Flexible Plug and Play

Capacity quota calculation for March Grid

25 February 2013

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Related History & Documents

Ref	Document or Source
-	Principles of Access Report - Final Report on smart commercial arrangement for generators connecting under the Flexible Plug and Play Project, December 2012
-	Revenue loss assumptions paper, January 2013

LIST OF ACRONYMS

AGR	Advanced gas-cooled reactor
ANM	Active Network Management
BSUoS	Balancing Services Use of System (charges)
CCL	Climate Change Levy
CfD	Contract for Difference
DUoS	Distribution Use of System (charges)
EHV	Extra High Voltage (voltages above 22kV)
EUA	EU emission allowance
EMR	Electricity Market Reform
FITS	Feed-in Tariff scheme
FPP	Flexible Plug and Play
GDP	Gross Domestic Product
GW	Gigawatt
HV	High voltage (voltages above 1kV and below 22kV)
IED	Industrial Emissions Directive
kW	Kilowatt
kWh	Kilowatt hour
LCPD	Large Combustion Plant Directive
LEC	Levy Exemption Certificate
LLF	Line Loss Factor
LLO	Limited Lifetime Obligation
LV	Low voltage (voltages below 1kV)
MW	Megawatt
MWh	Megawatt hour
NBP	Notional Balancing Point
Ofgem	Office of Gas and Electricity Markets
PPA	Power Purchase Agreement
RCRC	Residual Cashflow Reconciliation Cashflow
ROC	Renewables Obligation Certificate
SCR	Selective catalytic reduction
TNP	Transitional National Plan
TNUoS	Transmission Network Use of System (charges)

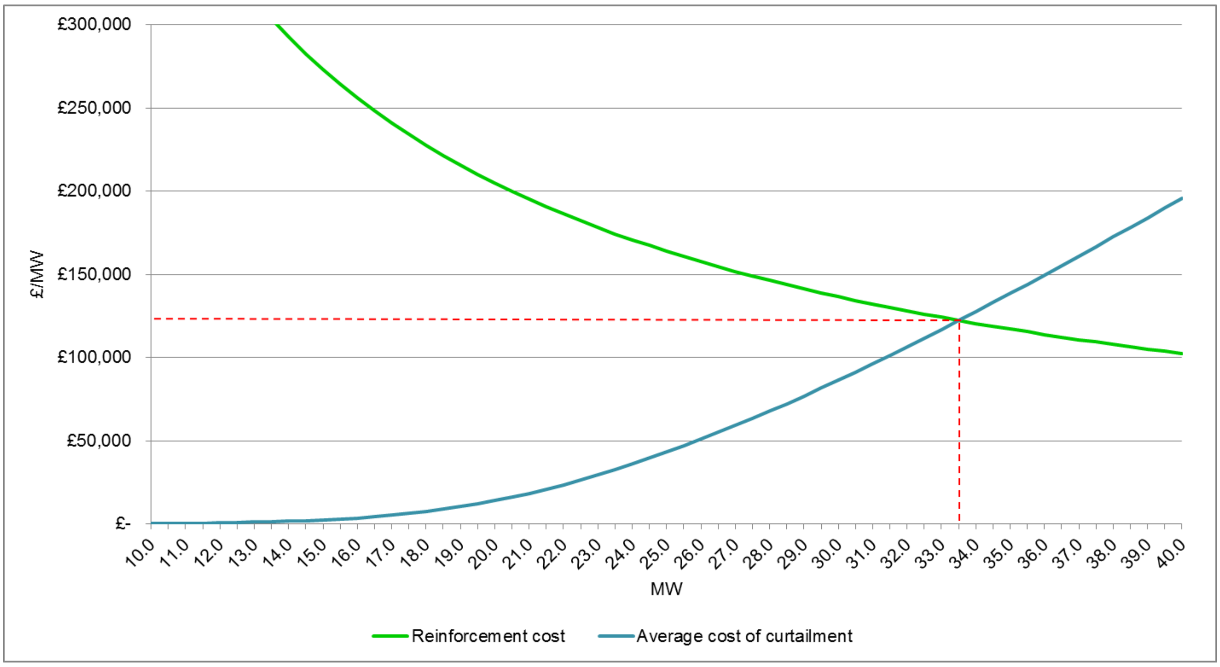
1. EXECUTIVE SUMMARY

Flexible Plug and Play (**FPP**) is a Low Carbon Networks Fund project that UK Power Networks is trialling on part of its Eastern Power Network. It aims to connect further new Distributed Generation (**DG**) without triggering network reinforcement, by using 'smart' technologies such as Active Network Management (**ANM**) to curtail generators' output in real time against network constraints.

UK Power Networks has developed smart commercial arrangements to allocate curtailment across new non-firm generators in an equitable way. Specifically, UK Power Networks has chosen to implement a **'Capacity Quota'** where curtailment is pro-rated across interruptible generators up to a cap (the quota or capacity limit) so as to provide these generators with long term certainty on the amount of curtailment (and hence revenue loss) that they are likely to experience. The size of this quota is set using the economic trade-off between the cost of curtailment and the cost of all generators sharing the cost of reinforcing the constraint.

