Supporting Analysis to the Single Cost-reflective Cash-out Price Modification Proposal

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A1 Introduction and Overview

A1.1 Introduction

This paper provides supporting data for the Modification entitled: *"Single Cost-reflective Cash-out Price"*, which was submitted by Electricity Direct but with the broad support of a wide cross-section of BSC parties as well as affected non-party generators.

The primary purposes of the paper are:

- to demonstrate the ways in which the current cash-out regime does not well facilitate the transmission company licence objectives that the BSC is intended to satisfy; and
- to provide the economic arguments as to why the single price proposal can be expected to be better.

However, in addition, this analysis will argue that:

- the single-price proposal is more in keeping with the broader NETA objectives; and will
- review most of the substantive arguments and assertions made against the single-price concept and provide a rational view of their validity.

The main sources of data used in the analysis are derived from the BMRS, with supporting data on prices published by Elexon (Best View prices). Additional data on BSAD is derived from NGC and the UKPX Reference Price series is used to represent spot market prices. Data cover the period 7th November to 25th March, dictated by availability (to us) of BSAD data. This period covers the winter and is post Mod 18A and so is not affected by any changes in pricing methodology. For some of the analysis, settlements data would have been useful but is not available in public domain and so proxy data has been estimated.

A1.2 Scope – the BSC Objectives and the NETA Objectives

In drawing a distinction between the BSC and NETA Objectives, it is clear that they are not contradictory. However, the BSC objectives tend to be assessed on a shorter timescale and so it is by reference to the aspirations of the longer term NETA framework that some judgements about better facilitation of the BSC Objectives must be framed. Therefore, in judging the better facilitation of the BSC objectives, the following broader NETA Objectives should be considered:

- Development of liquid and competitive forward and spot markets;
- Incentives to balance and to contract;
- Proper reward for flexible plant;
- Cost-reflective charging;
- Transparent regime with clear and prompt information.

Therefore, in this analysis, in addition to demonstrating better facilitation of the strict licence objectives, we show the extent to which a single-price model is more consistent with the wider NETA model.

A1.3 Main problems with the 2-price cash-out mechanism

- The 2-price cash-out mechanism fundamentally fails to incentivise balance. This is because it delivers an asymmetric punishment for errors, with a significantly larger risk cost to a participant for going short rather than going long. The economic driver on consumption accounts is consequently to spill.

- Over-contracting means that excess mid-merit plant is on the system crowding out peaking plant. The cost of this over-contracting feeds through to consumers in higher average costs relative to the cost of accurate contracting with use of peaking plant for the occasions when it is actually required.

- The risks of going short in the market apply particularly to generator trips. Generator reaction has been to part load plant, which allows rapid response from alternative plant in the event of trip. The reserve consequently carried in the system by parties is way in excess of the reserve required by the transmission company. The excess cost of this extra reserve feeds through to consumer cost.

- Increasing the amount of part-loaded capacity on the system greatly increases the level of emissions of CO_2, SOX and NOX.

- Imbalance prices are not reflective of the cost of imbalance. This was a major conclusion of the DTI smaller generator review. The gross costs of party imbalances greatly exceed the costs incurred by the transmission company in balancing the system. The beer fund transfers represent a net transfer of monies between accounts distorting competition. This is even true where the beer fund is close to zero because gross transfer costs remain as a cost of supply, which feeds through to consumers. However, this is ultimately a cost of imbalance risk, which consumers bear.

- Because meter risk cannot be effectively traded across the system with such a large buy-sell spread, a very limited set of risk management products (meter sharing, consolidation) can be offered in the market. This is restricting the options for parties to trade out of risk.

A1.4 Benefits of a one-price model

- **Incentive to balance**

  Parties will seek to go out of balance if it is more cost-effective for them to do so. In an ex post settlements system, however, parties will go out of balance against expectations of settlement prices. The expectation is dual in that, at gate closure, neither the prices nor the volumes of imbalance are certain. Therefore, the proposal for a single price is actually an exposure to two prices before gate closure.

  The fuller economic arguments explaining why a single price improves incentives to balance are given in Section A2 below. The most important factors in making these incentives economically efficient are:

  1. that there must be a connection between exposure to expected imbalance prices and pre gate closure market prices used to manage that exposure;

2. parties must be able to trade out the exposures on the system in these pre gate closure markets so that those best able to manage imbalance risk can absorb that risk.

