Small wind generation in Northern Ireland

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Summary

1. In 2010 the rest of the UK excluding Northern Ireland implemented a new scheme based on Feed-In Tariffs (FIT) as the primary form of support for small scale renewable generation, while Northern Ireland continued with a modified version of the Renewables Obligation (NIRO). Initially, the level of subsidy was similar under both schemes, but the subsidy for small wind turbines (less than 250 kW) in Northern Ireland remained high from 2014 onwards whereas gradual and then large reductions in subsidy were implemented in the rest of the UK.
2. In 2014-15 the subsidy premium for small wind turbines in Northern Ireland was 13% of the basic FIT subsidy in the rest of the UK. This premium had increased to 376% in 2017-18 when the NIRO scheme was closed. This generosity prompted a surge in the registration of small turbines under the NIRO scheme from 2016 to 2018 at a time when the number of new registrations under the FIT scheme was falling sharply in the rest of the UK.
3. In a report produced for RenewableNI, KPMG have argued that the NIRO scheme offered a return for the average turbine in the size category from 200 kW to 250 kW that was consistent with the target return set by the government. This argument is based on flawed statistical and mathematical assumptions. Further, it neglects the large dispersion of outcomes for different turbines – with a few duds and a larger number of very lucrative projects.
4. Using the published accounts for operators of small wind turbines in Northern Ireland, financial information for wind operators in the UK and actual output data, I have calculated the payback period (the time required to recover the initial investment) for a large sample of 200-250 kW turbines. This gives a much fuller picture than the KPMG analysis.
5. From my analysis, the capital and operating costs for the majority of small wind turbines in Northern Ireland are significantly below KPMG's average figures while the load factors are significantly higher. As a consequence, 50% of wind turbines would be expected to recover their initial outlay within 6 to 7 years, which is a very good return. There is a tail of very poor investments which have payback periods of greater than 12 years due to either high costs and/or poor wind conditions. These projects should never have been built and highlights the risks to unsophisticated investors of trying to take advantage of generous subsidies.
6. The average payment for small wind turbines above that paid to larger wind farms was about £82,000 per year per turbine at 2016-17 prices. This may seem modest but it amounts to £43 million per year in aggregate. Had the cost of these subsidies fallen on households in Northern Ireland the cost would be £88 per household per year or about 15% of the average electricity

bill. Because the ROC payments are adjusted by the RPI rather than the Consumer Price Index the burden of the excess subsidies to small wind turbines will increase over time.

7. The wider lesson that the Public Accounts Committee could draw from this example concerns the ease with which an apparently modest subsidy turned into an escalating drain on public resources because of a failure to keep its impact under review. The UK Government recognized the rapid growth in commitments under the FIT scheme. It responded by (a) reducing the generosity of the scheme and (b) imposing caps on total commitments. The Northern Ireland Executive failed to follow either step, so the overall cost of the scheme was only limited by the termination of the closure of the Renewables Obligation by the UK Government.

8. The burden of subsidies for small wind turbines is particularly egregious because of the very high cost incurred to reduce carbon emissions - an average of £504 per tonne of CO_2 saved, well in excess of even higher estimates of the Social Cost of Carbon. Taxpayers and the general public can reasonably insist that policies to lower CO_2 emissions should be subject to a test of value for money, and that the cure offered is not worse than the disease. This might be achieved by requiring the Executive to submit an annual report to the Assembly detailing the cost per tonne of CO_2 saved in the last fiscal year for all policies that have a reduction in CO_2 emissions as a primary or secondary objective.

Evidence

This paper extends the analysis presented in the earlier Renewable Energy Foundation (REF) blog, "*Extreme Subsidies to Small Wind Farms in Northern Ireland: A Bureaucratic Oversight*",[1] published on 24 September 2020. It is prompted by claims made in a study by KPMG for RenewableNI entitled '*An economic review of small scale wind in Northern Ireland'* (January 2021).

The headline claim in the KPMG study is that:

> "The average small-scale wind turbine in NI can expect to achieve an annual return (IRR) of 9.7%. This is broadly in line with the Government's target return of 10% and within the expected range of 8% - 12%."

Based on this claim, KPMG and RenewableNI argue that the terms of the Northern Ireland Renewable Obligation (NIRO) subsidy which allocated 4 Renewables Obligation Certificates (ROCs) per MWh from small scale wind generation were not overly generous.

To provide the context, the Feed-In Tariff (FIT) scheme was introduced as the primary form of support for small-scale forms of renewable generation in 2010 for the rest of the UK (RUK) excluding Northern Ireland. A small number of wind projects reported as being commissioned prior to 2010 were registered under the scheme. For practical purposes the FIT scheme took off in 2011 as only 27 wind projects of all sizes were registered under the scheme up to the end of 2010 while 84 wind projects were registered in 2011. FIT tariffs for small wind turbines (100 kW to 500 kW) were held

[1] https://www.ref.org.uk/ref-blog/362-extreme-subsidies-to-small-wind-farms-in-northern-ireland-a-bureaucratic-oversight

constant in real terms – using the December RPI for price adjustments – from 2010-11 to 2012-13. From 2013-14 onwards FIT tariffs for small wind turbines were reduced, initially in small steps but with larger reductions in each of years from 2015-16 to 2017-18.

The FIT scheme was not introduced in Northern Ireland but the rules for the Northern Ireland Renewables Obligation (NIRO) were altered in 2010. The new regime awarded 4 ROCs per MWh of output for wind turbines of up to 250 kW and 1 ROC per MWh of output for wind turbines or projects with a capacity of 250 kW to 5 MW. This structure of incentives remained in place until the closure of the NIRO scheme, nominally in 2017 but practically in 2018. The large difference between 4 ROCs and 1 ROC per unit of output provided a large incentive to install wind turbines of less than 250 kW.