This paper sets out the quota results, alongside our methodology and assumptions for a particular zone of the trial area known as March Grid[1]. The quota has been calculated to be **33.5MW**, where the pro-rated cost of reinforcement would be approximately **£122,000/MW** (see Figure 1 below).

Figure 1: Capacity quota calculation



[1] See section 4.2 of the Principles of Access report for further details of March Grid

2. INTRODUCTION

The commercial arrangements that UK Power Networks has decided to use to allocate curtailment are based on the Capacity Quota concept (previously referred to as Reinforcement Quota)**,** which was set out in its final report to Ofgem submitted at the end of 2012 (**PoA Report**).[2] The FPP commercial team are now working with participant generators to implement the Capacity Quota in the FPP trial area (**March Grid**).

The key principles of the Capacity Quota are as follows:

- Curtailment is allocated by pro-rating it across FPP generators contributing the constraint.
- In order to provide long-term certainty to generators around the likely long term levels of curtailment, the capacity of additional generation with which they will be pro-rata curtailed will be capped – termed a quota or capacity limit.
- This quota is to be sized based upon the anticipated economic trade-off between the cost of curtailment that generators are experiencing, (through revenue losses) and the shared cost of reinforcing the constraint. Put another way, the quota will be sized where the projected cost of curtailment equals the cost of reinforcement when it is shared between all non-firm generators in the quota.
- This means that in the long term, the reinforcement quota provides the interruptible generator group with a cost efficient path to a firm connection where it is economic for them to reinforce.

As such, the quota calculation involves modelling the likely level of curtailment as the quantity of interruptible generation increases, and the impact that this has on generators' lost revenues. UK Power Networks has commissioned Baringa Partners to calculate the size of the capacity quota for March Grid. This document is structured as follows:

- Section 3 sets out the input assumptions used to set the quota;
- Section 0 sets out the methodology used to set the quota;
- Section 5 sets out the results of the analysis; and
- Annex 1 sets out in detail the revenue loss assumptions underpinning the quota calculation.

3. INPUT ASSUMPTIONS

The quota calculation requires the following inputs:

- An accurate forecast of the cost of reinforcing the constraint in the future;
- Modelling of likely levels of curtailment as further generation connects; and
- Assumptions about the financial impact of curtailment on generators;

These are described in the sections below.

[2] The "*Principles of Access Report - Final Report on smart commercial arrangement for generators connecting under the Flexible Plug and Play Project"*, December 2012

3.1. Reinforcement Cost

The March Grid constraint is characterised by excessive reverse power flows on the existing transformers. The limit of reverse power flows has been reached with current volumes of firm generation, so that only interruptible connection is now possible (hence the trial of FPP in the area). Further firm connections in the area would require the transformers to be reinforced to 90MVA, an increase of 45MVA. UK Power Networks' Asset Management team currently forecast this reinforcement to cost **£4.1m.**

3.2. Curtailment

To calculate the Capacity Quota, we have used Smarter Grid Solutions' modelling results, choosing a scenario where the transformers are deemed to be operating at 45MVA, and using a conservative assumption of 11MW of micro solar generation connecting at lower voltage levels by 2034. We have also assumed that future connections will all be wind projects, which is justified considering the pipeline of DG planning applications that exist at present. Please refer to the "*Flexible Plug and Play: Curtailment Assessment Methodology*" report for detail on curtailment estimates.

3.3. Revenue Loss

The revenue loss assumptions are set out in detail in Annex 1 below, however the key assumptions are summarised in Table 1 below.

These have been built up from industry sources (e.g. updated banding review reports and Feed-in tariff tables), Redpoint Energy's[3] internal price forecast as well as verification with the recruited generators that are looking to connect at March Grid. As subsidy levels vary depending on the name plate capacity of the plant, it has been important to segment revenue loss by a number of different generator types.

Table 1: Summary of key revenue loss assumptions

Item	Assumption
Wholesale power	Discounted station gate price from Redpoint's Reference Case (January 2013)
ROCs	£40.71 (2012/13 buyout) + £4.07 recycle value, multiplied by ROC banding from 2013 (0.9 ROCs/MWh for onshore wind) = **£40.32/MWh**
FITs	Taken from FIT tariffs to apply from April 2013: Wind 0.5MW = 17.5p/kWh or **£175/MWh** Wind 1MW = 9.5p/kWh or **£95/MWh** Wind 2.5MW = 4.48p/kWh or **£44.80/MWh**

[3] Redpoint Energy is a business of Baringa Partners LLP

LECs	Discounted prices from Redpoint's Reference Case (January 2013)
Embedded benefits	Includes total benefits accrued across all parties. Breakdown assuming 1MWh of an HV connected wind generator using 2013 power price: – Generator Balancing Services Use of System (BSUoS) savings (average of last 2.5 years – RCRC = £1.375/MWh) – Generator transmission losses savings (45% of 1.6% losses, multiplied by generator gate price) (£0.36/MWh) – Supplier BSUoS savings (£1.375/Mwh) – Supplier transmission losses savings (55% of 1.6% losses, multiplied by NBP price (gate price plus generator BSUoS and transmission savings) (£0.45/MWh) – Supplier distribution losses savings (2013 LLF multiplied by NBP price) (£2.51/MWh) – Negative DUoS charges (£0.51/MWh) Total **£6.58/MWh**
PPA discounts	Wholesale Power: **85%** ROCs: **90%** LECs: **85%** Embedded benefits: **50%**
Marginal tax rates	As per 2012 budget: 26% in 2012, 25% in 2013 and assumed 21% thereafter (constant).

