Distributed Energy - Further Proposals for More Flexible Market and Licensing Arrangements

Document type: Consultation

Ref: 87/08

Date of publication: 18 June 2008

Deadline for response: 31 July 2008

Target audience: Owners and operators of distributed energy schemes, electricity suppliers, generators, distribution network operators, consumer groups, local authorities, property developers, and manufacturers and suppliers of small-scale renewable generation and CHP plants.

Overview:

This document follows on from the December 2007 consultation on initial options for introducing greater flexibility to the market, regulatory, and licensing arrangements for distributed low-carbon electricity. It sets out Ofgem and BERR's preferred proposals and explains the conclusions and decisions that underpin them.

Our preferred proposals focus on ensuring that the trading arrangements and regulatory regime are proportionate to the size and risk posed by DE schemes operating in different settings such as merchant generation or as suppliers to local developments. We have sought to ensure that distributed energy schemes can grow and thrive within a competitive framework, as in our view, competition remains the most effective form of protection for customers, and is also a key driver for encouraging technological innovation to address environmental concerns.

We would welcome input to finalise the operational detail of our preferred proposals by 31 July 2008. Where appropriate, we will then seek to implement the proposals by the end of the year.

Contact name and details: Anna Kulhavy, Senior Economist, European Strategy and Environment

Tel: 020 7901 7390

Email: anna.kulhavy@ofgem.gov.uk

Team: Martin Crouch, Director, martin.crouch@ofgem.gov.uk
Adhir Ramdarshan, Regulatory Economist, adhir.ramdarshan@ofgem.gov.uk
Wallacia Scott, Regulatory Economist, wallacia.scott@ofgem.gov.uk
Rita Wadey, Assistant Director, BERR, rita.wadey@berr.gsi.gov.uk

Context

Encouraging sustainable development through reduced carbon emissions is a key policy objective for Government. Distributed energy (DE) could make an important contribution to this and other goals, including security of supply and alleviating fuel poverty. The issues facing DE are wide-ranging and touch on many aspects of energy and environmental policy and regulation. This work programme sits within a broad context of other work underway across Ofgem and government, including:

- the EU Renewable Energy Directive and the development of a UK Renewable Energy Strategy;
- the development of a Heat Strategy to tackle the carbon impact of heating and cooling;
- changes to building regulations and planning policy, in particular Government's drive towards zero-carbon development;
- the EU Emissions Trading Scheme and the price of carbon;
- Ofgem's Review of Industry Code Governance;
- Ofgem's review of electricity cash-out arrangements;
- Ofgem's fifth electricity Distribution Pricing Control Review; and
- Ofgem's consultation on electricity network charging regime.

Associated Documents

- Selling to third parties report, June 2008
http://www.ofgem.gov.uk/Sustainability/Environmnt/Policy/SmallrGens/DistEng/Pages/DistEng.aspx

- Distributed Energy - Initial Proposals for more Flexible Market and Licensing Arrangements, December 2007
http://www.ofgem.gov.uk/Networks/ElecDist/Policy/DistGen/Documents1/DE%20con%20doc%20-%20complete%20draft%20v3%20141207.pdf

- Heat Call for Evidence, BERR, Defra and CLG, January 2008
http://www.berr.gov.uk/energy/sources/heat/page43671.html

- Review of Distributed Generation: A Joint Government/Ofgem Report, May 2007
http://www.berr.gov.uk/files/file39025.pdf

- Energy White Paper 2007: Meeting the Energy Challenge, Chapter 3 - Heat and Distributed Generation, May 2007
http://www.berr.gov.uk/files/file39567.pdf

Table of Contents

Summary

What is DE?

Distributed Energy (DE), also referred to as distributed generation or decentralised energy, is defined in our work as renewable electricity generation which is connected directly into the local distribution network, as opposed to connecting to the transmission network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported for use across the UK.

Environmental benefits

The Energy White Paper, published in May 2007, set out the potential role of DE in meeting Government's energy policy objectives. DE can contribute to the energy mix and lower greenhouse gas emissions in several ways:

- making use of waste heat from electricity generation to heat and cool buildings;
- reducing electricity losses by locating generation near to electricity demand;
- facilitating the use of local renewable energy sources; and
- encouraging increased awareness of energy consumption among consumers.

The majority of existing DE generation consists of CHP plants producing for industrial and/or commercial users in the immediate vicinity. The nature and scale of these schemes means that they often do not need to hold a licence to generate, distribute or supply electricity. However, Government, at central and local level, has recognised the potential for DE in decarbonising the built environment and have put in place initiatives such as the Planning Policy Statement on Climate Change to drive zero carbon development. These are likely to lead to larger-scale district and city-wide DE suppliers that will operate within the licensing and regulatory frameworks.

Progress to date

Recognising this changing environment, Ofgem and BERR launched joint work on facilitating DE in summer 2006. The current phase began with the Energy White Paper, leading to publication of a consultation in December 2007 on initial options for more flexible market and licensing arrangements. This document meets the next stage of a commitment to publish proposals for implementation by the end of 2008.

Response summary

Since December, we have reviewed submissions and completed further analysis to better understand the issues that stem from the licensing and market arrangements. We and stakeholders agree that:

- the costs of licensing (primarily related to complying with industry codes) are disproportionate for community DE schemes and small suppliers;

- the complexity of codes and market arrangements are material informational barriers for potential DE developers that lack energy market expertise;

- the risks and costs of energy imbalance (cash-out) can be high for single source and/or intermittent renewable generators;

- network charges do not always reflect the cost savings from locating generation close to demand; and

- the provision of supplier services, whereby licensed suppliers undertake high-cost, high-competency functions for DE schemes to operate on the public network, is underdeveloped and largely reflects low demand from DE suppliers.

The Proposals

With the above in mind, we have identified a package of preferred proposals to allow DE to grow within the competitive market:

- 'switching off' the requirement to be a party to and comply with the high-cost and high-competency industry codes, on condition that the DE scheme has appropriate alternative arrangements;

- encouraging the development and provision of alternative arrangements (such as supplier services agreements) from a licensed third party to enable DE schemes and small suppliers to operate on the public network;

- highlighting areas for industry to lead on with respect to cash-out reform, to reduce the penalty inherent for intermittent generators and small suppliers; and

- accelerating the introduction of cost reflective network use of system charging to ensure economic development on public networks as an alternative to constructing private wires.

In December, we set out the debate around the role of exemptions in the future development of DE. Responses to the consultation reached consensus that DE could and should develop within the current arrangements; as such we are no longer considering changing exemption limits. The European Court of Justice has now ruled on the "Citiworks" case and BERR are considering the impact of that decision on the current licensing and exemption regime, as well as existing exempt DE schemes.

Way forward

The above proposals will ensure trading arrangements and the regulatory regime are cost proportionate to the size and risk posed by DE schemes operating in different settings. Ofgem, Government, industry and DE proponents will share responsibility for taking forward some of the specific proposals set out in this document. Other actions will proceed through work already underway across Government. We will actively engage with these work streams to ensure DE interests are adequately considered. Several options from the December consultation, that we do not intend to pursue at this stage, will be held in reserve in case our proposals do not have the desired effect.

1. Introduction

Chapter Summary: This chapter sets out a definition of DE. We discuss the drivers for uptake of DE, provide some background to the December consultation and stakeholder responses, and outline the other relevant policy processes for DE that are underway.

1.1. Distributed Energy (DE), also referred to as distributed generation or decentralised energy, is defined in our work as renewable electricity generation which is connected directly into the local distribution network, as opposed to connecting to the transmission network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported for use across the UK.

1.2. The term covers many technologies including wind turbines, solar photovoltaics (PV), and CHP plants - which may be installed by individuals, businesses, communities, schools, commerce or industry. DE schemes may be owned and operated independently, or they may be developed by or in partnership with larger established players in the electricity market. Our work has focussed on plant with an electrical capacity less than 100MWe but greater than 50 kWe (below 50 kW is categorised as microgeneration). Heat-only technologies or the heat supply aspects of CHP schemes fall outside our scope but this is covered by a parallel workstream within BERR.

1.3. DE, particularly within Industrial & Commercial settings, is an established part of the UK's energy mix: over 10GW of DE is currently installed in Great Britain accounting for just under 10% of electricity supply[1,2]. The bulk of this capacity consists of single generation plant installed on-site for own-use energy demands (both thermal and electricity). The industrial sector represents the majority of this plant and often includes a CHP installation. CHP schemes are particularly attractive to industrial and commercial customers with high own-use requirements that require a steady source of heat such as oil refineries.

1.4. A range of policies in place or under development suggest that the contribution of DE to the UK's energy mix is likely to increase and change in nature in future. This raises the question of whether the current regulatory and market arrangements in electricity are appropriate, in terms of both facilitating the uptake of DE where this is cost-effective, and safeguarding protection for customers in a scenario where

---

[1] It should be noted that this figure includes all generation connected to the distribution network, regardless of size or fuel type. It is therefore a broader definition than that set out in paragraph 1.2 above.

[2] In 2005 there was 5,792MWe of installed CHP electrical capacity with around 94% of this capacity spread between the chemicals, oil refinery, beverages and tobacco industries. The remaining 6% is used for agricultural, commercial, public administration, residential and transport sectors. (Source: DUKES)

increasing numbers of them may be receiving their energy supply from localised sources.

Background to the Further Proposals

Distributed Generation Review and the Energy White Paper

1.5. A joint BERR/Ofgem Review of Distributed Generation was published in May 2007 alongside the Energy White Paper. The Review identified a number of barriers to DG, including cost, a lack of reliable information, electricity industry issues (particularly around networks), and regulatory barriers. The DG Review identified four key areas for action. These were set out in the Energy White Paper and comprise:

- more flexible market and licensing arrangements for DG;
- more clarity on the terms offered by energy suppliers to reward microgenerators;
- improving information, advice and guidance on options in DG; and
- making it easier to connect to and use the distribution network.

December Consultation on Initial Proposals

1.6. In the December consultation, "Distributed Energy - Initial Proposals for More Flexible Market and Licensing Arrangements", we set out initial options to improve flexibility and remove any obstacles to DE within the market and regulatory arrangements. These included a mix of short-term and longer-term measures to:

- support community DE in the transition to the mainstream, such as a proposal to re-introduce an Exempt Supplier Services obligation within the supply licence;[3]
- allow new technologies and market arrangements to come forward. For example, we invited distribution network operators (DNOs) and DE schemes to come forward with proposals for network trial projects that offer innovative technical and charging solutions for DE;
- address the key barriers to entry associated with the market and licensing arrangements. Options raised in this context included the delegation of high-cost aspects of the Supply licence to third parties; considering the needs of small intermittent generators as part of the ongoing cash-out review; and appointing a

[3] Services provided to exempt suppliers by a licensed supplier, which might include meter registration, data processing, and providing top-up and back-up.

DE representative to the Balancing and Settlement Code (BSC) panel. We also proposed strengthening the requirement on DNOs to implement more cost-reflective charging for DE; and

- explore longer term issues that might need to be addressed if DE is to become a significantly larger component of the energy supply mix and part of the answer to reducing carbon emissions. For example, one option put forward was establishing a dedicated wholesale market for DE.

Stakeholder Responses

1.7. In total, we received 42 submissions to the consultation.[4] Although views differed on the specific issues and options, stakeholders reached a high level consensus on the principle that it would be better to facilitate DE within the competitive market rather than to rely on licence exempt status for future DE developments. This alignment of views was prompted by various concerns about competition, consumer protection and potential incompatibility with EU law.

1.8. Stakeholder responses to this consultation have been highly informative, and we are grateful to those that made submissions for making time to engage constructively on the issues and initial options. A list of respondents to the consultation is included in Appendix 5 of this document and stakeholders' non-confidential responses are available from Ofgem's website[5].

1.9. On 3 March BERR hosted a Stakeholder workshop where the Minister for Energy set out the Government vision for DE and heat in the context of wider energy policy. The event provided an opportunity to explain and explore the questions set out in the December consultation and the closely related Heat Call for Evidence. This well attended and successful event was an excellent opportunity to test our understanding of the issues and the basis for the options/questions in the document.

Distributed Energy Working Group (DEWG)

1.10. We met with the DEWG[6],[7] in May 2008, prior to finalising the proposals set out in this document to test our emerging conclusions and obtain their feedback on our

[4] Responses were received from the big six suppliers, smaller niche suppliers, DNOs, energy producers, industry associations, DE developers, property developers, industry agents and interested members of the public.

[5] http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=160&refer=Networks/ElecDist/Policy/DistGen

[6] At the start of this project BERR and Ofgem established a Distributed Energy Working Group (DEWG) comprising representatives from relevant industry sectors and stakeholders, with an interest in DE.

[7] The Terms of Reference for the Group and the list of participants is available in the December 2007 consultation.

preferred proposals. The group's preliminary input has been valuable in further developing the proposals set out in this paper.

Environmental Drivers for Uptake of DE

1.11. DE is attracting increasing attention, both commercially and politically. A key reason for this is the potential DE has to address environmental concerns and Government policy objectives related to reducing carbon emissions. Specifically, DE can yield benefits due to:

- a reduction in electricity losses that occur when a generation plant is situated close to demand sites[8] that translates into lower generation requirements and lower carbon emissions. This can help to avoid the need for investment in large central energy networks that have their own carbon and environmental footprint;

- use of renewable energy. While the majority of DE schemes are currently gas-fired CHP, DE schemes can also be fuelled by low-carbon renewable energy sources such as wind, solar or biomass, producing significant carbon savings;

- improved thermal efficiency. DE based on fossil fuels CHP technologies are energy efficient as they use the heat produced through electricity generation to heat and cool homes and other buildings. CHP schemes can achieve thermal efficiencies of up to 90%, a significant improvement on electricity-only generation;

- Energy Services Companies (ESCOs) – which tend to operate many community DE schemes - can deliver energy supply solutions (hot water and electricity) alongside energy efficiency improvements and advice to householders; and

- driving behaviour change. There is some evidence that locating generation close to demand increases consumer awareness about their energy consumption, and induce behavioural changes that contribute to reducing carbon emissions.

1.12. In addition to environmental benefits, DE may also help to reduce dependence on imported fuel, through increased fuel efficiency and further diversification of the UK's energy mix. DE can potentially also play a role in addressing fuel poverty issues at a local level - for example by providing low cost heating to social housing via community-based CHP schemes. In the context of the competitive market, the

[8] In relation to local use of electricity, it is worth making the distinction between physical and commercial flows. When DE is connected to the grid the laws of physics determine where that electricity flows and is subsequently consumed. In practice, consumers close to the DE plant are likely to consume the electricity it produces irrespective of the commercial arrangements that have been established by the developer to construct the plant, be they with local or national customers. However, the implications of an increased amount of intermittent generation sources on the system is likely to increase the ancillary service costs (and by consequence the amount of carbon emitted) related to balancing system demand.

development of local DE supply schemes would also stimulate more competition into retail markets and more effective choice for customers.

Other Relevant Policy Work

1.13. The work undertaken for this consultation is only one element within a wider context of policy processes that are underway related to DE. This includes work that is being led by both Ofgem and BERR. In this consultation document, we have indicated where we consider issues would be more appropriately dealt with in other fora and have actively engaged with other policy teams to ensure that DE issues are being addressed.

1.14. The following policy processes are relevant to the development of DE[9]:

Renewable Energy Strategy

1.15. The Government has committed to new EU targets increasing the use of renewables to reduce carbon emissions. In March 2007, the European Council committed the EU to a binding target of reducing greenhouse gas emissions by 20 per cent, a 20 per cent increase in energy efficiency and a 20 per cent share of renewable energy in overall EU energy consumption by 2020. The Commission has indicated that the UK's share of the target will be in the region of 15%. This applies to heat and electricity, where DE has a key role to play, as well as transport.

1.16. In the summer, the Government will launch a consultation on further measures to increase renewable energy use to meet the UK's share of the EU 2020 renewables target. Renewable DE is expected to play an important role in meeting the UK's Renewable Energy Target, particularly given its potential to reduce the carbon impact of the built environment. To support the Strategy, BERR have commissioned a study into the potential for renewable DE to be installed in the community by local authorities, schools or businesses to meet their energy demands on-site. The results of this study will be published later in the summer.

Planning and Local Government Requirements

1.17. Developments in building regulations, which are motivated in large part by the environmental concerns outlined above, are expected to increase the demand for and uptake of DE. Most notably, the Government's zero-carbon new buildings policy which set a target for all new homes in England to be zero-carbon from 2016, and an

[9] More detailed background on related policy areas and their relationship with DE can be found in appendix 6 of the December consultation.

ambition to see 'zero carbon' schools from 2016, 'zero carbon' public buildings from 2018, and all other non-domestic buildings 'zero carbon' from 2019.[10]

1.18. The definition of zero carbon for homes will set the context by which this policy will bring forward investment in DE[11]. The 2008 Budget announced that the Government will be consulting in the summer with a view to agreeing the definition of zero carbon by the end of the year. Moves towards zero-carbon development are likely to bring new players into the energy market. It is therefore important that the costs and complexities of participation are not prohibitive.

