Making a positive difference
for energy consumers

Impact Assessment

Annex 7 - TCR Draft Impact Assessment Template

Division:	Energy Systems Transition	**Type of measure:**	SCR consultation of minded to decision
Team:	Targeted Charging Review	**Type of IA:**	Qualified under Section 5A UA 2000
Associated documents:	n/a	**Contact for enquiries:**	TCR@ofgem.gov.uk
Coverage:	Full		

Introduction

We launched the Targeted Charging Review (TCR) in August 2017 after stakeholder consultation. The scope of the review requires us to:

- consider reform of residual charging for transmission and distribution, for both generation and demand, to ensure it meets the interests of consumers, both now and in future; and

- keep under review the other 'remaining Embedded Benefits' that may be distorting investment or dispatch decisions.

These two areas of review are linked in terms of driving a need for reform.

The aim of this annex is to present the results of the analysis that has been carried out in a way that is consistent with other Ofgem Impact Assessments. Such consistency is useful both internally to decision-makers who wish to compare major policy changes, to others in central government who use similar templates, and to stakeholders who are focussed on the broad picture of the case for reform and its benefits and impacts. However, as the reforms are complex, there is also a need to tailor this assessment so it is tractable. This has been done through completion of two impact assessment summaries, before providing a final overview.

This report is structured as follows:

In **Section A**, we provide an Impact Assessment of demand based residual charging.

In **Section B**, we provide an Impact Assessment of Transmission Generation Residual and Balancing Services Use of System Reforms (remaining Embedded Benefits).

In **Section C,** we highlight overall results and any important analytical linkages between both set of reforms.

This order reflects the staged approach in which the reforms have been analysed. An Impact Assessment should also draw together the evidence base for policy choice, but it would be repetitious to replicate the detail in the main consultation, other annexes, and associated documents. Therefore only high-level evidence is reported while the pro-formas signpost where more detail can be found if it is required by the reader.

We have used two of National Grid's Future Energy Scenarios (FES)[1] for this work, reflecting the uncertainty of system evolution. These scenarios are Steady Progression (SP, which has quite slow decarbonisation and decentralisation) and Consumer Renewables (CR, which has much faster change in both areas). Table 1 illustrates the modelled valuation of benefits in aggregate.

Table 1. Overall Monetised benefits (demand residual charging, TGR reform and BSUoS reform)

Background FES Scenario	**System Benefit (£bn)**	**Consumer Benefit (£bn)**
Steady Progression	1.1	5.1
Community Renewables	3.1	7.2

System and consumer benefits cannot be added together as they are separate concepts. These figures should be used to indicate the nature, direction and magnitude of impacts. They support the case for principle-based reform. However, the limitations of the analysis are carefully described in the Frontier / LCP reports. It is emphasise that the model results should not be the principal reason for a decision.

Policy implementation will affect the benefits in Table 1 but these options are dealt with in the main report rather than here.

[1] http://fes.nationalgrid.com/media/1363/fes-interactive-version-final.pdf

Section A. Impact Assessment of demand based residual charging reforms

Summary: Intervention and Options

Rationale for intervention, objectives and options

What is the problem under consideration? Why is Ofgem intervention necessary?

As described in Chapter 2, there are network charges that are considered to be 'residual charges' and these 'top-up' the amounts collected from forward-looking charges to allow network companies to recover their allowed revenue. These charges are mainly on consumer demand, and at an early stage in TCR policy development,[2] we decided to transfer all the residuals to demand as this would involve less change than setting a new generation/demand split for recovery, avoid distortions that would occur if recovery was through generation and would be more transparent. The main element of the TCR is therefore demand focussed.

Under the current charging system, there is an incentive to reduce exposure to these residual charges. One of the primary actions that a network user can take to avoid exposure is through on-site generation. By distorting investment and operational decisions system costs are increased.

There is also an adverse effect on consumers when charges fall increasingly on users who are least active or do not have on-site generation. This complex issue affects all users of the network.

