OFFICE OF ELECTRICITY REGULATION

REVIEW OF ELECTRICITY TRADING ARRANGEMENTS

A POSSIBLE COMMON MODEL FOR TRADING ARRANGEMENTS

MAY 1998

A possible common model for trading arrangements

A discussion note by OFFER, 1 May 1998

1. Introduction

As a result of discussions during the Review of Electricity Trading Arrangements (RETA) seminar in April, it has become clear that there may be a wide range of agreement on the desirable elements of alternative trading arrangements. There are, for example, strong similarities between the various alternative trading arrangements proposed by OFFER (Models 3 and 4), Accord/British Gas Trading (BGT), the International Petroleum Exchange (IPE) and National Power. It was also urged that the models needed to specify more detail in order for interested parties to understand and appraise them. This suggests that a basis for proceeding is to condense the various models into a single "common model" which can then be developed further and more easily accessed.

This note outlines a model synthesised from the various models proposed and taken to a further degree of detail. The model is designed to provide a wide degree of choice to market participants over how they manage their positions. It incorporates the following features:

- Contractual freedom ("trading outside the Pool")
- A short-term bilateral market
- A balancing market

Each of these markets is described briefly in Section 2. All of the markets are voluntary and incorporate full demand side participation. Section 3 discusses the treatment of transmission constraints, Section 4 considers settlement issues relating to the common model. It is for debate whether an organised (but optional) day-ahead auction would be helpful; an outline of how such an auction might operate is included in Section 5. Governance considerations are outlined in Section 6. Finally, Section 7 highlights a number of issues that have still to be resolved.

At the RETA seminar in April it was suggested that further specialist discussion of alternative trading arrangements would be helpful. Accordingly, separate meetings have been arranged for generators, suppliers, customers and other interested parties in mid-May. This paper is being published now in order to inform discussion at these meetings, and to enable interested parties to comment on the model in their responses to the present consultation papers.

The assumptions incorporated in this model are intended to facilitate such discussion and appraisal: they do not necessarily represent interim conclusions of the Review of Electricity Trading Arrangements. Square brackets are used to indicate possible parameters of the model that will need to be confirmed or altered in the light of discussion, but the structure itself is also for consideration at this stage.

2. Outline of a possible common model

Contractual freedom ("trading outside the Pool")

Participants would have freedom to enter into whatever contracts they chose, thereby giving them the ability to secure cover for their anticipated output or demand. Trades would take place on a bilateral basis at prices (and on other terms) agreed between the buyer and the seller.

It is anticipated that market participants would take different views on contracting. Some might wish to secure their output or supplies a year or more in advance of physical delivery. Others would prefer to enter into transactions closer to the time that the electricity would be generated or consumed ("real time"). Yet others would want to contract and re-contract continually adjusting their position. Market participants would have flexibility with regard to the terms on which they conducted their business. This is likely to be attractive for generators, suppliers and customers, the latter group in particular having argued strongly that they would welcome such flexibility.

It is likely that there will be a demand for exchange-based forwards or futures markets. It is not proposed that such markets should be explicitly organised as part of the change in trading arrangements. Instead, it is anticipated that these markets would be set up and develop (as in other markets) in ways that market participants found most helpful.

Comparison to other models: The Accord/BGT and the IPE models incorporated optional forwards markets whilst OFFER Model 4 incorporated a mandatory forwards market. The existence of forwards markets was not discussed explicitly in the National Power model (although some reservations concerning trading outside the Pool were raised) or in OFFER Model 3 (although they were strongly implied).

Short-term bilateral market

This market would operate continuously up to the time that the System Operator (SO) takes control of balancing the system for a given half-hour. This could be say [one hour] before the start of each half-hour period. It would be a screen-based system in which bilateral trades, which are likely to be anonymous, enable market participants to fine-tune their positions on a half-hour by half-hour basis. Trades in the short-term bilateral market do not have to be location specific until the point at which the SO first needs to take account of constraints on the transmission network, which might prevent the matching of supply and demand at a national level. At that point in time, [say four hours before the start of a half-hour], market participants firmly commit to physical positions for the relevant half-hour, which they notify to the SO (see below). For the hours between the time at which the SO first takes account of constraints and the time at which the SO takes control of the system, trades are location specific and must be feasible with respect to constraints (this may require checking by the SO).

Generators and suppliers (and customers) can submit simple offers and bids to the short-term bilateral market. These specify volumes and prices for individual half-hours. Offers and bids can be posted, modified or withdrawn at any point until they are accepted. Accepted offers and bids represent firm financial commitments and are settled at the prices specified in the offer or bid rather than at a market clearing price. Participation in this market is optional.