1.19. In addition to the above, many local planning authorities have already taken active steps to encourage local energy schemes via planning rules. The new Planning Policy Statement (PPS) on Climate Change confirms the central role of regional and local planning in helping to speed up the shift to renewable and low-carbon energy. In particular, the new PPS gives a boost to supplying new developments with local renewable and low carbon energy through what is being called 'Merton-Plus'.[12] This (like existing Merton rules) expects all local planning authorities to have a council-wide target for the percentage of local energy to supply new developments and, additionally, tailored targets for sites where there is greater potential for using local energy. These targets should be flexible enough to consider community schemes (for example, wind turbines serving more than one site or CHP schemes such as in Woking town centre) as well as building specific technologies.

1.20. The Mayor of London's Climate Change Action Plan[13] sets a target for London of a 60% reduction for CO2 levels compared to 1990 levels by 2025. The key proposal for achieving this is to move away from reliance on the national electricity grid and towards DE, including CHP networks, energy from waste, and on-site renewable energy. The London Climate Change Agency (LCCA) was established to implement high impact CO2 reduction projects, with a focus on DE. Given the size of its population, the Mayor's targets for the expansion in DE in London alone will, if met, represent a significant shift in the UK's generation mix.

---

[10] The Planning White Paper (http://www.communities.gov.uk/publications/planningandbuilding/planningsustainablefuture) stated that Government would explore the potential for all new non-domestic buildings to achieve substantial reductions in carbon emissions over the next decade and for many to achieve zero carbon on non-process related emissions.

[11] The Code for Sustainable Homes Technical Guidance (http://www.planningportal.gov.uk/uploads/code_for_sustainable_homes_techguide.pdf) and the Regulations for Zero Carbon Homes Stamp Duty Relief (http://www.hmrc.gov.uk/ria/9-zero-carbon-homes.pdf) both currently set out definitions of zero-carbon. These existing definitions are tight and focus on on-site or direct connection to zero-carbon sources of energy. They offer an opportunity for learning about application, but will not necessarily form the basis of the 2016 definition. The final 2016 definition is still to be consulted on.

[12] http://www.communities.gov.uk/publications/planningandbuilding/ppsclimatechange

[13] http://www.london.gov.uk/mayor/environment/climate-change/ccap/index.jsp

1.21. Other relevant policy areas include:

- **options for incentivising Renewable Heat** that will be consulted on as part of BERR's Renewable Energy Strategy in the summer;
- Government is developing a **Strategy for Heat**, to be published in spring, which will focus chiefly on low-carbon solutions - including CHP - and help shape development of the Heat Strategy, to be published in Spring 2009 alongside the Renewable Energy Strategy;
- **Ofgem's electricity cash-out review**, which is considering how well the current arrangements meet objectives of transparency, cost-reflectivity, non-discrimination, and promoting competition in the electricity market;
- **Ofgem's fifth electricity Distribution Price Control Review** for 2010-2015 will consider whether the existing policy framework is appropriate to allow the DNOs to play their part in moving to a lower carbon economy;
- **Ofgem's consultation** for Distribution Network Operators to deliver revised electricity network charging arrangements by 1 October 2009;
- Ofgem's **review of industry code governance**, which should make it easier for small players and new entrants;
- the **Transmission Arrangements for Distributed Generation** (TADG) working group, which explored issues of cost-reflectivity and access with respect to the treatment of DG within the transmission arrangements; and
- the **Carbon Emission Reduction Target (CERT) and Supplier Obligation**, which may encourage suppliers to work with partners to fulfil their regulatory obligations by choosing DE measures, where this offers cost-effective carbon emissions reductions.

Overview and Structure of the Document

1.22. In the remainder of this document we set out our preferred proposals to improve flexibility and remove any obstacles to DE within the market and regulatory arrangements. These actions will assist the development of DE by:

- reducing the complexity involved in setting up a scheme;
- ensuring requirements on these smaller players are proportionate to their size and the use they make of the wider licensed distribution network; and
- encouraging, where possible, further growth of DE within the licensed framework, rather than outside it.

1.23. Chapter 2 deals with issues around exemptions from the requirement to a licence. Chapter 3 covers smaller generators that want to trade directly in the wholesale electricity markets. Chapter 4 sets out our findings on third party competition in the market for small generators output. In Chapter 5 we address the issues of operating as a DE supplier on the public licensed network.

1.24. Finally, Chapter 6 sets out the next steps for defining the operational detail of our preferred proposals with stakeholders and developing a timetable to implement these by the end of the year.

2. The role of licence exemptions in the future development of DE

Chapter Summary: This chapter summarises our view on the role of the Class Exemption Order in the future development of DE. Thinking has been informed by stakeholders' responses to issues raised in the December consultation, emerging thinking on the preferred package of measures for implementation and the outcomes of a European Court of Justice case 'Citiworks'.

2.1. The December consultation set out the circumstances in which DE schemes do and do not require licences under the Electricity Act 1989 and outlined the debate around raising the exemption thresholds in order to facilitate greater take up of DE schemes.

2.2. Licences under the Electricity Act 1989 are required for the generation, distribution or supply of electricity.[14]In the UK there are some circumstances where individual and class exemptions from the requirement to hold a licence have been granted by the Secretary of State.[15] The Electricity (Class Exemptions from the Requirement for a Licence) Order 2001[16] (the "Class Exemption Order") allows exemption from the requirement to hold a generation, distribution and/or supply licence to persons of various classes. In other cases the Secretary of State has granted individual exemptions. Provided they do not exceed the exemption thresholds, and comply with all relevant conditions, parties who qualify under the Class Exemption Order or an individual Exemption Order can generate, distribute or supply electricity (as the case may be) without the need for any licence.

2.3. The Consultation document set out initial proposals for introducing greater flexibility to the market, regulatory and licensing arrangements for distributed low-carbon electricity, as signalled in the Energy White Paper. In general, this meant the proposals sought to allow DE to grow within the existing competitive market framework as it safeguards consumer choice and protection and encourages innovation. However, we also explored the issues raised by those who had argued that requirements to license larger schemes would be an obstacle to the take up of DE.

2.4. This discussion was set in the context of an improved understanding of the costs and complexities facing DE; wider competitiveness issues; and a case before the European Court of Justice 'Citiworks' which concerned the compatibility of an exemption from third party access requirements with the 2003 Electricity Directive (relevant to Distribution exemptions). Our key consideration was to make the licensing system fit for purpose for DE, thereby decreasing the incentive for schemes to rely on the Class Exemption Order for their viability.

---

[14] See section 4 of the Electricity Act 1989
[15] See section 5 of the Electricity Act 1989
[16] SI 2001/3270

2.5. Against this backdrop the December Consultation sought stakeholder views on:

- appropriate exemption limits across generation, supply and distribution;
- the need for clarification of the 2001 Class Exemption Order; and
- whether the existing per company maximum exemption limit should be removed allowing one company to develop a number of different sites.

Stakeholders' Views

2.6. In the lead up to consultation some DE proponents had called for an increase in the licence exemption limits to allow more and larger schemes to operate outside the licensed framework. It was argued that DE is, by its very nature, different and that the separation of competitive activities such as generation from the ownership of monopoly networks, a key principle of the licensing system, conflicts with the benefits of local generation and consumption.

2.7. However, consultation responses showed that there has been a shift in this debate. There is now a broad consensus that reliance on the Class Exemption Order for larger DE schemes derives from the costs and complexities faced by schemes moving from exempt to licensed status (particularly in supply), rather than a true desire to operate outside the regulatory framework. All respondents recognised the benefits that the licensing system offers consumers; ensuring the safe supply and distribution of electricity, and providing choice and protection, particularly for vulnerable customers. Stakeholders agreed that this was of particular significance for DE schemes operating in a community setting, with supply and distribution to domestic customers; precisely the type of schemes we expect to see more of in future, as changes to building regulations and planning requirements take effect.

2.8. There was also wide agreement that any change to the thresholds set out in the Class Exemption Order would necessarily be arbitrary. There is a lack of real evidence about the size of DE schemes that would be considered economic and efficient in all settings; rather it is clear that the economics of schemes must be considered on a case by case basis. It was also recognised that a change to the limits would only provide short-term relief, and that in future there would likely be further calls to raise the limits to accommodate the larger DE schemes that might begin to be seen in the community setting. As such, there was broad agreement that it is better to tackle the costs and complexities of becoming licensed at this time, so that DE can develop within the competitive market, rather than delay tackling these issues until some date in the future.

2.9. Responses to the consultation overwhelmingly agreed that the way that the Class Exemption Order has developed over time makes it disjointed, ambiguous in places and generally difficult to interpret. A number of respondents noted that the likely rise in community DE will bring non-expert players into the electricity market, and that they in particular would benefit from simplification and plain English redrafting of the Order. A number of respondents offered to work with BERR in any clarification exercise, and this is welcomed.

2.10. Views from those respondents that addressed the issue of the per company maximum limit set out in the Class Exemption Order were mixed. For many the issue was closely tied to the wider debate around exemptions and the feeling that it is not right for DE to rely on exemptions in its future development. However, a range of stakeholders pointed out that not all future DE schemes would exceed the exemption thresholds, and that there could in fact be a lot of community DE that served domestic developments of less than 1MW or around 1000 households. It was argued that the per company maximum discriminates against larger DE developers who will operate over a number of sites, and that this not only affected the existing large suppliers, but could in fact restrict the ambition of smaller DE developers seeking to achieve scale in their operations. Some respondents believed that this was counter-productive and actually inhibits the full development of a market for DE.

Recent Developments

2.11. In December we were constrained in our approach to exemption limits or clarification of the Class Exemption Order because of uncertainties raised by a case before the European Court of Justice (the case referred to as Citiworks[17]), which concerned the compatibility of an exemption available under German law from third party access requirements with the directive on the internal market in electricity[18].

2.12. On 22 May 2008 the European Court of Justice delivered its judgment on the 'Citiworks' case[19], finding that the system in question did indeed constitute a distribution system under the Directive, and thus should be subject to the directive's provisions on third-party access to the network, one of the key elements of the liberalisation of the internal market in electricity launched by the first electricity Directive in 1996.[20] The judgement noted that a fully open market must enable all consumers freely to choose their suppliers and all suppliers freely to deliver to their customers, and that these two rights are necessarily linked. In order for customers to be able to choose freely their suppliers, it is necessary that suppliers should have the right to access the different distribution systems which carry electricity to the customers.

2.13. The Court made clear the limited circumstances whereby a distribution system could be considered to fall outside the third party access requirements of the Directive; namely whether a network falls within the definitions of 'small isolated system' or 'micro-isolated system' for which derogations may be sought;[21] or where

[17] C-439/06
[18] Directive 2003/54/EC
[19] http://eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=CELEX:62006J0439:EN:HTML
[20] Directive 96/92/EC.
[21] Definitions are set out in Article 2 Directive 2003/54/EC

Member States decide application of the third party access requirements would obstruct the performance of obligations imposed on electricity undertakings in the general economic interest. Operators of a distribution system may also refuse access where it lacks the necessary capacity.

2.14. BERR is responsible for the licensing system in Great Britain, and the Secretary of State sets the rules by which schemes can consider themselves exempt from the need to hold a licence. As such, we will need to give consideration to the implications of this ruling for existing policy, and the timings of any changes that prove necessary. This may in turn have implications for DE schemes seeking to establish themselves as exempt operators and also impact on existing schemes that are currently operating under an exemption.

2.15. As discussed in the December Consultation, DE schemes that fall below the exemption thresholds, often generate, supply and distribute electricity as a monopoly provider on private wires. They are in a position to refuse to offer terms for access to the network for third party suppliers. This gives them certainty over their customer base and improves the economics of their schemes; a factor which is particularly important in the set up phase of projects where they may be required to give fairly accurate forecast of future revenue in order to secure financing.

2.16. It is clear that this judgment may have implications for this business model in future, and that on the face of it, the need to offer third party access may have a detrimental effect on the economics of small-scale DE schemes. However, it appears that schemes that allow third party access when requested to do so will be able to operate as before.

2.17. There are several issues that need further analysis and examination. That activity is beyond the scope of this workstream, and BERR has begun detailed consideration and is keen to provide certainty to DE stakeholders, many of whom have expressed concern at the judgement, in a timely fashion.

Conclusions

2.18. It is the view of BERR and Ofgem that the debate around the role of exemptions in the future development of DE has moved on since the Energy White Paper. The proposals set out in this document seek to allow larger DE schemes to participate in the market on a cost proportionate basis, whilst maintaining the full range of protections that licensing offers consumers. Stakeholders have responded to this package very favourably and we believe that there is now a real opportunity for the DE market to mature. As such, it is not necessary to raise the thresholds for exemptions from licensing. Neither are we convinced of the need to remove the per company maximum.

2.19. We do, however, agree with the Stakeholders that the Class Exemption Order 2001 is in need of updating and clarification. It is possible that the ECJ judgment will require changes to be made beyond this, but it is too early to give a firm view. BERR will therefore consider clarification as part of its detailed consideration of the implications of the Citiworks case. We are grateful to those stakeholders who have offered to assist in this process, and we are keen to work openly to ensure that the Order can be a useful tool for DE developers, rather than a barrier. This is in line with Government's better regulation principles.

3. Wholesale Market Trading

Chapter Summary: In the December consultation, we discussed the potential risks and impacts that DE schemes might encounter from directly participating in wholesale markets. We have considered this further and estimated the discount that third parties price into offtake purchase agreements to take on these risks for DE. We see merit in enabling DE operators to come forward with their own proposals to address the issues they are facing in the current wholesale regime.

Question box

Question 1: We welcome views on whether the Authority should exercise its power as provided for under the BSC to designate a third party representative with DE interests or expertise to raise BSC code modifications.

Question 2: We welcome expressions of interest from stakeholders interested in having the power to raise code modification proposals on behalf of DE schemes. For those interested parties, please highlight specific reasons why this power should be conferred upon you.

Question 3: In terms of the length of designation, we believe that a period in line with the Panel's term (e.g. 2 years) may be a suitable period with which to trial this proposal. We would welcome stakeholders views on the period for which designation might last.

Question 4: We would welcome views on whether the designated party should be obliged to contribute fees to Elexon in order to participate in the BSC change process. If so, how should the level of contribution be determined?

Question 5: Should any other codes be examined in relation to lack of DE representation?

3.1. Larger DE generators can participate in the wholesale market to sell blocks of power such as base or peak loads during the summer or winter.[22] Single plant or intermittent generators, such as DE schemes, cannot always guarantee output. For generators trading in the wholesale market, shortfalls in production must be covered by other trades or face exposure to the balancing mechanism and face charges in the form of cash out prices.[23] The risks and costs of imbalance can be significant given the wide and unpredictable differential that sometimes exists between system buy and system sell prices.

[22] The generator needs to be a signatory to the BSC and other industry codes to fulfil its requirements under the terms of any trade.
[23] Imbalance prices are designed to reflect the costs that the system operator incurs in balancing the system every half hour.

3.2. However, the majority of DE generators are small and do not operate directly in the wholesale market. Instead, they are likely to sell their output through a purchase agreement with third parties. Nonetheless, even in these circumstances, DE generators can be indirectly affected by the balancing mechanism, particularly if the predictability of their output exposes the counterparty to risk of imbalance. In this instance, the DE generator is affected through a discount that third parties price into offtake purchase agreements as a compensation for the imbalance exposure they manage on behalf of the DE generator. Improvements to the cash-out regime could also benefit DE through the prices offered by market intermediaries (covered in the next chapter "Selling to a third parties").

3.3. The cash-out rules sit within the Balancing and Settlement Code (BSC), and changes to the rules can only be proposed by signatories to the code. However, most DE schemes are not signatories to the BSC and other industry codes as they operate on a licence exempt basis. Consequently, they do not have the power to propose code modifications to change industry rules.

Stakeholders' Views

3.4. In the December consultation, we consulted stakeholders on how best to accommodate the needs of small generators within the wholesale markets by considering the following:

- considering the needs of small intermittent generators as part of the ongoing cash-out review; and
- appointing a DE representative to the BSC modifications panel.

3.5. A number of respondents, including the majority of suppliers, felt that DE interests were already well represented in current BSC governance processes. Some thought that the addition of such a representative would be of limited value and low impact. Others argued that there was a case for examining whether a party should be given a right to bring forward code modification proposals under the BSC.

3.6. The majority of responses agreed that we had identified the major risks for DE when trading in the wholesale markets. An additional barrier identified as preventing active involvement by DE in wholesale trading is the credit requirements placed upon market participants.

Relevant Developments

Environmental Guidance from Ofgem to Industry Code Panels

3.7. Ofgem is looking to issue guidance to all Code Panels shortly on how some environmental considerations can be evaluated within the economic and efficiency code objective. This will include guidance on factoring the greenhouse gas impacts of code modifications when assessing proposals relative to the status quo and any alternative modification.

