Oxera

What is the impact of changes to the co-firing cap?

Prepared for
Department of Energy and Climate Change

September 2009

URN 09D/752

Executive summary

Co-firing has made a significant contribution to renewable electricity generation in the UK, and is supported through the Renewables Obligation (RO)—the government's primary tool for encouraging the large-scale deployment of renewable electricity.[1] However, the role of co-firing in the RO has been reviewed on a number of occasions, and revised through changes in the cap placed on the extent to which co-fired Renewable Obligation Certificates (ROCs) can be used by licensed electricity suppliers within the scheme.

This study provides an analytical basis to inform decisions by the Department of Energy and Climate Change (DECC) on whether to remove, loosen or retain the cap on co-firing. Analysis is provided to:

– determine the impact of the cap on co-firing on the ability of independent co-firers (those generators without a major licensed electricity supply business) to expand co-firing capacity to meet their economic potential.

As set out in DECC's Terms of Reference, economic potential is defined in this report as the output deployable under current or reasonably foreseen economic conditions.[2] In the event that the cap does limit the economic potential of independent generators, analysis is provided to:

– quantify the impact on other technologies (including the impact on ROC prices and investment) of solutions such as removing or loosening the cap on co-firing.

The role of co-firing in the RO

The RO requires licensed electricity suppliers to source a specific and annually increasing percentage of the electricity they supply from renewable sources; such supply must be evidenced by the production of ROCs. Licensed suppliers can meet their obligation by: presenting ROCs; paying a buyout price linked to the retail price index (equivalent to £35.76/MWh in 2008/09); or a combination of presenting ROCs and paying the buyout price.

From 2009/10, the banding proposals dictate that the number of ROCs issued for each megawatt hour of electricity generated is dependent on the technology used to generate that electricity. Co-firing with regular biomass receives 0.5 ROCs/MWh.

The number of ROCs that have been generated from the co-firing of regular biomass that a licensed electricity supplier can submit is currently capped at 10% of the supplier's total obligation, and will increase to 12.5% in April 2010.

Following previous government consultation, the 10% co-firing cap was believed necessary in order to mitigate the risk that the potential volatility of co-firing volumes could have on ROC prices. However, the government committed to review the cap if there is evidence that it is leading to a material restriction on competition.[3]

[1] In 2007, co-firing of biomass with fossil fuels generated around 2TWh of electricity, equivalent to around 10% of total renewable generation behind 'wind and wave', hydro and landfill gas. Source: Digest of UK Energy Statistics.
[2] Output deployable is interpreted to mean that which is technically feasible and economically rational to deploy, given prices for coal, biomass, electricity, and support revenues, absent any potential distortions from the co-firing cap.
[3] BERR (2008), 'Reform of the Renewables Obligation: Statutory Consultation on the Renewables Obligation Order 2009', June, p. 27. Available at http://www.berr.gov.uk/files/file46838.pdf.

While this study is focused primarily on the potential benefits of changes to the cap that relate to the ability of independent generators to compete, proponents of removing the cap highlight that other benefits could include: improvements in efficiency, if it were to promote a greater use of co-firing, which is a relatively low-cost renewable technology; the strengthening of incentives to develop an indigenous supply of biomass; and promoting the longer-term development of energy crops.

Against this, respondents to the government's previous consultations have warned that greater co-firing could lead to: increased ROC price volatility, deterring investment in other technologies; the undermining of investor confidence, through perceptions of future regulatory change; and increased total emissions, due to the dependence of co-firing on the joint production of coal-fired electricity.

The nature of competition for co-fired ROCs

The impact of the co-firing cap on independent generators' ability to meet their economic potential depends on the influence of the cap on those generators' output. This in turn is driven by the impact on demand for co-fired ROCs and their interactions with competing sources of supply.

Risks to the ability of independent generators to compete include the following.

– The market for independent generators may be smaller than that implied by the cap if vertically integrated suppliers 'self-supply' a considerable proportion of their demand.

– Independent generators may curtail output below the level at which they perceive there is a risk that a large supplier with a residual share of demand could negotiate significant ROC price discounts.

– Concentrated suppliers with significant bargaining power may be in a position to alter the timing of their demand, delaying the purchase of co-fired ROCs to the end of the compliance period, to the disadvantage of independent suppliers.

– Vertically integrated players have scope to increase their co-firing output through increased co-milling, which may provide the possibility that the co-firing cap becomes binding.

Set against this, these risks might be expected to be less prominent in the medium and long term, with the key factors mitigating any adverse effects including the following.

– Banding effectively doubles the cap as each megawatt hour of co-firing output is entitled to 0.5 ROCs.

– The volume of coal capacity, and hence the ability to co-fire, is set to decrease significantly in line with plant retirements.

– The size of the cap (in ROCs) will increase significantly over the next ten years, with increases in the RO size.

– Increased co-firing of energy crops from other generators increases the scope for independent generators to provide co-fired ROCs from regular biomass that is subject to the cap.

In summary, the structure of the players in the market for co-firing—in terms of both vertical integration and the concentration of such players—implies that the demand that independent generators compete to serve may be significantly smaller than that implied by the co-firing cap.

Based on the likely retirement of existing coal plant, and the previous historical co-firing output of vertically integrated generators, the co-firing cap might not be expected to be binding in the medium term. This is, in large part, due to the banding assigned to co-firing, which effectively doubles the cap.

However, past output decisions, by their nature, reflect the current imposition of the cap. If vertically integrated companies were to increase output to make full use of co-milling (which would require relatively little capital expenditure), the cap would become binding for independent generators wishing to invest in new capacity—and might be particularly acute in the period up to 2012/13. This also suggests that an increase in the level of the co-firing cap to around 20% could reduce the risk of the cap becoming binding under the most extreme scenario of potential output.

The volume of co-firing which it is economic to produce may be substantially less than that based on technical potential if the level of biomass prices is sufficiently high. As such, under the high biomass price scenario analysed in the second half of this study, changes to the level of the cap might not be expected to elicit increased levels of co-firing, or any of the other potential benefits, such as increases in total renewable generation or reduced carbon emissions.

Impacts of possible changes to the co-firing cap

A number of model scenarios have been examined to help substantiate concerns regarding the impact of changes to the co-firing cap on ROC prices and investment in other technologies.

The scenarios use DECC's commodity price assumptions and are developed using Oxera's GB Power Model and Renewables Model. The scenarios do not adopt the full set of assumptions used to generate DECC's projection of 29% renewable electricity by 2020 (presented as part of its consultation on renewable financial incentives),[4] but have been developed to examine the impact of changes to the level of the co-firing cap in light of:

– different commodity price assumptions, and hence the operation of coal plant;
– variations in biomass prices;
– changes to future banding levels for other technologies;
– the extent to which investment decisions discount the uncertain element of ROC prices.

The central scenario, which draws on biomass prices based on the study commissioned by DECC from E4Tech, suggests that it is likely to be economic to increase the level of co-firing significantly from current levels. If biomass prices are higher than those assumed, co-firing levelised costs may be higher than those contained within the analysis, which may act to reduce the level of co-firing deployment and dampen the effect of possible changes to the co-firing cap on the ROC price and other technologies.

The assumptions within this report can therefore be considered relatively conservative, in order to help understand the extent of the possible effects associated with changes to the co-firing cap.

The analysis shows that removing the level of the cap under the central scenario would be likely to increase the volume of co-fired ROCs, particularly during the period from 2013 to 2020. The maximum increase may be likely to occur in 2012/13, when ROC volumes could increase by around 30%. Increasing the level of the co-firing cap beyond 17.5% might be expected to have little effect on total deployment and ROC prices, as technical constraints become a more important restraint on further deployment.

[4] DECC (2009), 'Consultation on Renewable Electricity Financial Incentives 2009'.

Despite the potential increase in the level of co-firing resulting from changes in the cap, the effect on ROC prices might not be expected to be as large due to the dampening effect caused by the level of support of 0.5 ROC/MWh given to co-firing, and the subsequent extension of the RO size by the headroom mechanism.

In the central scenario, the increase in co-fired volumes could cause a reduction in the ROC price, of around £2.4/MWh in 2012/13. However, due to the limited number of years in which there might be expected to be an impact on prices and that this is likely to be prior to the large-scale deployment of offshore wind, the impacts on investment are likely to be limited.

As a result, increased levels of co-firing stimulated by changes in the co-firing cap could increase total renewable deployment and have an associated lifetime reduction in carbon emissions of around 1.3 million tonnes (or 0.7%). The increase in the RO size caused by this effect could increase the cost to consumers, which is driven by the RO size and the buyout price, by around £138m (or 0.3%).[5]

The risk of more volatile year-on-year changes in the ROC price might be expected to be included within future investment decisions. However, the effect is likely to be dampened in future years as coal plant is retired. ROC price risk may also be asymmetric and mainly upwards if the RO size with headroom reflects the potential for large volumes of co-firing which are subsequently not produced in later years. Analysis that examines the impact of increasing the discount applied to the variable portion of ROC prices within the investment decision highlights the possibility of delays to the deployment of certain projects by around one year, but with similar total levels of deployment by 2020.

The quantitative analysis in this report suggests that, on the basis of assumptions targeted to highlight the upper end of the range of potential co-firing output, an increase in the co-firing cap to 17.5% could be sufficient to ensure that technical rather than policy constraints are binding, which would act to increase the ability of independent co-firing generation to compete.

The case for reduced policy constraints on co-firing output is supported by the analysis, which suggests that the effects on ROC prices and total renewable investment over the long run might be expected to be limited, while the potential benefits include a reduction in the risk of distorting the ability of independent generators to compete, and also a potential increase in total renewable generation with the associated reductions in carbon emissions. Such benefits should be weighed against the increased costs to consumers from the potential increase in the RO size, and the impact on investment of perceived future regulatory changes caused by an increase in regulatory risk.

[5] This refers to the discounted lifetime costs.

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1 Introduction

Co-firing has made a significant contribution to renewable electricity generation in the UK and is supported through the Renewables Obligation (RO)—the government's primary tool for encouraging the large-scale deployment of renewable electricity.[6]

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The report is structured as follows.

– Section 2 sets out the policy context, and describes the current operation of the RO and changes affecting co-firing since 2002. It also covers the rationale for these proposed changes and consultation responses.

– Section 3 examines the nature of the interaction between co-firing generators and licensed suppliers, and the implications for co-fired ROC volumes and prices. This is used to explain historical market outcomes, and as a basis to discuss possible changes to the co-fired cap.

– Section 4 examines the wider impacts of possible changes to the co-firing cap under a range of commodity price scenarios. These scenarios are based on DECC fuel price assumptions but not all of the assumptions used to derive the 29% renewable electricity scenario in DECC's consultation on renewable incentives.[8] This section describes the results of modelling to help understand the possible scale of changes to the ROC price, and the implications for other renewable technologies caused by potential changes to the co-firing cap.

A discussion of the findings from a survey of co-firing generators is provided in Appendix 1; this includes an assessment of the drivers of co-firing output decisions and contracting methods, as well as participants' perceptions of the market. Modelling assumptions are provided in Appendix 2 and Appendix 3.

[6] In 2007, co-firing of biomass with fossil fuels generated around 2TWh of electricity, equivalent to around 10% of total renewable generation behind 'wind and wave', hydro and landfill gas. Source: Digest of UK Energy Statistics.
[7] Output deployable is interpreted to mean that which is technically feasible and economically rational to deploy, given prices for coal, biomass, electricity, and support revenues, absent any potential distortions from the co-firing cap.
[8] DECC (2009), 'Consultation on Renewable Electricity Financial Incentives 2009'.

2 Policy content and views of market participants

This section provides an overview of the support provided to co-firing by the RO, and describes the policy changes indicative of the role that co-firing has been intended to play within the scheme. The rationale for these changes, and respondents' views on previous government consultation, are set out in turn.

2.1 Overview of the RO and the role of co-firing

The RO requires licensed electricity suppliers to source a specific and annually increasing percentage of the electricity they supply from renewable sources; such supply must be evidenced by the production of ROCs.

Licensed suppliers can meet their obligation by:

– presenting ROCs;
– paying a buyout price linked to the retail price index (equivalent to £35.76/MWh in 2008/09);
– a combination of presenting ROCs and paying the buyout price.

Where a supplier chooses to pay the buyout price, the money it pays is placed into the Buyout Fund. At the end of the Obligation period, the Buyout Fund is recycled to those electricity suppliers presenting ROCs, which increases the value of a ROC to suppliers above the level of the buyout price.

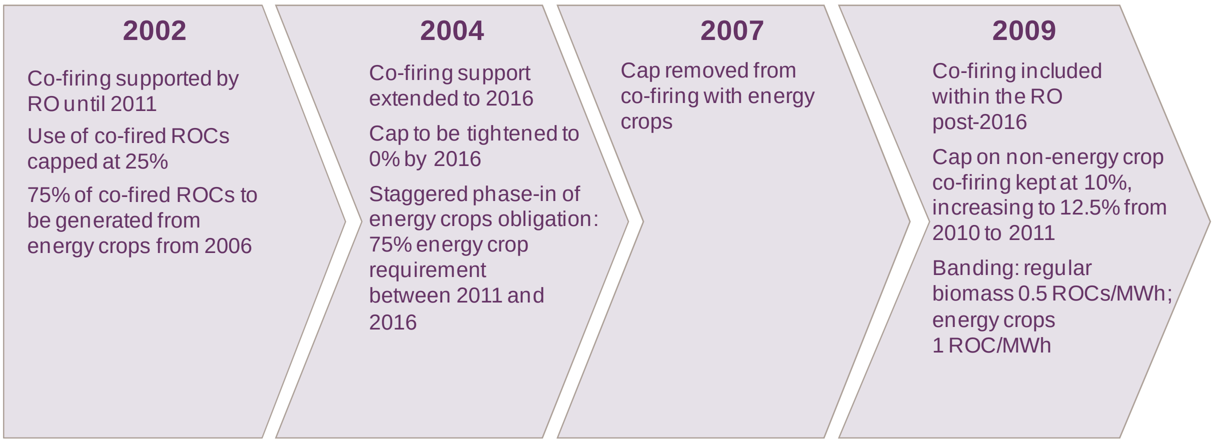
From 2009/10, the banding proposals (described in more detail below) dictate that the number of ROCs issued for each megawatt hour of electricity generated is dependent on the technology used to generate that electricity. Co-firing with regular biomass receives 0.5ROCs/MWh.

The number of ROCs that have been generated from the co-firing of regular biomass that a licensed electricity supplier can submit is currently capped at 10% of the supplier's total obligation, and will increase to 12.5% in April 2010. The recent changes to this element of the scheme, and their rationale, are discussed in more detail below.

2.2 Changes to the eligibility of co-firing within the RO

The eligibility of co-firing has been subject to a number of changes as the RO has evolved, from its introduction in 2002 to the implementation of the most recent reforms in 2009. Figure 2.1 below presents the key reforms over time.

Figure 2.1 Evolution of changes related to co-firing within the RO



Source: DTI/ BERR.

Figure 2.1 demonstrates that the major policy changes relate to the phasing-out of co-firing; the level of the co-firing cap; and the distinctions drawn between the co-firing of regular biomass and the co-firing of energy crops. The rationale for the various policy changes is described below.

Phasing out of co-firing from the RO

– **Original phasing-out proposals (2002)**. Co-firing was believed to have an important role to play in reducing carbon emissions in the short to medium term, as one of the lowest-cost renewable technologies. The support of co-firing through the RO was intended to incentivise the development of biomass supply chains (especially energy crops), at which point co-firing was expected to be commercially viable without support: phasing would, therefore, help to avoid over-subsidisation.

– **Postponement of phasing-out (2004)**. The original year from which co-firing was to cease receiving support was delayed to 2016.This was intended to provide biomass growers with a long-term market, and give them time to improve their processes and become more efficient.

– **Removal of phasing-out (2009)**. A study on the sustainability of co-firing highlighted the substantial emissions reductions delivered by co-firing; this helped shape the government's view that co-firing should be encouraged to play a long-term role in reducing emissions from the power sector.[9]

The co-firing cap

– **Introduction of the 25% cap (2002)**. The volume of co-fired ROCs that an electricity supplier could present was capped at 25% of that supplier's total obligation. This was in order to avoid an oversupply of co-firing ROCs, which was believed to be a plausible risk given the lower cost of co-firing generation, which could potentially lead to a risk of reduced ROC prices and undermine incentives to develop higher-cost renewable technologies. In addition, it was thought that larger volumes of co-firing could potentially contribute to an increase in total carbon emissions, as fossil fuels are complements of biomass in the co-firing process.

– **Tightening of the cap (2004)**. In response to the unsatisfactory development of energy crops, a number of changes in relation to the restrictions on co-firing were introduced to the RO in 2004. As explained by the DTI:

[9] Themba Technology Ltd in collaboration with the Edinburgh Centre for Carbon Management, commissioned for the DTI (2006), 'Evaluating the Sustainability of Co-firing in the UK', September 17th. www.berr.gov.uk/files/file34448.pdf.

> Minimal planting of energy crops has taken place so far and, as noted above, the industry has argued that this is, in part, due to overly restrictive rules on co-firing. We believe that modifications to the rules can be made to enhance the prospects for energy crops without a radical change to the Obligation.[10]

– Although it was recognised that the modified restrictions were likely to have only a minimal impact on ROC prices, they risked undermining investor confidence in the RO in general and ROC prices in particular, by giving rise to perceptions of higher regulatory risk. To address this, the cap on co-firing was to be gradually reduced from 25% to 10% in 2006, and further reduced to 5% from 2011, before being completely removed in 2016, coinciding with the phasing-out date.

- **Removal of the cap on the co-firing of energy crops (2007)**. This aimed to ensure continued impetus for the development of energy crops during the time between the consultation and the introduction of banding in 2009/10.

- **Cap on the co-firing of non-energy crops maintained at 10% (2009)**. Following further consultation, a 10% cap was retained (to be increased to 12.5% in 2010/11) in order to mitigate the risk of potential volatility of co-firing volumes, and the potential impact on ROC prices.[11] It was thought that the banding upgrade for co-firing with regular biomass (from 0.25 to 0.5 ROCs per MWh) increased 'the possibility that potential volatility in the volume of co-firing will have an impact on the stability of the ROC price'.[12] Further, the government committed to 'review the cap if there is evidence that it is leading to a material restriction on competition'.[13]

Obligations on the use of energy crops

- **Original obligation on energy crop content (2002)**. An obligation on co-firers to burn at least 75% energy crops from 2006 was intended to provide a clear signal to energy crop developers that there would be a secure source of demand. The factors underpinning the policy rationale for favouring energy crops over other types of biomass were that it could provide the following benefits:

  - an increased supply of energy crops minimises the impact on other biomass-using industries that could arise from greater demand from power generation;
  - the existence of indigenous biomass sources can enhance security of supply;
  - growing energy crops provides alternative commercial opportunities for farmers.

- **Relaxation of obligation on energy crop content (2004)**. Based on an independent study, it was concluded that the rules on energy crop content would be unlikely to achieve the objective of encouraging the development of energy crops, as they did not allow sufficient time for their development.[14] The requirements to co-fire certain proportions of energy crops were therefore delayed to allow more time for cropping, and were set to increase gradually, reaching 75% by April 2011.

Banding

- **Banding (2009)**. Following an initial proposal to award 0.25 ROCs/MWh to co-firing with non-energy crops, it was decided to set a level of 0.5 ROCs/MWh. Co-firing with energy

[10] DTI (2003), 'New and Renewable Energy: Prospects for the 21st Century: the Renewables Energy Obligation (Amendment) Order 2003 Strategy Consultation', p. 6. www.berr.gov.uk/files/file22098.pdf.

[11] One proposal considered suggested lifting the cap and introducing an emergency review criterion, to be triggered when co-fired ROCs exceeded 10% of the Obligation.

[12] BERR (2008), 'Renewables Obligation Consultation: Government Response', January, p. 12. www.berr.gov.uk/files/file43545.pdf.

[13] BERR (2008), 'Reform of the Renewables Obligation: Statutory Consultation on the Renewables Obligation Order 2009', June, p. 27. www.berr.gov.uk/files/file46838.pdf.

[14] ILEX Energy Consulting (2003), 'An assessment of changes to the Renewables Obligation rules relating to co-firing: a report to DTI', August.

crops was placed in the reference band and entitled to 1 ROC/MWh. This increased support was intended to encourage the further development of energy crops, in view of the benefits outlined above.

2.2.1 Respondents' views

Table 2.1 below summarises some of the main proposals considered in the various consultations regarding changes to the treatment of co-firing within the RO, and the responses received.

Table 2.1 Respondents' views to proposed changes to the co-firing cap

Year of consultation/ publication	Proposal	Justification	Respondents' views
2001	Co-fired ROCs to be eligible for contributing up to 25% of a supplier's obligation	Unrestricted co-firing could lead to an increase in overall carbon emissions if the balance of fossil-fuel use were to change Large volumes of co-fired ROCs could undermine incentives to develop other technologies	Responses not publicly available
2003	Cap on co-fired ROCs to be tightened as follows: – 25% to April 2006 – 10% from April 2006 to March 2011 – 5% from April 2011 to March 2016 – 0% after March 2016	Greater restriction on the co-firing of regular biomass required to balance incentives for more energy crops and reduce the risk of an oversupply of ROCs, which could pose a risk to wider investor confidence	Responses not publicly available
2006	Co-firing of energy crops removed from the existing cap on co-firing and awarded standard ROCs rather than 'co-fired ROCs', which are capped. Removal of energy crop requirements	To provide continued impetus for the development of energy crops in the time between this consultation and the introduction of banding in 2009/10	**Vertically integrated firms in favour**: (Centrica, EON, RWE, and Scottish Power) For reasons including: the desire to give a strong signal to the energy crops supply chain; the desire to demonstrate the higher level of support required to ensure the development of energy crops **Vertically integrated firms not in favour**: (SSE, EDF) For reasons including: the belief that the removal of the cap would not have the desired impact in the interim period; the belief that differential treatment would not be justified since there are no additional carbon benefits from the use of energy crops A large majority of other suppliers were in favour of the proposed changes

Year of consultation/ publication	Proposal	Justification	Respondents' views
2006	Removal of the cap on co-firing and reduction of support through banding	The preferred long-term approach since it involved less regulatory intervention, allowed for more co-firing, and reduced the impact on ROC prices and other biomass-dependent industries	**Vertically integrated firms in favour (with reservations)**: (Centrica and Scottish Power) Reservations included: a concern that restricting support for co-firing reduces the need for a cap but does not make it redundant; the belief that a new cap at 10% of total ROCs submitted is a more practical and transparent mechanism for the management of co-firing than it being used as a trigger point for a review of banding without the cap **Vertically integrated firms against**: (EON, EDF, RWE npower & SSE) Reasons included: the belief that uncapping co-firing increases uncertainty for investors; the belief that a cap on co-firing is necessary as protection against triggering a collapse in the ROC price A slight majority of other suppliers were in favour of the proposed changes.
2007	Emergency review criterion triggered if co-fired ROCs exceed 10% of Obligation	To mitigate the risk of potential volatility of co-firing volumes and the potential impact on ROC prices	A large majority were in favour
2007	Removal of cap on co-firing with non-energy crops	Energy-crop cap regarded as redundant, given banding down and the proposed review of support levels	Most respondents were satisfied with the removal of the cap in conjunction with reduced support through banding Large suppliers were in favour of retaining the cap due to the potential impact on ROC price certainty
2009	Retention of 10% cap on co-firing with non-energy crops and extension to 12.5% from 2010/11		Some respondents suggested that the cap works against independent generators and that only a share of the headline market for co-fired ROCs is available for co-fired ROCs Large suppliers were in favour of retaining the cap due to the potential impact on ROC price certainty

Source: Various DTI/BERR consultations. For a full list see the DECC website, available at http://www.decc.gov.uk/.

2.2.2 Summary of responses to consultations on changes to the cap

The co-firing cap and the proposed amendments have received mixed responses. There have been conflicting views among stakeholders regarding the merit of keeping a cap on co-firing. Their arguments are summarised below.

Arguments in favour of removing the cap

– As one of the cheapest renewable technologies, it is efficient to have significant generation from co-firing.

– Removal of the cap would be likely to strengthen the incentives to develop an indigenous supply of biomass. While this enhances security of energy supply in itself, the existence of co-firing also provides incentives to keep coal in the energy mix, further strengthening security of supply given concerns over rising dependence on gas imports.

– Removal of the energy crop co-firing cap could allow for the long-term development of the energy crop industry because:

  – it would allow the drafting of long-term contracts to mitigate commercial risk and facilitate investment, leading to further volumes being produced;
  – it would help create a more secure level of demand from co-firers. Investment and innovation in energy crops could increase efficiency and yields, and hence reduce unit costs.

Arguments against removing the cap

– Given the relatively lower costs of co-firing, an increase in its use could lead to an oversupply of ROCs, and thus to price instability. This would, in turn, reduce incentives to invest in more expensive, fully sustainable energy sources.

– Further intervention could undermine investor confidence, as interfering with the RO could give rise to greater uncertainty.

– Greater co-firing can lead to increased emissions since an increase in co-firing implies more coal being burned.

3 The nature of competition and co-fired ROCs

This section examines the nature of competition for co-fired ROCs. The incentives that influence the behaviour of co-firing generators and electricity suppliers are examined, as well as the implications of particular generating and buying strategies for co-fired volumes and prices.

To help understand the extent of co-firing potential, this section sets out the level of existing possible co-firing ratios, as well as the historical levels of co-firing. The possible retirement profile of existing coal plant is examined, as well as the potential for new coal-fired power stations. Consideration is also given to the ownership of existing and potential new plant, and the incentives that may influence output decisions in this respect.

On the demand side, the drivers of demand for co-fired ROCs are described, including the effect of the headroom mechanism and the impact of licensed suppliers' compliance strategies. This is followed by a discussion of the extent to which the buying power of suppliers can affect the timing of their demand and give rise to forward price discounts. The likelihood that more concentrated buyers of co-fired ROCs may be able to negotiate larger price discounts as total output approaches the cap is also discussed, since this may have an impact on the output decisions of independent co-firing generators.

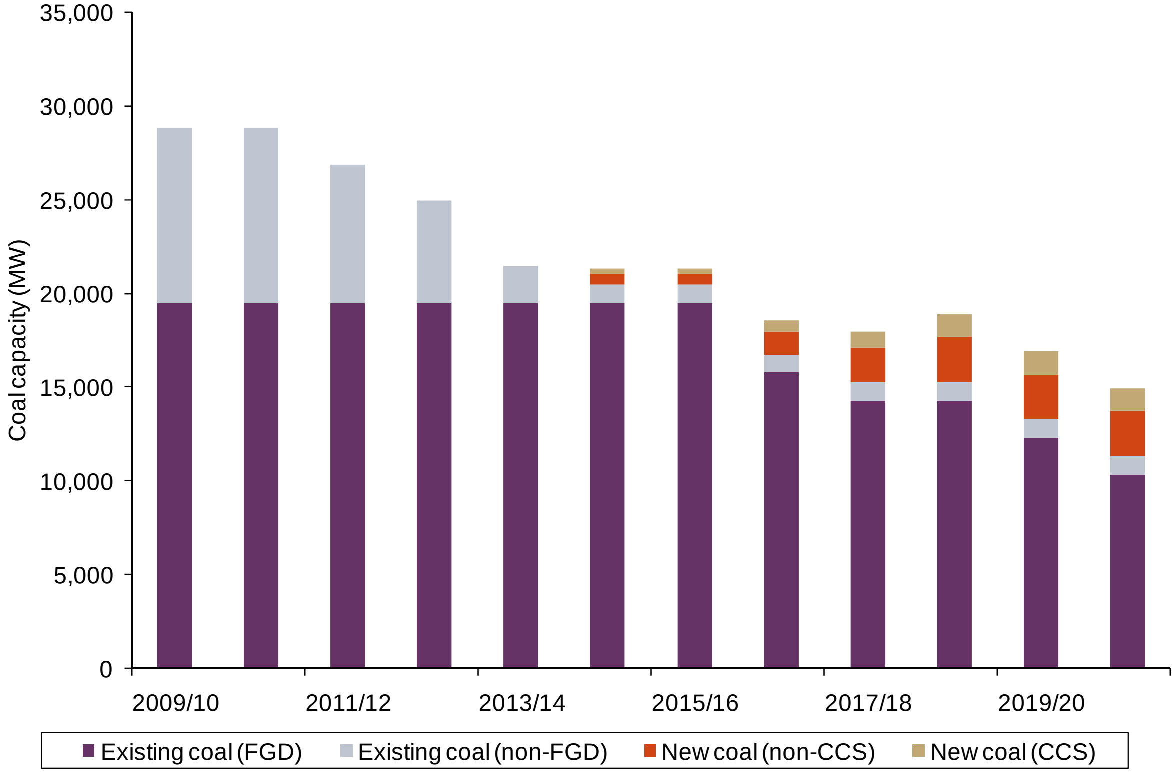
3.1 Supply and the ownership of co-firing generators

Co-firing is dependent on the availability and running patterns of conventional coal and oil plant: all 16 major coal plants in the UK have tested co-firing, although the average co-firing ratio used is below 5% on a heat-input basis.[15]

Figure 3.1 below shows the projected coal capacity of the UK to 2020. This shows a gradual decline in total capacity to 2020 and highlights the effect of the retirement of approximately 7GW of 'opted-out' plant under the Large Combustion Plants Directive (LCPD) prior to 2016.[16] It also highlights the potential build of a number of new coal-fired power stations, which (as set out in DECC's consultation on the development of new coal plant) will be required to demonstrate carbon capture and storage (CCS) on at least 400MW (gross) or 300MW (net) of the plant, and will be required to retrofit this technology to the entire plant.[17]

[15] Source: Biomass Energy Centre. See http://www.biomassenergycentre.org.uk/portal/page?_pageid=75,41175&_dad=portal&_schema=PORTAL.
[16] This timing could change in further negotiations as the European Industrial Emissions Directive (IED) is drafted.
[17] Capacity requirements are expressed on a gross basis. See DECC (2009), 'A framework for the development of clean coal: consultation document', June.