4. METHODOLOGY

The methodology for setting the capacity quota is as follows:

- Average annual curtailment (calculated as the number of MWh of lost production) for 0.5MW of wind generation is modelled as increasing capacity of generation is connected to the network;
- For each volume of generation connected behind the constraint, the revenue loss for each 1MW of capacity is calculated as the net present value of the annual revenue loss per year over the life time of the project (assuming 20 years and net of marginal taxation).
- This is compared against the shared reinforcement cost, calculated as the total cost (£4.1 million) divided by the capacity of generation connected behind the constraint;

- The capacity quota is the capacity of generation at which the cost of curtailment and the prorated reinforcement lines intersect.

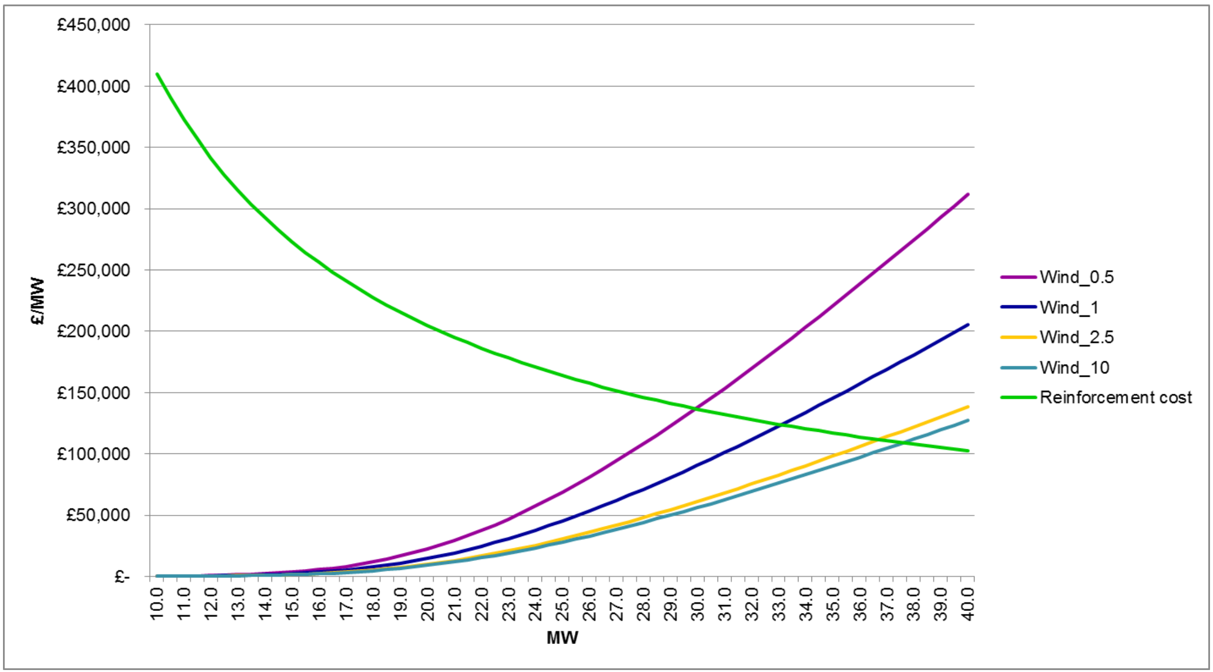
This methodology assumes that revenue loss is equal across all generators. As shown above and in Table 2, depending on the capacity of the generator in question, revenue loss will in fact differ.

Table 2: Assumed Government support schemes for different generator sizes

Generator class	Scheme	FIT generation tariff (£/MWh)	ROC value (£/MWh) *(buyout + recycle)*
Wind_0.5	FIT	175	
Wind_1	FIT	95	
Wind_2.5	FIT	44.8	
Wind_10	RO		40.39 *(post PPA discount)*

Given the diversity in opportunity cost across these different generator types, the trade-off between the cost of reinforcement per MW of capacity against the revenue loss over the project lifetime produces different quotas for each generation type – as shown in Figure 2 below.