The reasons why a single cash-out price will improve the incentive on all parties to balance are:

- o As already stated, in the pre gate-closure markets, the imbalance risk remains 2-price because the system net balance is unknown.
- o For generators, the opportunity cost of selling at a contract price that does not significantly reflect SBP will be greater once they have the potential option to spill at SBP as well as at SSP. Therefore, spot prices will rise, raising the cost to suppliers of spilling. Suppliers will therefore go less long.

- **Reduction in excess reserve**
  - o Because the system will be more balanced, the probability of peaking plant being accepted via the balancing mechanism to cover high demand will be increased, improving the efficiency of system balancing.
  - o The risk cost of trip will be reduced and so less reserve will be held by parties against exposure to SBP. This reserve could be made available either in pre gate closure markets or offer prices for it in the balancing mechanism will be lower reflecting the same reduced cost of plant failure.
  - o A system with less part-loaded plant will produce fewer emissions.
- **Incentive to contract**
  - o With the size of the buy-sell spread in the two-price cash-out mechanism there are limited ways of mitigating imbalance risk. Consumption accounts can be consolidated or put into portfolios; production accounts can only effectively benefit from portfolio. Cutting this buy-sell spread will allow financial products to compete with portfolio as a means of managing risk. There is likely to be more contracting in such a regime.
  - o CfD products will reduce the level of pre-gate closure contract notification but will not reflect a reduced level of contracting.
  - o Generators are currently holding part-contracted plant as reserve. Reducing trip cost will improve incentives to contract out this capacity.
- **Incentive to notify**
  - o Generators notify their gate closure FPNs in line with the Grid Code. Currently they deviate when they trip but also when they seek to replace lost generation form other gensets in their portfolio. Because the punishment for a trip may not always be a high SBP, there is less incentive to deviate from FPN.
  - o Even if selling on CfD rather than on bilateral contract, generators will schedule generation against their contracted position. There is no incentive not to notify this total contract position.

- By notifying fixed volume contracts, suppliers can guarantee delivery on the contract, thereby reducing bilateral credit risk even where residual volumes may be on CfD contracts.

- **Cost reflective imbalance costs and facilitation of competition**
  - In a long market, NGC has stated (supporting analysis to modification proposal P78): *"As the system operator can normally avoid taking any action to correct errors that reduce the system imbalance, no additional costs are imposed …"*. Therefore, there is no case on cost-reflective grounds, for imposing costs on those whose imbalance mitigates system imbalance. Accepting that imbalances requiring system actions do impose costs, then mitigating those actions will confer benefit.
  - Beer fund flows will be reduced and will only reflect the net costs of system imbalance, which will be targeted at those causing the net imbalance.
  - The benefit in forecasting of supplier error conferred by scale, will reduce. This will lower the barrier to entry for new suppliers.
  - The risk cost of trip will reduce, offering a lower cost of entry for new generation.
  - Unlike central systems generators, embedded generators cannot offer a firm product (free of imbalance risk) to suppliers. By mitigating the cost of this risk, the discount on the embedded product should be less.
  - The enhanced value of spill will increase the value of embedded generation to suppliers, reducing the discount due to lack of market power.

A2 Economics of cash-out price incentives

The essential aim of cash-out incentives is that parties will contract to balance because this will minimise their cost of imbalance. Clearly, ex post, suppliers who have balanced in a 2-price regime are best off because they have neither bought shortfall at the system buy price nor have they spilled energy at the system sell price that they had contracted for at some higher price.

However, in the ex ante world in which suppliers and generators are contracting, no party's balance position is certain and the prices of imbalance are also unknown. For example, if SBP defaults to SSP – a frequent occurrence in the current market – a supplier would have made more money by going short than by balancing.

A2.1 First order balance equations

The first-order balancing equations are used to derive the relationship between spot prices and expected imbalance prices as a prelude to calculating the optimal imbalance position for suppliers.

The primary factors faced by suppliers and generators in targeting balance are listed in Table 1. These are the main factors necessary for the first order balancing equations.

It should be noted that the assumptions made are first-order approximations. In particular, the assumption that SSP and SBP are exogenous will need to be relaxed. Also, the relationship between generator Offer prices and acceptance probability in the Balancing Mechanism is not sustainable.

