Electricity Market Reform

Analysis of policy options for DETI and NIAUR

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Final report

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Executive Summary

E.1 Context: Electricity Market Reform

The UK Government published its new Energy White Paper[1] in July following its Electricity Market Reform (EMR) consultation process. The White Paper sets out a package of reforms to the United Kingdom (UK) and Great Britain's (GB) electricity policy, including a new system of long-term contacts in the form of Feed-in Tariffs (FITs) with Contracts for Difference (CfD) which will replace the existing support mechanism for renewable electricity generation in GB (the Renewables Obligation (RO)).[2]

The White paper also highlights that it is likely an organisation (or organisations) at arm's length from Government will negotiate and administer the CfD FITs for GB. A decision on the roles and responsibilities of Government and those of the delivery institution (s), as well as more detail on the functions, contracting strategy and planning cycle of the CfD FIT policy, are expected to be set out around the turn of the year.

E.2 Purpose

Publication of the White Paper means that changes will be needed to the current renewable electricity support scheme for Northern Ireland (the NIRO), which were not explicitly set out within the White Paper. CEPA has been commissioned by DETI and NIAUR to look at the implications for Northern Ireland of DECC's EMR package, focusing on the implications of implementing a CfD FIT or Premium Feed-in Tariff (PFIT) in the Single Electricity Market (SEM). We have assessed a range of policy options through a combination of quantitative modelling and qualitative analysis.

E.3 Options to be considered

The high-level options for Northern Ireland that we have been asked to consider are as follows:

1. Continue with the NIRO as the sole support scheme for renewables indefinitely, even if the England and Wales RO closes to new applications from April 2017.
2. Continue with the NIRO indefinitely and introduce another support scheme alongside it.
3. Close the NIRO to new applications at the same time as the England and Wales RO, and introduce another support scheme to replace it.
4. Close the NIRO to new applications as soon as a new support scheme can be introduced to replace it.

[1] DECC (2011): 'Planning our electric future: a White Paper for secure, affordable and low-carbon electricity'

[2] The RO will close to new accreditations on 31 March 2017 and the Government will grandfather RO support for all technologies at the rate applicable on 31 March 2017.

These options involve both (i) the *structure* of the support arrangements in terms of the mechanism provided – particularly as regards whether the DECC proposals for GB can be paralleled for Northern Ireland - and the institutional arrangements needed to support it; and (ii) the issue of *who pays* for the given level of support – whether Northern Ireland electricity consumers alone, or whether such costs are socialised across the whole of the UK. Alternatives to the DECC proposals include the introduction of a PFIT or a structure of CfD FIT based more on that operating in the Republic of Ireland rather than on the structure being applied within GB[3].

However, even on an initial evaluation, Option (1) looks unattractive, both from an administrative feasibility and cost perspective. Moreover, Option (2) also looks unattractive, as it combines the downsides of running the NIRO indefinitely with the costs of running a new support scheme.

We would argue that the difference between options (3) and (4) is one of timing. The ambition to create a single EU electricity market[4] is the major driver here. A single market would link UK/ Ireland/ France electricity markets by the end of 2014. Even if this slips by a year or two, it might be expected to be firmly in place by 2017.

We would see the issue as being one of whether a new scheme should be introduced to a similar timetable as proposed by DECC (2014) or a less ambitious timetable aligned with the SEM's market integration project (we return to the issue of policy timing below).

Over and above this, there is the more detailed issue of the specific features and structure of the new support mechanism and the interaction with the SEM.

E.4 Design features of different support mechanisms

A starting point for understanding the differences between support mechanism is to understand the specific features of their design, the risks this gives rise to and how these risks might be mitigated. The appropriateness of a particular mechanisms can be driven by both *market requirements* as well as the requirements of the *types of technology* being supported.

Table E1 illustrates some of the specific support mechanism options, which include some of DECC's most recent proposals, as well as other mechanisms typically observed, including the REFIT[5], which operates within the Republic of Ireland.

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[3] Note that the *structure* of the support mechanism is a different issue to its *level*.

[4] Linked to the internal electricity market directive 2009/72/EC.

[5] Renewable Energy Feed in Tariff.

Table E1: Mechanism design features and resulting risks

Design features and resulting risks to generators	**Fixed FIT (REFIT)**	**Classic CfD FIT (GB – possibly for Nuclear baseload)**	**Metered CfD FIT (GB – for intermittent wind)**	**Premium FIT (GB – no longer recommended)**
Price	Fixed	Fixed (depending on design structure)	Fixed (depending on design structure)	Variable
Volume	Flexible	Fixed volume	Flexible	Flexible
Payment	Agreed strike price	Agreed strike price	Agreed strike price	Wholesale price plus subsidy
Market volume and trading risks	Out of the market	In the market	In the market	In the market
Balancing risk (post nomination)	None	Yes	Yes	Yes

Source: CEPA

As well as showing the economic characteristics of each support mechanism (e.g. FIT contract price and volume), Table E1 also illustrates the risks arising from the generators' potential "role in the market" in terms of whether they bear market volume and balancing risks. Both are important, as they influence market operation and investors' perception of market risk.[6]

Several of these risks already exist under the existing NIRO, which for a price (a discount to the revenues that they receive from suppliers) generators can mitigate through entering into negotiated power purchase agreements (PPA) or contractual arrangement with energy suppliers or another intermediary who might manage these risks for them (through the pool).

