap on installed capacity at any given node is too low to allow the node to become a net exporter.



(a) Unconstrained, High Storage Cost

(b) Constrained, High Storage Cost

Figure 9: Expected energy self-sufficiency per node within each region by 2030. Bigger circles refer to the regional average self-sufficiency levels.



(a) Unconstrained, Low Storage Cost

(b) Constrained, Low Storage Cost

Figure 10: Expected energy self-sufficiency per node within each region by 2030. Bigger circles refer to the regional average self-sufficiency levels.

While the constrained case leads to higher self-sufficiency, the unconstrained case sees several large-scale generation investments in remote locations with low or non-existent demand for electricity. This leads to 17% of the demand nodes under the unconstrained - high storage cost scenario being net exporters of electricity, by up to 2457%. The number of net exporting nodes is lower by one percentage point in the low storage cost case, but the exported RES energy is 14% higher, indicating a substantial reduction in RES power curtailment. In the constrained case, no transmission nodes are net exporters, regardless of storage cost. Table 5 compares the expected energy self-sufficiency levels, aggregated to regional level.

Table 5: Percentage of demand met locally from newly built renewable energy sources and storage

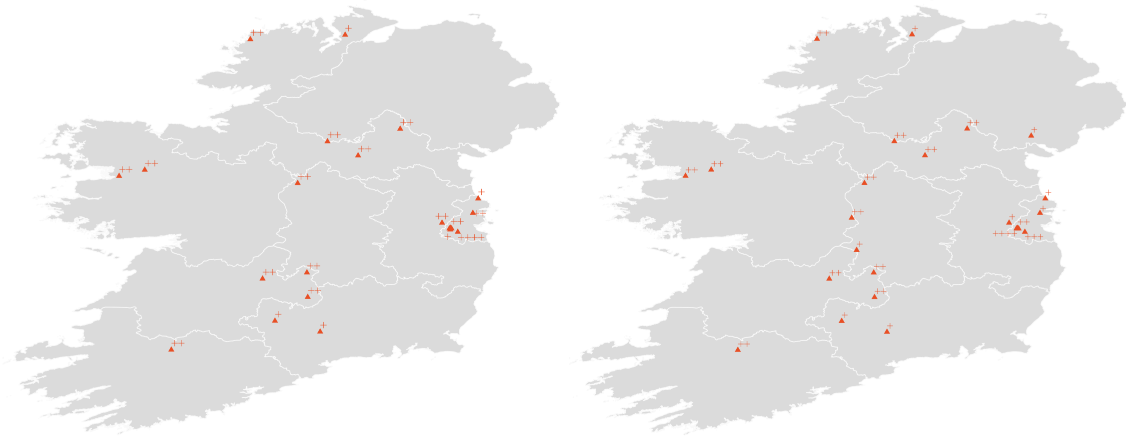
Region	High Storage Cost		Low Storage Cost	
	Unconstrained	Constrained	Unconstrained	Constrained
Border	96%	51%	102%	55%
Midland	267%	63%	297%	64%
West	67%	44%	71%	47%
Dublin	7%	8%	4%	6%
Mideast	29%	25%	28%	26%
Midwest	36%	39%	41%	42%
Southeast	66%	53%	68%	56%
Southwest	44%	34%	50%	38%
NI	13%	13%	14%	15%

In general, the constrained case leads to substantially higher levels of energy self-sufficiency on a nodal basis, whereas on a regional basis, the self-sufficiency levels are higher in the unconstrained case. This is driven by the fact that under the unconstrained case, the energy supply exceeds the demand to a large extent at a small number of nodes, which leads to a higher aggregate level of self-sufficiency for the region in which those nodes are located.

Storage investments have a less ambiguous effect on self-sufficiency, with the low storage cost case generally increasing self-sufficiency levels in each region. The exception is Dublin, which has the highest electricity demand. Self-sufficiency increases slightly in Dublin under a constrained RES development, but decreases slightly at low storage costs. This is primarily driven by the significant change in solar investment under the different storage cost cases.

4.4 System reliability and congestion

Expected energy not served (EENS) quantifies the amount of energy demand curtailed as a result of involuntary load shedding, mainly due to technical constraints in the system. Figure 11 shows the spatial distribution of EENS events. It should be noted here that these results are largely dependent on the value of lost load (VOLL) chosen, for both reactive and active power. While the total cost of EENS is similar for the unconstrained and constrained cases (see Table 4), far more regions experience EENS events under the unconstrained case, especially in 2030. This is driven primarily by network congestion, as the unconstrained case has less demand met by locally-generated energy (see the previous section) and therefore requires greater utilisation of the transmission network. In contrast, under the constrained case, most events occur near Dublin, where congestion is highest.



(a) Unconstrained (b) Constrained

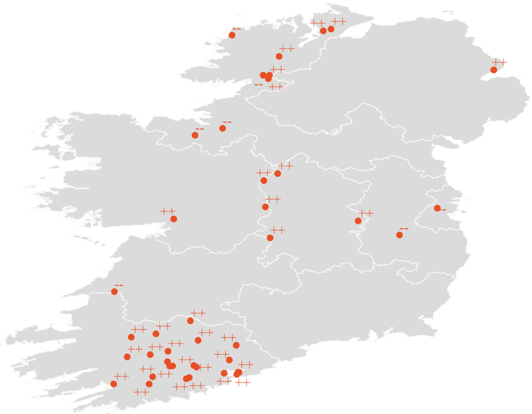
Figure 11: Geographical locations showing the risk of involuntary load shedding (Plus signs represent severity levels).