Table 1: First-order factors in balancing decisions in a Settlement Period

Variable	Description	Assumptions
SBP	Predicted System Buy Price. Derived from BSAD and Offer Acceptances in the Balancing Mechanism.	Offer prices are independent of market balance position. Prediction based on history of prices.
SSP	Predicted System Sell Price. Derived from BSAD and Bid Acceptances in the Balancing Mechanism.	Bid prices are independent of market balance position. Prediction based on history of prices. Price relatively stable and associated with marginal fuel for generation.
PXP	Spot price available close to gate closure.	Liquid market. Visible price. Parties mark their contracts to market at this price.
O	Offer price of a particular generator.	Not influenced by acceptance probability. (to be used in the generator equation).
p^s	Probability of an individual supplier or generator being exposed to SBP.	A function of the level of contract and, for suppliers, forecast error or, for generators, it is trip probability. Supplier forecast errors are assumed to be distributed normally around their central forecast of demand.
p^{ms}	Probability of market being net short.	
p^a	Probability of generator's offer O being accepted by NGC	

Equation 1 simply identifies the relationship between probabilities – i.e. if you have a certain probability of going short then your probability of going long is the reverse of that.

Equation 1: Probability equalities

Probability of supplier going long $= 1 - p^s$
Probability of market going long $= 1 - p^{ms}$

A2.2 Dual price model

In Equation 2, the same relationship is expressed in three ways. The equation is based on the fact that a supplier should buy (or sell) an extra MWh of energy up until the risk-weighted profit from reduced exposure to SBP equals the risk-weighted cost of spilling the additional energy. This equation by itself says nothing about the level of imbalance that a supplier should trade to but it does establish a relationship between spot prices relative to imbalance prices.

Equation 3 is slightly less obvious. Generators will sell out an additional MWh provided it is worth to them at least as much as the value of spilling (SSP) plus the cost of potential trip plus its worth to the generator as a BM Offer acceptance.

Equation 2: Supplier contract equation – 2-price cash-out

$p^s(SBP - PXP) = (1 - p^s)(PXP - SSP)$
$p^s = (PXP - SSP) / (SBP - SSP)$
$PXP = SSP + p^s(SBP - SSP)$

Equation 3: Generator contract equation – 2-price cash-out

$PXP >= SSP + p^s SBP + p^a O$
$PXP >= (1 + p^s)SSP + p^s(SBP - SSP) + p^a(O - SSP)$

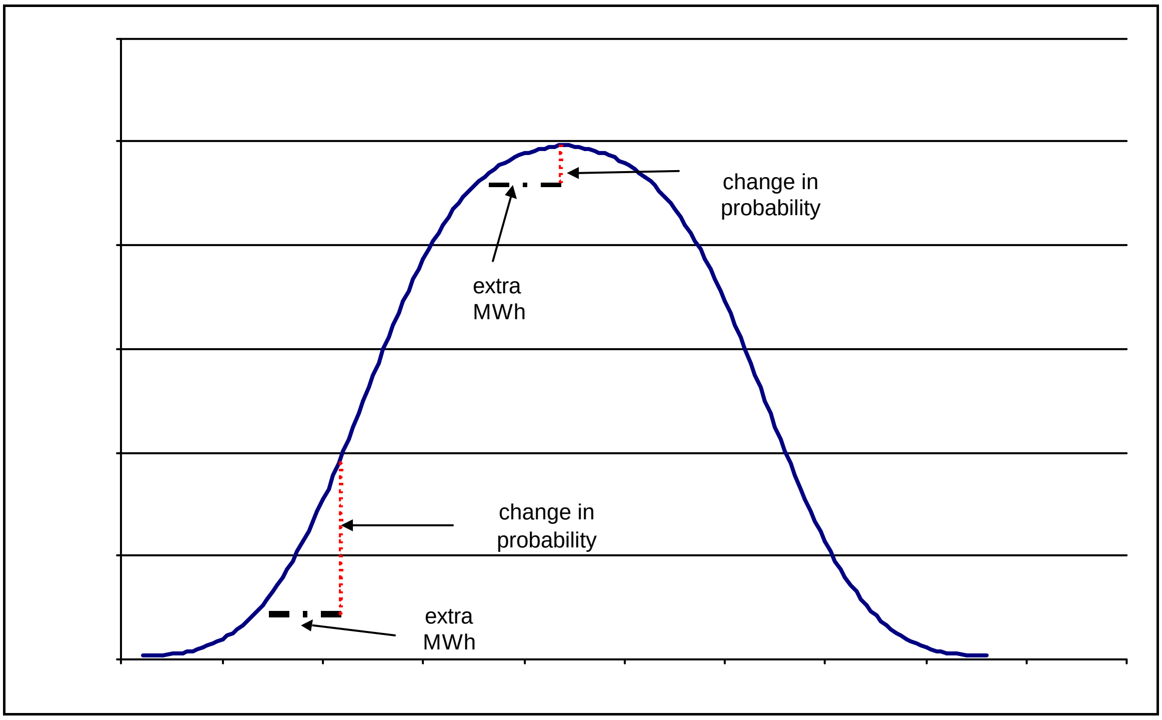
From Equation 2, it can be seen that, as the supplier goes longer, p^s will fall, and the value of marginal spot energy to him will sag towards SSP.

