October 1999

The New Electricity Trading Arrangements

Ofgem/DTI Conclusions Document

The New Electricity Trading Arrangements

Table of Contents

Note:

On 16 June 1999, the former regulatory offices, Ofgas and OFFER, were renamed the Office of Gas and Electricity Markets (Ofgem). References in the text to documents and events before this date use the name of the original regulatory office.

The New Electricity Trading Arrangements

Executive Summary

Introduction

This document summarises the conclusions reached following the consultation on the new electricity trading arrangements in England and Wales. It builds on proposals published for consultation by the Office of Gas and Electricity Markets (Ofgem) in July 1999,[1] taking into account the responses that have been received during the consultation period and the suggestions that were made at the public seminar on the arrangements that was held in early September. The July 1999 proposals were themselves built on the market-based trading arrangements suggested by the then Director General of Electricity Supply (The Director General) in July 1998[2] and accepted by the Government in October 1998 in its White Paper on Energy Policy.[3]

Consultation on the July 1999 proposals extended until mid-September, with 95 written responses being received from interested parties. Six key issues emerged on which conclusions are presented in this document:

- Imbalance cash-out prices;
- The timing of contract notification;
- Separation of production and consumption imbalance volumes;
- Meter splitting and aggregation;
- Governance; and
- CHP and renewables.

On the basis of this document and extensive work by the Programme for the Reform of Electricity Trading Arrangements (RETA), the business rules for the operation of central parts of the new arrangements – the proposed new Balancing Mechanism and Settlement Process

[1] The New Electricity Trading Arrangements, Ofgem, July 1999.
[2] Review of Electricity Trading Arrangements: Proposals, OFFER, July 1998.
[3] Conclusions on the Review of Energy Sources for Power Generation – Government Response to fourth and fifth Reports of the Trade and Industry and Committee.

– are being drawn up. The Government will introduce the necessary legislation as soon as Parliamentary time permits.

Overview of the Trading Arrangements

The trading arrangements are designed to be more efficient and provide greater choice for market participants whilst maintaining the operation of a secure and reliable electricity system. The proposals are based on bilateral trading between generators, suppliers, traders and customers. They include:

- Forwards and futures markets (including short-term power exchanges), which evolve in response to the requirements of participants, that will allow contracts for electricity to be struck over timescales ranging from several years ahead to on-the-day markets;
- A Balancing Mechanism in which NGC, as System Operator, accepts offers of and bids for electricity to enable it to balance the system; and
- A Settlement Process for charging participants whose contracted positions do not match their metered volumes of electricity, for the settlement of accepted Balancing Mechanism offers and bids, and for recovering the System Operator's costs of balancing the system.

It is envisaged that the present Pooling and Settlement Agreement will be replaced by the Balancing and Settlement Code (BSC) incorporating the rules of the Balancing Mechanism and Settlement Process. NGC, as System Operator, will be obliged to maintain the Code. Licensees will be obliged to conform to it. The Code will include flexible and effective governance arrangements to allow for modifications to the rules.

The Balancing Mechanism

The main focus of the work Programme since November 1998 has been on devising rules for the Balancing Mechanism and the associated Settlement Process. The balancing and settlement rules need to ensure efficient balancing of the system by the System Operator, whilst encouraging generators and suppliers to contract ahead for most of their requirements in forward, futures and short-term markets.

The Balancing Mechanism will provide a basis whereby NGC, as System Operator, can accept offers of electricity (generation increases and demand reductions) and bids for electricity (generation reductions and demand increases) at very short notice. The System Operator will accept offers to increase generation (or reduce demand) if it forecasts that the system will be short of electricity, or accept bids to reduce generation (or increase demand) if the system is expected to be over supplied. Accepted offers will be paid for at the prices offered (and accepted bids will pay the prices bid). As well as achieving an overall physical balance on its system, the System Operator will need to accept offers and bids at short notice and at different locations to overcome transmission constraints.

Actions on the Balancing Mechanism will not, however, be the only means by which the System Operator seeks to ensure safe and efficient balancing of the system. The System Operator will also contract in advance (sometimes up to a year or more ahead) for some balancing services such as reserve, frequency control and voltage support. Such contracts, together with its actions in the Balancing Mechanism, will enable it to balance physically the system second by second, and thereby maintain quality and security of supply. The System Operator will be incentivised to balance the system efficiently, taking account of both Balancing Mechanism and balancing services contract costs.

To help assess the likely physical balance of the system, the System Operator will ask participants to notify their expected physical position for each half hour trading period (ie. their anticipated generation output or demand). The final submission of physical notifications will take place as the Balancing Mechanism opens. These notifications will also provide the baseline for bids and offers from generators and the demand-side.

A wide range of participants will be able to make bids and offers to the System Operator through the Balancing Mechanism, including generators, suppliers and customers. They will be required to sign the BSC. However, nobody will be obliged to make bids or offers into the Balancing Mechanism.

Decisions on the Balancing Mechanism

NGC has indicated that it is considering the reduction of Gate Closure (the time before the trading period for which the Balancing Mechanism is open) to 3½ hours with a view to accommodating Ofgem/DTI's concerns regarding gas interruptions. These concerns were raised by a number of respondents. Moreover, experience with the new trading arrangements and the intended introduction of new transmission access rights designed to remove, or at least substantially reduce, the extent to which transmission constraints have to be resolved in the Balancing Mechanism, should enable Gate Closure to be shortened. Accordingly, subject to re-evaluation in the light of experience in operating the new regime, it is intended that Gate Closure should be reduced after six months and that further reductions should be implemented thereafter, as this becomes practicable.

The Settlement Process

The position of all BSC signatories will be assessed to determine whether their metered output or consumption of electricity matches their contracted position. If it does not then they will be 'out of balance'. Generators will be paid for uncontracted generation and charged for contracted volumes not covered by generation. Suppliers will be charged for uncontracted supply and be paid for contracted volumes not matched by consumption. Traders will be charged if they have sold under contract more electricity than they have purchased and will be paid if they have bought more electricity than they have sold.

Generators' metered generation and suppliers' metered demand will be compared with the contractual position they notify as the Balancing Mechanism opens together with any accepted Balancing Mechanism trades. The sum total of contracts negotiated in forward, futures and short term bilateral markets will be added together to arrive at these contract positions. Participants that act both as generators and suppliers will be exposed to separate production and consumption imbalance charges for the two sides of their business.

Decisions on Settlement

To provide for more effective co-ordination between the electricity and gas markets, Ofgem/DTI have decided that contract notification will initially take place three and a half hours before the start of a trading period. As the time between Gate Closure and real time shortens, so will contract notification.

Although it has been argued that production and consumption imbalances should be netted off one another rather than treated separately, Ofgem/DTI remain of the opinion that this would disadvantage participants who were only on one side of the market relative to those on both sides. Consequently, the proposed separate production and consumption imbalance charges will be retained, although this will be reviewed periodically particularly as Gate Closure shortens.

Imbalance Prices

The price paid or charged to 'out of balance' market participants will vary depending on whether they are over or under contracted ie. there will be a dual imbalance price mechanism. In general, generators who are under-contracted (and suppliers who are over-contracted) and 'spill' electricity on to the system, potentially imposing balancing costs on the System Operator, will receive a lower price for their electricity than if they had been fully contracted. Suppliers who remain under-contracted as the Balancing Mechanism opens and thus need to 'top-up' their requirements (and generators who under-generate), thereby potentially imposing balancing costs, will similarly be charged a higher price than if they had entered into contracts for their full requirements. These different charges are reflective of the additional costs incurred by the System Operator in instructing generators, suppliers or customers to vary their output or consumption at short notice to meet unanticipated imbalances via the acceptance of Balancing Mechanism offers and bids.

There is no unambiguously correct way of setting imbalance prices and three possibilities were discussed in the July report. Ofgem's preferred option was that the volume-weighted average of all the bids accepted in the Balancing Mechanism would form the price paid for spill, whilst the volume-weighted average of all the offers accepted in the Balancing Mechanism would be the price paid for top-up. This means that spill gets paid what others are prepared to pay not to generate whilst top-up has to pay what others require to be paid to generate. A disadvantage of this method, during the period in which transmission constraints continue to be resolved in the Balancing Mechanism, is that the costs of constraints will feed through into the energy imbalance prices.

Decisions on Imbalance Prices

Ofgem/DTI remain of the belief that there should be dual cash-out prices calculated from the volume-weighted averages of offers and bids although they acknowledge that there are strong arguments on both sides. Along with many respondents, Ofgem/DTI agree that it would be desirable to remove constraints from energy imbalance prices in the short-term, pending the implementation of a market-based approach to transmission access. The RETA Programme will continue to work closely with NGC to explore ways of flagging constraint-related trades as a simple and effective interim measure to address the issue.

Exposure to Cash-out

All licensed generators and suppliers will be required by their licence to comply with the BSC, which will include the Settlement Process rules. Licence exempt generators – such as the majority of renewables generators and some CHP plant – will not be required to sign the BSC. To the extent that their output is sold to BSC signatories, it will be taken into account by them when notifying their positions. This potentially widens the options available to small-scale generators that choose not to sign the BSC. Instead of selling their output to local suppliers, such generators may be able to sell it to or through other BSC signatories acting as aggregators on a national scale. By assigning the output of a number of generators to one imbalance account, aggregators can substantially reduce their imbalance risks compared to that to which a single site would be exposed. Consequently, aggregation may be seen by some participants as an attractive commercial opportunity.

The arrangements allow for the splitting of metered volumes by proportions notified in advance of the trading period. This will enable generators to sell their output to more than one supplier or customer and customers to purchase electricity from more than one supplier. Splitting of metered volumes maximises the commercial freedom of participants and increases their bargaining power. It also enables BSC signatories to pass on their imbalance risks to other parties, such as aggregators, who would provide such a service on commercial terms.

Decisions on Exposure to Cash-out

Ofgem/DTI remain committed to putting in place flexible arrangements for aggregation and meter splitting so that participants can manage their imbalance exposure in an efficient manner. To that end, we have decided that participants will be able to split metered volumes on the basis of fixed blocks as well as percentages.

Offer/DTI recognise the advantages that might arise from an active role being played by aggregators under the new electricity arrangements. There should be a natural limit on the extent of aggregation since portfolio players and those with stable loads are unlikely to find it worthwhile to utilise the services of a third party aggregator. Nonetheless, regulatory controls will be available to limit the extent of aggregation should this prove necessary.

IT Systems to Support the Balancing Mechanism and Settlement Process

Both the Balancing Mechanism and the Settlement Process will require new IT systems to be built and operated. Expressions of interest for the provision of these services were called for earlier in the year and a short list of 9 interested parties has been compiled. Detailed specification of the Invitations to Tender are now being drawn up on the basis of the business rules that have been developed. Contractors for designing and operating the supporting IT systems are expected to be appointed before Christmas. NGC will be the contracting party and will co-operate with the Programme in the procurement process.

Governance of the Balancing and Settlement Code

The rules for the Balancing Mechanism and Settlement Process, which will be incorporated in the BSC, will need to evolve in the light of experience and to ensure that the arrangements remain efficient and customer focused.

An obligation to establish and maintain the Code will lie with NGC as System Operator. However, a Balancing and Settlement Code Panel will be formed to supervise proposed modifications to the rules, which will comprise experts competent to reflect the views of a wide range of interested parties, including customers. It is expected that the Director General will appoint the Chairman of the Panel. The Director General will also approve all modifications to the Code. This will enable firm regulatory oversight of the rules that govern this central part of the market and ensure that change can be made in a timely manner if experience shows this to be necessary.

Decisions on Governance

Ofgem/DTI have decided that the Panel should be composed of a number of pre-defined industry representative categories, independent experts and consumer representatives.

Such an approach should achieve a streamlined governance process that provides reasonable comfort to BSC signatories in terms of transparency, scrutiny and cost control.

CHP and Renewables

Many sites with CHP plants will benefit overall from the new trading arrangements, because they generally import power and will therefore benefit from the expected lower wholesale electricity prices. Large CHP plants exporting power that can accurately predict their load four hours ahead of time will be able to maintain their position relative to other generators. Plants which have unpredictable loads and impose balancing costs on the System Operator will be more exposed to imbalance charges than other types of plant. Only a small number of the largest renewable and CHP plants will be directly exposed to such charges, and the vast majority will only be indirectly exposed via the contracts that they sign with BSC signatories. The output of many renewables schemes is presently covered by Non-Fossil Fuel Obligation (NFFO) contracts with suppliers, who in turn are compensated to the extent that these contracts are above market prices. Existing NFFO contracts will continue under the new arrangements, although a new market reference price will be required to replace the Pool price. The revised proposals on aggregation and meter splitting should be of substantial benefit in reducing the risks of all such plant.

Ofgem/DTI remain committed to exploring means of supporting the role of CHP and renewables within the new trading arrangements. We are of the view that the decisions that have been taken with regard to shortening Gate Closure and relaxing the rules on the splitting of metered volumes should reduce the imbalance risks to which such generators are exposed. A high priority is attached to the task of finalising a suitable reference price for NFFO contracts and to ensuring that the monopsony power of local suppliers does not result in embedded generators, particularly ex-NFFO renewables schemes, being disadvantaged in the contract price they receive.

Competition and the New Trading Arrangements

A major feature of the new arrangements is that the 'demand side' will be fully incorporated into the new arrangements. Suppliers and customers can offer load reductions into the Balancing Mechanism in direct competition with generators. In addition suppliers, in seeking to manage their 'out of balance' position, are likely to be more responsive to their customers. It will be important for suppliers to understand their customers' demand requirements more fully and to work closely with those customers able to offer load management services.

The new trading arrangements will help promote competition by removing the restrictive characteristics of the Pool that have served to facilitate the exercise of market power. More effective competition in generation also depends on changing the market structure through divestments, which are underway; on continuing to open generation to new entrants; on increased pressure on generators from electricity suppliers resulting from effective competition in electricity supply to domestic and larger customers; and on the actions of the Director General in discharging his Electricity Act and Competition Act duties. However, without effective trading arrangements, the restructuring of the generation and supply markets will be less effective in producing real benefits to customers. For suppliers, the new arrangements provide an opportunity to differentiate themselves from their competitors by keen power purchasing. For generators, the arrangements mean that they must seek more actively buyers for their power and sell it at the prices that purchasers are willing to pay.

Transparency and Liquidity

Some concern has been expressed that vertical integration between supply and generation in the electricity market will render the new trading arrangements less effective than they might otherwise be, by reducing liquidity and transparency in the bilateral markets due to internalised trading in the vertically integrated companies. However the proposed market arrangements are designed to provide the same opportunities for all market participants. The market rules do not benefit vertically integrated players at the expense of participants who are not vertically integrated. A consequence of this is that some rules (such as the settlement rules) will encourage contracting by all participants including by vertically integrated players. This will, in turn, foster liquidity and transparency. Furthermore, the powers in the Competition Act will be available to check market abuse. The Act prohibits anti-competitive agreements and market abuse by companies with a dominant market position.

Transparency will occur, in common with other commodity markets, as price reporting develops as a valuable service to market participants. Transparent prices are also expected to be available from a short-term power exchange and Balancing Mechanism offers, bids, prices and volumes will also be accessible to market participants.

It is expected that over time the new market will develop a rich range of price information. However, it may take some time for this degree of price transparency to develop, although there are already encouraging signs of price reporting appearing in advance of the new market. If required, the Director General could set in place arrangements to publish prices in the newly emerging markets. Such reports might take the form of simple price indicators drawn from information on real contracts. The Regulator could require, using his statutory powers, market participants to give him the necessary information for such indicators to be published. This would be a temporary arrangement which would be implemented only whilst price reporting developed.

Security of Supply

The new trading arrangements will provide strong incentives to ensure that security of supply is maintained in both the short and long term. The trading arrangements will encourage market participants to balance their own positions ahead of real time, since imbalances will expose participants to potentially unfavourable cash-out prices. These incentives for self-balancing will contribute to the achievement of efficient levels of supply security in both the short and long term.

When the system is under stress, prices realised in the Balancing Mechanism will tend to be high, providing incentives not only to provide extra output in these periods but also to have plant regularly available to take advantage of such commercial opportunities as and when they arise. At such times prices in bilateral markets may also be driven up. In the short-term, higher prices will encourage generating plants to be made available to meet demand, and in the long-term they will encourage the building of new plant. The expected emergence of forward prices for electricity several years ahead will provide better signals than currently exist of the longer term balance between demand and capacity, and therefore of the capacity required to maintain security of supply. Respondents to the consultation paper agreed that these mechanisms would provide security of supply, but emphasised that the market must be allowed to work at times of system stress without regulatory intervention to dampen price signals.

NGC will also be able to contract ahead for a number of Balancing Services, including the provision of reserve. This will provide additional security in that the SO will not need to rely solely on the Balancing Mechanism to match supply and demand in all circumstances. NGC purchases of Balancing Services will also contribute to security of supply in the medium and long terms by providing a further source of revenues for flexible plant and by providing rewards for flexibility on the demand side that will, over time, stimulate greater responsiveness of demand to price.

1. Introduction

1.1 The Purpose of this Document

This Ofgem/DTI conclusions document summarises the decisions reached in response to consultation on the New Electricity Trading Arrangements (NETA) in England and Wales. These build on proposals published for consultation by the Office of Gas and Electricity Markets (Ofgem) in July 1999, taking into account the responses that have been received during the consultation period and the suggestions that were made at the public seminar on the arrangements that was held in early September.

The July 1999 proposals were themselves built on the market-based trading arrangements suggested by the then Director General of Electricity Supply (The Director General) in July 1998 and accepted by the Government in October 1998 in its White Paper on Energy Policy.

1.2 The Process So Far

In November 1998 the Director General published a Framework Document[4] confirming that OFFER and the DTI would jointly lead the Programme for Reform of Electricity Trading Arrangements (RETA) based on the July 1998 Proposals. The Framework Document also confirmed that OFFER and the DTI would be assisted by a Programme Director, a Development and Implementation Steering Group (DISG) composed of senior staff representing all interested groups within the industry including customers, an advisory Programme Management Board, and Expert Groups. These groups have met on a regular basis, producing and reviewing numerous papers. Public seminars have been held to discuss progress. Throughout the review process, OFFER and the DTI have been supported by a panel of Special Advisors (Lord David Currie, Sir Peter Walters and Mr Nicholas Durlacher).

[4] Review of Electricity Trading Arrangements: Framework Document, November 1998.

1.3 Overview of the Trading Arrangements

The trading arrangements are designed to be more efficient and provide greater choice for market participants whilst maintaining the operation of a secure and reliable electricity system. The proposals are based on bilateral trading between generators, suppliers, traders and customers. They include:

- forward and futures markets (including short-term power exchanges), which evolve in response to the requirements of participants, that will allow contracts for electricity to be struck over timescales ranging from several years ahead to on-the-day markets;
- a Balancing Mechanism in which the National Grid Company (NGC), as System Operator (SO), accepts offers of and bids for electricity to enable it to balance the system; and
- a Settlement Process for charging participants whose contracted positions do not match their metered volumes of electricity, for the settlement of accepted Balancing Mechanism offers and bids, and for recovering the SO's costs of balancing the system.

It is envisaged that the present Pooling and Settlement Agreement (PSA) will be replaced by the Balancing and Settlement Code (BSC) incorporating the rules of the Balancing Mechanism and Settlement Process. NGC, as SO, will be obliged to maintain the Code. Licensees will be obliged to conform to it. The Code will include flexible and effective governance arrangements to allow for modifications to the rules.

1.4 Responses to the July Consultation Document

The main area of work since November 1998 has been on devising rules for the Balancing Mechanism and the associated Settlement Process and these formed the focus of the July 1999 proposals.

Consultation on the proposals extended until mid-September, with 95 written responses being received from interested parties. The vast majority of the responses indicated a broad level of support for the proposals contained in the July consultation document. Six key issues emerged on which conclusions are presented in this document:

- Imbalance cash-out prices;
- The timing of contract notification;
- Separation of production and consumption imbalance volumes;
- Meter splitting and aggregation;
- Governance; and
- Combined Heat and Power (CHP) and renewables.

1.5 Outline of the Document

Chapter 2 provides an overview of the responses received highlighting the key issues raised and the areas of consensus or disagreement. Chapter 3 details the responses and resulting Ofgem/DTI conclusions relating to the Balancing Mechanism and especially considers the timing of Gate Closure. Chapter 4 provides a similar discussion of cash-out and settlement arrangements, including imbalance cash-out prices, the timing of contract notification, separation of production and consumption accounts and meter splitting (or more technically Balancing Mechanism (BM) Unit splitting) and aggregation. Chapter 5 summarises comments received on the role of and incentives on the SO, which will be taken into account in Ofgem's forthcoming consultation on SO incentives and transmission issues. Chapter 6 outlines responses received in relation to the governance of the new balancing and settlement arrangements, including proposals for the composition of the BSC Panel. It also covers the legal framework particularly the position of aggregators under the new arrangements. Chapter 7 considers comments received from CHP and renewable generators and highlights the relevance of the proposals for meter splitting for these categories of generators. Chapter 8 summarises the responses on competition, covering liquidity and transparency, market power and demand-side participation. Chapter 9 considers other issues, including interactions between the gas and electricity markets and security of supply. Chapter 10 explains the structure of the Programme going forward, including the continuing involvement of industry expertise. Chapter 11 provides a summary of Ofgem/DTI conclusions.

Appendix 1 provides a list of those who submitted representations to the July consultation document. Appendix 2 summarises the views received. Appendix 3 gives a worked example of the mitigating effect of Balancing Mechanism participation on production and consumption imbalances. Appendix 4 details governance arrangements contained in certain gas and electricity industry agreements. Appendix 5 presents a report on the environmental impact of the new trading arrangements. Appendix 6 provides results of Ofgem/DTI's business simulation exercise.

1.6 Next Steps

On the basis of this document the business rules for the operation of central parts of the new arrangements – the proposed new Balancing Mechanism and Settlement Process – are being drawn up.

Invitations to Tender (ITTs) for the design, construction, maintenance and operation of the IT systems required to support the new central systems have also been written on this basis and will be issued to previously short-listed candidates. It is anticipated that contracts will be awarded before Christmas.

Legislation will be introduced to support the new trading arrangements as soon as Parliamentary time allows. The Programme to implement the new trading arrangements will enable them to come into effect in Autumn 2000.

2. Overview of Responses

Responses to the July consultation document came from generators, suppliers, traders, consumer organisations, academics, trade associations, business organisations and others. Most of the 95 responses supported the proposals with only 11 being generally opposed. This chapter discusses the top ten issues raised by respondents of which six cover key issues in relation to the proposals. The six key issues and the additional four issues most commented on are as follows:

Six Key Issues

- Imbalance cash-out prices;
- The timing of contract notification;
- Separation of production and consumption imbalance volumes;
- Meter splitting and aggregation;
- Governance; and
- CHP and renewables.

Four Further Issues

- Credit cover;
- Balancing Services;
- The role of NGC and its incentive scheme; and
- Timetable for implementation.

2.1 Imbalance Cash-Out Prices

Over half the respondents commented on the proposed imbalance cash-out regime. About a third of these (most notably customers and suppliers) supported the principle of dual cash-out prices, whilst just under half (mainly the CHP and renewables community) were opposed to it.

With regards to the specific options for the derivation of imbalance cash-out prices presented in the consultation document, the preferred option of Ofgem/DTI (ie. the volume weighted averages of the accepted offers and bids in the Balancing Mechanism) attracted majority support. However, most qualified this support by saying that they believed that it should not include actions to overcome transmission constraints.

2.2 The Timing of Contract Notification

Around a third of the respondents expressed views on the timing of contract notification. Of these, the majority accepted the proposal for *ex-ante* notification. However, many of those favouring the *ex-ante* approach would prefer the contract notification time to be closer to the trading period rather than at Gate Closure which was proposed as being four hours before the trading period. Similarly, there was a strong desire amongst respondents generally to see the timing of Gate Closure reduced to as close to real time as possible.

2.3 Separation of Production and Consumption Imbalance Volumes

Around a third of respondents commented on this issue. The majority of these were of the view that netting off between production and consumption should be allowed. However, a number of respondents (including suppliers, a generator, a trader and a consumer representative) were of the opinion that the proposed separation was desirable.

2.4 Meter Splitting and Aggregation

Over three-quarters of respondents commented on one or other of these issues. At a high level, strong support existed amongst respondents for the proposals of Ofgem/DTI in this respect. However, there was general agreement that the specific proposals on meter splitting were too restrictive.

2.5 Governance

Nearly half the respondents commented upon the proposed governance arrangements, particularly whether the BSC Panel should be comprised of representatives elected by BSC parties or independents appointed by the Chairman. There was generally more support for the first option, although a number of respondents suggested a hybrid approach involving a combination of industry representation and independent expertise.

2.6 CHP and Renewables

More than a third of respondents commented on the impact of the new trading arrangements on CHP and renewables schemes. There was general agreement among these respondents that the new trading arrangements would increase the risks to which such schemes are exposed, particularly those with unpredictable output such as wind generators. Many respondents suggested that unless there was additional support for CHP and renewables schemes, the government's targets for growth of these types of generation would not be met.

2.7 Credit Cover

Nearly half the respondents commented on the credit cover proposals. There was almost universal agreement that they were too onerous and would act as a barrier to participation and entry into the market.

2.8 Balancing Services

Almost half the respondents commented on the role of balancing services under the new trading arrangements. There was concern that if NGC contracts for large volumes of reserve, this could undermine trading in the forwards markets and the Balancing Mechanism and might depress price signals.

2.9 The Role of NGC and its Incentive Scheme

More than a third of respondents commented on the role of NGC and its incentive scheme. Many suggested that a more detailed description of the SO's role and its incentive scheme were required before it would be possible for them to form a judgement of the proposals. Most emphasised the need for an effective incentive scheme and the majority of respondents were in favour of a single incentive scheme covering all the costs of balancing the system, including actions in the Balancing Mechanism.

2.10 Timetable for Implementation

Around a third of respondents commented on this issue. Several responses expressed concern that some other important issues, such as transmission access and SO incentives, were being addressed separately from NETA. There were specific views on whether the proposed timetable was achievable but most respondents argued that the details of the trading arrangements needed to be settled as soon as possible if there was to be adequate time for the necessary systems, both central systems and those of individual participants, to be developed.

3. Balancing Arrangements

Chapters 5 and 6 of the July report outlined the balancing arrangements open to the SO. In addition to requesting general comments on the arrangements described, views were invited on the following specific issues:

- Appropriate *de minimis* levels for the provision of information to the SO;
- The dynamic data that should be provided by BM Units;
- An appropriate minimum size for Balancing Mechanism offers and bids;
- The need for Quiescent FPNs;
- An appropriate definition for Demand Capacities;
- The scope and volume of balancing services contracts (particularly with regard to response, reserve and options contracts for electricity); and
- The role of NGC's Ancillary Services Business.

In addition to providing views on these issues, respondents commented on:

- The timing of Gate Closure;[5]
- The proposed payment mechanism;
- Whether re-bidding of bids and offers should be allowed in the Balancing Mechanism;
- The need for Deemed Offers and Bids; and
- The need for Deemed Acceptances.

3.1 De Minimis Information Provision to SO

The July Consultation Document

In the July report it was recognised that NGC (as SO) will require information from market participants on their intended level of generation or consumption in order to balance the system efficiently. However, it was also recognised that an appropriate *de minimis* level of information provision may need to be established reflecting the level below which a lack of information will have little effect on system balance and security. In setting *de minimis*

[5] Gate Closure is the time at which the Balancing Mechanism for a trading period opens and participants have to inform the SO of their intended physical positions during the trading period.

levels, it was also noted that account should be taken of the burden that information provision might impose on smaller players.

Respondents' Views

The majority of respondents considered that NGC is best placed, in the first instance, to determine *de minimis* levels since they relate to information that will be of practical value to it as SO. Most respondents felt that NGC's proposed limits should be subject to confirmation by Ofgem. One respondent suggested that there should be different *de minimis* levels for different classes of participants. Those respondents that identified a specific *de minimis* level opted for 100 MW, in line with the current central despatch limit.

NGC suggested a 50 MW limit on the grounds that this would be consistent with current Grid Code obligations. It also suggested that there should be provision for it to make a case to Ofgem for submission of information from smaller sites where necessary.

Respondents also commented on the need for the demand-side to provide Initial and Final Physical Notification (IPNs and FPNs respectively) data. A few respondents stated that it is likely that demand-side information will be ignored by the SO who will continue to use its own demand forecasts. Consequently, they believed that it was unnecessary and uneconomic to require demand-side participants to submit IPNs and FPNs, especially if the participant does not intend to participate in the Balancing Mechanism. One respondent suggested that if NGC were to be incentivised to improve the accuracy of its demand forecasts, it would value good demand-side information and should reward customers for providing it. However, most other respondents stated that it is reasonable that all participants whose output or consumption is significant in determining the need for balancing actions should provide IPN and FPN data.

NGC believes that FPNs should encompass all generation and demand. The new trading arrangements may well change the pattern of consumption, so NGC will no longer be able to rely upon past data for demand forecasting, and will therefore wish to utilise demand information from suppliers.

Ofgem/DTI Conclusions

Ofgem/DTI agree that NGC is best suited to recommend the level of information that it needs to balance the system effectively. The suggested level of 50 MW is consistent with current limits on information provision and Ofgem/DTI accept that this should be the initial *de minimis* level for provision of information by both generators and those on the demand-side. It would also seem appropriate to require NGC to review and consult on the *de minimis* level in the light of experience in order to consider whether the level might be raised or to make a case to Ofgem to enable it to obtain information from smaller sites when necessary.

Ofgem/DTI believe that the provision of demand-side information is essential to enable NGC to forecast correctly demand under the new regime. Thus, FPN data will be required from both sides of the market.

It is envisaged that smaller participants will be able to use agents to submit and receive information on their behalf in order to share the costs of communication with the SO. For generation sites of greater than 50MW, it is proposed that agents may be used in pre-Gate Closure timescales, but not in post-Gate Closure timescales.[6] This represents minimum change from the existing arrangements, as larger participants currently use 'agents' ie. Energy Management Centres (EMCs) to submit the equivalent of Bid and Offer Data to the SO, whereas communications in operational timescales takes place directly with the power station.

However, it is proposed that for generation sites of less than 50MW, communications to and from the SO may take place through an agent. This provides the opportunity for smaller participants to share fixed costs of communications, as well as using the same system in pre- and post-Gate Closure timescales.

[6] Currently the Grid Code stipulates that any instructions within 3 hours of real time must be 'to the Generator at its Generating Plant'. This will be extended to cover *all* post Gate Closure acceptances.

For the demand-side the requirement to submit an FPN would apply to BM Units of greater than 50 MW.

3.2 Dynamic Data Provision and Bid/Offer Format

The July Consultation Document

In the July report a list of proposed dynamic data was included and the concept of Bid and Offer Pairs (the so-called price ladder) as the form in which price and volume information would be presented was described.

Respondents' Views

The majority of respondents suggested that the principle that should be adopted when considering how much dynamic data should be provided by BM Units is that the data should be restricted to the simplest set that will enable the SO to form an accurate picture of how a unit is likely to respond. Some respondents suggested that the list of dynamic data presented in the July report was already too complex. One respondent argued that using a power station rather than a genset approach to defining BM Units would provide participants with greater freedom of action and avoid the need for complex dynamics. A few respondents expressed concern that allowing re-declaration of technical parameters could lead to these parameters being used to exercise commercial advantage and that portfolio participants will effectively be able to re-price bids and offers in the Balancing Mechanism whilst single site players will not.

Of those respondents who commented specifically on the Bid-Offer Pair proposal the majority stated that the bidding structure should be as simple as possible. Responses were evenly divided as to whether the current proposals are unduly restrictive or an acceptable compromise.

NGC wishes to receive information on all the dynamic parameters that could affect the delivery of Balancing Mechanism offers and bids. This, it believes, will minimise the chance of unpredictable behaviour in response to technically challenging instructions. NGC was generally satisfied with the list of dynamic data but suggested adding Station Synchronising Intervals (SSI) and Station De-synchronising Intervals (SDI) and their equivalents on the demand-side. It agrees that dynamic parameters should be treated as 'standing data', as it would be both unhelpful and unnecessarily resource intensive for these items to be continually altering. However, it pointed out that the treatment in section 4.6 of 'A draft specification for the balancing mechanism and imbalance settlement' (BMIS), which accompanied the July report, in which an 'effective time' for changes in dynamics can be given seems to provide scope for multiple sets of dynamic parameters to be in operation at any one time. Therefore, NGC recommends that it be clarified that all changes to dynamic parameters take effect immediately upon notification.

Ofgem/DTI Conclusions

Ofgem/DTI agree that it is necessary to keep both BM Unit parameters and the bidding structure as simple as possible while accepting that NGC requires adequate information to enable it to balance the system. NGC has, for example, repeatedly stated that BM Units need to be at the genset rather the station level. Information requirements on some technical parameters could be covered in the Grid Code. Nonetheless, Ofgem/DTI believe that work should continue over the coming months to simplify the parameters. However, we also recognise that as Gate Closure shortens, the relevance of some of the dynamic parameters will lessen and it may be desirable to reduce the dynamic data requirements.

3.3 Minimum Size for Balancing Mechanism Offers and Bids

The July Consultation Document

The July report suggested 1 MW as a possible minimum size for Balancing Mechanism offers and bids.

Respondents' Views

Of those respondents who commented on this issue, two-thirds agreed that 1 MW was a reasonable lot size in the Balancing Mechanism whilst 5 MW was suggested by a few respondents. Others commented that the minimum lot size should be as small as possible consistent with the bid or offer being useful to the SO. One respondent suggested that the rules should allow agents to aggregate loads from the sub 1 MW range and bid these into the Balancing Mechanism.

NGC stated that a limit of 1 MW seems pragmatic for software design purposes, although currently the smallest entities it deals with are 3 MW, and so suggested that this might be a suitable limit for initial implementation.

Ofgem/DTI Conclusions

Taking into account NGC's views and those of respondents, an initial minimum lot size of 1 MW will be adopted.

3.4 The Need for Quiescent FPNs

The July Consultation Document

Quiescent FPNs were introduced at the request of customers, who raised the issue that they may only be able to control part of their consumption (for example, one process out of several that are taking place at a site). Moreover, the rate at which their overall demand can change may be much greater than the rate at which their controllable consumption can change. By allowing participants to submit two FPNs per BM Unit – one for total generation or consumption and one for uncontrollable generation or consumption (a 'Quiescent FPN'), this problem could be overcome since the dynamic data would only be applied to the difference between the total FPN and the Quiescent FPN.

Respondents' Views

Nearly a quarter of respondents commented on Quiescent FPNs, with a slight majority stating that they are an unnecessary feature of the new trading arrangements. Negative responses, mainly from generators, focused on the complexity of the proposals and argued that incorporating Quiescent FPNs could compromise the delivery of working systems within the proposed timeframe. It was suggested that it would be simpler and more efficient for demand-side participants to install additional meters.