In the first four years of the FIT scheme the effective revenues per MWh for small wind turbines registered under NIRO and FIT schemes were similar.[2] Variations in the wholesale market price and the ROC recycle value determined which of the NIRO or FIT schemes offered a higher value of effective revenue per MWh. However, from 2014-15 onwards the NIRO scheme was clearly more generous than the FIT scheme. In April 2017 the NIRO effective revenue was £245.20 per MWh while the FIT effective revenue was 82.50 per MWh at current prices, so the effective revenue per MWh of output for a 250 kW turbine in Northern Ireland was nearly three times the equivalent value in RUK.

Table 1 - Time profile of new wind projects registered under the RO and FIT schemes

Year of completion	Turbines 50-250 kW			Turbines > 250 kW		
	RO scheme		FIT scheme	RO scheme		FIT scheme
	Northern Ireland	Rest of UK	Rest of UK	Northern Ireland	Rest of UK	Rest of UK
Up to 2008	3	11	2	25	186	0
2009	4	3	3	2	27	6
2010	13	0	12	2	29	4
2011	12	0	55	4	23	29
2012	36	0	339	2	29	70
2013	53	0	151	3	68	67
2014	115	0	349	4	28	237
2015	95	0	234	3	29	227
2016	170	0	110	7	57	138
2017	234	0	6	16	43	29
2018	47	1	2	5	11	11
2019	1	0	0	0	0	8
2020	0	0	1	0	0	1

Source: Author's calculations using the Ofgem ROC & FIT Registers.

[2] Under the NIRO scheme the effective revenue per MWh is the sum of the wholesale price plus 4 times the ROC buyout price plus 4 times the value of recycled buyout and late payment revenues per ROC (the ROC recycle value). Under the FIT scheme the effective per MWh is the sum of the FIT tariff rate plus the FIT export rate since power from 250 kW turbines is almost entirely exported to the grid.

The generosity – or otherwise – of the incentives offered for generation from small wind turbines is clearly reflected in the pattern of new registrations under the various schemes shown in Table 1. In RUK the potential revenues from small turbines under the FIT scheme were particularly attractive in the early years of the scheme, so the numbers of new registrations each year were high up to 2015, but then fell off quickly. In contrast the number of new registrations under the NIRO scheme increased more gradually up to 2015 but peaked in 2016 and 2017, when the potential revenues were much larger in Northern Ireland than in RUK. The key role of generous subsidies in underpinning new registrations is reinforced by noting that nearly 90% of the turbines of more than 250 kW registered under the FIT scheme in RUK fell in the size range from 250 kW to 500 kW. These received the same FIT tariffs as turbines in the range from 100 kW to 500 kW up to 2016.

Overall, the profiles of turbine registrations under the RO and FIT schemes indicate a slow initial response to the incentives offered by the effective tariffs with a rapid acceleration when the potential returns on offer are understood by more developers and investors. Policymakers in RUK recognised the consequences of generous FIT support and adopted a phased policy of reducing this support, despite strong objections from developers. However, policymakers in Northern Ireland did not follow this path and, as a consequence, investment interest switched in 2015-16 from FIT-eligible generators in RUK to NIRO-eligible generator in Northern Ireland. It is likely that the rapid growth in the number of small turbines in Northern Ireland would have continued after 2017 but for the full closure of the Renewables Obligation scheme. This was prompted by broader concerns about the burden on electricity customers of covering the future subsidies that had been promised to renewable generators.

Turning to the details of the KPMG study, it has to be said at the outset that several of the claims in the study are undermined by elementary statistical errors. KPMG’s chosen method of analysis uses average values for parameters such as capital and operating costs, load factors, and others, to calculate an average rate of return. This method can only be correct if the rate of return were a linear function of the parameters (which it is not) **and** the distributions of the parameters were symmetric and uncorrelated (which they are not).

In any case, the average rate of return provides only limited information for the purpose of policy analysis. To illustrate the point, consider two groups of 10 projects each, A and B, which are promoted by different policy interventions. In group A all projects earn a return of 10% per year. In group B, five projects earn a return of 30% per year and five earn a negative return of -10% per year. The average return is 10% per year for each of the two groups, but would any reasonable person draw the conclusion that the two groups of projects are equally good or bad in policy terms? Of course not, because the distribution of returns across projects is critical to our understanding and evaluation of the outcomes of the respective policies. A method that obscures a major difference between the policy impacts, such as that in the example above, is clearly unsatisfactory, but that is what KPMG has done.

For clarity, KPMG’s reported Internal Rate of Return is a nominal, post-tax, return assuming no debt finance and an inflation rate of 2.5% per year. As is often the case, the financial model, which KPMG have not published, uses many detailed assumptions whose basis can be challenged but which make little real difference to the results. However, amongst these there is one assumption that is patently inconsistent with much of the discussion in the study. The model assumes a fixed operating life of 20 years in assessing the rate of return. At the same time, the study reports that 37% of small turbines were reconditioned models, and KPMG examines the return on repowering an existing site using a down-rated turbine. Experience elsewhere in the UK suggests that very few wind farms operate for 20 years before repowering and reconditioned models are unlikely to operate satisfactorily for that length of time.

This paper takes a different approach to that adopted by KPMG, and suggests that a better way of thinking about the return on small wind turbines is to calculate the payback period for an investment. The analysis focuses specifically on the payback period for an investment in a small (200-250 kW) wind turbine commissioned in 2017, the peak year for projects supported by NIRO before the scheme was closed. It is true that the payback period does not take account of discounting, i.e. the time value of money. On the other hand it does not force the analyst to assume a fixed life for the investment, and it gives an intuitive sense of the degree of risk involved in the investment were the operating life or performance to be worse than expected. Under the assumptions made by KPMG I calculate that the payback period was about 8.2 years in cash terms. This is not especially short and is broadly consistent with the cut-off values of 8 to 10 years that many potential investors might apply.