[6] Balancing risk – depending on market structure – can affect the generators' ability to sell power and the price (revenue) realised in the market. These risks depend on the structure of balancing and power sales in the wholesale electricity market structure in question. Balancing risks can be addressed differently according to support mechanism design and/or changes to market rules.

The REFIT – which from the point of view of the generator can be characterised as a Fixed FIT – allocates market and balancing risks to suppliers, through a standardised PPA, with the supplier receiving a contracted allowance to manage them.[7] In this case, suppliers are required to manage market revenues received across trading periods and the volatile nature of renewable output. The Fixed FIT provides a fixed predictable revenue stream for renewable generators.

Of the new options, it is the PFIT which most closely resembles the existing NIRO. It could operate in any future market structure by being delinked from the wholesale electricity price. Investors are comfortable with a fixed revenue stream which they know they can receive alongside wholesale market revenues (which are more risky).

However, an effective CfD FIT design structure should (in theory) be perceived more favourably by investors as it provides a more predictable revenue stream for generators. In comparison, under a PFIT policy generators bear wholesale electricity price risk, as currently under the NIRO. By providing a more predicable revenue stream, a CfD FIT could help to reduce risk and long term consumer costs through a slightly lower cost of capital.[8]

E.5: Implications of different market arrangements for the support mechanism

The proposals being developed by DECC are to deal with the specific requirements of the GB market. Thus, whilst having the same support mechanism structure as GB appears attractive, the practical implications of applying it within the SEM need to be taken into account. In evaluating the practicability of different support mechanism for Northern Ireland it is also essential that both *current* and *future* market arrangements are taken into account.

At the moment, the SEM is quite different to the British Electricity Trading and Transmission Arrangements (BETTA) operating in GB, which is a much less liquid, so called "net market", with most electricity being sold through bi-lateral contracts (PPAs) between generators and suppliers (see Table E2 overleaf). The SEM in contrast is a gross mandatory market with a separate energy component and a capacity payment, central dispatch and intermittent generation (such as wind) treated with *priority dispatch*.[9]

Under the SEM Trading and Settlement Code a renewable generator can sell electricity either directly into the pool or enter into a PPA with a supplier or intermediary to sell the energy on its behalf. While a generator (participating) in the SEM does not face balancing risks in the same way as a GB generator, it will still need to manage its output and the requirements from participating in the market. Market risks and requirements from participating in the market may differ by renewable generation technology.

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[7] Suppliers receive a balancing payment – 15% of the large wind category tariff – to cover the cost of managing the short term variable production of wind energy.

[8] See CEPA (2011): 'Note on the impacts of the CfD FIT support package on costs and availability of capital'

[9] See NIAUR & CER, July 2009, *Principles of Dispatch and the Design of the Market Schedule in the Trading & Settlement Code – A Consultation Paper*

Table E2: Comparison of SEM and BETTA wholesale market design

Issue	SEM	BETTA
Market structure	Gross mandatory pool	Bilateral contracts; net-market
Payment structure	Separate energy and capacity market	Energy only market
Dispatch	Central (priority) dispatch	Self-dispatch
Balancing	Central	Balancing market

Source: CEPA

The market differences between GB and the SEM are more important in developing a Fixed FIT or the CfD FIT approach than in the case of the NIRO or a PFIT, as a FIT CfD approach, in particular, is much more embedded within the electricity market, rather than being essentially an additional income stream that is added to that of the wholesale revenues.

To begin with, this means that the reference price for a CfD FIT policy will need to be determined differently within the SEM to what it is in GB. Currently, the reference price proposed for GB (in the case of intermittent generation) is a day-ahead price sourced from the best representation of day-ahead prices at the time the CfD FIT is allocated. The aim of the proposed reference price in GB is to try and keep generators within the already illiquid GB wholesale market. In contrast, in the current market a CfD FIT in the SEM would need to reference (in some form) the single System Marginal Price (SMP) for the SEM.

In itself, such a different reference price would not appear to be an insurmountable hurdle. Whereas, a concern with introducing a CfD FIT within the GB market is the basis risk that this gives rise to, generators within Northern Ireland might not face such a basis risk with the SEM. The central SMP and the balancing arrangements for the market, mean that in the SEM, there may not be the additional uncertainty through the introduction of basis risk which, for example, might be introduced through a CfD FIT policy based on an "average" wholesale traded price index as has been proposed in GB.[10]

From this perspective, a CfD FIT policy may actually fit better within the SEM than it does in the BETTA, at least from those considering investing in generation in Northern Ireland. However, at a more detailed level there may still be risks that we have not currently identified. Indeed, these might only be identified when new CfD FIT contracts are developed for generators in Northern Ireland, which cannot be based entirely on those developed for GB, due to the different market arrangements that need to be taken account of.[11] [12]

[10] Generators in the SEM would receive wholesale energy payments while an ex-post outturn SMP would provide a clear reference for settlement of the CfD FIT.