It should also be noted that p^s is dependent on how long the supplier is already. This is because, with normal distribution of errors around forecast, an additional MWh bought by a supplier who is long will have an ever-bigger impact on the supplier's probability of exposure to SBP. This is illustrated in Figure 1. Therefore, once suppliers go long, p^s falls rapidly until the supplier gets to the tail of its distribution and will only trade spot at a diminishing mark up over PXP.

Turning to the generator position in Equation 3, the probability of trip is a low constant and so the only factor leading to a mark-up over SSP is the probability of Offer acceptance. Given the supplier position of likely spill, the generator will have a diminishing probability of offer acceptance and so the price at which he is prepared to trade in the spot market will again tend towards PXP.

It should be noted that, given the length that suppliers have reached, their probability of exposure to SBP is so low that PXP should be almost equal to SSP. In fact, PXP is tending to trade about £3.50 above that level. This is because of another feature found in financial markets. The Black-Scholes model is used for pricing shares in option contracts. A principal input is the volatility of the price of the share being valued relative to the volatility of the market against which it is being valued. The greater the volatility in the share price, the greater the discount in its value. This is relevant to the valuation of exposure to SBP and SSP because of the relative volatilities of each price, with SBP being significantly more volatile than SSP and than spot prices in the power exchanges. This factor increases the risk cost of exposure to SBP to above its mean value, which accounts for the residual premium in the power exchange.

Figure 1: Impact of marginal energy trade dependent on contract position



A2.3 Single price model

Moving onto the single price model, the same relationships apply but with one crucial addition as given in Equation 4. There is a probability of exposure to SBP and SSP regardless of whether the participant is long or short.

Equation 4: Imbalance cash-out equation

$$\textit{Cash-out price} = p^{ms}SBP + (1 - p^{ms})SSP$$

This feeds through into the relationships previously given in Equation 2 and Equation 3. However, restating the relationships as per Equation 5 and Equation 6 leads to important differences.

The central difference from a supplier point of view (as is shown in Equation 5) is that an individual supplier imbalance does not impact on its exposure to SBP.

In Equation 6, the generator position is adjusted by the lower risk cost of trip. This is compared with the 2-price equation derived earlier and both are shown in Table 2. The crucial difference is in the term where the generator requires a mark-up to reflect SBP exposure. In the 2-price model, the acceptable price in the pre-gate closure market (*PXP*) is essentially determined by the generator's own trip probability (p^s), which is near to a constant exogenous variable. However, in 1-price model, the equivalent variable is $p^{ms}/(1+p^s)$, so that market shortfall probability is taken into account.

Without fully spelling out the implications of this, it can be considered to incorporate features of a LOLP function. This rationally brings the value of peak capacity into the market and so can be considered economically efficient and in accordance with NETA principles.