3.8. If followed, this guidance is likely to be a positive development for DE given its potential environmental benefits. For example, evaluating the potential impact of a modification on greenhouse gas emissions could lead to a broader range of factors being considered in the assessment of a proposal, including possible impacts on low carbon developments such as DE. Additionally, assuming that DE has a broadly positive impact on carbon emissions, modification proposals that are intended to address issues in the current arrangements that hinder DE will have a stronger case, if they can be shown to better facilitate the code objectives.

Industry code governance review

3.9. Ofgem issued an open letter[24] in November 2007 highlighting concerns that there may be weaknesses in the way the codes are governed that prevent both industry and consumers from getting full value from these arrangements. Ofgem consulted stakeholders on the scope of a review of the governance regime and will issue an open letter in June 2008.

3.10. In its November letter, Ofgem highlighted two issues of relevance to DE:

Review of code objectives in light of the wider statutory framework within which the Authority makes its decisions

3.11. When the BSC and other industry codes were introduced, the objectives the Authority and Code panels used to assess modifications to the codes were based around the statutory duties of the network businesses. However, since then the wider statutory framework, within which these decisions are made by the Authority, has changed. For example, the Authority was given duties relating to sustainable development in October 2004. As a result, the industry and the Authority make their respective decisions within different decision making frameworks.

3.12. Aligning the code objectives with the Authority's statutory duties may be broadly positive for DE because the various code panels and industry will need to develop processes and ways of working to consider impacts of modifications against broader objectives including the environment and sustainability.

Review of complexity of code arrangements

---

24 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=3&refer=Licensing/IndCodes/CGR

3.13. The lack of entry into the market place of smaller players, such as DE providers, has led to concerns that the existing code arrangements may be too complex and inaccessible. As such, the Review will consider whether the code arrangements in their current form may represent an undue barrier to entry to smaller players.

Further Analysis and Conclusions

3.14. Since the December consultation we have completed further work:

- to highlight potential avenues for cash-out reform from the perspective of DE schemes; and
- examining the case for DE schemes to come forward with their own proposals to address the issues they are facing.

Cash-out Reform

3.15. In February 2007, Ofgem launched a Cash-out Review[25] in response to concerns raised by some participants about the current arrangements. An industry participant subsequently raised an issues group, "Issue 30", under the BSC to discuss certain cash-out features identified as potentially sub-optimal.

3.16. Over the past year, three modifications have been proposed to address concerns that cash-out prices are being "polluted" by the costs of system balancing actions, such as those taken to manage constraints on the transmission network.

3.17. Ofgem published an Impact Assessment in December 2007 for two modifications[26]. The impact assessment found that the current costs of system pollution were borne disproportionately by those parties less able to balance due to the nature of their portfolio or scale of operation, such as small suppliers, distributed energy providers and intermittent renewable generators.

3.18. To inform future cash-out reform, we commissioned some further work to consider the interests of small and intermittent generators (for more detail see Appendix 4). The aim of this work was two-fold: to examine the discount third parties priced into DE offtake agreements as a result of the imbalance risk; and second, to better understand of the implications for DE of potential short- and medium-term developments to the cash-out arrangements.

---

25 http://www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Pages/CashoutRev.aspx

26 http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=98&refer=Markets/WhlMkts/CompandEff/CashoutRev

Discount Analysis

3.19. NFPA auction data shows that the purchase prices for intermittent generation sources includes a discount to wholesale electricity prices relative to less intermittent generators. The size of the discount is comparable to the expected net exposure of an intermittent generator directly participating in the wholesale market. This is a surprising result to some extent if the discount is attributable to the balancing risks associated with intermittent generation sources. We would expect DE generators to benefit from consolidation within the purchaser's existing portfolio relative to direct participation in the wholesale market. Some other possible explanations for the discount are uncertainty about the forward ROC values for intermittent renewables, an expected negative correlation between intermittent output and ROC prices, or other information about reliability of specific plants included in the NFPA auctions.

Implications of Potential Developments to Cash-out Arrangements

3.20. A qualitative evaluation of the implications for intermittent generators of possible reform to cash-out arrangements found that the key areas of cash-out reform which would benefit DE include making cash-out prices "cleaner", reducing the cash-out spread, increasing the predictability of cash-out prices, and allowing DE schemes to trade closer to real time.

3.21. Future developments in cash-out reform could have a material impact on intermittent DE generators, from the perspective of those directly trading in wholesale markets, and those that are affected indirectly through the terms offered to DE schemes by intermediaries in bilateral offtake agreements.

DE Representative on the BSC Panel

3.22. We have concluded that appointing a DE representative to the BSC panel would be disproportionate for a number of reasons, including:

- lack of stakeholder support;
- limited ability of panel members to raise modifications;
- current status of DE in the UK energy mix and the correspondingly small number of DE relevant modifications; and
- lack of funding remains a stumbling block and is unlikely to attract DE representatives given their small scale and associated lack of resources.

Preferred Proposal

3.23. In light of our conclusions on the impacts of cash-out arrangements for small and intermittent generators and the scope to pursue reform if a party were minded to, a more proportionate and effective proposal to increase DE's participation in the

BSC change process would be to designate a third party to have the power to raise modifications.[27] A third party could include anyone that has DE interests or expertise.

3.24. There is complementarity between the proposal to designate and cash-out reform because the rules for cash-out arrangements sit within the BSC. Modifications to the rules can only be proposed by a limited group of persons, primarily code signatories. By designating a third party to raise modifications on behalf of the DE community, a channel emerges through which DE can address the issues in the current wholesale regime such as the areas highlighted in the cash-out discussion above.

3.25. Ofgem consulted in February 2001 on whether it should designate a third party prior to the New Electricity Trading Arrangements (NETA) going live. No representations from small generators were received at the time so the proposal was abandoned.[28]

3.26. However, the debate about the obstacles the central trading arrangements pose for DE schemes and sustainability more generally have gained prominence since the 2001 consultation. In addition, encouraging sustainable development and mitigating climate change through the development of DE has become a policy objective for both central and local government.

3.27. This issue is compounded by the fact that where a licensed DE scheme is willing to participate, it often has insufficient resource to engage fully and effectively in the time-intensive BSC code modification process.

3.28. We have not formally consulted on the option of the Authority designating a third party. We would welcome stakeholders' views on this proposal. We think this measure has merit to help DE "find its feet" in the BSC process given the likely increase of DE in the UK energy mix. For this reason, we propose to review any such designation towards the end of its term. The Authority will only exercise this power with due consideration and if no suitable candidate is forthcoming, then it will not exercise this right at all.

3.29. We would welcome expressions of interest from stakeholders interested in representing DE in this way. The basic criteria we would expect any interested party to demonstrate include:

- a strong link to the DE sector;

[27] This is allowed under section F2.1.1(c) of the BSC.
[28] Ofgem/BERR – New Electricity Trading Arrangements – Balancing and Settlement Code: Modification Procedures – Designation of bodies representative of third parties - Conclusions, March 2001.

- an understanding of the BSC modification process;
- motivation to pursue beneficial changes for DE through the code governance change process; and
- sufficient resources to follow a modification through the whole process.

4. Selling to Third Parties

Chapter summary: In the December consultation, we proposed initial options for addressing concerns held by some stakeholders about insufficient competition for the output of small-scale generators. In response to requests for further analysis we have since examined in more detail whether there are signs of market failure in this area. Overall, we have found the offtake market to be competitive and diverse. All major suppliers are active in it, usually nationally, and increasingly smaller suppliers are becoming involved and competing vigorously.

4.1. Distributed generators do not ordinarily participate in the central traded markets because of their size and the associated costs. However generators of any size have the option of selling their output to a third party such as another generator, supplier or consolidator. Such activity can take the form of a long-term Power Purchase Agreement (PPA), shorter-term offtake agreement or within year trades including through the exchange-based platforms operated by the Non-Fossil Purchasing Agency (NFPA). The price offered to DE schemes through these agreements will depend on a number of factors, including: prevailing market prices, the predictability of the generation; supplier transaction costs and expected margin; any embedded and carbon related benefits; as well as the size of the purchaser's existing generation portfolio and its commercial objectives at any point in time.

4.2. Although we do not have a view on an appropriate value for the electricity from these generators, we would be concerned if there was evidence that there is insufficient competition for the output of DE schemes. Insufficient competition would undermine the prices paid in the market, and depress activity by developers over what it otherwise would have been. (For related information, please refer to the "Wholesale Market Trading" chapter).

Stakeholders' Views

4.3. Respondents were split evenly on whether third party purchasers undervalue exports from DE schemes. Purchasers of DE output argued that the prices paid reflect the wholesale price reasonably adjusted for the predictability of generation and the expected imbalance risks. Suppliers also argued that consolidation already occurred (not least through themselves) and that the lack of specialist consolidators in the market reflected narrow margins on small generator output trades, which they argued was symptomatic of high levels of competition.

4.4. On the other hand, DE generators were adamant that the output from DE was undervalued, a position that reflected a lack of competition for small packets of output by the large suppliers. There were several requests for Ofgem to undertake further analysis in this area.

4.5. The majority of respondents did not support the introduction of a specialist Energy Trader. Some argued that this would stifle innovation and it should be left to the market to develop this role if it were needed. Two respondents did think there was scope for a specialist energy trader but only if other options proved ineffective.

4.6. The majority of respondents also rejected the option of a dedicated wholesale market for DE for a variety of reasons, including insufficient volumes for it to be useful. Two large suppliers stated that if the market were to operate in a similar way to how the NFPA run the market for renewables output then this proposal may have merit; however, more detail was requested.

4.7. Some respondents suggested that DE schemes should consider using third party services to improve forecasting accuracy and that this would help them to achieve higher prices for their output. For instance, it was suggested that real time data feeds between generator and supplier would enable greater value to be extracted from the generation.

4.8. Other issues cited as barriers to smaller generators realising the maximum value for their output included: the legal costs of entering into contracts; the absence of relevant standardised industry contracts; credit issues; and the limited resources available to make contact with suppliers.

Further Analysis and Conclusions

Small Generator Experience in Selling Output

4.9. Since the December consultation, we commissioned a study, published separately, into the experience of small generators in selling their output to third parties to get a better understanding of the issues they face.[29] This exercise involved sending a questionnaire to small generators of various sizes and technologies, and conducting follow up conversations with a selection of survey respondents. Views were also sought from the counterparties to offtake agreements.

Key findings

4.10. On the whole, there was not widespread dissatisfaction on the part of DE generators, or any stand out issue on which respondents were united. Respondents did, however, raise familiar concerns regarding the market for small generator output, including:

- the difficulty in getting a route to market for some new entrants and lack of useful information over the options available;

[29] A full version of the consultants' report is available here: http://www.ofgem.gov.uk/Sustainability/Environmnt/Policy/SmallrGens/DistEng/Pages/DistEng.aspx

- disappointment about prices offered, although there is acknowledgment that this may have more to do with lack of information and unrealistic expectations before they entered the market rather than a result of any serious market failure;
- a lack of interest from some larger suppliers for smaller quantities of output, and/or similar offers and/or an inflexibility of approach on the part of counter-parties;
- credit issues; and
- physical issues with the distributor for new sites.

4.11. Offtake arrangements with third parties are very diverse and comprise a mix of long-term PPAs, shorter-term (typically annual or bi-annual) purchase agreements and within year trades primarily transacted through the NFPA's e-power auctions. Activity by third party providers other than a specialist consolidator, such as brokers and other intermediaries, is limited, and does not seem to have grown significantly over recent years despite the proliferation of distributed generation. Most contract structures are based on variable volumes (take then pay), and subsequently there are few surpluses available for trading.

4.12. A variety of approaches were evident in the commercial terms on offer. These included seasonal time of day arrangements and the use of market benchmarks based on expected forward prices (day ahead through to seasonal prices). In virtually all cases, prices were adjusted for green and embedded benefits as well as a discount for imbalance or margin. Renewable Obligation Certificates (ROCs) are sometimes sold with the power, sometimes without it.

4.13. Most developers referred to an improvement in the prices paid under offtake agreements in more recent contracting rounds. There are several reasons for the increase. First, there is the general increase in wholesale power prices since the trough in 2002-04. Second, there are reduced supplier margins due to improved understanding of the risks involved in contracting with often intermittent generation. In addition, there is more competition for output as demand for green energy has grown.

4.14. Most suppliers indicated they would be interested in purchasing packets of output of any size, subject to negotiation of an acceptable price. Some suppliers referenced a threshold below which they would not usually pursue acquisition of packets of output, instead relying on consolidators or agents to bring these forward. Suppliers also highlighted other factors that would influence their interest, such as the business context of the seller (for instance, if it required a supply agreement for on-site use), whether a deal might lead to more transactions down the line, and the level of contracting activity they have on the go at the particular time.

Conclusions

4.15. Overall, the market for small generator output seems to be competitive and diverse. All major suppliers are active in it, usually nationally, and increasingly smaller suppliers are becoming involved and participating aggressively.

4.16. Better understanding of the operation of the trading arrangements, the operational environment, and increasing familiarity with technologies such as wind and biomass have led to an improvement of prices, more flexibility on contract duration and structure, and better sharing of benefits to the DE schemes.

4.17. In line with the developments noted above we have concluded that the market for small generator output is maturing. As a result, and in line with the stakeholder's submissions, we believe that moving forward with the specialist trader and dedicated wholesale market for DE as set out in the December consultation is unnecessary and disproportionate. Indeed, we believe these may in fact have a detrimental impact on some parties who are already offering innovative consolidating and trading services.

4.18. Nonetheless, some modest developments could augment accessibility to the offtake market, the choices available and therefore the quality of competition at play. This includes: more within year trading; better information on entry options and requirements and available support for DE schemes; more standard terms and contracts for smaller power parcels; as well as set tariffs for smaller parcels of output.[30]

4.19. Many of the above conclusions are closely linked with improving and bringing together existing information available to DE schemes, and will inform Government policy in this area. Information provision will be addressed in more detail in the Government's Renewable Energy Strategy to be published later in the summer.

[30] The details of these recommendations are available in the full report here: http://www.ofgem.gov.uk/Sustainability/Environmnt/Policy/SmallrGens/DistEng/Pages/DistEng.aspx

5. Operating as a Supplier on the Licensed Distribution Network

Chapter summary: This chapter summarises our conclusions on the issues facing prospective DE schemes that want to or are required to meet local or community supply, either as a licensed supplier or as an exempt supplier, on the licensed distribution network. For DE operating as licensed suppliers, our preferred proposals aim to reduce the costs of becoming licensed by 'switching off' the condition to comply with the high-cost, high-competence industry codes, provided that arrangements are in place (e.g. a supplier services agreement) with a licensed third party that integrates the DE scheme within the competitive market. Both licensed and exempt DE suppliers operating on the public network will benefit from other work programmes that will bring forward cost-reflective network charging methodologies and potentially a more proactive role for DNOs in facilitating the development of DE schemes.

Question Box

Question 6: We invite stakeholders to identify any good quality information currently available that would be suitable for including in the development of a user friendly information hub on the process of setting up and operating a DE scheme.

Question 7: Do you agree with the proposed license amendment to SLC 11.2 (see Appendix 2)? Suppliers - please indicate whether you would accept the proposed license amendment.

Question 8: Should Ofgem issue guidance on eligibility criteria for switching off the code compliance licence condition? If so, what should the main criteria be?

Question 9: Should Ofgem establish an industry working group to develop a good practice guide on supplier services agreements?

Question 10: How should the risks of a breakdown in the DE-Agent relationship be mitigated?

5.1. In the December consultation, we outlined two key issues facing a DE scheme operating as an exempt supplier on the public licensed network:

- the price and availability of Exempt Supplier Services that are required to conduct commercial transactions on the licensed distribution network; and
- aspects of the current arrangements, that in some instances, encourage DE to operate on private wires rather than on the licensed distribution network.

5.2. DE suppliers who fall outside of a relevant class in the 2001 Class Exemption Order, and are not granted an individual exemption, must apply to become a licensed supplier. In the December consultation we discussed the step change in the overall costs faced by DE schemes as a result of complying with licence conditions.

Some of these costs are incurred irrespective of the scale of the scheme and are spread over relatively low quantities of electricity output.

5.3. The document also recognised the information barrier DE operators face in trying to set-up and operate schemes within the electricity market and how new players coming into contact with the market and licensing arrangements for the first time might need help to navigate the system.

Stakeholders' Views

5.4. Stakeholders agreed there were strong incentives for DE supply schemes to avoid operating on the public network. For example, schemes operating on private wires are only exposed to the rest of the system based on net energy flows at the meter on the boundary[31]. Similarly, DNOs' existing charging methodologies were also seen as a large disincentive. Most stakeholders were unanimous that efforts to put in place cost reflective charging methodologies sooner rather than later would assist the development of DE on the public network.

5.5. We received mixed reports from stakeholders on the availability of Exempt Supplier Services. Some DE proponents described difficulty in obtaining these services from licensed suppliers and expressed doubt that there is sufficient incentive for such services to be provided by the market. On the other hand, suppliers themselves indicated that they had not been asked to provide such services, but would be willing and able to meet the demand if approached. Large and small licensed suppliers strongly rejected imposing an obligation on suppliers to provide services saying that it would reduce innovation and crowd out niche players. It was also seen as a retrograde step given that an obligation had been removed under the banner of better regulation in the 2007 Supply Licence Review.