[11] For example, the limited number of market participants who we contacted during the course of our project highlighted future issues around compensation for constraints and curtailment of wind generation and the appropriate contract volume (should payment be based on metered volume or firm volume (i.e. availability))? We have not been able to explore the materiality of these issues further within the scope of our study.

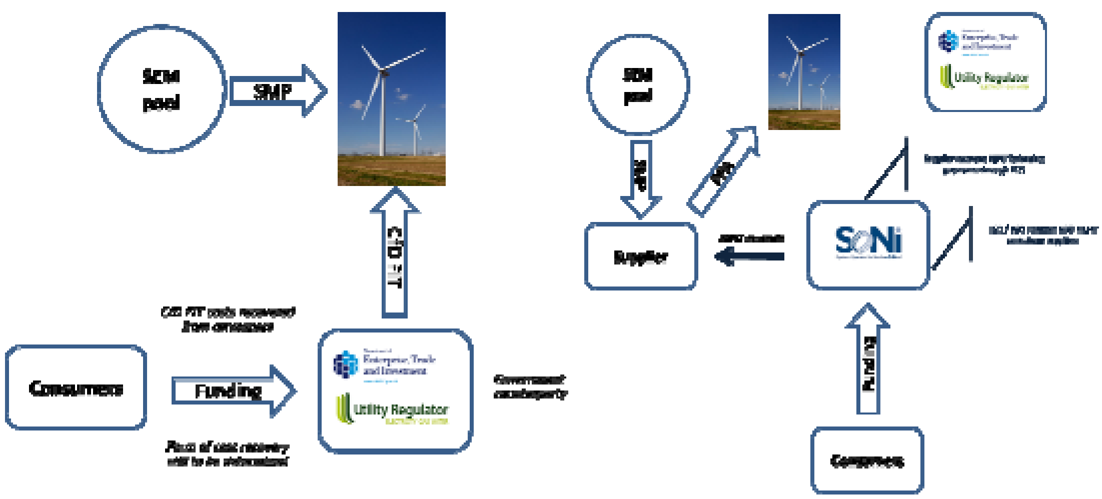
E.6: Subsidy payment flow

A major component of the reforms in GB is that the subsidy flow is intended to be *directly to the generator*, as opposed to *through the supplier* as with the RO/NIRO and indeed the REFIT in the Republic. The desired benefits of the proposals are to help independent, project-financed generators enter the GB market directly, rather than through a PPA with suppliers.

While in the context of GB, it remains to be seen whether the desired benefits of the proposals will be achieved in the absence of additional changes (even with subsidy flowing to the generator it is not clear that this approach will work where an independent renewable generation project requires a PPA in order to be bankable) the contractual interface of a CfD FIT policy requires similar consideration in Northern Ireland. Figure E1 sets out the options.

Figure E1: FIT approaches – GB CfD approach or REFIT

GB CfD proposal **REFIT**



There are certain attractions of a structure similar to REFIT where the subsidy flows through the suppliers to the generators, and remuneration of various balancing and market participation costs incurred by the generators are fixed rather than negotiated. Such an arrangement would provide renewable generators a fixed payment through PPAs, and has the benefits of simplicity, being enforced contractually, and being applicable to all sizes of generation including small-scale (a point we return to below).[13]

[12] See EirGrid / SONi "All Island TSO Facilitation of Renewables Studies" for challenges of managing the technical and operational implications associated with high shares of wind power in the All Island power balance.
[13] The model is also consistent with how REFIT operates in the Republic and would be consistent with supplier nomination of wholesale power through the SEM.

Under this approach, Northern Ireland's policy makers might be responsible for setting overall policy and administering the scheme (as currently under the NIRO) while suppliers would be responsible for managing renewable output in the market and the settlement ("cash-out") of wholesale and subsidy payments across trading periods. Institutionally the approach is also simpler (see Section E8 below) although the scheme would still require administration.

The alternative would be to follow a similar route to that proposed in GB with government responsible for negotiating, managing and monitoring the CfD FITs and the subsidy paid directly to Northern Ireland's generators. This model would allow renewable generators to sell directly into the pool and receive subsidy payments directly. This could provide more commercial flexibility than generators having to contract with registered electricity suppliers in Northern Ireland who then act as intermediaries for the generators in the market.[14]

While a renewable generator in GB generally requires a PPA to dispatch, renewable generators in the SEM (through priority dispatch rules) have a guaranteed route to market. The issue for Northern Ireland's generators (although compensation for constraints and curtailment may in future mean volumes become more of an issue depending on the design of support mechanism) would be the price realised for their power. A payment route *directly to the generator* would therefore seem to address price risk and allow renewable generators to continue to operate within the market.

However, compared to a REFIT approach, a direct payment route requires a more complicated contractual structure. This might deter investors. In some ways it is also an *advantage* rather than disadvantage that a subsidy payment flow *through suppliers* means intermediary agents manage renewable output in the market, rather than every generator in Northern Ireland having to interface with the market and manage these activities directly. In particular, with substantial numbers of new (predominantly wind) generators granted access to the SEM, transmission is expected to become increasingly constrained. The resulting compensation for constraints and curtailment may make market revenues more uncertain and costly for renewable generators. Part of the rationale for retaining REFIT's 15 per cent balancing payment within the SEM has also been to remunerate suppliers for managing ex-post correction of payments under the R-factor correction process which can take over a year.