In addition to EENS, voltage is a key variable that is continuously monitored and controlled (often ±10%) in order to ensure secure system operation. Figure 12 depicts expected voltage issues in 2030. A voltage issue here is defined as the voltage tending to breach either the upper or lower bounds. Such voltage issues are more prevalent in the unconstrained case than in the constrained one. The relatively high risk of voltage rises in the Southwest and Border regions is explained by the high renewable installations in the same. Figure 13a shows probability distributions of voltage deviations in the Irish system for all considered scenarios while 13b depicts the cumulative distributions of same. In all cases, average voltage deviations (from the nominal value) across the entire system ranges between 1.7% and 2.5%. The unconstrained case sees its probability distribution function slightly skewed to the right, indicating a tendency of increase in voltages throughout the system. This is attributed to the fact that there are bigger generation injections at various locations in the system, resulting in increases in voltages at nodes located nearby. The reverse tends to happen in the constrained case, as there are far greater nodes which are likely to see their voltages approaching the lower bound (see 12d). These results are indicative of the needs for network-related investments (such as new reactive power sources, transmission lines and transformers).

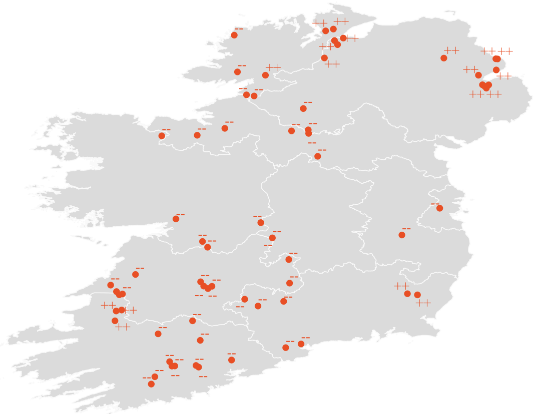
The ENGINE model is run excluding network investment decisions, but we can investigate the requirement for same by considering the total network congestion. We designate a transformer or line as congested if the power flows through it exceed 90% of its nominal transfer capacity. This value can be deemed high, particularly compared to other studies, for example in [6]. However, since we allow instantaneous power transfer through a line to reach an upper bound of the rated emergency capacity (between 110% and 120% of the nominal capacity), the 90% setting captures the heavily congested electric transmission assets.

To this end, we examine the proportion of system components that are congested for any given number of hours under each case in 2030. Generally, the constrained case has less congestion. Under low storage investment, the unconstrained case has far more components that are congested for 2000 or more hours per year, and it is this metric that is more likely to drive transmission upgrade requirements. For example, more than 10% of components are congested for at least 2000 hours per year in the unconstrained case with high storage costs, with the corresponding percentage for the constrained case (with high storage costs) at only about 5%. This reinforces the results found in subsection 4.3, which saw more generation in remote locations, giving rise to higher grid investment requirements.

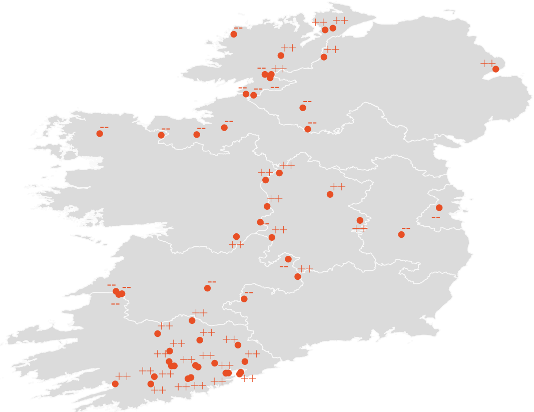
Figure 14 shows the geographical locations of overloaded paths and transformers. The



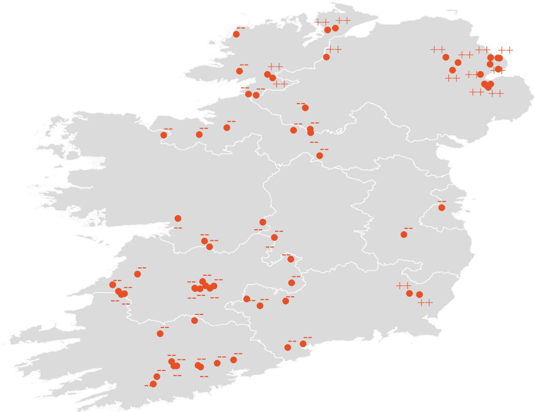
(a) Unconstrained, High Storage Cost



(b) Constrained, High Storage Cost

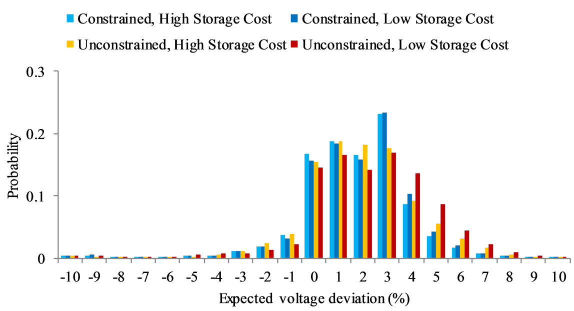


(c) Unconstrained, Low Storage Cost

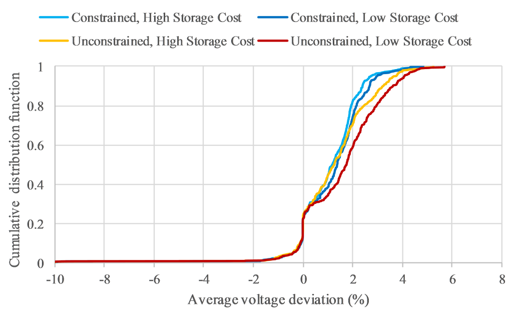


(d) Constrained, Low Storage Cost

Figure 12: Expected overvoltage (++) and undervoltage (–) issues in 2030.