It is useful to get a feeling for the sensitivity of the rate of return to the key assumptions.

- KPMG use a relatively low mean load factor of 22% in their analysis, while the actual mean load factor for small wind turbines in Northern Ireland from 2016 to 2020 was just over 25%. Increasing the expected load factor to 25% reduces the payback period to 6.9 years.
- We will see that the average capital cost used by KPMG seems to be in the upper part of the distribution. Lowering the capital cost by 25% reduces the payback period to 6.3 years.
- Similarly, KPMG's expected operating cost is high. Reducing the assumed annual operating cost by 25% reduces the payback period to 7.3 years.

Combining all three of the alternative assumptions reduces the payback period to 4.8 years, which is a rapid payback for investments with an expected life of 20 years. Clearly, the rate of return is very sensitive to the assumptions made, and it is not difficult to reach a different conclusion from that reported by KPMG.

The average capital and operating costs used by KPMG are derived from a database of information on small scale wind turbines apparently compiled by KPMG themselves. The database and the assumptions used in compiling it are not publicly available, so comparisons with other estimates must be qualified by the warning that it is not possible to ensure that like is being compared with like.

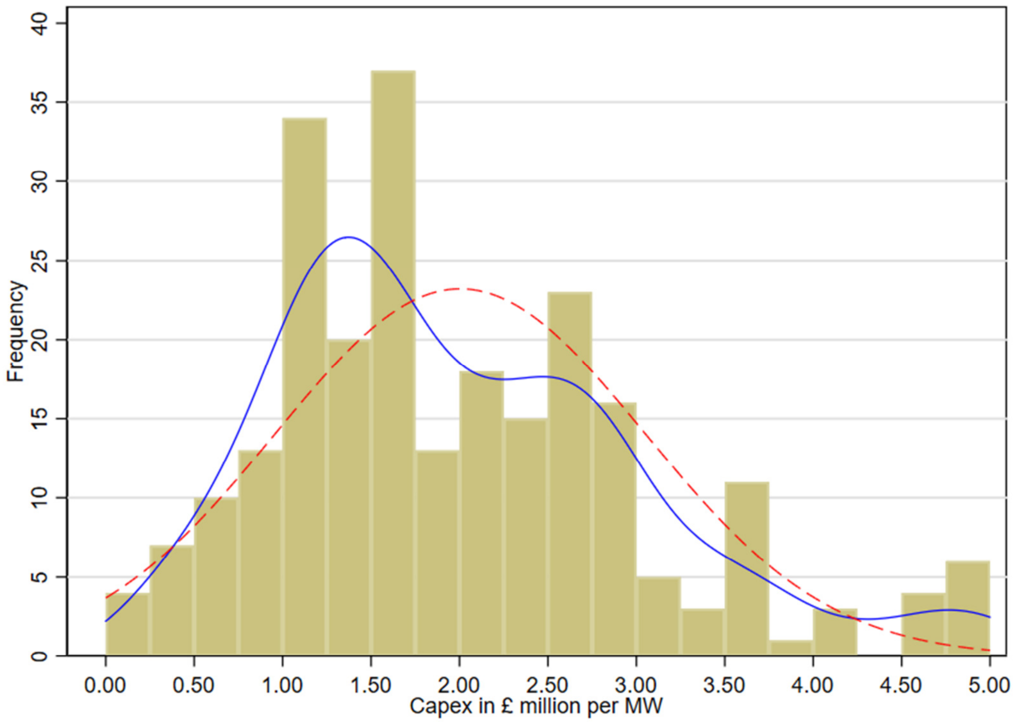
My analysis of the cost of building and operating medium and large onshore wind farms in the UK, published by REF in November 2020 as Volume 1 of *Wind Power Economics: Rhetoric and Reality,*[3]

[3] https://www.ref.org.uk/ref-blog/365-wind-power-economics-rhetoric-and-reality

implies an average capital cost of £2.21 million per MW capacity for 500 kW turbines (the smallest size in the sample) in Northern Ireland in 2016. The KPMG average is £2.55 million per MW, which is about 15% higher. This difference could be a consequence of the cost penalty for smaller turbines and developing sites for a single turbine.

To validate the capital costs I have examined the published accounts of a random sample of 122 out of a total of 339 companies that operate turbines registered under NIRO. The sample excludes organisations or individuals who do not file accounts or which operate wind farms outside Northern Ireland. Using the approach described in my UK study I have extracted the capital costs incurred by the operators and converted these to a standardised measure of £ per MW capacity at 2017 prices.[4] The distribution of capital cost per turbine is shown in Figure 1.

Figure 1 - Distribution of capital costs for onshore wind in Northern Ireland.



Source: Author's calculations using company accounts.

In this figure the dashed red line shows a normal distribution fitted to the data while the solid blue line shows a smoothed curve using a standard kernel distribution. The key point is that the

[4] The potential errors in the dataset are larger than in the database covering medium and large wind farms in the UK. Most of the companies choose to submit micro entity accounts which consist of a balance sheet plus (in some cases) notes, so detailed information on tangible fixed assets is usually not given. Using the accounts for a sequence of years it is possible to derive the value of fixed assets at the end of the year in which the wind farm is commissioned. This procedure may *over*state the capital cost of the wind turbine(s) because of the inclusion of fixed assets other than the turbine(s) – e.g. land or unrelated buildings – or *under*state it because of the way depreciation is applied. However, the distribution of capital costs should be unbiased.

distribution of capital costs is not symmetric, and that the normal distribution is a very poor fit. The median and modal (most frequent) values are well below the average, so assuming a symmetric distribution – as the KPMG procedure requires – is misleading.