The implication is a direct payment route to generators could lead to high levels of administration and complexity. Generators would need to manage cash payments on metered output across the year's trading period rather than receiving a fixed payment stream.

Clearly there are arguments in favour of either approach. Northern Ireland's policy makers need to consider the future role they envisage for renewable generators in the SEM, and how Trading and Settlement rules facilitate generators contracting financially through intermediary structures, rather than directly interfacing with the market.

[14] A risk with the REFIT approach (payment to suppliers) is generators ability to achieve a fair price for their power is diminished with only the small number of suppliers to contract with in Northern Ireland.

E.7: Market coupling

There are further complications, because of changes to the SEM to meet European electricity market integration goals, specifically in terms of the need for market coupling and it would seem, a market design more along the lines of the BETTA than the SEM.

If the expectation is that the GB market and the SEM will be more strongly coupled in future – in some ways, forming a single market – having a broadly similar *structure* for a support mechanism across the whole of the British Isles is likely to make sense. Indeed, the SEM Committee is currently considering a number of options for integrating the SEM with its neighbouring electricity markets.[15]

From market structure perspective, this might support delaying a move to a new scheme until future market arrangements become clearer. Against this, there is also an argument that with GB adopting a CfD FIT from 2014 (and REFIT in place in the Republic of Ireland) investment could be undermined in Northern Ireland, where there is delay in implementing a new (and potentially improved) support scheme.

There are pros and cons either way; clearly there may be value (from both an investor and policy-maker perspective) in delaying a final decision on *when to move* to a new scheme until the requirement for SEM redesign (if any) is clearer (expected to be early 2012). In the interim, more detailed analysis is required to examine how a CfD FIT might be designed for the SEM before and after integration with neighbouring markets.

E.8 Administration arrangements

Whilst as regards markets, there may be arguments on both sides as to whether to pursue the proposed GB approach, or that of the REFIT, we believe that these are less ambiguous when it comes to the institutional administration requirements of adopting the GB arrangements in Northern Ireland.

Under the likely GB delivery model, an arm's length organisation is likely to be responsible for negotiating, managing and monitoring the CfD FITs. The arm's length body may also be contract counterparty to CfD FITs. If this were to be applied in Northern Ireland, either a standalone parallel entity would need to be established for the SEM, or the GB entity would need to be the counterparty to contracts operating in the SEM.

The first would be likely to be costly, whereas the latter would require an understanding of the SEM as well as BETTA, so could also be administratively more complex than the operation of the NIRO and potentially expensive too. In comparison, under a REFIT arrangement, the suppliers would be responsible for managing both wholesale and subsidy flows through the PPA – as in the Republic of Ireland – which would seem administratively simpler.

[15] Including day ahead coupling using the financial contracts market and the potential long term redesign of the SEM to meet European single market requirements.

E.9 Funding

The White Paper makes no clear decision on how CfD FIT costs will ultimately be funded except that funding will be from electricity consumers. One option would be to use the same approach as the RO, which is funded by imposing an *obligation* on suppliers, who then recover the cost of this from their customers. The alternative is to fund the FIT through an explicit levy on consumer bills.

The final decision we expect will depend on the role of the arm's length organisation(s) functions vis-à-vis suppliers and their contractual positions with generators. Where the arm's length organisation is counter-party to the FIT contracts, a mechanism similar to the Public Service Obligation (PSO) levy is more likely.

In terms of *who* funds the support mechanism, *irrespective of its form*, we note that Northern Ireland is part of a UK wide renewable energy obligation. It may therefore make sense for Northern Ireland to be part of a UK-wide scheme in terms of funding the subsidy, rather than Northern Ireland operating its own scheme. However, it is also not necessarily the case that Northern Ireland's participation in a UK-wide scheme would lead to overall lower Northern Ireland consumer costs (an issue we return to below as part of the assessment of consumer costs).

E.10 Estimated costs of a standalone Northern Ireland scheme

In order to support some of the qualitative conclusions made above, we have sought to model the potential impacts on costs to consumers in Northern Ireland, under several different potential support mechanisms reform options (although our model does not have the degree of functionality to differentiate between the costs of the proposed DECC approach and a REFIT structure). We begin by assuming that the costs of each approach are borne entirely by the Northern Ireland customer. Note, however, that several assumptions have to be made in modelling future scenarios, so a degree of caution is required in interpreting the results. Moreover, the estimated costs do not take into account the costs of any additional transmission or other infrastructure, which could be affected by the choice of technology portfolio[16].

Each reform is set against a Baseline for the period 2012 to 2020. This Baseline assumes the continuation of the RO as the principal support mechanism for large-scale renewable generation in the UK and small-scale generation in Northern Ireland. We then go on to assess the implications (in terms of consumer cost and wholesale prices) of the introduction of PFIT and CfD FIT support payment structures.

Table E3 shows the considerable increases in Northern Ireland consumer costs from Northern Ireland adopting a standalone PFIT and FIT CfD policy relative to the Baseline – that is, without support costs being socialised across the UK. The table shows the costs of funding both large and small-scale renewable generation.