Figure 3.1 Projected coal capacity



Note: FGD, flue-gas desulphurisation.
Source: Oxera.

The ability to co-fire depends on the number of running hours of a plant, which in turn is driven by a combination of factors including the relative price of coal, gas and carbon allowances (which affect the cost of coal relative to gas-fired generation); restrictions imposed under the LCPD; and restrictions arising from the need for plant maintenance.

Table 3.1 shows that the historical output of coal plant in the UK has been relatively constant year-on-year, with load factors ranging from 62.3% to 69.4% between 2003 and 2007, and an average load factor of around 64%.

Table 3.1 Historical coal plant output

	2003	2004	2005	2006	2007
Conventional coal load factor (%)	65	62.3	63	69.4	62.5

Source: DECC, Digest of UK Energy Statistics.

Future coal plant output might be expected to be lower than these historical levels, due to the operating restrictions on those plants that have opted out of the LCPD. However, this might be mitigated to some extent because:

– the use of the available running hours of some opted-out plant is being front-loaded prior to closure by 2013, when the power sector will be subject to the full auctioning of EU Emissions Trading Scheme (ETS) allowances;
– new coal plant with higher operating efficiency will be able to operate at lower marginal costs, resulting in greater competitiveness in the provision of baseload power;

– medium- to long-term oil, gas and coal projections suggest that the marginal cost of coal plant may be lower than that of gas.[18]

Table 3.2 shows projected average coal load factors to 2020, under a range of DECC commodity price assumptions. The Oxera modelling approach is discussed in more detail in section 4.

Table 3.2 Average coal load factors under DECC commodity price assumptions (%)

	Commodity price assumptions			
	High-high	High	Central	Low
2009	49	42	33	23
2010	53	49	46	5
2011	58	55	50	3
2012	62	60	56	5
2013	65	65	64	12
2014	68	68	67	20
2015	68	67	67	28
2016	77	78	75	32
2017	79	79	77	36
2018	78	79	77	39
2019	80	81	78	39
2020	80	81	79	43

Note: Load factors are shown as an average across all coal plant in Great Britain. Model results are based on DECC commodity price assumptions except in 2009 where an average of historical data and DECC projections has been used.
Source: DECC and Oxera.

Table 3.2 shows that average coal load factors might be expected to increase over time, as older opted-out plant is retired. The co-firing ratio might also be expected to increase over time since those plant that are decommissioned in the next few years are those least likely to have additional capital equipment (to increase their ability to co-fire) installed. However, when combined with plant retirement, the net effect is likely to lead to a decrease in co-firing potential, as discussed in more detail below.

3.1.1 The co-firing decision

As with the marginal cost considerations that help determine the running pattern of coal relative to other generating plant, the decision to co-fire within a coal plant's existing co-firing capacity is also influenced by considerations based on marginal cost.

The majority of co-firing from existing capacity involves the co-milling of biomass with coal. This requires relatively little up-front capital expenditure, but offers only a limited co-firing ratio. Although co-firing ratios (on a heat input basis) of up to 10% may be possible, co-firing ratios of around 5–6% are observed on a commercial basis.[19]

The marginal cost-based co-firing decision depends on whether the marginal benefits of co-firing outweigh the marginal costs. The marginal cost of co-firing is equal to the cost of the biomass necessary to generate an additional unit of output. The marginal benefit is

[18] Based on DECC commodity price assumptions, discussed in more detail in section 4.

[19] Based on Oxera calculations, using historical ROCs generated, and Livingstone, B. (2008), 'Advanced biomass co-firing technologies for coal-fired boilers', Doosan Babcock.

equivalent to the coal and carbon costs avoided from burning biomass, plus the additional revenues associated with co-firing from Climate Change Levy Exemption Certificates (LECs) and the expected ROC price.

Marginal costs may also increase as a result of a loss in thermal efficiency: this depends on the moisture content of the biomass. However, with relatively dry biomass this effect can be as little as a 0.1 percentage point decrease on a gross calorific value basis.[20]

New capacity

New co-firing capacity involving investment in direct injection co-firing can enable larger co-firing ratios to be achieved. Specific examples include injecting pre-milled biomass into the pulverised-coal network, or the use of specially designed boilers. Experience of this approach in the UK has allowed co-firing ratios between 10% and 15%, although much higher ratios may be possible.[21] Investment appraisal in this case requires a comparison of the present value of the anticipated ROC and LEC revenues together with the avoided costs of coal and carbon, against upfront capital and future operating costs. Future investment might only be expected in opted-in coal plant with relatively longer operating lives remaining.[22]

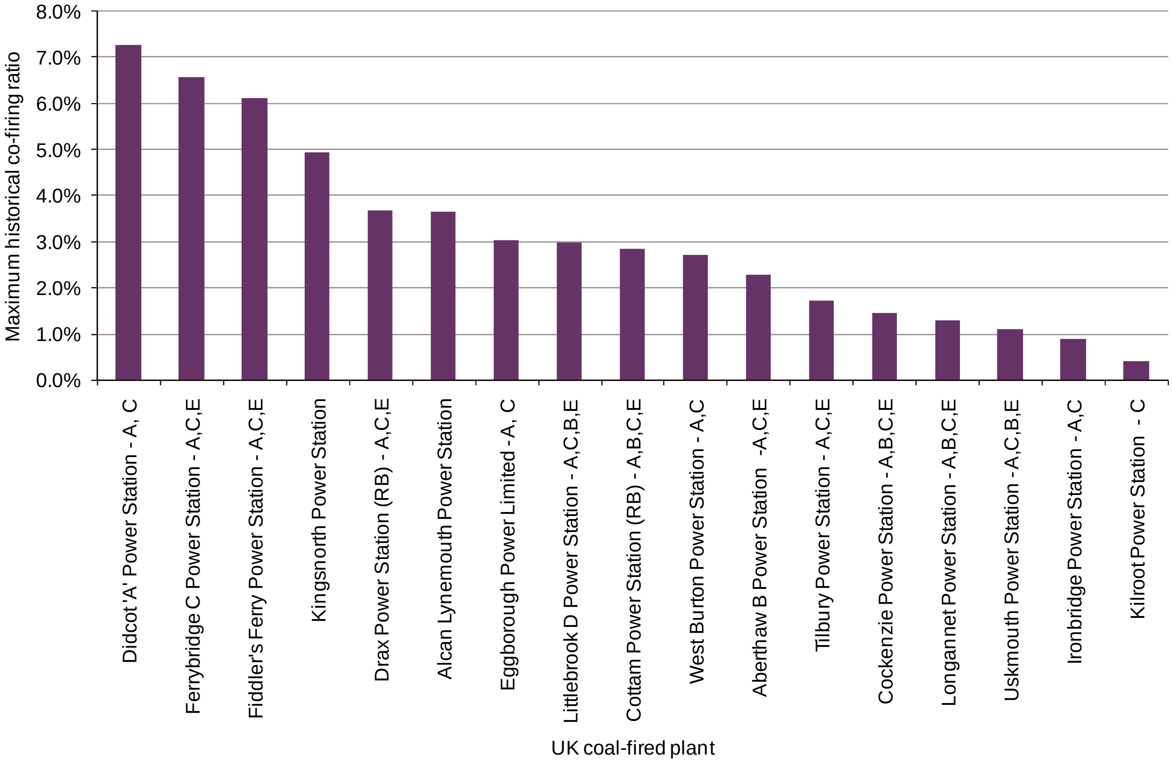
Figure 3.2 shows the distribution of estimated maximum historical co-firing ratios observed between 2006 and 2009 across various UK coal plant.

[20] IPA Energy Consulting (2006), 'The Economics of Co-Firing', July.

[21] The principal constraints to date on increasing co-firing ratios have included the availability of suitable biomass, the limitations of plant fuel storage and handling facilities, and technical concerns regarding boiler performance. See *Power Engineering International* (2008), 'Direct injection advances biomass co-firing in large coal-fired plants', July.

[22] A new facility costing £200/kW and with a two-year construction period, with an illustrative contribution to capital costs of £12/MWh (ie, the difference between ROC and LEC revenues plus the avoided costs of coal and carbon minus the cost of biomass) might be expected to have a payback period of around three years, and to be net present value (NPV)-positive after approximately five years of operation.

Figure 3.2 Estimated maximum co-firing ratios observed in UK plant



Note: Estimated maximum ratios are calculated using the actual number of ROCs generated, plant capacity and an assumed 75% load factor in winter months. This may provide an underestimate if higher ratios are achieved in summer months when relatively few ROCs are generated, or an overestimate if maximum values are recorded in winter months with load factors above 75%.
Source: Ofgem and Oxera calculations.

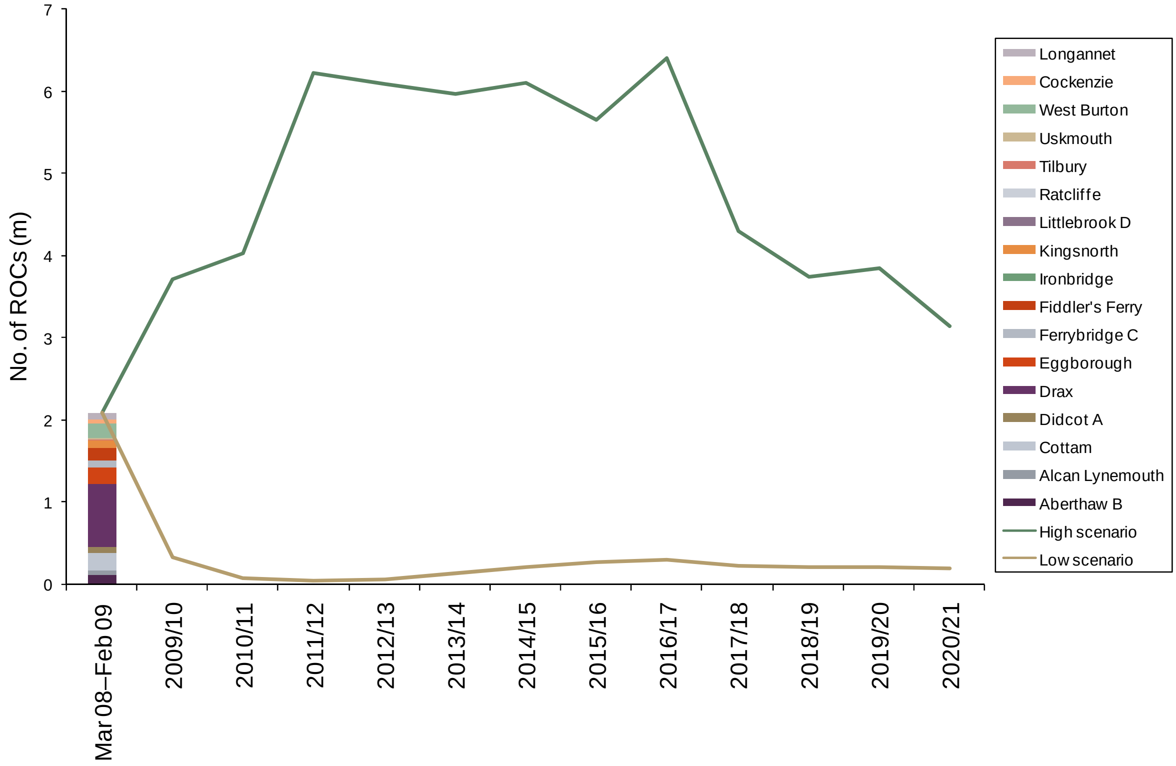
3.1.2 The range of potential co-fired output

The range of potential co-fired output depends on the retirement profile of the coal fleet, its operating regime, and the co-firing ratio. Figure 3.3 below highlights this range by combining the retirement profile shown in Figure 3.1 with the minimum and maximum coal load factor projections shown in Table 3.2 and a range of co-firing ratios between the historical average output and technical potential.[23]

Figure 3.3 shows a wide range of the potential supply of co-firing ROCs relative to historical levels, even after accounting for changes in banding—ie, with half as many ROCs produced for a given level of co-firing output in comparison with 2008/09. The fluctuations in the potential co-firing profiles are driven by changes in the projected load factors of a coal plant, as well as their projected retirement.

[23] The higher co-firing ratios associated with investment in direct injection are assumed to be achieved only by those coal plant that have opted in to the LCPD.

Figure 3.3 Extrapolated co-fired ROCs from large generators after banding



Source: Ofgem and Oxera analysis.

3.1.3 Output decisions of independent generators

The presence of the co-firing cap adds an additional price risk to be managed by generators. Some survey respondents have suggested that in order to manage the risk of creating an oversupply of co-fired ROCs, generators would not co-fire if this were likely to lead to the total volume of ROCs exceeding a risk-adjusted level below the level of the cap.

If there were many independent co-firers, such a strategy might not appear credible. That is, each generator would face an incentive to sell additional ROCs if it knew that other generators were likely to restrict output. In practice, given the existing market structure, this might not be the case as there are relatively few independent generators.

However, there may also be theoretical reasons that give further weight to considering this feature of supply in an analysis of the appropriate level of the co-firing cap (see section 3.2.4).

3.1.4 Output decisions of vertically integrated generators

Vertically integrated companies (ie, those with both co-firing generating capacity and a supply business) might be expected to internalise the decision of how many ROCs to produce and how many to buy. Indeed, a frequently cited motivation for vertical integration is management of market risks (eg, volume and price risk).

As owners of other renewable technology projects (in addition to being owners of supply businesses), vertically integrated firms might trade off a number of considerations in their co-firing output decisions. These could include:

– the maximum number of certificates that could be used by the supply affiliate;
– the price that could be achieved by selling surplus co-fired ROCs to other licensed suppliers;
– the consequent impact on the relative buying power of the supply affiliate;

– the impact on standard ROC prices and the implications for the profitability of other renewable projects.

The first three of these considerations concern the strategic nature of demand, and are discussed is more detail below.

3.2 Demand and the effects of vertical integration

This sub-section considers the incentives for electricity suppliers to purchase co-fired ROCs. The analysis examines the direct incentives created by the RO, as well as those that arise due to the structure of the supply market.

3.2.1 Demand for co-fired ROCs

The absolute level of demand for co-fired ROCs is determined by the level of the obligation on suppliers, multiplied by the co-firing cap.

The underlying factors that affect the level of the RO, and which therefore have some bearing on whether the cap is binding, are as follows.

– **The demand for electricity**. This is driven by various factors, including economic growth and seasonal and other temperatures, and changes in energy intensity arising from efficiency measures.

– **The obligation levels explicit within the RO**. The obligation level laid down in legislation increases from 9.7% in 2009/10 to 15.4% in 2015/16.

– **Extensions to the RO generated by the headroom mechanism**. The Obligation level will increase beyond the levels above if the total level of renewable deployment is sufficiently large. Current legislation is such that the level of the RO will be extended to ensure headroom of 8% above expected levels of deployment up to 10% by 2014/15.

The co-firing cap is currently set at 10%—ie, licensed suppliers may submit co-fired ROCs up to a value of 10% of their total obligation. This level is set to increase to 12.5% in 2010/11.

Leaving aside additional strategic incentives, which are discussed below, the demand for co-fired ROCs is therefore subject to some uncertainty.

The effects of fluctuations in electricity demand are mitigated to some extent by the fact that coal-fired output (and hence the ability to co-fire) is likely to be reduced where there is a fall in electricity demand: in contrast to other renewable technologies with low marginal costs that might be expected to run under both high and low demand.

The factors outlined above also highlight the possibility that increases in the deployment of other renewable technologies (which may be further encouraged by re-banding) could raise the demand for co-fired ROCs if this leads to an extension of the total Obligation size.[24]

3.2.2 Implications of vertical integration for the demand for co-fired ROCs

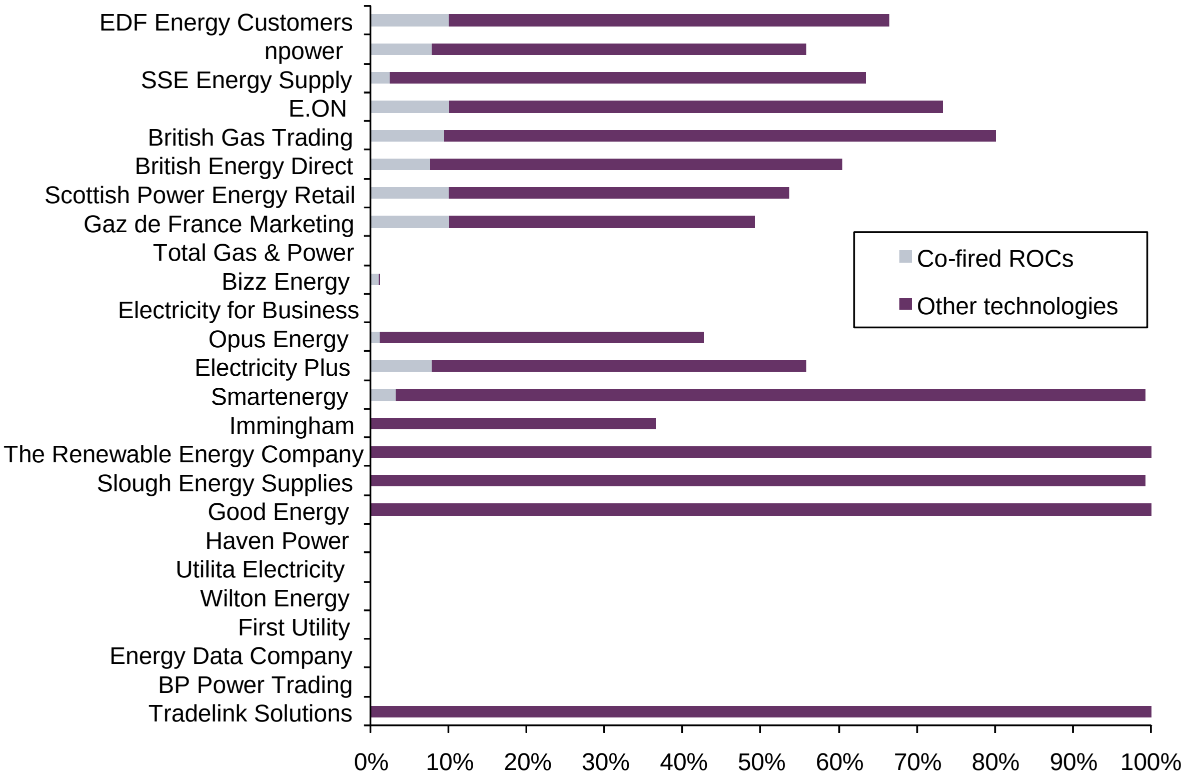
Licensed suppliers can meet their obligation by:

– presenting ROCs;
– paying a buyout price linked to the retail price index (equivalent to £35.76/MWh in 2008/09);
– a combination of presenting ROCs and paying the buyout price.

[24] If the total Obligation size were to increase by 8% as a result of the headroom mechanism, there would be an equivalent increase (in percentage terms) in the demand for co-fired ROCs.

A wide dispersion is observed in the extent to which licensed suppliers both comply with their overall obligation by submitting standard ROCs, and buy and submit co-fired ROCs, as highlighted in Figure 3.4.

Figure 3.4 Use of ROCs by suppliers in England and Wales 2007/08



Source: Ofgem.

Figure 3.4 ranks each supplier in accordance with the size of its individual obligation. This shows that the majority of licensed suppliers that are compliant in submitting 100% ROCs are not the biggest suppliers, and that a number of smaller suppliers do not submit any ROCs.

Some variety in the method of compliance might be expected, as the market for ROCs is 'short' overall (that is, the total size of the RO exceeds the expected number of ROCs produced in order to create a price above the buyout level), and so not all suppliers can fully comply with ROCs. A number of suppliers (for example, those independent suppliers specifically focused on green supply tariffs) may choose to fully comply as part of their value proposition, while others may choose to comply using ROCs, depending on the price they can negotiate.

It is to be expected that a supplier will be indifferent to submitting ROCs and paying into the Buyout Fund if it cannot achieve a discount on the ROC price.[25] If the additional incentives to comply from buying ROCs are relatively small (ie, if only a fraction of the ROC price can be captured by the supplier), suppliers might be expected to tailor their compliance strategy, where possible, in order to negotiate lower ROC prices in forward contracts.[26]

[25] ROC sales typically involve negotiation around the share of the buyout component and recycle component of the ROC value that is paid to the generator, which may be between 80% and 100%.

[26] As a supplier's share of the ROC value increases, the overall cost of compliance (ie, of submitting ROCs) falls, making it more attractive to purchase ROCs than pay the buyout price.

The observation that the Big Six energy companies—British Gas, E.ON, RWE npower, EDF, Scottish Power, and Scottish and Southern Energy (SSE)—choose, in general, not to comply by only submitting ROCs might be expected, given that the market is short by design.

Figure 3.5 shows that vertically integrated suppliers submit the majority of co-fired ROCs. The share of their obligation met with co-fired ROCs is also higher. This might be expected in view of the decisions of some smaller suppliers to pay into the Buyout Fund rather than buy ROCs, as discussed above. It may also be that smaller suppliers are more likely to be indifferent to buying ROC if they cannot negotiate a discount on the ROC price.

The low use of co-fired ROCs by independent suppliers might be expected in the event that liquidity is low, which could be caused for example where vertically integrated generators sell their co-fired ROCs to their supply affiliates and not to the wider market. Support for this is provided in the survey responses summarised in Appendix 1.[27]

Figure 3.5 Use of co-fired ROCs by vertically integrated and independent suppliers

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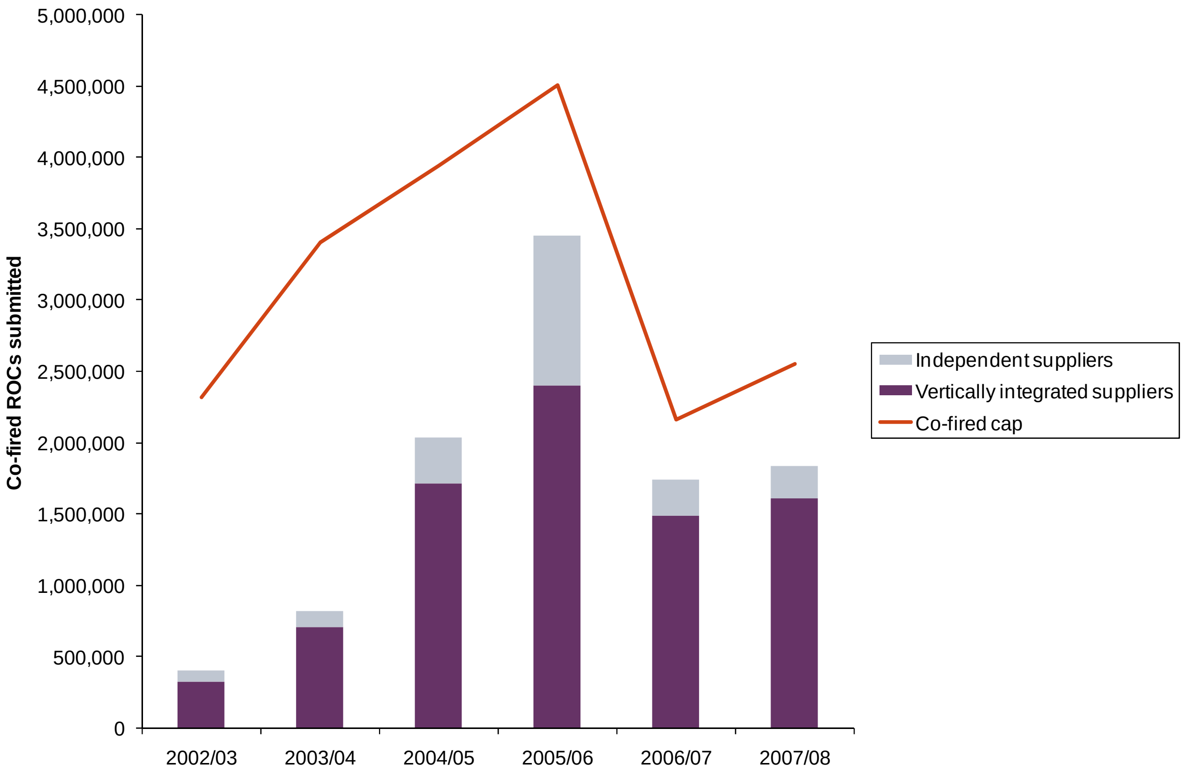


Source: Ofgem and Oxera analysis.

Table 3.3 shows the changes, year on year, in the number of co-fired ROCs *generated* by the vertically integrated energy companies, and the subsequent changes in the number of co-fired ROCs *submitted*.

Figure 3.4 and Table 3.3 show that, of the Big Six, SSE's submission of co-fired ROCs in 2007/08 was lower than those of the other vertically integrated suppliers, although it submitted the maximum of 10% co-fired ROCs in the previous year. This trend corresponds with a fall in the number of co-fired ROCs produced by its coal plant, of around 50% in 2007/08 relative to the previous year. Similar trends, in which the proportion of co-fired ROCs

[27] A representative view of independent generators on the evolution of the market has been that it 'has become increasingly illiquid and opaque so market price has become less visible. This is especially true for co-fired ROCs, where most of the market is satisfied by vertically integrated players without external trading.'

submitted increases or decreases in line with a company's own supply, are also observed over these two years for EDF, but not for RWE npower or E.ON.

Table 3.3 Year-on-year changes in co-fired ROCs generated and submitted

	2006/07		2007/08	
	Co-fired ROCs generated	Co-fired ROCs submitted (% of obligation)	Co-fired ROCs generated	Co-fired ROCs submitted (% of obligation)
Centrica		256,850 (10.0%)		279,413 (8.6%)
EDF	132,815	110,511 (3.7%)	203,492	411,143 (9.9%)
E.ON	233,370	101,013 (8.5%)	129,273	379,280 (10.0%)
RWE npower	271,856	304,658 (8.3%)	107,036	326,399 (7.8%)
Scottish Power	155,418	155,661 (9.2%)	189,046	124,363 (6.4%)
SSE	789,029	341,385 (10.0%)	382,132	89,413 (2.0%)

Source: Ofgem and Oxera analysis.

3.2.3 Forward price discounts

Forward price premiums and discounts are common phenomena in energy markets.[28] Risk premiums refer to circumstances under which the forward price of a good exceeds participants' expectations of the future level of spot prices, where discounts describe forward prices below the expected level of the spot price. Whether these arise can depend on the relative bargaining power and risk aversion of buyers and sellers.

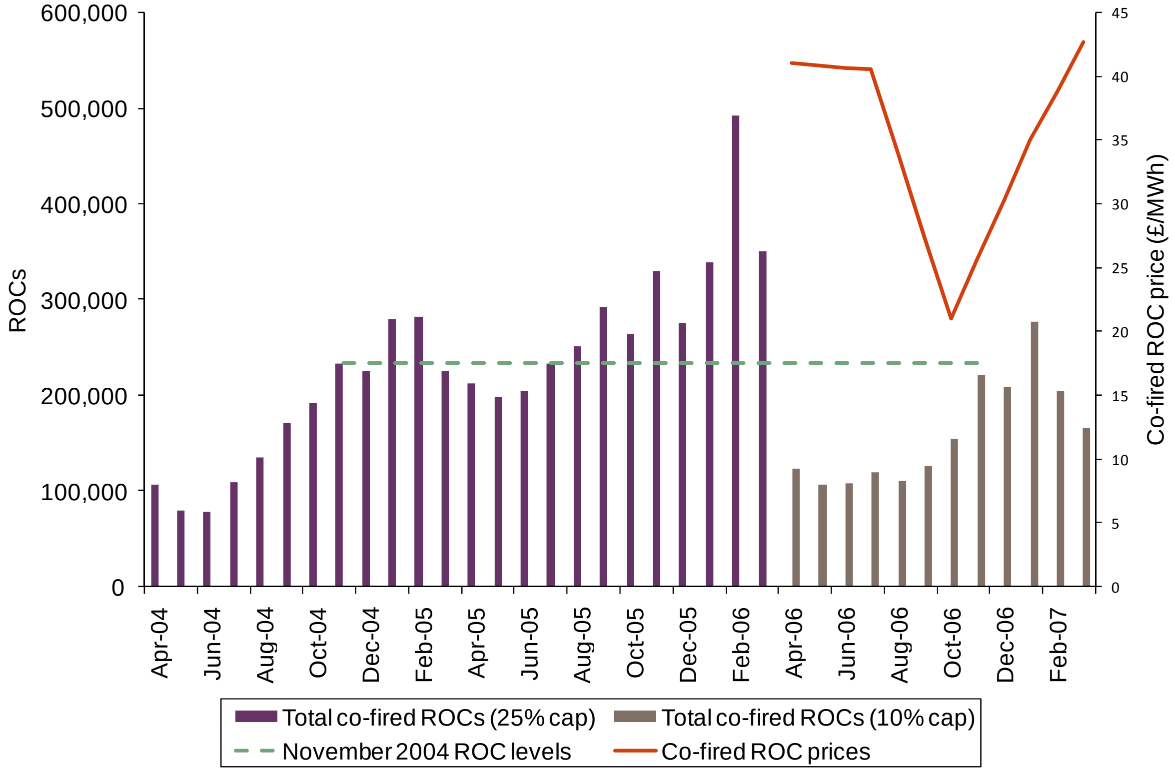
With regard to licensed electricity suppliers, co-fired ROCs can be regarded as having similar properties to a forward contract, since suppliers buy a certificate to be submitted during a future compliance period (or, indeed, which may be banked and used in subsequent years). If suppliers have a significant degree of bargaining power, they are likely to be able to negotiate ROC prices below the expected value of those certificates. However, suppliers also face an incentive to wait and buy ROCs later in a particular year if they think there is a chance that prices may fall—for example, if total co-firing output for the year is close to the aggregate level of the cap. The incentive to do so may be strengthened if, as may be the case for co-fired ROCs, the potential gains from prices falling are thought to be greater than the potential losses from prices increasing.