A Significant Code Review provides a role for Ofgem to review holistically a code-based issue (for the main commercial industry codes) and speed up industry reform.

What are the policy objectives and intended effects including the effect on Ofgem's Strategic Outcomes?

The policy objectives of this work are to find an option which will allow recovery of the required revenue with as little distortion as possible, provide maximum consumer benefits and meet Ofgem's statutory duties as a regulator.

We expect our preferred option to reduce bills for the majority of domestic consumers. It is based on consumer segments that can be readily identified, but how such charges are passed to consumers will be for suppliers to determine.

We expect our preferred option to make network charges more predictable and stable, improving the reliability of information on which to base investment decisions. Alongside delivering these specific benefits the proposed changes also benefit the overall system, delivering system as well as consumer savings. Removing the incentive to generate on-site means less incentive to use smaller scale generation, which is often less efficient than

[2] https://www.ofgem.gov.uk/system/files/docs/2017/11/tcr_working_paper_nov17_final.pdf

generation through the network. As well as reducing costs to consumers, this will help to reduce carbon emissions.

What are the policy options that have been considered, including any alternatives to regulation? Please justify the preferred option (further details in Evidence Base).

A description of the Business as Usual option (volumetric or per-unit charges for small users and volumetric and peak demand charges for large users) is provided in Chapter 2. Charging reform can be applied in many different ways but the policy options have been shortlisted to:

<u>Option 1. Fixed Charge</u>: Fixed by Volume (£/user). Customer segments would be defined by Line Loss Factor Classes (LLFCs) at high voltage (HV), low voltage (LV), and for transmission connected loads and extra high voltage (EHV) connected loads. The residual recovered from each customer segment would be apportioned by share of net total volume.

<u>Option 2. Agree capacity charge</u>: This would be deemed where necessary (for domestics and microbusinesses, for example), and based on specified capacity levels for other customers.

As option 1 and 2 both stop residual avoidance they fall under "full reform" in modelling and have identical system level benefit and consumer consequences. However, the distributional analysis in Frontier / LCP 's residual charges report (Chapter 3) shows from a static analysis that there will be different winners and losers under each system.

The option that is preferred in our 'minded to' decision is Option 1 – Fixed Charges. This is largely as it is better when measured against our defined principles and a number of other criteria.

Section A Preferred option - Monetised Impacts (£m)

	Residual charges
Business Impact Target Qualifying Provision	n/a
Business Impact Target (EANDCB)	n/a
Net Benefit to GB Consumer	**£540m (SP)[3] to £1,230m (CR)**
System Benefits	**£1,010m (SP) to £3,220m (CR)**

Explain how the Net Benefit was monetised, NPV or other

Consumer benefits have been estimated over the period 2019 to 2040. This period has been chosen as our proposals represent a significant change to the charging regime. However, we acknowledge that by 2040 the energy landscape may have greatly changed.

The NPV is calculated using 2019 as the base year for discounting. A 3.5% discount rate was used. Costs and benefits are in 2016 prices.

The 'Net Benefit to GB consumer' (described as a reduction in consumer cost in the Frontier / LCP Reports) and system benefits are separate measures so the numbers cannot be added together. For a fuller explanation of system and consumer costs / benefits see Section 5 in the Frontier / LCP Residual Charges Report.

The numbers quoted are based on modelling work that has been carefully undertaken but there are limitations to the precision of these and they are sensitive to assumptions. They also reflect the outcome of modelling residual reform before embedded benefits reform.

These benefit estimates are in support of a principle based assessment and should not be read out of that context.

Preferred option - Hard to Monetise Impacts

Describe any hard to monetise impacts, including mid-term strategic and long-term sustainability factors following Ofgem IA guidance

The preferred option delivers reduced harmful distortion because reducing exposure to the residual charge is only really possible if a user disconnects from the network.

It results in increased fairness as each segment contributes network residual charges that are proportional to overall use. There is also increased fairness in that each user

[3] Within the pro-forma boxes **SP** is used to refer to Steady Progression and **CR** to Community Renewables.

within a given segment and area contributes the same residual charge, although this inevitably means that there will be some winners and losers.