Equation 5: Supplier contract equation – single price cash-out

$p^s((p^{ms}SBP + (1 – p^{ms})SSP) – PXP = (1 – p^s)(PXP - (p^{ms}SBP + (1 – p^{ms})SSP)$
$p^{ms} = (PXP – SSP) / (SBP – SSP)$
$PXP = SSP + p^{ms}(SBP – SSP)$

Equation 6: Generator contract equation – single cash-out price

$PXP >= (p^{ms}SBP + (1 – p^{ms})SSP) + p^s(p^{ms}SBP + (1 – p^{ms})SSP) + p^a(O – SSP)$
$PXP >= (1 + p^s)SSP + p^{ms}(1 + p^s)(SBP – SSP) + p^a(O – SSP)$

Table 2: Comparison of generator equations – 1-price v 2-price

Equation 3: Generator contract equation – 2-price cash-out
$PXP >= (1 + p^s)SSP + p^s(SBP – SSP) + p^a(O – SSP)$
Equation 6: Generator contract equation – single cash-out price
$PXP >= (1 + p^s)SSP + p^{ms}(1 + p^s)(SBP – SSP) + p^a(O – SSP)$

For the single price proposal to produce the same result as the current 2-price model, the probability of the market being short must be $p^s / (1 + p^s)$. Remembering that in this case, this is a probability of the generator tripping, which is, maybe 1%, the market would need to be short for less than 1% of the time if the price results are to be the same.

Between 7th November and 31st January, the market was net short during about 11% of settlement periods. If p^{ms} is 0.11 and p^{s} is 0.01, then with SSP at 12.71 and SBP at 37.44 (the averages for the period in question), then, before accounting for the value of the energy reserved form Offer Acceptance, the 2-price model yields an average spot price of £13.08, while the single price proposal yields a price of £15.58.

Over that period, the UKPX price averaged £19.58. Using the supplier indifference equations (Equation 2 and Equation 5), p^{s} and/or p^{ms} should have been nearer 0.28. But this takes no account of the volatility impact of SBP.

A2.4 Second-order effects – SBP effects

The preceding section developed equations showing the relationship between SBP, SSP, spot prices and the incentive to balance (i.e. the incentive to avoid exposure to SBP and SSP). However, to prove incentive to balance the market (i.e. p^{ms} tends towards 0.5), second-order effects need to be considered.

One factor alluded to is that the supplier incentive in the 2-price model is inherently unstable – once a supplier starts to go long, then the rational response to small increases in the risk cost of SBP is likely to be that the supplier goes considerably longer because of the disproportionate movement in the suppliers net risk position. If all suppliers take a similar position then this considerably lengthens the market: all suppliers seem to have rationally taken that position. However second-order effects will derive from other reactions, most notably in the pricing of Offers into the BM.

In the previous section, it was assumed that the factor p^{a} – the probability of a BM Offer being accepted – was close to zero. This assumption needs to be relaxed in a more balanced market. This has an implication for SBP, which is also impacted by the extent of market length. If the market were to go less long, then NGC would be buying more energy in the BM. Because, currently SBP is dominated by actions required for system balancing rather then energy balancing, the prices are not reflective of the value of imbalance energy (an assertion supported by NGC in Modification Proposal P78). This is despite the ameliorating effect of Modification P18A. In a market where NGC is net energy short, the probability of Offer acceptance for all gensets competing in the stack should increase significantly.

If we reach a position where there is a 25% probability of an Offer priced at SBP being accepted (crudely a 50% probability of NGC buying and a 50:50 chance of the particular Offer being accepted at that price) then the generator PXP equation over this winter period would have set a value of £21.77 (assuming that this does not feed into expectations of the market going shorter) – closer to an expected winter price.

Feeding this price into the supply equation gives a market short probability of 0.37. Iterating this factor into the generator reserve price for trip leads to a higher market price that generators require.

This analysis is too crude to take further although it is capable of development. In particular, the probability of Offer acceptance has not been properly analysed. Nevertheless, some reasonable conclusions can be drawn:

- Generators will be able to command a price in the spot markets more closely representing the value of prompt energy in the balancing mechanism and the probability of lost load.

- This increases the cost to suppliers of going long and so they will go less long.
- The market will go closer to balance.