The median capital cost is £1.75 million per MW of capacity while the average capital cost is £2 million per MW. Both figures are well below the typical or average capital cost of used by KPMG. The dispersion of capital costs is high as illustrated by the inter-quartile range, i.e. the range which covers 50% of all cases from the 25th percentile to the 75th percentile, which extends from £1.18 million per MW to £2.67 million per MW. For 10% of all turbines the capital cost was less than £0.88 million per MW, while another 10% of all turbines had a capital cost greater than £3.60 million per MW. With such variability in capital cost it is difficult to design a subsidy regime that does not provide excessive support for a substantial fraction of all turbines.

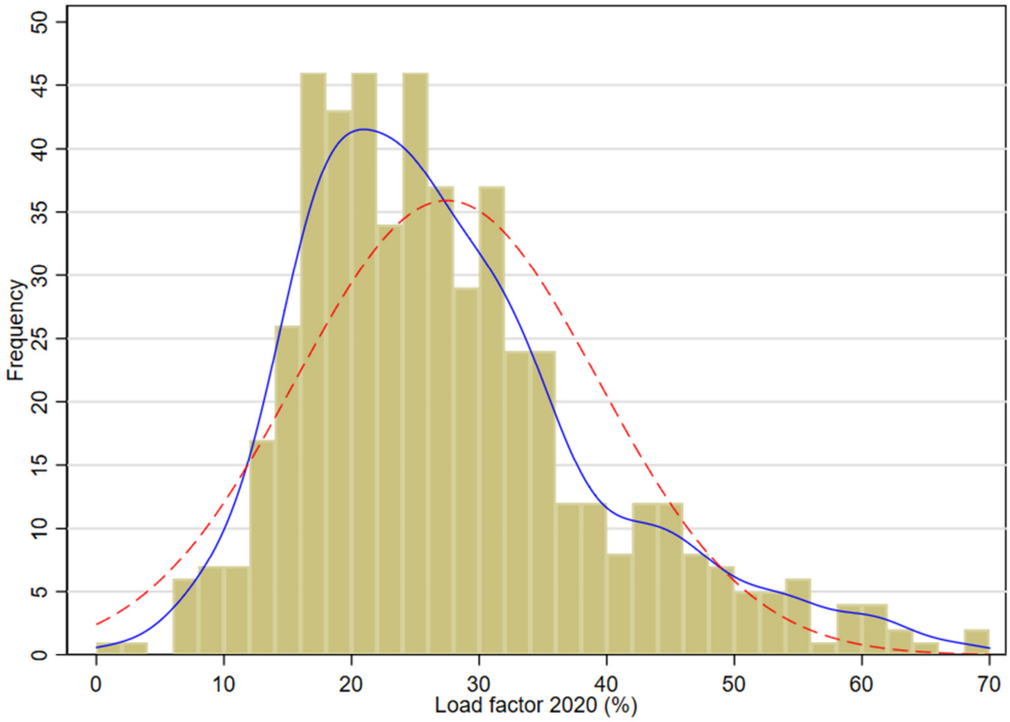
The number of sets of accounts with usable data on operating costs is too small to draw any conclusion other than that the dispersion of operating costs seems likely to be high with a range from £93,000 per MW to £398,000 per MW (all at 2017 prices) across eighteen annual observations for six operators. KPMG assume an average operating cost of just under £160,000 per MW at 2017 prices, which lies between the median and average values for the accounts data.

Operating costs of this magnitude are considerably higher than those implied by my analysis of medium and large onshore wind farms in the UK. For turbines in the size category from 0.5 to 1 MW the estimated operating costs for a wind farm commissioned in 2016 are about £87,000 per MW at age 1 rising to £129,000 per MW at age 15. Operating costs per MW increase by about 15% for each halving in turbine size, so the UK analysis implies operating costs of about £110,000 per MW at age 1 rising to £165,00 per MW at age 15. Note that the KPMG analysis takes no account of the increase in average operating costs with age, even though this tendency is very clear in the UK data.

The third main assumption in the financial model relates to the average performance of wind turbines as measured by either the load or capacity factor or the average output per year in MWh. Figure 2 shows the distribution of the load factors in 2020 for 532 turbines in Northern Ireland with a capacity of 200 kW to 250 kW registered under NIRO. The median load factor in 2020 was 25% for this population and the mean load factor was 27.5%. The distribution has a strong positive skew with 1% of turbines reporting load factors of greater than 60% and 10% of turbines reporting load factors of greater than 44%.

Such high load factors are almost certainly the consequence of down-rating turbine capacity to take advantage of the high level of subsidies available for turbines of less than 250 kW. Wind speeds in 2020 appear to have been unusually favourable, so that the average load factor in 2020 was more than 2 percentage points higher than the lifetime average load factor of 25.2% for the same population of turbines. Even so there is no reason to believe that fully rated small turbines would achieve annual load factors in excess of 40% in normal operating conditions, so the results highlight the effects of perverse incentives established by the subsidy regime.

Figure 2 – Distribution of load factors in 2020 for 532 turbines in Northern Ireland with a capacity of 200 kW to 250 kW registered under NIRO.