The model indicates that there will be environmental benefits as emissions are reduced under the reform scenarios. The scale of change is greater if there are more renewables in the future fuel mix, as illustrated in the community renewables future energy scenario compared to the steady progression scenario. There is also likely to be a change from less efficient gas generation, often used to reduce exposure to residual charges, to combined cycle gas turbine generation, which is more efficient.

Key Assumptions/sensitivities/risks

There are numerous key assumptions in this work and they are described in detail in the accompanying documents from Frontier / LCP. For example, assumptions are made about uncertain input variables (e.g., fuel prices, demand) and technical parameters associated with generation. Modelling the impacts of reforms over a long time period is inevitably subject to substantial uncertainty, for instance, in the technological and political environment. Within the modelling work, we have attempted to take account of the uncertainty by analysing different scenarios as described in the Frontier / LCP documents.

One source of uncertainty is that the modelling assumes that benefits are passed on to consumers both from generation and suppliers. If, for example, the generation sector is able to find a way to increase or maintain prices, rather than passing benefits through to consumers, then the consumer benefits would not be as high. Generally, we expect the pass through of benefits from suppliers to consumers to be high, but there may be particular circumstances where this does not occur, for instance if competition is limited.

Results also reflect the fact that the model is bottom-up and perfect foresight is assumed amongst market participants. While this is a simplification of reality, this is common practice in modelling of this nature. Results are sensitive to the FES scenario chosen and assumptions on residual levels – we explore some of the effects of this uncertainty in Tables 3 and 4 below.

One risk associated with the policy is that some users may decide to disconnect from the grid. Users that are more likely to disconnect are those that have long term site commitments or ownership, have invested significantly in a specific site, and have access to low cost fuel feedstocks or distributed energy resource surplus output from legacy or co-located activity (see annex 6). Further research in this area may be helpful, but we consider that the overall risk is low as the value of being connected to the grid goes beyond a source of supply and the cost of replacing the utility achieved from a grid connection is often prohibitively high.

Section A Evidence base

Problem under consideration

This is described in the main consultation document (Chapter 2 Context). In summary, as the energy system evolves and electricity is generated and consumed in new ways, the existing charging regime will allow some users to reduce or avoid residual charges in ways that could be inefficient or impose higher charges on other users.

Policy objective

The policy objective is to reform residual charges in a way that reduces distortions, is fair and is both proportional and practical.

Description of options considered (including status-quo);

A description of the Business as Usual option (volumetric or per-unit charges for small users and volumetric and peak demand charges for large users) is provided in Chapter 2. This has been ruled out in short-listing but forms the baseline within modelling work.

The initial long list of policy options included: Fixed Charges; Gross Volumetric Charges; Capacity Charges (ex-post and ex-ante); Net Volumetric Charges; Net Volumetric Import and Export charges; and Maximum Import and Export Capacity Charges. After considerable assessment and analysis (summarised in Annex 4), these were narrowed to five possible options (see Figure 4, in the main text).

1. Fixed Charges (£/user). The residual recovered from each customer segment is apportioned by share of net total volume. Customer segments would be defined by LLFCs at HV and LV, and for all transmission connected loads and EHV connected Loads.

2. Agreed capacity charges. This would be deemed where necessary (deemed for domestics and microbusinesses) and based on specified capacity levels for other customers.

3. Rolling Capacity Charges. Set on an ex-ante basis, but afterwards an excess capacity ratchet/adjustment is then used to reset the values (£/kW or £/user).

4. Mostly fixed and partally-exposte capacity charge. Fixed charges (75% with monthly ex-post capacity)

5. Mostly agreed capacity charge and net partially volumetric charge. Agreed capacity charge for domestics makes 75% of the capacity charge, supplemented with a net volumetric element (25%).

Options 1 and 2 are the final shortlisted options.

Monetised and non-monetised costs and benefits of each option including administrative burden and strategic and sustainability issues (as outlined in Ofgem's hard to monetise guidance).