Comparison to other models: OFFER Model 3 explicitly incorporates a short-term bilateral market although the options market in OFFER Model 4 performs a somewhat similar function because participants would enter into options contracts to cover differences between their actual positions and that established in the forward market.

Notifications of positions

As mentioned above, market participants have to inform the SO and of their committed physical positions[1],during the relevant period, [four] hours before the start of each half-hour. These are their "final physical notifications" (FPNs). The volumes for which market participants are exposed to balancing market costs, their imbalance volumes, are calculated as the difference between their ex-post metered volumes and their FPNs, allowing for subsequent trades in the bilateral and balancing markets.

Balancing market

A balancing market would operate for a period of say [one hour] before each half-hour begins (and throughout the half-hour). This is the market that the SO, which is presently the National Grid Company (NGC), uses, along with Ancillary Service contracts, to balance the system. Market participants submit offers and bids to the balancing market which specify the prices at which they are prepared to change upwards (incremental offers/bids[2]) or downwards (decremental offers/bids[3]) from their FPNs. The starting point for settlement purposes is that the FPNs represent output for which generators have deemed to have been paid and demand for which suppliers (and customers) are deemed to have paid. Thus, a generator that is expecting to produce 500 MW might be prepared to pay close to his fuel cost for reducing his output by 100 MW (since he is avoiding burning fuel) but might wish to pay significantly less (or even be paid) if his plant is to be shut-down. Conversely, a supplier with a demand of 500 MW might be willing to receive a relatively modest payment for reducing his demand by 10 MW but might require a much higher payment for a 250 MW reduction. At least initially, it may improve confidence if it is mandatory on all suppliers and generators submitting FPNs to provide balancing market offers and bids. Such a requirement could give the SO more flexibility in balancing the system.

The SO would select incremental and decremental offers and bids in price order to adjust generator output and customer demand to ensure that the system is operated in a safe and reliable fashion with generation matching demand at all times. The SO is the counter-party to all trades in the balancing market: no bilateral trades between market participants are allowed.

For the first say [half an hour] of the balancing market, market participants would be able to alter their balancing market offers and bids to the extent that they have not been accepted. After this point prices offered and bid cannot be changed. This provides the SO with a fixed

[1] These are there best estimates of the output they will produce or demand they will consume, rather than any contractual position they might have.
[2] The price they wish to be paid for an increase in output or are willing to pay for an increase in demand.
[3] The price they are willing to pay for a decrease in output or wish to be paid for a decrease in demand.

set of options from which to choose balancing actions. Prior to this time, the SO can also accept offers and bids but there will be a risk that a cheaper option will become available. It would seem desirable for the SO to continue to be incentivised to minimise the costs of constraints and energy balancing. Thus, the SO will have to balance the risk of paying more than may prove to be necessary for a particular balancing action against the possibility that only a more restricted, and hence expensive, set of balancing actions may be available closer to real time.

Comparison to other models: All the models, except OFFER Model 4 (which uses an options market instead), incorporate some form of balancing market.

Real time control

The SO will have ultimate control over the system and will be responsible for matching generation to demand. To assist in this process, it will enter into Ancillary Service contracts for frequency response and reserve, use fast response offers and bids from the balancing market and have available the automatic frequency response of all generating units that are operating. Together, these will ensure that the system can be balanced in an efficient way on a second by second basis.

3. Transmission constraints

Once FPNs for a half-hour have been made, the SO[4] can identify whether and where any constraints may occur during the period. The SO will make this information available to market participants as soon as is practicable after the FPNs are received, say [half an hour] later. From this time until the short-term bilateral market for the half-hour closes ([one hour] before the half-hour starts), market participant can themselves seek to resolve any constraints which may affect their physical commitments by entering into location-specific trades in the short-term bilateral market.

When the short-term bilateral market closes for a half-hour period, the balancing market opens. The SO will use this market (and his Ancillary Service contracts) to alleviate any remaining constraints or new ones that arise. He will accept incremental and decremental offers and bids from generators and the demand side which provide the least cost way of adjusting the flows on the system so that they are feasible.

The SO’s purchases and sales of increments and decrements will establish higher or lower prices for generation and supply. The expectation of such price differentials will give market participants the incentive to trade out the constraints before the SO itself takes action.