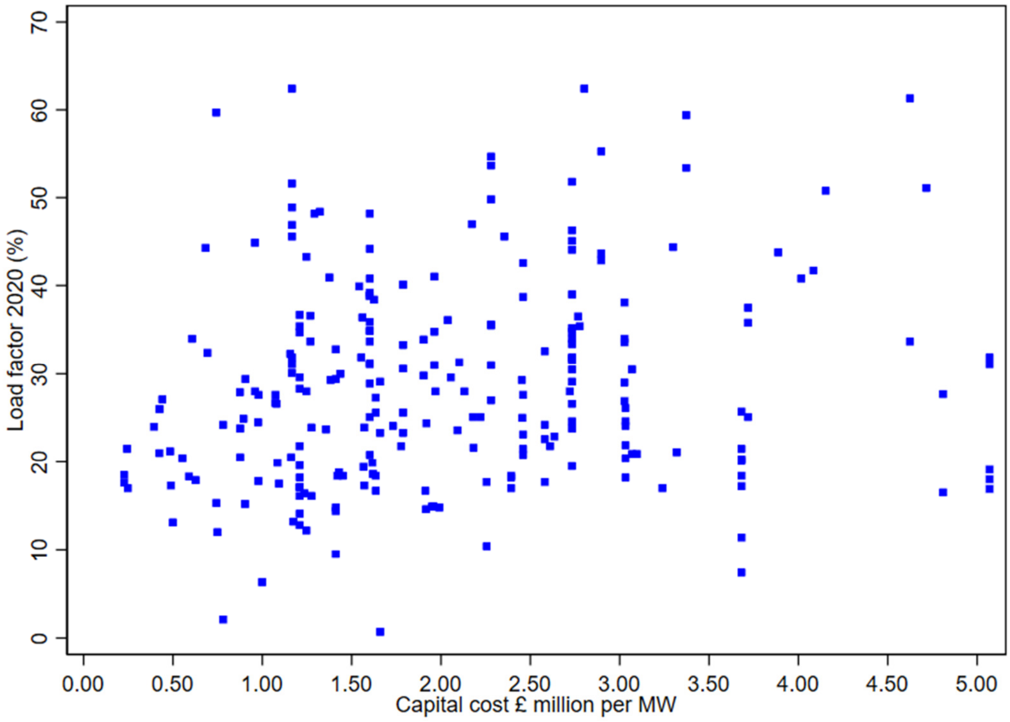


Source: Author's calculations using the Ofgem ROC Register.

From an investment perspective it is possible that turbines with high capital costs have an above-average load factor to compensate for the large initial outlay. Figure 3 shows a scatter plot of capital cost versus load factor in 2020. There is a very weak positive correlation between capital cost and load factor but the wide scatter of load factors for, say, a capital cost in the range of £1.00 to £1.50 million per MW indicates that the associated payback periods are likely to be distributed over a large range.

By combining the actual data on capital costs from company accounts and the mean annual output calculated from the ROC register with the parameter values adopted by KPMG I have calculated the payback period for a total of 243 turbines for which the necessary information is available. I will refer to this set of parameters as the base assumptions since they match the KPMG analysis with the exception of the added information on actual capital costs and load factors.

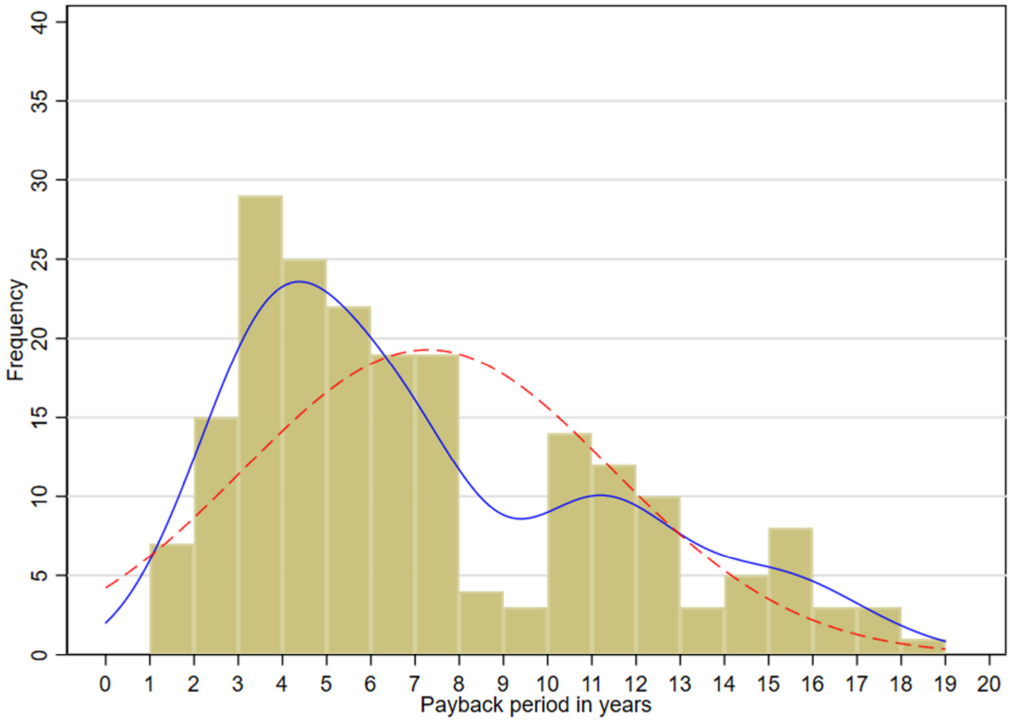
Figure 3 – Capital cost vs load factor in 2020 for onshore wind in Northern Ireland.



Source: Author's calculations using company accounts and the Ofgem ROC Register.

Under the base assumptions, 41 out of 243 turbines will never recover their capital cost. For convenience I have assigned a payback period of 25 years to these turbines but the statistics for the distributions of payback periods refer to the remaining 202 turbines. Figure 4 shows a histogram of the payback periods with a fitted normal distribution and the smoothed kernel distribution as in previous graphs.

Figure 4 – Distribution of payback periods under base assumptions.