Figure 2: Cost of curtailment for different 'classes' of wind generation



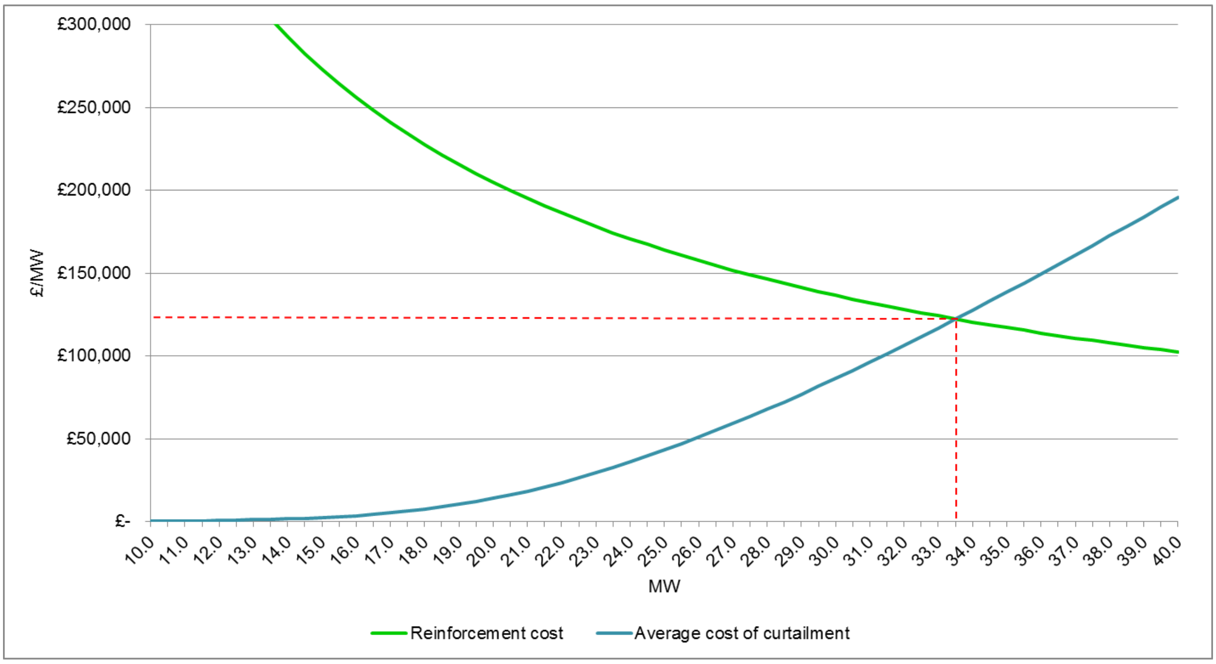
In view of this, an average revenue loss for all generator types is needed to return a single quota to be applied across all generators. This average position should reflect the most likely revenue loss experienced by a generator randomly selected from the existing pipeline. As such, we have opted for a weighted average that reflects the relative contribution of different generator types to that pipeline.

5. RESULTS

5.1. Quota Size

On the basis of the assumptions and methodology set out in Sections 3 and 4 above, the reinforcement quota for March Grid is **33.5MW**. This is shown in Figure 3 below

Figure 3: Capacity quota calculation using weighted average cost of curtailment



5.2. Savings to be realised from coordinated reinforcement

If all the interruptible capacity in the quota shared the cost of reinforcement at the point that the 33.5MW quota is exactly filled, and assuming all generators chose to contribute to the cost of the £4.1m reinforcement on a prorated basis, the total capital cost of FPP can be calculated for each project (i.e. excluding curtailment cost in lost revenue in the period between initial interruptible connection and the completion of the reinforcement scheme, if funded). This results on a shared reinforcement cost of approximately £122,000/MW.

ANNEX 1
REVENUE LOSS ASSUMPTIONS

1. REVENUE CALCULATIONS PER TECHNOLOGY

The revenue calculations for the generation technologies that have been considered in the curtailment analysis for March grid in Table 1.1 below have been updated. Wholesale power and LECs are projected to vary each year, so values from Redpoint's Reference Case for 2013 (49.82 £/MWh and 5.09 £/MWh respectively) have been used.

Table 1.1: Revenue loss breakdown per technology (per 1 MWh curtailed) [4]

Technology _(MW)	Support Scheme	Electricity (£/MWh)	FIT tariff (£/MWh)	ROC value (buyout + recycle) (£/MWh)	LECs (£/MWh)	Explicit embedded benefits (£/MWh)[5]	Totals (£/MWh)
Wind_0.5	FIT	42.35	175		4.33	3.29	**224.97**
Wind_1	FIT	42.35	95		4.33	3.29	**144.97**
Wind_2.5	FIT	42.35	44.8		4.33	3.29	**94.77**
Wind_10	RO	42.35		36.27	4.33	3.29	**86.24**
Solar_1	FIT	42.35	71		4.33	3.29	**120.97**

A fully worked example for 1 MWh loss for Wind_10 is provided in Table 1.7.

2. WHOLESALE ELECTRICITY PRICE ASSUMPTIONS

This section provides details of the assumptions surrounding our Reference Case for wholesale power price projections.