5.6. Most stakeholders acknowledged the large fixed costs involved in meeting licence conditions and the disadvantage of scale for DE in cost recovery. However, the option of introducing DE licence conditions which would restrict customers from switching for a certain period of time was not expected to be effective in helping DE unless the timeframe were long enough to allow payback through the standard tariff structure. It was also recognised that customer tie-in puts the protections offered by competition at risk. In general, there was a consensus that proposals to encourage DE must be based within the licensing framework where possible to retain the necessary customer protections which flow from the competitive market.

5.7. In response to the Call for Evidence that supported the Review of Distributed Generation, stakeholders highlighted a lack of clear information as a key barrier to the development of DE. However, respondents to the December consultation offered

[31] Or put another way, DE schemes avoid the energy risks and costs of paying third party suppliers a retail price on gross demand and receiving a lower wholesale price on gross generation.

mixed views on the availability and relevance of information for DE developers trying to set-up and operate a DE scheme. That said, it was acknowledged that an exercise to consolidate available information on the key steps and relevant parties involved in the development process of a typical DE scheme would be a useful addition. Government will give further consideration to these findings in the development of the Renewable Energy Strategy.

Relevant Developments

5.8. Since the December consultation, there have been several developments that are expected to benefit both licensed and exempt DE suppliers operating on the public network. These will mitigate current concerns about use of system costs, accessibility to public networks, realising the value of embedded benefits associated with DE in settlement, as well as increasing the transparency of connection processes. Overall the work programmes currently underway may result in DNOs being more proactive in locating and connecting DE schemes. Together, these developments are likely to mitigate most of the disincentives for operating on the public network.

Distribution Price Control Review

5.9. The fifth electricity Distribution Price Control Review (DPCR5) has started and one of its key objectives is to ensure that DNOs facilitate the connection of low carbon technologies to the distribution network.[32] Ofgem will decide, at a high level, on the key areas for DPCR5 and on any additional innovations needed to set the controls by the end of the year. Detailed proposals will be finalised in December 2009.

5.10. The scope of DNO activities relating to DE covered in the Price Control Review consultation includes connections, active network management and the commercial arrangements for DE connecting to and using the system. These encompass many of the issues DE faces in accessing and operating on public networks and the DPCR5 presents a timely opportunity to identify some innovative solutions. The outcomes for DE will depend to some extent on DNOs' vision around taking forward new business areas and their leadership to actively position themselves to support the growth of DE through to 2015 and beyond.

5.11. We encourage stakeholders interested in the future role of DNOs to facilitate DE to respond to the Price Control Review consultation which closes on 23 June 2008.

[32] http://www.ofgem.gov.uk/Networks/ElecDist/PriceCntrls/DPCR5/Pages/DPCR5.aspx

Ofgem's Distribution Structure of Charges Project

5.12. Ofgem launched the structure of charges project in 2000, with the aim of reviewing charging methodologies used to calculate distribution network charges by all DNOs. Owing to repeated delays in delivering revised charging methodologies, Ofgem recently consulted on placing a formal licence condition on DNOs to deliver appropriate charging methodologies by 1 October 2009. With concerns that the current charging regime does not properly reflect the benefits that DE can bring to the distribution system, this requirement will align charging methodologies with the price control aimed at encouraging DNOs to assist the connection of DE.

5.13. The Distribution Charging Methodologies Forum recently met to discuss common charging principles to enable the DNOs to progress their methodologies for lower voltage generation. A number of DNOs have already submitted modifications for lower voltage connected generation well ahead of the proposed timetable of October 2009. We are challenging other DNOs to do the same.

Methodology to Calculate Line Loss Factors

5.14. Ofgem recently approved P216, a modification requiring DNOs to adopt a set of high level principles with which Line Loss Factors (LLFs) must be consistent. It includes a principle that generic LLFs for import and export at the same site where the voltage level is the same shall have the same value.

5.15. This modification will partly mitigate the incentive to construct private wires because it will apply similar demand and generation Line Loss Factors (LLFs) to a DE scheme. These LLFs will ensure that the generation is attributed the benefits of being connected to the distribution as opposed to the transmission network and will help to realise the full value of the embedded benefits of DE schemes within the settlement process. In addition the approved modification will increase transparency and national consistency in the implementation of LLFs.

Further Analysis and Conclusions

Market Complexity and Information Barriers

5.16. Over the course of this project we have gained a better perspective of the information requirements and expertise needed by DE developers. In particular, we have found that information on the end-to-end process of setting up and operating a scheme is patchy for those individuals, communities and developers considering DE. Although several sources of information exist, some of which is DE-specific, the accessibility and helpfulness of such information could be improved if it was consolidated in one place and included advice on key steps, best practice and relevant parties involved in the process.

5.17. We are calling on stakeholders to come forward with suggestions for information that might be useful to DE developers. The information needs of DE developers and new entrants will be discussed in more detail in the Government's Renewable Energy Strategy published for consultation later in the summer.

Virtual Private Networks

5.18. We met with a small stakeholder working group to explore the merit and feasibility of a 'virtual private network' (VPN) in April 2008. The VPN concept was put forward last year as a way to replicate the majority of benefits of private wires for DE operating on the public network. Clearly a major benefit of operating on private wires is that customers are unable to switch to an alternative supplier. The VPN aims to replicate the benefits of private wires but at the same time ensure customer protections and their rights to freely choose and change energy supplier.

5.19. The virtual private network concept proposes formalising trading arrangements so that collections of generation and demand meters that relate to a DE scheme operating on the public network are aggregated and separately registered within the settlement system. Under these arrangements, the DE scheme would only be exposed to the market and regulatory arrangements at the boundary point. This metered point records the difference between the amount generated and the total amount consumed so that schemes interact with the electricity system on a net basis. This would offer several advantages given current tariffs for network use and would also mean that the DE's arrangements for top up and back up become a simple retail contract based on a single meter at the boundary. In addition, formalising these arrangements through central arrangements would also simplify access for small players.

5.20. However, the group concluded that overall this might have more costs than benefits when considered in the context of distribution charging tariff reform currently underway and the possibility of obtaining netting-off arrangements in the market. The major costs involved in formalising this arrangement would be incurred establishing a 'downwards' settlement scheme for the DE to allocate charges to end-users, and an 'upwards' settlement scheme to provide high-quality aggregated data to the central Settlements process. In addition to establishing expensive processes, other costs would include added complexity to existing arrangements and new management processes.

Cost of Complying with Industry Codes

5.21. Licensing costs add up to £4.50 per MWh to overheads for a small DE scheme of around 5MW. Nearly half relates to costs incurred complying with high competency industry codes requirements - most of which are not scalable and are incurred regardless of the size of the intended market share of the supplier. The high-cost, high-competency aspects of the licence primarily relate to MRA and BSC compliance and require significant investment in systems and specific expertise.

5.22. It is difficult to derive a general view of DE economics because of the small evidence base and the bespoke characteristics of individual commercial developments. For this reason the breakeven point in terms of customer numbers to recover licensing costs will depend on the particular market segment. However given the economics of the electricity supply industry are geared toward acquiring large numbers of customers each contributing a small margin, the costs are unlikely to be recovered on an economic basis over the electricity output of a DE scheme supplying a local development.

5.23. As well as established licensed suppliers, less experienced individuals, communities, property developers and ESCOs will either want to, or be required to, self generate and locally supply their energy requirements. Many of these parties will not be familiar with the industry and find the complexity of the market and industry arrangements a significant barrier to getting community DE developments off the drawing board.

5.24. New entrants have several options including developing expertise, procuring expertise or relying on a third party to manage these high-cost, high-competency functions on their behalf. Delegating responsibility for these requirements shifts the investment burden to established licensed players serving larger numbers of customers. However, there are no standard contracts in the market to transfer obligations, and having to negotiate such arrangements would involve significant legal costs and asymmetric contracting.

Underdevelopment of Supplier Services Provision

5.25. We have heard mixed reports about the availability of services in the market whereby licensed third parties undertake commercial transactions on the public network on behalf of exempt DE suppliers, in addition to offering to purchase export and provide top-up and standby. Although we do not have any evidence for market failure, we do think that there are some problems around the visibility and potentially the competitiveness in provision of such services.

5.26. The underdevelopment of these arrangements is mostly symptomatic of current low demand for such services. As described above, exempt suppliers have strong incentives to operate on private wires. In addition, community DE schemes that might prefer to procure services instead of developing in-house capacity have not yet materialised. Consequently, licensed suppliers do not see the provision of supplier services as a significant market opportunity and are not particularly active or innovative in this area.

5.27. However, the demand for such services is likely to increase with the expected development of DE supply schemes to local developments. And the availability of competitive services will be important for enabling DE suppliers to operate on public networks. But there could be some impediments to the development of these services due to:

- coordination problems between demand and supply – in a classic 'chicken or egg' situation we could find that demand for these services only materialises once DE developers have confidence that established suppliers are making competitive offers;

- uncertainty about the likely size of market could limit established suppliers' interest in planning significant activities and innovations in this area; and
- established suppliers could be reluctant to provide routes to market to potential competitors, particularly those they saw as having scope to increase their market share once they become more established.

Preferred Proposals

Proposal 1: Introduce the option of switching off the condition which requires the licensee to be a party and comply with the industry codes set out in Standard Licence Condition 11.2 in the Supply Licence[33].

5.28. This proposal focuses on facilitating community DE schemes to operate on the public network.

5.29. The most onerous requirement in the Supply Licence is the need to comply with the industry codes and be a party to the main agreements as set out in Condition 11.2. It is unlikely community DE will have sufficient scale to make it worthwhile to invest in the systems and specific expertise to develop capacity in-house. This proposal would ensure that the licensing regime does not unfairly burden small suppliers with disproportionate costs for arrangements that are less relevant for type of scheme they intend to operate. There is already some precedent for due discrimination within the licensing regime where small suppliers are exempt from costs that are considered to be too onerous[34].

5.30. Under this proposal, licensees would retain the obligation to be a party to and comply with the codes set out in SLC 11.2 but we would introduce the option to switch off this obligation. A necessary proviso for switching off the condition would be that it had arrangements in place with a licensed supplier that is party to the codes to undertake the necessary commercial transactions on behalf of the DE supplier to enable it to use the public licensed network.

5.31. In effect, DE operators would purchase services from a licensed third party, much in the same way as some exempt suppliers do currently. These services would include the high-cost and high-competency functions necessary to operate within the competitive market (as set out by the industry codes) and allow customers of a community DE scheme to access the competitive market and to switch suppliers. DE

[33] Section 7 (5) Electricity Act 1989 provides that: "Conditions included in a licence may contain provision for the conditions--(a) to have effect or cease to have effect at such times and in such circumstances as may be determined by or under the conditions". This is often referred to as introducing a provision to 'switch off' the licence condition.
[34] See Supply Licence Condition 27.2 (b).

suppliers will also want to contract other auxiliary services and we expect that DE suppliers might prefer to bundle these services into one arrangement.

5.32. This proposal would allow community DE schemes and small suppliers to swap the direct and upfront costs of developing industry systems and expertise in-house for ongoing transaction costs and a margin charged by a licensed third party to provide the services. For small schemes this would reduce the economic costs and risks of market entry while becoming established. It also keeps open the option of directly participating in the industry codes and central arrangements later on.

5.33. There are currently no standard contracts to transfer obligations, and negotiating such arrangements would involve significant legal costs and asymmetric contracting. We believe that formalising this arrangement within the regulatory instruments would simplify the process, provide clarity for DE and encourage the potential providers to offer these services.

5.34. There are two possible approaches for giving effect to this proposal. First we could consider individual requests from licensees to amend their individual licences. As part of this consideration we would be required to consult with persons likely to be affected by making this modification and the Secretary of State[35].

5.35. Alternatively we could amend SLC 11.2 to allow licensees to comply with SLC 11.2 in one of two ways, either sign up to the relevant Codes and comply with them or, as an alternative, seek a direction from the Authority which permits the licensee to have arrangements (such as a supplier service agreement) in place with a licensed party who is party to the codes to discharge the necessary functions on their behalf.

5.36. In our view, there are benefits in the second approach of formalising the option and amending the SLC 11.2 in that it could simplify access for less experienced developers; and avoids duplicating effort involved in amending individual licences. It would be relatively straightforward to include a provision in the SLC 11.2 that allows the Authority to issue a direction to relieve a licensee of its obligations with respect to the Codes if satisfactory alternative arrangements are in place. If a direction was given but it later transpired that satisfactory arrangements were no longer in place the direction would be revoked.[36]

5.37. The question arises as to how we would ensure the licensee fulfils the proviso to put in place adequate alternative arrangements with a licensed third party. One approach, which is our preferred approach at this stage, would be to issue separate guidance on the requirements that the licensee would have to meet. This guidance could, for example, set out the process Ofgem would follow and the criteria it would use to consider the licensees request. It could also provide details about the

[35] See section 11 Electricity Act 1989.
[36] SLC 2.7 already gives the Authority the power to revoke a direction given under any provision of the supply licence.

information that licensees would be required to give Ofgem as part of that process. We believe this approach would provide more certainty for all parties involved and scope for Ofgem and industry parties to refine the arrangements over time.

5.38. We invite respondents to provide feedback on the draft proposed amendment to SLC 11.2 set out in Appendix 2 and whether they agree that an amendment to SLC 11.2 using the collective licence modification procedure would be a better approach than amending individual licences on a case-by-case basis. We also invite stakeholders' views on the possible scope of the guidance. We discuss some potential aspects below to prompt further thinking on this issue.

Scope of guidance

5.39. Are there sufficient practical reasons to allow licensees to self-elect whether to apply for a direction from the Authority if they think this will suit their circumstances? Or, should the guidance explain that this option be restricted to a certain group of licensees? If so, what eligibility criteria would a licensee have to meet? For example, this could be based on:

- size of the scheme based on capacity or customer numbers;
- the commercial characteristics of the scheme e.g. a scheme that is characterised by a direct relationship between generator and customer; and/or
- the licensee has applied for a restricted licence based on the geographical area of the scheme.

5.40. The guidance would make clear that a decision to direct that SLC 11.2 be switched off would be contingent on the applicant licensee demonstrating that it would have in continuing operation arrangements with a licensed third party to be a party to and comply with the codes on the DE supplier's behalf. In the absence of such arrangements the direction would be revoked.

5.41. To demonstrate and satisfy the above, the applicant could be required to provide information described in the guidance, for example:

- details of the licensed third party the applicant has contracted to undertake the necessary industry arrangements on its behalf;
- details of the arrangements the licensee has to source electricity to supply its customers;
- the Distribution Company with whom the licensed third party has entered into a Distribution Use of System Agreement on behalf of the applicant;
- the arrangements the applicant has contracted with the licensed third party to service and read meters and manage customers that choose to change supplier.

5.42. We welcome stakeholders' views on whether other information would need to be considered in deciding to direct that SLC 11.2 be switched off.

Proposal 2: Encourage and facilitate provision of supplier services agreements to enable DE suppliers to operate on the public network

5.43. The success of allowing DE schemes to switch off the high-cost, high-competence industry code obligations would depend on the availability of supplier services provided by third parties. It would also depend on substitutability of these services for direct participation of the licensed DE scheme.

5.44. DE suppliers will probably also want to obtain auxiliary services from licensed third parties and bundle these with services undertaken on their behalf for code compliance. For example, top up and back up arrangements to guarantee continuity of supply for the supplier's customers. In addition, arrangements to purchase surplus electricity from the scheme and terms to treat the DE scheme on a net basis could be material to the economics of the DE scheme.

5.45. We expect that formalising a switch off within regulatory instruments would provide a strong signal for the development of third party supplier services, with specialist energy companies possibly entering the market (or new branches of existing companies) to provide services to DE developers. Such companies will be able to spread the licensing costs over a number of sites thereby reducing the overhead for their clients.

5.46. However, we remain open to the possibility that other incentives or possibly even regulation could be needed to ensure these services come forward. We welcome stakeholders' feedback and input on whether it is preferable to let the market develop as DE schemes come forward or whether other measures are necessary to provide more certainty that the services will be available. We note that if suppliers do not provide these services, the obligation will remain on the DE licensee to comply with the codes. In any case, we envisage monitoring developments in the market and reviewing the position in two years time to ensure that the market is responding adequately.

5.47. A starting point for thinking about the types of arrangements that DE suppliers would need are the services that were contained in Condition 53 of the previous Supply Licence, which broadly required established suppliers to offer:

- top-up and back-up to meet any shortfalls in production relative to customer demand and to cover plant outages due to a failure or maintenance;
- meter registration, data collection and processing; and
- settlement of the charges incurred by the licensed supplier on behalf of the licensed DE scheme / small supplier operating on the public network such as network use of system charges.

5.48. In addition to those above, it would be essential for the licensed third party to manage a process to allow customers of a DE scheme to switch to a third party supplier should they choose to do so.