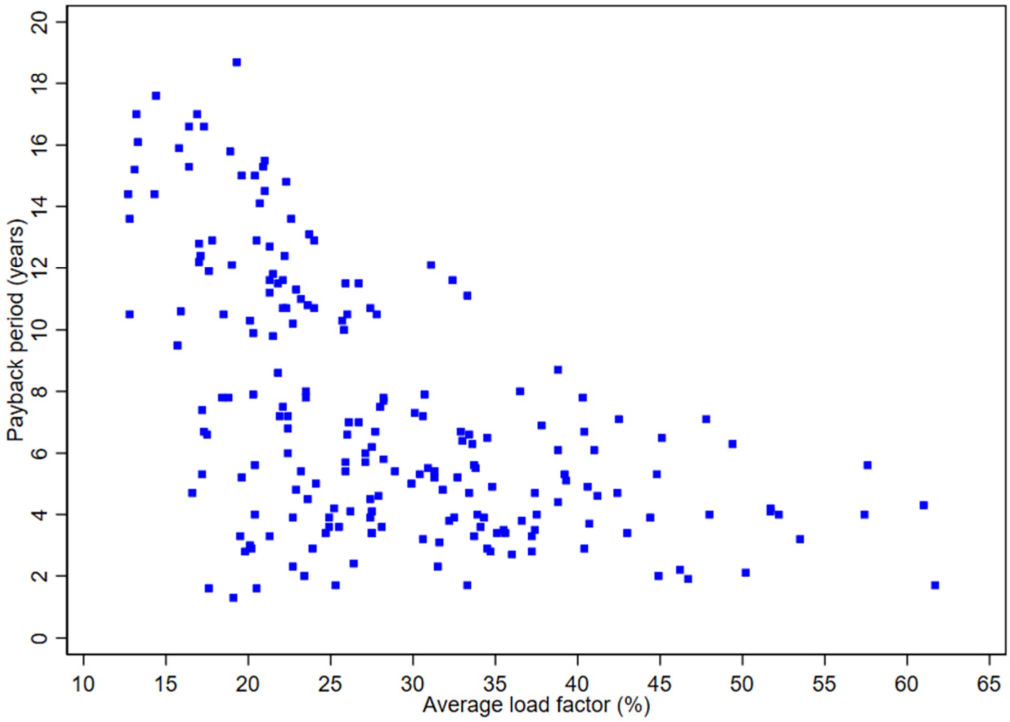
Source: Author's calculations.

Once again, the distribution is strongly skewed with a median payback period of 6.1 years and a mean payback of 7.3 years. The lower quartile is 3.9 years, so that about 25% of the turbines will recover their original investment cost in less than 4 years.

At the other end of the distribution the upper quartile is 10.6 years. The cut-off for investment in small scale turbines will vary according to perceived risk and alternative investment opportunities, but a payback period of 10 years was likely to be regarded as satisfactory in 2017 and one of 12 years may have been acceptable.

Figure 5 charts the average load factor vs payback period under base assumption, and shows a clear correlation between mean load factor and the payback period. There is still significant variation in the payback periods for turbines with similar load factors, especially in the range 20%–25%. Still, it is clear that better sites and down-rated turbines lead to higher profitability and returns that are greater than required to ensure investment.

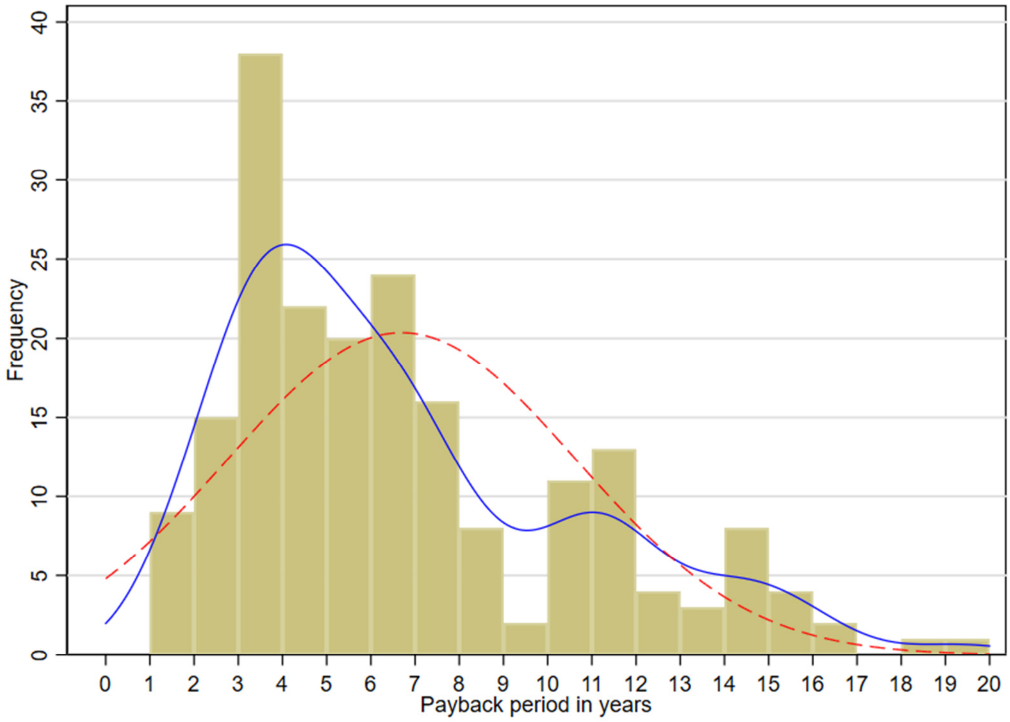
Figure 5 – Average load factor vs payback period under base assumption.



Source: Author's calculations.