As an Impact Assessment is a tool to help decision making, the emphasis that is placed on monetised and non-monetised costs will differ depending on the policy considered. The main basis of selecting the preferred option is principle-based and shown in the qualitative analysis below (Table 2). The modelling results provide monetised values that supplement these results.

Relevant Strategic and sustainability issues include Security of Supply (measured by Loss of Load Expectations within the Frontier / LCP Report) and these have been monetised. Carbon emissions are also considered and monetised.

Table 2 Summary table for short-listed options

Assessments		**Option**	
Considerations	**Subcategory**	**1 - Fixed Charges - set on segment volumes**	**2 - Agreed capacity charges - deemed where necessary**
Pro/Con	*Arguments for*	Least distortive with fewest user incentives Link to system quantity (volumes) adds justifiability Simple, low interaction with Access Equitable across segments with shares that update over time	Significantly less distortive for most users Link to system quantity (capacity) adds justifiability Equitable across and within segments
	Arguments against	Step-changes in charges between groups Equal charges within segment means potential redistribution within segment	Deemed capacity needed for most users with deeming level here driving redistributive effects, such as Low voltage (LV) non-domestic increases Some on-site generation / Demand Side Response (DSR) incentive remains, including by domestic users to drop into lower bands
Reducing Distortions	*Reducing Distortions*	Least distortive	Less distortive than status quo, more so than Fixed
	Distortion left in place	Disconnection Segment-wide volume reduction	Capacity reduction / peak reduction incentive Domestic incentive to drop to lower deemed bands Incentive to hand back capacity may have benefits
	Academic underpinning	Very Good - strong academic support	Good to extent relatively fixed compared to SQ, but distortions remain
Fairness	*Fairness*	High on segment level, but no equity within segments	Recognises different domestic users, but still impacts low users, reduces for high users, and has LV impact also
	Simplicity	Very	Not simple
	Transparency	Very	Somewhat
	Predictability	Very	Somewhat
	Justifiability	Very	Somewhat
	Equity vs Equality	Equity between segments, Equality within segments	Equity between and within segments using volume set bands
Proportionality and Practical Considerations	*PPC*	Very simple, except segmentation Volume forecast needed	Requires deemed capacity values, and management of capacity values

Assessments		Option	
Considerations	**Subcategory**	**1 - Fixed Charges - set on segment volumes**	**2 - Agreed capacity charges - deemed where necessary**
	Legal issues including Discrimination	No obvious issues, all users face same charge	On-site generation or DSR have differential impact to network generation EU RED2 checks needed
	Ease of implementation and administration	Simple but depends on designs	Volumes for bands need regular updating, capacity and deemed values need review
	Future proofing to industry changes	Segment volumes update over time	Deemed bands and capacity agreements will need to be updated over time for segment contributions to be up to date Classes may become outdated as system develops
	System Complexity	Low	Medium
	Cost	Not significant - small changes likely and in line with usual modification	Not significant - small changes likely and in line with usual modification
	Future proofing link to access	Low interaction	More interaction with Access
Impact on domestic demand users	*Vulnerable*	Increases low user bills c.£20	Increases low user bills by c.£20
	Domestic	Low users pay more, other users pay less	Low users pay more, other users pay less
	Impact on different technologies	No differential impact	Possible on-site generation incentive, domestic incentive to shift into lower bands
Impact on non-domestic demand users	*T*	Moderate segment increase	Segment decrease
	EHV	Moderate segment increase	Segment decrease
	HV/LV	Moderate segment increase	Segment decrease for high voltage (HV) Increase for low voltage (LV)
	BTMG / On-site generation	On-site generation does not reduce charges	On-site generation incentive, domestic incentive to shift into lower bands
	Impact on different technologies	Technology neutral	Different impacts on on-site generation DSR and network generation
Competition	*BTMG vs Network*	On-site generation has no advantages over network generation	On-site generation has advantages over network generation
	Generation vs DSR	DSR has no advantages over network generation	DSR has advantages over network generation
	Energy Efficiency impacts	Energy Efficiency has no advantages over network generation or on-site generation	Energy Efficiency has no advantages over network generation or on-site generation
Key Remaining concerns		Step-changes in charges between groups Equal charges within segment means potential redistribution within segment Low domestic user cost increases	Some retained incentives Distributional impacts Low domestic user cost increases
Overall		Preferred option	Clear improvement on status quo, deeming introduces challenges and some incentives remain

Colour codes: orange = less desirable, yellow = neutral, light green = desirable/beneficial, dark green = strongly desirable or beneficial.