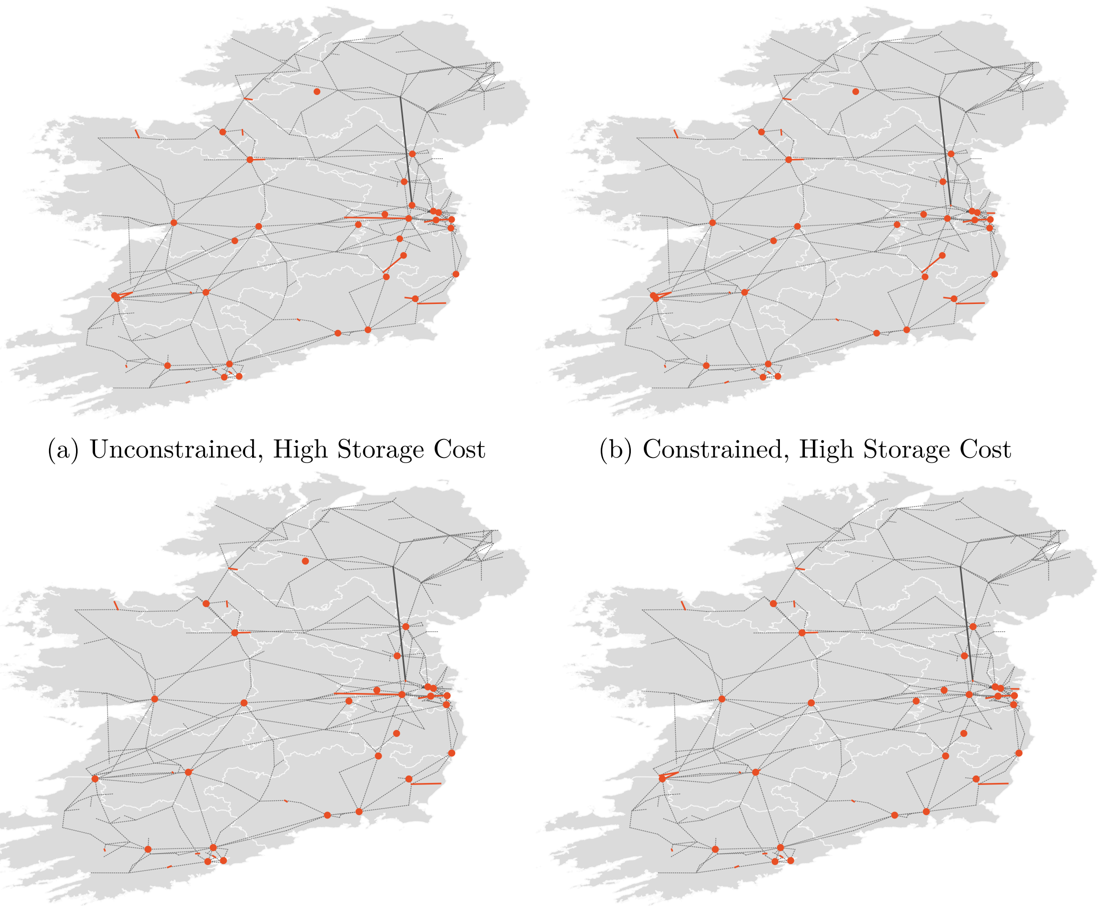
(a) Probability distribution function



(b) Cumulative distribution function

Figure 13: Distributions of voltage deviations in the island.

prevalence of congestion in the unconstrained case is higher than that of the constrained case, particularly under low storage investments. The highest congestion happens in the Dublin area. The difference in congestion level under high storage deployments is however not significant.



(a) Unconstrained, High Storage Cost

(b) Constrained, High Storage Cost

(c) Unconstrained, Low Storage Cost

(d) Constrained, Low Storage Cost

Figure 14: Corridors and transformers with high risk of congestion. Red dots represent congested transformers. The bold grey line is the planned 400 kV North-South interconnector, assumed to be completed by 2025.

Given public opposition to grid investment assets as well as generation assets, the potential for reduced network investment requirements in the constrained case is of relevance for policy makers when determining the optimal generation portfolio development.

4.5 Locational marginal prices

We also examine the impact each renewable development and storage investment level may have on electricity prices by examining locational marginal prices (LMPs) at each transmission node. The change in average LMPs for each region, relative to the unconstrained case with high storage costs, are shown in Figure 15. The average increase in prices for the constrained versus the unconstrained case (under high storage costs) is about 2%. This increase in prices compares with an increase in total costs of 3%, as described in section 4.1. There is some geographical disparity, however, most clearly visible in the Midlands region, which has higher average prices at every node under the constrained case, and the Southwest region, which has lower prices at every node. These results suggest that there is a transfer between regions as a result of a constrained renewable generation expansion.

Under low storage cost, LMPs in both constrained and unconstrained cases are on average about 4% lower than those in the unconstrained, high storage cost case.