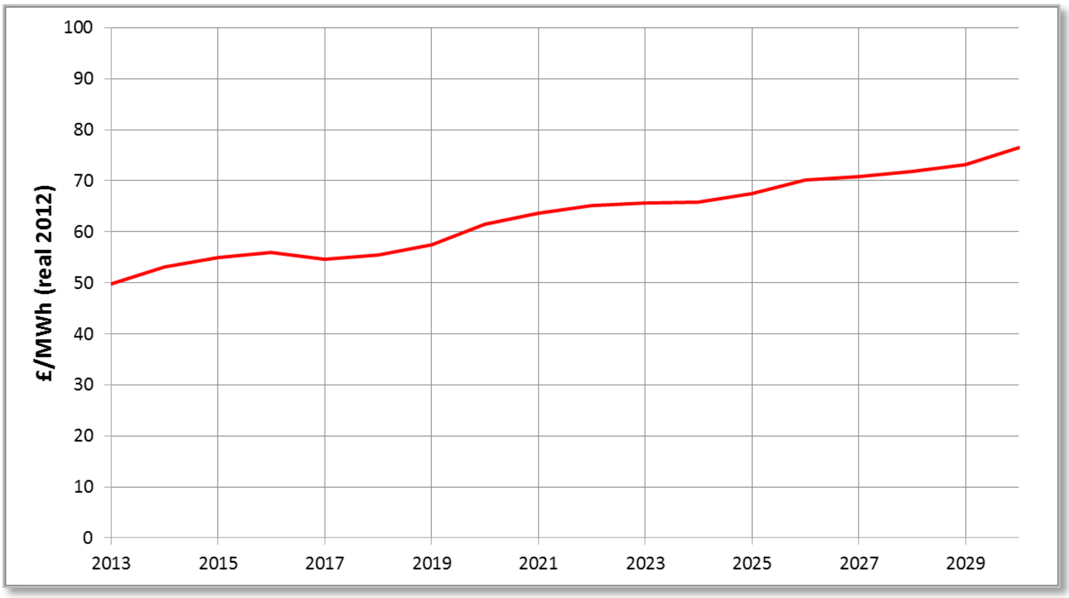
2.1. Redpoint Energy Reference Case

In the PoA Report, Redpoint Energy's 'Reference Case' was presented as the wholesale electricity price projection, which was sourced from Redpoint Energy's GB Power Market Report (November 2012). This has since been updated (see Figure 1.1 below).

[4] Figures rounded to 2d.p. – calculations for defining the quota will consider full values of prices and factors

[5] Assumes that all generators are connected to the HV network for Line Loss Factors (LLFs) and Distribution Use of System Charges (DUoS) (see paragraph 4.4)

Figure 1.1: Wholesale electricity price projections (January 2013)



Note: Prices are projected on a real terms basis, and on a station gate basis (i.e. they are not adjusted to be prices at Notional Balancing Point (NBP), which also incorporate Balancing Services Use of System (BSUoS) costs and transmission losses costs).

The Reference Case represents Redpoint's central view on the evolution of the GB power market. It is based on our current in-house reference assumptions, taking into account market and regulatory information available at present, and commodity price forward curves. Under the Reference Case, the Government continues to pursue a balanced energy policy, attempting to meet the sometimes competing demands of security of supply, competitive market structure, and environmental sustainability. Key assumptions are set out in Table 1.2 and the bullet points below:

Table 1.2: Reference Case summary of assumptions

GDP and demand	Oil prices	Gas prices	Coal prices	EUA prices
GDP growth of 2% per annum and underlying energy demand growth of 1%, offset by energy efficiency and increased by electrification	Forward curve to 2016, then trends to IEA Current Policies case of 149.6 $/bbl in 2035	Forward curve to 2014, then linked to oil curve	Forward curve to 2015, then trends towards IEA's long term price of 128.9 $/t in 2035	Forward curve to 2015, then trends towards 46.5 €/t in 2030, and held flat thereafter

GB specific assumptions:

- The rate of renewables development is consistent with earnings under the Renewables Obligation and we assume a similar level of remuneration under Contracts for Difference (CfDs).

- The carbon price used in the Reference Case is the greater of the European emissions allowance (EUA) price and the Carbon Price Floor trajectory. Until 2020, we assume the Carbon Price Floor follows the trajectory announced by the Government in the 2011 Budget. After 2020, we assume a constant Carbon Price Floor trajectory of 30 £/t. In the Reference Case the modelled EUA price becomes greater than the Carbon Price Floor around 2028.

- Capacity Payments are introduced. Currently the details of the capacity payment mechanism have yet to be finalised. Therefore we assume a form of universal capacity mechanism based on annual capacity auctions, as outlined in the November 2012 Electricity Market Reform (EMR) policy documents.

- The Magnox nuclear plant are decommissioned in accordance with the current schedule. The operating lifetimes of the Hinkley Point B and Hunterston Advanced Gas-cooled Reactors (AGR) plant have received approval for lifetime extensions of up to seven years each[6]. In addition, we have assumed that Dungeness B, Heysham 2 and Torness AGR plant are extended for a limited period of seven years, although the availability of plant is assumed not to improve from current levels.