This effect would seem to be apparent from the pattern of prices and output in 2006/07. Figure 3.6 shows a reduction in co-fired output in 2006/07 over and above the seasonal trend, and coinciding with the reduction in the co-fired cap from 25% to 10%.[29] However, prices for co-fired ROCs in the Non-Fossil Purchasing Agency (NFPA) auctions also fell during this period, implying that the effect of the reduction in demand exceeded that of the reduction in supply.

A possible explanation for this is that suppliers, uncertain of the future level of co-fired ROCs, faced a potentially large benefit from waiting to buy co-fired ROCs (in the event that ROC prices were to fall in subsequent months), but faced a relatively low risk of an increase in prices, which would be bounded by the level of standard ROCs.

[28] See, for example, Oxera (2009), 'Hedging your bets: why pay over the odds for forward electricity?', *Agenda*, April. This article is based on academic research and describes how forward price discounts (or premiums) are frequently encountered in energy markets.
[29] Co-fired output is typically higher in winter when coal plant is more likely to run at higher load factors, since the cost of coal generation tends to be lower than that of gas: thus reflecting seasonality in the gas price.

Figure 3.6 Demand and supply response to changes in the co-fired cap in 2006



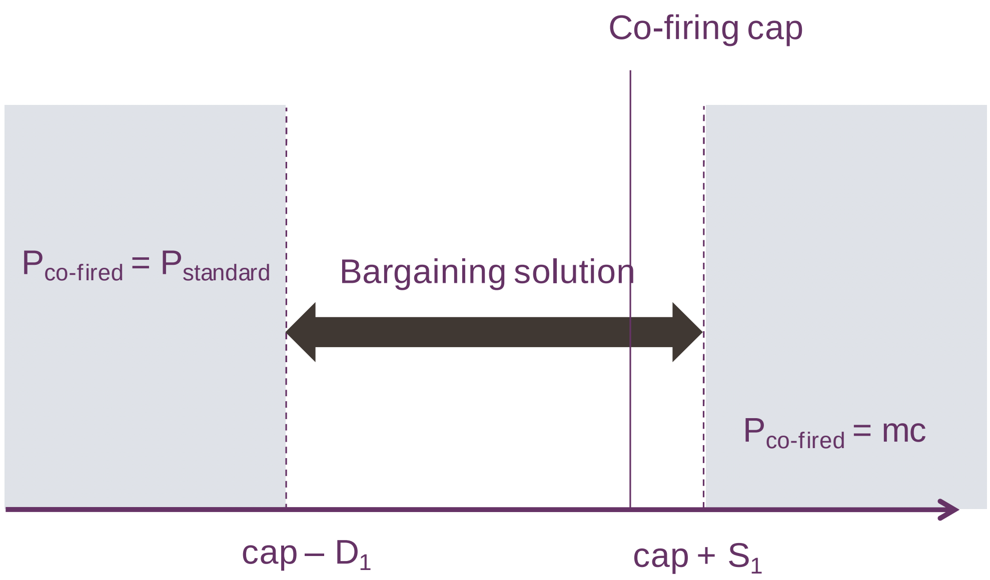
Source: Ofgem.

3.2.4 The price of co-fired ROCs and bargaining theory

The decision of independent generators to limit the volume of co-fired ROCs they produce to some threshold below the level of the co-firing cap may be supported by the outcomes that would be expected from the incentives created by a concentrated supply market.

As shown in Figure 3.7, when the volume of co-fired ROCs is significantly below the level of the cap, the price of a co-fired ROC might be expected to be equal to that of a standard ROC, since suppliers are indifferent between the two for compliance purposes.

Figure 3.7 The potential for a bargaining equilibrium



Source: Oxera.

However, as co-firing output reaches the level of the cap (and assuming that those co-fired ROCs have already been sold to suppliers), the supply company with the residual share of the market (D_1) might be expected to be able to negotiate a lower price for co-fired ROCs by adjusting its compliance strategy. The incentive to do this depends on the gains (in the form of a lower price of co-fired ROCs bought) and the losses (in the form of having to pay the price of a standard ROC for any sale that is not agreed within a given compliance period).

If independent generators are also aware of this, the volume of ROCs produced may be curtailed to avoid reaching this level. The supply market the share of the largest electricity supplier can constitute a significant proportion of the cap (eg, in the region of 20%), and the effect of this level of market share could be to tighten the cap significantly.[30]

Figure 3.7 also shows that the price of co-fired ROCs might not be expected to fall to the marginal cost of production until the expected surplus is greater than the production capability of the largest producer (S_1). After this point, contracts in which the generator recovers the marginal cost of producing a co-fired ROC might only be signed when suppliers expect that there will be ample alternative sources of supply to meet the market's requirements.[31]

3.3 Evidence from 2006

The theoretical foundations described above are applied in this section in order to interpret the market outcomes of 2006/07.

The reduction in the co-firing cap from 25% in 2005/06 to 10% in 2006/07 might have been expected to cause the following effects:

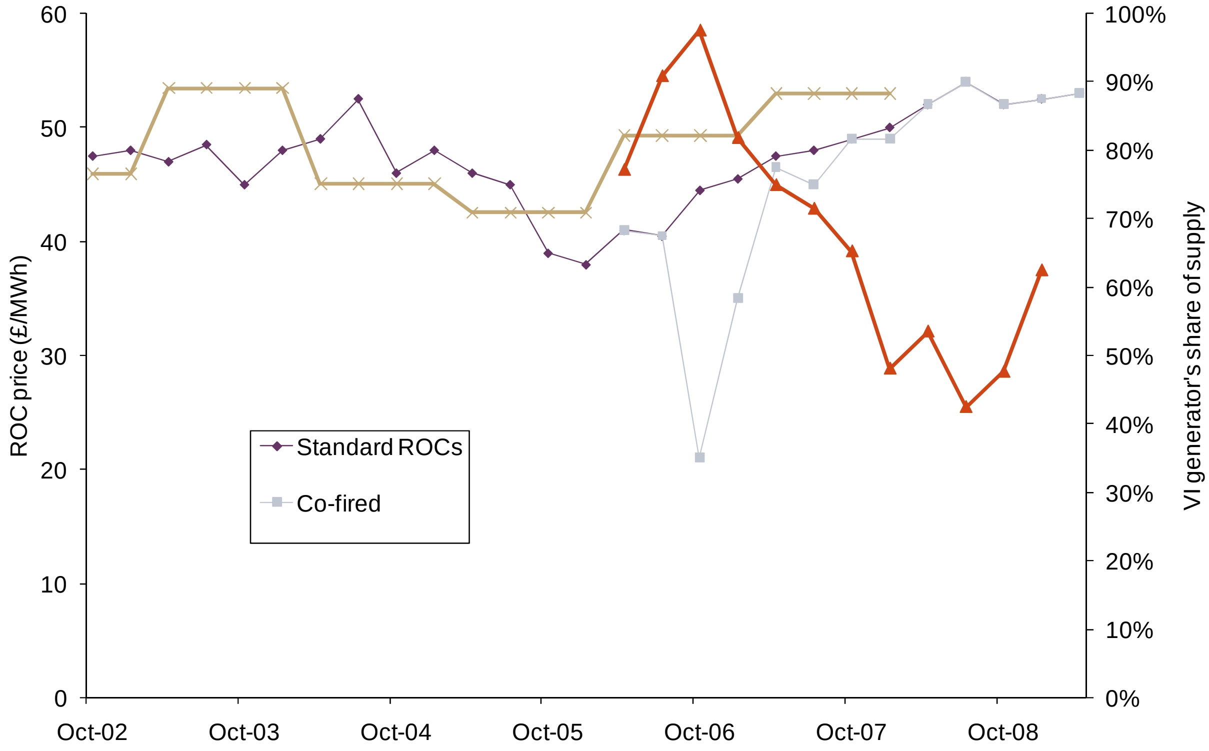
– the number of trades early in the compliance period might have been expected to fall, following increased expectations that future prices would fall if the market were in a position of excess supply;
– the price for co-fired ROCs traded in earlier in the period might have reflected an increased forward discount;
– the number of ROCs generated by vertically integrated players might have been expected to fall by a smaller proportion than the number from independent generators if demand were first to be met by vertically integrated firms' generation affiliates.

Figure 3.8 shows that these outcomes appear to have been borne out. Prices in earlier NFPA auctions show a larger discount on the prices of standard ROCs than in subsequent auctions.

[30] For a discussion see, for example, Ofgem (2008), 'Energy Supply Probe – Initial Findings Report', October 6th.

[31] Prices do not fall to zero since it is assumed that co-fired ROCs are only produced once a contract for sale has been agreed. In the event that an excess supply had been generated prior to negotiation, prices might be expected to fall to zero.

Figure 3.8 Historical standard and co-fired ROC prices

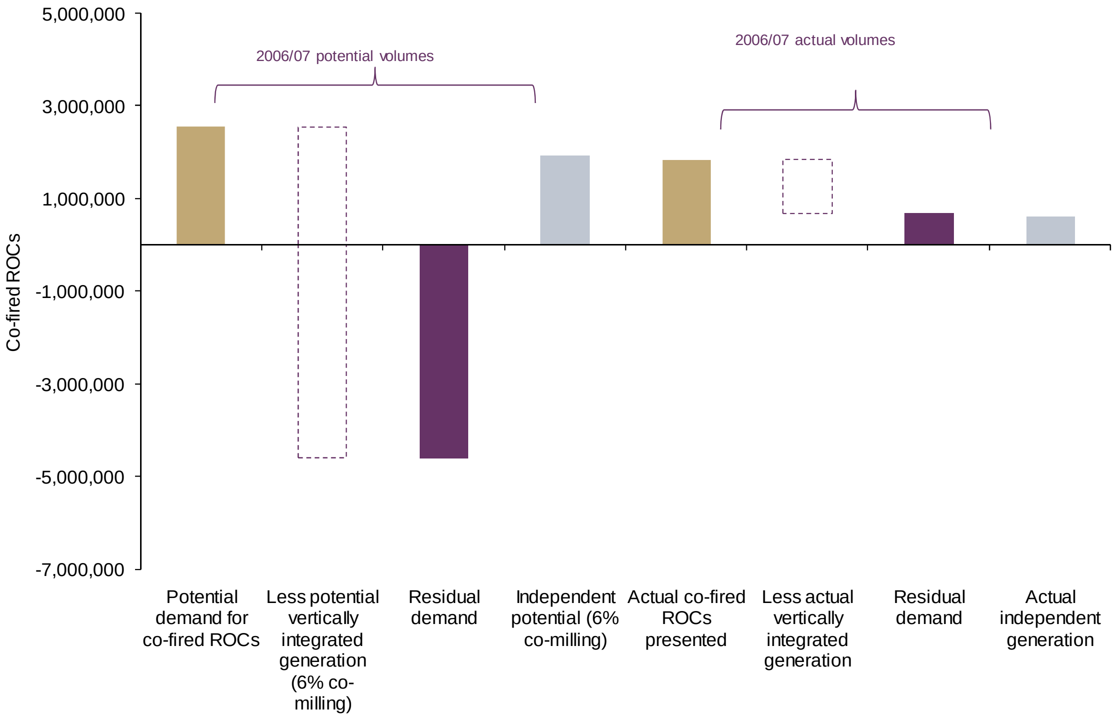


Source: NFPA, Ofgem and Oxera analysis.

While Figure 3.5 above shows that the pattern of total co-fired ROCs produced over the course of 2006/07 appears to reflect that of 2004/05 (and shows, therefore, that any reductions in earlier months are likely to represent the seasonal trend rather than the effects of the cap), Figure 3.8 shows that the share of generation from vertically integrated companies increased in the early part of the period. That is, reduced demand appears to have been met by vertically integrated companies' generation affiliates.

Figure 3.9 underpins the basis for expectations that the cap could have led to an oversupply of co-fired ROCs from independent generators.

Figure 3.9 Residual demand for independent co-fired ROCs in 2006/07



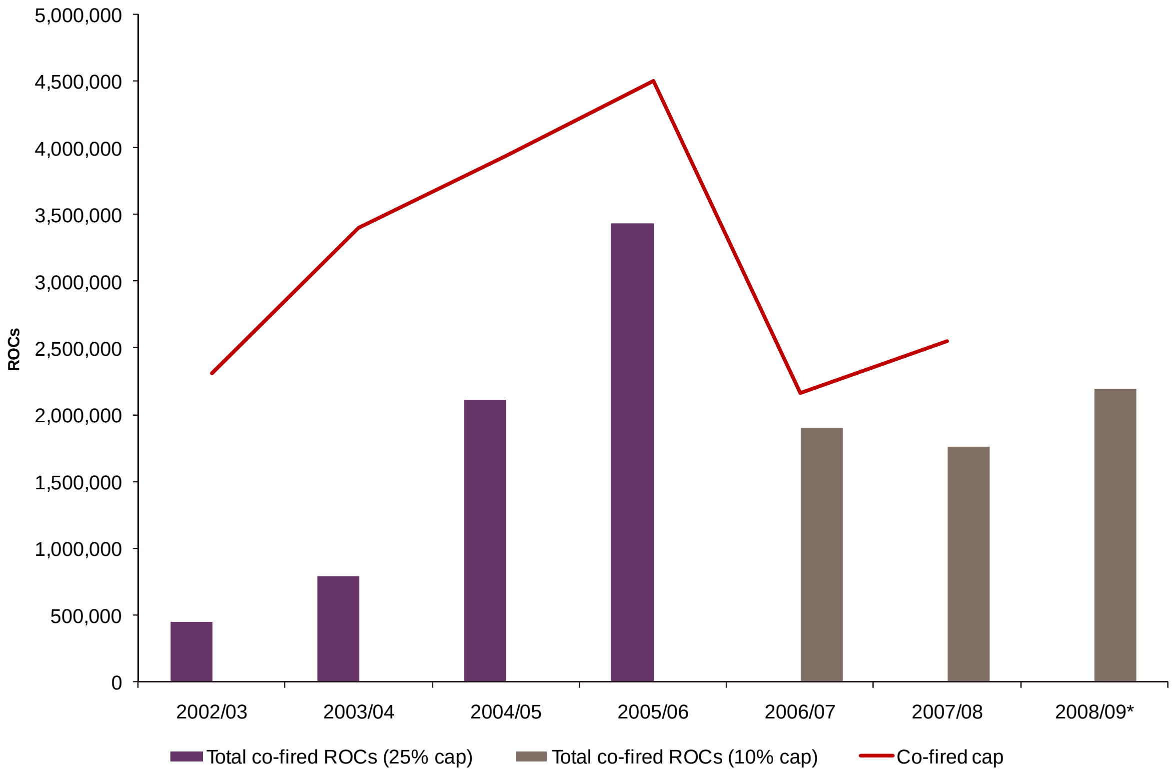
Source: Ofgem and Oxera analysis.

The first four bars in Figure 3.9 above (reading from left to right) show the potential maximum demand for co-fired ROCs; the potential co-firing output of vertically integrated generators (assuming a high case of 6% co-milling on an energy basis); the residual demand (based on this potential) that could be met by independent generators; and independent generators' potential output. This highlights the fact that high potential output from vertically integrated generators (shown by the dashed line) exceeds potential demand, which would result in negative (effectively zero) residual demand to be met by independent generators.

The final four bars show the realisation of outcomes, in which the number of ROCs presented was slightly below the maximum, and where vertically integrated generators produced the majority. As discussed above, the remaining independently produced co-fired ROCs were generated towards the end of the period.

Figure 3.10 shows co-firing output following the introduction of the 10% cap. This indicates that the previous trend (up to 2005/06) of increasing growth in co-fired output was significantly reduced in the periods following the tightening the cap, even though total output remained below the level of the cap.

Figure 3.10 Change in co-fired ROC production since 2006/07



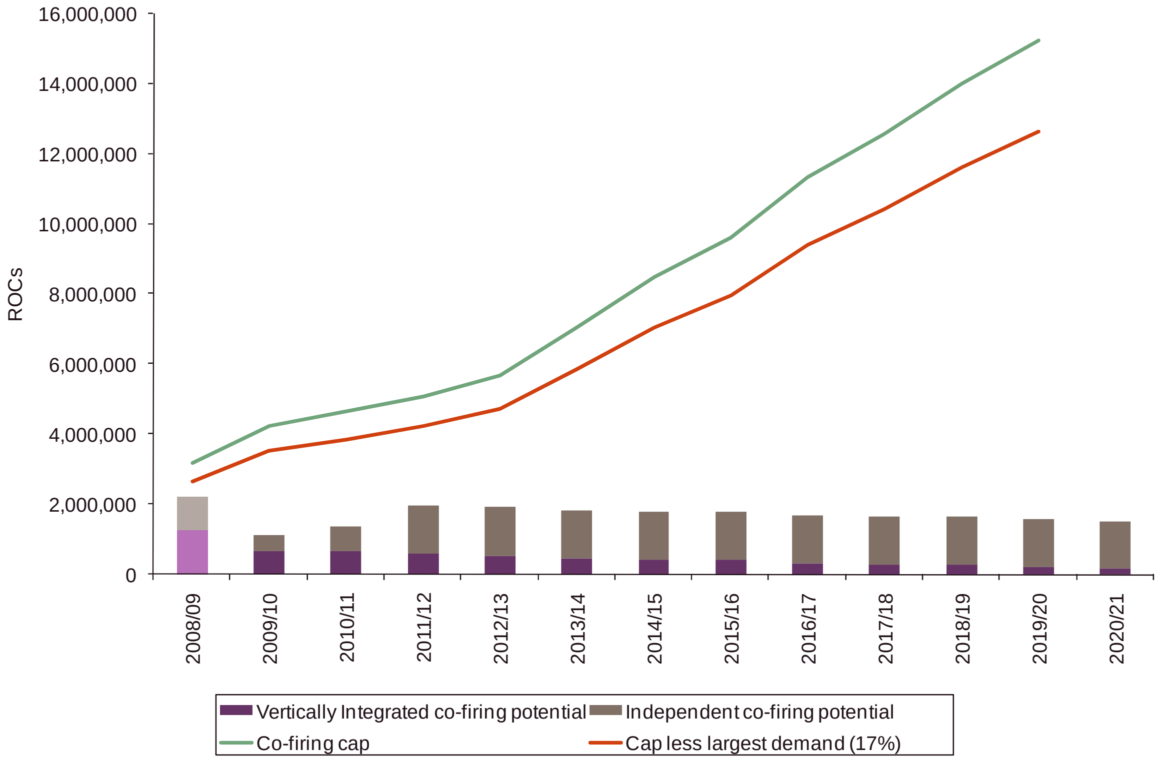
Note: 2008/09 figures are estimated from an extrapolation of the first 11 months of the period.
Source: Ofgem and Oxera analysis.

3.4 The future interaction of supply and demand: will the cap be binding?

This section compares the potential demand for independent co-fired ROCs on the basis of projections of the Obligation size, and is adjusted for any reduction that might be appropriate to account for the ability of suppliers to negotiate large price discounts close to the cap. This is compared with the potential sources of supply of co-fired ROCs, including the effects of the retirement of existing coal plant, potential new build and the extent of co-milling decisions and new co-firing investment.

Based on the likely retirement of existing coal plant, and the historical co-firing output of vertically integrated generators, it might be expected that the co-firing cap would not be binding in future years, as shown in Figure 3.11 below. Possible output is seen to be closest to the cap in 2008/09, which is, in large part, due to the impact of banding in later years, which effectively doubles the cap.

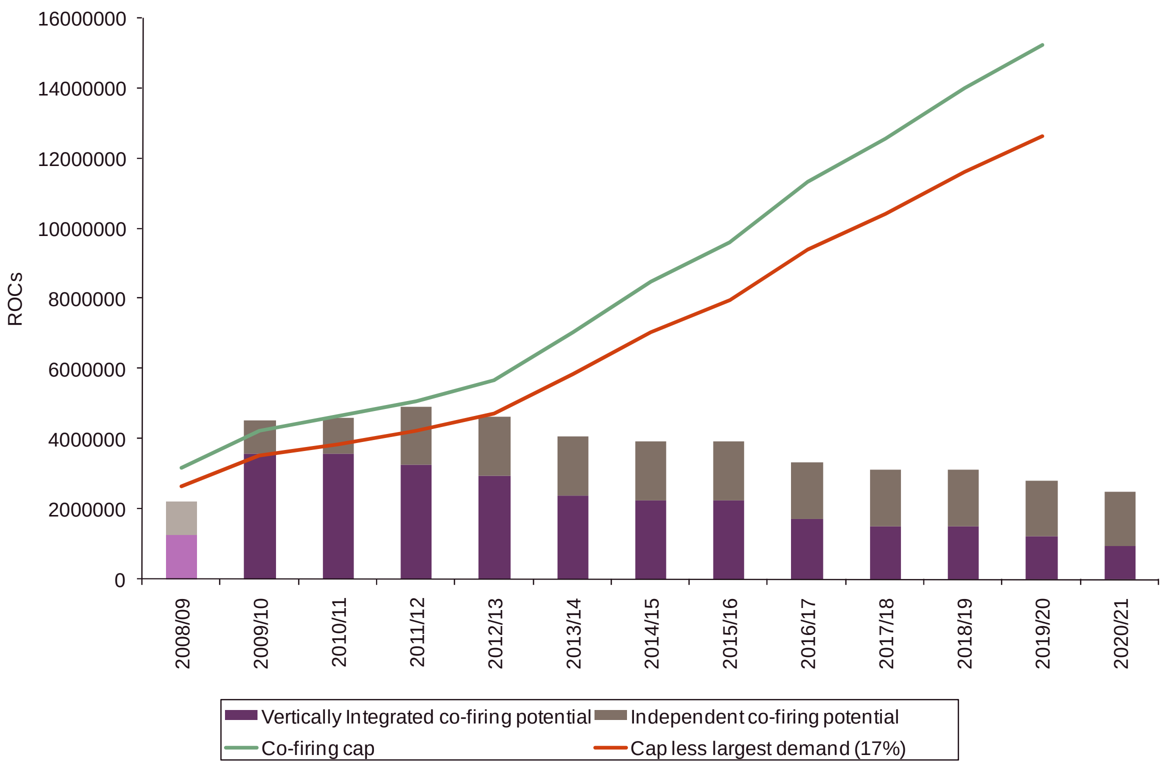
Figure 3.11 The market for co-firing: output based on historical levels



Note: Co-firing potential is based on 500MW capacity at Drax phased in from 2010/11, and 1.1% average co-milling from other coal stations.
Source: Oxera.

However, past output decisions, by their nature, reflect the current imposition of the cap. If vertically integrated companies were to increase output to make full use of co-milling (which would require relatively little capital expenditure (CAPEX)), the cap could become binding for independent generators wishing to invest in new capacity, and might be particularly acute in the period to 2012/13. This is shown in Figure 3.12 below.

Figure 3.12 The market for co-firing: increased co-milling



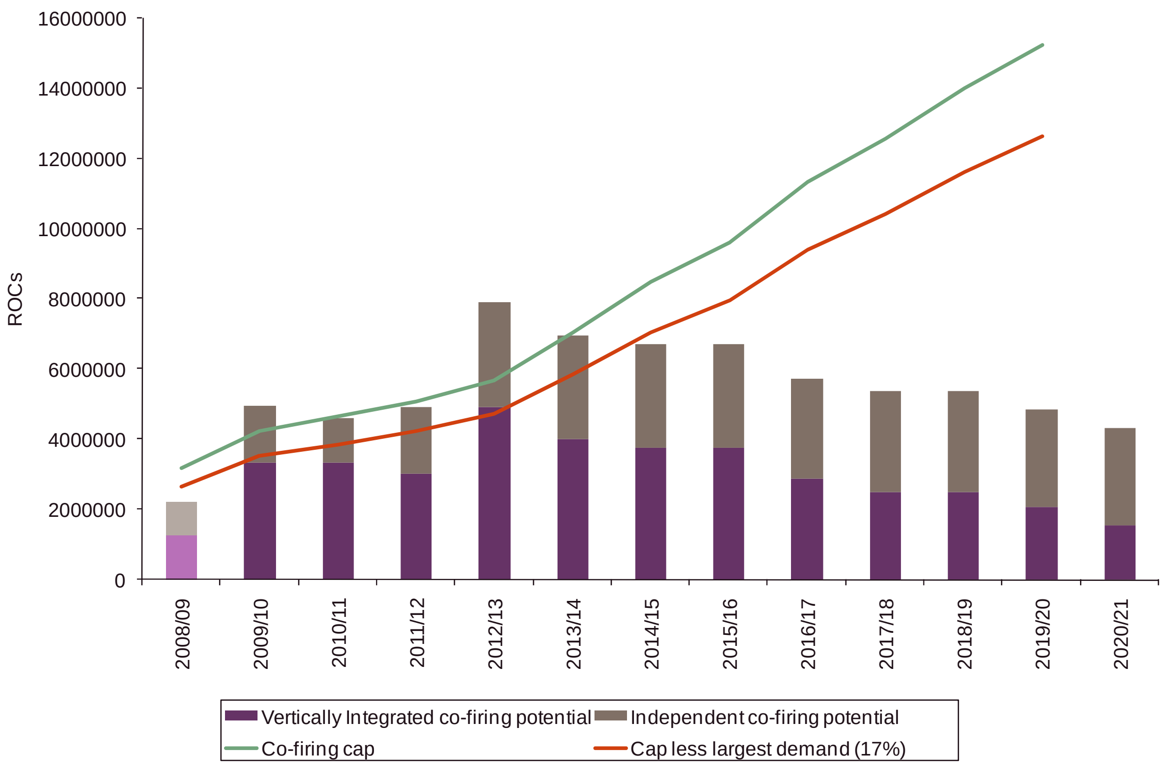
Note: Co-firing potential is based on 500MW capacity at Drax phased in from 2010/11, all other coal plant 6% average co-milling.
Source: Oxera.

A more extreme scenario is shown in Figure 3.13 below. Here, the level of co-firing of all coal plant is shown at 10% on an energy basis, which implies a combination of new investment in direct injection by some plant, and an increase in co-milling by others. This shows that the co-firing cap may be binding until 2014/15.

The level of investment in new direct injection facilities, which would allow the proportion of co-firing to be extended beyond 6% on an energy basis, might only be expected in plant that (in order to allow a sufficient return on investment) has not opted out of the LCPD. As an illustration, an increase in potential co-firing output from 6% to 10% on only the 15GW of existing opted-in coal plant could generate as many as 1.5m additional co-fired ROCs.[32]

[32] Assuming a load factor of 60%. The 15GW excludes Drax, which has already committed to a new direct injection facility.

Figure 3.13 The market for co-firing: increased direct injection



Note: Co-firing potential is based on 900MW capacity at Drax phased in from 2010/11, and 10% average from all other plant from 2012 (ie, co-milling and some new investment of direct injection at other plant).
Source: Oxera.

3.5 Summary of the implications for independent generators

This section has examined the nature of the interaction between generators and licensed electricity suppliers, and the likely effects on co-fired ROC prices and volumes. This analysis was used to assess the development of the market in 2006/07 (when the co-firing cap was tightened) and to extend the analysis to assess possible future outcomes.

The above analysis highlights a number of risks to independent co-firing developers' ability to exploit their potential. These risks partly stem from the current industry structure and the nature of the market for co-fired ROCs, and the interaction of these factors with the co-firing cap. That said, these risks might be expected to be less prominent in the medium and long term, with the key factors mitigating any adverse effects being as follows.

– **Banding effectively doubles the co-firing cap**. By awarding co-firing 0.5ROCs/MWh from 2009/10, the volume of co-fired electricity required to generate the number of co-fired ROCs permitted by the cap is doubled. As a result, the increase in the cap to 12.5% in 2010/11 might be expected to create a situation equivalent to the 25% cap in place prior to 2006.

– **The volume of coal capacity with which to co-fire is set to decrease significantly**. Around 7GW of coal plant that has opted out of the LCPD, as well as over 2GW of oil plant, is likely to retire in the next six years, although this may be partially replaced by new coal plant with CCS. This will reduce the total co-firing potential in future years, and, as such, the co-firing cap might not be expected to be binding from 2015/16.

– **The size of the co-firing cap will grow significantly (in absolute terms) over the next ten years**. The total obligation on suppliers within the RO (which is used to determine the absolute level of the co-firing cap) will, as a result of the headroom mechanism, increase from the explicit annual increases set out in the Renewables Obligation Order and beyond. A policy change to increase the rate at which the Obligation is extended by headroom of more than 8% would further exacerbate this effect. For example, the compound effect of an 8% increase in the Obligation size, year on year over seven years, could increase the Obligation size (and hence the size of the co-firing cap) by 70%. This provides further evidence that the cap is unlikely to be binding beyond 2015/16.

– **Greater co-firing from energy crops reduces the potential to co-fire from regular biomass**. Co-firing from energy crops is outside the cap. If some developers choose to use energy crops, the residual demand for generators producing co-fired ROCs from regular biomass will be increased. However, the decision to co-fire using energy crops is likely to depend on various factors including the relative prices of biomass, the availability of fuel, and the perceived risk that the co-firing cap on regular biomass may be binding. Greater use of energy crops may therefore be symptomatic (that is, greater as a result) of distortions caused by the cap.

– **Future banding-up of other technologies may extend the Obligation size or reduce the incentives to co-fire**. If, prior to any change in banding, year-on-year changes in the Obligation size are not driven by the headroom mechanism, banding-up of other technologies may act to encourage their deployment and thereby increase the total Obligation size and the absolute level of the co-firing cap. If this is not the case, or if the effect is small, there may be some substitution away from co-firing, which may also reduce the effect of the cap—by reducing the incentive of all co-firers to participate in the market. This is explored in more detail in the following section.

This section has demonstrated that, in the short term, the presence of the cap may give rise to the following concerns.

– **The market for independent generators may be considerably smaller than that implied by the cap**. If vertically integrated suppliers buy co-fired ROCs from their generation affiliates before considering alternatives, the residual demand for which independent generators compete is smaller than that implied by the cap.