5.49. DE supply schemes are also like to want to access the following auxiliary services and terms:

- to purchase of surplus electricity not required by the scheme;
- that apply arrangements for netting-off demand and generation and the scheme's incurred costs of energy; and
- that offer appropriate credit cover proportionate to the size of the scheme.

5.50. We welcome stakeholders' views on the services a DE supplier would require if it was operating without being a party and directly complying with the codes to ensure that the customers of any such scheme had access to the competitive market.

5.51. The form of any supplier services agreement will vary depending on the individual circumstances and aspects of the DE scheme. Negotiating agreements could take a bit of time and cost, especially in the near future as the different parties "learn from doing". One way to minimise the transaction costs of arranging these service agreements might be for suppliers and DE proponents to develop a good practice guide. We would welcome stakeholders' views on whether it would be useful for Ofgem to facilitate a working group comprising suppliers that might be interested in offering these services and DE proponents to take this approach forward.

5.52. It is not intended that Ofgem would regulate the prices at which these agreements are offered or approve these arrangements.

Further considerations

5.53. We are currently giving further consideration to the implications of implementing this proposal. In particular, we are considering the risks to the DE scheme and the operational integrity of the electricity system which may arise from the fact that the DE supplier is not a direct party to the industry codes.

5.54. A key issue to consider is whether customers ultimately belong to the DE supplier or the licensed third party. This will be important in the event of a breakdown of the relationship between the licensed third party and the DE supplier.

5.55. However, further thought needs to be given to this area. We have set out some initial thoughts in Appendix 3 and would welcome views on these issues, in particular how the risk of a DE supplier being put in breach of its licence through no fault of its own and/or effectively losing its customers could be prevented.

6. Conclusions and Way Forward

6.1. A six week period has been allowed for stakeholders to respond to the questions set out in this document. We will reflect on stakeholders' views and consider the best way to progress licence amendments and facilitate industry discussions on supplier agreements. Subject to responses, we could commence formal consultation on the draft licence amendments in September 2008.

6.2. Several issues relevant to DE developments discussed in this document are being taken forward within other work streams currently underway. We will actively engage with these to maintain the momentum for considering DE interests in these processes.

6.3. The responsibility and indicative timing for taking forward the proposals and related actions discussed in this document are set out in Table 1 below.

Table 1: Summary of Preferred Proposals and other Actions

Proposal/Actions	Way Forward	Responsibility	Timing
Exemption limits			
Determine implications of Citiworks ECJ ruling on Exemption Order 2001		BERR	By end of 2008
Consider clarification of the 2001 Exemption Order		BERR	By end of 2008
Wholesale Market Trading			
Short-term cash-out reform	Ofgem to decide on current modifications to address system pollution in cash-out prices	Ofgem	By end of 2008
Medium-term cash-out reform	Publish report on implications for DE of potential cash out developments Industry to take forward cash out reform with better understanding of implications for small and intermittent generators	BSC signatories	This document Beyond 2008
Authority decision on whether to designate third party to BSC	Review consultation responses and expressions of interest	Ofgem	By end of 2008
Environmental guidance to Codes	Guidance to be published in June	Ofgem	June 2008

Proposal/Actions	Way Forward	Responsibility	Timing
	Monitor implementation of guidance by Code panels		
Industry Code Governance Review	Publish open letter on scope of review towards end of June 2008	Ofgem	2008 - 2009
Selling to a Third Party			
Provision of more complete, accurate and understandable information for DE	To be addressed in UK Renewable Energy Strategy (RES)	BERR Ofgem Industry	Later in Summer
Becoming a Licensed Supplier			
Introduce amendment for SLC 11 to allow licensees to use alternative arrangements to being a party to the code	Commence informal consultation on standard licence amendment Statutory consultation on standard licence amendment Develop guidance on process and criteria for decision	Ofgem	This document September 2008 By end of 2008
Supplier Services Agreements	Review interest from industry and DE proponents to develop good practice guide Ofgem to facilitate process	Industry Ofgem	By end of 2008
Cost Reflective DUoS Charging	Decide on whether to introduce licence obligation DNOs introduce charging methodologies for lower voltage connected generation	Ofgem DNOs	September 2008 As soon as possible and no later than 1 October 2009
DPCR5: future role of DNOs to facilitate DE	Ensure DE interests are considered as part of DPCR5	Ofgem DE stakeholders	Final decisions 2009
Line Loss Factors	DNOs to implement the same LLFs to the demand and generation for DE schemes	DNOs	Implement by 20 April 2009

Appendices

Index

Appendix 1 - Consultation Response and Questions

1.1. Ofgem would like to hear the views of interested parties in relation to any of the proposals set out in this document.

1.2. We would especially welcome responses to the specific questions which we have set out at the beginning of each chapter heading and which are replicated below.

1.3. Responses should be received by 31 July 2008 and should be sent to:

Anna Kulhavy
Senior Economist - European Strategy and Environment
Ofgem
9 Millbank, London SW1P 3GE
020 7901 7390
anna.kulhavy@ofgem.gov.uk

1.4. Unless marked confidential, all responses will be published by placing them in Ofgem's library and on its website www.ofgem.gov.uk. Respondents may request that their response is kept confidential. Ofgem shall respect this request, subject to any obligations to disclose information, for example, under the Freedom of Information Act 2000 or the Environmental Information Regulations 2004.

1.5. Respondents who wish to have their responses remain confidential should clearly mark the document/s to that effect and include the reasons for confidentiality. It would be helpful if responses could be submitted both electronically and in writing. Respondents are asked to put any confidential material in the appendices to their responses.

1.6. Any questions on this document should, in the first instance, be directed to:

Anna Kulhavy
Senior Economist - Environment
Ofgem
9 Millbank, London SW1P 3GE
020 7901 7390
Anna.Kulhavy@ofgem.gov.uk

Rita Wadey
Assistant Director - Distributed Energy Unit
BERR
Bay 235, 1 Victoria Street, London SW1H 0ET
020 7215 2573
Rita.Wadey@berr.gsi.gov.uk

CHAPTER: One
There are no specific questions in this chapter.

CHAPTER: Two
There are no specific questions in this chapter.

CHAPTER: Three
Question 1: We welcome views on whether the Authority should exercise its power as provided for under the BSC to designate a third party representative to raise BSC code modifications.

Question 2: We welcome expressions of interest from stakeholders interested in having the power to raise code modification proposals on behalf of DE schemes. For those interested parties, please highlight specific reasons why this power should be conferred upon you.

Question 3: In terms of the length of designation, we believe that a period in line with the Panel's term (e.g. 2 years) may be a suitable period with which to trial this proposal. We would welcome stakeholders views on the period for which designation might last.

Question 4: We would welcome views on whether the designated party should be obliged to contribute fees to Elexon in order to participate in the BSC change process. If so, how should the level of contribution be determined?

Question 5: Should any other codes be examined in relation to lack of DE representation?

CHAPTER: Four
There are no specific questions in this chapter.

CHAPTER: Five
Question 6: We invite stakeholders to identify any good quality information currently available that would be suitable for including in the development of a user friendly information hub on the process of setting up and operating a DE scheme.

Question 7: Do you agree with the proposed license amendment to SLC 11.2 (see Appendix 2)? Suppliers - please indicate whether you would accept the proposed license amendment.

Question 8: Should Ofgem issue guidance on eligibility criteria for switching off the code compliance licence condition? If so, what should the main criteria be?

Question 9: Should Ofgem establish an industry working group to develop a good practice guide on supplier services agreements?

Question 10: How should the risks of a breakdown in the DE-Agent relationship be mitigated?

Appendix 2 - Draft Amendment for SLC 11.2

1.1. The licensee must be a party to and comply with:

(a) The Master Registration Agreement;

(b) The Distribution Connection and Use of System Agreement;

(c) The Connection and Use of System Code; and

(d) The Balancing and Settlement Code,

from the earlier of the date on which it offers to supply electricity or the date on which it begins to supply electricity to premises in Great Britain unless the licensee has a direction from the Authority, granted after consulting with the licensee and any other person or body likely to be affected, relieving it of its obligations (in whole or in part) under any of the codes set out in paragraphs (a)-(d) above, and the licensee acts in accordance with that direction.

Appendix 3 - Breakdown in DE-Agent relationship

1.1. A key issue to consider is whether customers ultimately belong to the DE supplier or the licensed third party. This will be important in the event of a breakdown of the relationship between the licensed third party and the DE supplier.

1.2. It might be argued that the customers belong to the DE supplier (as the licensee). If this is assumed, where the licensed third party becomes insolvent the DE supplier is likely to find itself in breach of SLC 11 of the supply licence through no fault of its own i.e. if it does not immediately have arrangements in place for a licensed third party to meet its code obligations and is not in a position to meet those code obligations itself.

1.3. Alternatively, it might be argued that the customers belong to the licensed third party given that it is a direct party to the industry codes (and subject to the code obligations and liabilities relating to those customers).

1.4. If this is assumed, where the licensed third party becomes insolvent one of two situations might arise:

- a supplier of last resort ("SOLR") might be appointed to take over all of the licensed third parties customers i.e. including the DE customers. Thus, the DE supplier might lose its customers to the SOLR through no fault of its own;
- the customers will revert to the DE supplier. In such circumstances, the DE supplier is likely to find itself in breach of SLC 11 of the supply licence through no fault of its own i.e. if it does not immediately have arrangements in place for a licensed third party to meet its code obligations and is not in a position to meet those code obligations itself.

1.5. In the event that the relationship between the DE supplier and the licensed third party breaks down (i.e. for reasons insolvency or otherwise), we would expect the DE supplier to make provision for the requirements of SLC 11 to continue to be met either by appointing a new licensed third party or by meeting the obligations of the industry codes itself. The DE supplier ought not, as a result of any breakdown in the relationship, cause itself to be in breach of the licence.

Appendix 4 - DE and Cash-out Arrangements

Introduction

1.1. The December DE consultation, published jointly by Ofgem and BERR, discussed the potential risks and impacts that DE schemes might encounter directly from wholesale market arrangements or indirectly through third parties managing these risks on their behalf.

1.2. Those DE generators participating directly in the wholesale market are exposed to cash-out prices for any imbalances between their contracted volumes and actual output. The majority of DE generators participate indirectly by selling their output to a third party such as a supplier or specialist consolidator. In this case, the counterparty assumes the imbalance risk on behalf of the DE generator, and typically incorporates a discount in the offtake purchase agreement to compensate for this exposure. Improvements to the cash-out regime may therefore impact DE generators directly or via the prices offered by market intermediaries. Ofgem and BERR have been considering steps to facilitate the participation of the DE community in the change process for cash-out and other aspects of the market arrangements.

1.3. Following the December consultation paper, we have completed some further work to consider the interests of small and intermittent generators within the cash-out arrangements. The aim of this work was two-fold: to examine the discount third parties priced into DE offtake agreements as a result of imbalance risk; and second, to better understand the implications for DE of potential short- and medium-term developments to the cash-out arrangements. This appendix summarises the results of this work.

PPA discounts and cash-out imbalance risks

1.4. We begin by considering the discount to wholesale electricity prices within DE offtake agreements and assessing the extent this can be attributed to features of the cash-out arrangements.

1.5. DE contracts with market intermediaries can take the form of a long-term Power Purchase Agreement (PPA) or a shorter-term offtake arrangement such as the seasonal contracts executed on the exchange-based platform operated by the Non-Fossil Purchasing Agency (NFPA). The NFPA platform provides the most transparent price marker for DE contracts, although additional research has been commissioned to study the overall market for DE offtake[37]. The analysis we present here is based upon three main sources:

- the NFPA e-Power auctions;
- Ofgem's cash-out simulation model; and
- DE consultation and questionnaire responses.

NFPA auction analysis

1.6. The NFPA e-Power auctions establish bundled prices for the output and renewables benefits (ROCs, LECs and REGOs as applicable) of generation projects, including wind, landfill, hydro, waste incineration and biomass schemes. The NFPA publishes average auction prices for each generation technology. We have assessed whether these auction prices for DE offtake are discounted below wholesale market rates by estimating the value of individual components within the bundled product sold by the NFPA. Our assumptions for the individual components are:

- power price – average reported baseload power price for the delivery season during the week of the auction;
- ROCs – price established at the NFPA e-ROC auction preceding the e-Power auction;
- LECs – Climate Change Levy for the financial year of the delivery season;
- REGOs – nominal value reflecting our understanding of limited trading to date;
- embedded benefits – estimate of the supplier's avoided BSUoS charges and network losses, assuming a 50% share[38];
- working capital discount – reflecting the average holding period between PPA settlement and the realisation of ROC benefits.

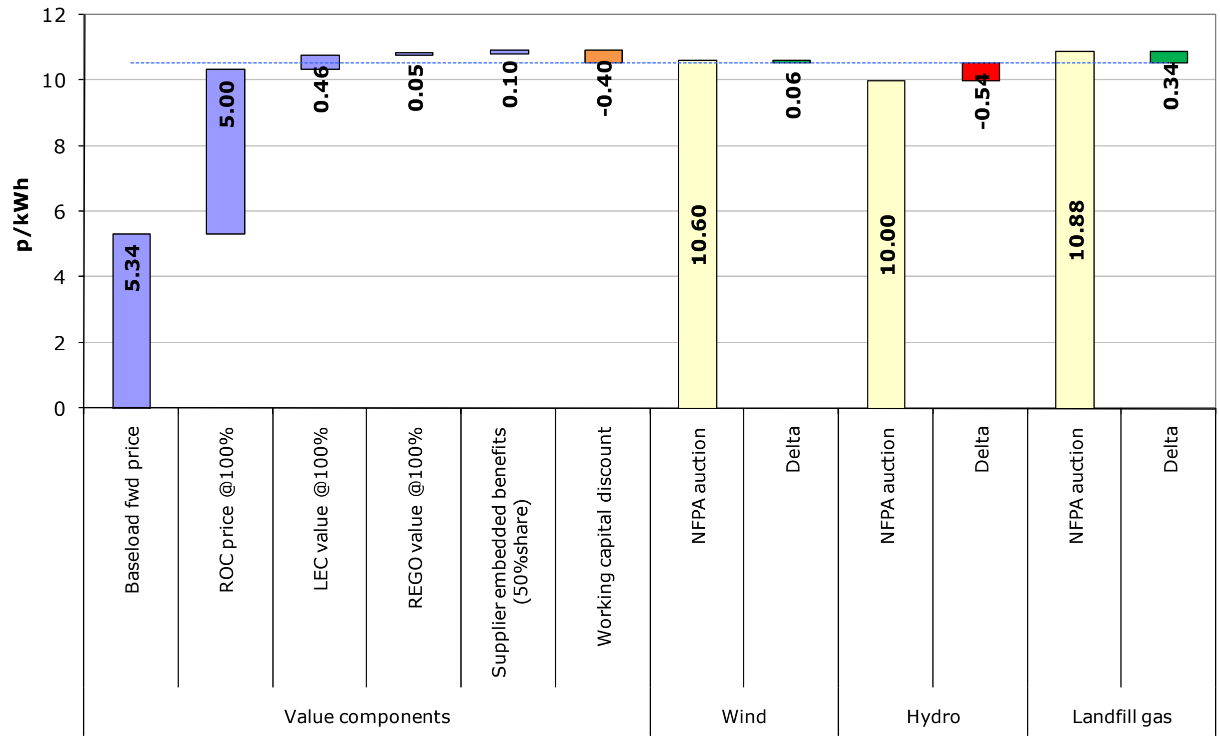
1.7. The differential between the NFPA auction price and the estimated value of these individual components provides an indication of the supplier's margin and any discount applied to account for volumetric / imbalance risk[39].

[37] http://www.ofgem.gov.uk/Sustainability/Environmnt/Policy/SmallrGens/DistEng/Pages/DistEng.aspx

[38] Under the standard NFPA PPA contract, the "Triad Avoidance Benefit" is accounted for separately so we assume this is not factored into the e-Power auction price.

1.8. Figures 1 and 2 below illustrate the results of the NFPA e-Power auctions for winter 2007/08 and summer 2008, together with our estimates of the value components. The analysis suggests that suppliers are not incorporating significant discounts and margins in pricing their bids for the NFPA auctions, even for intermittent generation sources such as wind. Indeed, the summer 2008 auction price for wind implies a small premium (0.06 p/kWh) to our combined estimate of the value components. This implies that suppliers have incorporated a more bullish view of forward power and ROC prices[40], and/or a more favourable allocation of embedded benefits compared to our assumptions.