It has been suggested that plant which do not typically run but may be required to operate to alleviate constraints from time to time, will require longer notification than would be available under the timescales suggested. Similarly, customers or suppliers may require longer lead times to be in a position to adjust their demand on the day. One possible way of overcoming

[4] It is for debate whether the SO should be allowed to use his own demand forecast in the constraints calculation rather than relying upon the aggregate demand FPNs.

this problem would be to require market participants to provide an initial assessment of their likely physical positions throughout the day (“initial physical notification”) by, say, [15:00] on the day ahead. These would not be binding notifications but they would be provided on a “best endeavours” basis. The SO would use these initial notifications to ascertain and publish by [17:00] whether any constraints seemed likely and where and when they might occur. Generators could use this information to decide whether to risk warming up their plant in order to be able to participate in the balancing and bilateral markets. Similarly, customers and suppliers could decide whether to take action to achieve demand flexibility.

The situation with regard to transmission rights under the common model would be the same as under the present trading arrangements. Generators and suppliers (and customers) would have “firm” access rights to the transmission system. They are compensated for any reduction in their desired exports or imports as specified in their FPNs if, in real time, they are not able to export to or import from the transmission grid whatever volumes they desire because of transmission constraints. The SO will only be able to alter their FPN positions by accepting a decremental bid from a generator or decremental offer from a supplier (or customer) with the price in the bid or offer providing the compensation[5].

4. Settlements

Two types of imbalance are possible, contractual and physical. Contractual imbalances are deviations between participants’ contractual positions and their final physical notifications. Physical imbalances are deviations between their final physical notifications and their metered quantities, taking into account any trades in the short-term bilateral and balancing markets.

Contractual imbalances have to be calculated to ensure that the costs of any balancing actions taken by the SO can be allocated appropriately. For example, suppose that a contract for 500 MW exists between a generator and a supplier. If, on a particular day, the generator is unable to meet this contract because his plant has failed, his FPN would be zero whereas the supplier’s FPN would still be 500 MW. Assuming that these FPNs matched their metered volumes, neither party would have a physical imbalance. Unless the generator purchased 500 MW (for example, via the short-term bilateral market), the system would be short of 500 MW and the SO would have to purchase 500 MW in the balancing market to balance the system. Calculation of contractual imbalances enables the balancing market costs to be allocated to the generator.

Hence, suppliers and customers (and traders, if they were net purchasers of contracts) would have to inform the Settlement Administrator of their half-hourly contracted quantities and specify with whom each contract had been signed. This would need to be done on a daily basis but could be done ex-post i.e. after the end of the schedule day. In the example above, the supplier would inform the Settlement Administrator that he had a contract with the generator for 500 MW which the generator’s FPN would show he was not meeting and hence it would be possible to allocate the balancing costs to the generator.

[5] Strictly speaking for a generator, the compensation he will receive is the difference between the contract payments associated with his FPN volume and the payment he makes to have his output reduced. For a supplier, the compensation is simply the payment he receives for reducing his demand.

The Settlement Administrator will need to be informed of:

- aggregated volumes from the forwards/OTC and futures markets
- the volumes of all trades in the short-term bilateral market
- the volumes of all trades in the balancing markets
- the utilisation of any Ancillary Services contracts
- imbalance charges for each half-hour

All imbalances will be settled on a half-hourly basis. Energy imbalance charges will be calculated from the prices of offers and bids that have been accepted in the balancing market for each half-hour and the utilisation fees of any Ancillary Service contracts that have been used in that half-hour. These charges could be calculated as volume-weighted averages or on a marginal basis (as in NordPool and California) or a combination of the two depending on the extent of the imbalance (as in the gas market). They might also include Ancillary Service contract availability fees in some way. Further consideration needs to be given to the question of how imbalance charges can most appropriately be set and the interaction of Ancillary Service contracts with the balancing market.

5. Possible structure of a organised day-ahead auction

The present Pool operates to set prices on a day-ahead basis. Generators all submit offers a day-ahead and the system marginal price is set day-ahead, to which customers and suppliers can respond on the day. If it is desired to provide an optional day-ahead auction to supplement the model described in this note, such a market might be of the following form.

Generators and demand side participants submit simple offers and bids which do not have to be location specific. No account is taken of transmission constraints. A Market Operator (MO) constructs supply and demand curves specifying the volumes of power that market participants wish to buy or sell at given price levels. Half-hourly prices are set on a market-clearing basis i.e. a system marginal price is calculated. Any bids or offers accepted in this market represent a firm financial commitment on the participants.

Whether such an auction would constitute a reassurance to market participants is debatable. It would require suppliers to bid prices and quantities, which they are not presently required to do. Generators would be faced with an active demand side rather than an estimate of quantity demanded. Many contracts would already have been signed and there would be the short-term bilateral market yet to come. Such a day-ahead auction would be very different from the present Pool. Experience in New Zealand is that an optional day-ahead market was organised but abandoned after a few days because of lack of support.