– **The concentration of supply companies may have the effect of tightening the cap**. As co-firing output reaches the level of the cap, a supply company with a residual share of the market might be expected to negotiate larger discounts to the price of co-fired ROCs. If independent generators are also aware of this, the volume of ROCs produced might be curtailed to avoid reaching this level. In a concentrated supply market, the share of the largest supplier may constitute a significant proportion of the cap (for example, as much as 20%), which could significantly tighten the cap.

– **The structure of supply companies may alter the timing of demand for co-fired ROCs, and increase the risk faced by independent generators**. For suppliers, the purchase of co-fired ROCs is similar to the purchase of a forward contract, in allowing the supplier to comply with the RO at a future date. A forward price discount might be established, whereby suppliers have greater bargaining power than generators, and suppliers have an incentive to delay buying co-fired ROCs, due to the possibility of a fall in prices if total output for the year is close to the cap. The high concentration of suppliers may exacerbate this effect, reducing the ability of independent generators to manage price risks by contracting in advance at competitive prices.

– **Independent and vertically integrated operators have scope to increase co-firing output through greater levels of co-milling and new investment**. To the extent that vertically integrated players expand output, this is likely to magnify the competition concerns above, which may hamper the full development of investment opportunities by independent generators.

In sum, the analysis in this section has shown that the structure of the players in the market for co-firing—in terms of both vertical integration and the concentration of players—implies that the demand that independent generators compete to serve may be significantly smaller than that implied by the co-firing cap.

Based on the likely retirement of existing coal plant, and the past co-firing output of vertically integrated generators, the co-firing cap might not be expected to be binding in the medium term. This is, in large part, due to the banding assigned to co-firing, which effectively doubles the cap.

However, past output decisions, by their nature, reflect the current imposition of the cap. If vertically integrated companies were to increase output to make full use of co-milling (which would require relatively little CAPEX), the cap would become binding for independent generators wishing to invest in new capacity—and might be particularly acute in the period to 2012/13.

4 Impacts on other technologies from changes to the co-firing cap

This section investigates the potential effects of removing the cap on co-firing on the wider dynamics within the RO, including the impact on ROC prices and investment.

A number of model scenarios are presented to help substantiate some of the concerns associated with changes to the co-firing cap that respondents to previous consultations have raised with DECC.

The main concerns include the possibility that:

– removing the cap could result in a large increase in supply of co-fired ROCs, and that this could lead to depressed ROC prices;
– lower restrictions on co-firing could lead to greater volatility in the ROC price, in particular in response to changes in the biomass price, and in coal and carbon prices;
– the effects on ROC prices could have an impact on investment in other technologies, and total renewable deployment.

These effects are examined in this section using the Oxera Renewables Market Model. This model simulates possible renewables investment, based on assumptions on the future costs of the various renewable generation technologies, and expected ROC prices. Outputs from the Oxera Power Market Model are used within the Renewables Market Model to determine projections of the electricity price and the operating patterns of the existing and new coal plant, using commodity price assumptions and expectations of the future level of electricity demand.

The models and their underlying assumptions are described in more detail in Appendix 3.

4.1 Overview of scenarios

In order to address the concerns above, a number of model scenarios have been developed to assess the implications of:

– changes to the level of the co-firing cap;
– changes to future banding levels for other technologies;
– different commodity price assumptions, and hence the operation of coal plant;
– variations in biomass prices;
– the extent to which investment decisions discount the uncertain element of ROC prices.

Table 4.1 below provides an overview of the scenarios used for this analysis, and the main differences between them.

Table 4.1 Scenarios

Index	Co-firing cap (%)	Power/ commodity price	Biomass price	Banding
1 (Status quo)	12.5%	Central	Central	Existing
2	15%	Central	Central	Existing
3	17.5%	Central	Central	Existing
4	20%	Central	Central	Existing
5	30%	Central	Central	Existing
6	100%	Central	Central	Existing
7	12.5%	High-high	Central	Existing
8	100%	High-high	Central	Existing
9	12.5%	High	Central	Existing
10	100%	High	Central	Existing
11	12.5%	Low	Central	Existing
12	100%	Low	Central	Existing
13	12.5%	Central	High	Existing
14	100%	Central	High	Existing
15	12.5%	Central	Low	Existing
16	100%	Central	Low	Existing
17	12.5%	Central	Central	Increased banding of offshore wind and wave and tidal
18	100%	Central	Central	Increased banding of offshore wind and wave and tidal

Note: The commodity price scenarios are based on DECC assumptions and set out in more detail in Appendix 2.
Source: Oxera.

Table 4.2 below also highlights the various combined power/commodity price assumptions and co-firing cap scenarios that have been explored.

Scenarios 1–6 assess the impact of progressively relaxing the co-firing cap under the central power/commodity price assumptions. Sensitivities are provided in scenarios 7–12 to examine the impact of the removal of the cap under high-high, high, and low commodity prices.

For the central commodity price scenarios, additional sensitivities explore the impact of removing the cap on co-firing under high and low biomass price assumptions (scenarios 13–16) and the impact of removing the cap in an environment where offshore wind and wave and tidal power generation technologies are banded up (scenarios 17 and 18).

Table 4.2 Renewables Market Model and commodity price sensitivities

		Renewables Market Model scenarios					
	Cap	**12.5%**	**15%**	**17.5%**	**20%**	**30%**	**100%**
	Additional sensitivities	High/low biomass price Changes to banding					High/low biomass price Changes to banding
Power Model scenarios	**High-high** **(DECC scenario: high demand, significant supply constraints)**	✓					✓
Power Model scenarios	**High** **(DECC scenario: high demand, producers' market power)**	✓					✓
Power Model scenarios	**Central** **(DECC scenario: timely investment, moderate demand)**	✓	✓	✓	✓	✓	✓
Power Model scenarios	**Low** **(DECC scenario: low global energy demand)**	✓					✓

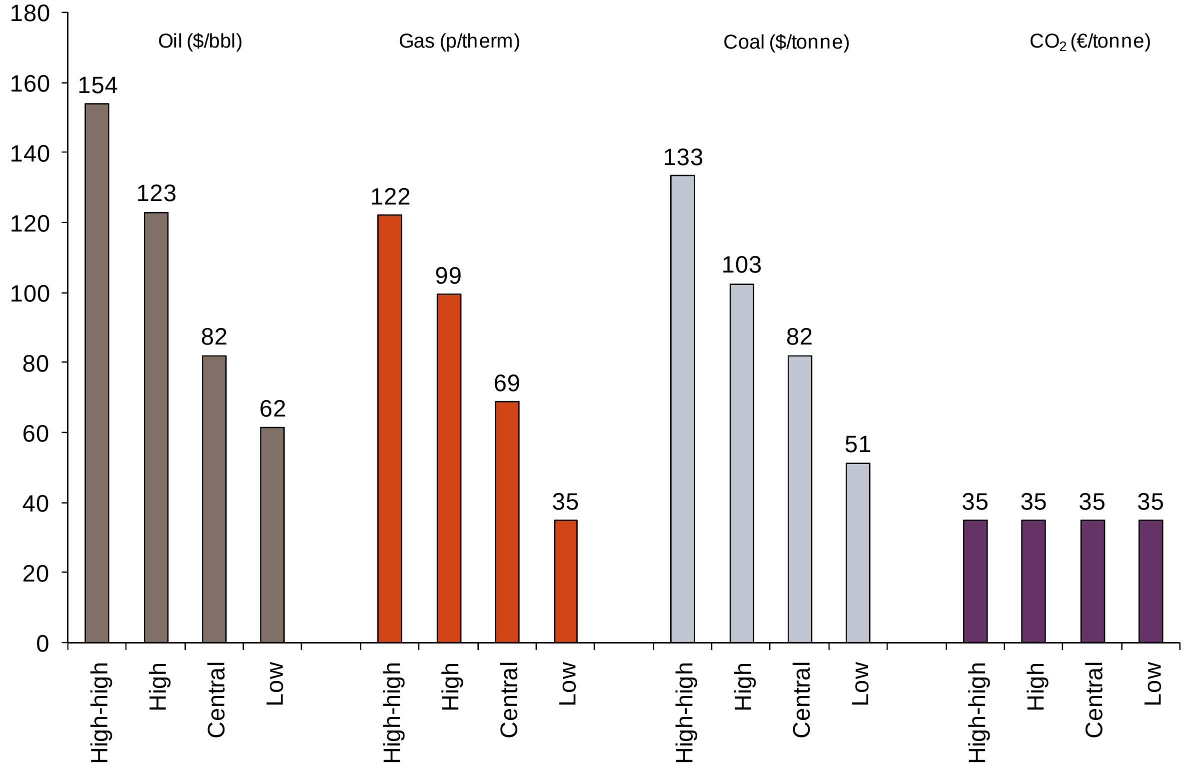
Source: Oxera.

4.2 Scenario assumptions

The scenario assumptions are summarised below. A more detailed set of assumptions is provided in Appendix 2.

Figure 4.1 below shows the range of commodity price assumptions used within the scenarios, based on data provided by DECC.

Figure 4.1 Commodity price assumptions, 2020 (2009 prices)



Note: Exchange rates used are as follows: a £/€ rate of 0.719 and a $/£ rate of 1.6.
Source: DECC (2009), 'Communication on DECC fossil fuel price assumptions', available at http://www.berr.gov.uk/files/file51365.pdf.

Biomass prices (based on data from E4tech) have been used to develop co-firing supply curves that describe the costs of potential co-firing capacity.[33] These supply curves have been built separately to derive the costs of the following increments of capacity:

– coal plants with existing co-firing capacity;
– new co-firing capacity.

The supply curves are developed from the following key components.

– Potential capacity. This is a function of the technical and policy constraints on co-fired generation.

– Price of biomass. This is based on the E4tech data, using the biomass volumes necessary to meet demand from the potential co-firing capacity. The central case is based on analysis using the E4tech 'Central RES' scenario.

– Capital costs of new co-firing capacity. A capital cost of £200/kW has been used, reflective of the capital costs of recent new co-firing injection facilities.

Table 4.3 below sets out the biomass prices used in the analysis, and Table 4.4 presents the levelised costs of co-firing, derived from these biomass prices.

[33] E4tech (2009), 'Biomass Supply Curves for the UK', March.

Table 4.3 Biomass prices (£/GJ of biomass, 2007 prices)

	2008	2010	2015
High	7.10	7.10	7.10
Central	4.99	3.80	4.99
Low	3.99	3.04	3.99

Source: E4tech (2009), 'Biomass Supply Curves for the UK', March and Oxera analysis.

Table 4.4 Levelised costs of co-firing, central case (£/MWh, 2007 prices)

	2008	2009	2010	2011	2012	2013	2014	2015
Existing co-firing	54.2	47.7	42.0	44.2	46.5	49.0	51.5	54.2
New co-firing capacity	67.1	60.7	54.9	56.4	58.0	59.6	61.2	62.9

Note: The modelling in this section assumes that all co-firing is of non-energy crops, in order to highlight the more extreme changes that might be possible if changes were made to the co-firing cap. In practice, the ability to co-fire energy crops outside the cap might be expected to dampen the effects on ROC prices of changes to the co-firing cap. In calculating the levelised costs of new co-firing, a plant efficiency of 35% has been assumed, as well as a plant life of five years, operating and maintenance costs of £3/MWh, and capital costs of £200,000/MW. From 2015 onwards, the levelised costs of co-firing are assumed to remain constant at 2015 levels.
Source: E4tech (2009), 'Biomass Supply Curves for the UK', March, and Oxera analysis.

In the event that biomass prices are higher than those above, co-firing levelised costs may be higher than those assumed within the analysis, which may act to reduce the level of co-firing deployment and dampen the effect of possible changes to the co-firing cap on other technologies. The assumptions within this report can therefore be considered relatively conservative in order to help understand the risks associated with changes to the cap.

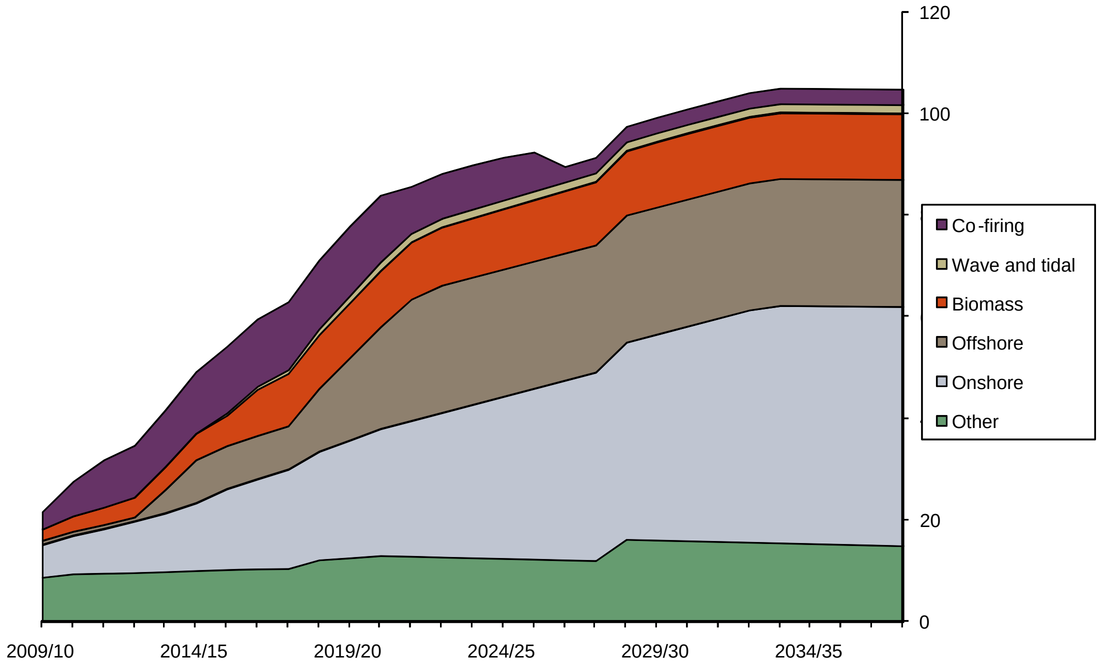
Section 4.4 provides additional analysis under high and low biomass price sensitivities. In particular, the impact of the high biomass scenario is to significantly reduce the volume of co-firing. The high and low scenarios are constructed as follows.

– **Low biomass price**. This represents a 20% discount to the E4tech 'Central RES' scenario.

– **High biomass price**. This is equal to the E4tech import price, and remains constant at 2008 levels (£7.28/GJ of biomass at 2008 prices) throughout the period under analysis.

Figure 4.2 shows the breakdown of projected deployment under Scenario 1 (the status quo).

Figure 4.2 Projected renewable deployment under Scenario 1



Source: Oxera.

4.3 Impact of relaxing the cap on co-firing

This section describes the potential impact of relaxing the co-firing cap, under the central power/commodity price assumptions (scenarios 1–6).

Table 4.5 and Figure 4.3 set out the technical constraints on co-firing, and the constraints implied by UK government renewables policy to 2020/21. These are derived as follows.

– The technical constraints are a function of the volume of coal-fired generation, which is driven by the relative price of coal, gas and carbon, and is also dependent on plant efficiencies and assumptions on the potential for increased direct injection by some plant.

– The policy constraint refers to the cap on regular co-firing within the RO.

The policy constraint is seen to be binding only in scenarios 1 and 2 (when the cap on co-firing is equal to 12.5% and 15% of suppliers' obligations) and mainly between 2012/13 and 2014/15. With a larger cap, the technical constraints become binding. In the 17.5% cap scenario, the technical and policy constraints are of similar size in 2012/13.

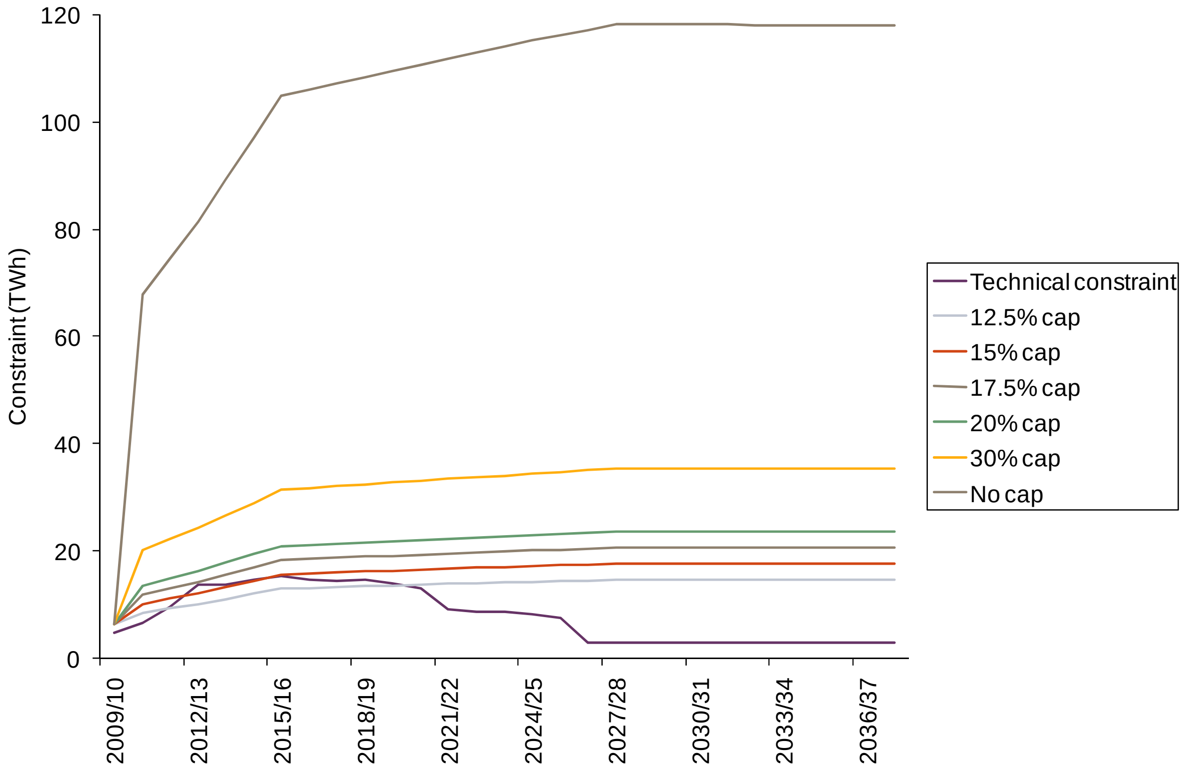
With the constraints on co-firing driven by the technical potential to co-fire when the cap is 17.5% or greater (scenarios 3, 4, 5 and 6), a further increase in the cap might not be expected to lead to greater co-firing output.

Table 4.5 Constraints on co-firing (TWh)

	Technical constraint on co-firing	Policy constraint on co-firing					
		Scenario 1 (cap 12.5%)	Scenario 2 (cap 15%)	Scenario 3 (cap 17.5%)	Scenario 4 (cap 20%)	Scenario 5 (cap 30%)	Scenario 6 (no cap)
2009/10	4.9	6.4	6.4	6.4	6.4	6.4	6.4
2010/11	6.8	8.5	10.2	11.9	13.6	20.3	67.8
2011/12	9.8	9.3	11.2	13.0	14.9	22.3	74.4
2012/13	13.9	10.2	12.2	14.3	16.3	24.5	81.5
2013/14	13.9	11.1	13.4	15.6	17.8	26.7	89.2
2014/15	14.8	12.1	14.5	17.0	19.4	29.1	97.0
2015/16	15.5	13.1	15.7	18.4	21.0	31.5	104.9
2016/17	14.8	13.3	15.9	18.6	21.2	31.8	106.1
2017/18	14.5	13.4	16.1	18.8	21.4	32.2	107.2
2018/19	14.8	13.5	16.3	19.0	21.7	32.5	108.4
2019/20	14.1	13.7	16.4	19.2	21.9	32.9	109.6
2020/21	13.2	13.8	16.6	19.4	22.1	33.2	110.7

Source: Oxera analysis.

Figure 4.3 Constraints on co-firing (TWh)



Source: Oxera analysis.

As seen in Table 4.6 and Figure 4.4, the effect of changing the cap on co-firing from 12.5% (Scenario 1) to 15% (Scenario 2) is to increase co-firing volumes by up to 2.4TWh (or 20%) in 2014/15, and by 0.4TWh in 2019/20. In subsequent years (ie, after 2019/20), the technical constraints on co-firing become binding within both scenarios, leading to the same level of co-firing output. In aggregate, an additional 13.9TWh (or 13%) of co-firing takes place in the period from 2011/12 to 2019/20 as a result of changing the co-firing cap from 12.5% to 15%, as highlighted in Table 4.6 (and shown in Figure 4.4).

The results are similar for increases in the co-firing cap from 12.5% to 17.5%. The largest increase in co-firing output as a result of the change in the cap is 3TWh (a 30% increase) in 2012/13. The aggregate co-firing output in the period from 2011/12 to 2019/20 increases by 15.7TWh (or 14%).

Table 4.6 Co-firing volumes

	Co-firing volumes (TWh)			Co-firing volumes as a % of cap		
	Scenario 1 (12.5% cap)	Scenario 2 (15% cap)	Scenarios 3, 4, 5 and 6 (17.5%–no cap)[1]	Scenario 1 (12.5% cap)	Scenario 2 (15% cap)	Scenarios 3, 4, 5 and 6 (17.5%–no cap)
2009/10	3.4	3.4	3.4	70%	70%	70%
2010/11	6.8	6.8	6.8	100%	100%	100%
2011/12	9.3	9.8	9.8	100%	100%	100%
2012/13	10.2	12.2	13.2	100%	100%	95%
2013/14	11.1	13.4	13.9	100%	100%	100%
2014/15	12.1	14.5	14.8	100%	100%	100%
2015/16	13.1	15.5	15.5	100%	100%	100%
2016/17	13.3	14.8	14.8	100%	100%	100%
2017/18	13.4	14.5	14.5	100%	100%	100%
2018/19	13.5	14.8	14.8	100%	100%	100%
2019/20	13.7	14.1	14.1	100%	100%	100%
2020/21	13.2	13.2	13.2	100%	100%	100%
Total co-firing 2011/12–2019/20 (TWh)	109.7	123.6	125.4			
Change in total co-firing 2011/12–2019/20 (TWh)	n/a	13.9	15.7			

Note: 1 Scenarios 3, 4, 5, and 6 are shown in a single column as the policy constraint is not binding in all years (ie, it is greater than the technical constraint).
Source: Oxera analysis.

Figure 4.4 Co-firing output (TWh)

Source: Oxera analysis.

The increase in co-firing caused by relaxing the co-firing cap leads to an increase in overall deployment of renewable generation rather than creating a substitution away from other technologies. This reflects the fact that the change in expected ROC price is not sufficient to alter the investment decisions of other technologies, while the headroom mechanism allows for the extension of the Obligation size with greater levels of co-firing.

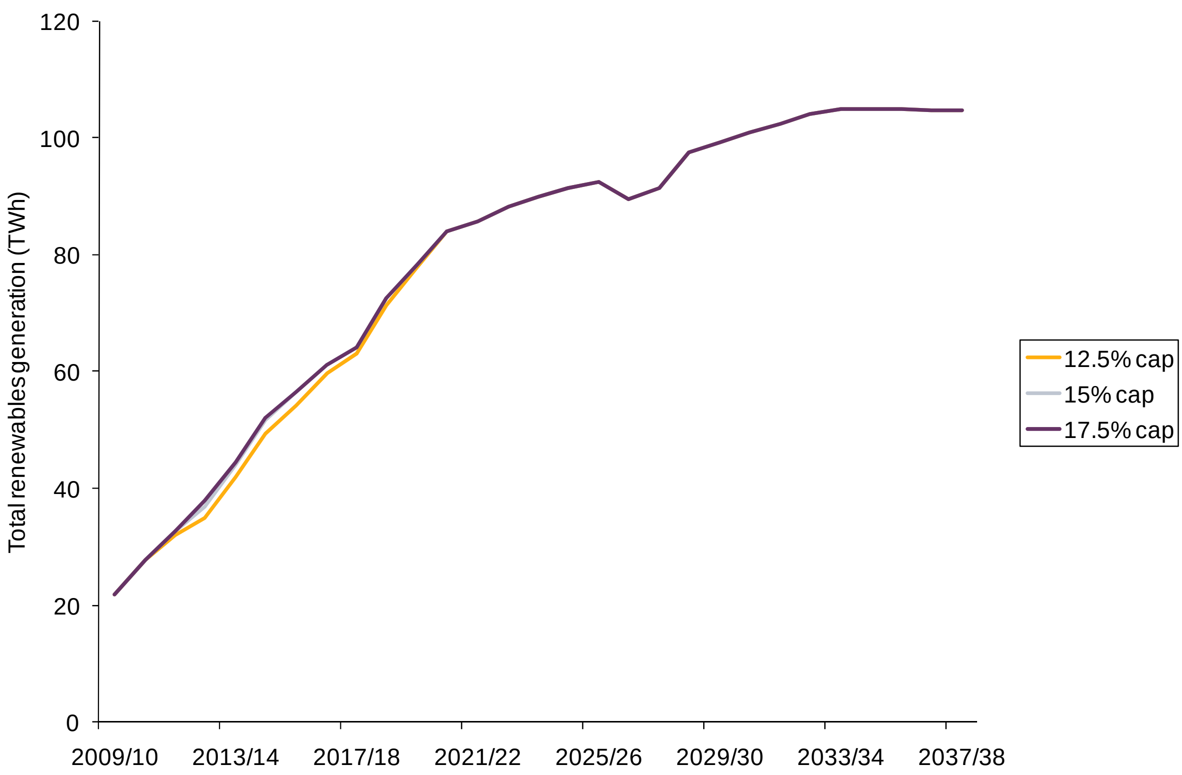
Table 4.7 and Figure 4.5 show that total renewable deployment increases under scenarios with an extension to the co-firing cap. The potential decrease in ROC prices from greater levels of co-firing is dampened by the headroom mechanism, which extends the Obligation from 2013/14, rather than 2014/15 following the extension of the cap.

Table 4.7 Total renewables deployment

	Renewables volumes (TWh)			Renewables volumes as a % of electricity supplied		
	Scenario 1 (12.5% cap)	Scenario 2 (15% cap)	Scenarios 3, 4, 5 and 6 (17.5%– no cap)	Scenario 1 (12.5% cap)	Scenario 2 (15% cap)	Scenarios 3, 4, 5 and 6 (17.5%– no cap)
2009/10	21.7	21.7	21.7	6.5%	6.5%	6.5%
2010/11	27.7	27.7	27.7	8.3%	8.3%	8.3%
2011/12	31.9	32.5	32.5	9.6%	9.8%	9.8%
2012/13	34.8	36.8	37.8	10.4%	11.0%	11.3%
2013/14	41.8	44.0	44.5	12.4%	13.0%	13.2%
2014/15	49.3	51.7	52.0	14.5%	15.2%	15.2%
2015/16	54.3	56.6	56.6	15.7%	16.4%	16.4%
2016/17	59.7	61.2	61.2	17.1%	17.6%	17.6%
2017/18	63.1	64.1	64.1	17.9%	18.2%	18.2%
2018/19	71.2	72.5	72.5	20.0%	20.4%	20.4%
2019/20	77.9	78.4	78.4	21.6%	21.8%	21.8%
2020/21	84.0	84.0	84.0	23.1%	23.1%	23.1%

Note: This analysis does not include all of the proposed modifications to the RO that have been used to derive DECC's lead scenario in the Renewable Energy Strategy, and therefore shows a lower total proportion of renewable electricity by 2020.
Source: Oxera analysis.

Figure 4.5 Total renewables deployment (TWh)



Note: The difference in total renewables deployment under the 15% cap and 17.5% cap scenarios rises to around 100MWh in 2014/15, falling to around 40MWh from 2019/20 onwards.
Source: Oxera analysis.

The impact on the ROC price of changes to the co-firing cap is set out in Table 4.8 and Figure 4.6 below. This shows that the ROC price falls slightly during the period 2011/12 to 2015/16, due to the increase in deployment. The largest impact occurs in 2012/13, when the price falls by £1.6/MWh if the co-firing cap is increased to 15%, and by £2.4/MWh as the cap is increased to 17.5% or higher.

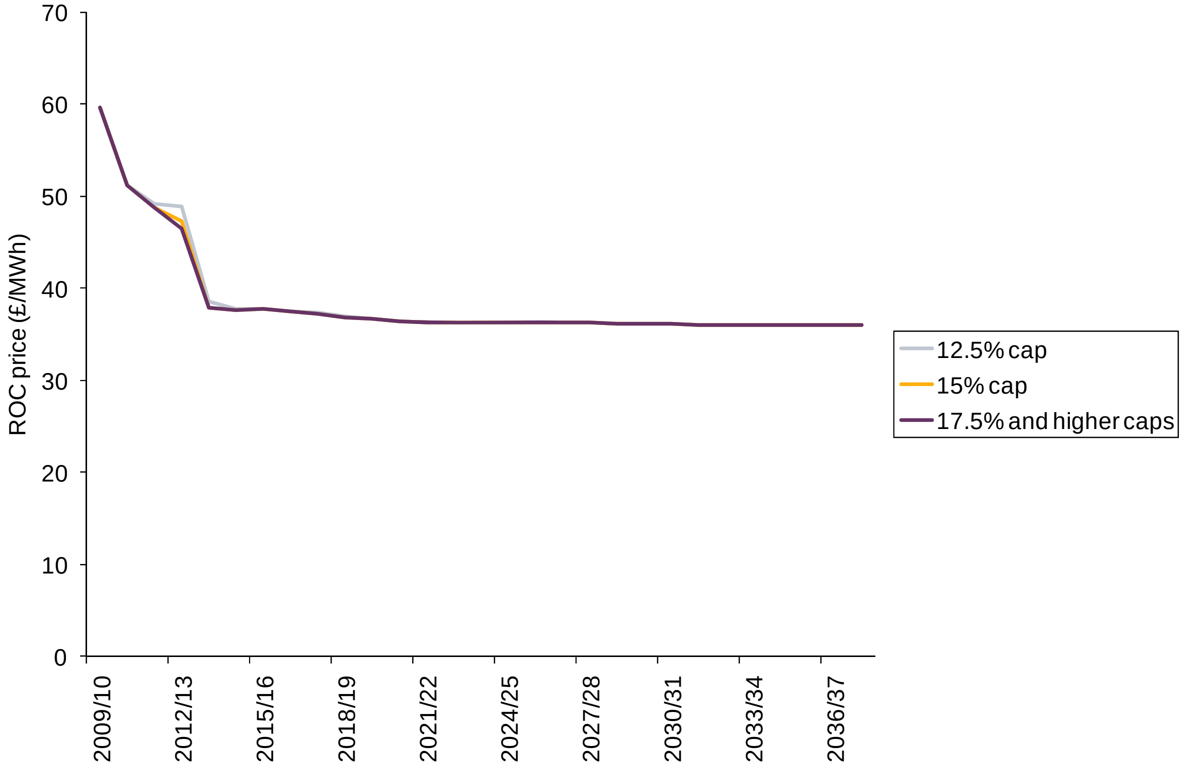
The difference in average prices from 2009 to 2020 between the 17.5% cap scenario (scenario 3) and the 12.5% cap scenario (scenario 1) is £0.3/MWh. As investment decisions are driven by long-run expectations of prices over the life of a project, this helps explain the relatively small impact on renewable investment. For instance, on changing the co-firing cap from 15% (scenario 2) to 17.5% (scenario 3), the present value of ROCs received by onshore wind generators in 2011/12 falls from £313/MWh to £311/MWh, a decrease of 0.6%.