The estimated monetised benefits of each option are shown within the accompanying Frontier report. LCP's Envision Model has been used to calculate system and consumer benefits in a number of different scenarios. A key point is that in terms of the two main options described above there are no differences in the system and consumer benefits as both options remove the identified distortions in their entirety. The benefits for option 1 and 2 are indicated below (Table 3).

Table 3. Modelled benefits for Option 1 and 2

Counterfactual	Factual	System Benefit (£bn)	Consumer Benefits (£bn)
SP Baseline Scenario	Full Reform	1.01	0.54
CR Baseline Scenario	Full Reform	3.22	1.23

A static analysis of bill impacts is provided in Chapter 3 of the Frontier Residual Charges Report. Chapter 4 outlines the behavioural impacts. Chapter 5 sets out the wider system impacts, which include the quantified carbon impacts above and assessment of Loss of Load impacts. Carbon impacts are monetised within the analysis while Loss of Load is monetised as energy unserved.

Risks and uncertainty

As referred to earlier there is considerable uncertainty about the evolution of the energy system. As we show in Table 3, the use of Community Renewables as a scenario results in higher system benefits and consumer benefits. There is also considerable uncertainty about the size of the residual over the longer term – Table 4 explores the impact of different values for the residual for the Steady Progression scenario.

Table 4. Sensitivity analysis for Options 1 and 2

Counterfactual	Factual	System Benefit (£bn)	Consumer Benefits (£bn)
Steady Progression - High Residual	Full Reform	1.04	1.57
Steady Progression - Low Residual	Full Reform	0.79	0.52

Frontier / LCP also reported figures over the 2019 to 2030 time period. This analysis is of relevance if reforms do not last as long as anticipated, for instance, due to an unexpected system change. The main impact is to reduce the benefit of the alternative FES background. However, as indicated by Frontier / LCP, large changes in a particular year's capacity market price can have a material impact on the overall figures.

Table 5. The impact of assessment over a shorter time-period (2019-2030)

Counterfactual	Factual	System Benefit (£bn)	Consumer Benefits (£bn)
Steady Progression (Baseline Scenario)	Full Reform	0.25	0.43
Alternative FES background – Community Renewables baseline	Full Reform	0.92	-0.01
Steady Progression High Residual	Full Reform	0.26	0.66
Steady Progression Low Residual	Full Reform	0.23	-0.04

Section B Impact Assessment of Transmission Generation Residual and Balancing Services Use of System (remaining Embedded benefits)

Summary: Intervention and Options

Rationale for intervention, objectives and options

What is the problem under consideration? Why is Ofgem intervention necessary?

The second stage of analysis deals with embedded benefits derived from balancing services use of system (BSUoS) charges and the impact of setting the transmission generation residual (TGR) charges residual to zero. The former gives rise to different treatment to generators according to their size and location on the network. The latter is part of our proposal to charge residuals only on final demand.

- In terms of the transmission residual charges, smaller embedded generation is not subject to transmission generation charges that are currently negative (ie a payment).
- There are payments from suppliers to small embedded generators for reducing their net demand.
- Small generators do not pay for balancing services.

Ofgem intervention through an SCR is necessary to achieve a holistic approach to the issues.

What are the policy objectives and intended effects including the effect on Ofgem's Strategic Outcomes?

The high-level policy objectives of the preferred option are to promote a level playing field for generation.

Consumer and system benefits result by removing the market distortions associated with embedded payments. This helps particularly to achieve the strategic objective of lowering bills and protecting vulnerable consumers, especially in the longer term.