Comparison to other models: The Accord/BGT, National Power models and OFFER Model 3 incorporate day-ahead markets with market-clearing prices i.e. an auction, whereas the main IPE model does not (although the “trading inside the Pool” IPE model does, albeit of a different form). OFFER Model 4 had no day-ahead market although an options market was intended to provide participants with the opportunity to adjust their positions over short timescales.

6. Governance

Views have been expressed, both at the RETA seminar and more generally, that governance arrangements need to be more flexible than the present Pool and that that there is merit in clearly separating the roles of System Operator and Market Operator. There are a number of ways in which this might be achieved.

A SO would be required to balance the system. This role would be quite distinct from that of the MO, and distinct from that of the owner and operator of the transmission system. In the short term, however, there could be advantage in NGC acting as SO.

A MO would be responsible for organising the short-term bilateral and balancing market. One possibility would be to licence separately this activity, which would effectively be a monopoly, for periods of, say [three] years initially. The obligations of the MO would be specified in its licence and the normal provisions for licence modifications would apply. The Director General of Electricity Supply (DGES) could propose licence amendments, which would be referred to the Monopolies and Mergers Commission if the licensee declined to accept.

The licence could be awarded on the basis of tenders for the role of MO. Rather than specifying the duties of the MO in narrowly defined licence obligations, general guidelines for the MO's role could be issued in the request for tenders. It would then be up to the parties who chose to bid to be the MO to indicate, for example, the charging structure they would propose to use to recover their costs, the return which they considered reasonable for undertaking the role, and the extent to which they would also wish to take responsibility for market monitoring and reporting (including the reporting of activities unlikely to be consistent with the operation of an orderly market). The successful bidder would be chosen partly on the basis of his proposed charging structure but also taking full account of all of the elements of his proposal for running the market. An alternative would be to seek tenders for the role of MO under the existing licensing regime.

It would be for consideration as to who should be responsible for initiating and managing the tendering process. A possible candidate would be NGC who, in its role as SO, has responsibility for balancing the system. NGC would be the counter-party to all trades in the balancing market and may also be a participant in the short-term bilateral market (with NGC being subject to appropriate incentives to encourage it to balance the system efficiently). Involving NGC in this way would enable the task of appointing a Market Operator to be carried forward more speedily under NGC's existing licence.

Whatever approach was adopted for the move to new trading arrangements, including the establishment of a MO, consideration would have to be given to matters of timing. Major shortcomings associated with the present trading arrangements have been identified and customers and others are calling for urgent action. It would also be helpful to align electricity trading arrangements with those in gas as soon as reasonably possible. OFFER would welcome the views of others as to whether this would present difficulties. It would appear that, by inviting suitably qualified parties to tender for the role of MO established via NGC's licence, the short-term bilateral and balancing markets could be put in place relatively quickly, for example, within one year.

7. Issues to be resolved

The issues that need to be resolved fall into three broad categories. First, those that relate to the overall structure of the proposed common model. Second, those that relate to the details of the common model outlined in this note. Third, those that will need to be considered when taking the model to the next level of detail. Below we list, by category, some specific issues. This is not intended to be an exhaustive list and it is likely that further issues will arise including some that are a result of the meetings that are being held over the next two weeks.

Overall structure

Price discovery in the forwards/OTC market: Will it be sufficient to rely on price reporters to provide price discovery in these markets, or should there be a requirement to notify prices and volumes (anonymously), or should OFFER have the ability (via a “reserve power”) to oblige disclosure, at least on major participants, if price reporting does not develop in a timely way?

Treatment of constraints: Does the outlined model provide sufficient distinction between energy imbalance costs and constraint costs as far as imbalance charges are concerned or should a day-ahead constraints market (as in the Accord/BGT model) be considered?

Transmission capacity market: Such a market was included in the IPE model. Should this be given further consideration at this stage?

An organised day-ahead auction: Is such a market required and, if so, by whom should it be operated?

Details

The operators of the short-term bilateral and balancing markets: Should the operator of the two markets be the same, as is suggested in this note?

Timescales envisaged: Are the various timescales in square brackets appropriate?

Calculation of imbalance charges: Should these be the volume-weighted average of offers and bids accepted after participants have notified the SO of their FPNs or the price of the marginal offer/bid accepted or some other mechanism?

Ancillary Service contracts: How should such contracts be treated both with regard to their utilisation instead of balancing market bids and offers and the inclusion of any availability fee in the calculation of imbalance charges?

Further considerations

Incentives on the SO: To what extent would the present incentives on the SO (NGC) to operate the system efficiently (by minimising the costs of Uplift) be appropriate or need to be amended?

Transmission losses: How should these be treated?