Table 4.8 ROC value (£/MWh)

	Scenario 1 (12.5% cap)	Scenario 2 (15% cap)	Scenarios 3, 4, 5 and 6 (17.5%–no cap)
2009/10	59.6	59.6	59.6
2010/11	51.2	51.2	51.2
2011/12	49.2	48.8	48.8
2012/13	48.9	47.2	46.5
2013/14	38.5	37.9	37.9
2014/15	37.7	37.7	37.7
2015/16	37.8	37.7	37.7
2016/17	37.5	37.5	37.5
2017/18	37.3	37.3	37.3
2018/19	36.9	36.9	36.9
2019/20	36.6	36.6	36.6

Source: Oxera analysis.

Figure 4.6 ROC price (£/MWh)



Source: Oxera analysis.

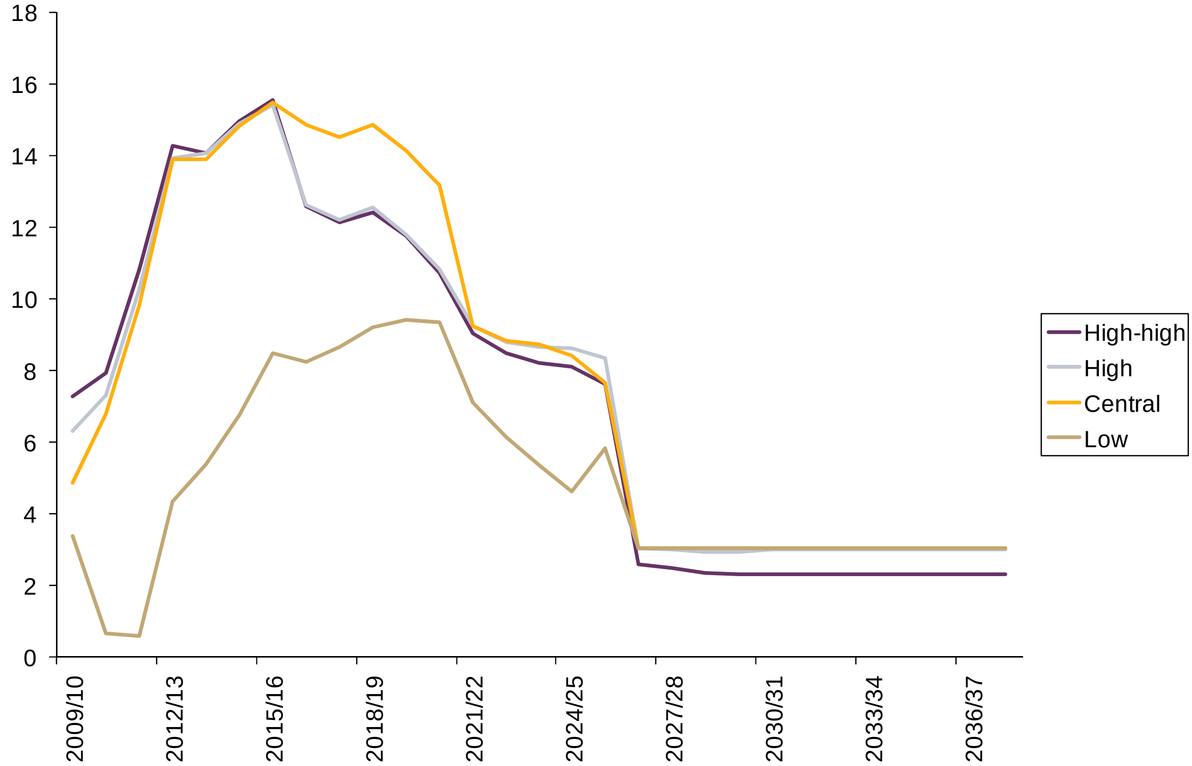
Other than the impact on co-firing, the change in output from other technologies is negligible in scenarios with changes to the co-firing cap.

Sensitivity to commodity price assumptions

The investment decisions reported above are based on expectations consistent with out-turn commodity prices. This section evaluates the sensitivity of the impact of removing the cap on co-firing to alternative commodity price scenarios.

Differences in commodity price assumptions affect the marginal costs of thermal power plant, and result in differing levels of coal output, which affects the technical potential/constraint. The difference in technical potential across the alternative commodity/power price scenarios is shown in Figure 4.7.

Figure 4.7 Technical constraints on co-firing (TWh) commodity price sensitivity

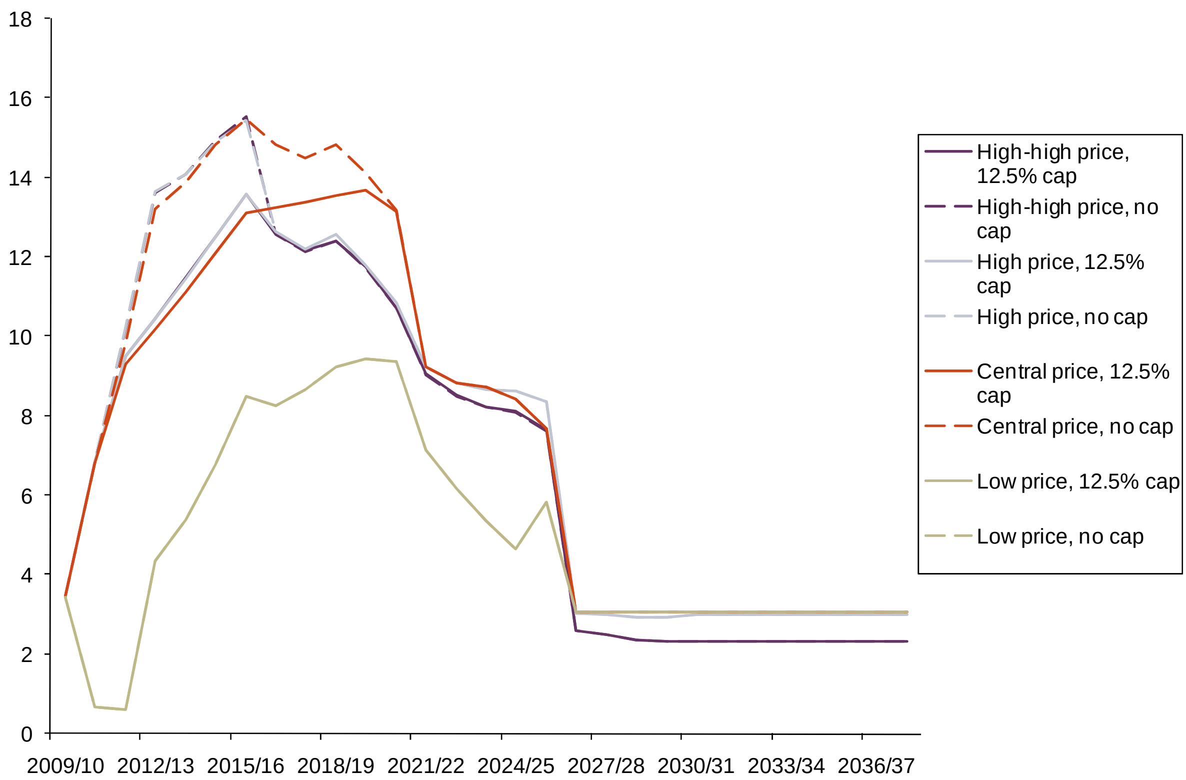


Source: Oxera analysis.

In the low price scenario, the technical constraints on co-firing are binding under a 12.5% cap on co-firing. An increase in the co-firing cap might not, therefore, be expected to have a wider impact on the renewables market. This is highlighted in Figure 4.8, which shows co-firing output within the different commodity price scenarios.

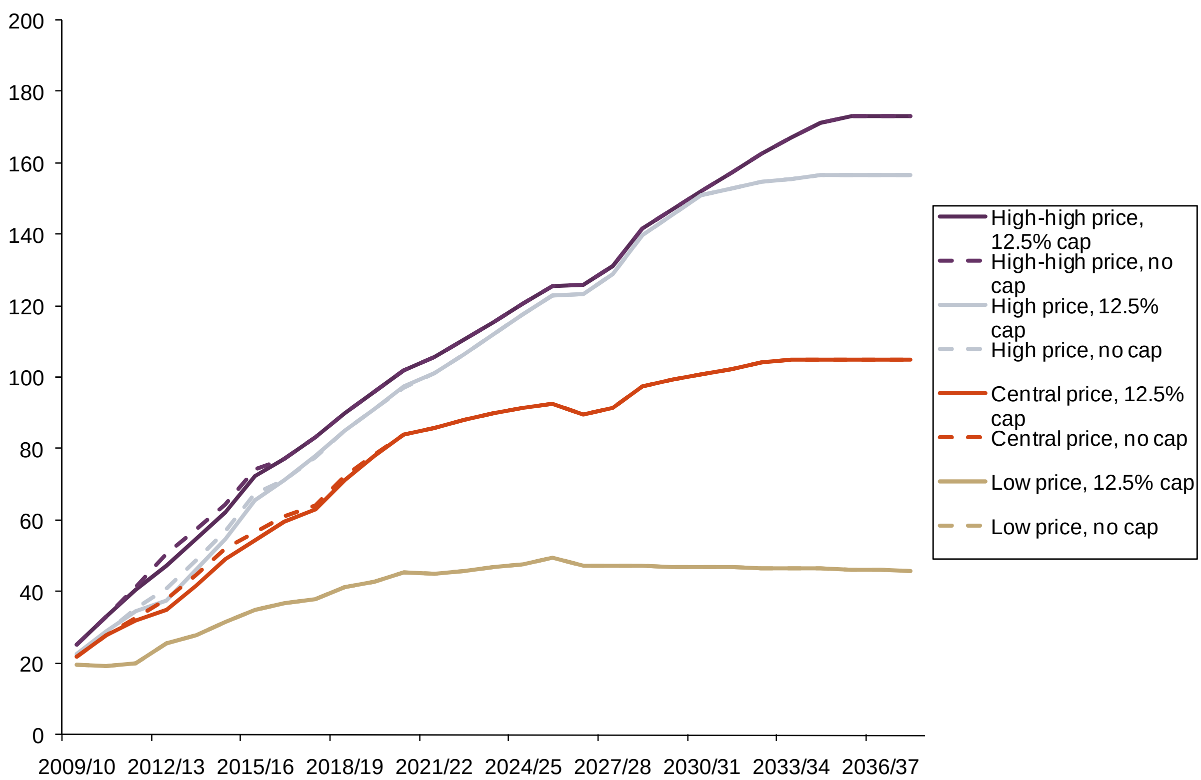
In contrast in the high-high and high scenarios, co-firing output might be expected to increase in the period from 2011/12 to 2015/16 if the co-firing cap were to be removed, after which the technical constraints on co-firing would become binding within both scenarios. The maximum increase in co-fired output is 3.2TWh, which occurs in 2012/13. The aggregate increase in co-firing to 2020 is around 11TWh, or around 19%.

Figure 4.8 Co-firing output (TWh) commodity price sensitivity



Source: Oxera analysis.

Figure 4.9 Total renewables deployment (TWh) commodity price sensitivity

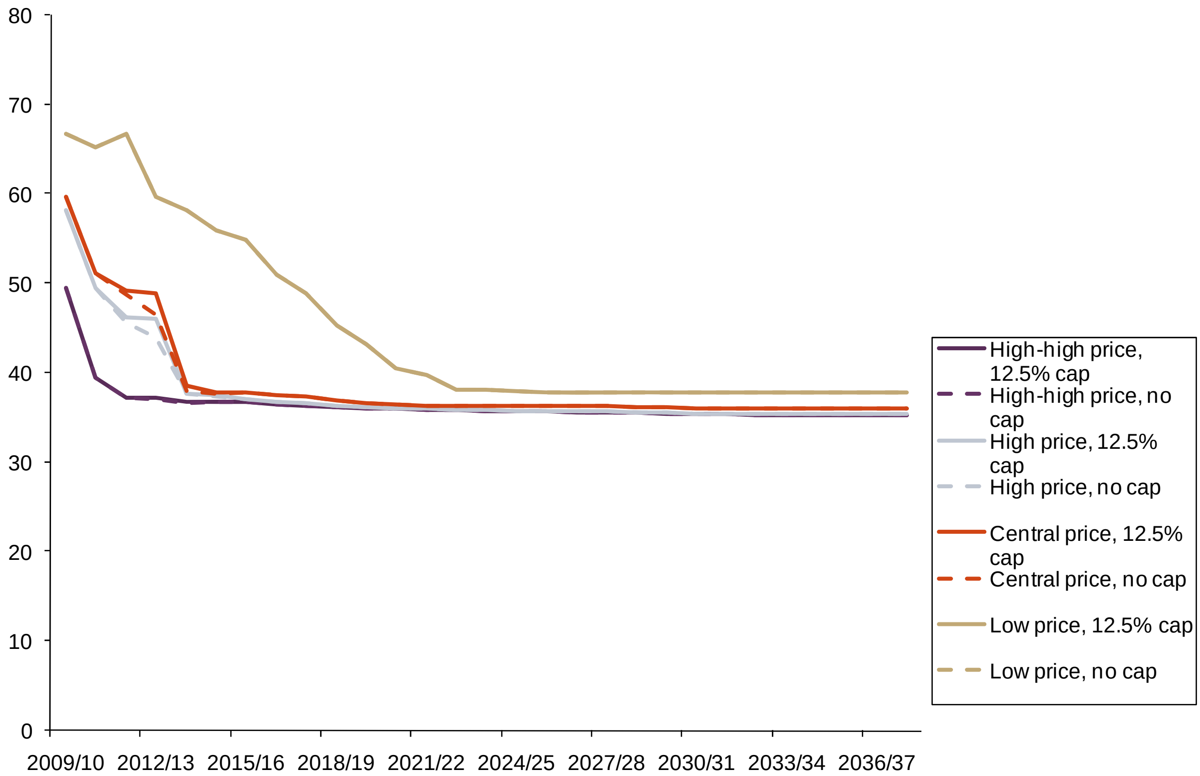


Source: Oxera analysis.

As in the central scenarios, the change in the deployment of other renewables technologies caused by the change in co-firing output in the high-high and high scenarios is close to zero, with the overall increase in total renewables volumes largely resulting from the increase in co-firing. This limited impact on other technologies is the result of a small change in ROC prices, again driven largely by the operation of the headroom mechanism.[34]

In the high scenario, despite the increase in renewable generation from 2011/12 onwards following the removal of the co-firing cap, the headroom mechanism does not extend the level of the Obligation until 2013/14, resulting in a reduction in the ROC price in 2011/12 (£0.6/MWh) and 2012/13 (£2.2/MWh). Consequently, generation from biomass plant falls by 0.2TWh in 2009/10 and 2010/11.

Figure 4.10 ROC price (£/MWh) commodity price sensitivity



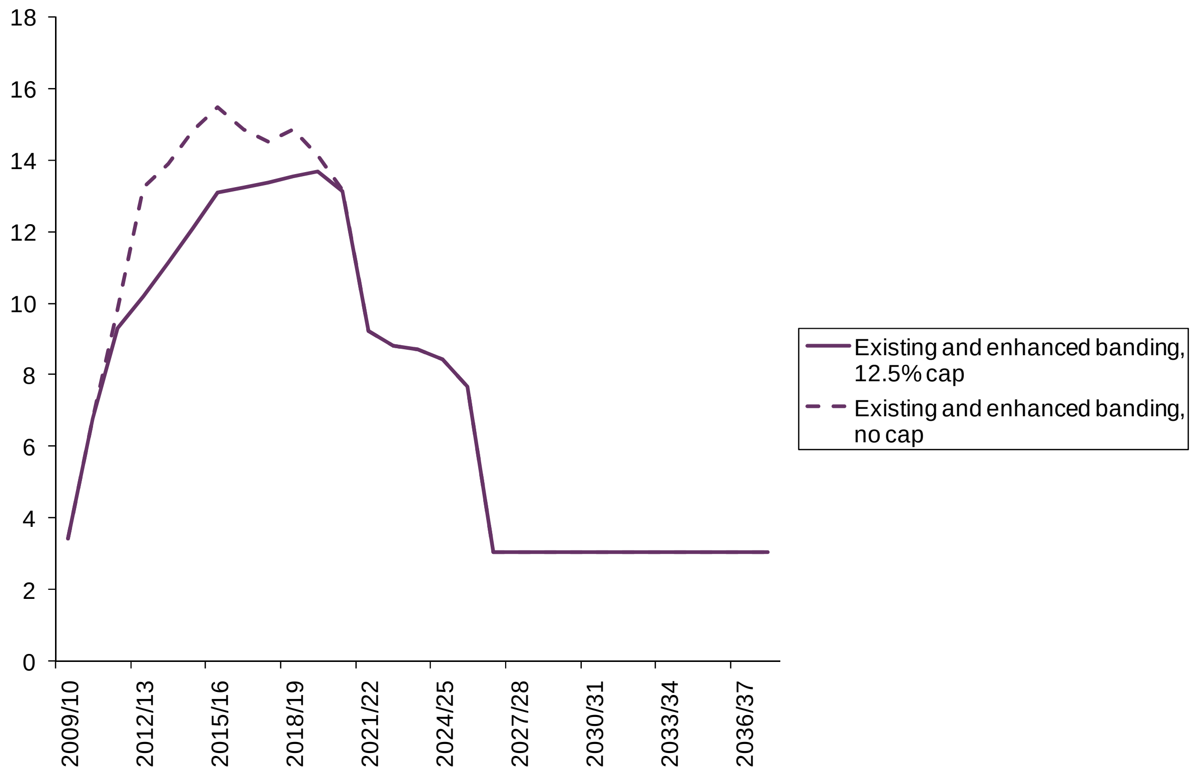
Source: Oxera analysis.

Sensitivity to banding assumptions

As Figures 4.11 to 4.13 highlight, changing the level of banding has a limited impact on the degree to which the removal of the cap on co-firing affects the renewables market.

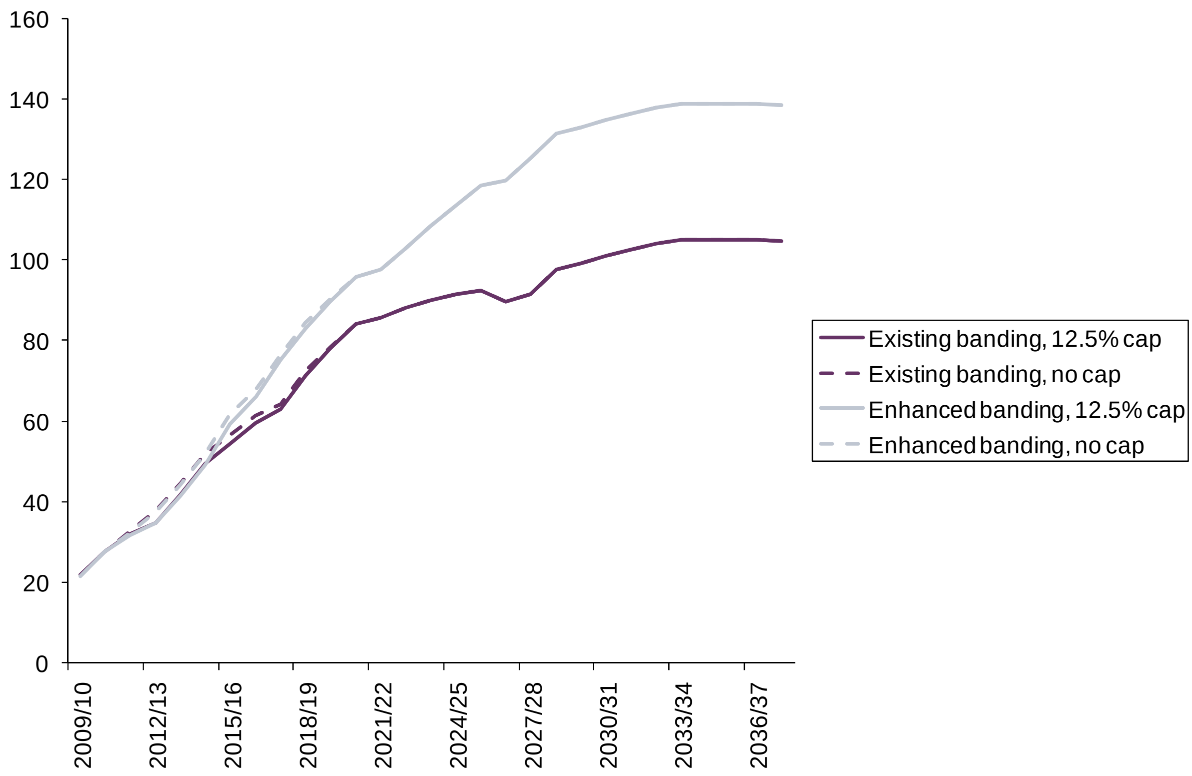
[34] In particular, with the headroom mechanism being operational from 2011/12 onwards in the high-high case under both the capped and uncapped co-firing scenarios, the ROC price remains unchanged.

Figure 4.11 Co-firing output (TWh) banding sensitivity



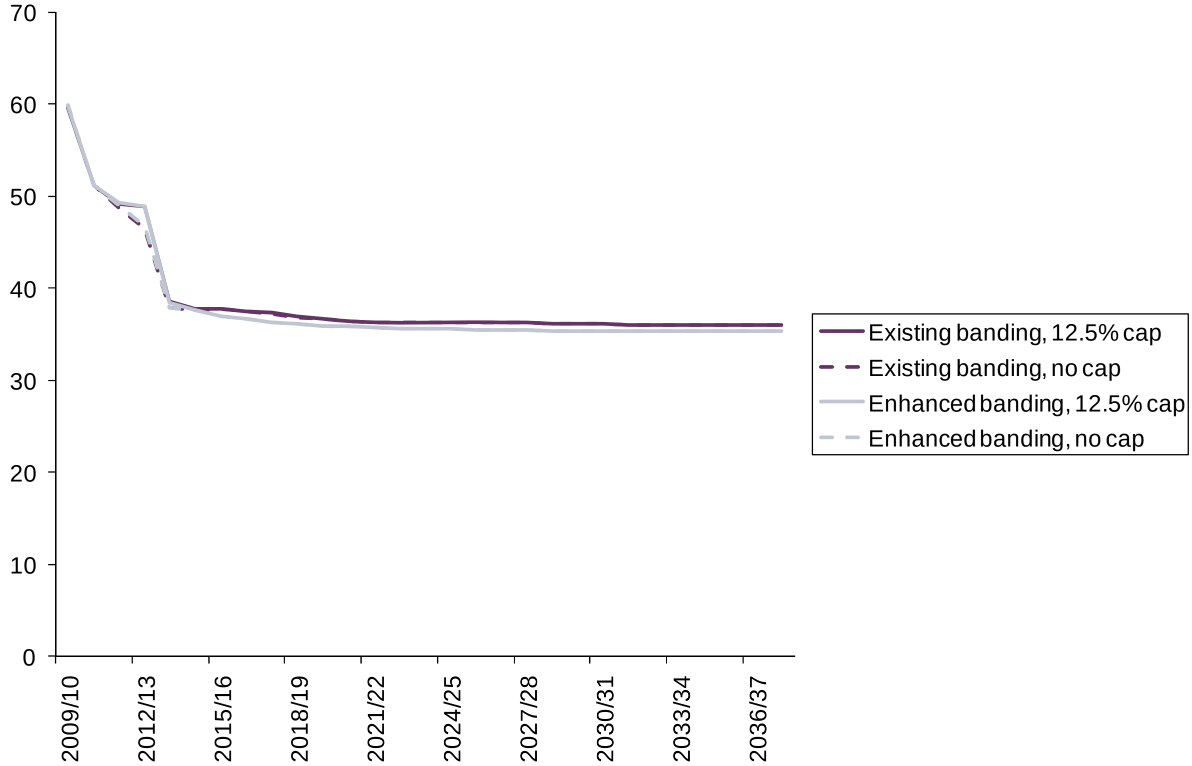
Source: Oxera analysis.

Figure 4.12 Total renewables deployment (TWh) banding sensitivity



Source: Oxera analysis.

Figure 4.13 ROC price (£/MWh) banding sensitivity



Source: Oxera analysis.

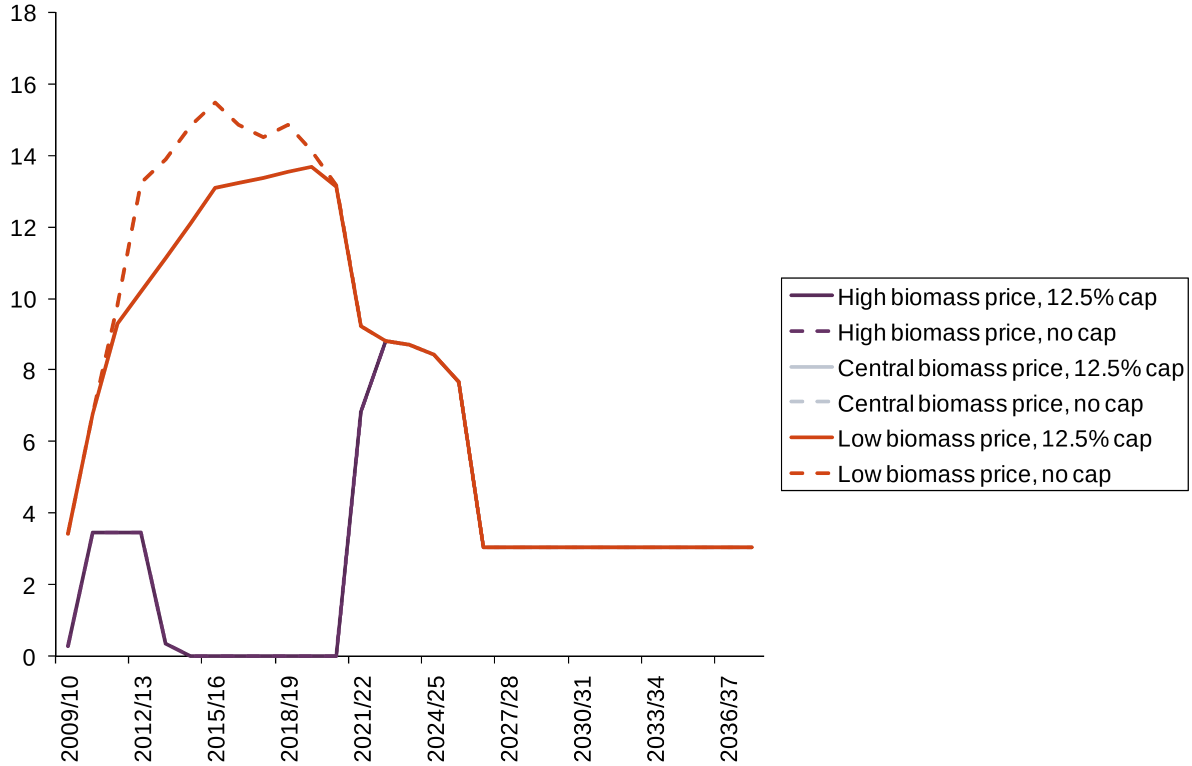
4.4 Impact of sustained changes to biomass prices

Figures 4.14 and 4.15 below show that the effects of removing the co-firing cap under the low biomass price scenario are identical to those under the central scenario. That is, the biomass price in the central scenario is sufficiently low that additional output is not encouraged by lowering the biomass price. While a number of survey respondents highlighted that the current level of support to co-firing may be insufficient to make it economic, given their expectations of future biomass, coal and carbon prices, the scenarios in this report act to highlight the most extreme impacts of the co-firing cap.

In contrast, the high biomass price scenario results in no co-firing output in the period from 2014/15 to 2020/21. Co-firing is economic in 2021/22 as a result of the projected increase in the carbon price, which increases to £34/tonne (real 2009 prices) and continues to increase in the following years. The increase in the carbon price implies that co-firing output reaches its maximum technical potential by 2022/23.

In the high biomass price scenario, the removal of the cap has no effect on co-firing output, which is constrained by the biomass price in the period up to 2021/22, and by technical constraints thereafter.