- Large Combustion Plant Directive (LCPD) opt out plant are assumed to retire at various points before the end of 2015, depending on their remaining running hours. Most coal plant is assumed to opt for the Limited Lifetime Obligation (LLO) under the Industrial Emissions Directive (IED), though some capacity opts to fit SCR. Gas fired plant affected by the Directive is assumed to split relatively evenly between the Transitional National Plan (TNP) and LLO.

- Tilbury Power station is converted from coal to biomass firing. One unit of Ironbridge coal power station is assumed to convert to biomass-firing in 2013. Three units of Drax Power station are assumed to convert to biomass in the medium term, and we have also assumed that all units of Eggborough Power Station convert to full biomass firing, giving a total installed capacity of 4 GW in 2020 and corresponding generation level of 19 TWh.

3. ENVIRONMENTAL AND EMBEDDED BENEFITS

This section provides a list of the green and embedded benefits that the March Grid developers will expect to receive as part of their project's revenues. They include revenues from:

- Renewables Obligation Certificates (ROCs) *or* Feed-in Tariffs (FIT),

- Levy Exemption Certificates (LECs),

- and embedded benefits.

[6] Source: Office for Nuclear Regulation (ONR), EDF Energy, other sources.

3.1. ROCs

3.1.1. Description

The Renewables Obligation is the Government's main financial support mechanism for developing large scale renewable generation. It works by putting an annual obligation on licensed electricity suppliers to source a certain percentage of the electricity that their customers demand from renewable generators. Suppliers demonstrate their compliance by presenting ROCs at the end of each year, which are often bought from generators at the same time as electricity in a PPA, or sold in the market through auctions.

If suppliers do not present ROCs at the end of the year then they can pay a penalty (the 'buy-out price'). Penalty monies are recycled back to those suppliers who presented ROCs.

Ofgem E-Serve administers the scheme, and also provides ROCs to accredited generators to sell to suppliers. Different technologies need to produce different levels of generation in MWh to receive one ROC (depending on their costs and level of commercial development). These levels are set in the Government's banding review[7].

The Government also sets the supplier obligation levels using a headroom calculation, which aims to provide a stable margin between the supply of ROCs from generators, and the demand for ROCs from suppliers, so that there is never a risk of oversupply of ROCs (which would cause the ROC value to plummet to zero). This practice creates a structurally short market, and means that there will always be some suppliers who are unable to meet their obligation, and will have to pay the buy-out price.

The Government's current headroom target is 10%. If the supply and demand for ROCs turns out to be as the Government expects, the recycle value should calculate to be exactly 10% of the buyout price. In recent years, the ROC turnout has deviated from the Government's expectations, with the recycle value varying between 8% and 41% of the annual buyout price over the last three years. While this variation is considerable, we think that it is reasonable to use the Government's headroom target as a proxy for this exercise.

The 2013 banding review decision means that onshore wind generators will be entitled to 0.9 ROCs/MWh from April 2013. In September 2012, the Government issued a call for evidence on the costs of onshore wind, and may make a further change to its banding decision, which will be implemented by April 2014 at the earliest (though there is considerable uncertainty around whether the level will change, and if so, what the new level will be – so for the purposes of this calculation we use the April 2013 banding level).

It follows that suppliers should be willing to pay up to the value of the buy-out price, plus the expected recycle value, for one ROC. Generators will agree this price with suppliers in a PPA. If generators are curtailed, their opportunity to produce ROCs at that point in time is lost, and their lost ROC revenue will be equal to the number of ROCs they expected to produce, multiplied by the price agreed with the supplier.

3.1.2. Revenue loss calculation

The calculation of the capacity quota requires a view of the value of 1 ROC to the FPP developers ahead of discounting with their supplier. The value of a ROC has been calculated from the 2012-13 buyout price (40.71 £/ROC) and a recycle value of 10% of the buyout price at 4.07£/ROC (in line with the Government's 10% target for the headroom between supply and demand for ROCs) has been assumed. The total is **44.78 £/ROC**. For

[7] The latest banding review applies for the period April 2013 – March 2018.

each technology, the ROC value is then multiplied by the technology banding applicable from April 2013[8] to produce a ROC value in £ per MWh prior to any PPA discount (i.e. 0.9 ROC/MWh for onshore wind).

3.2. Feed-in Tariff rates

3.2.1. Description

The Feed-in Tariff Scheme (FITS) was implemented in 2010 for small scale renewables and low carbon generation deployment. Generators under 50kW can only apply for the FITS, whereas generators above 50kW but below 5MW can make a one-off choice between the RO and FITS.

The FITS provides generators with a guaranteed support payment for each unit of electricity they produce, plus the option to sell the electricity that they export back to the network (i.e. electricity that has not been consumed on site) at a fixed rate called the export rate. The Government sets the Feed-in Tariff rates and export rates for different technologies and Ofgem E-Serve administers the scheme.

The relative simplicity of the FITS is appealing to small developers and those without the means to value and negotiate the sale of ROCs. Further, developers may also choose to opt out of selling power at the export rate and can strike up a PPA for the sale of power and other benefits instead (mainly larger developers).