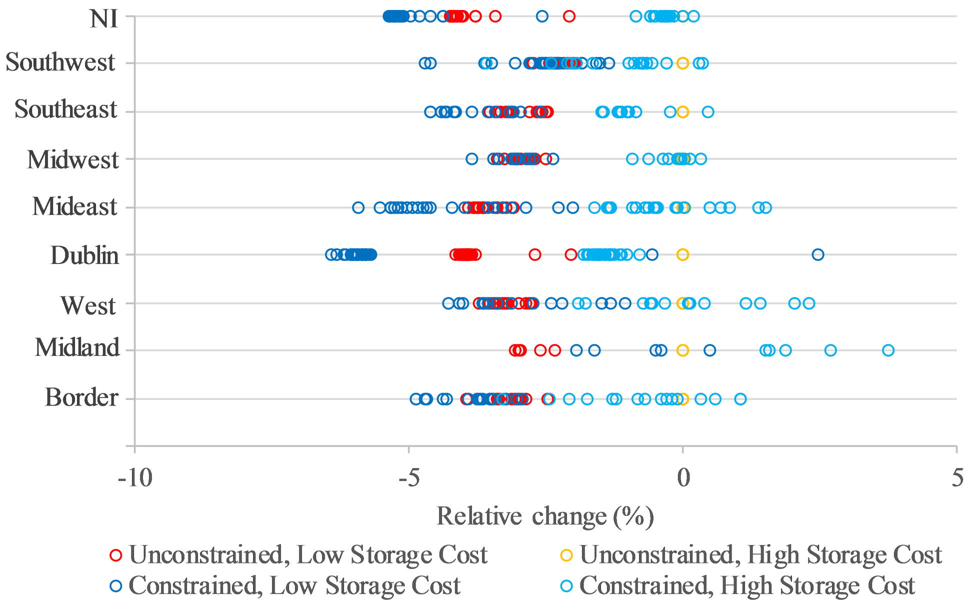
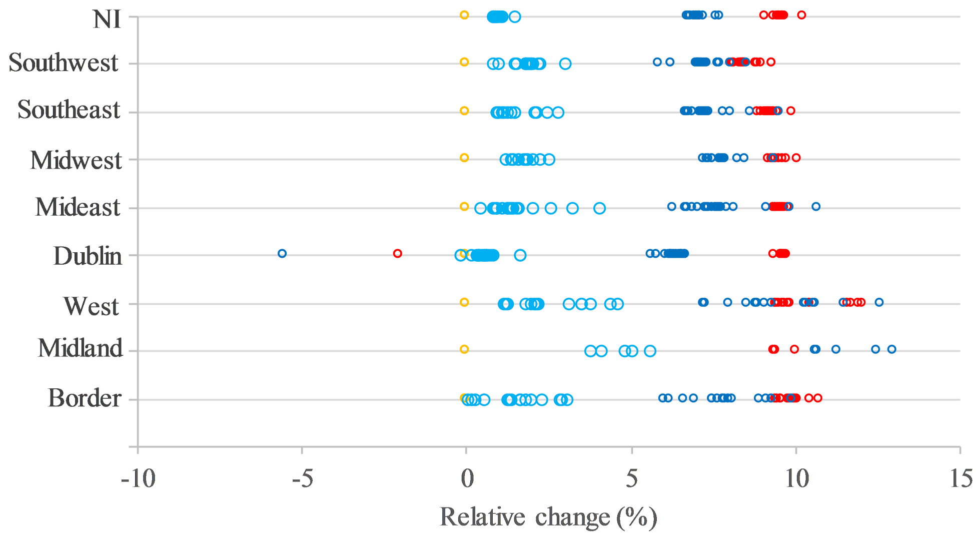
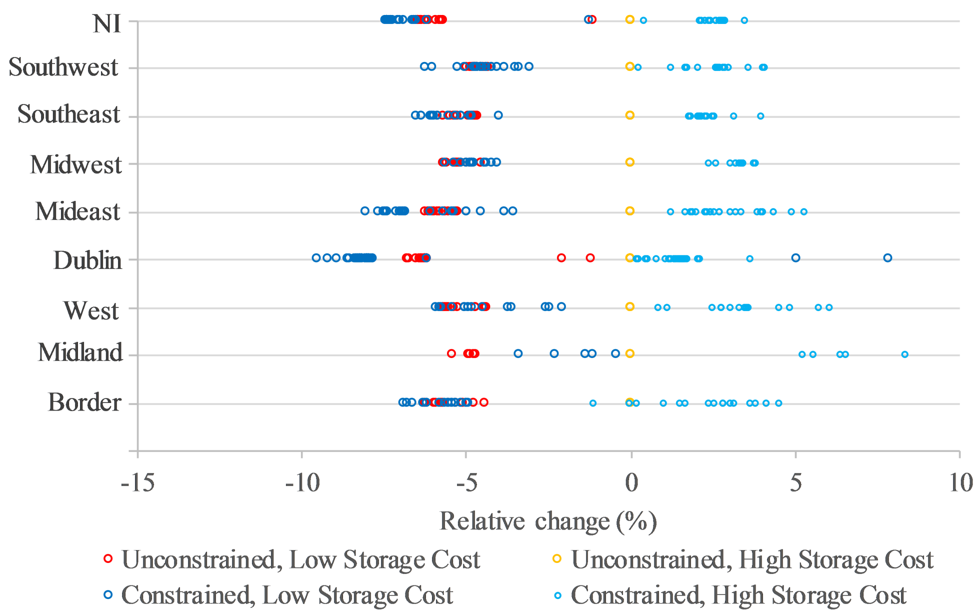


Figure 15: Expected LMPs within and among regions

Figure 16 illustrates the change in prices during the lowest and highest price periods. We define low and high demand periods as the hours in which demand for electricity is lower than 60% and higher than 80% of the peak demand in a given year, respectively. The LMPs during low price periods, shown in subfigure 16a, are fairly stable across the various regions, which suggests that although the unconstrained and constrained cases vary significantly in terms of energy imports and exports, the marginal technology (which sets the electricity price) is relatively stable. The unconstrained case with low storage costs sees very similar prices as the case with high storage costs. The constrained case with low storage costs sees decreases in LMPs of up to 5%, while the constrained case with high storage costs sees LMPs increase by more than 10%. This suggests that storage plays a significant role in reducing variation in prices under a constrained renewable power expansion. The unconstrained case does not see such a pronounced effect in LMPs.