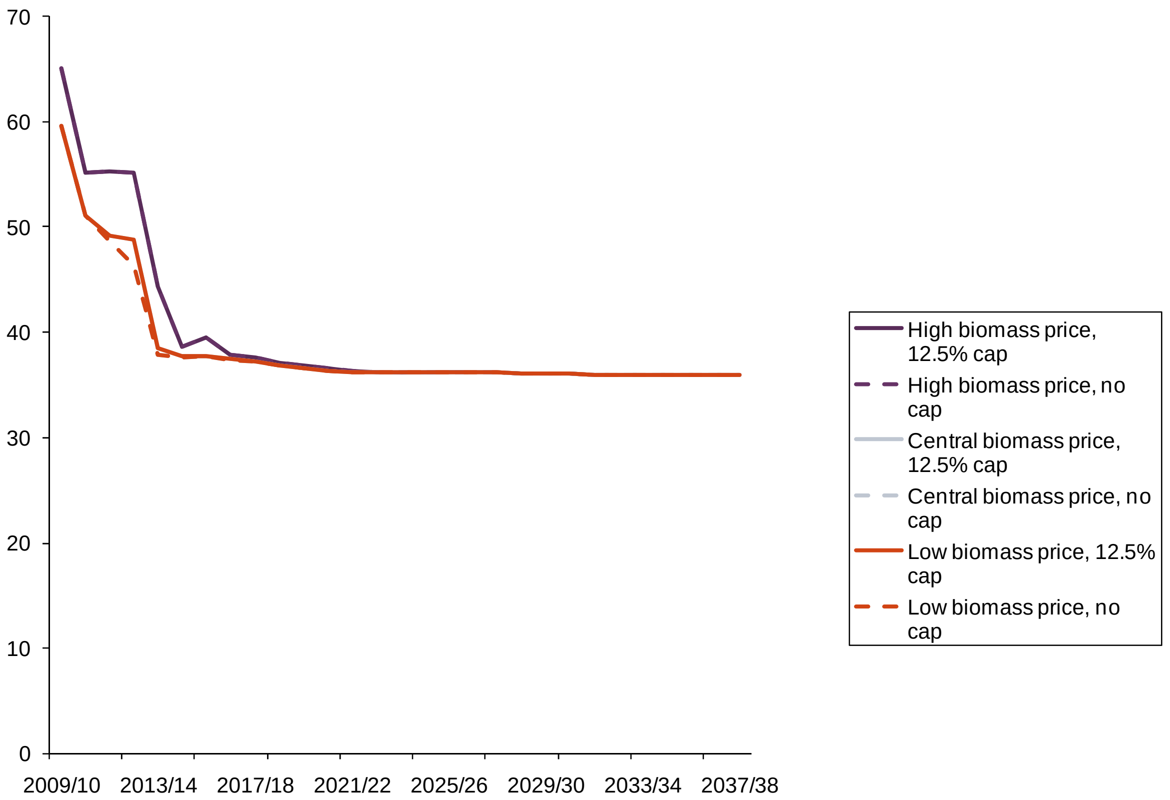
Figure 4.14 Co-firing output (TWh) biomass price sensitivity



Source: Oxera analysis.

As in the other scenarios, in the low biomass price scenario, the increase in co-firing output has a limited impact on the output of other technologies. The small increase in aggregate renewables deployment due to higher co-firing output is driven by the headroom mechanism extending the Obligation size a year earlier than when the cap is present, dampening the impact of increased renewables deployment on the ROC price. The maximum decrease in the ROC price—of £2.4/MWh—occurs in 2012/13, with the increase reduced to zero by 2015/16, as shown in Figure 4.15.

Figure 4.15 ROC price (£/MWh) biomass price sensitivity



Source: Oxera analysis.

4.5 The impact on investment from increased ROC price uncertainty

A comparison across scenarios indicates that the level of investment within a particular class of technology and in total varies in accordance with differences in the expectations of future electricity and ROC prices, captured in the different commodity price scenarios.

This section examines the extent to which changes to the co-firing cap could widen this range of price expectations, and provides an indication of the impact this could have on investment.

The out-turn ROC prices shown in Table 4.8 indicate that the greatest variation in prices that might be expected to arise from the removal of the co-firing cap within the central commodity price scenario could be as much as £2.4/MWh in 2012/13, but considerably less in other years. A similar effect occurs under the high commodity price scenarios as a result of removing the cap, while the effects are much smaller for other commodity price scenarios.

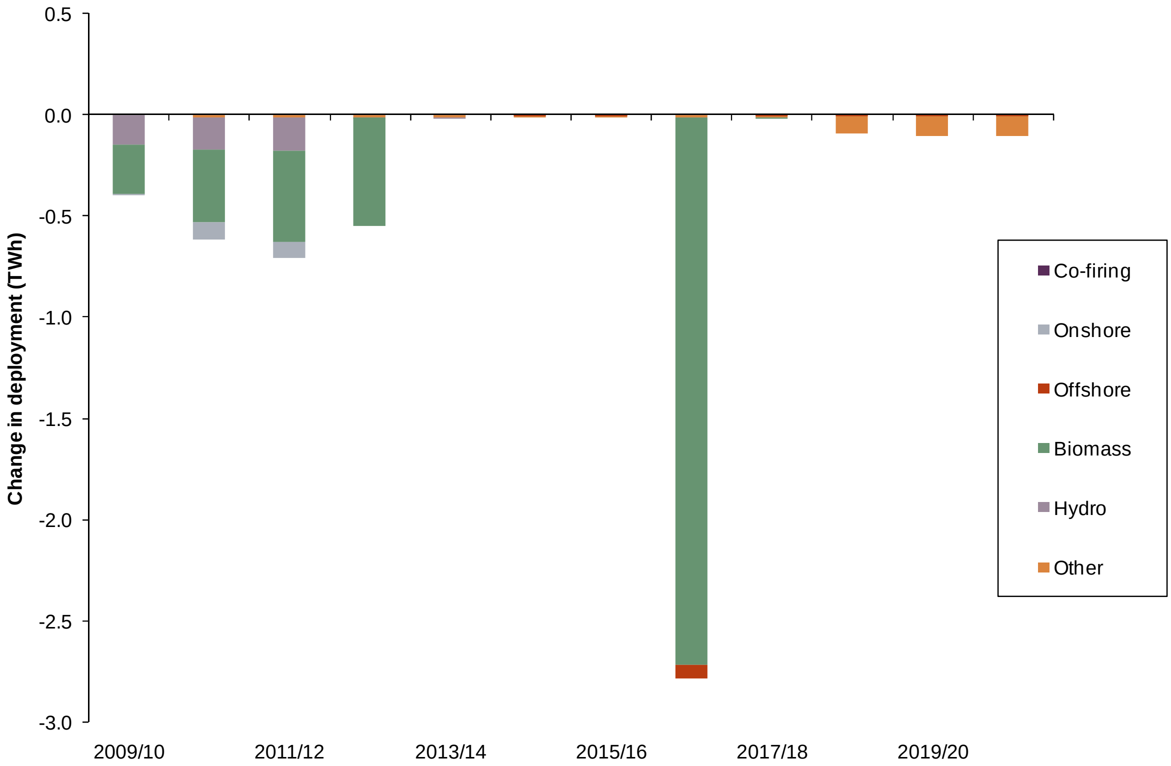
A reduction in the ROC price of £2.4/MWh is equivalent to a decrease in the recycled component of the ROC price, of around 15% during 2012/13.

In order to illustrate the impact of investment uncertainty, the analysis below describes the effect on investment within the central commodity price scenario with the co-firing cap removed, where investment decisions are based on an expectation of the realisation of 70% of the recycled component of future ROC prices, rather than the 90% generator share assumed in the other scenarios.[35]

[35] Investment decisions are based on generators' expectations of the future ROC price and the share of the buyout component and recycled of prices that they are able to realise. The derivation of ROC price expectations are described in more detail in Appendix 3.

Figure 4.16 shows the annual change in deployment under this scenario compared to those with investment decisions based on a 90% expected realisation of the recycled component of prices (scenario 6).

Figure 4.16 Annual change in deployment with discounted ROC price expectations



Source: Oxera

Figure 4.16 shows that the marginal technology for which there is the greatest impact is for large-scale biomass projects, with the most significant effect on investment in 2016/17.

However, the analysis also indicates that the annual change in deployment is not sustained. That is, investment is delayed by around one year in 2016/17, but total deployment reaches levels similar to those in scenario 6, which does not include increased discounting of the recycled component of prices in later years. The net effect by 2020/21 is less than 0.1TWh.

The limited effect described above might be expected given the relatively small and constant value of the recycled component of ROC prices once the Obligation size is extended year-on-year by the headroom mechanism.

4.6 Summary of wider impacts

The analysis in this section suggests that increasing or removing the cap on co-firing might be expected to be greatest in 2012/13, with an increase of around 3TWh, or 1.5m ROCs.

Although this increase is significant, the impact on the remainder of the renewables market might be expected to be limited. Due to the ability of the headroom mechanism to extend the Obligation size, the price effect might be expected to be relatively small and concentrated on earlier years, with little effect on investment in other technologies.

With technical constraints on co-firing being binding over the medium to long term, relaxing the cap beyond 17.5% might not be expected to provide additional benefits to co-firers.

4.7 Cost–benefit metrics

This section provides an assessment of the impact on a number of cost–benefit metrics in the scenarios considered above.

Table 4.9 shows discounted lifetime cost and benefit metrics within the scenarios. That is, an assessment is provided of the change in total renewable generation, associated resource costs, and carbon savings along with other metrics from 2009 until the end of the lifetime of the relevant projects in 2055. Costs and benefits are discounted at the social discount rate.

Within the central power price scenarios, the impact of increasing the size of the co-firing cap on renewable generation and carbon savings arise primarily as a result of changes in co-firing output. Lifetime resource costs—defined as the capital and operating costs of the renewable technologies deployed—increase by £126m as a result of increasing the cap to 17.5% or more. Total renewables output increases with greater co-firing, which displaces conventional generation rather than other renewables. This increase is relatively small compared to baseline costs (less than 1%) given the low costs of co-firing, which is reflected in the slight increase in cost-effectiveness—defined as total resource costs divided by carbon saved.

The net discounted lifetime costs—defined as the present value of the difference between resource costs and the value of carbon saved—increase by £92m (or 0.2%) on changing the cap from 12.5% to 15%, or £104m if the cap is increased to 17.5%. The corresponding changes in the discounted value of consumer costs are around £127m (or 0.3%) or £138m. The change in consumer costs reflects the increase in the obligation on suppliers with greater levels of co-firing as a result of extensions under the headroom mechanism.

The improvement in the cost-effectiveness of the RO in reducing carbon emissions is most marked for a change in the cap from 12.5% to 15%, with a smaller impact on a further change in the cap to 17.5%.

A shown in Table 4.9, carbon emissions savings increase by around 1.2 million tonnes or 0.6% on a lifetime basis from changing the cap to 15%, and by around 1.3 million tonnes from changing the cap to 17.5%.[36]

[36] Emissions savings are calculated based on the emissions intensity of the marginal conventional generator, assumed here to be gas-fired CCGT.

Table 4.9 Discounted lifetime costs and benefits of the RO, and changes within the central power price scenarios, real 2007 prices

	Scenario 1 (12.5% cap)	Change in Scenario 2 (15% cap)	Change in Scenarios 3, 4, 5 and 6 impact (17.5%–no cap)
RO eligible electricity generated, TWh	1,990.8	12.2	13.9
Resource cost, £m[1]	–58,369.9	–111.9	–126.4
Carbon saved, MtC	190.6	1.1	1.3
Value of carbon saved, £m	4,925.1	19.6	22.6
Net costs, £m[2]	–53,444.8	–92.2	–103.8
Cost-effectiveness, £/tC	–306.3	1.3	1.5
RO deadweight, £m[3]	8,615.2	–15.4	–11.3
Distributional analysis			
Exchequer cost, £m[4]	–3,572.2	–26.6	–30.7
Firms cost, £m[5]	–22,639.6	46.8	48.9
Consumer cost, £m[6]	–49,754.7	–127.3	–137.7

Note: Costs have been discounted at a social discount rate of 3.5% until 2037, and a discount rate of 3% beyond that. Metrics for scenarios 2 to 6 are shown as differences relative to Scenario 1.Lifetime costs are assessed over the period 2009–2055.
[1] The cost of renewable generation which encompasses both capital costs as well as O&M and other costs.
[2] Estimated as the difference between the resource costs and the value of carbon saved. [3] The RO deadweight is the difference between the resource costs and the consumer costs. [4] The Exchequer costs equal the Climate Change Levy (£4.41/MWh in real 2007 terms) forgone as a result of renewable generation.[5] Firms' costs are defined as the difference between the value of electricity revenues received and the resource costs of renewable generation.[6] Consumer costs are a function of the size of the Obligation and the buyout price.
Source: Oxera analysis.

Table 4.10 shows similar cost–benefit metrics for alternative commodity price scenarios. In each case changes in the metrics are shown for the scenario in which the co-firing cap is removed relative to the corresponding commodity price scenario with the cap at 12.5%.

This shows that the level of carbon saved on removing the co-firing cap is lower in the high-high and high price scenarios than in the central price scenario (around 0.9 million tonnes).

Removing the co-firing cap results in an increase in net costs of the RO of around £43–£62m (or less than 0.1%) in the high-high and high price scenarios, with costs to consumers increasing by £91–£149m (or 0.1–0.2%).

The low price scenario remains unaffected as removal of the cap has no impact on co-firing output in this scenario.

Table 4.10 Discounted lifetime costs and benefits of the RO, and changes within alternative power price scenarios, real 2007 prices

	Scenario 7 (High–high, 12.5% cap)	Change in Scenario 8 (High–high, no cap)	Scenario 9 (High, 12.5% cap)	Change in Scenario 10 (High, no cap)	Scenario 11 (Low, 12.5% cap)	Change in Scenario 12 (Low, no cap)
RO eligible electricity generated, TWh	3,072.7	9.0	2,956.4	8.9	862.9	0.0
Resource cost, £m	–120,186.4	–76.8	–103,438.3	–57.6	–17,000.3	0.0
Carbon saved, MtC	294.1	0.9	283.0	0.9	82.6	0.0
Value of carbon saved, £m	7,963.3	14.8	7,768.0	14.9	2,007.9	0.0
Net costs, £m	–112,223.2	–61.9	–95,670.3	–42.7	–14,992.4	0.0
Cost-effectiveness, £/tC	–408.6	0.9	–365.5	0.9	–205.8	0.0
RO deadweight, £m	45,667.9	–72.4	34,136.0	–33.7	–10,650.6	0.0
Distributional analysis						
Exchequer cost, £m	–6,391.4	–20.6	–6,154.4	–20.0	–1,482.6	0.0
Firms cost, £m	19,188.1	263.8	–16,789.3	111.0	–15,500.1	0.0
Consumer Cost, £m	–74,518.5	–149.1	–69,302.3	–91.3	–27,650.9	0.0

Source: Oxera.

Tables 4.11 and 4.12 show the cost–benefit metrics of changes in the cap in the scenarios that assess sensitivities around the biomass price assumptions and banding levels respectively. In the high biomass scenario, changes to the co-firing cap have a limited effect on the volume of co-firing as it is not economically viable in some years compared to other scenarios. In the low biomass price scenario, the volume of additional renewable generation from removing the cap is similar to that in the central scenarios. Additional resource costs are also lower due to the reduced cost of biomass.

Table 4.11 Discounted lifetime costs and benefits of the RO, biomass price sensitivities, real 2007 prices

	Scenario 13 (High price, 12.5% cap)	Change in Scenario 14 (High price, no cap)	Scenario 15 (Low price, 12.5% cap)	Change in Scenario 16 (Low price, no cap)
RO eligible electricity generated, TWh	1,871.3	0.0	1,990.8	13.9
Resource cost, £m	–58,456.3	–4.3	–57,034.2	–21.7
Carbon saved, MtC	179.1	0.0	190.6	1.3
Value of carbon saved, £m	4,735.2	0.0	4,925.1	22.5
Net costs, £m	–53,721.1	–4.3	–52,109.1	0.8
Cost-effectiveness, £/tC	–326.3	0.0	–299.3	2.0
RO deadweight, £m	9,758.0	4.4	7,279.4	–115.8
Distributional analysis				
Exchequer cost, £m	–3,320.2	0.1	–3,572.2	–30.6
Firms cost, £m	–24,582.2	–4.4	–21,303.9	153.5
Consumer cost, £m	–48,698.3	0.1	–49,754.7	–137.5

Source: Oxera.

Table 4.12 Discounted lifetime costs and benefits of the RO, banding sensitivity, real 2007 prices

	Scenario 17 (12.5% cap)	Change in Scenario 18 (No cap)
RO eligible electricity generated, TWh	2,693.2	14.0
Resource cost, £m	–89,142.5	–121.7
Carbon saved, MtC	257.8	1.4
Value of carbon saved, £m	7,023.9	22.8
Net costs, £m	–82,118.5	–99.1
Cost-effectiveness, £/tC	–345.8	1.4
RO deadweight, £m	13,849.2	–18.9
Distributional analysis		0.0
Exchequer cost, £m	–5,818.7	–30.6
Firms cost, £m	–40,466.4	56.3
Consumer cost, £m	–75,293.3	–140.7

Source: Oxera.

5 Conclusions

This report has provided an analytical assessment of whether the cap on co-firing within the RO affects the ability of independent co-firers to expand capacity to meet their potential—ie, that which is technically feasible and economic to produce, given the associated costs and revenues—and has quantified the effects that changes to the cap could have on the wider operation of the RO.

The likely retirement profile of the existing coal-fired fleet, combined with the effects of reduced support to co-firing in the RO through banding, are likely to limit the number of co-fired ROCs that can be generated by the middle of the next decade. Co-firing with energy crops is also placed outside the co-firing cap, and so offers an alternative and unrestricted option for co-firing generators.

However, given the possible trajectory of the Obligation size, developed for the scenarios in this report,[37] and hence the co-firing cap, as well as the structure of the electricity supply market and its potential effect on competition for co-fired ROCs, there may be reason for concern that the co-firing cap could hinder the ability of independent generators to meet their potential in the period to 2014/15.

This cause for concern may arise in a situation where the physical volumes that independent generators are able to sell is hampered by the size of the residual co-firing market, if vertically integrated players self-supply a large proportion of their co-fired ROC allowance. In addition, independent generators' co-firing potential may be limited if the market structure were to allow some supply companies with residual demand the ability to negotiate significant price discounts, which may be most acute where the total number of co-fired ROCs produced is close to the level of the cap.

The presence of the co-firing cap may influence the nature of interaction between suppliers and independent generators, and thus affect the timing and the level of prices that can be realised by independent generators, with a subsequent impact on their output decisions. Evidence of this could include forward price discounts, which can arise where supply companies are in a stronger bargaining position towards the beginning of the compliance period (given their ability to 'wait and see' if future co-firing output is close to the level of the cap), and the expectation that this may lead to lower prices. In response, independent generators may opt to limit expansion if they are unable to contract sufficiently far in advance to manage the associated price risk, which is likely to be higher in those years in which the cap may be binding.

An assessment of potential co-firing output and the possible absolute level of the co-firing cap suggests that the ability of independent generators to expand the level of co-fired output could be restricted in the years up to 2014/15 and could be particularly acute in the period up to 2012/13. This also suggests that an increase in the level of the co-firing cap to around 20% could reduce the risk of the cap binding under the most extreme scenario of potential output.

However, if the level of biomass prices were sufficiently high, as examined in the analysis in section 4, there may be only be limited volumes of co-firing that are economic in the period to 2020. As such, under the high biomass price scenario, changes to the level of the cap would

[37] These scenarios do not include all of the assumptions used to generate the 29% large scale renewable electricity projection in DECC's consultation on renewable incentives, and therefore do not exhibit the same increase in the Obligation size as may be the case under a situation in which there is an increased level of support.

not be expected to elicit increased levels of co-firing or any of the potential benefits, such as increases in total renewable generation or reduced carbon emissions.

Section 4 of the report also explored the potential effects on ROC prices of increasing the level of the cap, and the wider implications of this for the deployment of other renewable technologies.

The analysis shows that removing the level of the cap under a central scenario would be likely to increase the volume of co-fired ROCs, particularly during the period from 2013 to 2020. It was found that the maximum increase was likely to occur in 2012/13, when ROC volumes could increase by around 30%. Increasing the level of the co-firing cap beyond 17.5% was found to have little effect on total deployment and ROC prices, as technical constraints become a more important restraint on further deployment.

Despite the potential increase in the level of co-firing resulting from changes in the cap, the effect on ROC prices might not be expected to be as large, due to the dampening effect caused by the level of support given to co-firing of 0.5ROC/MWh, and the subsequent extension of the Obligation size by the headroom mechanism.

In the central scenario, the increase in co-fired volumes could cause a fall in the ROC price of around £2.4/MWh in 2012/13. However, due to the limited number of years in which there might be expected to be an impact on prices, and the likelihood that this will be prior to the large-scale deployment of offshore wind, the impacts on investment are likely to be limited.

As a result, increased levels of co-firing stimulated by changes in the co-firing cap could increase total renewable deployment and have an associated lifetime reduction in carbon emissions of 1.3 million tonnes (or 0.7%). The increase in the Obligation size caused by this effect could increase the cost to consumers, which is driven by the Obligation size and the buyout price, by around £138m (or 0.3%).[38]

The risk of more volatile year-on-year changes in the ROC price might be expected to be included within future investment decisions. However, the effect is likely to be dampened in future years as coal plant is retired. ROC price risk may also be asymmetric and mainly upwards if the Obligation size with headroom reflects the potential for large volumes of co-firing which are subsequently not produced in later years. Analysis examining the impact of increasing the discount applied to the variable portion of ROC prices within the investment decision highlighted the possibility of delays to the deployment of certain projects by around a year, but with similar total levels of deployment by 2020.

Changes to the regulatory framework introduce additional uncertainty and alter participants' perceptions of future changes. This regulatory risk is difficult to quantify, but is manifested in the required returns investors demand, and may ultimately affect the future level of investment. The impact of these changes on the required hurdle rate has not been examined in this report.

The quantitative analysis in this report suggests that, on the basis of assumptions targeted to highlight the upper end of the range of potential co-firing output, an increase in the co-firing cap to 17.5% could be sufficient to ensure that technical rather than policy constraints are binding, which would act to increase the ability of independent co-firing generation to compete.

The case for reduced policy constraints on co-firing output is supported by the analysis, which suggests that the effects on ROC prices and total renewable investment over the long run might be expected to be limited, while the potential benefits include a reduction in the risk of distorting the ability of independent generators to compete, and also the potential for

[38] This refers to the discounted lifetime costs.

increased total renewable generation and associated reductions in carbon emissions. Such benefits should be weighed against the increased costs to consumers caused by possible increases in the Obligation size, and the impact on investment of perceived future regulatory changes caused by an increase in regulatory risk.

A1 Survey responses

This appendix describes the responses to a survey of co-firing generators, designed to collect participants' views on the drivers of historical and future co-firing output decisions, the implications of market design for the ability of independent generators to compete, and to better understand contracting regimes and their implications for future levels of co-firing output.

The appendix summarises the responses to each of the questions in turn, which are grouped within the following themes:

– drivers of historical co-firing output;
– dispatch decisions and contracting methods;
– co-firing potential and investment requirements;
– perceptions of the operation of the market for co-fired ROCs.

A1.1 Drivers of historical co-firing output

What do you consider is the relative importance of the following factors in explaining observed co-fired generation?

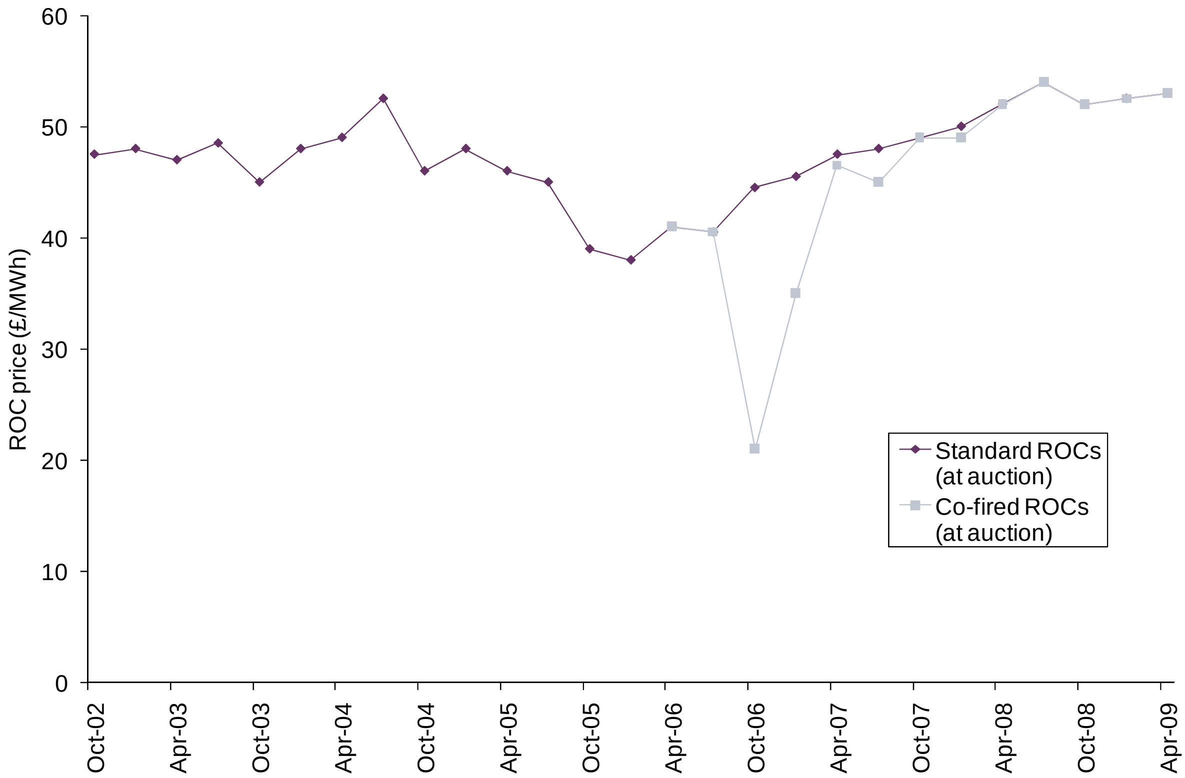
– **'marginal cost' economics;**
– **capacity constraints and investment;**
– **the co-firing cap.**

Theme	Summary of views
Marginal cost economics	Marginal cost economics are a critical factor, and we would expect the reduction of the banding on co-firing to significantly reduce output levels
	This is the most significant factor affecting the decision to co-fire or not. At the current level of ROC multiplier, co-firing is largely uneconomic for regular biomass and energy crops
	Historically, co-firing has been profitable except perhaps at the end of 2008 and in early 2009
	Marginal cost economics has been more significant since the introduction of banding but less so prior to that
	If co-firing is expected to be profitable in the forthcoming months, as much biomass as possible is bought (up to the capacity of the plant) and then burned, regardless of subsequent price movements, due to the limited life of the biomass
Capacity constraints	Not a significant factor historically
	Capacity constraints and fuel availability have had an impact, although broadly, setting up co-milling co-firing is relatively quick and allows stations to co-fire with a limited proportion of biomass. Most coal stations explored this and developed co-firing capacity, with output increasing to 2005/06, reflecting the attractive economics at that time
	This is of less importance in today's market than the other factors mentioned, as it is currently uneconomic to run many of the co-fired stations that already exist. In terms of capacity, we estimate that only 2% of the 12.5% ROC cap is currently generated

Theme	Summary of views
The co-firing cap	The implementation of the 10% cap on co-firing in April 2006 has limited co-firing levels, and has a particular impact on the ability of independents to access the market With higher ROC allocations, the economics would improve The co-firing cap has historically been a factor for generation, as generators need to forecast obligation levels and predict what other generators will produce, in order to determine whether there will be a market for their ROCs. This is easier for vertically integrated suppliers with co-firing capacity to manage, as they will certainly know their own requirements and can co-fire to meet this demand We estimate that only 2% of the 12.5% co-firing cap is currently generated, and therefore the cap is irrelevant at this level of ROC multiplier As mentioned above, we do not believe the current cap level should be the focus of this review as we believe that the market will need to dramatically change before it could ever be breached

Figure A1.2 shows historical prices for standard and co-fired ROCs.

Figure A1.1 Historical ROC auction prices



Source: NFPA.

– **Do you consider these prices to be reflective of those achieved in bilateral contracts?**
– **What was the cause of the co-fired ROC discount in 2006/07?**

Theme	Summary of views
Level of historical prices	Auction prices are in line with prices achieved elsewhere that are sold on a relatively short-term basis The prices broadly reflect the market, however the market has become increasingly illiquid and opaque so market price has become less visible. This is especially true for co-fired ROCs, where most of the market is satisfied by vertically integrated players without external trading The auctions operate on a fixed-price basis, whereas some bilateral contracts have been on a floating-price basis. Bilateral contracts provide greater flexibility in pricing structure and delivery dates, therefore it is difficult to provide a direct comparison Analysis of auction prices versus out-turn ROC prices, however, shows that prices achieved in the auctions have been 100% of out-turn price (discounted to reflect time value of money) Prices achieved in eROC auctions differ to those achieved under bilateral transactions, due to reasons including: timing of transaction; payment terms (working capital); risk profile of transaction; firmness of transaction; price (fixed/indexed); supplier participation; and total forecasted ROC supply versus forecasted UK RO target
Co-fired discount in 2006/07	The cap on co-fired ROCs led to a perceived over-supply in the market The discount on co-fired ROCs in 2006/07 was due to the reduction in co-firing cap The co-firing cap caused some independent generators to cease biomass activity The reduction in the cap led to uncertainty over the volume of co-fired ROCs that would be in the market— and there being potentially higher volumes of co-fired ROCs than the cap allowed. This uncertainty led to discounts being placed on co-fired ROCs in the early auctions for 2006/07. As the year progressed, this uncertainty eased as it became apparent that the 10% cap was unlikely to be exceeded and therefore prices recovered At the time of the October 2006 eROC auction referred to above, there was much speculation with regards to the future co-firing activity at Littlebrook Power Station that had carried out a large co-firing trial with liquid biomass and been issued with 282GWh of co-fired ROC's that, if continued, had the potential to saturate the co-fired ROC market for Compliance Period 5 (CP5), particularly as this coincided with the reduction of the supplier co-fired ROC cap from 25% to 10% If anything, this episode has taught us that certainty within the ROC market is crucial to maintaining investor confidence. Had there not been a co-fired cap in place during CP5, the uncertainty over co-firing at Littlebrook would have almost certainly had a marked impact on the non co-fired ROC market value We believe the discount in 2006/07 resulted from uncertainty in the market surrounding the government review of the support system, ie, the redirection of the co-firing cap to 10%, and the lag in data flowing to the market because of the three-month reconciliation period This situation has not been repeated, and recent amendments to the RO have served to increase headroom between co-fired generation levels and the co-firing cap

A1.2 Dispatch decisions and contracting methods

What drives the co-firing dispatch decision?