What are the policy options that have been considered, including any alternatives to regulation? Please justify the preferred option (further details in Evidence Base).

The distortions caused by both existing TGR and BSUoS arrangements could be addressed by removing all three charges and payments described above. However, there is some uncertainty about the amount of balancing services charges that generators should pay in future, which means that a lower change option of only removing the embedded benefit related to payments from suppliers was carefully considered. Hence, the policy alternatives consisted of:

Option 1: TGR reform and removing the ability of small embedded generators to receive payments from reducing suppliers' contribution to BSUoS charges.

Option 2: TGR reform, removing BSUoS payments, and requiring smaller embedded generation to pay BSUoS charges.

Section B Preferred option - Monetised Impacts (£m)

	Remaining Embedded Benefits
Business Impact Target Qualifying Provision	n/a
Business Impact Target (EANDCB)	n/a
Net Benefit to GB Consumer	**£4,520m (SP) to £5,990m (CR)**
System Benefits	**-£100m (CR) to £110m (SP)**

Explain how the Net Benefit was monetised, NPV or other

(As explained earlier on page 5).

These benefits are additional to the benefits described in section A, and are measured against the baseline of residual reforms having been implemented.

Preferred option - Hard to Monetise Impacts

Describe any hard to monetise impacts, including mid-term strategic and long-term sustainability factors following Ofgem IA guidance

The preferred option delivers reduced harmful distortion by creating a more level playing field for generators.

The model indicates that there will be environmental disbenefits as carbon emissions are increased. However, carbon accounting is complex and no allowance has been made for emissions associated with interconnector flows.

Key Assumptions/sensitivities/risks
The key assumptions and sensitivities in this work are those assumed in the modelling and they are described in detail in the accompanying documents from Frontier / LCP. The relative benefit of on-site generation that does not export may be increased. This is mitigated by reform to TCR residuals (which removes a major distortion favouring on-site generation) and potential for further reform to BSUoS based on the recommendations of the BSUoS task force. We judge the risk of early closure of generation as a result of the embedded benefits reform to be very low, since affected generation is mainly supported by a scheme such as Renewables Obligation or Contract for Difference, or able to bid into the Capacity Market. With any change to charging there may be cost of capital implications but we considered these qualitatively and expect them to be immaterial in this context. On the basis of the modelling, the proposed reforms would have relatively limited effects on wholesale energy prices, which means that consumer benefits are much greater than system benefits (effectively, the reforms would result in a transfer of surplus from generators as a group to consumers). The scale of consumer benefits could be smaller if wholesale prices were to increase as a result of the reforms.

Section B Evidence base

Problem under consideration

This is a level-playing field problem that arises as there are different charging arrangements for smaller (under 100MW) embedded generators (those connected to the distribution network) versus larger generators.

Some remaining Embedded Benefits arise because charges are levied on a 'net' basis at the point the transmission network meets the distribution network (see Figure 27 Chapter 6). In some cases, suppliers effectively receive a discount on their charges for contracting with smaller embedded generators. The vast majority of these discounts are passed onto smaller embedded generators in the form of payments from suppliers. In addition, smaller embedded generators can contract with National Grid to receive these payments directly.

In other cases, smaller embedded generators avoid the Balancing Service charges that transmission connected generators face. Smaller embedded generation is not subject to transmission generation residual payments, which are currently negative.

The remaining non-locational Embedded Benefits are described in detail in Annex 5.

Policy objective

The policy objective is to reform charges in a way that reduces distortions, is fair and is both proportional and practical.

Monetised and non-monetised costs and benefits of each option including administrative burden and strategic and sustainability issues (as outlined in Ofgem's hard to monetise guidance);

As identified in Section A, this is a principle-based assessment supplemented by monetised assessment. The main discussion of the relationship between TCR principles and remaining Embedded Benefits is in Annex 5.

Monetised benefits are shown in Table 6.