[16] These would be likely to vary between renewables portfolios which differed from that of the baseline.

Table E3: Change in Northern Ireland consumer costs under alternative policies in 2020

Metric	**Unit**	**NI Baseline**	**NI PFIT**	**NI CfD FIT**
Costs of subsidy				
Consumer cost in 2020	£m	70.5	353.6	268.0
Change from baseline	£m	n/a	283.1	197.5
Consumer cost (per unit of electricity consumed)	£/MWh	6.9	34.5	26.1
Change from baseline	£/MWh	n/a	27.6	19.2
Costs of subsidy and total NI wholesale electricity				
Consumer cost in 2020	£m	798.6	1,081.8	996.1
Change from baseline	£m	n/a	283.2	197.5
Consumer cost (per unit of electricity consumed)	£/MWh	77.9	105.5	97.1
Change from baseline	£/MWh	n/a	27.6	19.2
% increase from baseline	%	n/a	35%	25%

Source: CEPA

The analysis suggests (under the modelled designs of PFIT and CfD FIT policies) that a standalone Northern Ireland FIT scheme would be comparatively expensive relative to the NIRO (in its current form). This is because the total cost of funding investment to meet Northern Ireland's renewable electricity target is assumed to be recovered solely from Northern Ireland consumers. This is in contrast to the NIRO where the design of the RO and Northern Ireland's current lower obligation level mean deployment of renewable generation in Northern Ireland is in part supported by demand for Northern Ireland ROCs by GB suppliers.

The modelling also suggests that of the standalone Northern Ireland policies, a PFIT policy would be likely to result in the highest costs for Northern Ireland consumers. This is because in the modelling support payment levels are set at closer to projected renewable generation costs across different technology groups in the CfD FIT scenario.

The modelled impact on Northern Ireland domestic consumer bills under the different policy scenarios is illustrated in Table E4. The analysis also shows projected household bills in GB sourced from DECC's Electricity Market Reform Impact Assessment.

Table E4: Impact of alternative support options on NI consumer bills

	NI Baseline	NI PFIT	NI CfD FIT	GB bills[17]
Domestic (no NI efficiency savings)				
2010	£496	£496	£496	£490
2011 – 2015	£508	£509	£509	£490
2015 – 2020	£523	£576	£557	£504
Domestic (with 1% year-on-year NI electricity consumption efficiency savings)				
2010	£496	£496	£496	£490
2011 – 2015	£498	£499	£499	£490
2015 – 2020	£487	£536	£519	£504

Source: CEPA/ DECC

Table E3 illustrates that electricity bills are likely to rise relative to today even under the Baseline. This is due to rising wholesale electricity prices and support payments. The standalone FIT policies (where the total cost of funding investment to meet Northern Ireland's renewable electricity target is assumed to be recovered solely from Northern Ireland consumers) clearly show the issues Northern Ireland's policy makers face between meeting aspirations for renewable generation in the region and future impacts on consumer electricity bill costs.

In the absence of achieving year on year electricity consumption efficiency targets, the modelling suggests that average consumer bills could rise by over 20% by 2020 in Northern Ireland. This would add over £100 to the average consumer bill.

E.11 Consumer costs (UK-wide scheme)

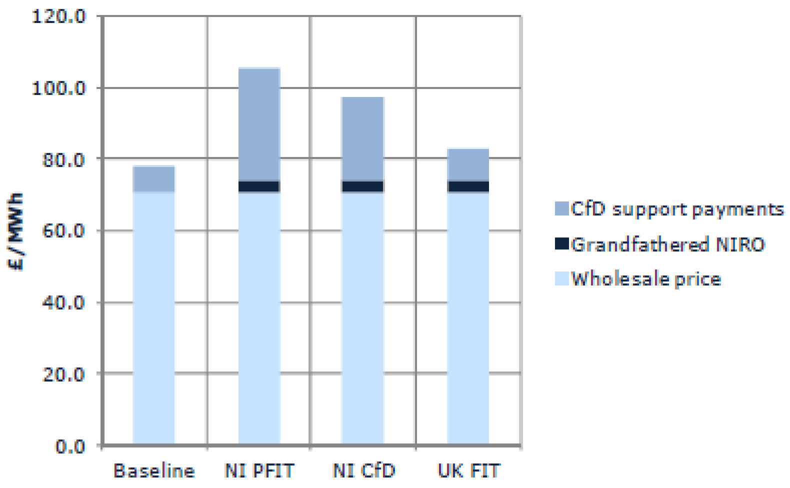
We have gone on to complete an assessment of the impact on Northern Ireland consumer costs if a single UK wide low-carbon generation payment cost recovery scheme were adopted – i.e. a scheme where UK low carbon generation support payments would form a single pot of money recovered across annual UK electricity consumption.

In order to assess *indicative* Northern Ireland consumer costs in the period to 2020 we have sourced average annual GB 'net' payments to low carbon generators for 2020 from DECC's Updated Impact Assessment analysis for the Contracts for Difference Electricity Market Reform policy modelling scenario (c. £2.9bn).[18] Figure E2 illustrates wholesale electricity prices and support payment costs in Northern Ireland (per unit of electricity consumed in the region) in 2020 for the Baseline, a standalone Northern Ireland PFIT, a standalone Northern Ireland CfD scheme and a single UK low carbon generation payment cost recovery scheme. The UK FIT scenario also includes NI CfD FIT payments from CEPA's modelling.