- **If a decision is made to co-fire would this apply to all of the potential co-firing capacity?**
- **What effect do environmental limits (eg, the LCPD) have on output decisions?**

Theme	Summary of views
Drivers of co-firing	An assessment is made of the expected marginal cost of co-firing, relative to the marginal cost of burning coal
	Co-firing despatch would predominantly reflect the underlying marginal economics at the time. When economic, we would plan to utilise all co-fire capacity available
	The price of carbon is a key driver affecting the marginal economics
	Long-term ROC sales have a greater effect on output decisions than movements in coal prices
	Long-term decisions requiring additional investment include the difference in marginal costs as well as the cost of investment
	The main driver must be the economics of running coal plant. Pre-April 2009 the standard would have been 'if coal is running, co-firing should also be running'. Post-April 2009, the marginal economics of co-firing are more of a deciding factor in whether to co-fire or not
	The economics of co-firing are considered separately for each plant
	Dispatch is calculated on a unit-specific basis; typically though, same instruction would apply to all units at individual station
	Co-firing tends to be an 'all or nothing' type of decision
Effect of environmental limits	None
	Generally, biomass does not have a major impact on LCPD compliance
	Co-firing opportunities at the opted-out stations are more limited
	The less viable the coal stations become due to tightening environmental legislation, the less viable co-firing becomes
	For plants in the NERP[1] there is a limited effect, due to the ability to buy extra SO2 if needed
	The potential future requirement for SCR (selective catalytic reduction) as part of Industrial Emissions Directive compliance has the potential to stop all co-firing. Fouling of catalysts, plant configuration and catalyst selection are all issues which would need to be overcome. At current levels of support, it is highly unlikely that appropriate investments and increased O&M costs can be remunerated by co-firing income. As little time remains in which to develop such an investment case, it is unlikely that capability to continue co-firing will be developed

Note: [1] The National Emissions Reduction Plan. See http://www.environment-agency.gov.uk/business/topics/pollution/32230.aspx.

What are the costs of switching between co-firing and coal-only generation?

- **Are there additional operating costs associated with co-firing?**
- **What are these costs?**

Theme	Summary of views
Costs of switching	Negligible Some labour and equipment-related costs
Additional costs	Additional costs relate to import, storage and transport costs, which are greater than those for coal, due to the lower calorific value of the fuel Additional costs required to man a materials handling facility with throughput and facility repair costs Considerable logistics costs, storage costs, sampling and testing, materials handling, mobile plant hire or purchase, plant cleaning, additional fire protection, plant maintenance, and possible impact on mill and boiler maintenance. In addition, the ROC accreditation and collection process has significant admin costs and working capital needs In the short term, the extra operational costs are negligible. In the long term, the extra operational costs include—additional resources for biomass import in the form of: manpower; transportation; storage; and sustainability reporting Additional costs include an independent conveyer system to input biomass on site storage, and sampling and testing Additional costs include: fuel sampling and analysis; labour; additional reporting requirements; increased maintenance; fuel stocking; and cash flow implications

How close to real time are dispatch decisions made?

- **Do output decisions reflect monthly/daily changes in coal and carbon prices or historical contract prices?**

Theme	Summary of views
Plant scheduling	If co-firing is expected to be profitable in the forthcoming months, as much biomass as possible is bought (up to the capacity of the plant) and then burned regardless of subsequent price movements, due to the limited life of the biomass Plant is scheduled based on forward prices, and fine-tuned throughout the day Dispatch decisions are made on a daily basis Output decisions would be primarily driven by current market prices. However, once started, biomass activity needs to be run continually to ensure effective operation Biomass instructions are made weekly based on that day's forecast prices—this can be overridden closer to real-time if there are significant movements in prices and/or plant conditions change. Actual dispatch decision for generating units are made day ahead/up to gate closure We do not respond on a daily/weekly price basis for the dispatch of co-firing. Biomass is purchased months in advance with a view to biomass price and ROC prices achievable

How do you contract for biomass?

- **With how many suppliers?**
- **Are contract prices indexed (and if so, to what)?**
- **For what volume/length of time?**

Theme	Summary of views
Number of suppliers	Large volumes can be contracted. Volumes of some material (eg, wood products) depend on the output of related industries such as construction
	Many different fuel types have been tested to help ensure a secure supply
	One or two suppliers are used
	Historically no more than six suppliers – currently one to two suppliers
	Over five
	We tend to use three main suppliers for most of our biomass requirements, but additional suppliers are used when required. We currently have 31 biomass suppliers on our approved counterparty list
	Due to typically poor credit rating of biofuel suppliers and potentially unreliable supply chains, a portfolio of suppliers and products is maintained
Location of biomass suppliers	A portfolio of contracts are used, with domestic and international suppliers
	There tend to be smaller numbers of domestic suppliers. These contracts tend to be for smaller volumes than those from international suppliers, and have a greater focus on energy crops
	Contracts with international suppliers are often for lower prices, but there are larger associated transport costs
Indexation	Some contracts are indexed to inflation, and others to a fuel index. Some price caps and floors are in place to restrict the effects of indexation
	No indexation
Duration of contracts	There has been a trend towards contracting for the medium term (five to ten years), on a bilateral basis
	Relatively short-term (eg, up to one year)
	Typically biomass contracts run for up to 12 months
	Contracts range from a spot basis to multi-year volumes

How has this contracting regime changed over time?

Theme	Summary of views
Changes over time	Previously, contracts were negotiated on a spot basis, due to regulatory uncertainty. Contracting is now over longer periods (ie, five years or more)
	Relatively short-term contracting regime has not changed
	Biomass contracts have tended to move from a spot basis to term contracts; however, the uncertainty and low ROC multiplier caused by the introduction of the banding regime into the RO is now pushing contracts back to a spot basis

On what metric (or index) do you assess the opportunity cost of using biomass

- **Are you able to trade to reverse a contracted position for biomass?**
- **Of the biomass you buy, are you able to sell it on? At what prices?**

Theme	Summary of views
Reference prices	Published prices are not representative of many trades
Reversing a position	This is difficult and would normally involve a loss We are conscious that co-firing economics are fragile, and that there may be periods where there is no co-firing plant available; therefore we tend to be cautious in our levels of commitment in order to avoid the need to reverse a contracted position. We have, on occasion, negotiated a contract 'get out clause; however, it requires the seller to have an alternative buyer. Occasionally but not easy

What are the key drivers of future biomass prices?

- **How volatile do you expect future prices to be (if possible, please quantify this)?**
- **Are you able to effectively hedge these risks?**
- **Can co-firing output decisions be attributed largely to movements in coal?**

Theme	Summary of views
Key drivers	EU-wide renewable policies and long-term confidence in regulatory policy has put upward pressure on prices Increased world demand is likely to put upward pressure on prices Development of stand-alone biomass plants will drive up the prices of certain types of biomass (eg, wood-based biomass) whilst prices for other types of biomass could face downward pressure Generally speaking, the UK demand for biomass is not a significant factor in price trends. This is evidenced by the trend in European biomass pricing since the introduction of ROC banding in the UK. Whilst there has been a fall in UK demand for biomass this has not resulted in any significant fall in European biomass prices, as overall demand in Europe is still strong. Value in other markets; value in UK market (recent fall in biomass costs following drop in support to 0.5 ROC/MWh to bring it back into the money) It is clear that on larger scale schemes there are a number of aggregators of smaller biomass supply contracts who provide a delivered service. These companies try to achieve prices very close to import parity, so unless you are able to run small local schemes you would expect the prices to gravitate towards international prices The biomass market is a global market. As other nations provide higher levels of support for co-firing generators than in the UK, more biomass and co-firing stations will be developed abroad. As demand begins to outstrip supply, the traded price of biomass fuels will increase. This will result in the economics of co-firing in the UK becoming more and more marginal, potentially removing co-firing from the market all together
Volatility	It is harder to assess the volatility in the UK market as there are so few trades Prices are expected to be volatile due to lack of liquidity We expect that prices will remain volatile as new plants are planned. Generation demand across Europe should continue to follow seasonal trends, which will result in peaks and troughs over 12-month periods (low summer/high winter) Prices have displayed high volatility Historically, biofuel prices have been volatile. There is no evidence to suggest that the underlying factors driving price volatility will reduce in the mid term

Theme	Summary of views
Hedging	Difficult to hedge price risk It is difficult to hedge these risks as there is little transparency or liquidity in the biomass market (no forward curves to hedge against) Risk management tools for biomass were being developed until the introduction of the banding regime. The new regime has removed a large amount of value from biomass trading and has stifled the development of risk management tools
Influence of biomass price on output	Generation is driven more by the carbon and coal price than biomass Since April 2009, ROC banding has marginalised the economics of co-firing to an extent that coal prices and carbon prices are now the deciding factor in whether to co-fire or not Coal is a major factor but also avoided carbon, biomass price change and cost of power (lost load)

A1.3 Co-firing potential and investment requirements

What are the technical options to increase co-firing output and their relative costs?

Theme	Summary of views
Co-milling	Co-firing through the mill requires relatively little CAPEX and can achieve co-firing ratios of around 6% Co-milling technology limits the amount of biomass that can be processed to no more than 5% by weight
Direct injection	Direct injection is likely to be technically and economically feasible on all opted-in plant with ten years or more remaining Cost of capital equipment £200–400/kW Direct injection would require relatively small incremental CAPEX once installed to increase co-firing ratios from less than 10% to 20%
Other	If the incentives were there the whole boiler could be converted to use biomass

What are technical constraints to increasing co-firing output in relation to:

- **Existing plant configurations?**
- **The ability to procure sufficient biomass?**
- **Storage and handling?**

Are there any other constraints different to the above ones?

Theme	Summary of views
Plant configuration	No major plant reconfiguration required except when dedicated biomass burners are needed, and hence a few modifications to the boilers would be required. There could be a logistical issue when large quantities of biomass are required, leading to rail modifications to track and signalling systems The pulverised fuel boilers used in today's coal-fired power stations are specifically designed to burn coal. Due to the reduced heat content of biomass it is unlikely that a flame produced from pulverised biomass could sustain itself. For this reason coal will be required for flame support. It is estimated that by using biomass direct injection the biomass heat input of a coal boiler could be increased to 50% Typical technical constraints to increasing co-firing rates include compatibility with emerging environmental controls (dynamic classifiers, milling performance, FGD, SCR catalysis, carbon capture). Combustion, boiler performance, efficiency, and materials handling capability further serve to restrict development

Theme	Summary of views
Ability to procure sufficient biomass	The availability of the right type of biomass is a constraint—eg, wood pellets or other pellets which fit the technical constraints of the plant configuration. This is a greater constraint post-April 2009, as the 0.5ROC/MWh banding does not support the market prices for these types of biomass Design of biomass facilities differs with the biomass we might burn. If insufficient biomass of a particular type is available (economically), the technology will not be able to cope with different biomass, or not to the same volume levels This could become a problem, but will greatly depend on the global expansion of co-firing and biomass stations Price: whilst large quantities of biomass are potentially available, only a relatively small quantity can be remunerated by the ROC banding of 0.5 ROC/MWh Lack of flexibility within supply chains combined with volatile dark spreads (ie, power station running) and poor market liquidity restricts the ability to take on large-scale and long-term fuel positions
Storage and handling	Co-firing requires higher volumes of biomass in the winter, and there is limited capacity to store biomass economically through the summer. The supply chain, however, must sell product throughout the year and are more likely to seek 12-month contracts. This will limit the ability to secure competitively priced biomass for co-firing Different biomasses must be stored and handled separately, requiring increased investment in technology Local and national authority planning procedures would need to be updated for the size of storage and infrastructure—ie, ports, road, rail, that would be required if biomass co-firing was to be significantly increased
Other/Regulation	Regulatory risks remain over grid access Biomass dust can be highly combustible and there is a high risk of fire or explosion in the plant if it is not managed properly. This requires a cautious approach to biomass volumes, and high amount of fire risk management in biomass handling and storage systems Some biomass fuels, from fast-growing products, eg straw, can have high potassium content and this can lead to attack of austenitic stainless steels (found in high temperature boiler superheater systems). This can result in reduction in firing temperatures, lower output and lower efficiency Public opposition; local authority transport and planning restrictions

What are the economic constraints to increased co-firing output in relation to:

- **Volume risks affecting investment in more capital-intensive technology?**
- **Level of banding support?**

Theme	Summary of views
Volume risk	**Independent generators** The ability to sell co-fired ROCs is a threat to expanding output **Vertically integrated generators** Availability and pricing of biomass do not support capital investment required for direct injection or other technology There would be a minimum throughput required to justify investment in direct injection Asset utilisation: co-firing volumes inherently follow coal generation and therefore follow clean dark spreads. Fuel Availability: reliability of fuel supply chains is critical in realising the benefits of co-firing. This requires investments to be based on mature and reliable supply chains with credit-worthy counterparties or counterparties able to attract credit support

Level of banding	**Independent generators** The level of support is a key issue in how much to co-fire. The limits should be lifted and rewards aligned with other biomass generation Level of banding is critical both to re-establishing co-firing and to any further investment in co-firing at the plant or in the supply chain. In addition, having a clear stable regulatory framework is critical to any CAPEX decisions **Vertically integrated generators** 0.5ROC/MWh does not support capital investment for direct injection or other technology Changes to banding from 2013 may mean it is not economical to burn non-energy crop. A reduction in energy crop banding will also seriously affect the business case The banding changes to the RO are the biggest constraint to future investment in biomass co-firing capability. This comes in two forms: i) the level of banding for co-firing is too low to recover capital expenditure, thus making capital investment in co-firing economically unattractive; b) lack of investor confidence in the RO from year on year changes Short time horizons resulting from the lack of any grandfathering of ROC banding; the reservation of 'emergency powers' to review the co-firing banding within band review periods further serves to undermine economic cases which may otherwise be attractive

What range of indicative regular co-firing output do you expect to produce in the following years?

This would depend on the dark spread.

A1.4 Perceptions of the operation of the market for co-fired ROCs

What are your perceptions of the ability to sell co-fired ROCs to suppliers?

– **What are the determining factors in certain years in which there is greater scope to sell to vertically integrated suppliers than other years?**

Theme	Summary of views
Ability to sell to suppliers	**Independent generators** Some vertically integrated supply companies will not buy from independent generators It is possible that different suppliers may attach more prestige and pay a premium for non-co-fired ROCs because they are developing a business model of 'clean' renewable energy and want to avoid links with coal-fired power stations. This is likely to be more the niche players, and the larger vertically integrated suppliers are probably looking for the cheapest way of meeting their obligation Current market is extremely limited. If the cap on co-fire ROCs is sufficient that it is not binding and co-firing is economic then it is likely that there would be a market for co-fire ROCs. Although the current market is less liquid and transparent than used to be the case – This is a key issue for us as a generator of ROCs with no internal obligation. The ROC market is extremely illiquid and there is little reported trading. Trading which is reported is either spot or auctions, with no forward market prices available. This makes decisions on co-firing inherently more risky – As suppliers are not required to submit ROCs until well after the period of generation, any bids for ROCs are heavily discounted to reflect cash flow and recycling fund risk

Theme	Summary of views
Ability to sell to suppliers (cont.)	– As much of our biomass is imported and is paid for on standard import terms, this ROC price uncertainty compounds the cash-flow-negative nature of biomass burn – Ability to sell to suppliers depends on the performance of generation plant owned by these suppliers—eg, many experienced lower than expected co-firing in recent years due to delays in FGD[1] commissioning; this left the suppliers sort of ROCs and incrementally increased demand for co-fired ROCs – This was, however, a transient impact; we see significantly reduced demand from vertically integrated generators as they increase the size of their in-house renewable portfolios We are not aware of any instances where other co-fired generators have had problems selling their ROCs **Vertically integrated generators** Provided there is sufficient under-compliance within the ROC market, and limited risk of the co-fired cap being exceeded, there should be no reason why suppliers would not purchase co-fired ROCs In the future, ROC prices could become more uncertain as targets become based on forecast output. Government will need to include assumptions on co-firing volumes when forecasting output for the coming Obligation period in order to set the target for that year. If these assumptions are too low and co-firing volumes are significantly higher than predicted, we could see a crash in ROC price (standard and co-fired ROCs). Headroom of 8% may not be sufficient to cover these variations As a supplier, we have purchased co-fired ROCs from other generators when our own plant has had extended outages (such as for the fitting of FGD) and has been unable to meet our own requirements Co-fired ROCs from own generation have only been used for own compliance, therefore we cannot comment on this directly There are a number of ways in which co-fired ROCs may be sold to suppliers, for instance bilaterally prior to, or post-generation, based on either firm or non-firm volumes, featuring either fixed or indexed pricing with differential payment terms. Most co-fired ROC volumes are typically sold via this route to market. The other route, as mentioned, is via the eROC auction; however, only a small volume of co-fired ROCs are sold via this method, mainly from the Northern Ireland equivalent to the E&W NFFO (Non-Fossil Fuel Obligation) support scheme **Certainty/confidence in the co-fired ROC market:** The economics of co-firing is linked to coal, carbon, biomass and, to an extent, power values affects ROC price confidence, in particular the value derived from the Buyout Fund The current co-fired cap helps promote co-firing generation since the decision to generate is based on short-run marginal costs and revenues, of which the Buyout Fund is a significant element. Without the cap, and in the event of significant co-fired ROCs within the market, the value of a co-fired ROC to a supplier would notably diminish, questioning the economics to generate co-fired ROCs for that compliance period in the first place Removal of the co-fired cap would have a damaging effect on investor confidence for other longer-term renewable technology investments

Have you observed a trend in the price you can achieve for co-fired ROCs relative to standard ROCs in some years rather than others?

– **What are the drivers of these price differences?**

Theme	Summary of views
Trends in prices	**Independent generators**
	Vertically integrated players will offer discounted prices closer to the beginning of the year when there is greater uncertainty over how the market will develop
	Volume risk is more of a concern than price risk
	Prices tend to increase towards the end of the compliance period, as most suppliers hold off purchasing their requirements until the end of the year
	The price suppliers will pay will differ through the year, due to the cost of money (interest rate) that they will incur in buying ROCs in advance of the compliance deadline and holding them until the end of the compliance period. This is the case for both co-fired and non-co-fired ROCs
	ROCs will sell for higher prices closer to the compliance deadline, due to the cost of money. It is possible they will command a higher price if they are non-co-fired
	The cap drives prices
	Vertically integrated generators
	As a supplier, we have seen a change in prices paid for co-firing ROCs. Previously co-fired ROCs could be purchased for less than non-co-fired ROCs, due to the potential for oversupply of co-fired ROCs in the market (ie, the volume of co-fired ROCs exceeding the 10% cap). As plant outages and the availability of biomass have limited co-firing output in the past couple of years, the risk of over over-supply from co-firing has been reduced, and there is now no difference in prices between standard and co-fired ROCs
	As the eROC prices demonstrate, similar prices can be achieved for co-fired ROCs and standard ROCs when you remove the effect of the October 2006 eROC auction out-turn co-fired ROC price
	Firmness of transaction affects prices. Particularly when you consider that standard ROCs have a higher degree of delivery certainty in any given compliance period (generation volume is typically driven by non economic factors) as opposed to co-fired ROCs, where the decision to generate is based on economic factors which will change day by day
	In the past, co-fired ROCs have traded at a small discount to non co-fired ROCs, due to the risks perceived by suppliers that the amounts of co-fired ROCs being generated could exceed the caps imposed on how many co-fired ROCs can be used by suppliers in the annual compliance return. This risk has been greatly diluted by the rising Obligation levels and reduced co-firing by generators

Does the price you can achieve for co-fired ROCs vary between suppliers?

– **In which circumstances are you able to achieve higher prices?**

Theme	Summary of views
Different suppliers	**Independent generators** There is little price variation between suppliers There is not a great difference between suppliers **Vertically integrated generators** Prices paid to purchase co-fired ROCs from other generators vary from generator to generator, due to preferences in pricing structures and delivery dates

Please comment on the use of NFPA auctions to sell co-firing ROCs rather than through bilateral negotiations.

– **Do you consider that with higher volumes, co-fired ROCs sold by auction could be under-subscribed?**

Theme	Summary of views
Use of auctions	There are risks associated with selling ROCs in the NFPA auctions as there is no reserve price The auctions provide an efficient route to market for generators with small volumes who wish to fine-tune their positions; for generators who do not forward contract co-fired ROCs; and for suppliers who are unsure of their position (which may increase throughout the year) For some generators, the NFPA auctions are a good route to market, as standard contracts are already established For larger generators selling large volumes of ROCs there is less of a requirement to have established contracts as they have access to legal teams to establish and review contracts. This enables more flexible contracts to be entered into, such as dealing on a floating price basis (paying a percentage of buyout and a percentage of recycle) to remove the risk of price movement and flexibility in delivery dates The only reason we see co-fired ROCs not being sold at auction or not achieving the same price as standard ROCs would be if there was a risk over over-supply in the market and therefore the co-fired cap would be exceeded for that compliance year To date, eROC auctions have consisted solely of historically generated volume sold for a fixed price, whereas bilateral transactions, on the other hand, offer a range of contracting structures (both short- and long-term) depending on the risk appetite of the generator and supplier In a bilateral agreement, both parties are aware of the price they are contracting at the time they enter into the contract, whereas in an auction the seller's only control is that of a minimum reserve price, which is set at a rate lower than the seller expects to achieve within the auction To date, all ROCs (co-fired or standard) have been awarded to suppliers within the auction timeframes. It is possible, if the reserve price is set too high, that some lots within the auction would not be sold;, however, one would expect sellers to set realistic reserve prices and suppliers to adjust their bid price to reflect market conditions whilst taking into consideration the RO framework (for instance, banking) The NFPA ROC auction tends to be the most transparent indicator of latest ROC values. Recent NFPA ROC auctions would suggest that there is currently no price difference between co-fired ROCs and non co-fired ROCs. We would not envisage higher volumes of co-fired ROCs in the auction causing any systemic issues The fees tend to be high relative for other routes to market

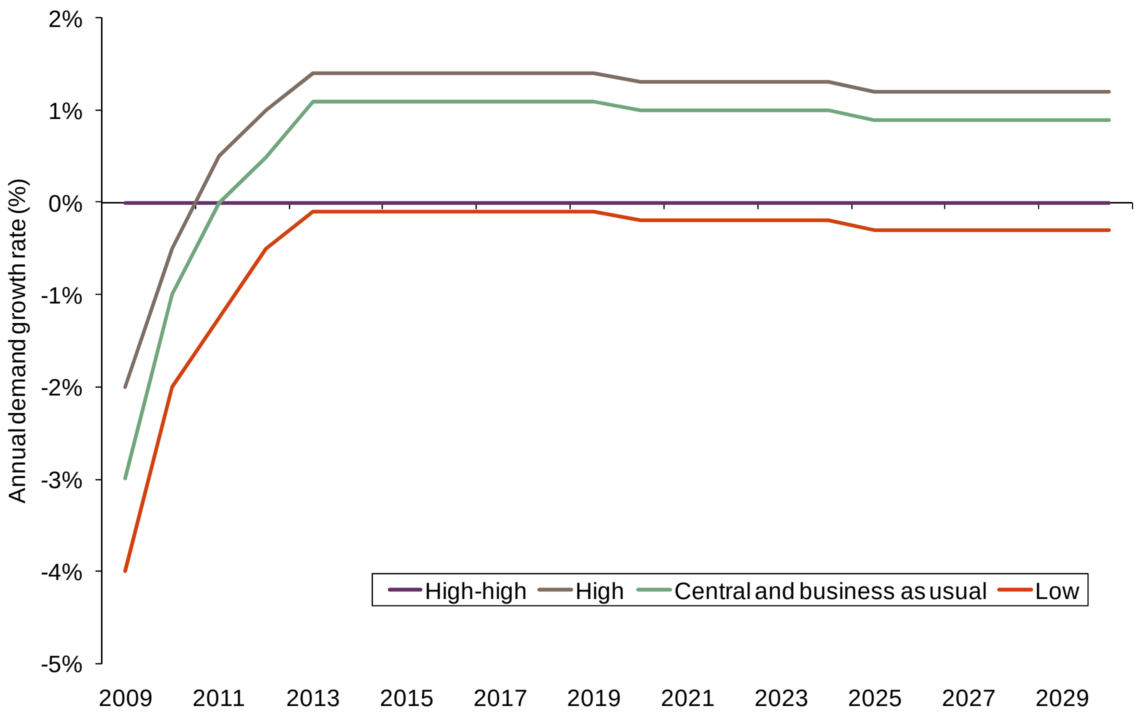
A2 Model assumptions

This appendix considers how supply and demand in the UK power generation and renewables markets may develop. Key model assumptions on demand growth, plant closures, new entry volumes and new entry costs are set out.

A2.1 Demand growth

Electricity demand growth rate projections are set out in Figure A2.1 and Table A2.1.

Figure A2.1 Electricity demand projections, 2008–30 (TWh)



Note: The Oxera high-high, high, central and low scenarios use the DECC 'High demand, significant supply constraints', 'High demand and producers market power', 'Timely investment and moderate demand' and 'Low global energy demand' fossil-fuel price scenarios, respectively.
Source: Oxera calculations based on National Grid (2009), 'Seven Year Statement'.

Table A2.1 Demand growth rates

Scenario	2009	2010	2011	2012	2013	2020
High-high	–2.00%	–0.50%	0.50%	1.00%	1.40%	1.30%
High	–2.00%	–0.50%	0.50%	1.00%	1.40%	1.30%
Central	–3.00%	–1.00%	0.00%	0.50%	1.10%	1.00%
Low	–4.00%	–2.00%	–1.25%	–0.50%	–0.10%	–0.2%

Note: It is assumed that, by 2013, growth rates revert to the medium-term trend implied by the National Grid Seven Year Statement, following a period of lower growth rates in the intervening years as a result of the impact of the current economic downturn. Demand growth rates are assumed to be following the implied National Grid

Seven Year Statement trend in the period up to 2019. In 2020, demand growth rates are assumed to decline as a result of energy efficiency improvements.
Source: Oxera calculations based on National Grid (2009), 'Seven Year Statement'.

A2.2 Plant closures

Table A2.2 shows the assumptions on nuclear plant closures.

Table A2.2 Actual and forecast nuclear plant closures

Station name	Type	Capacity (MW)	Open	High-high	High	Central	Low	Scheduled
Actual closures								
Hinkley A	Magnox	475	1965	2000	2000	2000	2000	2000
Bradwell	Magnox	240	1962	2002	2002	2002	2002	2002
Calder Hall	Magnox	192	1956	2003	2003	2003	2003	2003
Chapelcross	Magnox	150	1959	2005	2005	2005	2005	2005
Forecast closures								
Oldbury	Magnox	475	1968	2011	2011	2011	2011	2011
Wylfa	Magnox	1,081	1971	2011	2011	2011	2011	2011
Hinkley Point B	AGR	1,220	1976	2017	2017	2017	2017	2017
Hunterston B	AGR	1,190	1976	2017	2017	2017	2017	2017
Dungeness B	AGR	1,110	1984	2019	2019	2019	2024	2019
Heysham 1	AGR	1,150	1984	2019	2019	2019	2024	2019
Hartlepool	AGR	1,210	1984	2019	2019	2019	2024	2019
Torness	AGR	1,250	1989	2024	2024	2024	2029	2024
Heysham 2	AGR	1,250	1989	2024	2024	2024	2029	2024
Sizewell B	PWR	1,188	1995	2055	2055	2055	2055	2035

Note: A plant is assumed to be open (closed) if it is available (unavailable) in Q1 of a given calendar year.
Source: Nuclear Industry Association, Nuclear Decommissioning Authority, British Energy and Oxera modelling.

Table A2.3 shows the assumed closure of opted-out coal plant in the four scenarios.

Table A2.3 Modelled closure of opted-out coal plant

Station name	Controller	Capacity (MW)	Open	High-high	High	Central	Low
Tilbury B	RWE npower	1,020	1,968	2011	2011	2011	2011
Didcot A	RWE npower	490	1,972	2013	2013	2013	2013
Kingsnorth (coal/oil)	E.ON	1,940	1,970	2012	2012	2012	2012
Ironbridge B	E.ON	970	1,970	2011	2011	2011	2011
Lynemouth	Alcan	393	1,970	2012	2012	2013	2013
Ferrybridge C (non-FGD)	SSE	995	1,966	2014	2014	2014	2014
Cockenzie	ScottishPower	1,152	1,967	2011	2011	2013	2013

Source: National Grid Company and Oxera calculations.

Table A2.4 shows the assumed closure of opted-in coal plant.

Table A2.4 Modelled closure of opted-in coal plant

Station name	Controller	Capacity (MW)	Open	High-high	High	Central	Low
Fifoots Point	Uskmouth Power Co	393	2000	2016	2016	2016	2016
Eggborough	British Energy	980	1968	2016	2016	2021	2021
Ratcliffe on Soar	E.ON	2,000	1968	2021	2021	2021	2022
Ferrybridge C (FGD)	SSE	995	1966	2016	2016	2016	2016
Fiddler's Ferry	SSE	1,961	1971	2020	2020	2020	2020
Longannet	ScottishPower	2,304	1970	2016	2016	2016	2016
Rugeley B	International Power	996	1972	2022	2022	2022	2023
Drax	Drax	3,870	1974	2026	2026	2026	2026
West Burton	EDF	1,972	1968	2016	2016	2021	2021
Cottam	EDF	2,008	1969	2019	2019	2019	2024
Aberthaw B	RWE npower	1,455	1971	2017	2017	2017	2017

Source: National Grid Company, Oxera.