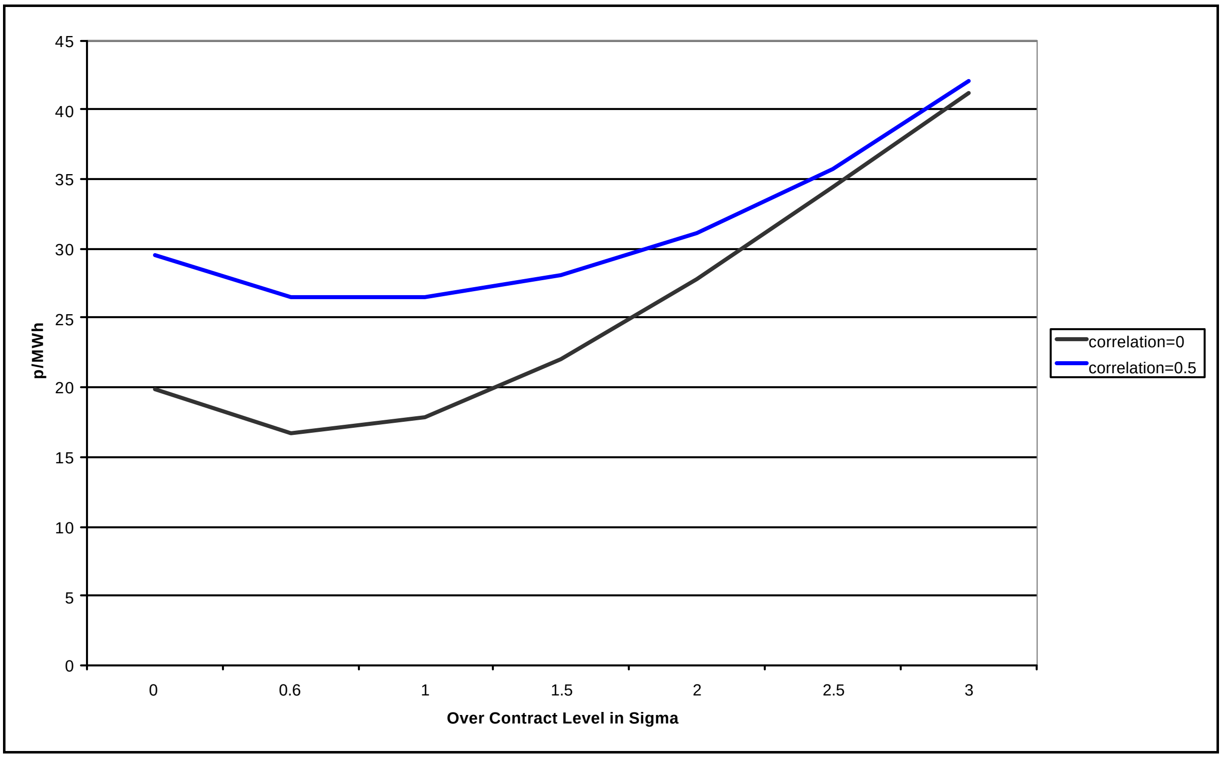
The description here is of a more efficient market where price signals will represent the proper value of prompt energy and where the incentive is to move closer to balance on a national level. There is an incentive to take a position in the opposite direction to market sentiment but that is normal in any traded market and such a position cannot be taken to extremes without being punished.

A3 Analysis of current optimal balance position of consumption accounts

Under the current cash-out prices and prevailing power exchange prices it is clearly prudent for suppliers to over-purchase. We carried out a short study looking back at the last winter on the actual cost of this over-purchase. This study covered the days from 7th November 2001 until 31st January 2002. UKPX prices were used together with SSP and SBP.

In the cases presented below the supplier was assumed to have a demand prediction error standard deviation of 2%. The average UKPX RPD was £19.58/MWh, the average SBP £37.44/MWh and the average SSP £12.71/MWh. In the first case the supplier's demand error is considered to be uncorrelated with the cash-out prices and in the second the correlation is considered to be 0.5. This second case represents strong correlation as the correlation between NGC net position and SBP was 0.02 and between NGC net position and SSP was 0.31.

Figure 2: Cost of supplier imbalance strategies



Cost is the sum of the contract purchase at UKPX price, shortfall at SBP and spill at SSP (negative).

Clearly the optimal position for suppliers was to contract in the range 0.6 to 1 sigma long. However this is with historic data and when looking forward the extreme volatility of SBP must be taken into account, which would increase the optimal position to (probably) 1.5 sigma.

Therefore, it is rational for suppliers to over-contract rather than to balance in a 2-price cash-out regime.