(a) Low demand periods



(b) High demand periods

Figure 16: Expected LMPs within and among regions (relative to the "Unconstrained, High Storage Cost" case).

During high demand periods (subfigure 16b), the unconstrained case with low storage costs sees a decrease in LMPs relative to the unconstrained case with high storage costs, with the LMPs again fairly stable across regions. This effect is more pronounced in the constrained cases. The case with low storage costs lead to much lower peak prices than the one with high storage costs. Furthermore, the constrained case with low storage costs has all regions with lower prices than the unconstrained case with high storage costs, while the constrained case with high storage costs has increased prices for every region.

4.6 Sensitivity analysis

Newly announced policy targets for Ireland include increasing the level of RES-E generation to 70% by 2030. We therefore perform a sensitivity analysis by revising the RES-E target for 2030 to 70% (with an interim 2025 target of 55%), in order to determine the extent to which the deviation between the unconstrained and constrained cases is driven by renewable energy targets. To facilitate this increase, we also assume the SNSP limit increases from its current value of 65% to 90% by 2030. Note that our dataset does not include DC interconnection to Great Britain or France, and so an SNSP limit of 90% means that, in practice, more than 10% of demand could be met by thermal generation, with the surplus renewable generation being exported via the interconnectors.

Table 6: Impact of high RES-E targets and progressive SNSP levels under high storage costs. Values represent the percentage changes of variables of interest in the "Constrained" case relative to those of "Unconstrained" one.

	SNSP level	*75%*	*75%*	*90%*
	RES-E Target	*55%*	*70%*	*70%*
Changes in investment (%)	*New CCGT*	-21	+56	-31
	Onshore wind	-40	-39	-39
	Solar PV	+62	-8	+14
	Offshore wind	+515	+58	+66
	Storage	-42	-2	-5
Changes in key system variables (%)	*Expected emissions*	0	0	0
	Expected RES curtailment	-14	-5	-13
	Expected self-sufficiency	+15	+6	+4
	Expected NPV	+3	+5	+5
	Case	RES-E 55	RES-E 70	RES-E 70 & SNSP 90

Table 7: Impact of high RES-E targets and progressive SNSP levels under low storage costs. Values represent the percentage changes of variables of interest in the "Constrained" case relative to those of "Unconstrained" one.

	SNSP level	*75%*	*75%*	*90%*
	RES-E Target	*55%*	*70%*	*70%*
Changes in investment (%)	*New CCGT*	-15	**-**	**-100**
	Onshore wind	-40	**-40**	**-40**
	Solar PV	+175	**-7**	**+103**
	Offshore wind	+563	**+55**	**+65**
	Storage	-7	**-3**	**-3**
Changes in key system variables (%)	*Expected emissions*	0	**0**	**0**
	Expected RES curtailment	-13	**-9**	**-14**
	Expected self-sufficiency	+15	**+6**	**+4**
	Expected NPV	+3	**+5**	**+5**
	Case	RES-E 55	RES-E 70	RES-E 70 & SNSP 90

The leftmost column in Tables 6 and 7, designated as "RES-E 55", shows the previously-reported percentage difference between the unconstrained and the constrained cases outlined above (and corresponds to the values shown in Table 4). The second and third columns show the percentage difference between the unconstrained and constrained cases for the new 70% RES-E target and the original SNSP of 75%, and for both the new higher RES-E target and higher SNSP, respectively.

The pattern observed previously is that of large changes in the percentage difference between the unconstrained and constrained case for the generation portfolio, but the difference in total costs is relatively low, at 3%. A similar pattern is observed here, but the magnitude of the difference in NPV between the unconstrained and constrained cases increases to 5% —the constrained case is 5% more expensive than the unconstrained case. This result holds regardless of whether the SNSP limit is increased. It should be noted here, however, that the absolute NPV is much higher for the high RES, low SNSP sensitivity: it is the differential between the unconstrained and constrained case that does not increase.

There are, however, differences in the portfolios of the unconstrained and constrained cases. For both sensitivities, the constrained case has a 39% reduction in new onshore wind installations, which is very close to the 40% reduction seen in the base case, and an increase in offshore wind installations. This is because, at high RES-E targets, the lower limits imposed on onshore wind installations in the constrained case are reached at the lower RES-E target of 55%, and offshore wind investment is required. Conversely, the constrained case sees a reduction of 8% in solar installations for a high RES-E, low SNSP scenario, but when both RES-E and SNSP are higher than the base case, the constrained case has an increase of 14% in solar PV installations. Similarly, the constrained case has a 56% increase in new CCGT capacity under the high RES-E low SNSP scenario, but sees a 31% reduction in CCGT installations when both RES-E and SNSP are increased. The effect of a constrained renewable power development is therefore heterogeneous across energy technology investments although the aggregate effect is a lower total installed capacity of renewable technologies, as was observed under the lower RES-E target. This is driven by the higher capacity factor associated with offshore wind.