Figure 1 Analysis of NFPA power auctions - summer 2008

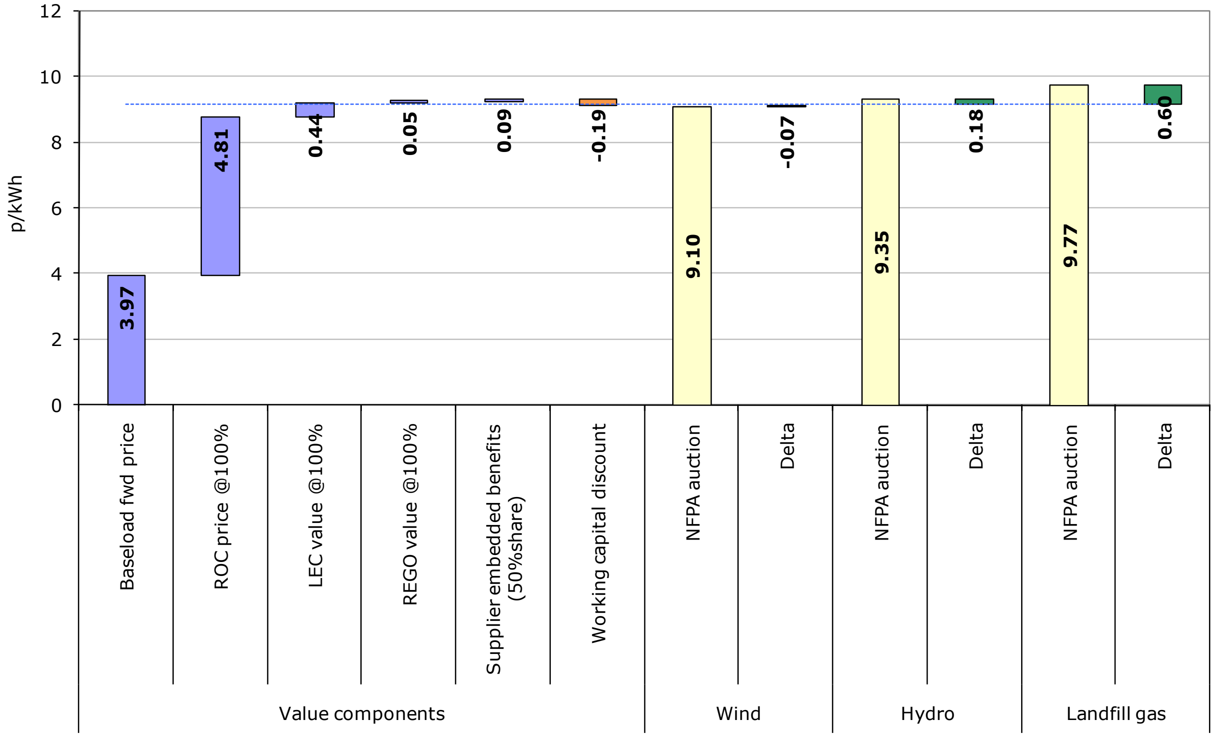


Source: NFPA, Heren, Ofgem analysis

---

[39] Other factors contributing to this differential may include transaction costs and any specific information on output predictability and profile for individual projects within the auction.
[40] Our ROC price assumptions are based on the benchmark prices established in the e-ROC auctions, but these are retrospective rather than forward-looking and may relate to a different compliance period. For example, the e-Power auction held in February 2008 sold bundled products for summer 2008, while the previous e-ROC auction in January 2008 sold ROCs delivered during the 2007/08 compliance year.

Figure 2 Analysis of NFPA power auctions - winter 2007/08



Source: NFPA, Heren, Ofgem analysis

1.9. The above analysis suggests that the bundled prices obtained by renewable generators participating in the NFPA auction are not significantly discounted below the underlying value components. However, a comparison of the NFPA auction prices received for different generation types does provide an indication of the discount applied to intermittent sources. Table compares average prices for wind and landfill gas projects from the four most recent NFPA e-Power auctions. As a proportion of the baseload forward wholesale market price, the apparent discount for wind projects relative to the more predictable generation source of landfill gas has ranged from 5% in the summer to as much as 17% in winter 2007/08.

Table Analysis of NFPA power auctions

p/kWh	Wind	Landfill Gas	Spread	Forward price	Spread/ Fwd price
Summer 08	10.60	10.88	0.28	5.34	5.2%
Winter 07/08	9.10	9.77	0.67	3.97	16.9%
Summer 07	7.36	7.47	0.11	2.12	5.2%
Winter 06/07	10.23	10.83	0.60	5.85	10.3%

Source: NFPA, Heren, Ofgem analysis

1.10. This discount for wind relative to landfill gas projects is likely to be largely attributable to the balancing risks associated with intermittent generation sources, although other factors may be a consideration:

- forward ROC values for wind plant may be discounted due to the greater uncertainty on seasonal plant output;
- forward ROC values for wind plant may be discounted if there is perceived to be a negative correlation between system-wide annual wind output and ROC prices[41];
- forward power values for wind plant may be discounted if there is perceived to be a negative correlation between system-wide wind output and wholesale power prices[42]; and
- plant reliability and output profile information for specific projects included in the NFPA auction[43].

Cash-out simulation model

1.11. Using the simulation model developed by Ofgem's cash-out team[44], we have sought to estimate the cash-out exposure of an intermittent renewable generator operating directly in the wholesale electricity market. Assuming a short-term forecast error of 25% for the intermittent generator, the mean estimated net exposure (including BSUoS and RCRC payments) is around 7.3% of the wholesale price under the current cash-out arrangements. As we show below, this level of exposure to cash-out is in part due to the dual price nature of the current arrangements, as well as the pollution of energy imbalance prices by the costs of system balancing actions.

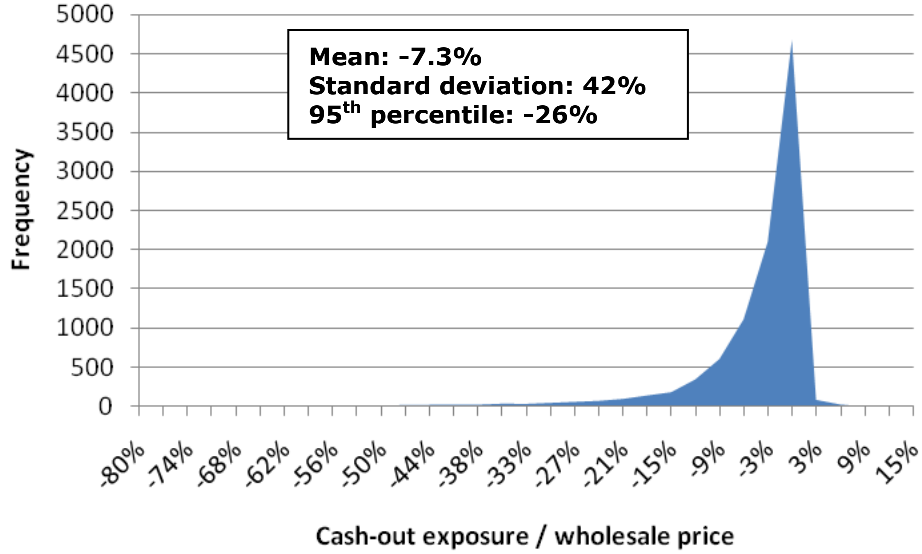
1.12. The mean cash-out exposure estimated by our cash-out model is clearly less than the 17% discount for wind relative to landfill gas projects observed in the NFPA auction for last winter. As noted above, the NFPA wind discount may reflect factors other than balancing risks such as the uncertainty on forward ROC values. Moreover, balancing risks for intermittent generators encompass the spot wholesale market as well as the cash-out regime. Relative to more predictable generation sources, intermittent generation is likely to result in greater exposure to spot market volatility for the party taking balancing responsibility. Our cash-out model only estimates the balancing exposure after gate closure. Finally, the discount to cover

[41] Above-average annual wind output will result in more ROCs being issued which, other things being equal, will lower recycle values and hence ROC prices.
[42] There is some evidence from other electricity markets with elevated levels of wind capacity that power prices can be inversely related to wind output.
[43] The output-weighted average wholesale price for a given generation project may be above or below the baseload price, depending on its output / availability profile.
[44] For an overview of the cash-out simulation model, see Appendix 11 of the Ofgem Impact Assessment for P211 and P212 (December 2007).

imbalance cash-out risk may reflect the distribution of potential exposures as well as the mean expected exposure.

1.13. Figure 3 shows the distribution of estimated cash-out exposures from our cash-out model for an intermittent renewable generator operating directly in the wholesale electricity market. The standard deviation of this asymmetric distribution is considerably larger than the mean, representing 42% of the average wholesale price. The cash-out model results imply that a discount of around 26% would be required to cover the 95% percentile of the potential exposure for an intermittent generator.

Figure 3 Distribution of estimated cash-out exposure



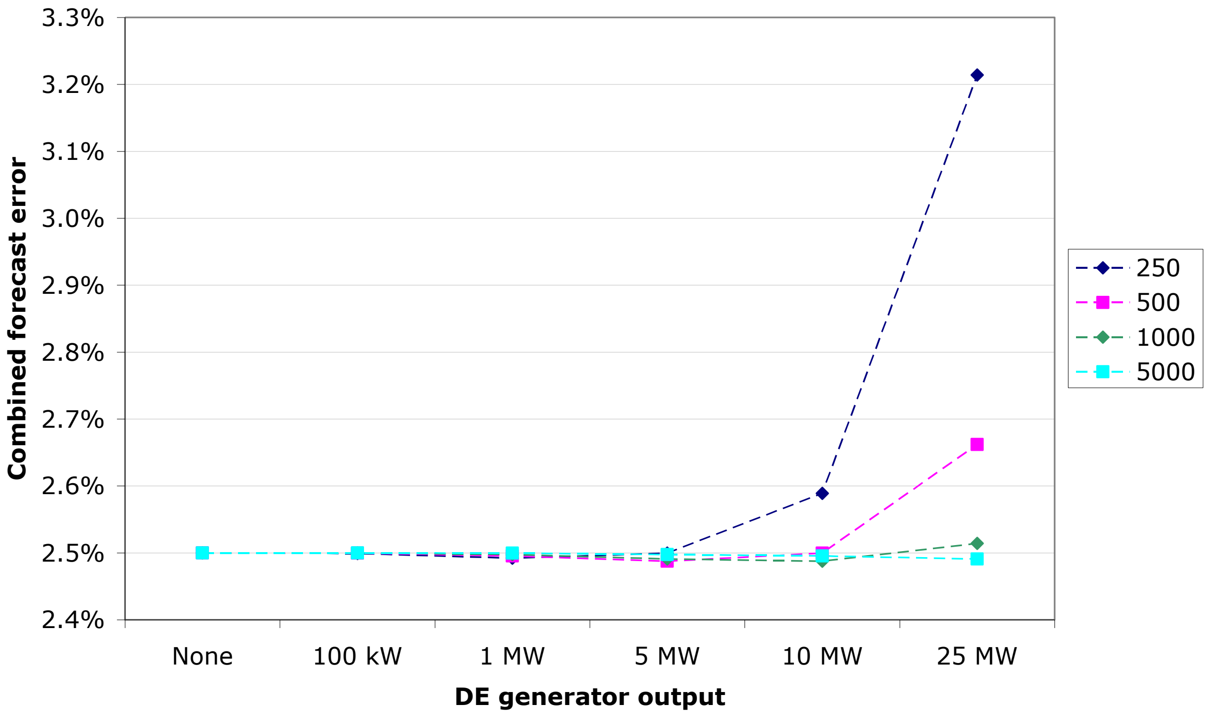
Source: Ofgem analysis

DE responses and consolidation analysis

1.14. In practice, small intermittent generators generally contract out imbalance risk to another party such as a supplier or a consolidator rather than participate directly in the wholesale electricity market. As was noted in the December DE consultation paper, the value of DE output may be influenced by the size of the purchaser's existing portfolio. Some suppliers have indicated that the premium applied for managing imbalance risk on behalf of DE generators is reduced by any aggregation benefit that the generator brings to the portfolio. Others have commented that the diversified portfolios of the larger suppliers are well placed to absorb the output variability of DE generators. E.ON, for example, stated that in its experience "small intermittent generation output is generally lost in the noise of our overall balancing position".

1.15. Figure 4 illustrates the potential aggregation benefits for a DE generator selling an offtake contract to a supplier. We have assumed that the intermittent generator has an output forecast error of 25%, while the demand forecast error of the supplier's customer portfolio is 2.5%. The graph shows the aggregate forecast error of the combined portfolio (assuming, as a first approximation, that the forecasts errors for retail customers and DE generator output are uncorrelated). The results are shown for various combinations of counterparty sizes, ranging from zero to 25 MW for the DE generator and 250 MW to 5000 MW for the supplier's demand portfolio. Elexon settlement data indicates that the average demand of a major supplier was of the order of 5400 MW in 2007.

Figure 4 Portfolio forecast errors for suppliers



Source: Ofgem analysis

1.16. The graph illustrates that DE generation can have a neutral or even positive impact on the supplier's aggregate forecast error, even for an intermittent generator with an output forecast error of 25%. In this example, only the combinations of larger DE schemes (10 MW and above) with smaller supplier portfolios (500 MW and below) exhibit a combined forecast error above the 2.5% demand forecast error excluding the DE position.

1.17. The diversification benefit would diminish as the supplier contracted with additional DE generators (due to the likely correlation of forecast errors). Nevertheless, this simplified analysis does demonstrate the potential benefits of consolidation for DE generators are substantial relative to direct participation in the wholesale market.

1.18. Our analysis of recent NFPA auctions implied that prices for intermittent generators are discounted materially (by 5% to 17%) relative to more predictable generation sources. To the extent this discount is attributable to balancing risks, it would appear that the benefits of consolidation are accruing largely to suppliers rather than DE generators. However, our analysis of the NFPA results also suggested that, in absolute terms, suppliers are not incorporating significant discounts and margins in their offtake pricing. NFPA auction prices for wind projects are close to the underlying market value of wholesale power and renewables benefits, while the bundled prices for more predictable generation sources such as landfill gas appear to incorporate a premium on average. Anecdotal evidence also points to healthy competition for the output of projects associated with renewables benefits.

Potential changes to the cash-out arrangements

1.19. Several modifications to the cash-out regime have been proposed since the New Electricity Trading Arrangements (NETA) went live in March 2001. Ofgem launched a Cash-out Review in February 2007 in response to concerns raised by some participants about the current arrangements. An industry participant subsequently raised an issues group, "Issue 30", under the BSC to discuss certain cash-out features that had been identified as potentially sub-optimal. The "Issue 30" Group presented a summary report of its discussions to the BSC Panel in April 2008. The "Issue 30" report outlines some further areas for consideration, were any participant minded to raise a related modification.

1.20. Here we summarise the implications for DE players of potential short and medium term developments to the cash-out arrangements. In addition to live modifications, we have considered other potential changes drawing upon discussions in the Cash-out Review and the "Issue 30" Group.

System pollution

1.21. Over the past year, three BSC modifications (P211, P212 and P217) have been proposed to address concerns that cash-out prices are being "polluted" by the costs of system balancing actions, such as those taken to manage constraints on the transmission network. The three modification proposals are mutually incompatible with each aiming to tackle the defect of system pollution in a different manner.

1.22. Ofgem published an Impact Assessment for P211 and P212 in December 2007[45]. P217 is still in the Assessment Phase with a Final Modification Report due for completion in July 2008. In February 2008, Ofgem announced that a decision on P211 would be deferred until October 2008 to allow consideration alongside P217. P212 was rejected at this time.

---

[45] This Impact Assessment is available on the Ofgem website: www.ofgem.gov.uk/Markets/WhlMkts/CompandEff/CashoutRev/Documents1/P211%20P212%20IA%20FINAL.pdf

1.23. P211 seeks to amend the cash-out arrangements such that the main imbalance price is calculated on the basis of the least expensive actions that the system operator (SO) could have utilised on an unconstrained system. A key difference from the current arrangements is that cash-out prices would be based upon actions that were theoretically available to the SO at gate closure to meet the net imbalance, rather than upon the actual actions taken. To the extent that system balancing actions are taken out of price order, cash-out prices may be less extreme under the P211 approach.

1.24. P217 seeks to introduce a revised tagging process with explicit identification of balancing actions taken to resolve constraints on the transmission network. Where tagged actions are taken out of price order, their price would be replaced in the cash-out price calculation, therefore preventing "system" actions distorting the resulting prices.

1.25. Ofgem's Impact Assessment for P211 and P212 supported the view that the current process for stripping out the costs of system actions from the cash-out price calculation is imperfect. Over the first nine months of 2007, the analysis suggested that system pollution had led to a 6.0% reduction on average in System Sell Price (SSP) when the system was long and an 11.2% increase in System Buy Price (SBP) when the system was short[46]. The Impact Assessment stated that the cost of system pollution was borne disproportionately by those parties less able to balance due to the nature of their portfolio or scale of operation, such as small suppliers, distributed energy providers and intermittent renewable generators.

1.26. The two pending cash-out modifications (P211 and P217) take contrasting approaches to differentiate system and energy balancing actions. The ex-post unconstrained schedule (EPUS) methodology proposed for P211 estimates the costs of resolving a notional half-hourly imbalance position using submitted bids and offers. Actual balancing actions that were taken to meet a requirement beyond half-hourly energy (e.g. frequency response, reserve creation, intra half-hour balancing and constraint management) may therefore be excluded from cash-out prices under P211. P217 focuses on removing the effect of constraint management actions on the cash out price, although existing mechanisms will be retained to tag out certain other types of balancing actions[47]. Analysis conducted for the P211 Impact Assessment indicated that the treatment of reserve creation[48] appears to have a material impact

[46] These results assumed that reserve creation actions are deemed to be system-related. Under an alternative approach in which reserve creation is deemed to be an energy action, system pollution was estimated to have caused a 4.4% decrease in SSP when the system was long and a 5.1% increase in SBP when the system was short.