Other respondents supported the underlying reasoning behind the requirement for Quiescent FPNs, but felt that other, less complex ideas, should be developed. One respondent argued that it would be better and more flexible, in the longer term, if demand beneath a Grid Supply Point (GSP) Group could be dis-aggregated into controllable and uncontrollable blocks and re-aggregated into an appropriate number of BM Units, each able to submit separate FPNs and separate dynamics.

However several respondents, mostly customers, supported the need for Quiescent FPNs. One customer asserted that Quiescent FPNs represent the simplest possible option to allow demand to participate in the Balancing Mechanism.

NGC believes that Quiescent FPNs are potentially of value to the extent that they assist demand-side participation.

Ofgem/DTI Conclusions

Ofgem/DTI accept that the proposed definitions of BM Units may be restrictive for demand-side participants and support the idea of allowing suppliers and customers to have more than one BM Unit per GSP Group or site. It is also recognised that it will be impracticable to introduce this change initially due to the limitations of the Stage 2[7] systems and the metering implications of such a change. In the absence of this development, Quiescent FPNs will be retained to encourage demand-side participation.

3.5 Definition of Demand Capacities

The July Consultation Document

The July report recognised the difficulties in finding a suitable definition of demand capacity for a BM Unit and suggested two possibilities. First, using the maximum metered demand over a half-hour recorded for the BM Unit over the previous twelve months up to and including the settlement period or, second, using the maximum metered demand for the BM Unit during the previous winter.

Respondents' Views

Of those who commented on this issue, few supported the first option although it was recognised that this would allow for both weather effects and changes in the customer base of a supplier. Most respondents felt that demand capacities should be set using the maximum level of demand metered during the previous winter. However, several stated

[7] Stage 2 is a set of systems designed to allocate electricity consumption between suppliers.

that it would be more sensible to use the highest recorded level of demand for the BM Unit plus a percentage. One respondent proposed using a defined percentage (eg. 5 or 10%) above peak demand data submitted to NGC's Seven Year Statement. Another argued that it was necessary to allow provision for changes to customer base and other appropriate determinants of demand, on an agreed and auditable basis.

NGC argued for an equivalent approach to that for generation, basing the limit on the physical capacity to supply available through each GSP. However, NGC also stated that the allocation of this capacity between suppliers using each distribution network could only be administered by the Distribution Network Operator.

Ofgem/DTI Conclusions

There is obviously no straightforward way to define demand capacity and some of the options discussed introduce a degree of complexity into the arrangements that is unlikely to be justified. Further consideration of this issue has led Ofgem/DTI to question whether it is, in fact, necessary to define demand capacity. Originally concerns in this area arose over the possibility of customers or suppliers posting FPNs substantially in excess of any likely level of demand. Such behaviour, it was felt, might occur as suppliers or customers attempted to create network constraints from which they might be in a position to benefit through the acceptance by the SO of demand-side offers in the Balancing Mechanism. In practice, such behaviour appears extremely unlikely. First, participants on the demand-side could have no confidence that their offers would be accepted (rather than the offers from other demand-side participants or generators). Second, even if a demand-side offer were accepted, it would lead to an exposure to imbalance cash-out, unless a corresponding reduction in demand were actually made. Third, any demand-side behaviour designed specifically to distort the market arrangements would potentially be in breach of provisions under the new Competition Act 1998.

Ofgem/DTI therefore consider that a definition of demand capacities is not required as part of the new arrangements but, will keep this under review.

3.6 Scope of Balancing Services Contracts

The July Consultation Document

The July report stated that in general, at least initially, the procurement of balancing services contracts by the SO would be similar to the existing arrangements for procurement of Ancillary Services. However, to the fullest extent possible, the procurement of balancing service contracts should take place competitively via transparent processes eg. auctions. It also outlined the debate as to whether NGC should contract for more or less reserve than currently and whether it should be allowed to sign option contracts.

Respondents' Views

Almost half the respondents commented on this issue. Many respondents felt that it was difficult to comment on balancing services contracts in the absence of a clear description of the SO's incentive scheme. However, they generally agreed that providing NGC is properly incentivised, it should be free to determine the scope and volume of balancing services it requires.

However, a majority of those who responded on this issue were opposed to NGC purchasing option contracts as they felt that this could foreclose short-term trading both in the Balancing Mechanism and in any on-the-day power exchanges thus reducing liquidity and undermining price signals. Some respondents also believed that it would undermine the liquidity and efficiency of the electricity market more generally. A number of respondents called for more detail on how options contracts for reserve would work. For example, would they specify a price at which the BM Unit would be made available in the Balancing Mechanism or would reserve be scheduled outside of the Balancing Mechanism?

The majority of respondents wanted to see the boundary between balancing services contracts and the Balancing Mechanism precisely defined. In particular, they were anxious that there should be rules governing the circumstances under which the SO can call on reserve contracts especially when Balancing Mechanism offers or bids could be used for the same purpose. In addition, many argued that the need for reserve contracts would diminish over time as the SO and other parties become comfortable with the depth and flexibility of the Balancing Mechanism. One respondent argued that there should be no reserve contracts so that all the energy required for balancing would be traded through the Balancing Mechanism.

There was general agreement that the procurement and use of balancing services contracts should be conducted in as competitive and transparent a manner as possible. One respondent argued that the decision tool used by the SO to determine what contracts to sign should be transparent to the market, and suggested that the arrangements should be similar to those in gas. Several respondents expressed support for the use of auctions for the procurement of balancing services (yearly and daily auctions were both mentioned) but one respondent argued that auctions would not be an economically efficient way for NGC to secure the services it requires.

NGC stated that its statutory and licence obligations with regard to operating an efficient system and economic purchasing, together with the incentive scheme(s) covering its activities in these areas, would ensure that the appropriate volume of balancing services is purchased competitively. Regarding interactions between balancing services contracts and the Balancing Mechanism, its preferred approach is that any balancing energy covered by contracts is priced via a hedge around the Balancing Mechanism (in a similar way to current contracts). It argued that such an approach would mean that the contract prices would not affect the imbalance price, as they would, for example, if the contracts specified the price at which the Balancing Mechanism bids and offers had to be made.[8] NGC believed that this approach would result in the costs of balancing services contracts and accepted Balancing Mechanism bids and offers being treated in a similar fashion (ie. as identified costs against which NGC would expect to be incentivised), and consequently that there should not be any undesirable interactions between the two balancing options.

NGC stated that it has promoted the continuing trend towards market-based arrangements for procurement of Ancillary Services in an increasingly open, transparent and contestable process. However, it has some concerns regarding implementing new procurement arrangements at the same time as implementing the new electricity trading arrangements.

[8] NGC also suggested that a further possible refinement is that the hedge only applies when the service is delivered, and would not apply when the bid/offer is used for pure energy balancing. This would give the participant an incentive to bid a genuine price into the energy market.

Therefore, NGC suggested that it would be beneficial for the proposed Frequency Response Market to be phased in after the implementation of the new trading arrangements.

Ofgem/DTI Conclusions

Ofgem/DTI believe that procurement of reserve contracts should be carried out competitively in an open and transparent manner. In addition we believe that the prices of reserve contracts should not impact on the Balancing Mechanism and hence on cash-out prices.

It is important to recognise the key role that the SO has to play in balancing the system and the most effective way of ensuring that this occurs at minimum cost is to define an appropriate incentive scheme for the SO. Providing this occurs, Ofgem/DTI agree that the SO should have freedom to contract for the services that it considers it requires, providing the purchase and exercise of such contracts is carried out in an open and transparent manner.[9]

However, recognising the concerns expressed by respondents, Ofgem/DTI believe that further consideration should be given, at least for the first year, to preventing the SO from signing contracts with options/capacity fees. As this does not affect the ITT there is scope for further debate on issues surrounding the relationship between balancing services and Balancing Mechanism.

3.7 The Role of NGC's Ancillary Services Business

The July Consultation Document

The July report stated that it was necessary to consider the role NGC's Ancillary Services Business would have in the procurement of balancing services contracts, and if it were to be involved whether the activity would be regulated (under the transmission licence) and accounted for separately as at present.

[9] The role of the SO is discussed further in Chapter 5 and participants will have an opportunity to raise more detailed points when a consultation document on NGC's incentives under the new trading arrangements and the issue of transmission capacity rights is published in November.

Respondents' Views

Several respondents commented on the role of the Ancillary Services Business, with approximately half of those believing there should no change to existing arrangements, while the other half suggested that there was no need for a separate business to be continued.

NGC considers that the current separation of the Ancillary Services Business from the main Transmission Business is largely for historical reasons and that now that it has incentives on the Transmission Business which include the costs of Ancillary Services contracts, this separation does not appear necessary. However, if it is felt that the separation is valuable, then NGC would have no objection to the current arrangements continuing.

Ofgem/DTI Conclusions

Ofgem/DTI believe that the introduction of appropriate incentives on NGC to balance the system efficiently makes it unnecessary for NGC to maintain the Ancillary Services Business as a separate business. This will have implications for certain of the conditions in NGC's transmission licence, which will be addressed in the course of aligning licence conditions with the new trading arrangements' requirements more generally.

3.8 Timing of Gate Closure

The July Consultation Document

The July report suggested that the initial timing of Gate Closure should be four hours ahead of the start of a half-hour trading period, based on NGC's argument that this time was required to enable them to have the ability to synchronise and run-up sufficient thermal stations to meet their balancing requirements. However, the July report made it clear that the expectation was that, over time, Gate Closure would shorten.

Respondents' Views

A quarter of respondents expressed views on Gate Closure. All of them except NGC and one other participant stated that Gate Closure should be closer to real time. In particular the CHP and renewables community felt that the proposed timing of Gate Closure would unfairly penalise intermittent and unpredictable sources of generation whose output may fluctuate within four hours. Their views are discussed further in Chapter 7.

Respondents variously noted that shortening Gate Closure would provide the SO with more accurate FPNs, make the market more responsive to system stresses, reduce the level of concern about *ex-ante* contract nominations and ensure that prices for imbalances reflected actual market conditions rather than being affected by trades conducted several hours in advance.

In addition, several respondents commented that allowing the Balancing Mechanism to run for up to four and a half-hours for each trading period[10] would present difficulties with regard to gas interruptions for transportation reasons. Although Transco, the gas transmission SO, notifies shippers of interruptions at least five hours in advance, shippers do not have to notify their customers until four hours before the interruption starts. Thus, interruptions could occur after Gate Closure for a particular period, leaving participants without the ability to trade out their contract exposure and potentially frustrating the delivery of any Balancing Mechanism bids or offers that had already been accepted.

NGC continues to assert that Gate Closure at around four 4 hours ahead is necessary given the technical characteristics of thermal plant on the system. However, NGC also stated that a shorter Gate Closure may prove to be feasible if genset notice periods and ramping times are seen to have consistently reduced.

Ofgem/DTI Conclusions

Having considered the views of all respondents, Ofgem/DTI conclude that Gate Closure should be set initially at 3½ hours before the start of a trading period. Reducing Gate Closure by only half an hour compared with the July report will overcome the concerns about interruptible gas contracts whilst recognising NGC's concerns about carrying out its balancing functions. NGC has told us that it is considering the reduction of Gate Closure to 3½ hours with a view to accommodating Ofgem/DTI's concerns regarding gas

[10] The four hours originally proposed for Gate Closure prior to the trading period plus the duration of the trading period itself.

interruptions. Ofgem will also reconsider the issue of transportation interruption timescales in gas.

Experience with the new trading arrangements (and the introduction of new transmission access rights, which would enable capacity constraints to be managed via the capacity regime rather than through the Balancing Mechanism), should enable Gate Closure to be shortened considerably. Accordingly, subject to re-evaluation in the light of experience in operating the new regime, it is intended that Gate Closure should be reduced again after six months and that additional reductions should be implemented thereafter as this becomes practicable.

3.9 Payment Mechanism

The July Consultation Document

The July report supported Balancing Mechanism actions being remunerated on a pay-as-bid basis.

Respondents' Views

Fourteen respondents commented on this aspect of the proposals, with the majority supporting this decision.

Ofgem/DTI Conclusions

Ofgem/DTI continue to believe that a pay-as-bid process will provide the appropriate economic signals and be consistent with the operation of the forwards and futures markets that are expected to emerge.

3.10 Re-bidding of Bid/Offers in the Balancing Mechanism

The July Consultation Document

In the July report, it was proposed that initially, there would be no rebidding ie. Bid-Offer Pairs could not be changed after Gate Closure. This restriction was proposed, at NGC's behest, to simplify NGC's transition from balancing the system under the present arrangements to doing so under the new arrangements. For example, not allowing re-bidding minimises the changes that NGC has to make to its systems and databases in order for the new trading arrangements to be implemented.

Respondents' Views

Fourteen participants expressed views on this issue, and most who commented said that re-bidding should be allowed after Gate Closure. It was felt that while the prices of accepted Bid-Offer Pairs should, of course, be firm, there was no reason why unaccepted Bid-Offer Pairs could not be simply withdrawn or revised and new ones submitted. One respondent asserted that allowing continuous re-bidding in the Balancing Mechanism would eliminate the requirements for submitting matched Bid-Offer Pairs and dynamic data and another felt that not allowing re-bidding would be a frustration of normal market activities. One generator argued that allowing re-bidding would enhance security of supply, while another stated that the restriction on re-bidding and the absence of option fees for bids and offers in the Balancing Mechanism will tend to result in the under-pricing of power at times of system stress. Several participants commented that allowing participants to adjust their Maximum Import and Export Limits effectively amounted to allowing re-bidding. These respondents felt that this form of re-bidding would benefit large portfolio generators, and that it not only created inherent inequalities in the new arrangements, but also increased the cash-out risks for other participants.

Apart from NGC, only one respondent was against allowing re-bidding in the Balancing Mechanism. Others stated that they believed that the restriction was necessary initially, but should be reviewed as the market evolves.

NGC stated that due to the tight timetable for implementation, given the systems requirements, allowing re-bidding would not be possible without jeopardising the implementation date.

Ofgem/DTI Conclusions

Ofgem/DTI agree that, in principle, allowing re-bidding would be desirable. Nonetheless, given NGC's belief that systems requirements cannot be met in time, we believe that the initial restriction on re-bidding is justified to ensure a timely introduction of the new trading arrangements. However we agree with the majority of respondents who consider that the issue should be reviewed in the light of experience. We anticipate that re-bidding will become less of an issue as Gate Closure shortens.

3.11 Deemed Offers and Bids

The July Consultation Document

The July report proposed that, in the unlikely event that all the relevant available offers and bids in the Balancing Mechanism have been exhausted and further actions to balance the system are still required, the SO will be able to make use of Deemed Offers (to curtail demand) and Deemed Bids (to reduce, and if necessary desynchronise, generation). Actions instructed by the SO via the acceptance of a Deemed Offer or Bid would be treated in the same manner as the acceptance of normal offers and bids. Hence, provided the participant reduces its output or demand in line with the instructed action, its overall imbalance position will be unchanged. The intention was that Deemed Offers and Bids would be settled at a price of zero to encourage participants to submit bids and offers covering the full range of their output or demand.

Respondents' Views

The majority of respondents did not feel that Deemed Offers and Bids were necessary. In addition, participants felt that they were arbitrary and the SO should use more market-related solutions. Some respondents expressed concern that setting the price at zero will encourage participants to submit very high-priced standing offers and bids which would create upward pressure on prices and might result in extreme prices being paid to generators or suppliers who are disconnected.

Other respondents accepted the concept of Deemed Offer and Bids for security of supply reasons but considered that there would be severe implementation issues – for example, determining the volume of Deemed Offers and Bids accepted. One respondent asked if NGC will have to issue the relevant warning instruction pursuant to the Grid Code in order to justify the use of Deemed Offers and Bids.

NGC raised a number of issues related to Deemed Offers and Bids proposal:

- The use of a zero price for both Deemed Offers and Bids would provide different incentives on the two sides of the market. A zero price is attractive for generation disconnections (as they effectively pay zero to buy back their lost generation) but unattractive for demand disconnections (since they receive no payment for their lost consumption);
- Instructed rota demand disconnections typically affect several suppliers. This raises the questions of whether multi-supplier bids are allowed and whether there can be different bids covering the same amount of demand. If not, NGC argued that the proposals would seem to lead to one bidding entity per GSP Group; and
- If only a proportion of demand in a GSP Group is affected, then determination of the volume of disconnection may not be straightforward. Lost supply cannot be ascribed to individual suppliers and so it will not be clear who should be assigned the volume of the Deemed Offer.

NGC was also concerned that only allowing Deemed Offers and Bids to be used once all the relevant bids/offers in the Balancing Mechanism are exhausted is overly restrictive and potentially unworkable.

NGC's preferred approach, at least initially, would be to reproduce the current treatment as far as practicable. Thus, suppliers affected by demand disconnections would receive the imbalance price (which will be a better price for them than a deemed price of zero[11]) whilst a Deemed Bid-Offer Acceptance would be assumed for generator output reductions or desynchronisations. The price of this would be set to the maximum of the Balancing Mechanism bid price applicable for the output reduction implemented and 0 £/MWh.[12] If there was no Balancing Mechanism bid, then a deemed bid of 0 £/MWh would apply.

[11] Except in the rare event where the system sell imbalance price is negative.
[12] However, if there were an applicable bid price there would be no necessity for a deemed bid.

Ofgem/DTI Conclusions

Deemed Offers and Bids would only be called upon in the unlikely event that all the relevant available offers and bids in the Balancing Mechanism had been exhausted and further actions to balance the system were still required. Therefore the acceptance of Deemed Offers and Bids would be an exceptional measure open to the SO to ensure that network security was maintained. However, if such a circumstance were to occur, it is necessary to determine a price at which participants would be remunerated. It would not send the correct signals for these bids/offers to receive as high a price as those posted in the Balancing Mechanism, else participants have no incentive to post bids and offers. Ofgem/DTI believe that one method to ensure all the above criteria is met is the introduction of Deemed Offers and Bids. Work is continuing on this issue with the Expert Groups and DISG on this issue.[13]

3.12 Deemed Acceptances

The July Consultation Document

The July report stated that disconnections can occur without a Bid-Offer Acceptance being issued. Transmission failures and automatic responses to short-term operational constraints (such as relay tripping for low frequency events) are examples of such events. For settlement purposes, these could be treated as 'Deemed Acceptances'. They would differ from the case of Deemed Offers and Bids in that they could occur when the participants affected might have submitted offers and bids, it is merely their acceptance that has to be deemed rather than instructed.

Respondents' Views

NGC believes that a sensible approach would be that only instructed actions result in the acceptance of Balancing Mechanism bids/offers (whether deemed or submitted) so that there would be no Deemed Acceptances. If there were to be Deemed Acceptances for automatic action, NGC suggests that the following points would require further consideration:

[13] See the DISG papers 19/06 – 'MEG Default Prices' and 19/07 – 'comments on MEG Paper on Default Prices'.

- Allowing participants to set their own price for these events may not be appropriate. This is an area that needs considerable thought, but it is worth noting that compensation rates for transmission disconnections will either need to be regulated, or relate to payments made for transmission access;
- Measurement of the volume affected is not always straightforward, for similar reasons to those discussed above;
- Transmission failures cannot always be simply defined or separated from other effects; for example, there are interactions between transmission and distribution failures (eg. a distribution fault can cause faults on the transmission system, and *vice versa*).
- It is not clear why it is proposed that the treatment of transmission and distribution failures should be different. It would seem appropriate to have a consistent approach.

Ofgem/DTI Conclusions

Ofgem/DTI acknowledge NGC's concerns regarding Deemed Acceptances. Therefore, it is proposed that further consideration be given to these issues with the industry in the coming months in conjunction with the transmission access review currently being undertaken.

3.13 Balancing Arrangements – Conclusions

As discussed in this chapter, a number of initial decisions on the balancing arrangements have been reached as a result of the consultation process. These can be summarised as follows:

- The *de minimis* level for the provision of IPN and FPN data to the SO will be 50 MW for both the generation and demand-sides of the market. However, NGC will review this level in the light of experience in order to consider whether the level might be raised or to make a case to Ofgem to request information from smaller sites where necessary;
- The proposals on the dynamic data to be provided by participants will be re-examined in order to further simplify them. Information requirements on some technical parameters could be covered in the Grid Code;
- The minimum lot size for Balancing Mechanism offers and bids will be 1 MW;
- Quiescent FPNs will be retained;

- Ofgem/DTI therefore consider that a definition of demand capacities is not required as part of the new arrangements but, will keep this under review;
- NGC will be able to sign balancing services contracts, providing that these are procured and used in an open and transparent manner. However, NGC will be subject to an appropriate incentive scheme. Issues surrounding the relationship between balancing service contracts and the Balancing Mechanism requires further discussion;
- NGC's licence requirement to operate a separate Ancillary Services Business will be removed;
- Initially, Gate Closure will be set at 3½ hours before the start of a trading period. Subject to re-evaluation in the light of experience in operating the new regime, this will be shortened further from 6 months after implementation, with the expectation of further reduction thereafter;
- Balancing Mechanism actions will be remunerated on a pay-as-bid basis;
- The initial implementation of the Balancing Mechanism will not allow re-bidding after Gate Closure, but this will be reviewed in the light of experience;
- The concept of Deemed Offers and Bids will be reviewed subject to further industry discussion; and
- Further consideration will be given to Deemed Acceptances in conjunction with the transmission access review and also needs further industry discussion.

4. Cash-out and Settlement Arrangements

Chapter 5 of the July report contained an overview of the cash-out and settlement arrangements and discussed three options for determining imbalance cash-out prices. Chapter 7 presented the imbalance cash-out and settlement arrangements in more detail, including the proposals for participation and credit cover. Several respondents commented on the general issues raised in these chapters, together with the detailed proposals on which views were invited. The following issues are addressed in this chapter:

- Cash-out prices;
- Contract notification;
- Separation of production and consumption imbalances;
- Aggregation and BM unit splitting;
- Recovery of net costs/revenues from imbalance charges;
- Credit arrangements and financial default;
- Information imbalance;
- Treatment of distribution and transmission network failures; and
- The need for Distribution Network operators to become parties to the BSC.

4.1 Cash-out Prices

The July Consultation Document

The July report proposed a two price cash-out regime for imbalances. Of the three options presented, the preferred method for determining the cash-out prices involved ‘buyers’ of imbalance electricity through the settlement system paying the volume weighted average price of the offers accepted in the Balancing Mechanism (the ‘System Buy Price’) and ‘sellers’ of imbalance electricity receiving the volume weighted average price of accepted Balancing Mechanism bids (the ‘System Sell Price’). The July report also presented some options for setting default cash-out prices in the event that no offers or bids for balancing actions were accepted in a particular direction in a given half-hour.

Respondents' Views

Around half the respondents commented on the proposed cash-out regime for settling imbalances. Several supported the principle of dual cash-out prices, believing that this would incentivise participants to trade in the forward markets. It was accepted by them that imbalance cash-out prices should reflect the full costs of imbalances which have to be resolved by the SO over relatively short timescales. It was also accepted that participants who spill electricity onto the system should receive a lower price than if they had been fully contracted, while participants on whose behalf the SO has to procure the flexible delivery of electricity should pay the full costs.

Others argued for a single cash-out price, stating that the volatility and uncertainty of this price would be sufficient to incentivise forward contracting. One respondent believed that the cash-out rules, in combination with the inability of parties to trade after Gate Closure, would perpetuate a mismatch between gross and net imbalances, and create trading inefficiencies, by incentivising parties to do what they said they were going to do, rather than to match production and demand.

Some respondents thought a wide spread between the two cash-out prices might be desirable and proposed marginal rather than average pricing. One large customer wished to see the sharpest possible incentives for participants to contract with each other ahead of Gate Closure rather than be cashed-out in the settlement process, and preferred a two-part marginal cash-out regime on the basis that this could provide sharper signals to contract. One generator recommended that, during times of system stress, the System Buy Price should be based on the marginal accepted offer rather than the average. Another suggested that, once the treatment of transmission constraints had been removed from the Balancing Mechanism, it would be appropriate to replace weighted-average pricing with marginal pricing.

Other respondents believed that the spread between the two cash-out prices was potentially too wide, leading to greater risks for participants and the possibility of higher contract prices. Some suggested alternative methods for deriving imbalance prices. One generator was concerned that it would be possible for parties to incur penalties by exposure to an unfavourable cash-out price even though at the time their imbalances actually contributed to achieving energy balance. This respondent suggested that ‘benign’ imbalances (ie. imbalances in the opposite direction to the net system imbalance) should attract the market price for energy (akin to the ‘commodity price’ discussed in Chapter 5 of the July report) and that only ‘unhelpful’ imbalances should pay or receive a price reflecting the costs of the flexibility required to balance the system over short timescales.

Many respondents were concerned that balancing actions taken to relieve transmission constraints would feed through to cash-out prices in the absence of a more enduring transmission access solution. One generator, for example, commented that the costs of actions to relieve transmission constraints and to match output and demand within the half-hour trading period (such as those related to the provision of frequency response) are not part of the energy market and should therefore be charged initially to NGC. Of those who expressed a preference for one of the three cash-out price options set out in the July report, many supported the position of Ofgem/DTI on the volume-weighted average of the accepted Balancing Mechanism actions but wished to see steps taken to exclude from the calculation bids and offers taken for constraint purposes.

NGC was concerned that the inclusion of transport effects in the calculation would result in energy imbalance prices not being reflective of the costs of energy balancing, and that this would be inconsistent with the principle of targeting costs on those who give rise to them. It also believed that imbalance prices derived in this way may not be very transparent and that there is likely to be a large spread between the two prices. NGC pointed out that these problems would not be entirely resolved by a reformed transmission access regime, as transmission constraints are only one of the transport effects. It stated that the bulk of current Transport Uplift costs relate to effects other than transmission constraints (e.g. instructing plant to part-load for frequency response), and so would remain in the imbalance price even if transmission constraints were removed.

NGC’s preferred approach was based on an *ex-post* unconstrained schedule (EPUS) or simple stack, in which the cheapest bids or offers required to meet the net imbalance volume of imbalances are identified. It suggested one option would be to use only accepted bids in the simple stack to address the concern raised in the July report that price signals would be dampened by the assumption of perfect foresight. NGC’s response also described a number of ways of defining two imbalance prices from a simple stack, including the second option presented in the July report (namely adding +/- 10% to the average price of bids or offers). However, NGC believed that a method using a marginal price for ‘unhelpful’ imbalances, and an average or Power Exchange price for ‘benign’ imbalances would be less arbitrary and give sharper signals at times of large imbalances.

Others respondents recognised that constraints would only be an issue in the short term and accepted the July report’s proposal on this basis. One generator stressed that it was important that no interim fix (eg. an ‘EPUS’ schedule) is adopted to remove the costs of transmission constraints which has the effect of removing energy costs as well, since this would significantly dampen the true costs of energy balancing. This generator supported Ofgem/DTI’s preferred cash-out option on the grounds that a price reflecting actual Balancing Mechanism trades provides the most accurate approximation to the true costs of system balance, thereby incentivising market participants to enter into contracts. The respondent also believed that a simple tagging of constraint trades to exclude them from the calculation of energy imbalance prices remained a simple and viable interim option.

This view was supported by another generator, who stated that tagging certain transactions as transmission and response related and excluding them from the cash-out price would provide the best approximation of cash-out prices to the real costs of energy balancing. This respondent believed that the preferred solution in the July report was an acceptable stopgap as transmission costs will only carry limited weight under the averaging proposal and that revised transmission access arrangements are, in any case, going to alleviate the problem within a few months of implementation. One supplier suggested that if, pending capacity reform, the distortive effect of including constraint costs in cash-out prices is likely to be significant, some further thought should be given as to whether, applying an element of judgement and pragmatism, a rough separation is achievable.

As to setting default cash-out prices in the event that no offers or bids for balancing actions were accepted in a particular direction in a given half-hour, there was some support for the option of using the average of the relevant prices over the previous 7 days (on the basis that this referred to the equivalent half-hours in the last 7 days rather than all half-hours).

Ofgem/DTI Conclusions

The cash-out option proposed in the July report will be retained on the grounds that it is simple and transparent in comparison to the alternatives suggested. The spread between the two prices may be lower than some respondents suggested as participants compete to offer flexible power in the Balancing Mechanism, particularly if the demand-side plays an increasingly active role. The business simulation modelling commissioned by Ofgem/DTI indicated with a dual imbalance price individual participants' reduced their imbalances more than with a single imbalance price. It was also observed that SMP approaches to cash-out produced statistically significant higher prices (see Appendix 6).

Ofgem/DTI agree that it would be desirable to remove transmission constraints and other transmission related costs from energy imbalance prices in the short-term, pending the implementation of a new approach to transmission issues. Ofgem/DTI will continue to work closely with NGC to explore ways of flagging constraint-related trades as a simple and effective interim measure.

4.2 Contract Notification

The July Consultation Document

The July report proposed that contract volumes should be notified to settlement on an *ex-ante* basis, that is, before the half-hour trading period in question, rather than *ex-post*. It was envisaged that contracts would be reported by Gate Closure, although it was recognised that, in practice, it may be necessary to allow sufficient time (say, half an hour) for the preparation and transfer of contract data.

Respondents' Views

Over half the respondents expressed views on the timing of contract notification. Among those who stated a preference, a majority supported Ofgem/DTI's proposal for *ex-ante* rather than *ex-post* notification.

One supplier described *ex-post* contract notification as "anathema to market fundamentals". However, this respondent also pointed out the potential difficulties for suppliers of *ex-ante* notification given the uncertainty in their customers' consumption. It noted that the proposal to set the information imbalance charge to zero would help mitigate this exposure. One respondent favoured an *ex-ante* regime because it would promote prompt trading which in turn would lead to better price discovery in the short-term markets. This respondent believed that an *ex-post* regime allows generators to manage the volume risk and pass the price risk to suppliers whereas an *ex-ante* regime distributes the volumes and price risk equally on both sides. It supported the final deadline for submission of contract data being at Gate Closure, with a participant having to take on the risk of trading close to this time.

Among those supporting *ex-post* notification, one argued that this would give participants more freedom in managing their imbalances and hence reduce the cost of managing their risks. This respondent believed that *ex post* notification would be simpler to implement and that its flexibility would make the realignment of present contracts much more straightforward. It urged Ofgem/DTI to consider, at the very least, real-time notification of contractual volumes rather than notification at Gate Closure. Another respondent claimed that a dual price cash-out regime which prevented parties from trading their final imbalances with each other would be inefficient, since the gross imbalances of market participants will always exceed the net imbalance on the system. It believed that there was no reason why parties who are out of balance in opposite directions after real time should not be able to trade out their positions. If, in anticipation of trading *ex-post*, players change their physical position after Gate Closure but before real time, the respondent suggested that an appropriate information imbalance charge should be applied, reflecting the costs to the system of deviating from the FPN.

Although more respondents favoured *ex-ante* notification than *ex-post*, many of those favouring the *ex-ante* approach wanted the contract notification time to be closer to the trading period itself rather than at Gate Closure (ie. less than four hours before the trading period).

Some respondents pointed out that a Gate Closure and contract notification time of 4 hours before the trading period could create difficulties for gas-fired generators and industrial customers on interruptible gas contracts. Such contracts typically have 4 hours notice of interruption, potentially leading to an imbalance exposure after Gate Closure. Notification closer to real time also found favour with some renewable generators - for example, it was noted that wind farms will benefit greatly from real-time contract disclosure as they will be able to estimate production far more accurately than at 4 hours out.

An independent generator claimed that contract disclosure at Gate Closure would increase the market power of portfolio generators relative to single site operators, since portfolio players may attempt to self-balance any errors after Gate Closure within their station portfolio. Moving contract disclosure to real time would, it believed, allow single site generators to trade out their errors and so compete more effectively.

Ofgem/DTI Conclusions

In the light of the strong representation of respondents Ofgem/DTI propose that, initially, contract notification will be three and a half hours before the trading period. As discussed in Chapter 3, it is intended (subject to further discussions with NGC), that Gate Closure will also be at this time. This should ease the concerns of many respondents, including customers and generators on interruptible gas contracts (see Chapter 9 for further discussion of the interactions with gas).

Following the implementation of the new trading arrangements, the timing of contract notification will be kept under review in the light of market developments. It is envisaged that the contract notification time will track the anticipated shortening of the Gate Closure period. If the timing of Gate Closure is not shortened as anticipated, then the synchronisation of contract notification and gate closure should be reviewed. Notification after Gate Closure would allow participants to continue trading to match more closely their expected physical positions. However, there is a risk that the SO's task would become more difficult if such trading led participants to change their physical positions after Gate Closure. It may therefore be necessary to reconsider the introduction of an information imbalance charge if such circumstances apply.

4.3 Separation of Production and Consumption Imbalances

The July Consultation Document

The July report proposed that imbalances relating to production (export) and consumption (import) meters would be calculated separately. Participants with both production and consumption meters would need to specify whether each notified contract was to be set off against either the aggregated production or consumption position.

Respondents' Views

Around a third of respondents commented on whether imbalances for production and consumption should be settled separately. Most of those who commented on this issue claimed it would be more efficient if production and consumption imbalances could be netted off against one another. Some large customers believed that such a facility might encourage generators to offer more innovative contract structures. One customer group strongly supported aggregation to improve efficiency and minimise costs and was concerned that without it there would be no incentive for generators to work closely with customers and suppliers to balance across the portfolio. Another respondent regarded aggregation across production and consumption as being essential to ensure efficient risk management for smaller participants on one side of the market.

Some respondents (including suppliers, generators and a consumer representative) supported the separation of production and consumption imbalances, stating that it should help to mitigate the adverse impacts of vertical integration within the industry. One generator said the proposed separation, taken together with dual cash-out prices and *ex-ante* contract notification, would stimulate competition in all market sectors and make it more difficult for vertically integrated parties to exclude competitors from particular sectors of the market. A supplier said that the separation was a crucial design feature and a vital tool to ensure compliance with licence restrictions.

Others expressed a preference for the market power of vertically integrated players to be tackled by regulatory measures rather than in the design of the trading arrangements. One respondent suggested that Ofgem should require only those companies deemed dominant to balance production and consumption accounts separately. Without the ability to combine production and consumption accounts, it feared third-party aggregators would not emerge to provide much needed competition to larger vertically integrated portfolio players.

Ofgem/DTI Conclusions

Ofgem/DTI recognise the concerns that some respondents have in this area. However, we continue to believe that there are several reasons for retaining the proposed separation of production and consumption imbalances when the new trading arrangements are initially implemented.

First, information provided to the System Operator at Gate Closure will be inaccurate if generators and customers continually adjust their positions in an attempt to self-balance with one another, without instruction by or the knowledge of the SO. This will make the SO's task of balancing the system more difficult and potentially more expensive. Second, as respondents have pointed out, the measure should ease concerns over providing vertically integrated players with undue advantages. Third, allowing production and consumption to be netted off could encourage vertical integration. The encouragement to vertical integration (including by contracts) would be general and might lead to consolidation of the market at its lower end, with control passing to a small number of 'lead parties'. Whilst the effects of this on competition overall are unclear, it would represent a structural distortion of the market and would create difficulties for smaller generators and suppliers who wanted to operate independently.