The key parameter for which some departure from the base assumptions seems clearly warranted is the starting level and evolution of operating costs. Figure 6 shows the distribution of payback periods if operating costs follow the path discussed earlier – increasing from £110,000 per MW at age 1 to £165,000 per MW at age fifteen. Since the initial level of operating costs is well below that in the base assumptions, the overall distribution of payback periods is shifted to the left, i.e. a reduction in the payback period for all turbines. In addition, in this case all of the turbines recover their initial investment within 20 years. The median payback period falls from 7.2 years under the base assumptions (for all 243 turbines including those which never recover their capital costs) to 6.6 years. While this reduction seems modest, it reflects a substantial increase in the overall profitability of an investment in small scale wind turbines.

Figure 6 – Distribution of payback periods under alternative operating costs.



Source: Author's calculations.

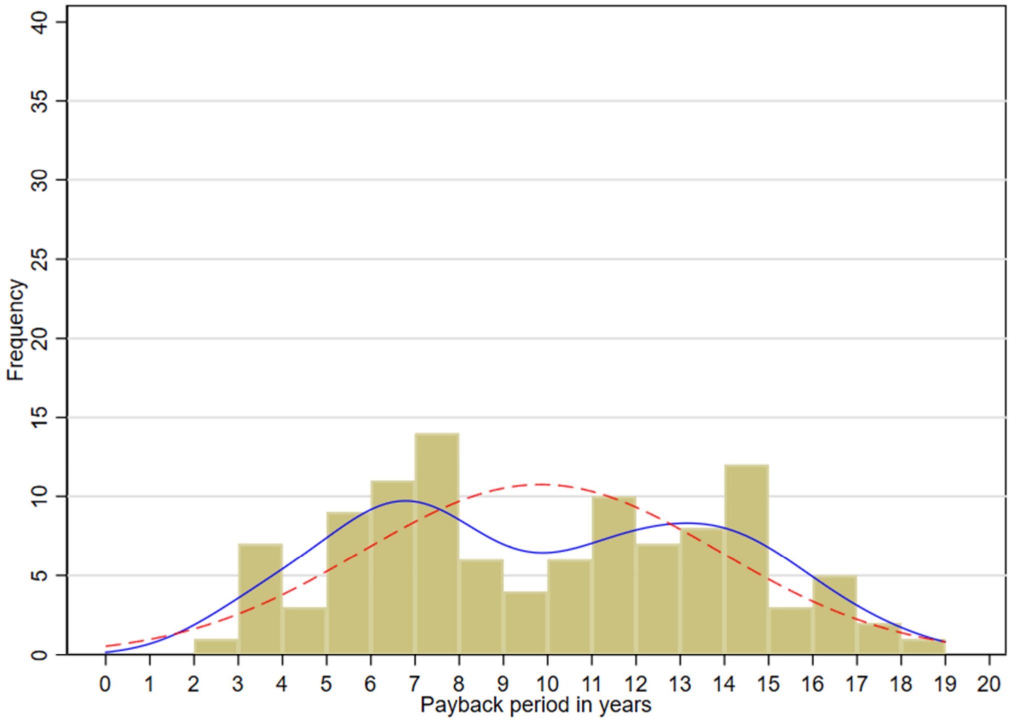
As the final step in this analysis I will examine two counterfactuals concerning the form and level of subsidies. Inevitably this raises the question of the interdependence of costs and subsidies. With lower or differently structured subsidies the operators of small wind turbines will have a stronger incentive to reduce both operating and capital costs. It seems especially likely that operators will not be willing to incur the relatively high operating costs which are reported for small wind turbines in Northern Ireland. Hence, I have assumed that operating costs in the two alternative subsidy scenarios correspond to the GB operating cost scenario discussed in the previous paragraph.

On that basis I have examined two alternative subsidy schemes:

- Alternative Subsidy 1: 2 ROCs per MWh
- Alternative Subsidy 2: GB Feed-in Tariff (FiT) scheme

The first of these scenarios – Alternative Subsidy 1 – is simple to model as the number of ROCs awarded per MWh of output is half of the number actually awarded up to 2017. The consequence of this change is that only 109 out of 243 turbines are able to recover their initial capital costs within 20 years. The distribution of payback periods for those turbines which are able to recover their costs is shown in Figure 7. Note that I have used the same vertical scale in this figure as that for Figure 6 to give a visual illustration of the differences between the two scenarios. Crucially, the distribution for Alternative Subsidy 1 is much flatter and the mode of the distribution is close to seven years as compared with four years in Figure 6.

Figure 7 – Distribution of payback periods under Alternative Subsidy 1: 2 ROCs per MWh.