[47] For example, "CADL tagging" is applied to bid-offer acceptances of less than 15 minutes duration, thereby mitigating the impact of intra half-hour balancing actions on the cash-out price.

[48] The SO takes balancing actions to create sufficient flexibility in the system to deal with unforeseen demand increases and/or generation unavailability. Such actions may include unit synchronisation or download regulation such that generation resources are positioned to provide reserve services.

upon cash-out prices. Reserve creation is effectively treated as a socialised system balancing cost under P211 but as a targeted energy balancing cost under the current arrangements and P217.

1.27. Using the cash-out simulation tool, we estimate the cost of system pollution to an intermittent DE generator is around 1.4% of the wholesale price under the current cash-out arrangements.

Single and dual cash-out prices

1.28. DE players have historically expressed concerns about the large and unpredictable spread between the dual cash-out prices. Some respondents to December's DE consultation paper echoed these concerns.

1.29. The merits of single and dual cash-out prices were discussed by the Issue 30 group. The Group agreed that a single cash-out price could form a reference price to underpin the development of financial hedging instruments. Conversely, it was argued that the spread between dual cash out prices provided an incentive to contract ahead of gate closure, and reducing this incentive could result in less liquidity in the forward market.

1.30. Parties out of balance in the opposite direction to the system would be cashed out on more favourable terms under a single price regime compared to the present reverse price (which, as we describe below, is intended to be a neutral "indifference" price at which the party could have traded out in the within-day markets). For example, the price paid to generators spilling in periods when the system was short would generally be expected to be higher than under the current dual pricing arrangements. The Issue 30 Group highlighted that any move to a single cash-out regime may trigger the need to review other elements of the balancing and settlement arrangements. This could include considering whether the "pay as bid" basis for settling accepted bids and offers in the Balancing Mechanism remained appropriate given the revised incentives to spill under a single cash-out regime.

1.31. The Issue 30 Group's report to the BSC Panel presented a list of factors that any future proponents of a single cash-out price may need to consider, including the incentives on parties to balance and participate in the Balancing Mechanism. The Group also noted the potential for a hybrid approach with a small fixed spread around a "single" cash-out price.

1.32. A modification proposal (P74) to introduce a single cash-out price was rejected by the Authority in September 2002. This modification was considered in parallel with modification proposal P78, which retained a dual cash-out price regime but introduced the concepts of "NIV tagging" (to mitigate pollution by system balancing actions) and a "neutral" reverse price based on a market index. P74 and P78 were both raised in response to concerns that the cash-out price spread was larger than would be the case if system balancing costs were correctly excluded. Variants of both modifications received majority support from the BSC Panel, but ultimately the Authority decided to approve the implementation of P78 instead of P74. In reaching this decision in 2002, Ofgem agreed with the concerns expressed by some market participants that a single price cash-out mechanism of the type proposed in P74 might weaken the incentives on parties to balance. The subsequent implementation of P78 in 2003 did have the intended effect of reducing the cash-out spread.

1.33. Subsequent cash-out modifications have focused on improving the main imbalance price (for example by addressing system pollution) rather than reviewing the case for a single cash-out price. However, the single and dual price issue has been raised on a number of occasions during the current cash-out review.

1.34. Using the cash-out simulation tool, we estimate the mean cash-out exposure resulting from dual pricing under the current arrangements is around 4.1% of the wholesale price for an intermittent renewable generator. This represents over half of the total exposure estimated for intermittent generators under the current cash-out arrangements, implying that dual pricing has a material impact on DE participants.

The reverse price

1.35. Revisions to the reverse price calculation could influence the cash-out spread without requiring any modifications to the BSC. The Issue 30 Group noted that the reverse price is intended to be reflective of the price attainable at gate closure in the wholesale markets. The Group identified the potential to improve the reverse price calculation by placing greater weight on short duration trades that occur close to gate closure. The Market Index Definition Statement (MIDS) sets out the methodology for deriving an index price from spot market trade data, and includes the following principles for setting product and time weightings:

- Weightings may be set to ensure that the Market Index Price is reflective of the price of trades as close as possible to gate closure; and
- Weightings may be set to minimise the flattening effect on the Market Index Price of including traded products used in the methodology that have one price for a time period longer than one Settlement Period.

1.36. At present, all APX spot products (Half Hour, 2 Hour Block and 4 Hour Block) traded within a 20-hour window before gate closure are equally weighted in the derivation of the Market Index Price (MIP). Trades executed before this 20 hour window and trades of longer duration APX products are excluded. The current product and time weightings imply that trades that take place 21 hours before delivery or that span multiple settlement periods can have the same bearing on the reverse price as Half Hour trades close to gate closure, by which time parties would be expected to have greater certainty as to the net system imbalance and the likely range of the main imbalance price.

1.37. The MIDS is reviewed by the BSC Panel at least annually. Changes to the MIDS weightings could lead to index prices more reflective of the market conditions prevailing at gate closure, although the influence of individual trades on the MIP at times of low market liquidity would also bear consideration. Analysis of alternative weighting factors would be required to model the impact of a revised reverse price calculation on the cash-out spread. However, it would be expected that placing greater weight on shorter duration trades near to gate closure would result in a reverse price that more closely tracked the main imbalance price on average. DE participants are likely to benefit to the extent that a revised reverse price reduce the spread the cash-out prices.

Marginal and average pricing

1.38. The respective merits of average and marginal pricing for determining cash-out prices have been much debated. Since NETA went live in March 2001, a number of modifications have been proposed to change the basis of the price calculation.

1.39. Cash-out prices were originally based upon the volume-weighted average of accepted bids and offers. Modifications P136 and P137 subsequently sought to introduce a fully marginal methodology for the calculation of the main cash-out price. The majority of parties did not support P136 and P137, and the BSC Panel recommended that the proposals should not be implemented. Authority rejected P136 and P137 in March 2004 due to concerns that a very small volume of energy accepted by the SO, or a "system" balancing action, could set the cash-out price. Ofgem was also concerned that a fully marginal cash-out regime could increase the risk that companies could manipulate cash-out prices.

1.40. Modification P194, raised in August 2005, proposed an alternative calculation for a 'chunky' marginal price based on a volume weighted average of a pre-defined maximum volume of the most expensive balancing actions. This eligible volume, known as the Price Average Reference (PAR), was set at 100 MWh by P194. The BSC Panel recommended that P194 should not be implemented, with some members considering that the proposal would adversely impact competition by having a disproportionate adverse financial impact on some categories of participants. However, P194 was approved by the Authority on the grounds that more marginal price signals were required to ensure that parties were taking the necessary actions to balance their positions, particularly at times of system stress. Analysis conducted for Ofgem's P194 Impact Assessment indicated that volume-weighted average cash-out prices were giving rise to dampened signals of the costs to National Grid of balancing the system.

1.41. Before P194 was implemented, Modification P205 was raised and subsequently approved by the Authority, revising the level of PAR to 500 MWh. P205 was supported by the majority of the BSC Panel. Ofgem was persuaded by analysis demonstrating that a PAR value of 500 MWh could lead to pricing signals similar to a PAR value of 100 MWh during periods of system stress, and yet would be less susceptible to distortions associated with "system pollution". P205 was implemented in November 2006 and remains the most recent change to the cash-out arrangements.

1.42. Live modification P217 has re-opened the debate on marginal and average pricing. As currently drafted, two variants of P217 have been proposed with different

PAR levels (500 MWh and 100 MWh). One argument for moving to a smaller PAR is that P217 is intended to address the problem of "system pollution", thereby mitigating the concerns that led to a larger PAR being adopted with the approval of P205. Others have argued that the effectiveness of a modification to tackle system pollution (such as live modifications P211 and P217) should be proven before further changes to PAR are introduced.

1.43. Elexon has re-calculated historic cash-out prices using different PAR values, most recently to support the assessment of P217. This type of retrospective analysis does not consider secondary effects such as behavioural changes but serves to inform debate on proposed modifications to cash-out. Analysis presented to the P217 modification group in March 2008 suggested that changing the PAR volume would, on average, have a more significant impact on the energy imbalance price than the introduction of constraint tagging. Over the analysis period, Elexon's results showed that constraint tagging would increase the average SSP spill price by 1.7% if the PAR value remained at 500 MWh, whereas a PAR value of 100 MWh combined with constraint tagging would reduce average SSP by 3.1%. The results also showed that constraint tagging would reduce the average SBP top-up price by 1.2% with PAR at 500 MWh but increase average SBP by 8.6% with PAR at 100 MWh.

1.44. A more marginal pricing methodology (lower PAR volume) would generally be expected to increase the dual cash-out price spread, other things being equal, if the main imbalance price became more volatile. However, the net impact on the cash-out spread would also depend on the extent to which expectations of a more marginal imbalance price were reflected in the reverse price established in the traded market ahead of gate closure. A wider cash-out price spread would increase the net cash-out exposure for renewable generators.

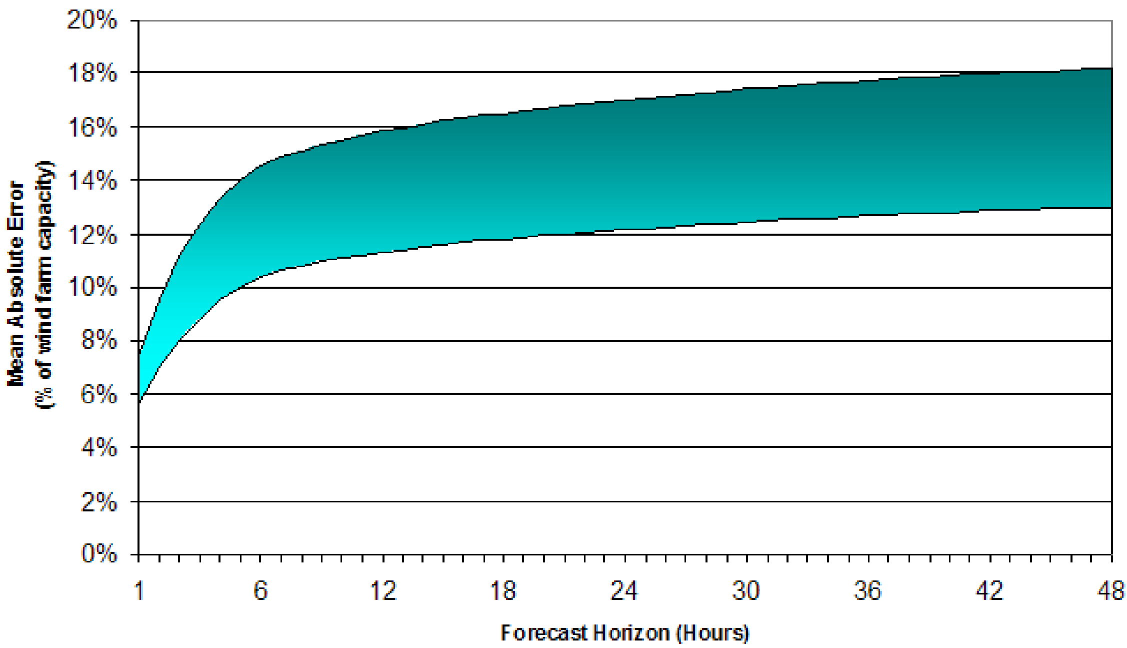
Gate closure

1.45. Gate closure is the last point in time at which parties can notify their contract position to central systems and at which parties can finalise their Physical Notifications to the system operator. The timing of gate closure has changed once since the introduction of NETA, being reduced from 3½ hours to 1 hour ahead of the settlement period with the implementation of Modification P12 in July 2002.

1.46. The Issue 30 Group noted that the market would potentially benefit from a shorter gate closure and/or contract notification deadline. DE generators and other participants would be able to trade closer to real time, presumably with greater certainty as to their output forecasts and plant availability levels, and thereby reduce their own imbalance risk and the overall imbalance on the system.

1.47. The Issue 30 Group did not undertake analysis to quantify the impact of a shorter gate closure on imbalance risk. However, Figure 5 below provides an indication of how the accuracy of wind forecasting improves rapidly close to real time. This chart, provided by Garrad Hassan, illustrates the range of forecast accuracies achieved for individual wind farms around the world over different forecast horizons[49]. Online feedback from the wind site is required to achieve the improved accuracies shown in the very short forecast horizon.

Figure 5 Indicative wind forecasting accuracy



Source: Garrad Hassan

1.48. In addition to reducing the volumetric imbalance exposure for DE participants, a shorter gate closure could reduce the cash-out price spread. The Issue 30 Group noted that increased trading close to real-time would make the reverse cash-out price more cost reflective, given the improved information on plant output and demand forecasts prior to the settlement period. Revising the market index methodology to place greater weight on short term trades (as discussed above) would reinforce the potential impact of a shorter gate closure on the reverse price and cash-out spread.

1.49. The Issue 30 Group's report to the BSC Panel states that any proposal to reduce gate closure would need to consider the potential impact on the Balancing Mechanism and the depth of plant available to the SO. The SO may need to take more balancing actions prior to gate closure if its ability to source flexibility in the Balancing Mechanism is limited. The Group acknowledged that there may a trade-off between the balancing costs incurred by the SO and by market participants with a shorter gate closure.

---

[49] Note that the forecast errors are for single wind farms and are normalised by the wind farm capacity. Lower forecast errors would be anticipated for a portfolio of wind farms.

1.50. An alternative solution to reducing gate closure would be to allow contract notification after gate closure. At present, parties effectively cease trading in advance of gate closure due to the time required for the submission and confirmation of contract notifications with central systems. Spot trading on the APX power exchange, for example, closes 30 minutes before gate closure. The Issue 30 Group suggested that it could be beneficial to extend the contract notification window for trades occurring prior to gate closure.

1.51. Given the potential for the output predictability of intermittent generators to improve considerably as the forecast horizon shortens, DE generators should be key beneficiaries of a proposal to enable trading closer to real time[50].

Balancing market

1.52. The concept of a balancing market has been discussed in the cash-out review and Issue 30 Group as an option for more fundamental reform of the cash-out arrangements in the medium term. Various high-level models have been presented to promote debate of the potential advantages and disadvantages of a market for balancing energy.

1.53. Under the current arrangements, the SO uses the same tools (the Balancing Mechanism and Balancing Services contracts) for both energy and system balancing. As discussed previously, there are concerns that the current mechanisms for deriving an energy imbalance price from the SO's balancing actions are not sufficient to prevent pollution by system costs. One objective of a balancing market would be to separate energy and system actions at the point of execution by creating a separate platform for energy balancing actions. The balancing market would be used to resolve net energy imbalances at the half-hourly level, while the Balancing Mechanism would remain as a tool for balancing the system in real time. Prices emerging from the balancing market would then be used to derive energy imbalance prices.

1.54. A balancing market could therefore provide a "cleaner" energy imbalance price than the current arrangements. As noted above, this would particularly benefit intermittent and smaller renewable generators, given that the impact of system pollution is more keenly felt by those less able to balance due to the nature or scale of their portfolio.

1.55. A balancing market may also enable trading to take place closer to real time, thereby benefiting intermittent generators whose forecasting accuracy improves significantly over shorter time horizons. As discussed above, it may be feasible to obtain similar benefits by shortening Gate Closure in the current arrangements.

---

[50] This assumes the necessary infrastructure is in place to forecast and trade out imbalances close to real time. For example, improved communication of output data from the DE site to the counterparty's trading operation may be required.

1.56. One potential disadvantage of a balancing market could be an increase in the SO's overall balancing costs, at least in the short term. Under the current arrangements, it is often cost effective for the SO to take actions that address a combination of energy and system balancing requirements. Introducing separate platforms could therefore lead to a loss of economies of scope from the SO resolving multiple requirements with one action. The Issue 30 Group considered that the proponents of a balancing market would need to demonstrate that the long term benefits to competition that might accrue from "purer" cash-out prices would outweigh any additional social costs incurred in the Balancing Mechanism.

1.57. The Issue 30 Group concluded that the balancing market concept would require considerable development to provide a workable solution on which further analysis could usefully be undertaken. Although a balancing market may have merits for DE generators, comparable benefits may be attainable in shorter timeframes by pursuing alternative reforms such as the measures to mitigate system pollution and shorten gate closure discussed above.

Tolerance bands

1.58. Tolerance bands have been considered in the past as a potential solution to a perceived defect that small participants face excessively high costs of balancing. Modification proposals P26 (raised in June 2001), P201 (raised May 2006) and P202 (raised June 2006) sought to introduce tolerance bands with "neutral" imbalance prices. P202, for example, proposed that the first 20 MWh of imbalance be cashed out at a tolerance price of the market index (i.e. reverse) price +/- 10% instead of the main imbalance price. All three modifications failed to attract majority support at the BSC Panel and were rejected by the Authority.