The proposal to calculate imbalances separately should not unduly restrict innovation in contract form since players with flexible loads will be able to mitigate their contractual exposure by placing appropriate offers and bids in the Balancing Mechanism. In addition, as Gate Closure is anticipated to shorten over time, more opportunities will become available for generators, suppliers and customers to balance with each other without relying upon the energy balancing role of the SO. Nevertheless, we are mindful that participants' commercial freedom should not be unduly restricted without good justification. We therefore expect to review the position in the light of experience.

4.4 Aggregation and BM Unit Splitting

The July Consultation Document

The July report discussed the concept of participants acting as energy aggregators on a national scale, mitigating the imbalance risks of single site operators by assigning the output of a number of generators to one imbalance account. The proposed arrangements also allowed for the splitting of metered volumes by proportions notified in advance of the trading period. BM Unit splitting would enable BSC parties to pass on their imbalance risks to other parties, such as aggregators, who would provide such a service on commercial terms. It should be noted that embedded generators, for example, whose meters fall within the Stage 2 system (and who will not in themselves comprise BM Units) will still be able to take advantage of existing functionality to allocate their output between two suppliers. The July report also proposed that facilities would be provided to allow consumption through a consumer's meter to be allocated to more than one supplier.

Respondents' Views

Nearly half of the respondents commented on the role of aggregators in the new arrangements. The majority felt that aggregators could play a useful role by helping to mitigate the imbalance risks of smaller players and those with unpredictable loads (such as some CHP and renewable generators). One generator expressed the view that an aggregator would need to be licensed in order to participate in the Balancing Mechanism and imbalance settlement process on behalf of parties with physical assets.

Many believed that the benefits of aggregation should not be restricted to certain classes of participants. For example, one respondent stated that it would be unacceptable if aggregation was allowed only for licence exempt companies. Another respondent proposed a cap on aggregation set at the level of the largest incumbent's output, to allay fears that aggregation could occur to an extreme level, eg. between two large portfolio generators.

The allocation of consumption through a meter to more than one supplier is a different form of splitting and would be provided to meet a customer requirement to be supplied by more than one supplier. A number of respondents supported the provision of this facility.

Many welcomed the idea of BM Unit splitting as a means of encouraging greater freedom in contracting and of facilitating the transfer of imbalance risk to parties better able to manage it. Several respondents requested more flexibility in the way BM Units could be split, the July report having proposed simple rules based upon fixed percentages. One respondent stated that the proposals for splitting BM Units on an *ex-ante* percentage-only basis were unnecessarily restrictive and at odds with the objective of creating more flexible trading arrangements. Another advocated complete freedom for participants to allocate settlement meter reads at individual locations.

A few respondents believed that BM Unit splitting was an unnecessary complication, particularly when the new trading arrangements are first implemented. A generator suggested that suppliers could facilitate multiple supply through a single meter through contractual means or that customers could modify their metering arrangements to accommodate multiple suppliers at the same site.

One supplier feared that allowing meter sharing for the premises of all customers would create significant complexities which could delay the implementation of the new trading arrangements. Another supplier suggested that meter splitting functionality could be initially restricted to those sites with half-hourly metering systems, with similar arrangements being adopted to those in the gas industry in relation to Shared Supply Points.

Ofgem/DTI Conclusions

Ofgem/DTI remain committed to putting in place flexible arrangements to facilitate aggregation and BM Unit splitting so that participants are able to manage their imbalance exposure in an efficient manner.

The consultation exercise and on-going discussions with participants have suggested that, particularly for smaller players, their commercial flexibility and negotiating position would be enhanced by building in the ability to split BM Units into fixed blocks as well as percentages. It is therefore proposed that BM Units can be shared by volume as well as by percentage.

Ofgem/DTI recognise the advantages that might arise from an active role being played by aggregators under the new trading arrangements. There should be a natural limit on the extent of aggregation since portfolio players and those with stable loads are unlikely to find it worthwhile to utilise the services of a third party aggregator. The provision of a facility to aggregate within the trading arrangements does not, of course, relieve participants of their obligations under the Electricity Act and general competition legislation. Participants will, for example, be subject to prohibitions on the abuse of dominant position and anti-competitive behaviour under the Competition Act 1998.

The BSC will allow for aggregation in various ways. As far as generators are concerned:

(1) A licence exempt generator will be able to appoint a BSC party to take responsibility in the BSC for his generation plant. In other words, the licence exempt generator will not be required to be a party to the BSC (or rather, the framework agreement), but can still have its generating plant counted as a BM Unit, for the account of a person who is a BSC party. It will not be necessary for the BSC party to be licensed for this purpose. The terms of such an arrangement will be a matter for the parties concerned, and will not be prescribed by the BSC. The BSC will require the BSC party to evidence that he has been authorised (by the licence exempt generator) to register the BM Unit.

A single BSC party may make such arrangements with any number of licence-exempt generators, allowing aggregation of 'exempt' generation without limit.

It will also be open to a licence exempt generator who is not a party to the BSC (or a party to the BSC in respect of 'exempt' generation) to assign his output to one or two suppliers in the same GSP group, in effect as negative demand (ie. what is currently 'non-pooled generation').

A licence exempt generator will alternatively have the option of becoming a BSC party.

(2) Although licensed generators must be parties to the BSC, aggregation for imbalance settlement purposes will be possible using the BM Unit splitting mechanism described in the July report. In other words, the output of a particular BM Unit can be allocated to the account of any BSC party (whether or not licensed as a generator) by appropriate notification of splitting. However the licensee must remain the lead party in relation to the BM Unit (and will retain the obligation to submit FPNs); and only the licensee may participate in the Balancing Mechanism in relation to that unit.

As far as suppliers are concerned:

(1) All licensed suppliers will be required to be parties to the BSC. On current principles, there would be no demand met by a licence exempt supplier which had not first been allocated (for BSC imbalance purposes) to the account of a licensed supplier party to the BSC. The exact treatment of licence exempt suppliers may require further consideration in the context of any exemption regime for distribution following the supply/distribution split.

(2) It will not therefore be possible for a supplier to appoint someone else to 'become a party to the BSC on his behalf'. However a supplier who has become a party to the BSC will be able to delegate the administration of his BSC responsibilities to an agent. This would be under normal principles of agency, rather than involving some special category of 'Agent' or agency provisions explicitly recognised by the BSC. The terms of the agency and functions of the agent would be entirely a matter for the parties involved. In principle the agent would not need to be a BSC party, although the BSC might impose some requirements in respect of appointment of agents, for example in terms of use of BSC communication networks/systems. The supplier would remain liable as principal for its BSC obligations (but, depending on the terms of the agency, the supplier might only be concerned with this liability in a case where the agent had failed to perform its duties).

(3) As with generation, the BSC will facilitate aggregation on the demand side for imbalance purposes via the BM Unit splitting mechanism. A supplier will be able to allocate demand at a particular BM Unit to another BSC party (whether or not licensed as a supplier) for imbalance calculation purposes, by submitting appropriate notifications. Again, however the supplier will remain the lead party, with the responsibility for submitting FPNs, and only the supplier will have the ability to submit Balancing Mechanism bids/offers for the BM Unit.

(4) Allocating customers' meters between different suppliers should be provided for. This is likely to require significant change within the Stage 2 systems. Its implementation will therefore require an impact assessment to determine exactly how and in what timescale this could be delivered.

4.5 Recovery of Net Costs/Revenues from Imbalance Charges

The July Consultation Document

As a consequence of having two cash-out prices, each applied to different volumes, a net surplus will generally be associated with the revenues and payments from imbalance charges. The July report proposed that they could either be passed through to the SO to modify the costs that it incurs (or revenues that it earns) or that they could be returned to (or recovered from) all BSC parties via some form of shared charge.

Respondents' Views

A large majority of respondents argued that imbalance surplus/deficits arising should be shared pro-rata between the market participants, with some suggesting that they should be shared according to participants metered generation/demand or market share. A further suggestion was that any surplus amounts are distributed to those who have helped secure the system, with deficits allocated to those who have not.

With regard to the revenues (or costs) being passed through to the SO it was generally felt that this did not recognise either the SO's ability to influence directly cash-out prices or the perverse incentives this would place on the SO as a result of benefiting from large gross imbalances. However it was also recognised that it may be appropriate to include some of the net costs/revenues within the SO incentive scheme. One respondent argued that to the extent that those who incur imbalances generally increased the costs of operating the total system it would seem appropriate to set off the costs and income of Balancing Mechanism trades against the imbalance cash-out charges. Any surplus or under-recovery over an extended period could then be used either to offset or increase the cost of transmission losses or the administration costs for the next period. One respondent suggested constructing an arrangement that left the Balancing Mechanism financially neutral, leaving the SO with simple incentives to minimise the operational cost of the Balancing Mechanism.

Ofgem/DTI Conclusions

Ofgem/DTI share the view of many respondents that any surplus (or deficit) arising from imbalance cash-out should be returned to BSC parties on the basis of their metered volumes. There is also the question of how the costs or revenues that the SO incurs in accepting Balancing Mechanism actions should be recovered. Since the prices of the bids and offers accepted by the SO will set the imbalance prices paid by participants, Ofgem/DTI consider that charging methodology for these costs (or revenues) should also be on the basis of the metered volumes of BSC parties. However, it is intended that the costs/revenues of Balancing Mechanism actions will fall within the SO's incentive scheme. The impact of the incentive scheme on the SO's recoverable costs and revenues will need to be taken into account before the costs (revenues) are recovered from (paid to) BSC parties.

4.6 Credit Arrangements & Financial Default

The July Consultation Document

The July report invited views on the most appropriate approach to credit and security cover, and the way in which the potential problem of default should be dealt with under the new arrangements. The draft BMIS specification set out some initial proposals for determining the level of credit required from each party based upon their potential imbalance exposure.

Respondents' Views

Nearly half the respondents commented on the issue of credit cover. The proposed credit requirements set out in the draft BMIS Specification were almost universally regarded by respondents as being too onerous. It was emphasised that the requirements for credit cover should not be made so onerous that they raised barriers to entry or added significantly to the cost of the entire value chain for electricity.

One respondent agreed that credit requirements are needed to cover potential imbalance risks, but stated that this was essentially a participant risk and that participants do not wish to see an unduly onerous level of safety margin that will only lead to substantial additional cost. It believed that credit cover should be at a prudent level based on a rolling position net of contract since all contractual credit exposure will already be covered bilaterally.

One independent generator suggested that requiring all parties to provide individual credit cover was a less than efficient solution and that some form of bond administered by the BSC Company (BSCCo) would offer a more cost effective arrangement. Another respondent proposed that the volume for which security cover is required should be reduced to an arbitrary value of 10%, to be adjusted in the light of experience of the size of imbalances.

There were calls for as much flexibility as possible, in terms of the instruments by which credit cover is provided.

It was acknowledged that arrangements must be put in place to cover continuity of supply for customers of a defaulting supplier. One respondent suggested that the costs of providing a supplier of last resort could be funded through a form of surcharge or levy on suppliers. Another believed that default should be covered by external insurance and included in the NGC incentives scheme. In the unlikely event of default occurring, it was felt to be unavoidable that these costs would need to be recovered from market participants.

Ofgem/DTI Conclusions

Ofgem/DTI recognise that the credit cover proposals set out in the draft BMIS specification were unduly onerous. We consider that, in the first instance, credit requirements should primarily be an issue for participants to resolve among themselves, with subsequent oversight by Ofgem/DTI. It would thus appear sensible for an industry working group to be charged with the task of developing acceptable proposals for credit cover. The DISG is probably best placed to oversee this process. Ofgem/DTI's interest will be limited to ensuring that the outcome protects customers and facilitates competition, for example by ensuring they will not lead to discrimination or barriers to entry.

4.7 Information Imbalance

The July Consultation Document

It was indicated in the July report that the settlement systems would be capable of supporting an information imbalance charge levied on the difference between participants' FPNs, modified by accepted bids or offers, and their metered volumes. Such a charge would be a penalty for providing inaccurate information or for changing physical position after Gate Closure, other than in response to instructions from the SO. The charge would apply at the BM Unit level. It was proposed that initially the charge will be set at zero as the SO believes that licence obligations to provide accurate information will be sufficient.

Respondents' Views

Over a quarter of participants commented on this issue. Several respondents were concerned that uncertainty over the future use of the information imbalance charge will result in a higher perception of risk and increased financing charges. The CHP and renewables community was particularly concerned about this uncertainty. It was suggested that it would be useful to specify how the price for charging information imbalances would be derived were such a charge to be implemented.

A number of respondents argued that the information imbalance charge would be one of the main drivers incentivising participants not to deviate from their FPNs for commercial reasons and thus enabling NGC (as SO) to balance the system effectively. The fact that it will initially be set to zero was of concern as some respondents believed that portfolio participants would be better able to take advantage of these commercial opportunities than single participants. One respondent argued that if the information imbalance charge is set to zero there is little benefit in having Gate Closure four hours ahead since the SO will not have full confidence in the accuracy of FPNs. Another felt that the information imbalance charge proposals were not appropriate as they do not distinguish between failure to balance a portfolio and an intention to mislead the SO through the provision of inaccurate information. One respondent suggested that the SO should pay for the information it needs on a contractual basis, perhaps imposing charges if the information proves inaccurate.

One respondent requested that the procured settlement systems should be capable of applying different rates of charge to different participants, since some would provide more useful information at a higher level of resolution than others. It was stated that the proposed method of calculating the information imbalance volume at the BM Unit level was discriminatory on the generation side and against coal-fired power stations in particular, which tend to have more individual units than gas-fired plant of the same size.

A few respondents commented on the interaction of the information imbalance charge with energy imbalance charges, and asked that these be treated consistently. In particular they suggested that if an information imbalance charge is introduced then some consideration should be given as to whether there is a consequential need to adjust cash-out prices.

Ofgem/DTI Conclusions

Ofgem/DTI continue to believe that, whilst it is appropriate to have the functionality available to levy an information imbalance charge, initially its value should be zero. There are a number of reasons for this. First, NGC, who as SO will be most directly affected by inaccurate information, does not believe that an information imbalance charge is necessary. Second, participants who submit bids and offers into the Balancing Mechanism will have an incentive from the non-delivery rule to ensure that their output or consumption matches their FPN adjusted for any Bid-Offer Acceptances. Third, it is not obvious what the pricing mechanism for such a charge should be since it would be important to avoid any double charging of costs between information imbalance charges and energy imbalance charges.

4.8 Treatment of Distribution and Transmission Network Failures

The July Consultation Document

The July report indicated that the risk of exposure to imbalance charges arising from distribution failures will fall on participants. It also suggested that, until firm transmission access rights are sold, interim arrangements need to be established to determine the treatment of transmission failures. It was suggested that they should be treated in an equivalent manner to transmission constraints, requiring a deemed volume to be associated with the parties affected by the failure and its impact.

Respondents' Views

A third of respondents commented on this issue. Many felt it would be unacceptable if there was no compensation available to parties whose energy imbalance was caused by network failures outside their control. Several held the view that imbalance costs arising from failures of transmission and distribution systems should fall to transmission and distribution operators.

A few respondents emphasised that distribution and transmission network failures should not be treated in isolation from transmission access and distribution access issues. One generator observed that the issue of transmission network failures would be addressed by the long term solution to transmission access. In the interim it felt that treating a network failure in the same way as any transmission constraint would be sensible. Others also accepted the proposed interim treatment of transmission failures.

Some respondents were particularly concerned about the treatment of constraints and failures on the transmission system being different from that on distribution systems, stating that this would disadvantage embedded generation and demand. One respondent called upon Ofgem urgently to review distribution connection contracts and exercise its regulatory powers to modify these to enable generators to recover imbalance costs arising from network faults.

One generator presented four options for the treatment of network failures:

- Give all suppliers and customers who do not normally constitute BM Units the same opportunities to be paid for their offers as suppliers of half hourly metered BM Unit customers.
- Simply reflect the effects of disconnections in a variation to metered consumption or output. It would be up to participants to negotiate compensation with the relevant distribution or transmission company.

- Similar to the second option, except that the BSCCo would assume responsibility for paying compensation.
- A hybrid between the second and third options in which the BSCCo would act as an intermediary paying compensation to parties, but recovering the costs from distribution companies.

Opinions on this issue were divided among the distribution companies themselves. One Public Electricity Supplier (PES) believed, in common with many respondents, that it seemed unreasonable for participants to incur costs arising from circumstances beyond their control in the case of distribution failures. It supported arrangements that would take network failures into account in the determination of imbalances provided they were practical, fair and cost effective. Another PES commented that a fundamental principle and objective underlying the new trading arrangements is to ensure that costs are borne by those parties who cause them and felt strongly that costs stemming from network failures should be met by the relevant network operator. Not making such parties responsible for these costs would, in its view, place undue financial burdens and unmanageable risks upon other market participants.

One PES supported the proposed treatment of distribution failures. Another observed that in essence the proposals left the situation of distribution failures as at present in that first and foremost the risk was borne by suppliers. It commented that any changes to this would require commensurate changes to the liability clauses in the Distribution Use of System Agreement.

Ofgem/DTI Conclusions

Ofgem/DTI agree with the majority of respondents that, in principle, network operators should bear responsibility for imbalance costs arising from failures of transmission and distribution systems. The move towards allocating firm transmission and distribution rights will allow this responsibility to network operators. The issue of transmission failures will be considered as part of the present review of transmission access while it is envisaged that similar changes will occur for distribution access in the future. The interim proposal is to treat transmission failures as constraints so that participants' imbalance positions will not be affected by them; this will mitigate the imbalance exposure of participants under these circumstances. Ofgem believes there is a strong case for reviewing the incentives upon distribution companies. It also intends to examine the terms of distribution connection and use of system agreements to ensure that fair compensation is available to embedded generators and customers in the event of network failures.

4.9 The Need for Distribution Network Operators to Become Parties to the BSC

The July Consultation Document

Views were invited upon the need for Distribution Network operators to become parties to the BSC.

Respondents' Views

Few respondents commented on this issue. One stated that metering information is of intrinsic value in the new trading arrangements' environment and that Distribution Network owners ought to be parties to the BSC in order to ensure adequacy of meter registration.

Ofgem/DTI Conclusions

Ofgem/DTI agree that Distribution Network operators should be parties to the BSC in order to maintain the integrity of metering information and meter registration both at GSPs and on the boundaries between distribution networks.

4.10 Treatment of Interconnectors

The July Consultation Document

The rules set out in the draft BMIS specification allowed an element of *ex-post* volume allocation for interconnected parties.

Respondents' Views

Some respondents believed that the rules for *ex-post* volume allocation would be discriminatory unless the proposals suggested for interconnectors were equally applicable to all market participants. One respondent put forward a case for more than one BM Unit per Interconnector User to be considered, in order to make more effective use of the differing plant and demand dynamics across the interconnector in both directions. It was also suggested that superposition[14] should be included in the BMIS Specification and exports from England and Wales should be explicitly accommodated.

Ofgem/DTI Conclusions

Ofgem/DTI believe that interconnectors should be treated in a way consistent with other participants. Consequently, proposals have been developed that more closely align the timing of volume allocations for interconnected parties with the arrangements for other participants. The proposal to increase the number of BM Units per Interconnector User is being considered further,[15] as is the application of the Balancing Mechanism non-delivery rule in the case of interconnectors. Detailed proposals in these areas will be presented to DISG and more widely in due course.

4.11 Conclusions

As discussed in this chapter, a number of decisions on settlement have been reached as a result of the consultation process. These can be summarised as follows:

- There will be dual cash-out prices with the System Buy Price defined as the volume weighted average price of the offers accepted in the Balancing Mechanism and the System Sell Price as the volume weighted average of accepted Balancing Mechanism bids;
- Contract notification will be *ex-ante*. Initially it will occur 3 ½ hours before the start of a trading period but the timing will reduce in line with the anticipated reductions in Gate Closure;
- There will be separate production and consumption accounts;
- Participants will be able to split BM Units by volume as well as by percentage;
- There will be a facility available to participants to aggregate, however, this facility will not remove the obligations on participants arising from the Electricity Act 1989, the Competition Act 1998 and other competition legislation;

---

[14] Superposition refers to the netting off of imports and exports across an interconnector.

[15] Conceptually, the issue is similar to that of suppliers with several load-managing customers within a GSP Group.

- An assessment of the impact on Stage 2 will be undertaken to identify the method and timescale for providing a facility to allocate consumption through a single meter to more than one supplier.
- Surplus/deficits from imbalance charges will be shared among BSC parties on the basis of their metered volumes;
- In the first instance, credit requirements should primarily be an issue for participants to resolve among themselves with subsequent oversight by Ofgem/DTI;
- Provision will be made to levy an information imbalance charge but none will be levied initially;
- The introduction of firm transmission and distribution rights will allocate responsibility for network failures to network operators. In the interim, transmission failures will be treated as constraints resulting in no imbalance, while Ofgem intends to ensure that fair compensation is available to affected participants in the event of distribution failures; and
- Interconnector parties will be required to notify volumes *ex-ante.*

5. The Role and Incentives of the System Operator

Although the issues of the role and incentives on NGC under the new trading arrangements are being addressed separately, and there will be a consultation paper on the subject in November, the July report presented a preliminary discussion of these issues and several respondents commented on the ideas presented.

5.1 The Role and Incentives of NGC Under NETA

The July Consultation Document

NGC currently both operates and owns the transmission system ie. it acts as SO[16] and transmission asset owner (TO). The SO function covers all the short-term operational activities required to keep the system balanced and operating within safe limits. The TO function relates to the maintenance and longer-term development and investment in the transmission system.

The SO and TO functions will continue to be undertaken by NGC under the new trading arrangements, although there will be changes in the way that they are carried out and possibly in the split of responsibilities. The SO and TO roles both require NGC to incur costs which are subsequently passed on to market participants and as NGC is a monopoly provider of these services, it is important that it is properly incentivised to provide the services efficiently.

In the July report, it was recognised that any incentive structure must take account of the interactions between system operation costs and longer-term investment requirements. Two different approaches to incentivising system operation costs were outlined, the principal differences of which related to the costs they covered. Under the first approach, the costs associated with energy balancing (ie. the matching of generation and demand at

---

[16] The role of SO can conceptually be split into two parts – Balancing Operator (BO) and Transmission Services Operator (TSO). The BO function covers balancing the supply and demand of electricity on a second by second basis. The TSO function encompasses all the other short-term operational activities including the management of transmission constraints and losses and the purchase and use of ancillary services. Whilst Gate Closure remains four hours ahead of a trading period, participants will not be able to respond to market signals with regard to the need for balancing measures. Consequently, the BO and TSO functions will not be separated initially.

the half-hourly level) would be separated from the costs of alleviating transmission constraints and other SO costs. No incentives would be placed on NGC regarding the costs of energy balancing, but all other costs associated with system balancing would be subject to an incentive arrangement. Under the preferred second approach to incentives, NGC would be incentivised to minimise the overall costs it incurs in fulfilling its SO role, including overall energy balancing costs. The report stated that placing incentives on overall SO costs (ie. approach 2) was a framework that is more consistent with the new trading arrangements.

Respondents' Views

Over a third of respondents commented on the role of the SO and its incentives under the new trading arrangements, with the majority calling for a clearer understanding of the SO's role and more details about how the proposed incentives schemes would work in practice. Most respondents agreed that, in principle, approach 2 was the better approach to take when incentivising the SO. However, several participants commented that the thrust of work over the last five years has been to separate the transmission and energy markets yet the preliminary discussion on the matter appears to be based on the assumption that the markets should be combined again.

Many respondents recognised that it will not be possible to introduce a perfect scheme at the outset of the new arrangements and the proposal that the initial incentive scheme should only last for a year received significant support. In addition respondents felt that there must be boundaries established, which are not for negotiation by the SO, to prevent manipulation of the first year figures.

Ofgem/DTI Conclusions

The comments made in response to the July report will be taken into account in preparing the forthcoming Ofgem consultation paper on SO incentives and transmission issues, due to be published in November. The assumption that the proposals would combine the transmission and energy markets will not be the case once new capacity arrangements are in place. As the July report went on to discuss, the intention is to introduce a market-based approach to allocating transmission capacity rights which will reduce or remove the need for the SO to take transport related actions in the Balancing Mechanism.

5.2 Transmission Losses

The July Consultation Document

The July report stated that the systems procured for balancing and settlement purposes will be required to have the capability to scale generation as well as demand for losses and to incorporate locational scaling factors. The procurement of such systems will allow for the implementation of a system of charging for losses that more accurately reflects the extra costs imposed by changes in generation output or demand at particular locations.

Respondents' Views

In general, respondents supported the introduction of locational loss charging on both sides of the market and felt that this should be introduced as quickly as possible. However, one respondent suggested that only generators should be exposed to loss charges since the majority of customers have a geographically captive demand and have priorities other than electricity price signals to take into account. One respondent stated that the untested proposal to move to locational loss allocation was inappropriate.

Ofgem/DTI Conclusions

The treatment of losses will be considered in further detail in Ofgem's forthcoming November paper on SO incentives and transmission issues. However, we agree with respondents that locational loss charging on both sides of the market should be considered and introduced as quickly as possible. Depending on the detailed incentive arrangements proposed for NGC, there would appear to be merit in the SO purchasing losses, with the costs being recovered via charges to system users. With NGC properly incentivised to minimise the costs of purchasing losses, it is anticipated that it would obtain benefits from charging out the costs on a locational basis.

5.3 Transmission Capacity

The July Consultation Document

The July report said that it is important that changes implemented in the shorter term be consistent with prospective longer term developments. Therefore, the July report indicated that Ofgem intends to introduce a market-based solution to transmission capacity, based on tradable access rights. This would, in effect, set up a separate transport market that would be consistent with the general thrust of the proposed reforms to energy trading.

Respondents' Views

Approximately a quarter of respondents commented on the proposed changes to the transmission capacity regime. Many respondents mentioned the different timetables for changing the energy regime and the capacity regime, with the majority favouring the implementation of the two regimes simultaneously. Participants stated that the uncertainty surrounding the capacity regime would create additional and unnecessary difficulties for participants as well as potentially increasing their costs if it meant that contracts had to be renegotiated twice. However, a few respondents felt that efforts should be concentrated on the implementation of the energy trading arrangements, with the development of the transmission market dealt with on a separate basis.

While most respondents who commented on this issue supported the concept of a market-based solution of tradable access rights, one respondent stated that it was not supportive of Ofgem's proposals for auctioning Transco's capacity; and felt that such proposals would be even less appropriate for NGC.

Ofgem/DTI Conclusions

A review of all aspects of the role and incentives of the SO has already commenced as part of the preparations for setting revised incentive schemes consistent with the new trading arrangements and for the next NGC transmission price control, which will take effect from April 2001. The interval between the introduction of the new trading arrangements and the commencement of the next NGC price control is a relatively short one. Initial consultation papers on these issues will be published shortly and work on these aspects of the electricity market will continue in parallel with the implementation of the new trading arrangements. The new arrangements will be implemented as quickly as possible. By proceeding in this way, it is the intention that participants will have a good understanding of the transmission proposals before the new trading arrangements start. The basis for the new proposals for transmission capacity, on which views will be invited, will be as outlined in the July report. The intention is to introduce a market-based solution, under which firm capacity rights are purchased and secondary markets for capacity emerge.

6. Legal Framework and Governance Issues

The July report described the legal framework within which the new trading arrangements will be implemented. This included an outline of the changes required to licences (particularly the Transmission Licence of NGC), other regulatory instruments and key industry documents. It also addressed a number of other issues including participation in the BSC and the proposed status and scope of the BSC. Views were invited on all these issues.[17] Respondents also commented on the role of the regulator.

In addition, the July report outlined proposals for and invited views on the governance of the new balancing and settlement arrangements. This included possible options for the composition of the BSC Panel, a mechanism for selection to the Panel and the role the Panel should undertake.

6.1 The Constitutional Arrangements for Governance

The July Consultation Document

It was proposed in the July report that NGC's Transmission Licence be modified to place an obligation on NGC to establish and modify a BSC approved by the Director General. The scope and high level objectives of the BSC will be defined in the licence condition. The BSC would be given contractual force by a separate multilateral agreement. NGC would be a party to the multilateral agreement and therefore required to comply with the BSC.

The BSC will provide for the management and operation of the arrangements to be carried out by a limited liability company (BSCCo), which would be a wholly owned subsidiary of NGC. Modifications to the rules will be supervised by a BSC Panel and subject to approval by the Director General.

The July report also suggested that it might be desirable to add licence conditions relating to NGC's use of the Balancing Mechanism and to replace the current provisions relating to the

[17] The position of aggregators under the new trading arrangements, on which views were specifically requested, has been discussed in Chapter 4 and is not referred to here.

maintenance of records and the dissemination of information with suitable requirements in the BSC.

Respondents' Views

Around half of the respondents commented in general on the governance arrangements outlined in the July report. The majority was supportive of the proposed structure. It was suggested that the proposed arrangements would provide greater ability to protect customers and promote competition than currently exists.

The views of respondents focused largely on the establishment of the BSC via the Transmission Licence, the resulting arrangements for BSCCo and the intention to set high-level objectives for the BSC against which any proposed developments would be considered. Some respondents repeated concerns that establishing the BSC and the BSCCo via the SO's licence and shareholding would give rise to potential conflicts of interest.

Some respondents expressed concerns that establishing the BSC and BSCCo via the Transmission Licence would give rise to potential conflicts of interest for NGC in its capacity as SO. There was a concern that if the BSCCo were established as a wholly owned subsidiary of NGC then legal and structural safeguards would be required. Those respondents who commented on the issue agreed that the BSC must include high level objectives against which developments to the BSC itself would be considered.

NGC expressed reservations with regard to the proposed obligation that they utilise all Balancing Mechanism offers and bids before invoking emergency actions.

Ofgem/DTI Conclusions

The constitution of the arrangements will be specifically designed to achieve an arms-length relationship between NGC and the BSCCo and so as to minimise the scope for the BSCCo directors to owe any duty to the shareholder that might conflict with decisions appropriate to implement the BSC. As stated in the July report, a variety of safeguards will be included, in terms of the objectives of the BSCCo (in its Articles of Association), the funding of BSCCo participants, and the governance arrangements (particularly the basis for appointment of its directors). The latter will be prescribed in the BSC, compliance with which will be a licence obligation on NGC. Ofgem/DTI believe that these measures should alleviate participants' concerns about potential conflicts of interest for NGC in its capacity as SO. Ofgem/DTI will be publishing more detailed objectives against which developments to the BSC would be considered. These will appear in the draft licence conditions to be published for consultation shortly.

Ofgem/DTI acknowledge the validity of the concerns expressed by NGC with regard to the proposed obligation that they utilise all Balancing Mechanism offers and bids before invoking emergency actions have been recognised. The licence obligation on NGC will be appropriately qualified.

6.2 Participation in the BSC

The July Consultation Document

The July report proposed that all licensed entities will be required to be parties to the BSC. Other participants could choose to become a BSC party although customers would only be able to participate directly if they became licensed suppliers.

Respondents' Views

A number of respondents expressed concern regarding proposals for the mandatory participation in the BSC of licensed suppliers and generators. One respondent was of the view that by forcing such participants to sign the BSC (and therefore face exposure to imbalance cash-out), Ofgem/DTI would effectively limit the development of the competitive market. Another respondent commented that the obligation on licence holders to sign the BSC would impose significant restrictions. One respondent commented that suppliers should be able to 'outsource' obligations to sign the BSC to a third-party. Yet another respondent observed that the licence condition obliging BSC participation would need to be carefully worded so as to exclude the obligation from licensees who do not trade.

In respect of the present licensing exemption rules, one respondent commented that the present limits appear to work well. Early confirmation that the same (or similar) limits will continue to apply was required. A counter view was that any person who creates an imbalance on the system should be required to sign the BSC and be regulated accordingly and that there should be no exceptions to this rule.

Ofgem/DTI Conclusions

The position of Ofgem/DTI has not changed since July. Licensed generators and suppliers will be required to be parties to the BSC but will not be obliged to participate in the Balancing Mechanism. Mandatory participation in the Settlement Process is necessary to ensure that all participants, above the *de minimis* sizes in the licence exemption orders, are treated the same as regards settlement and do not receive the benefit of electricity for which they have not paid.

6.3 Scope of BSC

The July Consultation Document

The July report suggested that the BSC should set out:

- The Balancing Mechanism rules;
- The Settlement rules; and
- Governance rules.

Respondents' Views

There was general consensus that the BSC should be the principal industry wide document for commercial matters. Respondents agreed that the Grid Code should be concerned with, and take precedence for, matters of a technical nature (security, quality of supply and safe operation of the transmission network for example) whilst the BSC should focus on and take precedence for the commercial aspects of the market.

Ofgem/DTI Conclusions

Ofgem/DTI agrees that the scope of the BSC should be primarily limited to commercial matters with the Grid Code governing technical issues.

6.4 Role of the Regulator

The July Consultation Document

One of the criticisms of the present arrangements raised in the July report was the inability of the Director General to take steps directly to secure change in the Pool. The intention is to remedy this situation under the new arrangements and all modifications to the BSC will be subject to the approval of the Director General. In addition, it was proposed that the Director General should have the ability to direct NGC to consider a proposal.

Respondents' Views

A number of respondents expressed concern regarding the increased powers that would be available to the regulator. One commented that the perception of regulatory risk had been significantly increased. Another observed that increasing the regulator's powers was inconsistent with the objective of introducing more market-orientated trading arrangements.

Ofgem/DTI Conclusions

Given the general criticism of the slow pace of reform under the Pool governance arrangements, Ofgem/DTI remain firmly of the view that it is necessary for the Director General to have powers to ensure that the implementation of desirable modifications is not delayed by the BSC governance arrangements.

6.5 Composition and Appointment of the BSC Panel

The July Conclusions Document

The July report said that the BSC will provide for the existence of a Panel to supervise the management, modification and implementation of the BSC rules. Two possible options for the composition and appointment of the BSC Panel were set out in the July report and views were sought on the relative merits of the two approaches. Under Option 1, the Panel would comprise members elected by the industry, while Option 2 entailed members being appointed by the Panel Chairman and being independent of the industry.

Respondents' Views

Almost thirty respondents commented on the two BSC Panel proposals. Many respondents recognised the importance of achieving a well-chosen range and balance of expertise on the Panel. Many also acknowledged the tension between wishing to access the expertise of those directly involved in the market and the desire to avoid factionalism in decision making.

Eight respondents favoured Option 2, arguing that the Panel should be in a position to act as independently as possible. They suggested that a Panel comprised of representatives of specific interests would be unlikely to be conducive to effective decision making, as conflicts of interest would inevitably arise.