The current fleet of combined-cycle gas turbines (CCGTs) was largely built in the 1990s which, combined with an assumed 30-year life, would imply attrition in the 2020s. The physical operating life of these stations is uncertain given the use of relatively new technology, and because the advances made in thermal efficiency in CCGTs since the early 1990s leave older CCGTs at a considerable fuel-cost disadvantage relative to their more recent peers.

In the high-high and high scenarios, the CCGTs are assumed to start closing after 30 years, while, in the other two scenarios, a 35-year life span is assumed. The impact of these assumptions is set out in Table A2.5.

Table A2.5 Modelled closures of CCGTs in the four scenarios (MW)

Period	High-high	High	Central	Low
2020–24	7,931	7,931	0	0
2025–29	10,138	10,138	7,931	7,931

Source: Oxera modelling.

A2.2.1 New entry

A simplified uniform distribution of new nuclear and coal entry is assumed, as highlighted in Table A2.6 and A2.7.

Table A2.6 New nuclear entry (MW)

Scenario	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
High-high	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	0	0
High	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	1,600	0	0
Central	800	800	800	800	800	800	800	800	800	800	800
Low	0	0	0	800	800	800	800	800	800	800	800

Source: Oxera.

Table A2.7 New coal (with part CCS) MW

Scenario	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024
High-high	457	607	607	607	607	607	607	0	0	0	0
High	457	607	607	607	607	607	607	0	0	0	0
Central	457	607	607	607	607	607	607	0	0	0	0
Low	457	607	607	607	607	607	607	0	0	0	0

Source: Oxera.

Table A2.8 Committed new CCGT plant build

Site	Company	Status	Year	Capacity (MW)
Langage stage 1	Centrica Langage	Under construction	2010	885
Marchwood	Marchwood Power	Under construction	2010	800
Immingham CHP stage 2	ConocoPhillips	Under construction	2010	601
Grain Re-Powering	E.ON UK	Under construction	2011	1,200
Staythorpe C Stage 1	RWE npower	Under construction	2010	400
Staythorpe C Stage 2	RWE npower	Under construction	2011	400
Staythorpe C Stage 3	RWE npower	Under construction	2011	850
Severn Power Stage 1	Severn Power	Under construction	2011	850
West Burton B Stage 1	West Burton	Under construction	2011	1,270

Source: National Grid Company and company websites.

Additional entry by gas or coal stations is determined within the model by comparing commodity prices and the resulting rates of return (based on the new-entry costs), with modelled wholesale prices to 2030.

A2.2.2 New-entry costs of fossil-fuel plant

The assumptions regarding the capital and operating costs of new fossil-fuel plant are set out in Table A2.9 below.

Table A2.9 Assumptions on capital and operating costs of fossil-fuel plant (2007 prices)

		CCGT	CCGT + CCS	Coal pf (CCS-ready)	Coal pf + CCS	Coal IGCC	Coal IGCC + CCS
Construction costs	£/kW	671.9	1,702.2	1,791.8	3,144.6	1,888.4	2,866.9
Lead time	years	2.0	4.0	4.0	5.0	5.0	5.0
Investment recovery period	years	20.0	20.0	20.0	20.0	20.0	20.0
O&M fixed	£/kW	10.8	14.4	32.3	55.0	46.0	57.3
O&M variable	£/MWh	2.5	2.7	2.1	10.1	2.1	2.7
Thermal efficiency (HHV)		52%	43%	40%	32%	42%	34%
CO_2 emissions	t/MWh	0.35	0.07	0.76	0.16	0.72	0.13
Capital cost change	% pa	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Thermal efficiency improvements	% pa	0.20%	0.20%	0.25%	0.25%	0.25%	0.25%
Maximum thermal efficiency		56%	45%	46%	33%	50%	42%

Note: Thermal generation is assumed to have a cost of capital of 10%.
Source: Oxera assumptions. Relative differences across technologies based, in part, on DTI (2006), 'The Energy Challenge. Annex B. Overview of the Modelling of the Relative Electricity Generating Costs of Different Technologies', available at http://www.berr.gov.uk/files/file32014.pdf.

A2.2.3 Renewables build costs

Table A2.10 below presents the capital and operating costs of onshore wind. Cost estimates differ according to the size of the plant and wind speed.

Short-term capital costs are based on Oxera project experience. Medium- to long-term cost assumptions are based on studies carried out by the Pöyry and Redpoint plants. The cost reduction from 2010 to 2020 is assumed to be half that suggested in the study carried out by Pöyry in 2008.[39] This is in line with the assumptions made as part of the analysis underlying the BERR Renewables Consultation, launched in 2008.

A €/£ exchange rate of 1.116 has been applied to covert Pöyry's assumptions on cost reduction to GBP terms.

[39] Pöyry (2008), 'Compliance Costs for Meeting the 20% Renewable Energy Target in 2020', March. Available at http://berr.gov.uk/files/file45238.pdf.

Table A2.10 Onshore wind—capital and O&M costs (real 2006 prices)

	2010	2015	2020
Capital costs: large (£'000/MW)			
High	1,377	1,425	1,293
Medium	1,293	1,381	1,253
Low	1,179	1,336	1,213
Capital costs: small (£'000/MW)			
High	1,583	1,638	1,486
Medium	1,488	1,588	1,441
Low	1,355	1,536	1,394
O&M costs: large (high wind) (£'000/MW/year)			
High	51	48	45
Medium	39	36	34
Low	36	34	32
O&M costs: large (low wind) (£'000/MW/year)			
High	41	39	37
Medium	39	36	34
Low	36	34	32
O&M costs: small (high and low wind) (£'000/MW/year)			
High	61	58	54
Medium	45	43	40
Low	41	39	37

Note: Onshore wind is assumed to have a cost of capital of 10%.
Source: Ernst & Young, and Oxera assumptions.

Table A2.11 presents the capital and operating costs of offshore wind plant.

Table A2.11 Offshore wind—capital and O&M costs (real 2006 prices)

	2010	2015	2020
Capital costs (£'000/MW)			
High	3,304	3,158	3,046
Medium	2,973	2,842	2,741
Low	2,643	2,527	2,437
O&M costs (£'000/MW/year)			
High	81	78	76
Medium	74	71	69
Low	67	65	63

Note: Offshore wind is assumed to have a cost of capital of 12%.
Source: Ernst & Young, and Oxera assumptions.

Capital costs of new direct injection co-firing capacity are assumed to equal £200/kW. This figure is derived from information provided by Drax. Drax has indicated that the capital costs of its new 400MW co-firing injection facility are equal to £80m, and that the capital costs of co-firing facilities developed as part of the construction of new coal plant are negligible.

A2.2.4 Renewables build-rate constraints

This section sets out the build-rate constraints for renewables new build applied in the Oxera modelling. The assumptions draw on a range of sources including:

– analysis carried out by SKM for BERR;[40]
– the Renewables Energy Statistics Database being updated by AEA on behalf of DECC;[41]
– information gleaned from recent analysis of the renewables market carried out by Oxera.

The constraints are more restrictive over the short run (defined here as the five-year period to 2013) than over the long run, as technological, planning, supply chain and grid constraints are expected to ease by 2020.

The short-run build-rate constraints for onshore wind, offshore wind and biomass used in the Oxera scenarios are set out in Table A2.12. For comparison, the constraints implied by the SKM analysis are also presented.

Table A2.12 Average build-rate constraints, 2009–2013

	Average annual build-rate constraints (TWh/year)	Constraints applied in January 2009 report TWh/year	Implied SKM annual build-rate constraints (TWh/year)[1]
Onshore wind	**1.4**	**n/a**	**1.7**
Onshore wind: large high wind	0.6	0.8	
Onshore wind: large low wind	0.6	0.9	
Onshore wind: small	0.2	n/a	
Offshore wind	**2.4**	**2.4**	**2.5**
Biomass	**0.9**	**0.9**	**1.0**

Note: [1] Implied Sinclair Knight Merz constraints are calculated from the annual average volume generated in 2010 and 2020.
Source: Oxera.

The key long-run build rate constraints for onshore wind, offshore wind and biomass in the scenarios are as set out in Table A2.13 below. This reflects the assumption that constraints will ease by 2020.

The implied constraints in the SKM/AEA report also suggest that onshore and offshore constraints will ease in the long run, but that biomass constraints may increase with rising international demand for fuel.

The Oxera scenarios do not impose an annual build rate for biomass in the long run, but assume constrained total deployment in each year to be below maximum potential. As a result of subsequent build decisions using forecast electricity and ROC revenues, this potential is not exceeded in any of the scenarios. In the central scenario, unconstrained deployment grows between 0.5TWh per annum and 1.0TWh per annum from 2015 to 2020.

[40] Sinclair Knight Merz (2008), 'Quantification of constraints on the growth of UK renewable generating capacity', June.
[41] See http://www.restats.org.uk/.

Table A2.13 Long-run average build-rate constraints

	Oxera average annual build-rate constraints (TWh/year)	Implied SKM annual build-rate constraints 2020–30 (TWh/year)[1]
Onshore wind	**n/a**	**2.5**
Onshore wind: large high wind	0.8	
Onshore wind: large low wind	0.9	
Onshore wind: small	n/a	
Offshore wind	**3.8**	**3.4**
Biomass	**n/a (max potential used)**	**0.8**

Note: [1] Implied SKM constraints are calculated from the annual average volume generated in 2020 and 2030.
Source: Oxera.

Technical constraints on co-firing are derived as a function of total coal output. Potential co-fired volumes are based on a percentage of coal output (in TWh terms) in any given year. This percentage is based on the plant mix, and assumes that direct injection may be installed at opted-in plant with sufficient life remaining to recover the costs of the investment.

The Oxera Renewables Market Model separately models energy crop co-firing and regular co-firing. The maximum potential volumes of energy crop co-firing in each year are a fixed volume, based on data obtained from BERR as part of the analysis carried out for the Energy White Paper, 2007.[42] The maximum potential volumes of regular co-firing are obtained as the difference between the maximum co-firing figures implied by the coal output and the cap on energy crop co-firing. However, in order to understand the scale of the impacts of changes to the cap on co-firing and the potential for non-energy crop co-firing, co-firing of energy crops is, for the purpose of illustration, assumed to be negligible.

A2.2.5 Fossil-fuel costs

The fossil-fuel cost assumptions used in the modelling are the latest scenarios published by DECC.[43]

[42] Oxera modelling results included within BERR (2008), 'Renewables Obligation Consultation: Government Response', January, available at http://www.berr.gov.uk/files/file43545.pdf.
[43] DECC (2009), 'Communication on DECC Fossil Fuel Price Assumptions', May.

A3 Oxera Power Market and Renewables Market Models

This appendix describes the underlying methodology within the Oxera Power Market Model and the Renewables Market Model.

The Power Market Model is used to calculate future wholesale electricity prices, which are, in turn, used by the Renewables Market Model to estimate the deployment of renewables. The two Models are run iteratively to capture the feedback between the wholesale price of electricity and the deployment of renewables.

A3.1 Oxera Power Market Model

The Power Market Model calculates an average annual baseload electricity price as the sum of a short-run marginal cost (SRMC) component and a capacity premium based on the capacity margin on a quarterly basis. In order to do this, the profile of entry of new thermal generation is also determined within the Model.

This appendix discusses the following major components within the Model:

– determination of the SRMC;
– determination of the level of the capacity premium;
– the impact on new-entry decisions, and feedback to electricity prices.

A3.1.1 Short-run marginal cost

The SRMC component of prices is calculated by matching a load–duration curve to a supply stack of individual plant SRMC on a quarterly basis. This is used to produce baseload and peak-load prices.

Each load–duration curve is calculated by applying the annual level of peak demand to a historical quarterly load shape.

The supply stack is built from the available capacity and marginal cost of generation for each plant. The available capacity reflects a reduction in total plant capacity that varies by fuel type and quarter. The marginal cost of generation includes fuel and carbon costs as well as variable non-fuel costs. A line is included in the Model for each generating plant on the system and new entry by technology and year.

The load factor of each plant is calculated within this section of the Model, based on its position in the stack and the level of demand. This is used in a number of ways, including in calculating an appropriate sulphur premium to limit the operation of coal plant that have opted out of the LCPD,[44] as well as in the new entry calculations discussed below, and to report station output and emissions.

A3.2 Capacity premium

A capacity premium is added to the SRMC component of prices, based on the extent to which expected available capacity exceeds demand at each point on the load–duration curve.

[44] A sulphur premium is added to the marginal cost of opted-out coal to effectively reduce its running time. The resultant load factors of the plant are compared with those implied by the LCPD, and adjustments are made to the level of the premium if needed.

This element effectively estimates a loss of load probability (LoLP), which is multiplied by a value of lost load (VoLL). Although this is no longer a formal mechanism in electricity trading as it was in the Pool, the framework allows the Model to recognise that the value of electricity at any point in time depends on the extent to which supply is able to meet demand.

A3.2.1 Overview of VoLL estimates

The value of power supply reliability is usually measured in terms of the implied reduction in consumer outage costs, with a wide range of estimates found in the literature.

The costs of interruption are ultimately reflected in lower economic prosperity. These comprise both private costs and social costs—ie, those that cannot be allocated to a particular consumer group.[45] Typical cost components considered in the literature include lost production, restart costs, damage to resources, as well as lost leisure time. Outage costs vary across region, time of day, frequency and duration of the outage, as well as by customer group.

A VoLL estimate can be calculated using a weighted average interruption cost based on a dataset that varies according to interruption duration, timing, and individual customer.[46] This involves calculating a composite customer damage function per sector, which represents an aggregate cost normalised by the energy usage per customer. This is used to create a system-wide VoLL for a given outage duration by weighting each sector's damage function according to total energy use. Further weighting each of these estimates by the probability of the outage occurring can then be used to derive a single VoLL.

A useful cross-check can be applied by considering the ratio of economic output to electricity consumed. This is presented in Table A3.1 below, alongside average VoLL estimates in the literature.[47] This shows that an appropriate VoLL estimate may lie in the range £4.5/kWh to £16/kWh (at 2004 prices). This is above the value of £2/kWh (at 1990 prices) adopted by the electricity supply industry as part of the Pool.

Within this context, the Oxera scenarios use a VoLL of £5/kWh in 2007, which is towards the lower end of the range in the literature, but above that used in the Pool.

Table A3.1 Comparing VoLL estimates with proxy measures for the UK (£/kWh)

	Residential	Commercial	Industrial	Total
UK gross value added (GVA)/kWh annual electricity consumption	6.40	7.99	0.74	4.75
Average of three key studies (Monash, 1997; CRA, 2002; UMIST, 1994)	3.81	20.29	25.20	15.86

Note: For estimates based on studies in the literature the total VoLL is calculated using UK sectoral electricity consumption as weights.
Source: Office of National Statistics, Oxera.

[45] Consumer groups can be broadly defined as residential, commercial, industrial and agricultural, with greatest energy use in the residential and industrial sectors, followed by the commercial sector.

[46] An example can be found in Kariuki, K.K. and Allan, R.N. (1996), 'Evaluation of Reliability Worth and Value of Lost Load', IEE Proceedings: Generation, Transmission and Distribution, **143**:2, March.

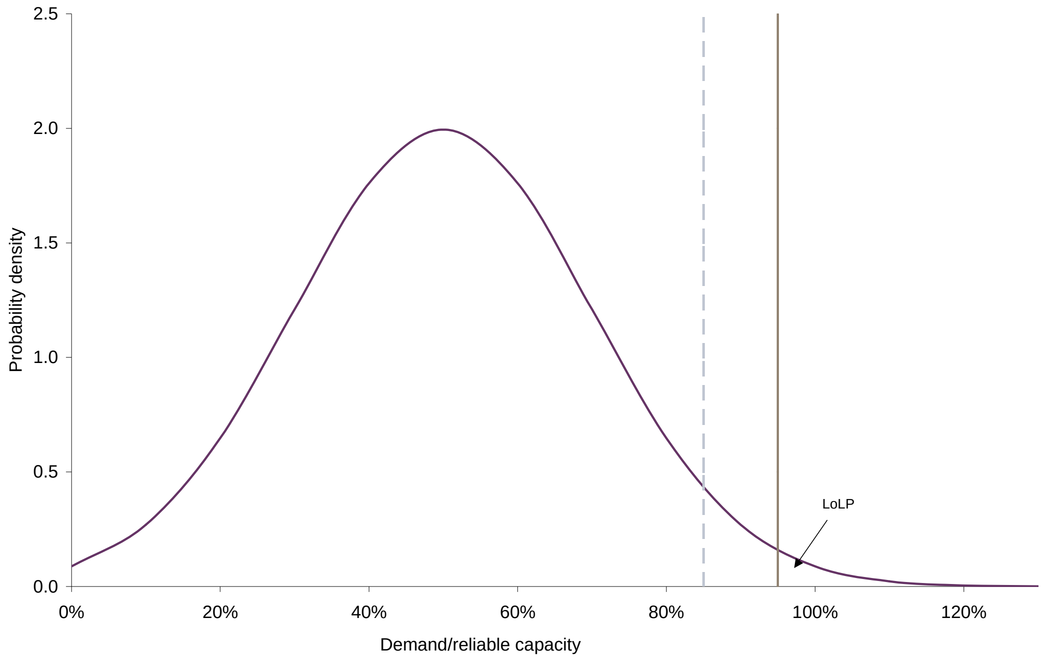
[47] Three relevant studies include Monash University (1997), 'Value of Lost Load Study for Victorian Power Exchange', Monash University Centre for Electrical Power Engineering, Report No 1997-C-10, August; CRA (Charles River Associates) (2002), 'Assessment of the Value of Customer Reliability', *Final Report for VENCorp*, December; and Rios, M., Kirschen, D. and Allen, R., (1999), 'Computation of the Value of Security: Final Report', Manchester Centre for Electrical Energy, UMIST, November.

A3.2.2 LoLP estimation

LoLP is estimated for each point on the load–duration curve by calculating the probability that out-turn demand measured as a percentage of reliable capacity exceeds that available in a particular quarter.[48]

The ratio of demand to reliable capacity is represented by a normal distribution with a mean equal to the expected ratio calculated from the load–duration curve and reliable capacity based on the average availability of plant in a given year. The LoLP is calculated as the probability that the demand is greater than reliable capacity, with the available capacity varying according to the quarter in the year, as shown in Figure A3.1.

Figure A3.1 Capacity premium modelling



Source: Oxera.

A3.3 Entry and exit

Exit of plant is an exogenous input to the Model, the timing of which is governed by company announcements, the age of plant, and changes to the operating environment—such as the full auctioning of allowances to the power sector in the European Union Greenhouse Gas Emission Trading System (EU ETS) from 2013, and the closure of plant that has opted out from the LCPD by 2015.[49]

A new entry profile for CCGT and coal plant is input into the Model, which is reflective of the fixed and capital costs of the entrant as well as the anticipated impact on prices, the expected future load factors given the level of existing capacity, the assumed retirement profile, and other entry decisions.

[48] Reliable capacity is calculated in each year to exclude a proportion of renewable generation, autoproducers and imports.

[49] The timing of plant retirement is not automatically adjusted to reflect anticipated increases in prices in the years following a particular retirement date; this can lead to price spikes, especially where this might coincide with the retirement of similar plant, reflecting the scarcity of capacity in subsequent periods.

The composition of new entry is chosen to reflect likely deployment, given government policy, the market framework and the level of market prices relative to costs.[50] The possible technologies considered include:

– nuclear;
– renewables;
– coal;
– CCGT.

The profile of new thermal investment is chosen so that new capacity comes online if the level of wholesale prices exceeds the levelised cost of generation, assuming recovery of fixed and capital costs over a 15-year period and a load factor equal to the average of that calculated by the Model, given the input entry profile. In this way, the entry decisions are consistent with the modelled out-turn—ie, that the load factor of a particular entrant will fall over time as it loses output market share to new and more efficient capacity, and that there is a risk of relatively low utilisation after 15 years.[51]

Note that while spark spreads for the scenarios are reported in all years for a plant with 55% efficiency, new-entrant efficiencies reach 62% by 2030, consistent with International Energy Agency (IEA) projections.[52]

Price spikes may occur under this approach due to the lumpy nature of capital investment and the maximum deployment assumed in a given year.

The volume of renewable new entry is determined using the Oxera Renewables Market Model, which models outcomes under the RO. This calculates the volume of renewable generation and the price of ROCs using input-cost curves, the RO buyout price and the wholesale electricity price. The Renewables Market Model and Power Market Model are run iteratively to capture the feedback between the wholesale price of electricity and the deployment of renewables.

A3.4 Oxera Renewables Market Model

The approach taken in Oxera's Renewables Market Model is to simulate the likely pattern of renewables investment, based on key assumptions regarding the future revenue streams and costs of the various renewable generation technologies. Three main sources of revenue are represented within the model:

– wholesale electricity prices;
– Climate Change Levy Exemption Certificates (LECs);
– ROCs.

The first two of these revenue streams are treated as exogenous input assumptions to the Model, while the value of ROC revenues is determined endogenously. The other key set of assumptions feeding into the Model is a set of supply curves, representing the levelised generation costs of various forms of renewable generation. In the case of co-firing, the avoided costs of coal and carbon are used in place of electricity revenues.

A high-level overview of the Model structure is shown in Figure A3.2. This diagram highlights a central circularity in understanding the drivers of investment in renewable generation. The investment decisions taken in any given year will be influenced by an investor's expectations

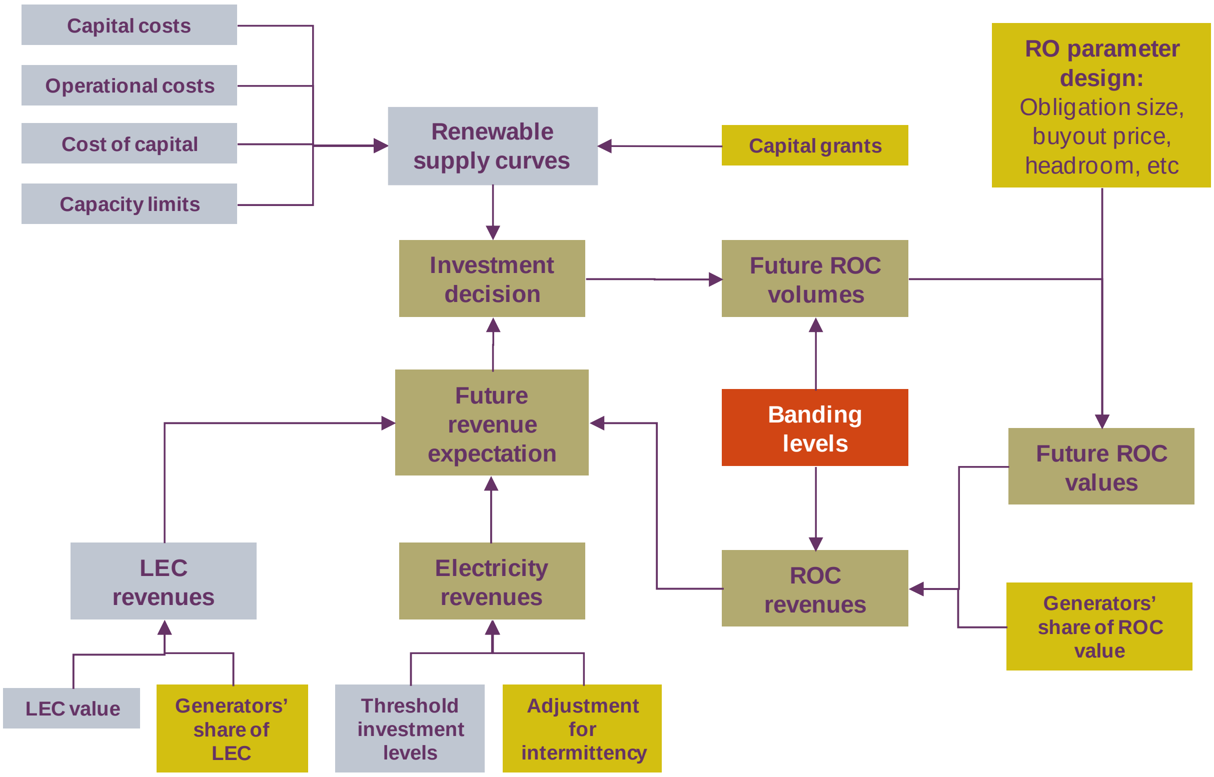
[50] For example, new coal and nuclear deployment is likely to depend on the level of prices as well as government intervention, such as approval for new coal without CCS or additional support mechanisms for CCS.
[51] Given that the realised load factor of new entrants falls over time, a larger proportion of revenues is earned in earlier years than in later years. Using an average load factor is therefore a conservative approach to ensure that the assets are not stranded, as the earlier revenues with a higher load factor than the average would be worth more in present-value terms.
[52] International Energy Agency (2008), 'Energy Technology Perspectives—Scenarios and Strategies to 2050', p. 87.

of future ROC revenues. However, investment decisions will, in turn, affect future revenue expectations through the impact of ROC volumes on the size of the Buyout Fund, and hence the market value of ROCs.

Oxera's Renewables Market Model addresses this circularity between investment decisions and future revenue expectations by using a multi-phase simulation approach. The first phase of the simulation uses renewable generation supply curves and build-rate constraints to determine an expected path of future ROC prices, based on the costs of the marginal renewable technology. The second phase then uses these ROC price expectations to simulate a set of investment decisions consistent with the ROC price expectations. Finally, the outcomes of these investment decisions are used to update the future ROC price expectations.

The advantage of this approach is that it ensures that investment decisions will take account of the impact of policy decisions on the future ROC market. For example, changes to future banding levels may reduce the value of support for some technologies. This would be reflected within the revenue expectations and would therefore influence investment decisions.

Figure A3.2 Overview of modelling approach



Note: Blue boxes are input assumptions; orange boxes are model parameters; and brown boxes are model calculations.
Source: Oxera.

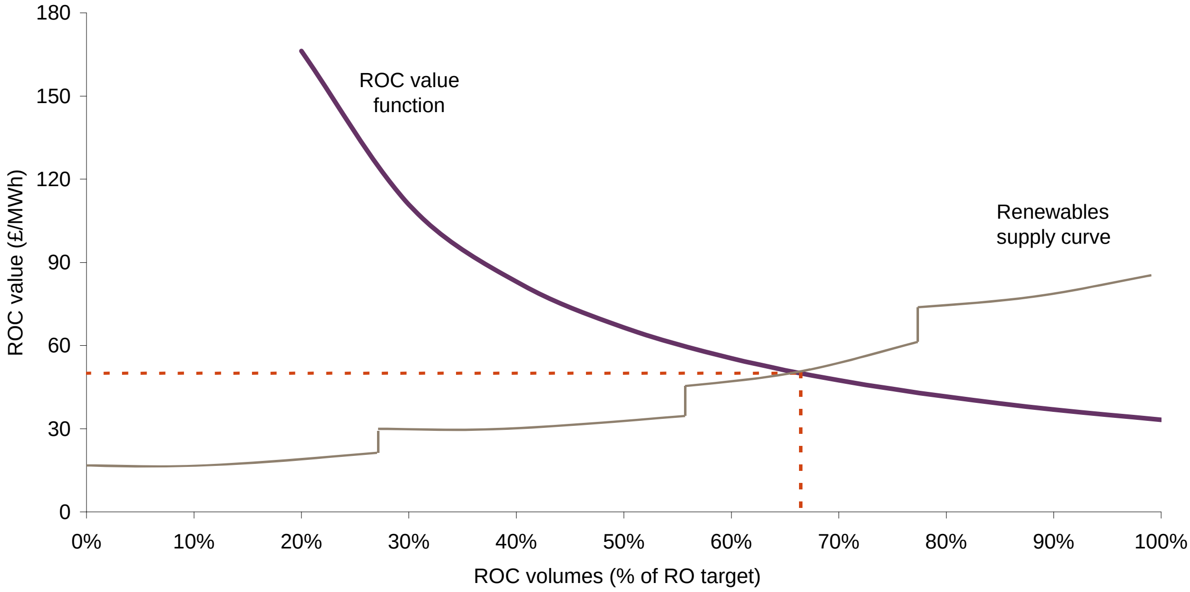
In each year, the expected ROC price is determined from an assessment of the renewable supply curve in that year against a ROC value function. The supply curve is defined in terms of the ROC price required to support a given volume of renewable generation, and is derived from an assessment of the revenue and cost streams in each year and the maximum availability of each technology. The supply curve exhibits step-changes between projects based on different technologies; within a given technology it will be upward-sloping, representing variations in cost due to, for example, differences in project size, location or fuel costs.

The ROC value function draws on the direct relationship between the level of support required by renewable generation technologies and the volume of generation that can be supported. The value of ROCs is defined in the equation below and implies that, as the total volume of ROCs in the market approaches the Obligation size, their value will fall towards the buyout price.[53]

$$\text{ROC value} = \frac{\text{Buyout price} * \text{Overall obligation size}}{\text{Total volume of ROCs}}$$

Figure A3.3 illustrates the interaction between renewable generation costs and ROC values, using a hypothetical supply curve for renewable generation projects. In this example, ROC volumes must stay below 66% of the Obligation size in order for the RO to provide the £50/MWh support required by the marginal project.

Figure A3.3 Intersection of supply curve and ROC value function



Source: Oxera analysis.

As Figure A3.2 above illustrates, the Model has two main sets of inputs that influence the results.

– **Cost and revenue assumptions**. The underlying components that determine the renewables supply curve over time.

Model parameters. Factors that define the regime (RO design parameters and banding levels), related policies (capital grants), and commercial interactions (shares of revenue and cost streams that the renewable generator/investor can expect to receive).

[53] This equation holds only where total ROC volumes do not exceed the Obligation size.

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