1.59. The proponents of P201 and P202 expressed concerns that smaller participants were disadvantaged by a lack of liquidity in the spot market and reduced access to balancing tools compared to larger players. In deciding to reject these proposals, Ofgem stated its concern that the modifications would dilute the commercial incentives to balance. Ofgem agreed with the majority of the BSC Panel that the perceived defect of insufficient liquidity for smaller trades had not been not demonstrated at that time. It was noted that the proposed tolerance bands could reduce liquidity for small volume products, to the detriment of the longer term development of the market and competition.

1.60. In evaluating the P201 and P202 proposals, Ofgem stated the modification process had not demonstrated that existing tools were inadequate to assist small players to balance their positions. It was noted that consolidation/aggregation services were of potential value to smaller players, but the benefits and barriers relating to these services had not been fully explored during the modification process.

1.61. During the assessment process for P201 and P202, Elexon published analysis to illustrate the impact of tolerance bands on participant cash flows. This indicated that the cash flow of small suppliers in particular would benefit from tolerance bands.

However, the results also suggested that large suppliers would account for a significant majority of the total imbalance volume benefiting from the application of the tolerance price. Ofgem conducted analysis which indicated that the proposed P201 tolerance band would have reduced imbalance prices in 89% of periods when the system was short over a two year period. Both sets of analysis implied that tolerance bands would reduce the cash out exposure of smaller participants, but did not quantify the potentially offsetting effect of increased SO costs due to weaker balancing incentives.

1.62. An alternative approach to developing tolerance bands was proposed by Professor Stephen Littlechild in a paper published in September 2006[51]. This paper set out the case for a quantity premium band (or bands) of cash out prices based on the SO's imbalance costs rather than on the market price (as in P201 and P202). Since the SO balancing actions are ranked in price order, the marginal cost of balancing is always greater than (or equal to) the average cost. Recognising that average and marginal pricing each have their advantages and disadvantages, the paper proposes setting prices for different levels of imbalance reflecting the costs of meeting that imbalance requirement. For example, a higher price – a quantity premium – could be charged for imbalances above a certain threshold to reflect the SO's costs of taking balancing costs at the margin. Professor Littlechild argued that such an approach would be analogous to the quantity discounts offered by businesses in situations when marginal cost is below average cost. He considered that banded cash-out prices would provide cost-reflective signals to all participants, regardless of size.

1.63. A banded approach to setting cash-out prices reflective of the SO's balancing costs may warrant further consideration. If there was a general move towards more marginal cash-out pricing (such as introducing a lower PAR volume), quantity bands may mitigate the adverse impact for smaller participants such as intermittent DE generators.

[51] Professor Stephen Littlechild: "Imbalance prices, tolerance bands and quantity premium bands" www.econ.cam.ac.uk/eprg/pubs/misc/littlechildimbalance.pdf

Summary

1.64. Table summarises the likely impact for intermittent DE generators of potential developments to the cash-out arrangements.

Table Summary of potential cash-out developments

Potential change	Likely impact for intermittent DE generators	
	Potential advantages	**Potential disadvantages**
Mitigating system pollution	Reduced cash-out spread More predictable cash-out prices	None identified
Single cash-out price	More favourable price for “reverse” imbalances May facilitate financial hedging instruments	Wider impacts on balancing incentives require further examination
Revised reverse price	Reduced cash-out spread if reverse price more reflective of real time system imbalance	None identified
More marginal price (smaller PAR)	None identified	Increased cash-out spread
Shorter gate closure and/or extended contract notification	More accurate output forecasts available to trade out exposure Reduced cash-out spread if reverse price more reflective of real time system imbalance	None identified
Balancing market	Mitigates system pollution issue Platform for short term trading	Implementation costs and wider impacts require further examination
Tolerance bands	Reduced cash-out exposure	Reduced liquidity for small volume trades

Conclusions

1.65. We have conducted analysis to assess the discount to wholesale electricity prices contained within DE offtake agreements and to estimate the extent that this can be attributed to features of the current cash-out arrangements.

1.66. The evidence from recent NFPA auctions is that the prices for intermittent DE generation sources such as wind are discounted relative to more predictable sources. The size of the discount is comparable to the expected net exposure of an intermittent generator directly participating in the wholesale market.

1.67. In principle, the premium applied for managing imbalance risk on behalf of DE generators should be reduced by any aggregation benefit that the generator brings to the portfolio. The NFPA discount for intermittent generation sources, relative to more predictable sources, suggests that the benefits of consolidation are accruing largely to suppliers rather than DE generators. However, in absolute terms, the bundled prices obtained by renewable generators participating in the NFPA auction are not significantly discounted below the underlying value components (Power, ROCs, LECs, embedded benefits etc). Indeed, the bundled price for more predictable sources such as landfill gas appears to be at a premium to the underlying value, reflecting healthy competition for DE output associated with renewables benefits.

1.68. We have also considered the implications for DE of potential short- and medium-term developments to the cash-out arrangements, taking account of live modifications and potential reforms discussed in Ofgem's cash-out review and the "Issue 30" group. The key generic areas of cash-out reform which would benefit DE include reducing the cash-out spread, mitigating "system pollution", increasing the predictability of cash-out prices, and allowing DE schemes to trade closer to real time.

1.69. Such developments could have a materially beneficial impact on intermittent DE generators, both from the perspective of those directly trading in wholesale markets, but more importantly, in the terms offered to DE schemes by intermediaries via PPA and offtake agreements.

Appendix 5 - List of Submissions to December Consultation

1. Details withheld on request
2. Details withheld on request
3. Peterborough Council
4. RWE Npower
5. Good Energy
6. Centrica
7. Renewable Energy Association
8. Arup
9. W. Alexander Hamilton
10. Inenco
11. Details withheld on request
12. Western Power Distribution
13. M. Hillard
14. Sembcorp
15. Elexon
16. E.ON
17. Fulcrum
18. Welsh Power
19. Greenwich Peninsula Regeneration
20. Details withheld on request
21. energywatch
22. Greenpeace
23. Land Securities
24. National Grid
25. SmartestEnergy
26. Details withheld on request
27. CHPA
28. Lend Lease Retail
29. EDF Energy
30. Details withheld on request
31. CE Electric
32. Micropower
33. LCCA
34. Swanbarton
35. R. Brocklehurst
36. WRAP
37. Scottish Power
38. Home Builders Federation
39. SERA
40. Country Land and Business Association
41. Business Council for Sustainable Energy UK
42. English Partnership

Appendix 6 - The Authority's Powers and Duties

1.1. Ofgem is the Office of Gas and Electricity Markets which supports the Gas and Electricity Markets Authority ("the Authority"), the regulator of the gas and electricity industries in Great Britain. This Appendix summarises the primary powers and duties of the Authority. It is not comprehensive and is not a substitute to reference to the relevant legal instruments (including, but not limited to, those referred to below).

1.2. The Authority's powers and duties are largely provided for in statute, principally the Gas Act 1986, the Electricity Act 1989, the Utilities Act 2000, the Competition Act 1998, the Enterprise Act 2002 and the Energy Act 2004, as well as arising from directly effective European Community legislation. References to the Gas Act and the Electricity Act in this Appendix are to Part 1 of each of those Acts.[52]

1.3. Duties and functions relating to gas are set out in the Gas Act and those relating to electricity are set out in the Electricity Act. This Appendix must be read accordingly[53].

1.4. The Authority's principal objective when carrying out certain of its functions under each of the Gas Act and the Electricity Act is to protect the interests of consumers, present and future, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the shipping, transportation or supply of gas conveyed through pipes, and the generation, transmission, distribution or supply of electricity or the provision or use of electricity interconnectors.

1.5. The Authority must when carrying out those functions have regard to:

- The need to secure that, so far as it is economical to meet them, all reasonable demands in Great Britain for gas conveyed through pipes are met;
- The need to secure that all reasonable demands for electricity are met;
- The need to secure that licence holders are able to finance the activities which are the subject of obligations on them[54]; and
- The interests of individuals who are disabled or chronically sick, of pensionable age, with low incomes, or residing in rural areas.[55]

---

[52] entitled "Gas Supply" and "Electricity Supply" respectively.
[53] However, in exercising a function under the Electricity Act the Authority may have regard to the interests of consumers in relation to gas conveyed through pipes and vice versa in the case of it exercising a function under the Gas Act.
[54] under the Gas Act and the Utilities Act, in the case of Gas Act functions, or the Electricity Act, the Utilities Act and certain parts of the Energy Act in the case of Electricity Act functions.

1.6. Subject to the above, the Authority is required to carry out the functions referred to in the manner which it considers is best calculated to:

- Promote efficiency and economy on the part of those licensed[56] under the relevant Act and the efficient use of gas conveyed through pipes and electricity conveyed by distribution systems or transmission systems;
- Protect the public from dangers arising from the conveyance of gas through pipes or the use of gas conveyed through pipes and from the generation, transmission, distribution or supply of electricity;
- Contribute to the achievement of sustainable development; and
- Secure a diverse and viable long-term energy supply.

1.7. In carrying out the functions referred to, the Authority must also have regard, to:

- The effect on the environment of activities connected with the conveyance of gas through pipes or with the generation, transmission, distribution or supply of electricity;
- The principles under which regulatory activities should be transparent, accountable, proportionate, consistent and targeted only at cases in which action is needed and any other principles that appear to it to represent the best regulatory practice; and
- Certain statutory guidance on social and environmental matters issued by the Secretary of State.

1.8. The Authority has powers under the Competition Act to investigate suspected anti-competitive activity and take action for breaches of the prohibitions in the legislation in respect of the gas and electricity sectors in Great Britain and is a designated National Competition Authority under the EC Modernisation Regulation[57] and therefore part of the European Competition Network. The Authority also has concurrent powers with the Office of Fair Trading in respect of market investigation references to the Competition Commission.

---

[55] The Authority may have regard to other descriptions of consumers.
[56] or persons authorised by exemptions to carry on any activity.
[57] Council Regulation (EC) 1/2003

Appendix 7 - Glossary

B

Balancing Mechanism

A market-based mechanism that enables National Grid to instruct generators and suppliers to vary electricity production or consumption close to or in real-time, in order to maintain safe operation of the system.

BETTA

British Electricity Transmission and Trading Arrangements: The introduction of NETA throughout Britain by combining English/Welsh and Scottish rules on 1 April 2005

BSC

The Balancing and Settlement Code: Industry code covering the rules for electricity balancing and imbalance charges in Great Britain

BSUoS

Balancing Services Use of System Charges: Charges paid by suppliers and generators based on the energy taken from or supplied to the National Grid system in each settlement period. These charges are paid to cover the cost of keeping the system in balance and maintaining the quality and security of supply.

C

Cash Out Arrangements

Arrangements whereby generators and suppliers pay or are paid for imbalances i.e. shortages and surpluses of power relative to their contracted commitments.

CCL

Climate Change Levy: A tax on energy delivered to non-domestic users in the UK, aimed at providing incentives to increase energy efficiency and reduce carbon emissions. Energy generated from renewable sources is not taxed.

CHP

Combined Heat and Power: A technology where electricity is generated at or near the place where it is used, with the heat produced being used for space heating, water heating or industrial steam loads. This potentially leads to much higher efficiency than conventional generation.

D

DCMF

Distribution Charges Methodology Forum: A group which meets every six to twelve weeks to consider and progress policy relating to the DNOs' charging methodologies

DEWG

Distributed Energy Working Group: A working group set up by Ofgem and BERR to discuss the commercial, environmental and regulatory issues arising in the context of small, low carbon generation, and potential solutions to these problems.

Distributed Energy/Distributed Generation

Any generation which is connected directly into the local distribution network, as opposed to the transmissions network, as well as combined heat and power schemes of any scale. The electricity generated by such schemes is typically used in the local system rather than being transported for use across the UK.

DNOs

Distribution Network Owners: Monopoly providers of local, lower voltage electricity networks.

DUoS

Distribution Use of System charges: Charges paid by generators and suppliers for the use of the distribution network

E

ECVAA

Energy Contract Volume Aggregation Agent: Agent that receives ECVNs and MVRNs from ECVNAs and MVRNAs. The ECVAA stores and provides this data to various BSC Agents.

ECVN

Energy Contract Volume Notification: The notification sent for a contract between two parties by the ECVNA

ECVNA

Energy Contract Volume Notification Agent: Agent that sends contract notifications between two trading parties to the Energy Contract Volume Aggregation Agent

Embedded Benefits

Benefits gained by smaller generators by avoiding the charges associated with use of the electricity transmission grid and becoming signatories to the BSC.

ESI

Electricity Supply Industry

EU ETS

European Union Emission Trading Scheme: The EU-wide greenhouse gas emissions trading scheme, under which governments must set emission limits for all large emitters of carbon dioxide in their country. Each installation is then allocated an allowance for the particular phase in question, with the first phase running from 2005 – 2007 and the second from 2008 – 2012. Installations may meet their cap by either reducing emissions below the cap and selling the surplus, or letting their emissions remain higher than the cap and buying allowances from other participants in the EU emissions market.

Exempt Supply Services

Services provided to exempt suppliers by a licensed supplier. These might include meter registration, data processing, and providing top-up and back-up services.

Exemption Order

The Exemption Order 2001 allows schemes of under a certain size to operate without the need to apply for a generation, distribution, and/or supply license. For generation, the limit is 100MW when consumption is for own use, or 50MW where it is for on-site third party use. For distribution, the limit for residential load connected via a private wire is 1MW, and for supply the limit is 1MW for residential customers supplied on-site or via private wires.

L

LCCA

London Climate Change Agency. An agency established by the Mayor of London as the primary delivery vehicle for reducing London's carbon dioxide emissions.

LECs

Levy Exemption Certificates: Evidence of CCL exempt electricity supply generated from qualifying renewable sources. Organisations that pay the CCL can enter into agreements with suppliers to purchase renewable electricity which is exempt from the levy.

LLF

Line Loss Factor: Factor that is entered into settlement as an estimate of the electricity losses in distribution network lines.

M

MPAN

Meter Point Administration Number: A unique number relating to a metering point under the MRA

MRA

Master Registration Agreement: The agreement that sets out terms for the provision of Metering Point Administration Services and procedures in relation to the Change of Supplier to any premise/metering point.

MVRN

Meter Volume Reallocation Notification: A notification of Metered Volume Reallocation in relation to Settlement Period(s) in any Settlement Day(s). Sent by the MVRNA to the ECVAA.

MVRNA

Meter Volume Reallocation Notification Agent: An agent giving MVRNs to the ECVAA on behalf of parties.

N

NETA

New Electricity Trading Arrangements: A system of wholesale electricity trading based on bilateral contracting between suppliers and generators, introduced in England and Wales in March 2001.

P

PES

Public Electricity Supplier: One of the fourteen regional integrated supply/distribution companies that existed prior to liberalisation of the GB electricity market.

PPA

Purchase Power Agreements: are purchasing agreements with third parties.

R

Renewables Obligation (RO)

The government's main support programme for renewable energy generation, under which electricity suppliers must source a proportion of their supply from renewable generation.

ROCs

Renewable Obligation Certificates: Certificates received by eligible renewable generators for each MWh of electricity generated. These can be sold to suppliers in order to fulfil their obligations under the RO.

RPZ

Registered Power Zone: An area of the national grid network specifically designated for the research, development and demonstration of new technologies concerning the power network, specifically to develop solutions to the problems associated with connecting generating capacity at the distribution network level.

T

Top-up/Back-up

Additional electricity provided to an exempt supplier by a licensed supplier to meet any shortfalls in production relative to customer demand and to cover plant outages due to failure or maintenance.

Transmission Access for Distributed Generation (TADG) Working Group

Working Group established by Ofgem in July 2006 to review and develop high level options for change to the existing transmission arrangements with respect to distributed generation.

TNUoS

Transmission Network Use of System Charges: Charges paid by generators and suppliers directly connected to the electricity transmissions grid for use of the grid.

U

UKPX

UK Power Exchange / APX Power UK: The main short-term trading exchange for wholesale electricity in the UK.

V

VPN

Virtual Private Network: An approach which attempts to replicate the exposure to trading arrangements faced by private wire schemes for DE schemes using the licensed distribution network.

Z

ZCH

Zero Carbon Homes: The government's zero-carbon homes policy, set out in the Housing Green Paper, "Building a Greener Future", proposes that all new homes in England should be zero-carbon from 2016.

Appendix 8 - Feedback Questionnaire

1.1. Ofgem considers that consultation is at the heart of good policy development. We are keen to consider any comments or complaints about the manner in which this consultation has been conducted. In any case we would be keen to get your answers to the following questions:

1. Do you have any comments about the overall process, which was adopted for this consultation?
2. Do you have any comments about the overall tone and content of the report?
3. Was the report easy to read and understand, could it have been better written?
4. To what extent did the report's conclusions provide a balanced view?
5. To what extent did the report make reasoned recommendations for improvement?
6. Please add any further comments?

1.2. Please send your comments to:

Andrew MacFaul
Consultation Co-ordinator
Ofgem
9 Millbank
London
SW1P 3GE
andrew.macfaul@ofgem.gov.uk