However, a majority of respondents favoured some degree of industry-elected membership on the Panel. Many argued that Option 2 would lead to a Panel devoid of direct ongoing knowledge of the workings of the industry and with a less sharp incentive to manage and develop the arrangements as effectively as possible. It was also argued that there would be benefit in the industry and its customers being fully engaged in developing the BSC and that this would only be achieved under the Option 1 model.

Others suggested a hybrid model, involving a combination of industry appointed members and independent expertise. It was suggested that, even where there were industry-appointed members, the Panel need not be representational, provided that the decision-making processes were open with opportunities for full access to all interested parties.

Ofgem/DTI Conclusions

Ofgem/DTI agree with the view that a hybrid model would be the best option and therefore proposes the following arrangements (further details of the proposals can be found in Appendix 4). The Panel Chairman will be appointed by the Director General. The BSCCo, the Panel, and the Board cannot be created formally until the BSC is in force. It is proposed that in the interim the Chairman (or Chairman Designate) is appointed by the Regulator and the Chairman should appoint or otherwise identify a number of senior managers thereafter. The Chairman will also be Chairman of the BSCCo and will be required to ensure the effective and efficient implementation of the BSC rules.

The Panel will contain five industry members, two consumer representatives and two independent members, as well as the Chairman. In addition, NGC will nominate a representative to attend Panel meetings and provide expertise on system operation matters. As discussed below, further consideration needs to be given as to how the industry members should be appointed. We suggest that the consumer representatives should be appointed by the proposed National Energy Consumers Council (formerly the Electricity Consumer Councils) whilst the Chairman will appoint the independent Panel members.

In developing a mechanism that provides for the selection of those members of the Panel drawn directly from the industry, a key concern has been to obtain a Panel that contains a broad range of views. The obvious way of guaranteeing a broader representation is to create constituencies, but this raises the problem of how to define the constituencies, and how to determine to which constituency a participant belongs, given the various forms of vertical and horizontal integration that exist in the electricity industry. Ofgem/DTI are considering establishing constituencies on a simple size criterion, perhaps very large, large, medium and small, with one constituency for other groups that might be unable to obtain representation in such a system. Under this proposal, all participants would be assigned to a category on the same basis that the boundaries of the categories were determined. Nominations and voting would be exclusive to each category, so that for example only members of the very large category could nominate and vote for the representative of that category. Voting would be on the basis of one person one vote, to avoid one or two participants being able to 'capture' a category.

Whilst this proposal has the merit of simplicity, it is recognised that the industry may favour an alternative model for the definition of constituencies and voting arrangements for its own members of the BSC Panel. If the DISG are able to come to a consensus on an alternative approach to the selection of the five industry members of the Panel within a reasonable time, (say one month from the date of the publication of this report), the alternative approach will be given further consideration. Failing such a consensus, the proposals described here will be progressed.

The Chairman and the Panel will select four persons to become non-executive directors of the BSCCo and to form the BSCCo Board. Ofgem/DTI considers that the Board should be smaller in size than the Panel, as a smaller body is better able to exercise the required level of scrutiny and control of the BSCCo. Two of the directors will be drawn from the industry members of the Panel. The remaining two directors could be selected either from within the remaining Panel members or from outside, if particular skills were required on the Board that were not present among the Panel membership.

6.6 Role of the BSC Panel

The July Consultation Document

In the July report, views were sought on whether the BSC Panel should take a position on the merits of modification proposals or whether it should simply administer the modification process.

Respondents' Views

The majority of respondents who expressed a view on this issue recommended that the Panel should vote and make recommendations on modification proposals. It was argued that this would provide transparency of process, fully engage participants in debate and provide strong signals to the Director General in reaching his final decision on modifications. Others noted that this would also allow for proper accountability of the Panel to emerge.

Ofgem/DTI Conclusions

Ofgem/DTI concur with the proposal that the Panel should make recommendations on modification proposals.

6.7 Conclusions

As discussed in this chapter, a number of decisions on governance and other legal have been reached as a result of the consultation process. These can be summarised as follows:

- The constitutional arrangements, including those relating to the role of the regulator, will remain as outlined in the July report;
- The proposed licence condition on NGC relating to utilising all Balancing Mechanism offers and bids before invoking emergency actions will be appropriately qualified;
- The BSC will be primarily limited to commercial matters with the Grid Code governing technical issues;
- A new hybrid model for the BSC Panel is proposed with the Panel consisting of a Chairman who, it is proposed, will be appointed by the Regulator in the near future, five industry members, two independents and two customer representatives; and

- In addition to operating the modifications process, the Panel will make recommendations on modification proposals to the Director General.

7. CHP and Renewables

Thirty-eight respondents to the consultation document commented on the impact of the new trading arrangements on CHP and renewables projects, including existing Non Fossil Fuel Obligations (NFFO) schemes. The majority of these responses were from CHP or renewables generators or their trade associations. Almost all these responses expressed some concerns about the consequences for CHP and renewables of the new trading arrangements. These concerns fell into four main areas:

- The length of gate closure and the timing of contract notification;
- The potential erosion of embedded and other benefits;
- The removal of the Pool Purchase Price (PPP); and
- Exposure to imbalance charges.

In addition, it was widely acknowledged that allowing aggregation and BM Unit splitting was helpful in reducing the risks to which CHP and renewables schemes would be exposed. However, there was general agreement that proposed rules for splitting BM Units for settlement purposes were too restrictive. As discussed in Chapter 4, it is intended to relax these restrictions so that BM Units can be split by volume as well as by percentage. The remaining concerns are discussed in turn below.

7.1 The Length of Gate Closure and Contract Notification

The July Consultation Document

The July report proposed, for all participants, Gate Closure should be four hours before the trading period, with simultaneous contract notification.

Respondents' Views

Three of the respondents indicated that a shorter contract notification, would reduce the potential exposure of CHP and renewables schemes to imbalance prices. It is true, for all participants, that the closer to real time that Gate Closure occurs, the better they should be able to predict their output. However, the respondents argued that a shorter contract notification might be of particular assistance to renewables schemes with intermittent sources of energy, such as wind power, and CHP schemes whose exports are determined by an on-site load that can change at short notice. It was also suggested that the possibility of allowing small-scale generators to have a shorter contract notification than that generally allowed should be considered.

Ofgem/DTI Conclusions

It has been made clear that the setting of Gate Closure and contract notification at four hours before the start of a trading period was only considered to be an interim measure. As discussed in Chapter 3, NGC has told us that it is considering the reduction of Gate Closure to 3½ hours with a view to accommodating Ofgem/DTI's concerns regarding gas interruptions. Contract notification will be reduced in line with Gate Closure.

Experience with the new trading arrangements should enable Gate Closure and contract notification to be shortened considerably. Accordingly, subject to re-evaluation in the light of experience in operating the new regime, it is intended that Gate Closure and contract notification should be reduced again after six months and that additional reductions should be implemented thereafter as this becomes practicable.

Moving contract notification in this way will help CHP and renewable generators manage their risks and obviate the need for consideration of a separate contract notification for small-scale generators. Indeed a special contract notification for small scale generators would have limited benefit, since after the general Gate Closure and contract notification, trading could only take place between the small scale generators. Given that most CHP and renewables schemes are unlikely to sign the BSC, it is the time of contract notification rather than Gate Closure that is the more important issue for such schemes. In this regard, it is intended that the gap between contract notification and real time will reduce substantially within six months of the implementation of the new arrangements.

7.2 Embedded and Other Benefits

The July Consultation Document

An objective of the new electricity trading arrangements is to ensure that all forms of generation, including CHP and renewables, are treated equitably. The Government is examining issues particular to embedded generators to ensure that the costs they face are fair and that they face no discrimination.

Most CHP and renewables schemes are embedded within distribution networks, rather than being directly connected to the transmission grid. As a result, they are able to offer significant benefits to suppliers that contract with them. These mainly arise because the output from the embedded generator is deducted from the demand allocated at the Grid Supply Point Group level to the contracting supplier. The benefits to the contracting supplier which the embedded generator can capture include:

- Reductions in payments for transmission losses.
- Avoidance of Uplift payments, including Transmission Services Use of System (TSUoS) charges, for the electricity they provide.
- Reductions in Transmission Network Use of System (TNUoS) payments (also known as the triad benefit).

consequently, embedded generators can obtain an increase in their revenues from providing these embedded benefits to suppliers. Furthermore, embedded generators do not on their own behalf have to pay transmission or distribution use of system charges (thus in respect of these charges they receive two benefits).

Respondents' Views

Most of the respondents on the subject of CHP and renewables expressed a concern that the value of embedded benefits would be eroded under the new trading arrangements. They argued that any changes to the way in which transmission loss charges or Transmission Use of System Charges (both Network and Services) are made could reduce the benefits that embedded generators are able to provide. Moreover, they suggested that there would be a reduced market for Green Benefits since suppliers contracting with renewable schemes with unpredictable output would be increasing their risk of imbalance exposure.

The solution to the erosion of embedded and other benefits suggested by most respondents was twofold. First, to relax the restrictions on BM Unit splitting. Second, to ensure that selling some of their output to receive embedded benefits does not prevent CHP and renewables schemes from benefiting from national aggregation schemes.

Ofgem/DTI Conclusions

The suggestion that the BM Unit splitting arrangements should be broadened to allow the notification of fixed volumes as well as percentages has been adopted. With regard to the second part of the proposed solution, it has never been intended that the trading arrangements should impose restrictions on the types of participants between whom the output of a BM Unit can be split. Embedded generators will be able to choose between a number of different options for splitting the sale of their output, all of which will allow them at least to retain the cost advantage of avoiding use of system charges (both transmission and distribution) and, where applicable, the Green Benefit.

Further work on embedded issues is being carried out by the DTI's embedded generation focus group.

7.3 The Removal of the Pool Purchase Price

The July Consultation Document

The issues associated with the removal of Pool-based price markers was considered in the July report. In the short-term, it was envisaged that some administered price index designed solely for NFFO contracts could be used. Over time, it was felt that it would be preferable if the Public Electricity Supplier (PES) compensation payments were based on a reference price emerging from an electricity commodity market, such as a power exchange.

Respondents' Views

Sixteen respondents, including several CHP and renewables schemes, commented on the implications of the removal of PPP. The removal of PPP as a reference price affects plant with long-term offtake contracts for differences as well as CHP and renewables schemes. Whilst the need for a replacement reference price is particularly acute for PESs with NFFO contracts, other CHP and renewables schemes have commented that the removal of a universal reference price will make it harder for them to price exports of power. Several respondents commented that, irrespective of the reference price that is adopted, the current financial neutrality of PESs to NFFO contracts will disappear under the new trading arrangements due to the effect of imbalance prices.

A number of suggestions were made regarding potential replacement reference prices for NFFO contracts. Three respondents suggested that the replacement price should be the average of the two cash-out prices ie. the average of the System Buy Price and System Sell Price. Another respondent suggested that the reference price should be the System Buy Price since this would reflect the lower value that generally unpredictable output from renewables schemes might be expected to receive. There was also a suggestion that the reference price should be the average of the contract prices established at auction following the expiry of the NFFO 1 and 2 contracts.

Three respondents suggested that the need for a reference price could be overcome if an auction-based mechanism was introduced. The suggestion was that the output from schemes (both existing and new) with NFFO contracts would be auctioned to suppliers for anything up to three years. Any shortfall between the auction prices and the NFFO contract prices would be made good through the Fossil Fuel Levy. One respondent also suggested that auctions could also be used to determine which new schemes achieved NFFO status. Similar suggestions have been made to the DTI in response to its Renewables Review.

Ofgem/DTI Conclusions

Many suppliers offer premium ‘green tariffs’ under which suppliers either guarantee to purchase the electricity from renewable sources or to use the premium to fund green energy schemes. The typical premium for these tariffs is around 4 – 5%. It will be appropriate for some account to be taken of this ‘green tariff’ premium that some customers have demonstrated they are willing to pay in setting an initial reference price for PESs with NFFO contracts.

In the light of suggestions made by respondents, Ofgem/DTI consider that it is appropriate to take forward work on the establishment of a reference price on the basis of the average of the System Buy and System Sell price plus a ‘green premium’. This premium could be established, for example annually, on the basis of the average percentage premium charged by suppliers for renewables electricity compared with conventional tariffs. Such a reference price, which would only apply for an interim period until more transparent prices for renewables emerge in the market, would ensure that a significant element of potential risk that suppliers would face as a result of holding NFFO contracts under the new trading arrangements would be mitigated, but would ensure that proper account was taken of the higher price commanded by renewables electricity.

The reference price could be used not only as the market price for NFFO contracts, but also as a benchmark against which bids made by suppliers to NFFO-expired schemes might be assessed. Ofgem/DTI will still monitor the extent to which bids to purchase electricity from NFFO-expired schemes fall short of this reference price as a means of assessing whether large suppliers are exerting market power when making such purchases. Ofgem/DTI believes that the need to calculate a renewables reference price along the lines discussed above will be relatively short-lived. As further NFFO contracts expire, additional renewables schemes will be without long-term contracts and it is expected that transparent prices for renewables will emerge in the market.

The wider issue of encouragement for environmentally efficient forms of generation is a matter for Government. In considering appropriate measures, the market conditions faced by these generators will be one of the factors the Government takes into account.

7.4 Exposure to Imbalance Charges

The July Consultation Document

The July proposals discussed the possible impact of exposure to imbalance prices for CHP and renewables plant. The report pointed out that the exposure would, in many cases, only be indirect. For these plants the BM Unit splitting arrangements outlined in section 7.2 will be available to manage imbalance exposure. The proportion of CHP and renewables plant that are licensed and hence will be required to sign the BSC is very low.[18] CHP schemes who only very occasionally spill electricity can also choose to forego payment for that electricity on the few occasions when spill occurs rather than enter into contracts with other parties to manage this risk.

Respondents' Views

Most of the responses on this issue were linked to the timing of Gate Closure and contract notification. Most respondents also commented on the calculation of imbalance charges,

[18] For example, in 1997, less than 15% of CHP capacity was licensed.

stating that dual cash-out prices posed greater risks to unpredictable or small-scale generators than would a single cash-out prices.

Ofgem/DTI Conclusions

CHP and renewables schemes will have three options available to them to transfer their imbalance risk to another party. First, they can sell their output to one (or two) suppliers within the same GSP Group with the suppliers' registering the meter in Stage 2. CHP and renewables generators without direct exposure to imbalance can, in addition, aggregate their imbalance exposure nationally if they choose by splitting their BM Units. Second, they can sell their output to a BSC signatory who registers their meter in Stage 1[19] and as a BM Unit. Third, they can sign the BSC and register their meter in Stage 1 but transfer all their metered output to another BSC signatory (or several signatories).

Although all three options transfer direct risk away from CHP or renewables schemes, indirect exposure will remain since third parties offering contractual terms to them will clearly take account of the potential exposure to imbalance cash-out prices that they would be taking on. The exposure to imbalance price risk will be greatest for plant with unpredictable output. The consequences of the options differ in other respects. Under the first option, the choice of contract counterparties may be limited but the full range of embedded benefits are retained. The range of counterparties under the second option should be wider but those embedded benefits that rely on a generator's output being treated as negative demand will be lost. However, the cost advantage of avoiding transmission and distribution use of system charges will be retained as will any green benefit. The third option requires the CHP or renewables scheme to sign the BSC, with its attendant costs and liabilities, but enables the scheme to participate directly in the Balancing Mechanism. This will be of benefit to those schemes that can easily adjust their output as it will enable them to submit offers and bids in the Balancing Mechanism and hence potentially receive an additional source of revenue.

[19] Stage 1 is the set of systems that calculate prices and measure volumes to determine payments between suppliers and generators.

7.5 Conclusions

The impact on CHP and renewables schemes of the new trading arrangements must be considered in the context of their expected benefits for industry, consumers and the economy as a whole. It is inevitable that the introduction of new arrangements will have different effects for different market participants. Nonetheless, the Government has made it clear that encouraging the development of CHP and renewables schemes is part of its overall energy policy.

The changes to the BM Unit splitting arrangements and the intended reductions in the timing of Gate Closure should go a long way to addressing the concerns of renewables and CHP schemes with regard to exposure to imbalance prices. The new BM Unit splitting arrangements will, for example, allow the predictable portion of a scheme's output in terms of a fixed volume to be sold to a supplier within the same GSP Group. Since the output contracted is fixed and secure, the price achievable for this output should be attractive. Moreover, by contracting with a supplier or customer within the same GSP Group, the scheme will be able to capture all the available embedded, triad and green benefits. The remaining unpredictable portion of the scheme's output could then be managed either directly by the generator or by using the services of a supply aggregator, acting at either a local or a national level. Such arrangements should provide the flexibility that CHP and renewables schemes have indicated that they require to mitigate their exposure to imbalance risk.

An environmental impact assessment of the new trading arrangements has been undertaken and is presented in Appendix 4. The future for CHP and renewables schemes clearly forms an important part of this assessment. The Government is also giving consideration to the position of CHP and renewables schemes with regard to the proposed Climate Change Levy.

8. Competition

The July report noted that competitive pressures in wholesale and retail electricity markets will both affect and be affected by the new trading arrangements. Varying degrees of competition can be expected to have effects on the liquidity of markets and on the efficiency with which electricity is traded, whilst changes in the rules that govern the trading of electricity can be expected to lead to changes in selling and buying strategies of companies operating in the relevant markets. The July report also emphasised that greater demand side involvement was a key innovation and a major objective of the New Electricity Trading Arrangements.

Respondents commented in particular on the potential problems that vertical integration within the electricity market might cause in relation to liquidity and transparency under the new arrangements, on the possible effect of certain of the Balancing Mechanism and Imbalance Settlement trading rules on competition and on prospects for demand side participation.

8.1 Vertical Integration, Liquidity and Transparency

The July Consultation Document

The July report said that some concern had been expressed that vertical integration between supply and generation in the electricity market will render the new trading arrangements less effective than they might otherwise be, by reducing liquidity and transparency in the bilateral markets due to internalised trading in the vertically integrated companies. The report noted that a substantial degree of vertical integration raises competition issues when effective competition has not yet fully emerged in generation and supply.

However, vertically integrated companies can only avoid trading if load shapes on both generation and supply are the same, which is typically not the case at present. Moreover, experience suggests markets are usually liquid and transparent even if they take only relatively small proportions of the physical market. Transparency will occur, in common with other commodity markets, as price reporting develops as a valuable service to market participants. Nevertheless, it noted that it may take some time for price transparency to develop, although there are already encouraging signs of price reporting appearing in advance of the new market. Consequently, it suggested that, if required, the Director General could set in place arrangements to publish prices in the newly emerging markets.

Respondents' Views

Some respondents expressed concern that vertical integration between supply and generation in the electricity market will render the new trading arrangements less effective than they might otherwise be, by reducing liquidity and transparency in the bilateral markets due to internalised trading in the vertically integrated companies.

Several respondents commented on transparency and the issue of the visibility or otherwise of market prices. In general, there was support for the principle of greater transparency than at present, with one respondent noting that market sensitive information should be made available to all at the same time, another wanting details of constraints and outages to be made available, and one suggesting limits on contracting activity to encourage transparency. Others noted that price reporters were already emerging and suggested that the backstop powers for the Director General to provide price information in the event that it did not materialise were not needed. Moreover, one respondent questioned whether the regulator would have the experience or incentive to judge the kind of information that should be made available from a price reporting perspective.

Ofgem/DTI Conclusions

The proposed market arrangements are designed to provide the same opportunities for all market participants. The decision to separate production and consumption for the purpose of imbalance calculations ensures that the market rules do not benefit vertically integrated players at the expense of participants who are not vertically integrated. A consequence of this is that some rules (such as the settlement rules) will encourage contracting by all participants including by vertically integrated players. This will, in turn, foster liquidity and transparency. Ofgem/DTI continue to believe that transparency will develop under the new trading arrangements and that, over time, the range of price information readily available should be much greater than at present. However, it still seems appropriate to retain the backstop option whereby the Director General may publish price information in the event that price transparency is slow to emerge.

Under the new Competition Act 1998, which replaces the Competition Act 1980, the Director General will gain additional concurrent powers with the Director General of Fair Trading (DGFT) from 1 March 2000. These will include the ability to impose financial penalties of up to 10% of turnover on companies infringing the prohibitions under the new Act. The Act prohibits anti-competitive agreements (Chapter I) and abuse of a dominant position (Chapter II).

8.2 Market Power and the New Trading Arrangements

The July Consultation Document

The July report said that whilst public policy will continue to promote competition where feasible and to target significant abuses of market power, some degree of market power can be expected to persist in electricity markets. Trading arrangements in the industry therefore need to be relatively robust across a range of different market structures and it is desirable that, in their detail, they be sufficiently flexible as to accommodate appropriate modifications as and when justified by changing market conditions. The New Electricity Trading Arrangements proposals have been developed with these points in mind.

Respondents' Views

Generally there was a presumption from respondents that market power, or more specifically the threat of the abuse of market power, is an issue that needs to be addressed. A number of respondents said that the large portfolio participants, of those who were vertically integrated, would be better able to benefit from whatever change took place. One pointed out that it was the large generators who owned the flexible plant who were likely to be rewarded under the New Electricity Trading Arrangements. Some respondents separately noted that NGC would have considerable market power under the new arrangements and that this needed to be addressed.

Various respondents proposed measures to limit the potential to abuse market power. These included regulatory oversight generally, and specific licence conditions in particular. One suggestion was that there should be a requirement to offer 90% of output ahead of gate closure, another was a proposal to require generators to offer power to the SO; and a further suggestion was that there should be an obligation to behave within the spirit of the BSC rules. Others said that a complex set of prescriptive rules was not the way to deal with market power concerns, and some argued that in dealing with market power there was a risk of costs being imposed on market participants generally.

Ofgem/DTI Conclusions

In developing the new trading arrangements, Ofgem/DTI have paid attention to the issue of market power. Overall, the new trading arrangements seek to remove unnecessary restrictions and to secure a set of relationships between buyers and sellers that are more akin to those found in other markets (and which have proved themselves capable of functioning effectively across a range of different market structures). The elimination of the presently restrictive rules in the Pooling arrangements should open up greater opportunities for discovery and innovation in selling and buying electricity and the contract-based nature of the proposals will put buyers in direct contact with sellers, thus increasing rivalry.

Since electricity storage options are limited and production and consumption must be instantaneously and continually balanced, there is a need for central system co-ordination as real time approaches. But this is not the same as requiring a single centralised market. All that has to be co-ordinated centrally is close to real time actions by participants that will materially affect the balance between production and consumption.

Given the physical characteristics mentioned above, electricity markets cannot function in real time in the sense of the SO seeking offers and bids on a second by second basis to deal with each new balancing issue as it arises. However, under the new trading arrangements market activity will continue much closer to real time than at present. Initially participants will only have to freeze their bid and offer prices 3½ hours (the expected initial time for Gate Closure and contract notification) ahead of a trading period and they will effectively be able to withdraw Balancing Mechanism offers and bids up to real time, if they have not been accepted. With an anticipated reduction in Gate Closure and contract notification, active bilateral and exchange-based trading will continue close to real time. This will lead to price discovery closer to real time than in many other electricity markets and to short term prices that reflect the supply/demand situation.

The debate on the trading arrangements has focused on Balancing Mechanism and Imbalance Settlement. However, it is the complete set of markets, trading over a variety of different timescales, that will replace the existing arrangements. It is anticipated that most electricity will be traded through forwards markets, including any short-term power exchanges that develop. Prices in these other markets will, in general, be a far more important determinant of the payments made to and by market participants than those in the Balancing Mechanism and Imbalance Settlement.

Insofar as it is spot prices that drive forward prices, in the new arrangements it is likely that those forward prices will be driven more by expectations of closing power exchange prices than by Balancing Mechanism or Imbalance Settlement prices, because the latter are materially different in type, more difficult to predict and likely to be more volatile. The fact that the RETA Programme will only procure the latter should not disguise the attention that has been paid to the former and the encouragement that the new trading arrangements will give to such markets.

In terms of the Balancing Mechanism and Settlement Process, aspects of the trading rules, discussed in previous chapters, should help to counter the abuse of market power, including the following:

- The simplicity of the prices associated with offers and bids made in the Balancing Mechanism, as compared to those in the Pool, should aid price transparency and the associated monitoring of behaviour;
- The BSCCo will monitor offers, bids and prices and report to the Director General on a routine basis; in addition data will be made available to participants and other interested parties;
- The default pricing proposals will help ensure that participants offer all feasible output and consumption to the SO, and Ofgem will investigate any evidence of participants withholding offers and bids from the Balancing Mechanism in an attempt to manipulate prices; and
- The new BSC governance arrangements will enhance the ability of the Director General to secure appropriate modifications to BSC.

One issue that has been a focus of debate has been the proposal in the July report that payments for accepted Balancing Mechanism offers and bids would be on the basis of pay-as-bid rather than system marginal price (SMP). Considerable theoretical, analytical and empirical work has been undertaken on pay-as-bid and system marginal price setting. Different authors have come to different views but in general the work supports the view that, when markets are broadly competitive, SMP and pay-as-bid produce similar results, but that when market power is evident, pay-as-bid can have advantages. As long as all participants are paying the same price, competition is lessened because buyers need not search for a better price and can be content that their competitors cannot undercut them on generation costs. Under a pay-as-bid system, buyers have to go out and find the best deal available, which will increase the competitive pressures on generators. Similarly, under SMP, generators can seek to increase market prices by bidding higher prices for marginal output whilst protecting their volume positions by bidding lower prices for infra-marginal output. Under pay-as-bid, prices received for infra-marginal output cannot be sheltered in this way: volume can only be protected by offering a better (lower) price to the buyer.

These points are supported by the business simulation modelling that has been conducted by the RETA Programme, where prices under SMP came out higher than pay as bid (details of this modelling are given in Appendix 6). Another result from the modelling was the observation by participants that gaming - seeking to exercise market power - was perceived to be easier under SMP pricing rules than pay-as-bid – the ability to affect the prices received by all plant in a portfolio by varying the bids of one seemed to be a factor.

In addition, Ofgem recently proposed[20] to amend the licences of the major generators to include a 'good market behaviour' condition. The condition will guard against the generators abusing their market power in the wholesale electricity market. A proven breach of this condition will render the generator open to an enforcement order by the regulator and to civil action by those affected. Whether or not similar conditions should be more widely imposed as a part of the implementation of the new proposals is under consideration. As noted above, the Director General also gains enhanced powers under the Competition Act 1998 from 1 March 2000.

[20] Rises in Pool Prices in July: A Decision Document, Ofgem, October 1999.

Ofgem/DTI acknowledge that the SO will have a considerable degree of market power under the new arrangements. This will be managed by an appropriate combination of licence conditions, prescriptive elements of the BSC and the design of the incentive scheme under which NGC will operate.

8.3 Demand-Side Potential

The July Consultation Document

The July report indicated that greater demand-side involvement was a key objective of the new arrangements. It suggested that initially any increase in demand-side participation was likely to come from customers with half-hourly meters with expansion into the participation of non-half-hourly metered customers depending on the introduction of more sophisticated profiles and technological advances in control systems.

Respondents' Views

There was no consensus amongst respondents on the possibility of a greater role for the demand-side. Some welcomed the opportunities for the demand-side to participate more fully than at present whilst others argued that the incentives in the new arrangements were not sufficient to encourage participation, particularly since a lead time of more than four hours for some load management would be required. It was also argued that it was unfair to treat generation and demand in the same manner, since electricity trading was the primary activity of generators but not of customers. One respondent noted that non-half-hourly metered demand offered a significant and as yet unrealised potential for exploitation in terms of demand-side response, but another argued that technological improvements were necessary first if this were to happen. Concerns were also expressed about the ability of second-tier suppliers to provide accurate information about their radio teleswitched[21] customer demand in advance of Gate Closure and hence participate in the Balancing Mechanism. Furthermore, the lack of information would mean that such suppliers would be subject to imbalance charges and additional costs may result for the SO in balancing the system.

[21] Demand that is controlled remotely by radio signal using the BBC Radio Network.

Ofgem/DTI Conclusions

Ofgem/DTI believe that the proposals do provide significant additional encouragement to participation by the demand-side compared to the present arrangements. The volume of demand-side bidding will be dependent upon how individual customers, and suppliers acting on their behalf, realise the opportunities that the arrangements offer, and this will in turn require consideration of the priority of various commercial and industrial processes in relation to price signals. Several customers have told Ofgem/DTI that they are already considering these issues and over time it is expected that, if they gain a competitive advantage from doing so, others will follow suit. The extent to which the current radio teleswitching regime imposes restrictions on demand-side participation will be investigated further by Ofgem.

8.4 Conclusions

Ofgem/DTI agree with respondents that the New Electricity Trading Arrangements is only one aspect albeit a very important aspect of a wider energy and competition policy framework and the benefits that it will provide should be judged in terms of its contribution to the effectiveness of that framework, taken as a whole. We continue to believe that the new arrangements will directly remove a number of restrictions and barriers which currently impede the development of effective competition. They will be less vulnerable to abuse by participants with market power, be more open to innovation, be more conducive to the effective monitoring of anti-competitive practices, strengthen the influence of the demand side on wholesale price formation, and be more flexible and adaptable to changing economic conditions. It is not expected that vertical integration will impede the development of transparent and liquid markets for electricity, not least because competition in electricity supply and associated variations, over time, in the requirements of suppliers will encourage trading at the wholesale level. However, the new trading arrangements will not, and are not intended to, eliminate market power and the Director General will rely on his existing powers and his new powers under the Competition Act 1998 to continue to promote more effective competition at both the wholesale and retail levels.

9. Other Issues

The July report considered other issues, including how the new trading arrangements in electricity would interact with the arrangements currently being implemented in the gas industry. It also provided an assessment of the arrangements against objectives, especially with regard to the maintenance of a secure and reliable supply. A consideration of costs of implementing the proposals was also made.

9.1 Interactions with Gas

The July Consultation Document

The July report gave an outline of the proposed new gas trading arrangements and briefly discussed some of the interactions between the gas and electricity markets. The new trading arrangements, including new entry capacity arrangements, were implemented on 1 October 1999.[22] Ofgem has sought to ensure that the same principles underlie the new trading arrangements in both the gas and electricity markets.

Respondents' Views

There were relatively few responses received that addressed the interaction of the new electricity trading arrangements and the gas market. Only seven respondents commented in total. A few respondents commented on the fact that the Gate Closure and the contract notification time of 4 hours before the trading period could create difficulties for gas-fired generators and industrial customers on interruptible gas contracts. Another stated that a fuller examination of interactions between gas and electricity markets, focusing on customers, should be made available as soon as possible. a few respondents stated that Ofgem should ensure that the new trading arrangements in electricity and gas are complementary and that they facilitate efficient and economic arbitrage within the energy markets. Two respondents suggested that gas and electricity Operating Guidelines should be aligned since Transco and NGC could find their actions in conflict if the balancing mechanisms sent out signals that were strongly concurrent or mismatched.

[22] The New Gas Trading Arrangements: A decision document, Ofgem, September 1999.

Ofgem/DTI Conclusions

It is proposed that contract notification and Gate Closure will be 3½ hours ahead of real time so alleviating the concerns of customers and generators on interruptible gas contracts. In addition, Ofgem will be undertaking a review of the present gas exit capacity and interruptions regime in winter 1999 and will also be reviewing the new gas trading arrangements in the light of experience in Spring 2000. Both reviews will take into account the proposed new trading arrangements in electricity.

9.2 Security of Supply

The July Consultation Document

In the July report it was stated that under the new trading arrangements greater reliance would be placed on efficient pricing signals emerging from the market. NGC will also continue to play a major role in securing system balancing over very short timescales and will be incentivised to do so in an efficient way. It is expected that long-term security of supply will be enhanced by the emergence of forward prices for electricity that extend several years ahead.

Respondents' Views

There were limited comments from respondents on security of supply. In general respondents agreed that the proposals meant that the level of security of supply would be maintained under the new arrangements, however one respondent stated that the costs of achieving the present level of security of supply in shorter time scales would rise. One respondent suggested that, as long term security of supply will be determined by the market under the new trading arrangements, it is important that during times of system stress the market is allowed to function without regulatory intervention. Another suggested that equal obligations should be put on all generators to hold stocks of fuel to meet emergency conditions.

A number of respondents commented specifically on the need for Deemed Offers and Bids. Although several respondents agreed that it may be necessary to implement a special category of 'system stress' bids, which would be called upon when ordinary Balancing Mechanism bids had been exhausted, several respondents expressed concern about the current proposal of Deemed Offers and Bids. This issue was dealt with in Chapter 3, section 3.1.1.

Ofgem/DTI Conclusions

The new trading arrangements will encourage market participants to balance their own positions ahead of real time, since imbalances will expose participants to potentially unfavourable cash-out prices. These enhanced incentives for self-balancing will contribute to the achievement of efficient levels of supply security in both the short and long-term.

In periods when demand is high relative to capacity, prices in bilateral markets may be driven up, providing incentives to increase supply and reduce demand. In the short-term, higher prices will encourage generating plants to be made available to meet demand, and in the long-term they will encourage the building of new plant. It is also expected that there will be greater response of demand to price under the new arrangements than there is at present. The expected emergence of forward prices for electricity several years ahead will provide better signals than currently exist of the longer term balance between demand and capacity, and therefore of the capacity required to maintain security of supply.

Security of supply in the short-term will be underpinned by the actions of NGC in its role as SO, including by calling on bids and offers in the Balancing Mechanism. When the system is under stress, prices realised in the Balancing Mechanism will tend to be high, again providing incentives not only to provide extra output in these periods but also to have plant regularly available to take advantage of such commercial opportunities as and when they arise. Some demand-side participants are also likely to wish to exploit commercial opportunities available to reduce demand in the face of high prices. NGC will also contract ahead for a number of balancing services, including the provision of reserve. This will provide additional security in that the SO will not need to rely solely on the Balancing Mechanism to match supply and demand in all circumstances.

Ofgem/DTI believe that all of the above will ensure that the current level of security of supply will be maintained.

9.3 Costs

The July Consultation Document

The July report provided an estimate of both the central system and participants' direct costs arising as a consequence of the new trading arrangements. The costs of implementing and operating the new trading arrangements were estimated to be between about £136m to £146m per annum, for a five-year period. Thereafter the operating costs are expected to be one of the order of £30m per annum. These estimates take no account of any of the costs that will be avoided as a result of the reforms, including as a consequence of terminating Pool contracts.

Respondents' Views

Only a limited number of responses were received on this issue. Of those a few stressed that it was important that the costs did not disadvantage smaller participants. Two respondents commented on the need for allowances for these costs to be included in the next Supply Price Control, another suggested that implementation costs would be reduced by resolving issues now rather than adopting transitional measures.

Ofgem/DTI Conclusions

Ofgem/DTI consider that the new arrangements offer the prospect of relatively large and rapidly achieved reductions in wholesale electricity prices and lower prices for both industrial and domestic customers. Beyond the immediate change in price level, there is the prospect of continuing pressure to reduce prices. It is estimated that, if wholesale prices are reduced to a level equal to the full costs of new generating capacity, the benefits to consumers could be of the order of £1.5bn per annum. Among the accompanying measures that are relevant here are those designed to ensure that reductions in suppliers' costs resulting from lower wholesale electricity prices are, in the event, passed on to final consumers. In seeking to ensure that this happens, the Director General will be able to rely on his ability to influence retail prices directly via Supply Price Controls and indirectly through his new powers under the Competition Act 1998.