[17] DECC (2011): 'Planning our electric future: a White Paper for secure, affordable and low-carbon electricity'

[18] This includes only projected Contract for Difference support costs.

Figure E2: Northern Ireland wholesale prices and support payment costs under policy scenarios in 2020



Source: CEPA

Figure E2 illustrates a number of important points. First, a Northern Ireland PFIT is likely to be the more expensive of the Northern Ireland standalone FIT policy options. As importantly, even with a UK wide cost recovery arrangement (i.e. a socialised cost) Northern Ireland consumers may still be worse off (relative to the Baseline scenario) under a CfD FIT than they are at present in the absence of an arrangement which might replicate the benefits of the existing lower obligation level under the NIRO. Even so, the modelling suggests Northern Ireland consumers might still benefit significantly by participation in a UK wide cost recovery scheme (the modelling suggests support payment costs might be reduced by around £14 - £15 /MWh by 2020) were costs even recovered *proportionally* across annual UK electricity consumption.

While the modelling results are informative, there are reasons to be cautious about the conclusions. Under the RO headroom mechanism calculation, suppliers' obligations are set in proportion to UK regional shares of electricity sales adjusted for the size of the UK obligation and the relative regional obligation levels. This inevitably leads to demand for Northern Ireland ROCs from GB suppliers (our modelling suggests as much as 40-50 per cent in some years) and, therefore, support payments to Northern Ireland renewables paid by GB consumers. In other words, the consumer cost of support payments under the RO (per unit of total electricity consumed in the region) is lower for the Northern Ireland consumer than for the GB consumer (as GB suppliers have a higher obligation level relative to overall obligation size).

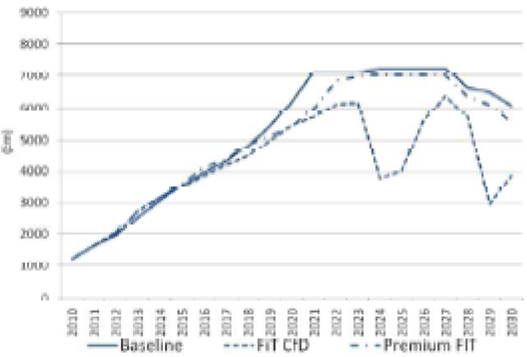
Unless some new mechanism is put in place to replicate the benefit of this lower obligation level for Northern Ireland, removing the NIRO would increase the proportion of the total cost of UK low-carbon generation paid by Northern Ireland consumers. In that situation, Northern Ireland consumers would be worse off *unless* the decrease in total UK consumer costs from introducing a

UK CfD FIT (relative to continuation of the RO) compensated for this increase. The modelling suggests that it would compensate to some extent but not fully.

Figure E3 shows DECC's modelled GB CfD support payments in the White Paper Impact Assessment, both relative to DECC's Baseline scenario (continuation of the RO) and under high and low fossil fuel price projection scenarios (net CfD support payments shown in Part B are used to derive the indicative UK FIT cost for Northern Ireland consumers presented in Figure E2).

Figure E3: Costs of support for low carbon mechanisms (Great Britain under EMR reform options)

Part A: Costs of support for support mechanisms   Part B: Cost of support for CfD FIT low/high fuel prices



Source: DECC

GB's proposed introduction of a CfD FIT may lead to quite significant reductions in overall UK support payment costs relative to the RO both before and after 2020. Therefore, even in the absence of an arrangement similar to the lower obligation under the NIRO, Northern Ireland consumers may not be significantly worse off under the proposed new arrangements. However, this depends on a number of key assumptions, particularly future developments in fossil fuel prices (which drive future wholesale prices) and low carbon generation costs (which drive CfD strike price levels) amongst many other market uncertainties. In the event *wholesale prices* in the SEM were also higher than those projected in the modelling then there would still be the potential for much higher total costs to consumers in Northern Ireland over the period to 2020 and beyond, even where support payments are constrained under the CfD design in the UK.

Our modelling of Northern Ireland support payments and prices in the SEM (together with DECC's modelling of GB support payments and wholesale prices in GB) suggests there are scenarios where Northern Ireland consumers might not be made comparatively worse off by the proposed new arrangements. However, the assumptions that lead to this conclusion need to be investigated further as this is an area of both uncertainty and importance to the overall impacts of any new arrangements on Northern Ireland consumers. We would recommend, therefore, that DETI and NIAUR complete further analysis as part of any future design of reforms to the UK's low-carbon generation support mechanisms.

E.12 Paying for the support mechanism

The previous section suggests Northern Ireland could benefit from participation in a UK-wide FIT cost recovery scheme although the impact on overall consumer costs relative to the Baseline scenario is subject to uncertainty. That is, there may be *affordability* benefits from Northern Ireland's participation in a UK-wide rather than standalone scheme.