3.2.2. Revenue loss calculation

If FITS generators are curtailed, then they are unable to claim the Feed-in Tariff support payment and the export rate or agreed electricity price in a PPA.

For the Feed-in Tariff payment, the revenue loss is equal to the Government set tariff rates, which are taken from the rates published on Ofgem's website applying to the period 1 December 2012 to 31 March 2013, and 1 February to 1 May 2013 for photovoltaic installations. Relevant tariff rates are listed in Table 1.3 below.

Table 1.3: Feed-in Tariff rates for relevant technologies for FPP

Technology and capacity	Feed-in-Tariff p/kWh	*£/MWh*
Wind 0.5MW	17.50	*175.00*
Wind 1MW	9.50	*95.00*
Wind 2.5MW	4.48	*44.80*
Solar 1MW	7.10	*71.00*

While this approach could apply for the lost electricity revenues (at the export rate), for the FPP developers we have assumed that the FITS generators would sell power in a PPA instead of taking the export rate. This is because they are of sufficient size where they would have access to commercial expertise to develop PPAs with suppliers, to try to extract more value than would be possible at the export rate. This means that our assumed electricity revenue loss is the same as our wholesale market price projections, adjusted by the assumed PPA discount. Even after PPA discounting, the power price received is greater than the export rate.

[8] From the Government's response to the consultation on proposals for the levels of banded support under the Renewables Obligation for the period 2013-17 and the Renewables Obligation Order 2012.

3.3. Levy Exemption Certificates

3.3.1. Description

Levy Exemption Certificates (LECs) are proof of exemption from the Climate Change Levy (CCL). The CCL is a tax on the use of energy in industry, commerce and the public sector to encourage these sectors to become more energy efficient and to reduce their greenhouse gas emissions. The tax is applied to fuels including gas, petroleum, coal and lignite. It is not applied to fuels for generating electricity, but is applied to electricity itself (to avoid double counting).

Electricity generated from renewable resources is not subject to the CCL. These generators collect LECs from Ofgem E-Serve for each MWh that they produce. The designated industry sectors are willing to buy these certificates to decrease their overall CCL exposure, and should be willing to pay a price up to the prevailing CCL rate for electricity as long as demand for LECs outstrips their supply. Similar to ROCs, the value received for LECs is often negotiated in an off-take agreement such as a PPA.

3.3.2. Revenue loss calculation

In Redpoint's Reference Case, we assume that the price received for LECs falls from 2014 onwards as a result of the a growth in the supply of LECs from increasing amounts of renewables generation exceeding the growth in demand from industry (also owing to the reduction in levy for energy intensive users). Redpoint's Reference Case has been used to calculate the value of LEC prices across the lifetime of the projects, and discount these to NPV.

3.4. Embedded benefits

Generators and suppliers normally face various charges for using the transmission system and the distribution system. These charges are related to either the cost of building and maintaining the network, the cost of balancing and managing flows on the network, or the cost of electricity losses (arising from resistance). These charges are listed in Table 1.4 below.

Table 1.4: Transmission and distribution system charges

Name of charge	System	Who pays? (Ratio)
Transmission Network Use of System (TNUoS)	Transmission	Generators and suppliers* (27:73)
Balancing Services Use of System (BSUoS)	Transmission	Generators and suppliers* (50:50)
Transmission losses	Transmission	Generators and suppliers* (45:55)
Distribution Use of System (DUoS)	Distribution	Suppliers* and generators (specific)
Distribution losses	Distribution	Suppliers*

*Note that 'suppliers' is used here but can also be interchanged with 'demand customers'.

Generators ensure that their electricity prices are adjusted to recover these charges by quoting their prices upwards to cover the costs (i.e. prices at NBP). Suppliers ensure that their billing covers their share of the charges.

However, if generators are able to embed within the distribution network, they do not have to pay some, or all of these transmission related charges. This is a relative advantage to other generators connected to the transmission system, as they may be able to collect or reference the same price as transmission connected generators (the NBP price), but they do not have to pay the same costs. These benefits are refered to as 'implicit benefits'.

Suppliers also benefit from buying electricity from these embedded generators, as it lowers their overall demand from the transmission system, meaning that they too can alleviate themselves of transmission related charges. The reduced flows also mean that suppliers pay less in terms of distribution losses (which are normally greater than transmission losses owing to the lower voltage of flows). We call these benefits 'explicit benefits'. The two parties will normally negotiate the sharing of benefits provided from the generator's embedded connection.

For the revenue loss calculations, embedded benefits are considered to include both implicit and explicit benefits.

We have adopted the conservative view that there will be no Triad benefit accruing to FPP generators due to their intermittent characteristics, so there is no Transmission Network use of System (TNUoS) benefit.

3.4.1. Transmission losses

The transmission losses component of embedded benefits comprises:

- the generator's share of overall transmission losses (45% of the current average 1.6% losses), multiplied by the wholesale price at 'station gate' (not including NBP adjustments)
- the off-taker's share of overall transmission losses (55% of the current average 1.6% losses), multiplied by the NBP price (which is calculated as the sum of the station gate price, and the generator's transmission losses and BSUoS costs).