Whilst the costs of implementing the new trading arrangements are not insignificant, the benefits appear likely to far exceed the costs. Nevertheless, we remain committed to keeping implementation costs down to as low a level as is practical.

10. Timetable and Process

10.1 Timetable

The July Consultation Document

As laid out in the July report, the planning assumption is that new trading arrangements will be introduced in Autumn 2000. As one of the elements necessary to achieve this, contractors for the design and operation of the supporting IT systems are expected to be appointed towards the end of 1999.

Respondents' Views

Around a third of the respondents commented on the timetable and process for the implementation of the New Electricity Trading Arrangements. Ten respondents suggested that the benefits of reform could have been achieved more quickly, more cheaply and with less risk through modifications to the existing trading arrangements under a separate and independent market operator. A small number of respondents expressed the view that RETA has been hurried and consequently has not been as fully consultative with interested parties as was originally intended.

Several responses expressed concern that new trading arrangements are preceding consideration of other important issues, such as transmission access, transmission losses and NGC incentives. Some respondents pointed out that the planned implementation date of Autumn 2000 presents a significant challenge, and stressed the need for a robust and clearly defined start date for the new arrangements. Two respondents advocated a phased implementation (or 'soft landing') of the new arrangements.

Ofgem/DTI Conclusions

The July report explained the concerns that existing Pool arrangements tend to facilitate non-competitive outcomes. Among the problems are the vulnerability of the price-setting process to manipulation, the repeated nature of the standardised bidding process, and the small role afforded to the demand-side in price determination. In principle, such problems might be addressed by a programme of Pool reform. In practice, the Pool has proved difficult and cumbersome to reform, and the supporting policies that may be required in this scenario run the risk of introducing a prescriptive approach to market structure that may itself be anti-competitive.

The proposals contained in the July consultation document followed an intensive programme of work led by Ofgem and the DTI and included all interested parties. There has been wide and detailed discussion, including at public seminars, since the Review was initiated in October 1997. Over 300 papers have been produced and published on the OFFER web-site and over 100 meetings of the DISG and Expert Groups have been held.

As discussed in Chapter 5, work on transmission access, transmission losses and NGC incentives will continue in parallel with the implementation of the new trading arrangements so that participants should have a good understanding of the transmission proposals before the new trading arrangements are implemented.

The need to move rapidly towards detailing the business rules, including their legal drafting, is fully appreciated and work is in progress. A requirement for careful industry-wide trialling and testing is also fully appreciated and a 3 month period has been set aside in the timetable to this end.

Ofgem/DTI consider that the disadvantages of a phased implementation ('soft landing') of the new arrangements outweigh the advantages. If the new arrangements were to be introduced under interim commercial terms that differed significantly from those discussed in previous chapters, it is likely that the behaviour of market participants would similarly differ significantly from that which would be observed were the arrangements to be implemented in full. Such a situation was observed when the gas Network Code was introduced in 1996, initially under so-called 'soft landing' terms. During the 'soft landing' period in gas, shipper balancing behaviour was significantly different from that witnessed subsequently – less rigorous balancing occurred - and provided only limited experience of how the final arrangements would work.

10.2 Central Systems Procurement

Both the Balancing Mechanism and the Settlement Process will require new IT systems to be built and operated. Expressions of interest for the provision of these services were called for earlier in the year and a short list of 9 interested parties has been compiled. The drafting of the invitation to tender (ITT) for the new trading arrangements systems is nearing completion. It is intended that the ITT will be issued on 21 October to the short-listed suppliers. The ITT will cover the procurement of four service delivery packages:

- Settlements (consisting of a number of services);
- Contract data collection and aggregation;
- Meter data collection and aggregation; and
- Funds transfer.

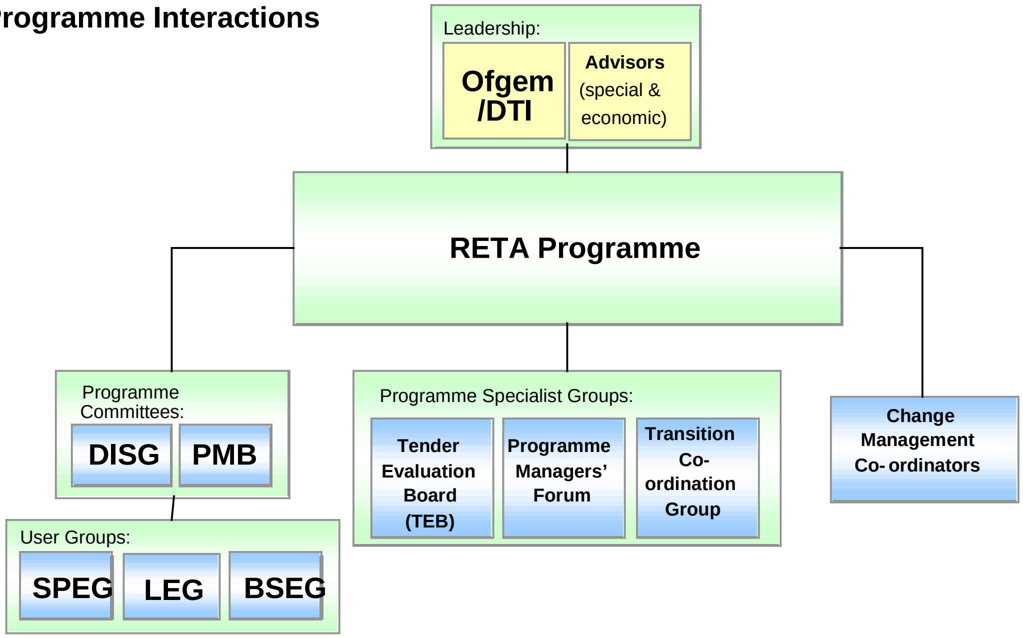
The necessary data transfer services form an integral part of each service package. Suppliers will be able to bid to provide either individual service packages or all four services. Bids will be assessed by the Tender Evaluation Board against five groups of evaluation criteria: business requirements, future flexibility, cost, delivery capability and contractual and commercial requirements.

The ITT will seek fixed and firm prices for all services. It is intended that the costs for both the design and build phases, including implementation costs, will be recovered by service providers through standing charges paid monthly over the initial operational term of five years from the implementation of the new trading arrangements. Operations and maintenance charges will be a mix of standing charges and volume related charges. It is expected that preferred suppliers for each service delivery package will be chosen before Christmas.

10.3 Overview of Implementation

The Programme will continue to be led by the DTI and Ofgem in the Implementation Phase. It will be important that information flows effectively from the Programme to those making their own preparations for the new trading arrangements. In order to ensure the necessary communication and to ensure appropriate transparency, the Programme will continue to work with a number of groups bringing expertise and challenge from customers and the wider industry. The structure shown below sets out how the Programme will interact with those groups.

Programme Interactions



This structure is broadly similar to that adopted during the recently completed Design Phase of the RETA Programme. Leadership and sponsorship will continue to be provided by Ofgem and the DTI, with the RETA Programme Team, led by the Programme Director, providing the main support and central resources.

As before, two Programme Committees, the DISG and the Programme Management Board (PMB) will provide ongoing input to the Programme Director. The DISG will be supported by three User Groups - the Balancing and Settlement Expert Group (BSEG), the Legal Expert Group (LEG) and the Specials Expert Group (SPEG). The role of these User Groups will be to provide analysis and review as the detailed design proposals are developed and to provide a forum for on-going consultation.

Within the RETA Programme, there will be a series of implementation projects. The Contracts and Supplier Management Project will be responsible for managing the procured suppliers whilst the Legal, Regulatory and Commercial Arrangements Projects, will have responsibility for drafting the Balancing and Settlement Code and securing changes to other legal documents. Responsibility for co-ordinating changes across existing systems and processes, including NGC will lie with the Transition Management Project. The Building the Future Organisation Project will establish the Balancing and Settlement Code Company

(BSCCo) with supporting management resources. The Programme Office will also include the Central Design Authority responsible for maintaining an overall design and assessing changes to it, and the Programme Management Office, responsible for Programme planning, change management and issue and risk monitoring and reporting.

The RETA Programme will also be supported by the Tender Evaluation Board, (until systems suppliers have been selected and appointed). The Programme Managers' Forum, which will be a key forum for information exchange with industry participants, and the Transition Co-ordination Group, which will provide support to the Transition Management Project. Change Management Co-ordinators will also be nominated by participants as a focal point for contact and interaction with the Programme Change Control Procedures.

It is anticipated that industry will be required to take the lead in developing, drafting and implementing changes to key industry documents closely connected to the BSC with appropriate oversight by and liaison with the RETA Programme. Documents that will need changing via this route include the Grid Code, MCUSA and Supplemental Agreements, Master Registration Agreement, Interconnector Agreements, Distribution Codes and the Settlement Agreement for Scotland, together with the arrangements for the transition from the Pooling and Settlement Agreement). The Programme will be discussing the process for taking this work forward with the relevant 'owners' of these documents over the coming weeks.

The RETA Programme will not address changes to other contracts which industry parties (or others) may have entered into within the framework of the existing central industry documents. It will be for the parties to such contracts to agree and make any changes necessary to reflect the introduction of the new trading arrangements.

10.4 The Way Forward

Work is now being take forward within the RETA Programme to draw up detailed business rules, to provide legal drafting of those rules and to award contracts for IT systems. Considerable work is also underway by various participants. The DTI and Ofgem will continue to consult frequently and widely, including through public seminars, both on the new trading arrangements and on closely related issues, such as the transmission access regime and the appropriate incentive structure for the SO. Implementation of the new trading arrangements remains on target for Autumn 2000.

11. Conclusions

In the light of responses to the July consultation document, Ofgem/DTI have come to a number of conclusions on the way forward for the New Electricity Trading Arrangements. In their respective chapters, decisions with regard to the Balancing Mechanism, cash-out and settlement arrangements, the role of and incentives on the SO, legal and governance issues and CHP and renewables, have been described in detail. We have also discussed responses received on competition and the trading arrangements and other related issues, including gas and electricity market interactions, and security of supply. In this chapter we present a summary of the conclusions reached on key issues, and briefly list other decisions that have been taken.

11.1 Key Issues

Imbalance Cash-out Prices

The preferred option of dual cash-out prices, as outlined in the July report, with the System Buy Price defined as the volume weighted average price of the offers accepted in the Balancing Mechanism and the System Sell Price as the volume weighted average of accepted Balancing Mechanism bids, will be retained. Ofgem/DTI believe that it is simple and transparent in comparison to the alternatives suggested. However, Ofgem/DTI agree that it would be desirable to remove constraints from energy imbalance prices in the short-term, pending the implementation of a market-based approach to transmission access. Ofgem/DTI will continue to work closely with NGC to explore ways of flagging constraint-related trades as a simple and effective interim measure.

The Timing of Contract Notification

Contract notification will be *ex-ante* and initially occur three and a half hours before the start of a trading period. Ofgem/DTI believe this is a useful step to ease concerns of customers and generators with interruptible gas contracts. Following the implementation of the new electricity trading arrangements, the timing of contract notification will be kept under review in the light of market developments. It is envisaged that the contract notification time will track the anticipated shortening of the Gate Closure period (discussed below).

Separate Production and Consumption Imbalance Volumes

Ofgem/DTI recognise the concerns that some respondents have in this area and strongly believe that any features of the trading arrangements which, over time, prove to restrict unduly participants' commercial freedom should be re-examined.

Nevertheless, at least initially, there will be separate production and consumption accounts in order to aid the SO in balancing the system and alleviate concerns over providing vertically integrated players with undue advantages. However, as Gate Closure is anticipated to shorten over time, more opportunities will become available for generators, suppliers and customers to balance with each other without relying upon the energy balancing role of the SO.

Meter Splitting and Aggregation

Ofgem/DTI remain committed to putting in place flexible arrangements for aggregation and meter splitting so that participants are able to manage their imbalance exposure in an efficient manner. Having taken due consideration of respondents' views, splitting of meter splitting by volume as well as by percentage will be allowed.

Ofgem/DTI recognise the advantages that might arise from an active role being played by aggregators under NETA. No limits will be placed on aggregation but this does not remove participants from their obligations under the Electricity Act and general competition legislation.

An assessment of the impact on Stage 2 will be undertaken to identify the method and timescale for providing a facility to allocate consumption through a single meter to more than one supplier.

Governance

In the July report Ofgem suggested that the BSC Panel members could either be elected from and accountable to market participants or be appointed by a Chairman and be independent of market participants. After taking account of industry views, Ofgem/DTI now believe that a hybrid model would be the best option with the Panel consisting of a

Chairman, five industry members, two independents and two customer representatives. The Regulator intends to appoint a Chairman in the near future.

CHP and Renewables

It is inevitable that the introduction of new arrangements will have different effects for different market participants. Ofgem/DTI believe that the changes to the BM Unit splitting arrangements and the intended reductions in Gate Closure should provide greater flexibility and help alleviate the concerns of renewables and CHP schemes with regard to exposure to imbalance prices. The Government has made it clear that encouraging the development of CHP and renewables schemes is part of its overall policy.

11.2 Timing of Gate Closure

Having taken due consideration of the views of all respondents Ofgem/DTI consider that Gate Closure should be set initially at 3½ hours before the start of a trading period. Reducing Gate Closure by only half an hour compared with the July report will overcome the concerns about interruptible gas contracts whilst recognising NGC's concerns about carrying out its balancing functions. NGC has told us that it is considering the reduction of Gate Closure to 3½ hours with a view to accommodating Ofgem/DTI's concerns regarding gas interruptions. Ofgem will also reconsider the issue of transportation interruption timescales in gas.

Experience with the new trading arrangements (and the introduction of new transmission access rights, which would enable capacity constraints to be managed via the capacity regime rather than through the Balancing Mechanism), should enable Gate Closure to be shortened considerably. Accordingly, subject to re-evaluation in the light of experience in operating the new regime, it is intended that Gate Closure should be reduced again after six months and that additional reductions should be implemented thereafter as this becomes practicable.

11.3 Role of the System Operator

Ofgem/DTI recognise the key role that the SO has to play in balancing the system and believe that the most effective way of ensuring that this occurs at minimum cost is to define an appropriate incentive scheme for the SO. On this basis, the SO should have freedom to contract for the services that it considers it requires, providing the purchase and exercise of such contracts is carried out in an open and transparent manner. However, recognising the concerns expressed by respondents, Ofgem/DTI believe that further consideration should be given to the relationship between balancing services contracts and the Balancing Mechanism.

The role of transmission losses will be considered in further detail in Ofgem's forthcoming November paper on capacity arrangements and NGC incentives. However Ofgem currently believes that there would appear to be merit in the SO purchasing losses, with the costs being recovered via use of system charges, which would probably be charged out on a locational basis.

A review of all aspects of the transmission pricing regime has already commenced as part of the preparations for setting revised incentive schemes consistent with the new trading arrangements and for the next NGC transmission price control which commences in April 2001. Initial consultation papers on these issues will be published shortly and work on these aspects of the electricity market will continue in parallel with the implementation of the new trading arrangements. By proceeding in this way, Ofgem believes that participants will have a good understanding of the transmission proposals before the new trading arrangements start.

11.4 Other Decisions

The *de minimis* level for the provision of IPN and FPN data to the SO will be 50 MW for both the generation and demand sides of the market. However, NGC will review this level in the light of experience in order to consider whether the level might be raised, or to make a case to Ofgem to request information from smaller sites where necessary. Ofgem/DTI envisage that smaller participants will be able to use agents to submit and receive information on their behalf in order to share the costs of communication with the SO.

Ofgem/DTI believe that both BM Unit parameters and the bidding structure should be kept as simple as possible while accepting that NGC requires adequate information to enable it to balance the system. We believe that work should continue over the coming months to simplify the parameters.

Ofgem/DTI agree with the general industry consensus that the minimum lot size for Balancing Mechanism offers and bids will be 1 MW.

Quiescent FPNs will be retained to encourage demand-side participation. However, although some further consideration of alternative definitions would appear to be warranted it is also recognised that it will be impracticable to introduce this change initially due to the limitations of the Stage 2 systems.

Although Ofgem/DTI agree that allowing re-bidding would be desirable, given NGC's belief that the necessary systems cannot be implemented in time, we accept that this restriction will be retained. However, we agree with the majority of respondents that this issue should be reviewed in the light of experience, although the reduction in Gate Closure will reduce the need for re-bidding.

Ofgem/DTI believe that the use of Deemed Offers and Bids is one method to ensure that, in the unlikely event that all the relevant available offers and bids in the Balancing Mechanism had been exhausted and further actions to balance the system were still required, the SO had a mechanism to instruct load and a method of remunerating participants who followed those instructions. However, we consider this issue requires further consideration.

NGC's concerns regarding Deemed Acceptances are acknowledged by Ofgem/DTI. The issue also requires further discussion over the coming months in conjunction with the transmission access review.

Ofgem/DTI share the view of many respondents that any surplus (or deficit) arising from imbalance cash-out should be returned to BSC parties on the basis of their metered volumes. In addition, Ofgem/DTI consider it would be appropriate for the costs or revenues that the SO incurs in accepting Balancing Mechanism actions, suitably adjusted by its incentive scheme, to be shared back across BSC parties using the same charging methodology as that adopted for charging net imbalance revenues/costs, that is on the basis of metered volumes.

The credit cover proposals set out in the draft BMIS specification were unduly onerous. Ofgem/DTI believe that credit requirements should, in the first instance, be an issue for participants to resolve among themselves, since parties to the BSC will ultimately be exposed to any uncovered liabilities in the event of default. We propose that an industry working group to be charged with the task of developing acceptable proposals for credit cover, which will then be reviewed by Ofgem and the DTI.

Ofgem/DTI continue to believe that, whilst it is appropriate to have the functionality available to levy an information imbalance charge, initially its value should be zero.

Ofgem/DTI agree with the majority of respondents that, in principle, network operators should bear responsibility for imbalance costs arising from failures of transmission and distribution systems. The issue of transmission failures will be discussed further and considered as part of the present review of transmission access. In the interim, transmission failures will be treated as constraints resulting in no imbalance. Ofgem believes there is a strong case for reviewing the incentives upon distribution companies to ensure that fair compensation is available to affected participants in the event of distribution failures.

The treatment of interconnectors should be consistent with that of other participants. Consequently, the July proposals have been changed, more closely to align the timing of volume allocations for interconnected parties with the arrangements for other participants.

Ofgem/DTI believe that the introduction of appropriate incentives on NGC to balance the system efficiently will make it unnecessary to maintain the Ancillary Services Business as a separate business and therefore its licence requirement to operate a separate Ancillary Services Business will be removed.

Over time the range of price information readily available under the new trading arrangements should be much greater than at present. However, Ofgem/DTI believe that it is appropriate to retain the backstop option of the Director General having powers to publish prices in the event that price reporting is slow to emerge.

Ofgem will continue to ensure that the new trading arrangements in electricity and gas are complementary and that they facilitate efficient and economic arbitrage within the energy markets.

Appendix 1 Responses to the New Electricity Trading Arrangements Consultation Document of July 1999

*Denotes electronic copy available.	Company
	ABB Energy Information Systems Limited
	ALP Energy Ltd
	Aquila Energy Limited
	Associated Electricity Supplies Limited
*	Association of Electricity Producers
*	Automated Power Exchange, Inc
	BCN Data Systems Ltd
*	BOC Limited
	Box Ten Limited
	BP Gas
	British Energy plc
*	British Nuclear Fuels plc
	British Steel plc
*	British Wind Energy Association
*	Campbell Carr Consultancy
	Centrica plc
	Chemical Industries Association
	Combined Heat and Power Association
*	Confederation of British Industry
	Confederation of Renewable Energy Associations
	Confederation of United Kingdom Coal Producers
*	Dalkia Utilities Services plc
*	Department of the Environment Transport and the Regions
	Dynegy UK Limited
*	EA Technology Limited
*	Eastern Power and Energy Trading Ltd
	Edison Mission Energy
	ElectraLink Ltd
	Electricity Consumers' Committee - Midlands Region
*	Electricity Consumers' Committee - North West Region
*	Electricity Consumers' Committee - South East Region
	Electricity Consumers' Committee - Yorkshire Region
*	Electricity Direct
	Elf Gas and Power Ltd
	Ener G plc
	Energy from Waste Association
	Energy Intensive Users Group
	Energy Saving Trust Ltd
*	Enfield Energy Centre Limited
	Enrici Power Marketing Limited
*	Enron Europe

*	Entergy Power Group
	Fellside Heat and Power Limited
	Fibrowatt Limited
*	First Renewables Ltd
	Glenton Bruce Ltd
	Humber Power Limited
*	ICI Chlor-Chemicals
	Impax Capital Corporation Limited
*	Independent Energy UK Limited
	Intergen (UK) Ltd
	Kvaerner Energy Limited
*	Logica UK Limited
	London Business School
*	London Electricity plc
	M & N Wind Power Ltd
	Major Energy Users' Council
	MRA Service Company Limited
	National Economic Research Associates
*	National Grid Company plc
*	National Power
*	National Wind Power Ltd
*	NECC – Generation Focus Group
	Non Fossil Purchasing Agency Limited
*	Northern Electric and Gas Limited
	Norweb Energi
	OM London Exchange Ltd
*	PowerGen
	RES
*	RJB Mining
*	Royal Society for the Protection of Birds
	Scottish and Southern Energy plc
*	Scottish Electricity Settlements Ltd
*	Scottish Power plc
	Seeboard plc
	Shell UK Limited
*	Slough Heat and Power Limited
	South Coast Power Limited
*	South Wales Electricity plc
*	SWEB
*	Teesside Power Ltd
*	Thames Power Limited
	TM Environmental Power
*	Unit(e) energy Ltd
*	University of Hull (Richard Green)

* Utility Buyers' Forum
* Viridian Power Resources Ltd
* Yorkshire Electricity Group plc

Appendix 2 Views of Respondents

The following indicates the range of views expressed in response to the New Electricity Trading Arrangements consultation paper (Volume 1). It does not seek to quantify the extent of support for any particular view or attribute comments to individual respondents.

Need for Reform

- There is a clear need for much reform
- Strongly support Ofgem's intention for the proposed changes to make arrangements more competitive, more transparent, more responsive to the demand side and easier to change in future should further refinement be required
- Very supportive of the new electricity trading arrangements because more sensible commercial arrangements will be a step towards the development of a market which will deliver internationally competitive prices to large and intensive electricity customers
- Strongly support the objectives of the NETA programme
- Strongly support the broad thrust of Ofgem's proposals
- You can be assured of our full support and commitment to the Programme
- The new trading arrangements will promote competition and deter the new entrants seeking to capitalise on an apparent "easy wicket"
- The proposals represent a major step forward for the development of an efficient market
- The proposed new arrangements are considered flexible and effective and should result in a more balanced system of trading
- The new electricity trading arrangements model will allow all parties the flexibility to develop a contract framework suitable for their needs and should provide a fairer basis for trading whilst avoiding discrimination against any one fuel technology
- These arrangements certainly represent an improvement on those in place
- Supportive of the overall direction outlined in the document
- The development of trading arrangements in Scotland should now proceed as a matter of urgency
- Improving the trading arrangements is valuable, but only part of the solution

- Ofgem should not be tempted by temporary solutions; a well thought through and rounded design is required
- The Pool should be reformed in an evolutionary manner, with a licence
- We do not accept Ofgem's characterisation of previous trading arrangements
- The current trading arrangements were originally stifled and are only now beginning to develop with the introduction of full competition and the ending of the coal contracts
- The introduction of the 1998 trading arrangements has been beset with problems, and were are not yet operating within a stable environment
- Wish to re-affirm commitment to delivering reforms but remain convinced that the benefits could have been achieved more quickly, more cheaply, with less risk and without jeopardising substantial investments through modifications to the existing process under a separate and independent market operator
- The present arrangements have encouraged supply competition
- By concentrating on greater competition in generation the new arrangements will damage and reduce effective competition in supply (since suppliers will have to establish additional systems and infrastructure)
- Reject many of Ofgem's assertions about the failings of the current trading arrangements but recognise and support the importance of exploring alternatives
- It is essential that the proposals are tested rigorously against the Programme's objectives
- The option should be subject to environmental appraisal, and wider economic and social appraisal.

Compatibility with Government Policies

- NETA is consistent with the central Government energy objective of providing secure, diverse and sustainable supplies of energy at competitive prices
- The proposals are inconsistent with Government's other policy objectives which are to promote CHP, not just treat it equitably
- With the implementation of the new electricity trading arrangements we expect that the current moratorium on Section 36 consents to CCGTs would be rescinded
- Particularly concerned that the recent focus of DTI consents has been on fuel diversity issues that has nothing to do with trading arrangements
- If the DTI and Ofgem have revised their position on the implementation of the new electricity trading arrangements such that there is little change in consents policy, then

this will have major implications in respect of future market development, if coal is going to be given significant protection from market forces

- The consultation has been drawn up mainly to try to bring down electricity prices. In environmental terms its effects will be adverse
- Concerned at the marginal manner in which CHP (and renewables) has been treated in the consultation paper despite the centrality of CHP to a number of important Government policies
- Deliberations surrounding the Climate Change Levy and Renewables Review have not acknowledged the imminent impact of reduced prices under the new electricity trading arrangements
- Unless the introduction of the new electricity trading arrangements is compensated for through the Climate Change Levy (with due exception being given to CHP) then there is a clear danger that the development of CHP in the UK will be stifled
- Investment in CHP will be discouraged
- The reference to the Climate Change Levy is not considered to bode well for coal. It could be construed as distinctly discriminatory
- Price reductions of 20% would be an important factor in investment decisions affecting the life of a number of nuclear power stations. This in turn could affect the prospects for diversity of UK fuel sources and have a significant influence on expectations of the UK's ability to meet the carbon dioxide emission reduction targets to which the Government is committed.

Timetable

- It is vital that the October 2000 target is met
- Given the stricter consents policy is tied to reform of electricity trading arrangements, it is crucial that the new electricity trading arrangements programme adheres to its agreed schedule
- There is a need for a clearly defined start date
- We are concerned that the reforms could be delayed by constraints in the legislative timetable
- It is essential that Ofgem recognises the major development needed by IPPs in particular, if they are to continue to operate in the new trading environment
- The current implementation date of Autumn 2000 represents a significant challenge

- An April 2001 start will provide adequate time to clear all the necessary legal issues associated with the MCUSA and other contracts
- The new electricity trading arrangements should commence in April 2001 rather than Autumn 2000 because Autumn precedes a period of rising prices and the effect of trading on the balancing mechanism, if not properly understood or operated could result in yielding higher average prices for suppliers in a period when prices are naturally high and margins naturally negative for suppliers
- It takes at least 6 months to specify and design IT systems and business processes around any new arrangement; an Autumn 2000 start only leaves 6 months to deliver the system once it has been specified and designed
- There is an urgent need to agree the formats and media for data exchange with the Grid Operator
- When the new arrangements are fully implemented they should be allowed to take effect without Government or regulatory intervention.

Process

- The review has been hurried and consequently has not been fully consultative with interested parties as was originally intended
- Recognise that extensive debate has taken place on a large number of the proposals within the DISG and Expert Groups
- Pleased to see good progress has been made and that many of the concerns we have previously expressed have been addressed
- Industry and customers were not sufficiently involved in the decision making process
- Perceptions of regulatory risk have been greatly increased by the extent of the detail still to be decided
- The new electricity trading arrangements programme is so extensive and rests on so many uncertainties, that it should be treated to a full-scale ongoing evaluation of impacts
- There is still some way to go before a complete and credible design is in place
- Concerned at the lack of quantitative analysis behind decisions
- There has been no analysis of the economic benefit that will flow from the reform.

Implementation

- For the new electricity trading arrangements to move ahead clear assurances must be given that the market structure that may emerge will enable the Government to not only deliver its more immediate goals in relation to competition but also to secure its broader, long term, environmental targets.

Systems Development and Procurement

- Recommend that the procurement exercise includes, in the tender/specification, for a terminal and connection to be provided at each user's premises. Together with a firewall between the SO licensed access facility and user's own systems this would ensure that delays incurred by individual participants due to development timescales and extensive testing requirements could be eliminated or minimised
- Development costs by the industry could be reduced by a "one spec-one system" approach
- The terms of the current Data Transfer Agreement must be reviewed since they include excessive charges with minimal liability
- Ensure that the timeframe is sufficient to specify build and test both the central and participant IT systems
- Ensure that any specification is in the public domain for sufficient time to ensure that there is competition between IT providers so lowering the IT costs
- Greater clarity is needed as to how is procuring or providing software and/or infrastructure services.

Communications

- Access costs should be minimal
- Taking full advantage of eCommerce when building the market infrastructure will provide flexibility, promote transparency and enable rapid response to changing market requirements at low cost as will simplifying access to market information
- A common user (Internet based) interface should be built to allow participants to interact with the Balancing Mechanism, Contract Aggregator, Meter Data Collector and Settlements Administrator.

Balancing Arrangements

- Fully support pay as bid for accepted bids in the BM
- Accepted bids should be firm on both sides
- Basic principles for the operation of the Balancing Mechanism are sound, in particular firm delivery of bids and offers and pay as bid are correct and a non-delivery charge is sensible – only concern relates to the receipt of that charge
- Simplifying the Balancing Mechanism will result in lower barriers to entry, greater flexibility and lower overall market costs
- The design (of the BM and Imbalance Settlement) has become very complex and cumbersome as rules have been added to fix perceived problems with the existing Pool
- Complexity imposes significant cost burdens on all parties, particularly smaller players who will be driven to seek refuge with the larger players
- No party should be allowed to withdraw plant except for technical reasons
- Ofgem should seek to ensure that most generators participated in the BM
- There is no way to control the behaviour of the party whose trade has been accepted
- Participants need to be assured that the SO is buying and selling on a transparent, non-discriminatory basis
- The design of the market is generator-centric with little attention given to determining how the demand side can compete on equal terms
- Balancing Mechanism settlement periods should be shortened from 30 minutes to 5 minutes, increasing volatility and making prices more reflective of the costs and operating risks associated with providing flexibility
- Imperative to restrict the size of the BM so as to limit the impact of cash-out prices on the forward price curve
- Transparency in price setting and operation of the market is not adequately addressed.

Appropriate Levels for the Provision of Information to the SO

- FPNs should encompass all generation and demand
- All parties wishing to participate in the balancing mechanism should be required to submit an FPN
- Appropriate to receive information from those whose actions are discernible by the SO and would potentially require action – ie 100 MW
- See no reason to change significantly from present arrangements; for embedded generation, this would mean retaining the current 50 MW export limit
- All those generators and suppliers who trade more than 10 MW should be obliged to provide generation/demand information to the SO
- All generators or suppliers whose output or consumption is significant in determining the appropriate balancing action
- Information should be provided to the SO to assist in system security planning and it is inequitable that size alone can change the commercial consequences of embedded status for 100MW generator compared to an aggregation of unlicensed generators
- Smaller suppliers should be allowed to choose to submit only one daily IPN (which could also count as the FPN)
- Only those customers wishing to participate actively in the BM should be required to give FPNs
- *De minimis* levels should be based on what is of practical value to the SO – this could mean different levels for different classes of participant
- The *de minimis* limit applies where specific FPNs are required for a site otherwise the site's generation of demand can be included in a higher level aggregation (eg GSP group)
- *De minimis* levels are likely to differ according to the type of information; the trend elsewhere is to accept smaller volumes as competition matures
- The *de minimis* limit applies where specific FPNs are required for a site otherwise the site's generation of demand can be included in a higher level aggregation (eg GSP group)
- Preference would be for all participants to provide the same information
- Demand side data must be of similar standard to that of the generation side to ensure the integrity and security of the system

- NGC has not required demand information below a high threshold in the past; it is not clear that it needs it now
- The principle adopted should be based on a cost/benefit judgement comparing the extra cost for a participant who has not previously communicated with NGC against the added value to NGC in controlling the system in real time
- Submission of FPNs and bid/offer pair data will impose a significant cost on BM participants (ie. barrier to entry).

Dynamic Data that Should be Provided by BM Units

- Generation and demand should manage their own concerns about technical specification by submitting competitive bids and offers
- BM units should be free to define whatever dynamic data they wish to provide to the SO. Failure to recognise this will result in missed opportunities and higher prices to customers
- The level of data submission should be the minimum that NGC requires commensurate with the need to operate the system
- Should be sufficient to describe the true dynamic characteristics of the BM unit
- List seems reasonable though Station Synchronising and De-synchronising Interval could also be included
- A Minimum Export Limit should be included
- The present price ladder is unduly restrictive; more than one price pair should be permitted for any given inc/dec relative to FPN reflecting the different dynamic characteristics that a BM participant may be prepared top offer
- There should be a requirement for information on demand side MVAR as well as the capability of generation
- Prefer to see the list reduced and controls and process put in place which recognise this is standing data and changes should be limited
- Allowing complex bids will inhibit transparency and liquidity
- Should not be attempting to replicate GOAL and a simpler approach to dynamics should be adopted
- Dynamic data should be time stamped thus enabling changes to be tracked, the right choices to be made and answers provided after the fact

- Dynamic data can be used to both withdraw and place bids and effectively allows portfolio participants to effectively bid re-pricing
- Appropriate to consider the provision of "spare" dynamic data items when specifying software systems thus minimising restrictions on future development.

Appropriate Minimum Size for Balancing Market Offers and Bids

- 1 MW is probably adequate but the key relationship is to metering accuracy
- 1MW would be practical for software design but a 3MW limit might be appropriate initially
- 5 MW initially to ensure the greatest level of participation and liquidity whilst offering NGC practical solutions to actions it may be required to take
- 5-10MW
- Whatever is consistent with the metering standards adopted for meters at direct connections to the transmission system.

Quiescent FPNs

- Unclear as to who would use this; it appears to be a level of complexity that is as yet not supported by an assessment of its value
- Does not appear to be any advantage from introducing Quiescent FPNs and it will make the Balancing Mechanism more complicated
- The concept of Quiescent FPNs does not address the fundamental inequities stemming from unpredictable loads and Stage 2 arrangements more generally
- Both producers and suppliers could have negative energy values at the GSP Group; it is inequitable to determine that any negative supplier values are set to zero whereas negative producer values are acceptable
- Consumption should not be treated as negative generation. Quiescent FPNs seriously discriminate against the demand side – information requested by the SO recognises the complexities of generation yet the composition of a typical large demand site is far more complex
- Preferred approach, at least initially, would be to preserve the current treatment as far as possible
- The arrangements for shared supply through interconnectors would be equally applicable and easily administered

- Multiple BM units are possible at an interconnector and similarly the complexities of demand sites should be recognised
- Support the ability to submit quiescent FPNs. This will encourage more demand side participation
- Potentially of value to the extent that they assist demand-side participation
- The use of deemed bids/offers looks arbitrary
- Wouldn't it be simpler and more efficient to install a meter?
- If NGC is incentivised to reduce costs, zero priced offers would be an attractive proposition.