However, equally there are scenarios where consumer costs might be lower than those projected in the Baseline modelling, in which a stand-alone scheme may be more attractive. However, to significant degree, the attractiveness of a stand-alone versus a socialised cost recovery, depends upon the composition of the renewables generation portfolio being supported. By way of example, Figure E4 compares consumer costs for the NI CfD scenario under baseline renewable generation deployment and a scenario where there is lower marine / offshore wind deployment displaced by higher onshore wind deployment in the region. As with the previous sections, this excludes any analysis of associated changes to infrastructure costs.

Figure E4: Consumer costs under low marine / offshore wind deployment (CfD scenario)

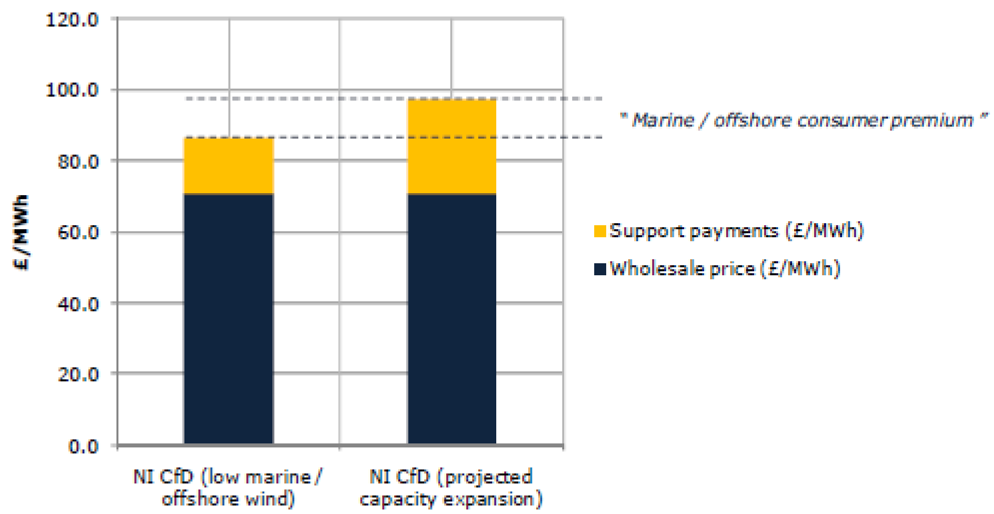


Figure E4 shows the higher resource, and therefore consumer cost, of a modelling scenario with more marine / offshore generation deployment (an "offshore consumer premium"). In comparison, under a UK-wide cost recovery scheme, the cost to *Northern Ireland consumers* of low-carbon generation FIT payments is much less sensitive to the generation mix deployed in *Northern Ireland*, as a UK-wide cost recovery scheme (similar to the NIRO currently) means consumer costs are driven more by deployment across the UK as a whole.

A UK-wide CfD FIT would spread consumer costs, and might provide Northern Ireland with greater flexibility to balance environmental objectives and affordability constraints under different scenarios of renewables deployment in the region. Against this, a stand-alone cost recovery scheme could lower consumer costs where the portfolio comprised technologies – such as on-shore wind – where support costs were lower.

But it is difficult to see how any new arrangement could be as attractive as the existing one. Under the current RO and NIRO arrangements, Northern Ireland has a relatively lower obligation than GB, for reasons including the difference in electricity prices between the two regions. This lower obligation translates into a relatively lower cost for Northern Ireland consumers compared to those in GB. This arrangement could not be replicated exactly under a FIT, because there is no equivalent of the 'obligation level' in a FIT. However, other arrangements for distributing the cost are possible, which might help in retaining some of the benefits to Northern Ireland's consumers of the RO arrangements. These would, however, need to be designed with reference to the final structure and institutional arrangements for a UK-wide CfD FIT.

E.13 Small-scale generation

For both PFIT and CfD FIT policy scenarios, we have also modelled a Northern Ireland small-scale generation "top-up" FIT tariff over and above the current NIE export tariff offered to different classes of small-scale generator. The GB small-scale generation FIT scheme operates according to a similar framework whereby small-scale generators receive an export tariff (for electricity exported off the generation site) plus a fixed "top-up" (generation) payment for total metered generation from the small-scale unit.

Table E5 illustrates the cost to Northern Ireland consumers of a small-scale generation FIT (note these costs are captured in the consumer cost analysis in the previous section as the same FIT structure is assumed in both the PFIT and CfD FIT scenarios).

Table E5: Consumer costs of small-scale generation

Metric	Unit	Small-scale FIT
Consumer subsidy costs (in 2020)		
Consumer cost	£m	52.7
Consumer cost (£/MWh renewables generated)	£/MWh	125.7
Consumer cost (£/MWh demand)	£/MWh	5.1

Source: CEPA

An obvious alternative to a standalone Northern Ireland small-scale generation FIT scheme would be Northern Ireland participation in the current GB small-scale FIT scheme. The clear advantage with this approach is it would reduce implementation risks and administration costs. The main disadvantage is it may lead to reduced Northern Ireland policy discretion over the rates set for the region's small-scale generators.

It should be noted, however, that this scheme is currently under review; as such, it is probably better to wait until the results of the review are known, before taking final decisions.