3.4.2. BSUoS

The BSUoS component of the embedded benefits is the generator and offtaker's BSUoS costs, calculated from the average of the last two and a half years' annual BSUoS less the average Residual Cashflow Reallocation Cashflow (RCRC). This figure is 1.375 £/MWh for each party (i.e. 2.75 £/MWh total).

3.4.3. Distribution line losses

The distribution losses component of embedded benefits is calculated as the product of the time weighted average of UK Power Network's Line Loss Factors (LLF) from its Indicative Charging Statement for Eastern Power Networks from April 2013, and the NBP electricity price.

The time weighted average for Extra High Voltage[9] (EHV) networks is calculated to be 1.011, the weighted average LLF for High Voltage[10] (HV) networks is calculated to be 1.049 and the weighted average LLF for Low Voltage[11] (LV) networks is calculated to be 1.076.

[9] Nominal voltages of 22kV and above
[10] Nominal voltages of at least 1kV and less than 22kV
[11] Nominal voltages of 1kV or less

3.4.4. DUoS

Embedded generators can benefit from negative DUoS charges (i.e. they are paid to use the network at certain periods). DUoS charges vary between different voltage levels, types of generation and times of the day. For simplicity, we have calculated a time weighted average for each voltage level – see Table 1.5 below. EHV tariffs vary between sites and will need to be calculated specifically by UK Power Networks. All unit rates are extracted from UK Power Network's Indicative Charging Statement from April 2013.

Table 1.5: DUoS tariff calculations

DUoS tariff	Fixed charge (p/MPAN/day)	TWA Unit rate (p/kWh) (negative is benefit)	*£/MWh*
LV Generation Intermittent		-0.079	*-0.79*
LV Generation Non-Intermittent		-0.879	*-8.79*
HV Generation Intermittent	41.44	-0.051	*-0.51*
HV Generation Non-Intermittent	41.44	-0.570	*-5.70*
EHV (all)	*Requires consultation with UKPN*		

4. PPA DISCOUNTING

Embedded generators of a certain size generally sell their power, environmental benefits and embedded benefits through a PPA with an off-taker such as an electricity supplier. The value that the generator receives for each of these items is subject to a discount offered or negotiated with the off-taker (in return for assuming certain risks – egg liquidity risk, and/or balancing risk).

Therefore the revenue loss calculations assume PPA discounting across each of these items. The discount level assumption for each PPA item is listed in Table 1.6 below.

Table 1.6: PPA discount rate assumptions

PPA item	Value received by generator after discounting
Electricity output	85%
ROCs	90%
LECs	85%
Explicit embedded benefits	50%

All values listed in the preceding sections and in the PoA Report are 'vanilla' values, taken before PPA discounting is applied.

5. CORPORATE TAX

For this exercise, we assume that each curtailed MWh would have been marginal profit, and therefore would be charged at marginal tax rate (rather than any average tax rate). We use UK corporate tax rate and apply it to curtailed revenues at 24% in 2013, and at 21% thereafter in line with the UK Government's 2012 Autumn Statement announcement.

6. USING THE REVENUE LOSS ASSUMPTIONS TO CALCULATE THE QUOTA

The 'cost of curtailment' is calculated by using these assumptions with curtailment modelling results to work out the cost of curtailment at different levels of connected non-firm distributed generation for one year. This is then applied across the lifetime of the project and discounted to compare against the shared cost of reinforcement. We use a hurdle rate of 10%, and an assumed project life of 20 years.

7. EXAMPLE OF REVENUE LOSS CALCULATION

Finally, this section includes a worked example below of the revenue loss calculation for an RO supported onshore wind generator connected at HV for 1MWh of curtailment, using an illustrative prices for wholesale power and LECs taken from Redpoint's Reference Case for 2013 (49.82£/MWh for power; 5.09£/MWh for LECs in real (January 2012) terms).

Table 1.7: Worked example of revenue loss calculation for 1MWh of curtailment for RO onshore wind

Item	Calculation (£/MWh)	PPA discounting	Total £/MWh
Wholesale power	*Illustrative example from Redpoint Reference case 2013 (station gate) = 49.82*	*85% * 49.82*	**42.35**
ROCs	*(40.71 + 4.07) * 0.9 = 40.32*	*90% * 40.32*	**36.27**
LECs	*Illustrative example from Redpoint Reference case 2013 = 5.09*	*85% * 5.09*	**4.33**
Embedded benefits *(Generator transmission losses)* *(Generator BSUoS)* *(Supplier transmission losses)* *(Supplier BSUoS)* *(Distribution line loss)* *(DUoS)*	*45% * 1.6% * 49.82 = 0.36* *1 * 1.375 = 1.38* *55% * 1.6% * (49.82+1.38+0.36) = 0.45* *1 * 1.375 = 1.38* *4.9% * (49.82+1.38+0.36) = 2.53* *1 * 0.51 = 0.51*	*50% * 6.60*	**3.30**
Totals	*101.84*		**86.25***

***Note:** Uses rounding to 2 decimal places. Actual calculations consider full values.