An Appropriate Definition for Demand Capacities

- The first approach is more accurate but costs more to implement and operate however, many markets are moving to this approach
- Favour the more pragmatic approach of the previous winter maximum demand figure with an allowance for weather variation
- Any historic measure of demand capacity discriminates unduly against those suppliers actively competing and growing their business
- Demand capacities should be based on recorded maximum metered demand adjusted for weather and other justifiable factors eg increase in site load
- Demand capacities should be set using the maximum level of demand metered during the previous winter (possibly with allowance made for particularly unusual weather)
- Support the pragmatic proposal to based Demand Capacity on the maximum metered demand during the previous winter until a long term solution to transmission access which addresses the issue of demand capacity is introduced
- Any definition should allow for both weather effects and changes in a supplier's customer base
- Limiting demand capacity to historic levels discriminates against expanding suppliers if bids are limited by the FPN
- Linking the Demand Capacity to supply through each GSPP would be consistent with the general approach for generation
- Use a quarterly prediction of demand +/- a factor (x%) to allow for likely customer migration based on the prevailing trends for individual suppliers within the GSP group

- A more sensible definition might be to allow up to a defined percentage (perhaps 5% or 10%) above the data submitted as peak demand to the Seven Year Statement.

The Scope and Volume of Balancing Services Contracts

- Correctly structured balancing services contracts could significantly enhance competition to provide balancing services
- Contracting is appropriate for fast acting plant
- Tenders should be held frequently
- As many balancing services as possible should be treated as options
- Existing ancillary services should be sufficient to ensure within half-hour balance
- The service provider required to procure balancing service contracts should be appointed utilising the competitive tender route
- The scope and volume of balancing service contracts will have to be greater than at present initially and should be limited to a one year maximum and ideally six months to allow some experience of the market to be obtained before entering in to longer term contracts
- Support NGC having reserve, response and options contracts, at least at the start
- Contracting by NGC should be transparent both in tendering and in operational processes
- To minimise distortion NGC should be confined to purchasing options in an open and transparent day-ahead auction for limited volume
- NGC's role should be limited to the period of balancing which ideally should be much shorter than 4 hours
- NGC should be encouraged to exercise options on any generation it does not require prior to gate closure and sell back that generation in an open and transparent way
- NGC's ability to forward contract reserve, response and options may inhibit or place artificial caps on the operation of the balancing market resulting in distortion and reduce liquidity
- Allowing the SO to enter into a high volume of reserve contracts would distort prices in the BM and Power Exchange
- NGC should not be able to buy energy before Gate Closure in the form of balancing services contracts

- NGC should not be allowed to participate in trading Balancing Mechanism derivative contracts
- Concerns about balancing the system using Balancing Mechanism trades should be addressed by changing the time of Gate Closure rather than allowing NGC to trade balancing mechanism hedges
- The present arrangements compel market participants to provide NGC with certain services; these restrictions are incompatible with arrangements under which NGC is incentivised on system balancing costs
- Will not accept giving the SO a free hand in providing Ancillary Services; if NGC wishes to pursue this activity then it should be established as a wholly separate business
- The proposals should be refined for further consideration; there is concern at the thinness of the balancing market and the interaction of market power across segments and the consequent difficulty of establishing cost reflective prices
- If a market-based solution for reactive power is developed then NGC's reactive power related assets should become part of the market in a separate ring-fenced or divested business
- Any NGC 'mattress' to soften the impact of balancing would have the same effect as regulatory intervention
- Balancing services contracts could help to provide a soft landing.

The Role of the Ancillary Services Business

- Ancillary Services should be purchased annually by way of an open and competitive auction
- Auctions would not be an economically efficient way for NGC to secure these services
- There is no need to change the role of the Ancillary Services Business
- Ancillary services should continue to be a ring-fenced commercial activity
- Ancillary services should be procured by market participants with operational control turned over to NG in real time. NGC's role in procurement should be limited to publishing technical standards and acting as agent to procure capacity on behalf of parties that fail to do so on their own by the time FPNs are to be submitted
- Strong argument for this to be a licensed activity separate from NGC
- There seems no real reason to alter the general nature and type of ancillary services

- Now that there are incentives on the Transmission Business which include the costs of Ancillary Services contracts the separation of the two businesses does not appear necessary
- Severe restraints need to be imposed on NGC's ability to both operate and play the market given that there is no clear distinction between the role of Ancillary Services and the Balancing Mechanism
- Customers should continue to have the option of longer-term contracts
- An operational interface for call off of Ancillary Services has not been addressed – over time direct contact with each power station will decline and the direct interface will be with energy management centres – NGC's insistence on genset by genset IPNs and FPNs bid and offers is merely seeking to perpetuate an unnecessary degree of central control
- A market in response should not pre-date RETA
- Preferred approach is that any balancing energy covered by Ancillary Services is priced via a hedge around the Balancing Mechanism
- Significant modelling is needed.

Gate Closure

- Would support an increase to six hours to encourage people to manage their positions
- Should not be reduced to less than four hours for at least the first two years after the implementation of the new electricity trading arrangements
- Evolution of market arrangements may be possible once there is evidence from actual market operation eg if genset notice periods and ramping times consistently reduce and are proven in practice then a short Gate Closure may be feasible
- Not convinced by the reasons put forward by NGC for four hour Gate Closure
- To resolve concerns with the discrepancy in timing between the gas and electricity markets either the period between Gate Closure and real time should be decreased or the notice period for gas interruption increased
- Bids and offers should be accepted up to four hours before real time with the period for submission of FPNs reduced to one hour
- Allowing contract data to be submitted within a half hour of Gate Closure is practical but could be constraining
- Trading up to real time will reduce the benefit to large vertically integrated players

- The final deadline should be at least real time
- Uncoordinated activity by participants post Gate Closure could result in cost, no net overall benefit to consumers and could jeopardise security of supply – consideration should be given to advising the market (say by enabling forward balancing market cash-out prices to be predicted) that there is no basic problem requiring wholesale control action
- Replacing complex bids and offers with shorter intervals in the BM will substantially simplify and greatly reduce development and operating costs for the two-way communication between SO and generators

Re-bidding

- Permit the withdrawal and resubmission of BM Units bids and offers after Gate Closure
- Re-balancing on a commercial basis should be allowed to take place continuously
- Continuous revision of balancing bids and offers reduces the SO's task to calling bids and offers based simply on price, or on price and location where there are grid constraints. This makes settlement simpler and reduces the likelihood of disputes over why certain bids and offers were called "out of market"
- Support the principle of no re-bidding at the outset but entering new bids should be considered for the demand side
- No rebidding allowed after Gate Closure
- Introduce the use of Generator Performance Monitoring within the balancing mechanism settlement rules.

Deemed Bids and Offers

- See no justification (in terms of security of supply issues) for the proposal to allow non-market related solutions such as Deemed Bids and Offers to aid the SO if there are no bids/offers on the Balancing Mechanism. The SO will contract through ancillary services to insure itself against this possibility
- There should be no requirement for Deemed Balancing Mechanism Bids and Offers as there should be a facility for both generation via MAXGEN declarations and demand by an analogous value, to be able to declare the appropriate level at which the SO can take action and whatever the mechanism there must be a robust warning system in order to prevent such events occurring in the first place

- A mechanism for standing bids in the Balancing Mechanism must be created as well as an easy way of direct despatch to the customer
- Understand and agree the need for Deemed Bids and Offers in the context of security of supply but the proposal to settle at zero price effectively introduces the mandatory element of the Pool by the back door. It creates upward pressure on prices and it is not clear whether the SO may call upon deemed offers from participants.

Settlement

- The systematic unpredictability that the Stage 2 processes create for profiled customers will, under RETA, cause these customers to be more risky and therefore more expensive to supply – the option of tolerances should be considered
- Stage 2 was designed for a "pool" and it does not fit well with the new electricity trading arrangements. It should either be left out of the arrangements or given a softer treatment for cash-out eg only pay commodity price
- The current Stage 2 constraint on non-pooled generators only being able to trade with two suppliers needs to be lifted
- All trades made through the power exchange should be automatically notified to Settlements thus reducing the risk of error and minimising dispute volumes, and could facilitate notification well ahead of Gate Closure
- A trader who has signed the BSC Code will be able to write contracts with other BSC participants that can be notified for settlement. If a trader is not a participant the contracts will not be capable of recognition under the BSC – the issue of any resulting imbalance accruing to a counter party would be treated does not seem to have been addressed.

Cash-out

Preferred Options

- Strongly support dual cash-out
- Strongly support dual and weighted average cash-out when partnered by ex-ante contract notification proposals
- Support dual cash-out with *ex-post* contract notification
- Support Ofgem's inclination to prefer the third option
- The proposal for a weighted average Buy and Sell price is a workable solution
- Not in favour of the two price balancing mechanism, but of the two price options the one proposed is best
- Option 3 would be the most reflective of true costs if transmission constraints costs were removed and this formulation should provide a smoother transition to the potential future changes in transmission access rights
- Option 3 is flawed since it includes the costs of constraints and other transport related and AS related costs; it is also highly dependent on SO purchasing decisions
- Significant reservations about the preferred (third) option for calculating the imbalance prices
- A variant of Option 2, based on accepted offers/bids is preferred
- Participants who spill should receive a lower price than if they had been fully contracted and participants on whose behalf the SO has had to procure the flexible delivery of electricity should pay the full costs; this suggests a dual cash-out price is required
- Our preferred approach is an imbalance price based on dual cash-out and ex-post unconstrained schedule in which the cheapest bids or offers required to meet the net imbalance volume of imbalances are identified
- The option put forward by NGC, entailing dual imbalance prices based on system average weighted formulations for bids and marginal pricing for offers (when the system is short), will provide the most economically robust pricing signals
- Support a dual price determined from a simple EPUP stack however, the question of equitable recovery of the transport and common balancing services costs remains to be answered

- The preferred formulation of the imbalance price will not provide appropriate economic signals
- Dual imbalance price undermines the risk sharing principles of Stage 2
- The primary incentive of a two-price model is to aggregate and pool errors. This leads towards the 2-pool model considered and discarded before privatisation
- Dual pricing introduces great complexity, risk and inefficiency
- The complexity of dual price cash-out and the inability to hedge economically will make the market unattractive to inward investors in energy intensive businesses
- The arrangements are complex; support simple and transparent pricing
- A single imbalance cash-out price should be adopted
- Single pricing should be reconsidered to give efficiency and remove complexity
- Revert to a single, broadly cost-reflective cash-out price which would avoid the need for additional rules relating to aggregation and to limitations on the timeframe within which contracts can be traded or as a fallback adopt a methodology for calculating dual cash-out prices.

Interaction Between Energy, Transport and Other Costs

- Imbalance cash-out should not be polluted by transport costs
- Constraints must not be dealt with through the balancing mechanism
- Constraints should not be included in the cash-out arrangements
- Accept in principle that imbalance cash-out prices should reflect the full costs which have to be resolved by the SO over relatively short time scales; given the difficulty in calculating the full costs, the construction of any pricing system requires an element of judgement and pragmatism
- Important to find the best approximation possible to separating the costs of achieving energy balance from those of ensuring a stable transmission system
- Any interim fix which is adopted to remove the costs of transmission constraints should not have the effect of removing energy costs
- Recommend that until transmission access rights are suitably defined and allocated constraint costs should be extracted from imbalance price derivation

- Issues associated with transmission access and pricing are inseparable from energy balancing and there may be value in taking the timescales for the transmission review into account when planning the new electricity trading arrangements implementation date
- Constraints come about as a result of localised problems and should be borne by the individual parties causing them
- Aggregating the costs of alleviating transmission constraints around the country into one system imbalance charge will remove one of the central tenets of the value of embedded generation such as CHP
- In gas, the pollution of energy imbalance prices with capacity and constraints costs leads to inappropriate price pressure and undesirable price volatility in primary, associated and secondary markets
- An additional stage in the process should be to exclude those Bids/Offers taken for constraint purposes
- Imbalance charges should not be used as a vehicle for recovering other costs (such as set up costs).

Cash-out and Market Power

- A two-price regime will give incentives to deviate from FPN for commercial reasons; Portfolio participants will be relatively advantaged by this
- Dual cash-out, in combination with the proposal to assess imbalance charges separately on generation and demand penalises vertically integrated firms
- The ability to trade out imbalance exposure ex-post could result in large incentives for post Gate Closure physical re-balancing by large portfolio companies
- NGC has the potential to lessen price movement immediately before the BM opens.

Calculation of Cash-out Price

- The advantages and disadvantages of different cash-out methodologies have been extensively debated
- Recommend the development of a differential cash-out structure with flow-weighted average price applied to minimal imbalances and marginal price being applied to large imbalances

- Agree the use of a flow weighted average cash-out price has a number of advantages, however this is by no means unstinting support
- Support the use of weighted average dual price cash-out with the non-delivery rule but would like to see further analysis of marginal cash-out
- The volume weighted average of the actual Buy and Sell trades is the least worst option
- Support a cash-out price where System Buy Prices is the maximum price paid by the SO when purchasing energy in the BM and System Sell Price is the lowest price paid the SO when selling energy in the BM
- SMP sends appropriately sharp price signals to both generators and demands in respect of the cost of deviating from contracts
- In the interim it may be more appropriate to replace the use of marginal pricing with a weighted-average price
- Would oppose any move to marginal pricing
- The selected method is better than arbitrary bands
- A seven-day average seems likely to give a reasonable cash-out price
- Suggest a 7-day average of the same ½ hour in each day for the calculation of default prices
- We only need a simple mechanism eg commodity pricing plus a penalty premium/percentage
- Support the use of a price indicator from a traded spot market as substitute cash out prices.
- Deadbands could be considered. A neutral cash-out price for the deadband is needed – a System Average Price will be the most cost neutral
- The cash-out regime should ensure that bids and offers are delivered against physical and locational trades and should accurately derive an energy imbalance price reflective of the costs incurred by the SO. The costs should be targeted effectively
- A cash-out price that reflects actual Balancing Mechanism trades provides the most accurate approximations
- Prices should reflect the energy costs to which the SO is exposed rather than Power Exchange prices
- Dual pricing would not be necessary if compulsory participation were adopted; if not a seven-day average price appears to set a fair price marker

- Adopt a methodology for calculating dual cash-out prices which clearly does not overstate the true costs imposed by those parties out of energy balance over a half-hour
- There may be an issue of legal enforceability if these (energy imbalance) charges could be categorised as other than a reasonable estimate of the liquidated damages incurred as a result of the actions which result in their being levied.

Exposure to Cash-out

- Costs imposed by all users on the system should be borne equally by those users
- Fully support the principle that imbalance cash-out prices should be cost reflective
- Market distortions caused by the proposed methodology of imbalance volume calculations may deter new entrants and reduce the number of existing generators
- Players left exposed to the cash-out regime should be those out of balance in the same direction as the system ie those who have caused NGC to incur balancing costs
- Participants should be exposed to a penalty at least as onerous as the price of that trade by application of a non-delivery rule
- Imbalance prices should send very strong signals to participants on days of system stress
- The energy imbalance charge mechanism will severely devalue wind generation due to its unpredictability
- Imbalance volume liabilities for CHP, trading sites and commissioning IPPs should be included in the SO charge
- Non-penal cash-out pricing should be adopted for CHP and renewables
- Power consumption related events should not enter into the calculation of all imbalance charges for CHP
- Plant has a variable output in CHP mode and though volumes might be small the cumulative financial effect of such exposure in the imbalance market balance may be significant
- Market distortions caused by the proposed methodology of imbalance volume calculations may deter new entrants and reduce the number of existing generators
- A “tax” on imbalances will discourage the development of innovative technologies such as end-use devices that respond to real time prices
- Dual cash-out will discourage users of Interconnectors from providing assistance at time of system stress outside the forward markets. Any attempt to rectify this by creating special, preferential rules for users of Interconnectors is unfair to parties in the UK

- Zero imbalance tolerances will discriminate against commissioning IPPs
- In the case of imbalance charges allocated against individual or aggregated renewable generators the imbalance charge should be offset through a renewables levy
- The perceived penalty of dual pricing will be factored into Bid/Offer pricing which will increase the penalty
- The prospect of volatile prices in the Balancing Mechanism should incentivise players to balance their position
- It will not be possible to replicate requirements contracts under a dual-pricing regime.

Contract Notification

- Strongly support ex-ante contract notification; it is a vital element to encourage a change in behaviour so as to ensure forward contracting
- The principle of ex-ante contract notification should not be lost during consultation
- Ex-ante notification provides the right incentives to encourage physical energy balancing prior to gate closure
- Ex-ante contract notification acceptable subject to a review of the imbalance pricing formulation and further consideration of the NGC option
- Ex-post trading is an anathema to market fundamentals
- An ex-post regime allows generators to manage the volume risk and pass the price risk to suppliers whereas an ex-ante regime distributes the volume and price risk equally on both sides
- If ex-ante were decided upon it should be as late as possible after Gate Closure
- See no difficulty with contract notification being at Gate Closure
- Ex-ante contract notification is a constraint on trade and is likely to result in substantially more complex contractual arrangements being put in place
- Ex-ante notification will impose significant new risks on our business because it constrains the types of contract that we can trade
- Prefer ex-post contract notification so that contract forms are not restricted
- Ex-post contract notification has advantages in moving decisions from the System Operator to the market
- Ex-post contract disclosure will level the playing field for smaller players
- Small/new suppliers and generators should be allowed to trade ex-post

- Ex-post trading should be permitted for CHP and renewables to enable “full output” contracting
- It might be better to accommodate ex-post trading when the new electricity trading arrangements is confident to maintain the necessary liquidity in forward markets
- Moving to real time contract notification will reduce the competitive advantage enjoyed by portfolio participants in reacting to late events
- Offering more flexibility in the contract types recognised by settlements will avoid the need for participants to us use “work arounds” to administer more complex commercial arrangements and will promote liquidity in the forwards and futures markets
- Include the validation of contract authorisation with the central aggregation agent.

Aggregation of Demand and Generation Accounts

- Totally against the principle of participants being able to aggregate the supply and demand side of their business
- Imbalances relating to production and consumption meters should be calculated separately
- Only those companies deemed dominant should be required to balance production and consumption accounts separately
- The ability of large players to manage risk is unfairly enhanced by aggregation at licence level
- Separate BSC signatories who are part of the same affiliated group should be able to register all appropriate production/demand meters within the one account
- The issue of separation of the accounts of vertically integrated businesses relates to abuse of market power and is thus a regulatory issue and not a reason for making the whole market inefficient
- The concept of forced separation of demand and generation is counter intuitive and unrecognisable in free commodity markets
- The requirement that a party’s demand and generation imbalances be cashed out separately is punitive and should be removed

- Aggregation across both generation and supply would be more economically efficient, consistent with the gas market and in the interests of customers. It is not efficient to require portfolio players with demand and generation to balance each account separately
- Matching trades of participants ahead of the balancing period will reduce the risk of exposure to cash out prices for participants
- Aggregation across production and supply would minimise costs and risks further and ensure the balancing mechanism really is a last resort
- Seems unreasonable that participants with equal and opposite inadvertent imbalances, which cause no extra costs to the SO, cannot trades these out prior to settlement
- Aggregation between generators and suppliers would allow the full value of the relationship between higher wind speeds and higher heating demands to be realised in contractual negotiations.

Meter Splitting

- See no reason for arrangements any less flexible than those available in the gas market or enjoyed by interconnectors under the current proposals
- Would be gravely concerned if, in an attempt to reduce the claims of discrimination in favour of Interconnectors, the existing meter splitting arrangements were applied to the allocation of Interconnector capacity
- A variety of agency arrangements are possible within the current legal and regulatory framework while not compromising the relevant obligations of the licensed party. We would expect similar flexibility to continue in future
- Several BM units should be allowed to exist at a single meter point
- Split metering/supply should be permitted to give greater flexibility in managing imbalance
- More complex arrangements than the simple percentage split are required
- Metered values should be split by MWh as well as percentage this would allow people to trade base load, peaking and shape contracts
- Allocations of shared meter points could be allowed ex-post
- Allowing more than one Supplier to serve a single metering point will have significant implications for Registration Services and the MRA

- Seek clarification on how the volume from an individual meter could be split between a number of participants; this may have a significant impact on Stage 2 Settlement and on the rules regarding metering point administration, as defined in the MRA
- Sharing a meter for the premises of all customers creates significant complexities which may delay the implementation of the new electricity trading arrangements and should be considered for development post October 2000
- The consultation does not consider the impact on Supplier, PES Distribution Businesses (Use of System and Metering Point Administration Service (MPAS)) and Supplier Agent systems
- Remove the restriction on Stage 2 Settlement which limits a supplier to a metered demand of zero or higher
- Remove the constraints on the ability of Stage 2 to accommodate negative net demand
- The Metering Point Administration Service registration and supplier systems have been built on the basis that only one supplier should be registered as responsible for supplying any metering point for a particular day
- Metering arrangements must be consistent with any specific measurements that HM Customs and Excise might require in relation to the Climate Change Levy
- Suppliers could facilitate trading through contractual means or customers could modify their metering arrangements to accommodate multiple suppliers at the same site
- Meter registration should not be restricted to the asset owner
- Experience from gas indicates that customer interest is limited
- Development of systems to accommodate limited demand does not appear to be cost effective
- Most consumers have meters with the same technology in the year 2000 as they had in the year 1900.

The Role of Aggregators

- Aggregation of production meters should not be allowed
- Strongly support the attempt of the PDO to establish a role for aggregators; if aggregation can be achieved by contract then it should be allowed Role of aggregators must be more fully defined to facilitate a flexible and innovative approach to demand management
- Aggregators could allow independent plants to compete with portfolio players

- Support the concept of aggregators on behalf of those who not required to submit FPNs or who are not BSC signatories but do not support aggregation for other participants as this could directly impact on market liquidity and in particular benefit companies operating both in generation and supply
- Aggregation of generation and supply imbalances nationally should be permitted for smaller (or exempt) suppliers/generators
- Aggregation for the purpose of providing BM services will be limited by geographic proximity of small generators and may not be viable
- Aggregation is unfairly inconsistent between players
- It would be unacceptable if rules on aggregation were allowed only for licence exempt companies
- The decision to allow aggregation below the GSP but not across GSPs appears to be discriminatory and should be reconsidered
- If dual pricing is retained facilitate the aggregator role in as inexpensive and flexible a form as possible including the possibility of national aggregation of contractual positions for unlicensed generators
- Aggregation will incentivise suppliers to become familiar with their customers' needs
- The services of agents or service providers will incur a cost
- Aggregation rules should make every effort to remove the constraints on the ability of Stage 2 to accommodate negative net demand for suppliers
- For aggregation to be effective there must be payment for negative demand for a supplier at the GSP group level
- Aggregators should be licensed in order to participate on behalf of parties with physical assets
- Aggregators would need to be BSC signatories
- In an efficient market the aggregator would be helping to reduce contractual imbalance in a way that supported the SO drive to reduce physical imbalance
- Aggregators of generation are the generation equivalent to supply businesses and should be treated equivalently.

Treatment of the Net Costs/Revenues from Imbalance Cash-out Charges

- Cash-out pricing should reflect real balancing cost without over-recovery
- Each option is viable – the market should decide
- Maximum flexibility would be achieved by exposing contracting parties to cash-out charges for their net imbalance
- Should be minimised by the adoption of cost reflective cash-out (single pricing)
- The true cost of balancing should be based on expected system imbalance backed up by standard SO information and not the total of all ex-ante contractual imbalances which the SO is unaware of
- With SMP settlement is revenue neutral and hence simpler and less controversial
- There is no rational basis for recovering a non-cost reflective penalty
- These can be treated independently from NGC's incentives
- Any surplus amounts should be distributed to those who have helped secure the system, with deficits allocated to those who have not; if carried out on a daily basis then there may be a potential to avoid having to pay VAT on transactions within the Balancing Mechanism
- May be appropriate to include some or all within the SO incentive scheme since his actions can reduce these costs and revenues
- Revenues or costs should be returned to or recovered from all participants on the basis of metered and contract volumes and should not be passed to NGC
- Should be allocated, on a half-hourly basis, pro-rata to each energy account's metered energy
- Participants should only be liable to imbalance costs that have been incurred genuinely
- The smearing of unaccountable revenues/costs from balancing across all players is the most equitable way to ensure neutrality to the SO Penal costs for imbalance work against the small supplier
- Set off the costs and income of BM trades with the imbalance cash out charges. Any surplus or under recovery over an extended period, say quarterly, could then be used to offset or increase the cost of transmission losses or administrative charges
- The penalty should be returned in proportion to those in imbalance
- Small business customers and domestic consumers should not pay disproportionately for the imbalance cash out price

Default Issues

- Arrangements must be put in place to cover the continuity of supply for customers of a defaulting supplier
- A guarantee option would appear to warrant consideration
- The costs of providing a supplier of last resort could be funded through a form of surcharge or levy on suppliers
- Default should be covered by external insurance. It should be included in the NGC incentives' pot
- In the unlikely event of default occurring it would appear unavoidable that these costs are recovered from market participants
- Important to introduce a graduated scale of incentives administered by the BSC Co and enforced by the Regulator
- The Pool's attempts to solve the issue have failed.

Credit and Security Cover

- The credit proposals are almost universally abhorred. Why not use the gas (Flexibility Mechanism) arrangements as a model?
- The first three suggestions have the advantage of being relatively easy to administer, potentially cheap but also present risk if they are not renewed or replaced
- The fourth suggestion has the advantage of greater security but presents administration risks for the central body
- Credit arrangements should truly reflect risk and prevent duplication of cover (eg single central credit cover which can be called upon by bilateral contract parties, exchanges and BSC)
- Some form of bonding through insurance and administered by the BSC Co would offer a more cost-effective arrangement
- Credit cover should be provided from (in order of preference) an approved credit rating, parent company guarantee, letter of credit from appropriately rated institution or cash deposit
- Allow a clearing house operation for credit cover or any other provider that could facilitate credit cover for smaller players
- Cover should only be needed for residual volumes which are subject to imbalance prices - an agreed credit rating should suffice – at least solid investment grade

- Provisions should cover the full potential exposure of participants at a credible high price
- For the BM the credit cover should be determined on the basis of the net difference between net contracted and physical volumes over as short a period as is practical
- Credit cover is an issue for small players since large players are allowed to avoid having to raise cash for security
- Further consideration should be given as to whether the current 28 days settlement period can be reduced significantly, perhaps to 14 days.

Information Imbalance Charge

- Lack of financial incentives to provide accurate information causes concern
- The SO requires the provision of accurate information ion so why has the information imbalance charge been set to zero? If the information received by NGC is poor then this could impede its ability to minimise system costs, thus all participants face higher costs
- Support the establishment of an obligation on information accuracy in order that participants adhere to their FPNs
- The application of a positive information charge for plant/demand behind transmission constraints may help to reduce gaming
- The concept has some attraction; it would be the logical vehicle for the costs of NGC's management of potential system developments occurring within the four hour run-up to real time
- Systems should be capable of applying different rates of charge to different participants since some provide more useful information at a higher level of resolution than others
- The SO should pay for the information he needs on a contractual basis which perhaps imposes charges if the information is inaccurate
- The information imbalance charge should be set at nil initially

- Calculating the information imbalance charge on the difference between FPN and metered volume is unduly restrictive and discriminatory on the generation side and against coal fired power stations in particular. Similar concerns apply to the non-delivery charge applied to BM bids and offers
- Capital providers (to renewables) will not be likely to take a sanguine view of a charge "initially set to zero" and the possibility that it will not remain zero over the period of the contract will consequently result in higher finance charges
- The proposed structure of calculating information imbalance charges disadvantages directly connected demand sites which cannot aggregate with other sites.

Treatment of Distribution and Transmission Network Failures

General

- The cost of failures, both economic and physical should be targeted to where they can best be managed
- Customers receive compensation for both economic loss and physical damage
- Both transmission and distribution failures will have a significant impact for generation and demand participants who have no control over such events; NGC must bear its fair share of these costs
- There is a need for distribution/transmission companies to provide information on the timing and extent of outages and arrangements to determine the volume affected – this could either be in the BSC (in which case distribution companies would need to be signatories) or in the distribution/transmission use of system agreements
- The SO will accept offers and bids in the BM to work around transmission system constraints and failures but may simply ignore distribution system constraints and failures so that the affected market participants would simply be out of balance
- Consideration should be given to re-declaration of FPNs for wires failure
- Essential to set a *de minimis* level below which network failures would be ignored eg down to half hourly metering is installed
- Failures affecting non-half hourly demands would need to be allocated on a grid group basis
- Suppliers of non-half hourly customers and half hourly customers who do not normally constitute BM units should have the same opportunities to be paid for their offers as suppliers of half hourly metered BM unit customers

- Non discrimination would also require that generator disconnections from the system due to transmission/distribution faults are also treated as demand or system stress bids.

Transmission Network Failures

- The resolution of transmission issues should not be separated from the new electricity trading arrangements process but in the interim transmission failure should be treated in an equivalent manner to constraints
- Does not seem reasonable to expose NGC to the market liabilities associated with ‘force majeure’ events such as widespread storm destruction.

Distribution Network Failures

- Distribution operators are monopolies; connection contracts place all liability on the generator leaving them no opportunity to recover the cost of failure from the distributor
- Would not support the recovery of imbalances from the distribution businesses the performance of which is regulated and it would not be appropriate to allocate costs which that business is not experienced in managing
- Not appropriate to extend the boundary of the trading arrangements within a distribution network and access issues should therefore be dealt with by bilateral agreements between participants and network operators
- Distribution failures will give rise to imbalance costs which will be borne by embedded generators (and which are avoided by centrally despatched generators)
- Would expect embedded generators to negotiate compensation arrangements with the Distribution network owner
- Ofgem should urgently review Distribution Connection Contracts to enable generators to recover costs arising from network failures
- The different treatment of constraints and failures on the transmission system compared to distribution systems disadvantages embedded generation

Charging

- System users cannot negotiate solutions with monopolies
- Distribution companies have no incentive to encourage embedded generation as it reduces income by limiting growth and use of their networks
- Embedded generation is discouraged with high connection costs, network unreliability and, in the case of NGC as SO, choosing not to select balancing bids/services
- Distribution network operators should be incentivised in the same way that NGC is
- Ofgem should revise Distributor and NGC incentives to ensure that they do not work against the development of CHP, renewables and embedded generation
- Licensed embedded generation potentially pays DUOS and TUOS charges on the same assets
- Embedded generators may be limited in their choice of supplier and removing Stage 2 restrictions to expand their choice would have no impact on physical power flows or on the cost of developing, maintaining or operating NGC's system and so would not imply that embedded generators should start to pay TNUOS charges
- If NGC purchases transmission losses then distribution businesses should be charged with the responsibility to purchase distribution losses

Distribution Network Operators and the Need to Sign the BSC

- Distribution network owners should sign the BSC in order to ensure adequacy of metering
- Distribution network operators should sign the BSC because of the interaction between failures on their system and the balancing mechanism
- Metering information is of intrinsic value in the RETA environment and Distribution Network owners ought to be signatories of the BSC in order to ensure adequacy of meter registration
- There is no need for Distribution network owners to sign the BSC
- Not clear that Distribution operators need to be a party to the BSC; why not oblige them to contract their responsibilities for GSP meters to NGC

Interconnectors

- Interconnected parties must be able to enter into contracts, to use any short-term bilateral market and to bid in to the Balancing Mechanism
- Bids over the interconnector should be made firm at or around 09.00
- More than one BM Unit per IU must be considered
- The proposals suggested for interconnectors should be equally applicable to the whole market otherwise discrimination is introduced
- Superposition should be included in the BMIS Specification and exports from England and Wales should be explicitly accommodated

The Role of the System Operator

- Over time NGC's role in overall balancing of electricity production with consumption will decline
- Participants need a clear understanding of the role of the System Operator, suggest: to balance the total system physically using bids, offers and balancing services at net cost
- Concerned that the operation of the balancing Mechanism (and presumably Settlements) will be carried ought under a licence obligation by NGC so that there is no facility to expose this activity to commercial pressure
- Due to potential conflicts of interest subsidiary companies of NG involved in the provision of services to the market should be separated from NGC
- If the SO is allowed to arbitrage within the balancing mechanism it would seem reasonable to remove the limit on SO losses that might be incurred if it failed as a result to deliver under its incentive scheme
- Recognise that for a time the SO will have to manage balancing in real time by acting as a principal in the markets but it is important to set the stage now for reducing its involvement so that the market place has an incentive to develop the innovations that make self-balancing in real time possible
- The new electricity trading arrangements should not foreclose on any future options to integrate cost-reflective regional signals into the long-term management of the system

- In electricity the shorter time constants mean that self balancing by participants cannot take place in parallel to balancing actions taken by the SO therefore short term balancing of the system has to be done in a co-ordinated. This points to a fundamental inability to separate the conceptual Balancing Operator and Transmission Services Operator even in the longer term

The SO Incentive Scheme

- Approach 2 should be adopted with an incentive on overall costs
- Support option 2 whereby NGC would be incentivised to minimise the overall cost it incurs in fulfilling its SO role including balancing costs It will not be possible to introduce a perfect scheme at the outset
- The thrust of work over the last five years has been to separate the transmission and energy markets – the preliminary discussion on the matter appears to be based on the assumption that the markets should be combined again
- Until the components of uplift are fully defined there is no way of valuing embedded benefit
- Strongly support proposals that the initial incentive scheme should only last for a year
- Agree that a one-year duration would be an appropriate period for the first scheme
- Support a sliding scale incentive based on a 20% of costs as the cap and collar
- Incentivise NGC in such a way that those players that are out of balance on average more often (ie smaller operators) will not carry the cost of operations that are unconnected to their energy imbalance, for example capacity constraints
- In setting satisfactory incentives it is essential to quantify targets and an opening position. There must be boundaries established, which are not for negotiation by the SO, to prevent manipulation of the first year figures

Treatment of Transmission Losses

- Losses should be cost reflective
- The burden of locational messages should fall on generators since the majority of customers have a geographically captive demand and have priorities (other than electricity price signals) to take into account

- Totally unacceptable to suggest that the demand side must continue to take the risk associated with ex-post publication of transmission losses
- A robust and widely supported methodology has already been developed and it is extremely surprising that this has not been adopted in the new trading arrangements. Northern generators and southern suppliers have benefited at the expense of their competitors and ultimately at the expense of consumers for a number of years – extremely disappointing that this distortion is set to continue
- The untested proposal to move to locational loss allocation is totally inappropriate
- Cost of transmission losses should be allocated at the same time as the new arrangements are introduced, failing that the functionality that has been written in to the specification should be put to early use through the introduction of a rule modification
- The Transmission review should aim to pass ownership of the purchase of energy losses from generation/demand to the SO
- Solution should be based on ex-ante publication of forecast transmission losses, with incentives on NGC for accuracy

Transmission Access

- Support the concept of a market-based solution of tradable access rights
- Implement a transmission capacity trading simultaneously with the new electricity trading arrangements
- Encouraged with the proposal to move to a market based solution based on tradable access rights
- Not supportive of Ofgem's proposals for auctioning Transco's capacity; such proposals would be even less appropriate for NGC
- Efforts should be concentrated on the implementation of the new electricity trading arrangements with the further development of the transmission market dealt with on a separate basis The difficulties of delivering a robust and sustainable solution to transmission access should not be underestimated

- Deeply concerned that the substantive issues of losses, transmission access and NGC incentives are to be addressed separately from the new electricity trading arrangements – the lack of clarity will create uncertainty which will prove unhelpful when re-financing of projects is undertaken. The six month delay in confirming the transmission arrangements create additional and unnecessary difficulties for participants
- Outlined tradable transmission access regime may have an adverse effect on market liquidity; erode existing access rights; and require changes to the new electricity trading arrangements systems soon after implementation, thus entailing extra costs
- Significant risk that the new electricity trading arrangements specification will have to be reviewed materially to accommodate a unconsidered transmission access issue with consequential costs implications for central system users and energy risk and management systems
- Traders on the E&W system currently have firm transmission access rights on the supply side and up to the value of their Registered Capacity on the generation side (provided they are included in the Unconstrained Schedule). Any move to put in place a market in which participants have to purchase access rights would result in an erosion of contractual entitlement to access. This would be unacceptable unless appropriate compensation were to be received
- Given the date of commissioning of the plant at Blyth, the station should have firm access rights
- The current proposals offer fully firm access rights – this is not efficient; an undefined right has been converted into a fully firm right at no cost to the beneficiary
- By setting out a view on the treatment of transmission constraints now it would be possible to design and appraise a more appropriate set of prices for cashing out imbalances (eg prices that varied by location)
- Once the market is segmented by transmission constraints it becomes possible to set prices for cashing out that are not affected by irrelevant balancing actions
- Concerned about the management of transmission constraints and the undue burden that has been carried by the coal-fired station at Blyth

Constraints

- Arrangements concerning transmission constraints should be considered in the context of the relatively low materiality involved
- Report balancing trades by constraint zone to provide a locational price signal
- A set of rules should be included where the SO can constrain plant and compensate such plant with a market price by the SO who would be incentivised to limit constraints.