E.14 Additional issues / options to consider

DETI and NIAUR have also requested that we explore in the modelling an additional scenario where the NIRO would continue beyond 2017. Out of all the policy options this is the most difficult to assess (quantitatively) given future consumer costs depend on a number of policy assumptions. For example, at what level would be Northern Ireland's obligation be set going forward, and how would the scheme be operated and administered without ongoing GB participation?

To explore this option, we modelled a scenario where the NIRO remains open operating essentially as a PFIT scheme with the costs recovered solely from NI consumers. The tariff levels offered under the scheme approximate the banding levels currently offered to NI generators in the NIRO. Whilst not a direct comparison to the operation of the NIRO, the modelling results do provide an illustration of what it might cost Northern Ireland consumes to operate a standalone scheme based on similar tariff rates as under the NIRO.

The analysis suggests that the continuation of the NIRO on a standalone basis – like the other support payment reform options - could be a relatively high Northern Ireland consumer cost scenario. The NIRO in its current form provides relatively generous support payment levels to Northern Ireland generators. As the majority of Northern Ireland renewable deployment (particularly offshore) is expected to take place *after 2017*, Northern Ireland consumers might be expected to fund the costs of the scheme on a standalone basis were the scheme operated independently of GB, resulting in high consumer costs.

The difficulty is the inherent uncertainty of what Northern Ireland consumers might need to fund under a reformed NIRO. What the modelling illustrates is that were Northern Ireland to pursue the option of retaining the NIRO, the existing concessionary obligation level (and therefore efficient Northern Ireland consumer cost of the NIRO) should not be taken as a guide to suggest the option of retaining the NIRO would necessarily lead to a reduction in projected consumer costs compared, for example, to alternative policy options such as a CfD FIT. Indeed, there are scenarios where it could potentially result in higher Northern Ireland consumer costs.

There is an additional issue with the NIRO, which is that it closes in 2033 rather than 2037 as elsewhere in the UK. Unless there is new legislation to extend this, applications accepted after April 2013 would receive less than 20 years of support. This may well not be material, but needs to be considered. It may be appropriate to look into extending the life of the NIRO to 2037 to maintain investor confidence, irrespective of what choices are made about new support mechanisms in GB or Northern Ireland.

E.15 Conclusions and recommendations

Having considered carefully the qualitative and quantitative analysis in this report, of the available options, we believe that neither a continuation of the NIRO nor the introduction of a PFIT, offer workable or desirable support mechanisms for Northern Ireland. The choice is one of applying DECC's CfD FIT proposals to the SEM, or introducing a REFIT type – Fixed FIT - model to Northern Ireland.

The main differences between the two approaches are the flows of subsidy (in the former it is direct to the generator, rather than through a supplier) and the institutional requirements necessary to support each.

In the highly illiquid GB BETTA market, the proposed CfD FIT will need to be struck against an index, giving rise to concerns about basis risks (i.e. not being able to achieve the index). Together with the potential balancing costs for non-dispatchable renewables and the need for physical off-take to receive payments, this could mean that generators continue to seek to access markets through a PPA. Whilst not having been designed for the SEM, the particular features of a CfD FIT mean that many of the problems identified in the GB market are unlikely to bite within the SEM.

Thus, in many ways, it might be expected that the CfD FIT would work *better* in the context of Northern Ireland and the SEM than in GB.

Against this, the REFIT is a proven approach that carries less risk of applying something that was designed for another market and which will need to be adapted for a new one. The associated costs of introducing a REFIT approach would likely be lower - as there are already existing contracts from which to work – than for CfD FITs, for which contracts would need to be specifically written for the SEM.

A REFIT type approach is also less administratively burdensome and costly from an institutional perspective, in that the public sector is not a contracting counterparty – which is likely to be the case for the CfD FITs. However, it requires generators to contract directly with suppliers rather than operating directly within the market.

There are pros and cons for both options, and they need to be examined in much greater detail before a final view is arrived at.

As Northern Ireland is part of a UK-wide renewable energy obligation we recommend that DETI seeks to socialise the costs of the support regime across the UK, unless there is a desire to focus on lower cost renewables technologies, which might reduce the costs to Northern Ireland customers under a stand-alone scheme.

A UK-wide approach would spread consumer costs, and may provide Northern Ireland with greater flexibility to balance environmental objectives and the region's affordability constraints under different scenarios of renewables deployment.

We recommend DETI and NIAUR make a clear statement to the Northern Ireland market of the future direction electricity policy in the region so as to avoid the risk of an investment hiatus during a key investment period, potentially according to the following:

- Like the RO in GB, the NIRO will remain open to new accreditations until 2017 after which the scheme will be grandfathered.
- In terms of timing for joining a new scheme, Northern Ireland would plan for a similar implementation date as the rest of the UK (i.e. 2014).

- However, the final implementation date will need to be confirmed following a clearer decision on the adopted option (s) for market integration in early 2012.

In early 2012, were significant revisions required or *envisaged* to fit with future European market requirements, the timeline for implementing a new policy would need to be revisited. In the interim, there is detailed analysis to examine the impacts on consumer costs further, and how a FIT approach might be designed for the SEM before and after integration with neighbouring markets.

To support the transition to the new arrangements, the option of extending the life of the NIRO to 2037 should also be considered.