Table 6. Monetised Benefits under Steady Progression

	System Benefit (£bn)	Consumer Benefit (£bn)
Option 1	0.0	3.33
Option 2	0.11	4.52

Based on the modelled monetised benefits, full reform (Option 2) is preferable to partial reform (Option 1) in terms of consumer benefits. System benefits are small in either option.

Risks and assumptions

Input assumptions and outputs are provided in the associated data tables to Frontier / LCP's TGR and BSUoS reforms modelling report. Frontier / LCP assume that in Business as Usual the BSUoS cost saving is split between the supplier and embedded generator, with 90% of the benefit being passed on to the generator.

Table 7 shows the assessment based on FES Consumer Renewable conditions. System benefits become slightly negative in this scenario while consumer benefits increase. Figure 14 of the Frontier / LCP TGR and BSUoS report shows the basis for this finding. An increase in system cost is driven primarily by the replacement of more efficient new build CCGTs with on-site generation and distribution-connected peaking plants. These have higher associated fuel and carbon costs, leading to increased system costs.

Table 7. Monetised Benefits under the Consumer Renewables FES background

Alternative FES	System Benefit (£bn)	Consumer Benefit (£bn)
Option 1	-0.16	4.11
Option 2	-0.1	5.99

Section C Overall Summary

	Complete Reform Package
Business Impact Target Qualifying Provision	n/a
Business Impact Target (EANDCB)	n/a
Net Benefit to GB Consumer	**£5,060m (SP) to £7,220m(CR)**
System Benefits	**£1,120m (SP) to £3,120m (CR)**

Explain how the Net Benefit was monetised, NPV or other

See page 5.

The LCP model is agent based, so we would expect these aggregate figures not to be affected by the order of analysis. However, it is possible that, had the first stage of analysis consisted of reforming embedded benefits and the second stage of reforming residual charges, sections A and B would have had different modelled results.

Preferred option - Hard to Monetise Impacts

Describe any hard to monetise impacts, including mid-term strategic and long-term sustainability factors following Ofgem IA guidance.

For the reforms, the full package delivers reduced harmful distortions.

While carbon values are monetised, the analysis of remaining Embedded Benefit reforms suggests that there would be an increase in the volume of GB CO_2 emissions. This may be a carbon accounting issue, as no CO_2 emissions are allocated to interconnector flows in the modelling, which is unrealistic. Full reform has a small negative effect on Loss of Load expectations, but this remains within the security standard of 3 hours per year (ie it never exceeds 0.7 hrs per year during the assessed period).

Key Assumptions/sensitivities/risks

The key assumptions and sensitivities in this work are those assumed in the modelling and they are described in detail in the accompanying documents from Frontier / LCP. Modelling the impacts of reforms over a long time period is inevitably subject to substantial uncertainty, for instance, in the technological and political environment. Within the modelling work, we have attempted to take account of the uncertainty through analysing different scenarios as described in the Frontier / LCP documents.

There is some risk of users who have invested heavily in generation equipment in order to avoid charges deciding to disconnect from the network in order to avoid charges. However, we have explored this possibility and believe it to be an unlikely outcome.

For reform of remaining Embedded Benefits, the relative benefit of on-site generation that does not export may be increased. This is mitigated by reform to TCR residuals (which removes a major distortion favouring on-site generation) and potential for further reform to BSUoS based on the recommendations of the BSUoS task force.

We judge the risk of early closure of generation as a result of the embedded benefits reform to be very low, since affected generation is mainly supported by a scheme such as Renewables Obligation or Contracts for Difference, or able to bid into the Capacity Market.

Will the policy be reviewed? Yes (further details at final decision)	**If applicable, set review date: month/Year**

Is this proposal in scope of the Public Sector Equality Duty?	**No**

<u>Costs of implementation</u>

Due to the difficulty of monetising the implementation cost of the reform options, the assessment of proportionality in this area was a qualitative one and done by identifying the practical changes which would have to occur in order for the reform option to be implemented, and then qualitatively assessing the relevant options against one another. This assumed that greater levels of practical change would, in turn, generally lead to higher costs.