Legal and Regulatory Framework

- Perceptions of regulatory risk have been greatly increased by the proposed arrangements
- Contract re-alignment will be severely constrained by the current proposals
- Strongly urge the DTI and Ofgem to allow the separation of industry obligations and customer obligations between the shipper and supplier respectively by incorporating the shipper role in the electricity market
- Seek the assurance of Ofgem that the economic purchasing obligation is met and that the RECs do not discriminate in favour of gas fired stations
- Helpful if the Programme could provide draft BSC language – Transco's Network Code provides a model
- There are significant implications for market participants of the PSA becoming obsolete in that the documentation in E&W and in Scotland would be out of step
- Would welcome greater change co-ordination across the industry but do not believe that such rules should be placed in the BSC since such rules are already set out in the MRA which is a GB wide Agreement

Grid Code Vs BSC

- The BSC should take precedence thus ensuring that discrimination does not occur between the MRA and Grid Codes to not frustrate the development of the BM
- The BSC should be the principal industry wide document with agreed service levels and penalties
- The BSC should contain as much as possible and issues should be unbundled
- The Grid Code should be related to System security and physical matters including Safety
- Technical issues should be covered in the Grid Code and commercial issues in the BSC ie rules relating to the nature of FPN and IPN data should reside in the Grid Code along with obligations of parties to submit this data

- Rules relating to IPN and FPN notifications and balancing offer and bid rules should sit within the BSC rather than the Grid Code
- BSC modification processes will be much more effective than those in the Grid Code and over time there would be value in having comparable modification processes in the Grid Code

The Balancing and Settlement Company

- The BSC must include high level objectives which set the framework for all developments and management of the rules. The objectives should be binding on all participants
- The overriding objective must be that the market is about delivering to customers
- The BSC must have an objective which is to meet the needs of customers through lower prices and better services
- The BSC Co should be a non-profit making organisation
- The BSC Co should be an independent company owned by all signatories to the Code, including the system operator, on a fixed annual fee basis, so all participants have an equal share of ownership and costs
- Legislation could establish a new licensed activity
- The arrangements appear to be an over-reaction to the present situation
- The Directors of NGC will be employees of NG and will be required by law to operate BSC Co for the benefit of NGC; it would be preferable if the BSC Co could be separately owned (vis Claims Validation Services Ltd)
- If BSC is a wholly owned subsidiary of NGC then legal and structural safeguards need to be considered eg an indemnity from all signatories to the BSC in respect of all liabilities of the BSC and the establishment of arrangements that protect the position of NGC's directors and shareholders

- The proposed model for the BSC Co is similar to that of SESL with a small core staff supported by out-sourced services; this has proved to be an efficient use of our administered budget. Service providers offer flexibility and expertise, working to defined costs and timetables leaving SESL to concentrate on key market operations rather than managing operations
- The proposals represent a significant increase in the power of the DG and this does not sit comfortably with the objective of making the trading arrangements more market driven
- The CEO's Office is the best place to take up the role of BSC Co initially
- A shortcoming of the Pool's arrangements is the area of cost control – new disciplines in the management of central expenditure is required
- The BSC Co should be required to gain sign off of an annual operating plan and associated budget for the industry participants
- Effective contract management is the key to successful, efficient and productive service providers
- The split of responsibilities between the Settlements Administrator and the BSC Co should be clearly stated
- No downside in splitting Management from the Modification/Compliance activities
- The SO must not be allowed to delay any changes
- Intellectual property rights should be vested in the BSC Co with all income being used to mitigate the impact of costs incurred. NGC should not have privileged access to these rights
- To avoid any use of the arrangements in support of the development of other markets, the BSC Co should be responsible for maintaining the IPR for the systems, procedures etc thereby ensuring that those who funded such products benefit from their use elsewhere
- If the Scottish market is to develop in a compatible and cost effective manner it is vital that SESL has continued access to IPR granted to it by the Pool and that it has access to current and future products

- Funding for BSC Co should come directly from customers via a levy set by Ofgem in recognition that BSC Co is a common cost for all participants. This would result in lower entry costs and encourage greater participation. It also imposes greater discipline in managing costs since they would be subject to approval by Ofgem
- Support the proposal for the DG to advertise, interview and appoint a Chairman
- By appointing the chair of BSC Co and of the Modification Panel, the regulator is potentially fettering his discretion in the policing of both
- A strong, capable and firmly independent Chairman is the first requirement

Signing the BSC Code

- Suppliers should be able to outsource any obligation to sign the BSC to a third party
- By forcing particular participants to sign the BSC and participate in imbalance settlement, Ofgem is effectively limiting the development of the competitive electricity market
- The obligation on licence suppliers and generators to be signatories to the BSC is a significant restriction

Constitution and Role of the BSC Panel

- The Panel should have clear objectives – to include prices for customers explicitly and transparent and efficient processes
- Broadly supportive the arrangements which are designed to result in objective and efficient decision-making.
- The approach is conservative and unimaginative
- The Panel's approach to prioritise, budget, schedule and fund enhancements needs to be described in order to understand the maintenance and operational requirements
- Essential to establish clear accountabilities between the BSC Co Board and its shareholder, NGC and between the BSC Co Board and the Panel
- There is some confusion as to the objectives of BSC Co directors and the relationship with Panel members and in particular whether Board and Panel Member could be the same
- The Board should be truly independent and not a device of the regulatory office or the Government

- Participants should have a voting role
- Further clarification is required on dispute resolution

Preferred Option for the Composition and Appointment of the BSC Panel

- Support Option 1 involving paid industry participants
- Prefer option 1 and factionalism could be overcome by introducing additional rules on the terms of service
- Support Option 1 with two/three customer seats but these should not be solely in the gift of the NECC
- Option 2 is more likely to enable the Panel to act independently
- As a compromise suggest the industry (including consumers) propose a number of candidates from which the chairman would select panel members
- The options under consideration place the Panel at one remove from the market participants to which it should be accountable
- Neither of the options are acceptable
- No strong views
- Full consultation on the representative arrangements must be launched
- Panel selection rules would need to ensure diversity of representation
- Governance arrangements must rely on an independent panel who demonstrate relevant industry expertise
- Since signatories will bear the costs of the mechanism it is vital that their interests are properly represented
- Experience has shown that representation from those operating commercially in the market has proven critical to the success of the debate.
- Explicit Customer representation is welcomed/required
- Customers must have voting rights
- Major balancing participants along with customer representatives should be included on the BSC Panel
- Special interests must be provided for
- Adequate representation of the renewables industry in market governance is important to ensure that the future evolution of the trading arrangements does not unreasonably disadvantage renewables (and other smaller players)
- There is no specific reference to important groups such as unlicensed players, customer CHP or renewable generators

- Consumers should not be greatly outnumbered by the industry
- The Panel should not consist of a small number of stakeholders
- If Panel members represent specific interests this is unlikely to be conducive to effective decision making
- Do not believe that in depth knowledge of the industry itself is always helpful to proper consideration of the issues and effective decision making
- Consideration should be given to an option whereby a stakeholder Panel including customer representatives is drawn from classes of industry stakeholders
- Should not be necessary to have sectoral representation and comfort may be enhanced by having Panel meetings in open forum
- It is essential that Panel members be appointed on the basis of their expertise and that customer groups play a full role
- Regulatory executive authority, coupled with a streamlined modification process will together remove the negative effects of factional negotiation and support efficient decision making
- A small panel will not be representative and will no produce robust decisions
- A small panel may be exposed to undue influence from the BSC Co
- A large panel would not form an effective Board
- The Panel should comprise approximately 7 people with an independent Chairman
- A panel membership of 11 including the chairmanship would strike the right balance
- The Panel should be representative and sufficiently large (say 15) to represent all views.
- The chairman should be able to make a small number of direct independent appointments
- Elections should be held on the same basis as the Transmission Users Group

Alternative structures

(a)

Board

Chairman	- Executive position, appointed by Ofgem
Directors	- One Non-executive Director appointed by NGC
	-Three Non-executive Directors appointed from nominations put forward by BSC signatories

Secretariat

General Manager	- appointed by BSC Co Board
Finance Manager	- appointed by BSC Co Board
Company Secretary	- appointed by BSC Co Board

Panel

Chairman	- BSC Co Chairman

Five Panel members selected from nominations from industry through a single transferable vote process

Three Panel members appointed by Chairman to achieve a balance of expertise/customer representation

(b)

Chairman appointed by Ofgem

Chief Executive/Managing Director appointed by NGC

General Manager, Finance Director and Company Secretary appointed by the Board

Non Executive Directors – three to be appointed from nominations put forward by BSC participants and representative bodies

Chairman of BSC Co could also be Chairman of the Panel, if not he should be a BSC Co Director. Other Panel members should be nominated from within the industry and customers with say four being appointed on the basis of a voting process and four selected by the Chairman so as to achieve a reasonable balance of expertise

Modifications

- Arrangements must be capable of introducing robust modification proposals
- The Panel should take a position on the merits of proposals
- The Panel should have a duty to make recommendations
- Customers should be allowed to propose modifications
- Adopt governance arrangements that recognise the trade off between the importance of facilitating essential changes to the rules and the costs that frequent rule changes would impose on all market participants
- Some failings are inevitable and the arrangements will need fine-tuning. There should be regular monitoring with quarterly reports which should be in the public domain
- A public statement from the Panel on the merits of proposals will provide some balance to a process that is otherwise wholly judged and executed by Ofgem
- Experience in the gas market should be heeded; the pressure to demonstrate speedier decision making could lead to a series of rapidly implemented but disconnected decisions
- There should be some attempt at cost benefit analysis in assessing, prioritising and reporting change proposals to the DG
- The costs for participants associated with transitional arrangements and repeated rule modifications will disproportionately affect smaller players
- Regulatory direction should be capable of appeal so that judicial review is not the only alternative to acceptance
- The DG should have the power to propose modifications if he feels the new electricity trading arrangements are not delivering the required benefits or are working against stated Government policy
- The DG should be required to give explanations for his decisions, particularly where he has departed from the recommendations of the Panel
- The DG’s decisions should be subject to the right of appeal, perhaps on specific grounds
- Ofgem should not be allowed to propose modifications
- Modifications should be made available on the BSC Co web site

- The rules should deliver timely outcomes to modifications proposals and similar objectives should apply to the DG when deliberating upon recommendations

Participation

- The present (licensing) limits appear to work well; companies affected by the new electricity trading arrangements should have confirmation that similar thresholds will continue to apply
- Greater clarity is needed on participation – is it only licensed participants or those responsible for generation and demand? We recommend it be the latter
- Any party which creates an imbalance on the system, either through physical requirement, must be signatory to the BSC and be regulated accordingly – there cannot be any exceptions
- The licence condition requiring signatory of the BSC should be carefully worded to exclude the obligation from licensees who do not trade
- How can licence exempt parties be required to install meters
- Unlicensed or exempt customers should be able to participate in the Balancing Mechanism without a licence subject to them signing the BSC
- Participation in the balancing mechanism should be voluntary however those with market power should be obliged to make power available to the SO
- Licence obligations should be imposed on generators to prevent self-hedging. Entry and exit processes must be robust in design and sufficiently rigorous to secure other market participants from financial abuse
- The regime for generation which is not currently centrally despatched also needs review

CHP and Renewables

- Recognise that there are a number of broadening initiatives which will help resolve CHP concerns
- Increased competition and trading between generators and the consequent reduction in generation prices will reduce the viability of CHP and renewables
- It is the end customer that directly benefits from lower import prices not the CHP plant
- Technologies that cannot accurately predict their output in the short-term will become permanent hostages to the BM and will receive lower revenues than justified by the cost of their intermittence to the system

- Ofgem has based its analysis on historical data that bears little relation to the arrangements which will need to be in place to ensure that the Government's planned target of 10Gwe of CHP by 2010will be achieved
- Process-led CHP operation does not encourage flexible electricity export management

NFFO

- If the Government wishes to fund support for renewables they should do so via general taxation not via an energy tax
- Remove the fossil fuel levy and allow the market to support renewables via green accreditation
- Individual NFFO contracts could be auctioned (probably on a two to three year time scale). To the extent that the auction price fell below the contract's guaranteed fixed price the difference would need to be made good through a levy
- A central agency should hold an auction for new build from renewables and suppliers (who would be obliged to purchase a volume of renewable energy proportional to their customer take) would bid for the output annually; any shortfall would be recovered through a renewables levy
- It is inequitable to ask a (currently obligated) host PES Supplier to carry the risk of exposure to imbalance prices for the full range of output of NFFO schemes when its direct competitors will not
- We emphatically do not accept the bald, unexplained assertion in the appendix that "the PES with whom the scheme has a contract will effectively absorb and manage the risks associated with the variability of the scheme's output
- The new electricity trading arrangements does not appear to recognise the benefit to the system of having a large number of small generating units with diverse fuel sources and geographic locations

Reference Prices

- The choice of a reference price should be resolved without delay (so that planning and development of existing and new plant can continue)
- The reference price should be transparent and the closest match economically to the superseded Pool Price
- A central agency should hold an auction for new build from renewables and suppliers (who would be obliged to purchase a volume of renewable energy proportional to their customer take) would bid for the output annually; any shortfall would be recovered through a renewables levy
- The reference price should be the System Buy Price

Market Power

- Market power is an issue; for all the legitimate reasons of size and flexibility, portfolio players are best suited to manage risks. They have excess generating capacity, and are the natural suppliers of balancing power and ancillary services as well as aggregation services
- Flexible generators frequently demonstrate their ability to manipulate the current arrangements; the new arrangements reward owners of flexible plant, currently owned by the same players
- Predatory pricing will be a great risk if portfolio players seek to use their excess capacity to gain contracts
- It is not acceptable that a supplier by exercise of its teleswitching capabilities is able to alter the imbalance position of other suppliers
- Portfolio players provide security and efficiency to a well-regulated market but in attempting to limit their power additional complexity has been created which has the sole effect of decreasing efficiency and increasing transaction costs for single site players
- Dominant players have always been able to respond in such a way as to offset the benefits of any changes
- Suppliers will suppress the prices offered to small generators
- NGC prefers to operate the system with a few large generating plants rather than with many small generators. Given the control NGC will have over the whole electricity system proper controls should be put in place to prevent NGC from abusing its market power
- The design of new trading arrangements should not restrict trading opportunities merely because of concerns about the potential abuse of market power
- An extensive set of detailed prescriptive rules is not an effective deterrent to manipulation and other undesirable behaviour – better to have a few simple rules that place all parties on an equal footing and give contractual force to all matches between buyer and seller
- The new trading arrangements will not develop as intended without the issue of market power being properly addressed
- The RETA Programme has attempted to deal with very real market power issues by making the BM more unattractive than perhaps it needs to be. There is a fear that this will lead to economically unjustifiable costs being imposed on participants, with a real danger that these will be passed on to customers
- Regulation should address market power
- It is essential that licences address behavioural issues. New electricity trading arrangements will make anti competitive behaviour more transparent but they will not eradicate it
- Generators should be required to submit, on a quarterly basis, a 12-month rolling forecast of available capacity, which takes maintenance schedules into account
- Generators should be obliged to offer 90% of their daily output ahead of gate closure

and be given licence obligations to prevent self-contracting between vertically integrated players

- A licence requirement on dominant players to make power available to the SO should be considered
- There should be more formal arrangements in place to regulate trading between separately licensed entities of the same group of companies
- It is essential that contracting restrictions are applied equally to all PESs and generators irrespective of the extent to which they are vertically integrated
- Suggest that licence holders, other than NGC, should be required to: act in a reasonable and prudent manner in the use it makes of the Grid; and not knowingly or recklessly to pursue any course of conduct (either alone or with some other person) which is likely to prejudice the safe and efficient operation by NGC of the Grid; the efficient balancing of the Grid by NGC or the due functioning of the arrangements provided for in the BSC and Grid Code
- Market participants should be obliged to behave within the spirit of the rules specified within the BSC Code

Transparency

- Competition in the provision of price indices is already emerging and intervention by the regulator is unlikely to be necessary. In any event it is questionable whether the regulator would have the experience or incentive to judge the information with which he has been provided
- Every encouragement should be given (to the Power Exchange) to ensure full transparency of essential information
- Market sensitive information must be available to all participants in forward markets as well as balancing mechanism participants
- Pool Members have invested much time unbundling the costs associated with the activities undertaken by NGC and such transparency should be replicated in the BSC
- Wish to have access to on-line regional demands, information about interconnector and transmission/distribution constraints and information about interconnector and transmission/distribution outages
- Restricting PES contracting activity (for CfDs) to a set percentage of full requirements with one generator for single year duration and a separate (lower) percentage where the contracts are for more than one year is essential in the early years of the new market

development to stimulate trading in the forwards and futures market thereby increasing liquidity and transparency

Demand Side Potential

- The significant inclusion of the demand side within the pricing process is welcome
- There are equivalent if not better opportunities for using smaller, geographically disparate loads in demand side participation
- The profiled sector should not be excluded from participation and a modest investment in enhancing the profiling system could open further opportunities for non-half hourly demand side participation
- Demand participation is fundamental to the success of the new arrangements yet little has been made of the lack of technological advance and prohibitive cost of participation for a significant proportion of consumers
- There should be an over-riding obligation on the SO to pay regard to the backup security of industrial process with integrated generation
- The extent to which the SO must use demand side bids/offers in despatch will be determined by his objectives
- Experience in Scotland with more sophisticated energy charging regimes may indicate that the Domestic market may have a daytime balancing presence
- There will be no great incentives on the majority of demand to participate in the new market
- It is unlikely that this volume (2.5GW) of demand reduction could become available in a time scale of less than four hours. Balancing services contracts would allow these and other participants to compete fully
- It is unfair to treat demand in the same way as generation

Barriers to Entry

- Both the Pool and the Electricity Association will provide information to enable suppliers to determine customer demand profiles; the EA will only give information members and the Pool requires full membership (ie completion of MRASCO testing) prior to providing it – this makes it very difficult for a new entrant to assess the risk of entering the market prior to applying for a supply licence

- There is no provision on incumbent suppliers to pass on information regarding historic consumption to a customer – this is already a significant barrier to entry and will be exacerbated in future as accurate demand forecasting becomes critical to avoiding exposure to imbalance charges
- Under the present trading arrangements commissioning stations are paid for generation that is declared. Under the new electricity trading arrangements it will be necessary to either 'spill' this randomly generated power into the BM or to sell to an aggregator at prices well below the current PPP
- We would ask for a relaxation of the tolerances on contract volumes notified for generators going through commissioning
- With the removal of a liquid market a new generator is forced to confront overwhelming barriers of entry of building a bilateral contract base
- Feedback from rating agencies indicates that it may be impossible to achieve an investment grade rating for projects in light of the proposed regulatory changes
- Concerned that the ability of gas-fired stations to bid into the BM will be severely curtailed because of the inflexibility of the terms of their LTI gas contracts

Interactions Between Gas and Electricity

- Ofgem must ensure that the new trading arrangements in electricity and gas are complementary and that they facilitate efficient and economic arbitrage within the energy markets
- A fuller examination of interactions between the gas and electricity markets, focussing on customers should be made available as soon as possible
- May be prudent to harmonise the settlement days with those in gas ie 06.00 to 06.00
- Although some portfolio generators are self shippers, many electricity producers and large customers are not and hence may only be given 4 hours notice of interruption – the timing of this is crucial
- The gas market will be using marginal price cash out for the foreseeable future and efficient arbitrage will only be achieved with players facing marginal or average imbalance costs in both markets
- There will be a requirement for Ofgem to police instances of arbitrage which result in significant market squeeze and take the appropriate action
- Gas and electricity Operating Guidelines should be aligned since Transco and NGC could find their actions in conflict if the similar balancing mechanisms sent out signals that were strongly concurrent or mismatched

Security of Supply

- The BM proposals strike the right balance between conditions likely to provide security of supply and the degree of discomfort which out of balance participants will suffer
- The level of security of supply influenced by NGC can be maintained under the new arrangements
- There is a political and social dimension which needs to be considered
- Long term security of supply will be determined by the market under the new trading arrangements and it is imperative that during times of system stress the market is allowed to function without regulatory intervention
- The issuing of NISMs by NGC would ensure the correct price signals in the Power Exchange prevailed thereby delivering a market solution at times of system stress.
- Limitations on the ability to physically disconnect individual participants mean that security of supply has to be delivered centrally
- Are the present standards sufficient for the future?
- Security of supply can be jeopardised by recalcitrant planning authorities who fail to take account of fully prepared and orchestrated applications for coal extraction
- The costs of achieving the present level of security of supply in shorter time scales are likely to rise
- In the event of failure to meet demand now is it possible to attribute and reallocate imbalance costs?
- There is a risk that gas stations will continue to free ride on the security of supply that coal offers in the UK market
- Equal obligation should be put on all generators to hold stocks of fuel to meet emergency conditions
- It may be necessary to implement a special category of "system stress" bids …which would be called upon when ordinary BM bids had been exhausted;
- In times of system stress there must be a presumption that NGC must accept offers (under which participants receive payment) before it is able to exercise deemed bids/offers or impose disconnections
- Concerned with the concept of placing an obligation on NGC to use all Balancing Mechanism offers before energy actions can be invoked
- Would it not be appropriate to continue to agree an administered cap on prices, at least in the early stages since where market forces apply prices can reach considerable extremes – where is the economic rationale to justify such high prices?
- Is it proposed that all suppliers within PESs specific GSPs will negotiate a common value at which rota disconnections can begin?
- Concerned at the safety implications of deemed bids. An economic price for disconnection at manufacturing sites where power is essential to the containment of hazardous chemicals will be a

politically sensitive issue. We would welcome an approach that recognises a hierarchy of disconnection. We note that allowing several BM units at a consumer site could create this

- Happy to have standing offers to load shed as a real valuation of security of supply

Costs

- The proposed new electricity trading arrangements appear to ignore the role of transaction costs
- Visibility of costs will be important
- Concerned at the increase in costs which the electricity industry incurs to serve its customers, assertions about the overall benefits should be viewed in that light. The set up costs for a party to able to participate are totally prohibitive for a small (under 500MW) generator; a cheap, simple alternative must be found
- Reduce implementation costs by resolving issues now rather than adopting transitional arrangements
- We do not understand why central operating costs are put at £30m when the current Pool budget is £46m
- Do the estimates take account of the additional costs incurred in re-negotiating contracts?
- For the implementation of RETA the financial controls are not resting with those who are funding the project, but will simply be passed on to us thorough licence fees. The practical implication of this is that the new electricity trading arrangements costs will be an element in the Supply price control arrangements and thus define the budget for the work to be done an, effectively defining the new electricity trading arrangement's ultimate scope and timescale
- It is essential that set up and additional operational costs are taken into account during the current supply price control review; regulated supply businesses will not have the freedom to factor into their price an element to recover all their operational expenditure
- Master Registration Agreement (MRA) parties will resist a significant increase in their costs in administering the MRA that are directly attributable to implementation of the new electricity trading arrangements. Secretariat resources are limited and cost recovery will become an important consideration
- Costs should be recovered from all participants who choose to trade within the new arrangements rather than only those who are licensed

- Ofgem should ensure that the cost of participation is minimised to ensure they do not unduly disadvantage smaller players
- Seek assurances from Ofgem that the likely costs and credit cover arrangements will not act as a barrier to entry for new generation (particularly smaller forms of generation)
- Important that there is a clear understanding of the VAT treatment of electricity trades in each environment (forwards, futures, Power Exchange and BM).

Effects on Market Participants

- Analysis is needed on the impact of RETA on different classes of customer eg consider the relative ease with which a Supplier of half hourly metered customers will know his exposure to the Balancing Mechanism compared with the difficulties that a Supplier of say two million profiled customers will have in managing its exposure
- The re-negotiation of existing power purchase contracts linked to PPP will be difficult and expensive given the dual pricing mechanism and its potential effect on long term prices

- Initial (electricity trading arrangements) were deliberately designed to discriminate against consumer driven generation options such as CHP since the Government took the view that such activity would undermine the market's evaluation of the RECs
- Larger, more sophisticated players will benefit from the opportunities for opportunism created in the Balancing Mechanism – RETA is not creating a level playing field
- Single site operators, particularly those with export, face an uncertain future because of the prospect of higher standby power prices and lower export revenues
- The new electricity trading arrangements represents a retrograde step for smaller generators
- Increased risk has a disproportionate impact upon participants who have no natural internal hedge through portfolio ownership or vertical integration

Modelling

- Little analysis involving modelling and simulation of the new trading arrangements has been conducted
- Risk is that modelling will reveal undesirable features that may require potentially costly changes

Prices

- With lower prices new coal fired generation will be less likely to be built
- Prices can be expected to increase since new generators will factor increased price risk into their prices
- Prices to end consumers are higher in Germany than in the UK
- Wary of committing ourselves to contracts that do not deliver the reductions you anticipate
- Yet to see any evidence of the price reductions you refer to in the contract market and would be unwilling to see the full risk of reductions placed onto suppliers through the Supply Price Review

Forward Markets and the Power Exchange

- Ofgem should ensure that the forward markets are well developed before committing to the full implementation of RETA
- The provision of a power exchange is vital
- Needs to be in place at the start of the market
- There are risks associated with the decision not to procure an exchange; in the early stages there are likely to be a number of competing short-term markets with either

limited or uncertain liquidity. It would be prudent to put some form of transitional arrangements in place

Firmness of Bids

- Flexibility should be provided for new generators to offer into the balancing mechanism and then withdraw offers if the plants trip

Demand Forecasts

- NGC's demand forecast should be made public
- NGC should adopt a national forecast in planning its despatch activities
- The SO's demand predictions should be made available in real time to enable more accurate balancing before and after Gate Closure
- Take action to remove all barriers to information that will improve the ability of smaller players and market entrants to forecast and assess risk of positions in the market
- Be aware that the ability to forecast demand in this market is likely to be a function of market size, due to the size of statistical sampling available to the small suppliers
- Current Pool participants should be able to access real-time NGC created forecasts of demand and transmission losses in advance of the introduction of new trading arrangements
- For BM Units with active demand that comprise embedded demand consideration should be given to determining values on the aggregate EAC for all the meters included in the BM Unit for which the participant is responsible thus reflecting the effect of customer switching
- Data about the profile and past consumption of customers should be made freely available to all suppliers

Change Control

- An effective enduring change control process is required and should be established as soon as practicable

Appendix 3 Aggregation of Production and Consumption – a Worked Example

One of the stated objections from respondents to separate aggregation of consumption and production accounts is that it removes the ability of a participant with both generation and demand to manage its own imbalance position by adjusting its generation level to match that of its demand. However, this ignores the potential mitigating effect of participating in the Balancing Mechanism. Consider a vertically integrated company that submits a 100 MWh contract volume for both its consumption and production. In this example, the System Buy price is 25 £/MWh and a System Sell price of 15 £/MWh.

If the participant's demand increases to 110 MWh in real time there are a number of options available to the participant:

- Scenario A – do nothing;
- Scenario B – self balance; and
- Scenario C – do nothing but place an offer into the Balancing Mechanism.

Scenario A – do nothing

The participant's generation business remains at its contract position and therefore faces no imbalance charges and no additional fuel costs. However, its consumption account will have to buy 10 MWh at the System Buy price of 25 £/MWh and therefore faces an imbalance charge of £250.

Scenario B – self balance

The generation business would increase its output by 10 MWh to match that of its demand. This would result in the generation business being 10 MWh long and would receive the System Sell price of 15 £/MWh for this volume resulting in a payment to the generation account of £150. The consumption account would still be 10 MWh short and would therefore have to purchase this quantity from the SO at the System Buy price resulting in an imbalance cost of £250. Thus the total imbalance charge the participant faces is £100. In addition, the generation business would incur additional fuel costs. If these fuel costs were to be, say 20 £/MWh, this would lead to an additional cost of £200. Thus, the total net cost to the participant would be £300.

However, if netting off were allowed, as advocated by some respondents, there would be no imbalance charges faced by the participant who would presumably be paid by its customers for the extra 10 MWh, which would more than offset the increased fuel cost.

Scenario C – do nothing but place an offer into the Balancing Mechanism

Under this scenario, the generation business does not attempt to self balance but places an offer into the Balancing Mechanism of 10 MWh at a price of 25 £/MWh. If this offer is not accepted the result is equivalent to scenario A, above. If, on the other hand, the offer were to be accepted and the generation business produced an extra 10 MWh, it would receive the offer price of 25 £/MWh and incur its fuel cost of 20 £/MWh, resulting in net revenue of £50. The consumption account would still incur an imbalance charge £250 (as stated above). This would result in a net cost of £200, £50 less than the costs of doing nothing.

The above example shows how placing offers/bids into the Balancing Mechanism can, to some extent, mimic the effect of netting off production and consumption imbalances internally under the new arrangements. By placing an attractive offer/bid into the Balancing Mechanism the participant potentially receives revenues against which consumption imbalance charges can be offset. It is possible to create examples where the participant is better off self balancing under the new arrangements as the outcome depends on the relative sizes of imbalance prices, fuel costs and offer/bid prices. That is Scenario B may result in a lower cost to the participant than in Scenario C. Nonetheless, it is generally likely to be the case that participating in the Balancing Mechanism will provide some revenues to offset against imbalance charges and, in addition, will minimise the risk associated with being exposed to uncertain imbalance prices.

Appendix 4 Governance Proposals

Ofgem/DTI propose the following model for governance arrangements.

BSC Panel

The Panel Chairman will be appointed by the Director General. The Chairman will also be Chairman of the BSCCo and will be required to ensure the effective and efficient implementation of the BSC rules.

The Panel will contain five industry members, two consumer representatives and two independent members, as well as the Chairman. In addition, NGC will nominate a representative to attend Panel meetings and provide expertise on system operation matters. As discussed below, further consideration needs to be given as to how the industry members should be appointed. We suggest that the consumer representatives should be appointed by the proposed Statutory Energy Consumers Council (formerly the Electricity Consumer Councils) whilst the Chairman will appoint the independent Panel members.

The independent members will be selected on the basis that they would bring a wider perspective and viewpoint and more general expertise (law and economics might, for example, be two areas in particular where the Chairman might want independent views). The Chairman will seek applications for independent Panel membership via advertisement. All successful applicants will need to demonstrate that they possess relevant expertise and that they were independent of any vested interests (in particular that they were not currently employed by any industry participant). It will be open to the Chairman to consider individuals identified and recommended by interested parties.

Appointment of industry members

In developing a mechanism that provides for the selection of those members of the Panel drawn directly from the industry, a key concern has been to obtain a Panel that contains a broad range of views. The preference for Option 1 expressed by respondents seems to imply a desire for some form of election for the industry members. There are issues in relation to a simple election process, however. For example, if participants' voting rights related to the volumes they traded, then there would be a danger that the five industry members will be representatives of the five largest participants. Conversely, under a "one person one vote" arrangement, the class of participants with the most members might dominate the Panel.

The obvious way of guaranteeing a broader representation is to create constituencies, but this raises the problem of how to define the constituencies, and how to determine to which constituency a participant belongs, given the various forms of vertical and horizontal integration that exist in the electricity industry. This Appendix contains details of the election arrangements for three other utility industry groups, the gas Modifications Panel, the Transmission Users Group (TUG), and the Meter Registration Agreement Executive Committee (MEC). All offer insights, but none would seem to be ideal in terms of defining constituencies or voting arrangements for the selection of the industry members of the BSC Panel.

A functional basis for the constituencies seems to raise as many problems as it solves. Ofgem/DTI are therefore considering establishing constituencies on a simple size criterion, perhaps very large, large, medium and small, with one constituency for other groups that might be unable to obtain representation in such a system. The criteria for determining the calculation of the boundaries of the constituencies would need further work, but, broadly speaking, the breakdown of categories might be:

- Very large – the biggest vertically integrated companies;
- Large – most of the PESs;
- Medium – independent suppliers (including large customers supplying themselves) and independent power producers;
- Small – smaller suppliers and generators;
- Others – traders, aggregators and others.

Under this proposal, all participants would be assigned to a category on the same basis that the boundaries of the categories were determined. Nominations and voting would be exclusive to each category, so that for example only members of the very large category could nominate and vote for the representative of that category. Voting would be on the basis of one person one vote, to avoid one or two participants being able to ‘capture’ a category.

Whilst this proposal has the merit of simplicity, it is recognised that the industry may favour an alternative model for the definition of constituencies and voting arrangements for its own members of the BSC Panel. If the DISG are able to come to a consensus on an alternative approach to the selection of the five industry members of the Panel within a reasonable time, (say one month from the date of the publication of this report), the alternative approach will be given careful consideration. Failing such a consensus, the proposals described here will be progressed.