The constrained case sees lower levels of renewable curtailment for both sensitivities, but the difference is far greater for the case with high SNSP. This is because a low SNSP, relative to the level of renewable generation, leads to greater curtailment. Thus, while the difference between the unconstrained and constrained cases is lowest for the high RES-E, low SNSP case, the absolute levels of curtailment are highest in this case. Finally, the unconstrained case leads to higher levels of average self-sufficiency in general, but this result is influenced by the sensitivities performed - the base case saw the constrained case bringing about a 15% increase in self-sufficiency, but this drops to 4% in the high RES-E and high SNSP case. Given that self-sufficiency is hypothesised to drive social acceptability, this result sees one of the main benefits of a constrained expansion considerably eroded by policy objectives such as increased RES-E.

The results of this sensitivity analysis show that the costs of the constrained power expansion are dependent on the underlying policy and technical parameters, particularly those relating to renewable power generation. This is an important finding as the rationale for constraining onshore renewable developments is the potential to increase public acceptability of renewable energy projects. However, an increase in electricity costs could actually fuel objections to renewable energy developments. Thus, using constrained onshore expansions as a mechanism for increasing renewable generation could undermine itself if it in turn gives rise to an unacceptable increase in energy costs, especially given then the reduced potential for a constrained expansion to drive self-sufficiency. The policy choice to move towards smaller, more widespread renewable generation investment should therefore be considered in light of other policy objectives.

5 Conclusion and Policy Implications

In this study, we determined the optimal generation capacity investment on an isolated power system under an unconstrained and constrained renewable capacity expansion. The methodology is a generation expansion planning model, which incorporates a linearised ACOPF, and so determines optimal generation investment and operation at nodal level. The two approaches are distinguished by the total capacity investments in renewable power and in storage that are permitted at each transmission node. The impact of policy decisions regarding renewable generation and instantaneous renewable penetration is determined.

In general, the results indicate that the unconstrained case is cheaper than the constrained one, which is as expected. This holds regardless of the cost of, or subsequent investment in, storage. However, while the generation portfolio that results from the two cases is very different, the difference in total costs is relatively small - about 3%. This is at least partly driven by the fact that the RES-E targets for all cases are the same, and are the main determinants of the final NPV. Thus, policy makers may choose to trade achieving RES-E targets off against arriving at the least-cost scenario. If a constrained roll-out of renewables overcomes public opposition to the high levels of RES installations required to meet higher renewable integration targets, the 3% increase in total costs may be acceptable, from a policy-maker's point of view.

The constrained expansion leads to lower onshore wind investment and higher offshore wind investment, as well as higher solar PV investment in high demand areas. Energy self-sufficiency at a nodal level is also higher under the constrained approach. There are large changes in the spatial allocation of investments, and there is evidence of transfers between regions when locational marginal prices are examined.

The total costs can be slightly reduced by investments in storage, for both unconstrained and constrained cases. The differential between the unconstrained and constrained cases is therefore sensitive to the costs of storage. Storage reduces costs primarily by increasing the reliability of the system, reducing expected energy not served. The value of lost load chosen here (€3,000/MWh) may be too low for a risk-averse policy maker, and is lower than the short-run VOLL estimated for Irish consumers [24], but given that this study is a long-run study, a lower value may be appropriate. Even assuming a value of lost load of €10,000/MWh, the cost of expected energy not served would still be a small portion of the total cost, which are driven primarily by investments.

The sensitivity analysis suggests that the extra cost of the constrained renewable expansion increases as renewable energy targets increase, and this result holds regardless of

SNSP levels. The trade-off between the increased financial cost of the constrained expansion and the benefit of potentially increased social acceptability is therefore more acute, especially given that increased energy prices and reduced self-sufficiency may themselves prove a barrier to social acceptance. However, policy makers may determine that ancillary benefits to a constrained expansion that are not captured here, namely the potential to reduce public opposition to renewable projects, may justify the increased costs.

Appendix

Acknowledgements

Desta Fitiwi acknowledges funding from Science Foundation Ireland (SFI) under the SFI Strategic Partnership Programme Grant number SFI/15/SPP/E3125. Muireann Lynch acknowledges funding from the ESRI's Energy Policy Research Centre. The opinions, findings and conclusions or recommendations expressed in this material are those of the authors and do not necessarily reflect the views of the Science Foundation Ireland. We are grateful to ESRI seminar participants for useful comments and to EirGrid for providing much of the data necessary to complete this study, along with invaluable insights and advice.

References

[1] Bauwens, T., Gotchev, B., Holstenkamp, L., 2016. What drives the development of community energy in europe? the case of wind power cooperatives. Energy Research & Social Science 13, 136–147.

[2] Bell, D., Gray, T., Haggett, C., 2005. The 'social gap'in wind farm siting decisions: explanations and policy responses. Environmental politics 14, 460–477.

[3] Bertsch, V., Hyland, M., Mahony, M., 2017. What drives people's opinions of electricity infrastructure? empirical evidence from ireland. Energy Policy 106, 472–497.

[4] Brennan, N., Van Rensburg, T.M., 2016. Wind farm externalities and public preferences for community consultation in ireland: A discrete choice experiments approach. Energy Policy 94, 355–365.

[5] Burke, M.J., Stephens, J.C., 2017. Energy democracy: Goals and policy instruments for sociotechnical transitions. Energy Research & Social Science 33, 35–48. URL: https://linkinghub.elsevier.com/retrieve/pii/S2214629617303031, doi:10.1016/j.erss.2017.09.024.