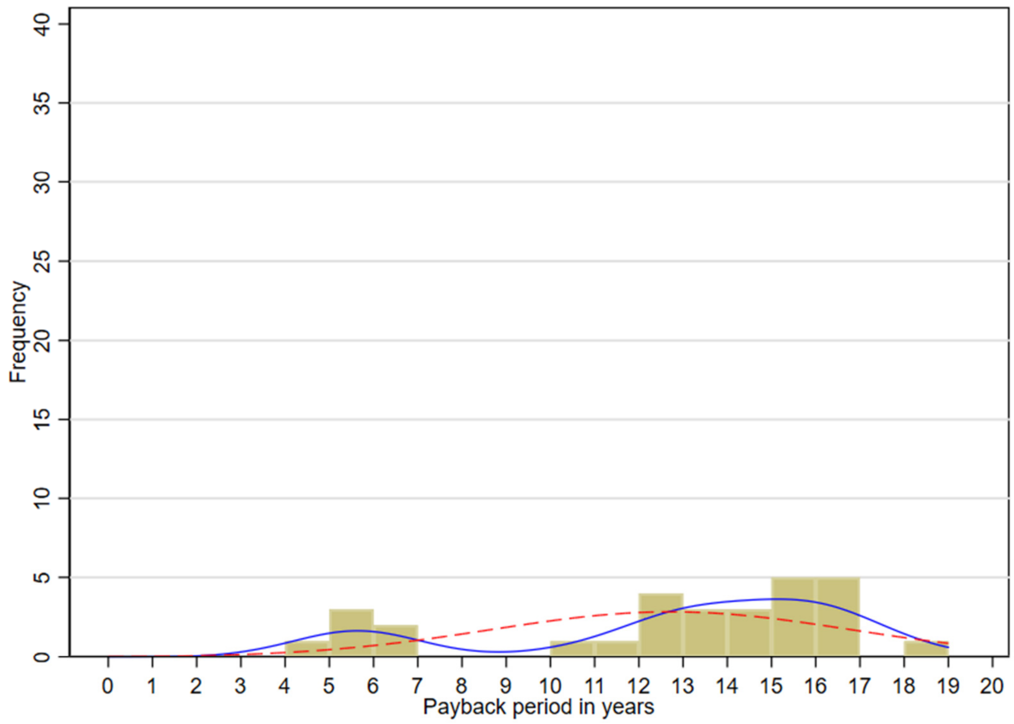


Source: Author's calculations.

Figure 8 shows the distribution of payback periods for Alternative Subsidy 2, i.e. assuming that the FIT scheme for the rest of the UK, had been implemented, and also assuming the lower operating costs as in the previous scenario. In this case only 29 out of 243 turbines recover their initial investment and 75% of those have payback periods of 12 years or more. For practical purposes almost no small turbines would have been installed if the FIT scheme had been adopted.

The central point is clear and highlights the key question that must be addressed. The subsidy scheme actually adopted in Northern Ireland, 4 ROCs/MWh, was exceptionally generous relative to the incentives to install small turbines in the rest of the UK. As a result, a large number of turbines were installed in Northern Ireland that would not have gone ahead elsewhere. If the goal of the policy was, somewhat cynically, to promote farm and small business diversification using funds provided by electricity consumers across the whole of the United Kingdom, then one might conclude that the policy was successful in those very narrow terms. However, that was not the ostensible purpose of the policy, which was to contribute to the mitigation of climate change by reducing the emissions of greenhouse gases.

Figure 8 – Distribution of payback periods for Alternative Subsidy 2: GB FiT payment.



Source: Author's calculations.

Viewed in the context of other policies to reduce carbon dioxide emissions the Northern Ireland small wind policy is a scandalous waste of money. The output from small wind turbines could have come from wind farms with medium or large wind turbines that in 2016/17 were entitled to 0.9 ROCs per MWh implying a subsidy for such generation of £43.10 per MWh at 2017 prices. In contrast a 250 kW turbine in Northern Ireland received a subsidy of £191.40 per MWh. Since system and other environmental costs for twenty separate 250 kW turbines are almost certainly considerably higher than for one 5 MW wind farm, it is hard to justify the difference in subsidy support.

We can go further. Additional output from small or medium wind turbines in Northern Ireland displaces generation from gas-fired plants either in the island of Ireland itself or in Great Britain (via the two interconnectors from Ireland to Great Britain). The carbon dioxide emission factor for gas plants in 2017 was approximately 0.38 tonnes of carbon dioxide equivalent (tCO_2e) per MWh of output. On this basis, the cost of reducing emissions was about £113/tCO_2e via ROC subsidies for medium and large wind farms but about £504 per MWh from small wind turbines in Northern Ireland. Paying such an amount to reduce emissions when a very similar policy would have a cost that is less than a quarter of the subsidies for Northern Ireland's small wind turbines is neither an efficient nor a reasonable policy choice.

One factor which contributes to the lack of attention given to such excessive subsidy payments is that the amounts involved per unit appear to be relatively modest. These are not 500 MW offshore wind farms receiving £375 million in guaranteed revenue under the Contracts for Difference (CfD) scheme. The average subsidy in excess of what have been paid on the standard basis of 0.9 ROCs per MWh is about £82,000 per turbine per year, while the excess subsidy relative to the FIT scheme is about £80,780 per turbine per year.

However, the amount of money at issue looks somewhat different when the subsidies of all such wind turbines in Northern Ireland are aggregated and set in the context of the province's electricity costs. There are 535 wind turbines registered for NIRO with a registered capacity of 200 to 250 kW. The total cost of the excess subsidy payments is about £43 million per year at 2016-17 prices, or £860 million over 20 years. The total number of households in Northern Ireland is a little under 490,000. If the excess NIRO subsidies for small wind turbines had been paid for by Northern Ireland households, then the average cost would have been about £88 per household per year. Since the average household electricity bill in 2019 was estimated to be £590 per year, the burden of excess subsidies for small wind turbines would have looked very different had the costs been covered fully by Northern Ireland electricity customers. It seems reasonable to conclude that had the Northern Ireland government been responsible for raising these funds domestically, and with full political accountability, they would have been more careful with the subsidy for small turbines.

There is a history in Northern Ireland and the rest of the UK of adopting and persisting with schemes that are justified on the grounds that they contribute to reducing CO_2 emissions but which prove to be either ineffective or very costly. Since the Public Accounts Committee's primary remit is to scrutinise the value for money of public spending, I would like to propose a simple measure that would enable the PAC to perform that function more effectively. This would be to require that the Northern Ireland Executive should present an annual report to the Assembly detailing the cost per tCO_2e saved in the previous fiscal year for all policies adopted, implemented or overseen by the Executive which have the reduction in emissions of CO_2 as a primary or a secondary objective. The calculation of the cost per tCO_2e saved is usually simple but in more complicated cases the calculations should be agreed with the Statistics Authority. The methodology applied should be published so that the public can have confidence in the results of the analysis.

10th April 2021