BSC Board

The Chairman and the Panel will select four persons to become non-executive directors of the BSCCo and to form the BSCCo Board. Ofgem/DTI feel that the Board should be smaller in size than the Panel, as a smaller body is better able to exercise the required level of scrutiny and control of the BSCCo. Two of the directors will be drawn from the industry members of the Panel. The remaining two directors could be selected either from within the remaining Panel members or from outside, if particular skills were required on the Board that were not present among the Panel membership. For example, the Chairman might want to have accounting and IT advice available to him on the Board. The Board responsibilities will include the approval of the BSCCo business plan and budget and the monitoring of performance. The fact that the Board will be non-executive, and include representatives of those paying BSCCo fees, should reassure participants that there will be sufficient transparency, scrutiny and control of costs.

BSCCo Management Team

The BSCCo Board will appoint the General Manager and the senior executive management team responsible for the day to day operations of the BSCCo and the administration of the BSC. However it is probable that the appointment of senior managers will be delegated to the General Manager. The General Manager of the BSCCo and appropriate senior managers will attend Panel and Board meetings.

Interim Arrangements

The BSCCo, the Panel and Board cannot be created formally until the BSC is in force. There would be value in creating a shadow organisation to provide clarity of responsibility in the lead up to “go-live”. It is proposed that the Chairman (or Chairman Designate) is appointed by the Regulator in the near future and that the Chairman should appoint or otherwise identify a number of senior managers thereafter.

Accountability

In the hybrid model proposed above, the Panel would be responsible to the Regulator, in the sense of considering modification proposals in the light of the objectives set out in NGC’s Transmission Licence. The Panel members will also have some degree of responsibility to the industry itself for the other functions covered by the BSC. For this reason, it is suggested that the tenure of the industry posts is set at two years; this would allow a reasonable time in the job, but also provide the ability for the industry at regular intervals to replace members. Consideration should also be given as to whether, for the initial term, appointments within each general category of industry, customer and independent group should be for one, two or three year duration to avoid the possibility of having to replace the whole Panel at the end of the initial two year period.

The Board will be accountable to the BSC parties in the sense of being required to discharge functions under the auspices of the Code, which means in practice that it is accountable to the forum representing the parties, that is the Panel[23]. Hence, the Panel will be able to give instructions to the Board in relation to the discharge of the functions under the BSC. How the lines of accountability and responsibility will be determined requires further work. At this stage, it is suggested that Board members should be appointed and removed by the Chairman and the Panel, with the former under a duty to consult the latter before appointing or removing Board members. The Chairman would be appointed for a fixed term, say three years, but could be removed by the Regulator if necessary. If these arrangements failed, the backstop would be the ability of NGC to step in and remove the

[23] Once the Director General has ruled that a modification should be made to the Code, the Board will be responsible for ensuring that the company gives effect to the modification.

entire Board. They would only be able to do this if instructed by the Regulator, but having the power ought to act as a restraint on the Board.

Separately, the Panel and the Board probably have some accountability to the public generally. It is suggested that this is discharged in two ways:

- certain Panel meetings being open to whoever wants to attend;
- the Panel and the Board holding a joint annual meeting at which stewardship reports would be presented and questions answered. For the avoidance of doubt, such meetings would have no voting or other powers.

Other governance models

This Appendix discusses how the members are appointed in three other bodies within the utilities industry, the Modifications Panel for the gas industry network code, the Transmission Users Group and the Meter Registration Agreement Executive Committee.

Gas Industry Modifications Panel

The gas industry votes for members of the Modifications Panel and for a variety of sub committees to it. There are four sections amongst the Users Representatives in the Gas Forum; these are Independents, Producers, Users and Utilities. These groupings were in place before the election arrangements described here were developed, and they were used as they represented existing alignments in the industry.

All members of the Gas Forum and all licensed shippers, whether or not members of the Forum, are able to participate in nominating and voting. Shippers decide which group they wish to be affiliated to, and they then have the right to vote for the representatives within their group. Each section nominates its candidates. After four section representatives have been elected (the “aligned” candidates), the four remaining candidates with most votes are elected as “non-aligned” members. BGT does not have a right to vote as it is automatically allocated a voting place on the Panel. Therefore, in total, shippers have nine voting places on the Modifications Panel. As well as Transco, which also has voting places on the Panel, Terminal Operators and Ofgem each have an automatic non-voting seat. All other interested shippers can attend Panel meetings in a non-voting capacity, and other groups can also apply to Transco should they wish to attend. Some customer groups have standing invitations and currently there are proposals to allow customers an automatic non-voting place.

Transmission Users Group

The Transmission Users Group (TUG) has fifteen industry members on the Group. Voting is weighted according to payments made for Use of System charges. Any participant is allowed to nominate one, but only one, candidate, and there are rules to ensure that those participants that have more than one set of votes, for example vertically integrated participants, can still nominate only one candidate.

Meter Registration Agreement Executive Committee

The Meter Registration Agreement (MRA) has established an MRA Executive Committee (MEC). There are five seats on the MEC, two of which are appointed by the Pool Agent and Scottish Electricity Settlements Ltd (SESL), and the other three of which are elected by three separate constituencies, host PESs (the Provider member), suppliers that are PESs (the PES member) and other suppliers (the Supplier member). For the elected seats, each member of the relevant constituency may nominate one candidate. For the Provider and PES members, each party in the constituency has one vote. For the Supplier member, voting is weighted by a formula relating to the number of registered metering points within the Supplier community, subject to a limit of 20% of all such votes.

Appendix 5 Environmental Appraisal

Summary

The primary purpose of the New Electricity Trading Arrangements is to encourage competition in the electricity market. This will deliver lower electricity prices which contribute to the sustainability of the UK economy in which access to electricity at affordable prices is a key element. They will help to fulfil the DTI objective "to ensure the development of competitive markets in gas and electricity with prices which are below the median of EU countries while maintaining effective regulation where it is needed, security of supply and addressing social and environmental issues". The implementation of the new trading arrangements is likely to have both positive and negative environmental impacts, but overall is likely to be slightly negative. Estimates of the environmental impact of lower electricity prices are given below. Lower electricity prices will benefit the UK's industrial competitiveness and provide social benefits to the fuel poor and those on low incomes.

Introduction

The Government asked the Director General for Electricity Supply to undertake a review of the wholesale electricity trading arrangements in October 1997. In the White Paper on Fuel Sources for Power Generation published in October 1998 (Cm 4071) the Government confirmed that the current Electricity Pool should be replaced by new trading arrangements. The White Paper explained that new trading arrangements were needed to remove distortions in the current Pool pricing mechanism which favoured some sources of generation over others and amplified weaknesses in competition in the electricity market. The White Paper contained an environmental appraisal. This paper builds on that work.

The new trading arrangements are part of a wider programme of reform of the electricity market which also includes the completion of the introduction of supply competition and the divestment by the major generators of some coal fired generation plant. The Government expects that the overall programme of reform will encourage a more competitive market which will reduce wholesale electricity prices by at least 10% over the medium-term.

Taking full account of the effect of the proposed new trading arrangements on the environment has been, and continues to be, one of the central objectives of the Review of Electricity Trading Arrangements. The relevant Reform objective (set out in the March 1998 terms of reference for the Review) is:

> ".. what changes in the electricity trading arrangements will best be compatible with Government policies to achieve diverse, sustainable supplies of energy at competitive prices and with wider Government policy, including environmental and social issues."

Electricity generation has environmental impacts. It is the largest single source of emissions of carbon dioxide (although emissions have fallen by 29% since 1970 whilst generation has increased by 39%) and two thirds of sulphur dioxide emissions come from power stations (although since 1970 there has been a 68% fall in the sulphur emitted per unit of electricity).

The Proposed New Electricity Trading Arrangements

The key features of the new trading arrangements are that:

- Bilateral contracting is the normal method of business;
- Greater responsibility for delivering contracted electricity rests with market participants; and
- Those who do not fulfil contracts can expect to receive less advantageous terms than if they had contracted fully in advance.

The effect is to transfer the responsibility for delivering contracts to market participants. At present the risk is managed centrally by the grid operator, NGC, and the costs smeared across participants. In the new trading arrangements costs imposed on the central system by uncontracted actions will be passed back more directly to those causing these costs.

The market will consist of forwards and futures markets where participants will be able to contract bilaterally over a range of periods from a few days to a year or more ahead of real time delivery. There will be a screen-based power exchange which will operate from a day or more ahead of real time up to (initially) four hours ahead. This market will enable participants to trim their contractual positions, taking account of the latest information - such as the weather. From four hours ahead of real time NGC will take control of the electricity system. NGC will match supply and demand in real time using a balancing mechanism which will open four hours ahead. Generators will be able to offer increases and decreases in output into the balancing mechanism, and customers will be able to offer decreases in consumption. NGC will call these bids as necessary to balance the system. There will be a settlements process to arrange for the financial settlement of balancing mechanism trades, and for the settlement of contractual imbalances.

There are two main effects which are likely to have environmental consequences and are addressed in this paper:

- Electricity prices are expected to fall; and

- The removal of market distortions will change the relative competitive position of market participants.

Falling Electricity Prices

The Government has indicated that its wider programme of electricity market reforms, which includes the implementation of new electricity trading arrangements, will result in reductions in wholesale electricity prices of at least 10% over the medium term. Lower electricity prices are an important contribution to the Government's policy to encourage UK competitiveness and this is reflected in the DTI objective mentioned above. The new trading arrangements will encourage the economically efficient use of resources which will free those resources for other purposes. Lower prices are important to help address the social problems resulting from fuel poverty and assist consumers on low incomes. Lower prices will have a range of environmental consequences:

Effect on Demand

- *Effect on incentive to reduce electricity consumption by switching off.* Simple energy saving measures, such as switching off appliances when they are no longer required, are principally motivated by the potential saving in the cost of electricity. Lower electricity prices will reduce the financial incentive. However, it will continue to be possible to make significant savings through these means and the effect of lower prices is unlikely to be significant. The promotion of energy saving will continue to be an important part of Government policy.

- *Effect on incentive to invest in energy saving measures.* Decisions to invest in energy saving technology will depend on the anticipated return on investment which in turn depends on the value of the energy saved. Lower electricity prices are likely to reduce the incentive to invest in energy saving measures.

On the other hand, the new trading arrangements include a more active role for electricity suppliers and, potentially, consumers. Suppliers will be able to offer balancing services to the system operator if they can encourage their customers to take steps to reduce electricity consumption at short notice. The increased incentives for demand-side participation could offset to some degree any increased consumption arising from the points raised above. Demand-side participation is explored in further detail below.

Estimated impact on emissions

The possible long run effect on gaseous emissions of an illustrative 10% fall in wholesale electricity prices, to which the new electricity trading arrangements will contribute, has been explored using the DTI Energy Model (this is basically a set of interlocking models of final user energy sectors and the electricity supply industry). This can be used to consider possible impacts on CO_2, SO_2 and NOx. The impacts are uncertain and will depend, for example, on what is assumed about other factors influencing the level of electricity demand. The results reported in the table below, which are based on a 10% fall in wholesale electricity prices, can only give an indication of the scale of the long term impact on emissions:

	2010
CO_2 (as million tonnes of carbon)	+0.5
(%age of 1990 UK CO_2 emissions)	(0.3)
SO_2 (kilotonnes)	-4
(%age of 1990 UK SO_2 emissions)	(-0.1)
NOx (kilotonnes)	-2
(%age of 1990 UK NOx emissions)	(-0.1)

The modelling suggests that for 2010 there could be an increase in CO_2 as a result of the extra electricity demand. SO_2 and NOx could be reduced since extra electricity demand could encourage additional gas fired generating capacity and this serves to reduce the load factor on coal and oil plants. Gas fired plants emit virtually no sulphur dioxide and much less NOx than coal or oil fired plants, per unit of output.

Overall, the effect on CO_2 is rather small - a 10% fall in wholesale prices increases CO_2 by around a quarter of one per cent of its 1990 value. The same is true for SOx and NOx - the effect in 2010 is to decrease emissions by 0.1% for both emission types.

The Government has a Kyoto commitment to a reduction in the emissions of a basket of greenhouse gases by 12.5% below 1990 levels over the period 2008-12. It also has a domestic goal of a 20% cut in CO_2 emissions. The Government will consult on a draft climate change programme later this year - that programme will take account of updated projections of greenhouse gas emissions which effectively allow for the impact of the new electricity trading arrangements and other measures to improve competition in electricity markets.

Removal of Market Distortions

The new trading arrangements will have the effect of:

- Enabling pant that is able to flex its output in short timescales to receive full value for providing this service. This will tend to increase the market value of flexible plant as compared to inflexible plant. Customers will also be able to receive payment for reducing electricity consumption;

- Applying charges to those who do not meet their contracted electricity volumes.

Payment for flexibility

Flexible generation plants, and customers who are prepared to shed electrical load at short notice on request, will be able to offer this service into the proposed balancing mechanism. NGC will then be able to call these bids, as required and in economic order, to balance supply and demand on the grid system. The use of generation in this way reflects current practice and is, of itself, unlikely to have any significant environmental impact. The use of demand reductions, however, is likely to increase significantly. Demand reduction would reduce the need for generation and consequently would have a significant beneficial environmental impact. Currently NGC's ancillary services contracts with the demand side for response services amount to 680MW, made up of large forms with a consumption of over 3MW. It is not possible to forecast the extent to which demand will play a role in the proposed balancing mechanism as there is little experience to draw upon. However, chapter 13 of the Ofgem consultation document on the New Electricity Trading Arrangements (July 1999) explores the potential for greater demand-side involvement in providing flexibility and concludes that it is substantial compared to current levels, in particular for smaller consumers.

Imbalance charging

The new trading arrangements will apply imbalance charges to market participants who do not meet their contracted volumes. Those requiring electricity from the system to top up their contractual position are likely to pay more than their contract price, whilst those with electricity in excess of their contract position are likely to receive a lower price. This reflects the cost of flexing plant to make the necessary system compensations in short timescales. The arrangements encourage predictable behaviour.

Unpredictable output or demand is addressed principally through NGC instructing flexible plant to adjust its output to compensate. Flexible plant used in this way is mainly (but not exclusively) fossil fuelled plant. Using plant in this flexible fashion results in a lowering of the thermal efficiency of the plant and consequently has a greater environmental impact than operating such plant with a constant output. The encouragement of predictable electricity consumption and production patterns will have a beneficial environmental impact, although it is not likely to be great.

Some CHP and renewables plant has an unpredictable output, whilst others have a predictable or flexible output. The effect of the new trading arrangements on such plant is considered below.

CHP and Renewables Generation

CHP and renewables generators are not homogenous groups. The impact of the new trading arrangements will be different for different groups. CHP and renewables generators are expected to make a significant contribution to achieving the UK's legally binding target to reduce emissions. For this reason the Government has policies to encourage generation from CHP and renewable sources. The Government has set a target of 5000MW electrical capacity of CHP capacity by the year 2000 and is considering a target of 10,000 MWe of CHP capacity by 2010. It is working towards a target of renewable energy providing 10% UK electricity supplies as soon as possible, which it hopes to achieve by 2010.

This section of the paper explores the effect of the new trading arrangements on CHP and renewable generators. However, the effect of wider Government policies on these groups also needs to be considered. The conclusion is that CHP and renewables plants will not be affected equally. Some types of plant will be encouraged by the new trading arrangements whilst others will not. It is very difficult to quantify this differential effect, but it is likely that on balance the net effect of electricity price falls and the creation of a level playing field through the new trading arrangements will reduce the market value of renewables generation and the incentives to invest in new CHP, with a resulting detrimental environmental impact. Significant measures to mitigate the direct impact of the new trading arrangements on CHP and renewables generators have been taken including the development of the concept of aggregation to reduce the exposure to imbalance charges of individual small generators, and setting a threshold below which the rules of the new trading arrangements do not apply directly. The Government continues to have an objective to ensure that 10% of electricity in the UK is supplied from renewable sources. The measures that it employs to achieve that goal will have to take full account of the expected market conditions, including the effect of the new trading arrangements. This can be expected to offset the effect of the new trading arrangements. The Government is also considering the application of the Climate Change Levy to renewables and CHP. Decisions on this could also affect the competitive position of CHP and renewables generators in the market place.

CHP

Overview

There are 1132 CHP sites in England and Wales with a total of 3329 MW electrical capacity. There is no statistical information which enables the predictability and flexibility of these CHP sites to be quantified. To achieve maximum efficiency, and thus maximise environmental benefits, CHP plant needs to produce heat and power simultaneously. Consequently, the output of CHP plant is dependent on the requirements of the associated heat load. The heat load could be predictable and relatively uniform, for example where the heat output of the CHP plant is used for the heating of premises. In other cases it could be less uniform, such as where the heat output is used in certain industrial process applications. Because CHP electrical output is influenced by heat demand, CHP is likely to be inflexible, although it may be possible in some cases for electrical output to be raised at the expense of the heat output if electricity prices made this change beneficial.

Existing CHP sites which import electricity

The majority of sites with CHP are electricity importers as the CHP is sized to provide only a portion of the site electricity needs. They are in a similar position to sites with no CHP. They are net consumers of electricity and will need to forecast their demand if they self-supply, or contract with a supplier who will do so on their behalf. Such importing sites would benefit from lower electricity prices. However, importing CHP sites have the additional risk, compared to non-CHP sites, that the CHP plant may fail. This would result in the site importing much larger volumes of electricity and, in the short-term, could put the site into imbalance. There would be a cost for the site in managing this risk. The cost would depend on the reliability of the CHP plant. As with other electricity customers using a supplier, the site would benefit from being aggregated with other customers for imbalance purposes.

CHP sites which export electricity

There are 232 existing CHP sites in England and Wales which export electricity (i.e. 20% of the total number of CHP sites) with a total electrical capacity of 1795 MW (54% of the total). CHP sites with a predictable electricity output have a low risk of exposure to imbalance charges. Consequently, these generators should be able to obtain a reasonable market price for their output, whether they are selling directly to customers or to an aggregator. However, given the general reduction in wholesale prices expected from the new electricity trading arrangements, the position of these generators may deteriorate slightly. In general, licence exempt embedded CHP plants will be able to sell their output to local suppliers. Predictable output from embedded generation should be attractive to such suppliers because it avoids transmission charges without raising imbalance risks. The extent to which CHP plants will be able to capture these benefits will depend, among other things, on the extent of supply competition in their area.

CHP plant with an unpredictable output will be exposed to imbalance charges, either directly or indirectly. Although the proposed power exchange will remain open until at least 4 hours ahead of real time, very small CHP sites are unlikely to have the manpower resources available to trade actively in such short timescales.

Licence exempt CHP sites with an unpredictable output will be able to ameliorate their exposure to imbalance prices by aggregating their output with that of other licence exempt generators. The settlements process would see only the net imbalance rather than the individual imbalances of each site. Nevertheless, there would be some cost to the sites for the cost they are imposing on the system.

Licensed CHP sites with an unpredictable output will be required to sign the Balancing and Settlement Code and will therefore be exposed directly to imbalance charges. For such generators imbalance charges will be potentially volatile. When there is surplus generation on the system, generators may be paid to reduce output which could result in plants with an unpredictable output paying for any excess they may have produced above that they had contracted for. At other times, when the system is short of generation, such generators could receive high payments for their excess output. Such generators could choose to aggregate their output with that of other generators so that the combined group were exposed only to the net imbalance. This would significantly reduce each plant's risk. They would, however, bear some penalty for the cost they are imposing on the system. In general, CHP sites with unpredictable exports of electricity are expected to be the most affected by the new electricity trading arrangements.

New CHP investment

New investment in CHP plant where the site is importing or exporting electricity will be affected by lower electricity prices. CHP Association figures suggest that a 10% reduction in electricity prices (assuming no other offsetting measures, such as fiscal incentives) would make investment in new CHP less attractive (a 15.1% return would fall to a projected 12.6% rate of return in investment). As has been noted, lower electricity prices are a Government aim and new electricity trading arrangements are one element in achieving that goal. Improvements in technology might improve the ability of some CHP plants to have a predictable output, or even a flexible output. For example, Energy Technology Support Unit (ETSU) suggest that CHP plant with the potential for flexible operation is already planned. Such plant will be able to earn premium prices in the market.

Renewables

Overview

In 1997 there was 3372 GWh of electricity produced from renewables plants in the UK excluding large scale hydro and pump storage. Of this 665 GWh (20% of the total) came from wind, 159 GWh (5%) from small scale hydro, and 2549 GWh (75%) from biofuels, including landfill gas, sewage sludge, and municipal waste combustion.

Renewable Plants with an Unpredictable Output

Wind generation is the principal category of plant with an unpredictable output. The output of these plants is entirely dependent on wind speed. Low or very high wind speed prevent such plants operating. Industry studies of land-based wind generation plant suggest that wind generators are able to forecast their output accurately four hours ahead of real time with only 60% confidence and will therefore have a significant exposure to imbalance charges.

All current wind generators are licence exempt. The aggregation of generation output with other exempt generators is therefore an option available to wind generators. A plant operator might aggregate the output of their plant with a number of other wind generators, or aggregate with other types of exempt generator. This would spread and reduce the individual imbalance risk of each plant and thus help to reduce the risk premium but is unlikely to offset the impact of the new electricity trading arrangements completely. Although a plant operator could also contract with a local supplier or with a larger generator to pass the risk on, it is likely that the plant operator would have to pay a significant risk premium.

Renewable plants with a predictable or flexible output

Most biofuel and hydro plants have a predictable output and many will have the potential to operate flexibly. They are all licence exempt. Predictable plants should be able to obtain reasonable prices for their output for the same reasons that apply to predictable CHP plants. Plants able to offer flexible output will have the potential to obtain a premium price for their output. Such plants could, for example, offer flexibility into the balancing mechanism. They could also, as embedded generators, contract directly with suppliers. Suppliers might be prepared to pay a premium for the ability to call on flexible embedded generation capacity to change their physical imbalance position during the four hour gate closure period.

New renewables investment

The higher prices achievable by plant with predictable or flexible output is likely to influence the type of renewables plant constructed.

Increased generation from renewable sources remains an important part of the Government's policy to combat global warming. The Non-Fossil Fuel Obligation (NFFO) scheme obliges Public Electricity Suppliers to secure specified amounts of renewable generation capacity. This scheme will substantially reduce the impact of any adverse effect of the new trading arrangements, such as lower electricity prices, on renewables generators. The Government is currently considering revised arrangements for encouraging support for electricity generation from renewable sources and will take full account of the new market conditions in developing its proposals.

Summary of Environmental and Social Impacts of the New Electricity Trading Arrangements

CATEGORY	***% EFFECT***	**ENVIRONMENTAL EFFECT**	***OTHER ACTION***
Electricity prices	Wholesale prices at least 10 % lower	Reduced incentive to save electricity and to invest in electricity saving. Positive effect on fuel poverty and social exclusion	Energy Efficiency Standard of Performances (EESOPs), Home Energy Efficiency Scheme (HEES), Social Action Plan
Payments for flexibility	New opportunities for demand-side bidding. Increased reward for flexible plant	Reduced generation from marginal plant will reduce emissions. May extend life of coal plant	
Imbalance charging	Incentive to predictable output	Increased risk for plant with unpredictable output. Should benefit base load generation – nuclear, gas.	
CHP – existing	Lower prices, imbalance charges, aggregation rules, exemption thresholds.	CHP importing sites (80% of sites, 46% capacity) will benefit from lower prices. Exporting sites will continue to have market for power. Predictable and flexible plant should have increased value as result of imbalance arrangements. Unpredictable plant will face additional risks. This can be significantly offset by aggregation arrangements	Government is considering the treatment of CHP under the Climate Change Levy arrangements
CHP – new investment	Lower prices, imbalance charges, aggregation rules, exemption thresholds	Lower prices plus increased risk for some types of plant will reduce incentive to invest. Aggregation rules should allow some risk to be offset.	Government is considering the treatment of CHP under the Climate Change Levy arrangements

Renewables - existing	Lower prices, imbalance charges, aggregation rules, exemption thresholds	Existing NFFO contracts should not be affected. Ex-NFFO generation should be competitive in new market. Aggregation rules will allow some risk to be offset. Flexible renewables plant will have the opportunity to earn a premium for that service	Government is considering the treatment of renewables under the Climate Change Levy arrangements. Replacement for the NFFO scheme is also under consideration
Renewables – new	Lower prices, imbalance charges, aggregation rules, exemption thresholds	Plant with predictable output should be able to achieve competitive prices. If flexible as well, will receive additional reward. Inflexible plant will face new risks. Wind most affected. Will benefit from exemptions and aggregation opportunities. New investment likely to favour technologies which provide predictable and flexible output.	Government is considering the treatment of renewables under the Climate Change Levy arrangements. Replacement for the NFFO scheme is also under consideration, to be decided later this year.

Appendix 6 Business Simulation Modelling

This appendix describes the experimental business simulation modelling commissioned by Ofgem/DTI and reports on its results.

The Broad Objectives

Two broad objectives were set for the modelling activities:

- To gain insights into aspects of the new trading arrangements; and
- To provide a platform which potential participants can use to gain experience of the trading environment that they will face under RETA.

The first objective was achieved by conducting a series of experiments using the business simulation model that was developed. The second was achieved by encouraging the industry to participate in those experiments and then making the model generally available.

The Approach to Modelling

To capture all the markets expected to operate under the new trading arrangements and explore all their interactions within one model would be a considerable task and would result in a model of substantial complexity, both in its construction and its operation. This would lead to significant risks, including that:

- The development and operation of the model would be prohibitively time consuming;
- The results of any run of the model would be hard to interpret, as so many factors would need to be taken into account; and
- The model would be too complex for meaningful insights to be obtained from its use by potential participants.

The Programme therefore decided to focus its modelling efforts on the specific parts of the new electricity trading arrangements proposals most likely to generate results of interest. A range of modelling approaches that might be helpful was considered. The principal interest was not so much to investigate what level of prices might be obtained, as to explore how different incentives might influence participants' behaviour. It was therefore decided to commission an experimental simulation model, as this was felt to fit best the need to assess behaviour by market participants.

The RETA Model

Since the interest is in the incentives to trade in the various markets that together make up the new trading arrangements, the modelling effort could not focus solely on the those elements that are being procured by the Programme, namely the Balancing Mechanism (BM) and the Imbalance Settlement Mechanism (ISM). At the same time, as noted above, it could not capture all the markets in their entirety. It was therefore decided to focus on trading in a Power Exchange (PX), with the assumption that prior trading has taken place on the forwards and futures markets, and assess the impact of the Balancing Mechanism and the ISM in terms of what trades take place in the PX, and what are left to those mechanisms. In doing this, the implicit assumption was that the PX trades are a proxy for trades in all the markets that might operate in advance of gate closure, including those with longer-term activities than the day ahead usually assumed for the PX.

It is accepted that this is only one of a number of approaches that could have been used and that other models could also provide insights into the operation of the markets under the RETA proposals.

An Outline of the Model

The model simulated trading in a PX. A team of people traded in real time, each playing the role of a market participant and working from information on prior trades, production or consumption costs, capacity limits and potential prices, to develop trading bids and offers. The model simulated the operation of a PX and matched beneficial trades and then allowed unmatched positions to be offered into the Balancing Mechanism; any open positions that were not closed out by the acceptance of offers or bids became subject to Imbalance Settlement. The overall results of trading were then analysed and passed back to participants to allow them to amend their behaviour in future runs in the light of experience.

The software platform for the model was provided by the Automated Power Exchange (APX). As used by the Programme, the model worked by using a network of PCs that were the input screens for each ‘trader’, linked via the internet to APX’s mainframe which processed bids and offers and cleared the market. A number of enhancements to this platform were written to allow participants to operate in a game environment and to incorporate the effects of the Balancing Mechanism and Imbalance Settlement.

In the experiments conducted by the Programme, the model was run with up to fourteen teams of players representing a variety of industry participants. A game supervisor took overall charge of each run, acted as both market and system operator, introduced selected random events such as demand perturbations or generating station failures, and contributed to the post run analyses. The runs were made in a room devoted to the purpose, fitted with some 15 PCs with appropriate hardware and software.

Two separate sets of runs were conducted. In the first set, the participants were students who were paid a basic rate per day and who were incentivised by the offer of small cash prizes. The second set of runs used two groups of participants from the industry, who were not paid.

Simplifications

The model made several simplifications. These included the following:

- All trades contain price and quantity only. Other contract forms, such as caps, collars and load following were excluded;
- Plant technical constraints, such as ramping, were not modelled or included in the Balancing Mechanism calculations;
- Transmission constraints were not modelled or included in the Balancing Mechanism calculations;
- Offers and bids to the Balancing Mechanism were made once only; and
- The Balancing Mechanism was treated as a 'one-shot' market and the real time effects of emerging Balancing Mechanism acceptances was not modelled.

Running the Model

A run of the model proceeded as follows:

- Forwards contracts arising from any vertical integration and the customer base were represented by an 'opening position' provided to each participant before a model run began.
- The PX opened for trading and participants posted offers and bids. The model provided a decision support tool called a payoff calculator, which assessed the best trading approach given input on market conditions and likely prices.
- The market clearing software both cleared any mutually acceptable offers and bids (in other words an offer at or lower than a bid) and allowed participants to accept an extant offer or bid. Until the end of

trading, participants were allowed to post new offers and bids and to remove unaccepted extant offers and bids.

- ♦ Once the relevant trading period was closed, participants submitted FPNs for generation to the system operator and, if they so chose, Balancing Mechanism bids.

- ♦ The model then optimised and balanced the system at a single turn, accepting offers and bids necessary to do this and allowing for any random perturbations in demand or generation failures introduced by the model operator. System and participant imbalances were then calculated.

- ♦ Imbalance prices and payments were calculated. Participants who were out of balance were charged or paid at energy imbalance prices.

- ♦ Results were collated and participants informed how they had performed.

Outputs

The model provided the following types of output:

- ♦ Traded volumes and prices in the PX;
- ♦ Balancing Mechanism trades and volumes;
- ♦ Imbalance Settlement prices and volumes;
- ♦ Costs of generation;
- ♦ Short run profitability for each participant.

Scenarios Assessed in the Experiments

The experiments looked at three sets of scenarios:

- the base case, broadly that set out in the July Consultation Document but with the spread between the two cash-out prices fixed at 10%;

- a single cash-out price case;

- a system marginal price cash-out case.

Each scenario was run with an approximation of the market structure likely to be in place in around 2002, that is with the divestment of plant recently concluded by PowerGen and in train by National Power. Because the modelling exercise employed only 14 teams, some simplifications to the full complexity of the anticipated structure had to be made. As well as the three main scenarios, sensitivities were run either with shocks, such as a generator failure or a change in fuel prices, or with a changed industry structure, especially greater vertical integration.

Most cases were repeated eight to ten times, usually over a period of a week. To allow for learning during the case, the students kept to the same role for each run.

Experimental Results

The results of the experiments were analysed in terms of:

- Prices;
- Volumes;
- Timing of trades;
- Distribution of rewards between participants.

General conclusions

- The type of trading arrangements envisaged by the RETA Programme was able to produce prices and dispatch close to the theoretical optimum[24]. Prices were close to this level in all cases, deviating on average by approximately 1£/MWh (5%). Generating costs were on average less than 3% above the theoretical optimum.

- The prices in all cases come out well below existing prices. Generally, prices averaged over the day for the winter day being used in the model came out at around 18 £/MWh to 21 £/MWh, compared to the week day Winter PPP for 1998/99 of around 33 £/MWh[25]. There seem to be at least two reasons for this:

  The model assumed a lesser degree of generator concentration than is currently the case; and

[24] The theoretical optimum was defined as all participants bidding marginal costs (including start up and no load costs correctly apportioned over the number of hours each unit was called) on all units, and least cost despatch based on those bids and offers.

[25] Time weighted weekday PPP (October 1998 – March 1999).

The experiments lasted for a maximum of ten runs of a case. This gave little opportunity for participants to observe the behaviour of others and subsequently adjust offers accordingly. In real life, participants literally have years to achieve this.

- In general, the type of trading system envisaged by the RETA Programme was able to respond efficiently to changing supply and demand conditions. The response of prices to demand variations through the day was close to optimal, and there was no evidence from the experiments that there would be any problems in the system responding to supply and demand shocks.

- Participants failed to find higher priced non-competitive equilibria that were sustainable on the modelled system. These non-competitive equilibria required substantial capacity withdrawal simultaneously by at least three participants. With no more than ten rounds of play for each case and limited analytical resources available to players, it appears that participants remained unaware of these equilibria.

- At least one type of opportunity for gaming the system was found. This involved the participant going out of balance in the same direction as the system, then ensuring a favourable imbalance price by submitting manipulative offers or bids to the Balancing Mechanism. Further work is in hand to assess whether, over time, this gaming would be competed away and if not what rules would be required to eliminate it.

Comparison of Balancing Mechanism rules

- SMP pricing in Imbalance Settlement produced the least efficient dispatch and pricing of the systems investigated. Whilst this may have been the result in part of the difficulties the participants had in reaching equilibrium in this case, there is no evidence from these experiments for the claimed superior efficiency of SMP pricing.

- There was some slight evidence of higher PX prices with a dual imbalance price, although the effect was not statistically significant. In those runs, however, the higher PX prices were balanced by lower BM prices, leading to no material differences between average prices. There was no evidence of significant differences in dispatch efficiency between simulations using single and dual imbalance prices.

- The most even distribution of rewards between participants was under pay-as-bid with a single imbalance price, although the magnitude of differences of rewards for participants between cases with single and dual imbalance prices was not significant. The least even distribution of rewards was with SMP. This largely reflected the price variations between the cases.

- Moving from a single to a dual cash-out significantly reduced system imbalance volumes. This implies that the 10% spread used in most of the experiments provided substantial incentives to trade forward. An increase in the dual cash-out spread from 10% to 40% produced a further decrease in system imbalance.

- A dual imbalance price greatly reduced individual participants' imbalances compared with a single imbalance price, implying that the incentives to avoid the dual cash-out were apparent. In subsequent discussions with participants they were unanimous that this had been a motivating factor. However system imbalances were less markedly different in each case, because individual participant imbalances tended to cancel each other out.

Differences between industry participants and students

The first group of industry participants produced higher prices than either the students or the second group of industry participants (if simulation runs involving gaming are excluded). The reasons for this are unclear but it appears in part to reflect different anticipations of sustainable prices, based on whether or not the participant had experience of present market price levels. However, the industry participants' much shorter exposure to the system means it is not valid to draw firm conclusions in this respect.

There were more attempts to manipulate prices by the industry participants than by the students. This included both attempts at collusion between participants, and individual attempts to game prices.

Next Steps

The Programme has finished its experiments with the simulation model. The results will be presented to the DISG in due course. The Programme is continuing to assess those results and will determine whether any changes to the proposed rules are necessary to deal with the gaming opportunities that have been identified.

The industry has now been offered access to the model in whatever way it chooses to use it. A note to this effect was posted on the Ofgem website in September.