[6] Desta Z. Fitiwi, F. de Cuadra, L. Olmos, Rivier, M., 2015. A new approach of clustering operational states for power network expansion planning problems dealing with RES (renewable energy source) generation operational variability and uncertainty. Energy 90, 1360–1376. URL: http://www.sciencedirect.com/science/article/pii/S0360544215008348, doi:10.1016/j.energy.2015.06.078.

[7] Devine-Wright, P., 2011. Place attachment and public acceptance of renewable energy: A tidal energy case study. Journal of Environmental Psychology 31, 336–343.

[8] Di Silvestre, M.L., Favuzza, S., Riva Sanseverino, E., Zizzo, G., 2018. How Decarbonization, Digitalization and Decentralization are changing key power infrastructures. Renewable and Sustainable Energy Reviews 93, 483–498. URL: https://linkinghub.elsevier.com/retrieve/pii/S1364032118304283, doi:10.1016/j.rser.2018.05.068.

Table 8: Parameter assumptions of generator and storage technologies [34, 21, 22, 18]

Technology	**Operation cost*** (€/MWh)	**Emission rate** (tCO2/MWh)	**Investment cost** (M€/MW)	**Cumulative cost reductions (%)**		
				2020	**2025**	**2030**
Offshore wind	22.80	0.02	3.65	0.05	0.10	0.20
Onshore wind	13.00	0.02	1.40	0.05	0.10	0.20
Solar PV	11.40	0.05	1.50	0.05	0.10	0.20
Biomass	54.00	0.23	2.25	0.02	0.05	0.10
Coal	34.00	0.93	0.90	0.05	0.08	0.10
Coal with CCS	38.00	0.19	4.40	0.05	0.08	0.10
CCGT	40.00	0.37	0.90	0.05	0.08	0.10
CCGT with CCS	55.00	0.04	2.40	0.05	0.08	0.10
Hydro	10.50	0.01	-	-	-	-
Gas oil fired	80.00	1.04	-	-	-	-
Heavy fuel oil fired	100.00	0.77	-	-	-	-
Storage	5.00	0.00	1.00	0.00	0.05	0.10

* *includes fuel costs but excludes emission costs.*

[9] EirGrid, 2016. All-Island TenYear Transmission Forecast Statement 2016. Technical Report. URL: http://www.eirgridgroup.com/site-files/library/EirGrid/All-Island-Ten-Year-Transmission-Forecast-Statement-2016.pdf.

[10] EirGrid, 2017. Tomorrow's Energy Scenarios 2017: Planning our Energy Future. Technical Report.

[11] Engelken, M., Römer, B., Drescher, M., Welpe, I., 2016. Transforming the energy system: Why municipalities strive for energy self-sufficiency. Energy Policy 98, 365–377.

[12] Fitiwi, D.Z., Lynch, M., Bertsch, V., 2019. Optimal development of electricity generation mix considering fossil fuel phase-out and strategic multi-area interconnection. Working Paper 616. ESRI Working Paper. URL: https://www.econstor.eu/handle/10419/193952.

[13] Guler, B., Çelebi, E., Nathwani, J., 2018. A 'Regional Energy Hub' for achieving a low-carbon energy transition. Energy Policy 113, 376–385. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301421517307188, doi:10.1016/j.enpol.2017.10.044.

[14] Guo, Y., Ru, P., Su, J., Anadon, L.D., 2015. Not in my backyard, but not far away from me: Local acceptance of wind power in china. Energy 82, 722–733.

[15] Harold, J., Bertsch, V., Lawrence, T., Hall, M., 2018. Drivers of people's preferences for spatial proximity to energy infrastructure technologies: a cross-country analysis. ESRI Working Paper No. 583 .

[16] Hicks, J., Ison, N., 2011. Community-owned renewable energy (cre): Opportunities for rural australia. Rural Society 20, 244–255.

[17] Hyland, M., Bertsch, V., 2018. The role of community involvement mechanisms in reducing resistance to energy infrastructure development. Ecological economics 146, 447–474.

[18] IEA, 2015. Projected Costs of Generating Electricity 2015 Edition , 215.

[19] Intergovernmental Panel on Climate Change, 2018. Global warming of 1.5°C. URL: http://www.ipcc.ch/report/sr15/. oCLC: 1056192590.

[20] of Ireland, G., 2018. Renewable Electricity Support Scheme (RESS). URL: https://irishsolarenergy.org/RESS%20Design%20Paper.pdf.

[21] IRENA, 2017. Renewable power generation costs in 2017. Technical Report.

[22] IRENA, 2019. Renewable Capacity Statistics 2019. Technical Report. URL: /publications/2019/Mar/Capacity-Statistics-2019.

[23] Lai, C.S., McCulloch, M.D., 2017. Levelized cost of electricity for solar photovoltaic and electrical energy storage. Applied Energy 190, 191–203. URL: //www.sciencedirect.com/science/article/pii/S030626191631933X, doi:10.1016/j.apenergy.2016.12.153.

[24] Leahy, E., Tol, R.S., 2011. An estimate of the value of lost load for ireland. Energy Policy 39, 1514–1520.

[25] ltd, R.a.M., 2019. Lithium-ion Battery Market - Growth, Trends, and Forecast (2019 - 2024). URL: https://www.researchandmarkets.com/reports/4847422/lithium-ion-battery-market-growth-trends-and.

[26] Manghani, R., McCarthy, R., 2017. GLOBAL ENERGY STORAGE: 2017 YEAR IN REVIEW AND 2018-2022 OUTLOOK , 13.

[27] McKenna, R., 2018. The double-edged sword of decentralized energy autonomy. Energy Policy 113, 747–750. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301421517307796, doi:10.1016/j.enpol.2017.11.033.

[28] Moroni, S., Alberti, V., Antoniucci, V., Bisello, A., 2019. Energy communities in the transition to a low-carbon future: A taxonomical approach and some policy dilemmas. Journal of Environmental Management 236, 45–53. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301479719301100, doi:10.1016/j.jenvman.2019.01.095.

[29] O'Dwyer, C., Ryan, L.L.B.., Flynn, D., 2017. Efficient large-scale energy storage dispatch: challenges in future high renewables systems. IEEE Transactions on Power Systems 32, 3439–3450. URL: https://researchrepository.ucd.ie/handle/10197/9103, doi:10.1109/TPWRS.2017.2656245.

[30] Quéré, C.L., Andrew, R.M., Friedlingstein, P., Sitch, S., Hauck, J., Pongratz, J., Pickers, P.A., Korsbakken, J.I., Peters, G.P., Canadell, J.G., Arneth, A., Arora, V.K., Barbero, L., Bastos, A., Bopp, L., Chevallier, F., Chini, L.P., Ciais, P., Doney, S.C., Gkritzalis, T., Goll, D.S., Harris, I., Haverd, V., Hoffman, F.M., Hoppema, M., Houghton, R.A., Hurtt, G., Ilyina, T., Jain, A.K., Johannessen, T., Jones, C.D., Kato, E., Keeling, R.F., Goldewijk, K.K., Landschützer, P., Lefèvre, N., Lienert, S., Liu, Z., Lombardozzi, D., Metzl, N., Munro, D.R., Nabel, J.E.M.S., Nakaoka, S.i., Neill, C., Olsen, A., Ono, T., Patra, P., Peregon, A., Peters, W., Peylin, P., Pfeil, B., Pierrot, D., Poulter, B., Rehder, G., Resplandy, L., Robertson, E., Rocher, M., Rödenbeck, C., Schuster, U., Schwinger, J., Séférian, R., Skjelvan, I., Steinhoff, T., Sutton, A., Tans, P.P., Tian, H., Tilbrook, B., Tubiello, F.N., Laan-Luijkx, I.T.v.d., Werf, G.R.v.d., Viovy, N., Walker, A.P., Wiltshire, A.J., Wright, R., Zaehle, S., Zheng, B., 2018. Global Carbon Budget 2018. Earth System Science Data 10, 2141–2194. URL: https://www.earth-syst-sci-data.net/10/2141/2018/, doi:https://doi.org/10.5194/essd-10-2141-2018.

[31] Rae, C., Bradley, F., 2012. Energy autonomy in sustainable communities—A review of key issues. Renewable and Sustainable Energy Reviews 16, 6497–6506. URL: https://linkinghub.elsevier.com/retrieve/pii/S1364032112004716, doi:10.1016/j.rser.2012.08.002.

[32] Santos, S.F., Fitiwi, D.Z., Cruz, M.R.M., Cabrita, C.M.P., Catalão, J.P.S., 2017. Impacts of optimal energy storage deployment and network reconfiguration on renewable integration level in distribution systems. Applied Energy 185, Part 1, 44–55. URL: http://www.sciencedirect.com/science/article/pii/S0306261916314970, doi:10.1016/j.apenergy.2016.10.053.

[33] Schumacher, K., Krones, F., McKenna, R., Schultmann, F., 2019. Public acceptance of renewable energies and energy autonomy: A comparative study in the French, German and Swiss Upper Rhine region. Energy Policy 126, 315–332. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301421518307614, doi:10.1016/j.enpol.2018.11.032.

[34] SEAI, 2016. Energy-Related Emissions in Ireland: CO2 Emissions from Fuel Combustion.

[35] SONI, E.a., 2010. All-Island TSO Facilitation of Renewables Studies. Technical Report. URL: http://www.eirgridgroup.com/site-files/library/EirGrid/Facilitation-of-Renewables-Report.pdf.

[36] Tracker, C., 2018. EU carbon prices could double by 2021 and quadruple by 2030. URL: https://www.carbontracker.org/eu-carbon-prices-could-double-by-2021-and-quadruple-by-2030/.

[37] Weinand, J., McKenna, R., Fichtner, W., 2019. Developing a municipality typology for modelling decentralised energy systems. Utilities Policy 57, 75–96. URL: https://linkinghub.elsevier.com/retrieve/pii/S095717871930013X, doi:10.1016/j.jup.2019.02.003.

[38] Woodmac, 2019. Global energy storage outlook 2019. URL: https://www.woodmac.com/reports/power-markets-global-energy-storage-outlook-2019-295618.

[39] Yu, H.J.J., 2018. A prospective economic assessment of residential PV self-consumption with batteries and its systemic effects: The French case in 2030. Energy Policy 113, 673–687. URL: https://linkinghub.elsevier.com/retrieve/pii/S0301421517307437, doi:10.1016/j.enpol.2017.11.005.

[40] Zakeri, B., Syri, S., 2015. Electrical energy storage systems: A comparative life cycle cost analysis. Renewable and Sustainable Energy Reviews 42, 569–596. URL: http://www.sciencedirect.com/science/article/pii/S1364032114008284, doi:10.1016/j.rser.2014.10.011. 00039.

[41] Zoellner, J., Schweizer-Ries, P., Wemheuer, C., 2008. Public acceptance of renewable energies: Results from case studies in germany. Energy policy 36, 4136–4141.