A4 Net cost of long positions

As described in Section A3, suppliers who target balance risk losing substantial sums in terms of their margin because of the risk of exposure to SBP. However, spilling is not a costless option either. Suppliers who have over-contracted are buying higher priced energy and then selling it back at SSP. It is reasonable to mark contracts to market value and so spot prices are a reasonable proxy for measuring supplier loss.

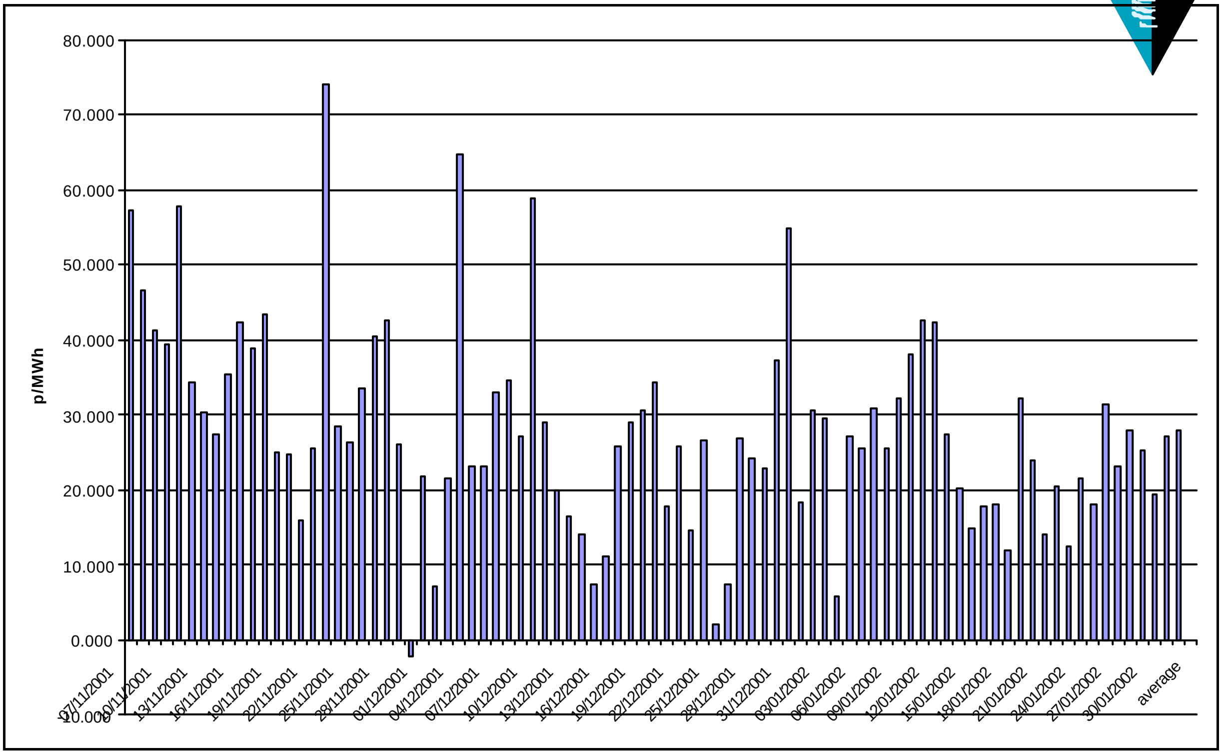
Generators will remain exposed to SBP and, as is measured in Section A6.1, part-loading is the main strategy used by portfolios to cover for this trip risk exposure.

The extent that suppliers have gone long is estimated by the net system position (System Sells + System Buys + BSAD volumes) adjusted for estimates of generator trips.

Generator trips are estimated as follows:

- Generator delivery is deemed to follow FPN;
- However, where Maximum Export Limit (MEL) is below FPN, then the generator is deemed to have tripped.
- Trip volumes are therefore an integration of (FPN - MEL).

Figure 3: Daily cost per MWh of over-contracting



This net long position represents purchases at spot price (represented by UKPX) that are sold down at SSP. On occasion, suppliers will have gone net short. On these occasions they will have bought at SBP but will have saved money by not buying at the spot price.

This position has been an average add-on cost of 28 p/MWh over the period from 7th November 31st January. This is in line with the results given in Section A3 above. It is a significant factor in terms of supplier margins but is also a potential cost to consumers.

A5 Extent to which consumption accounts have followed the profile of demand

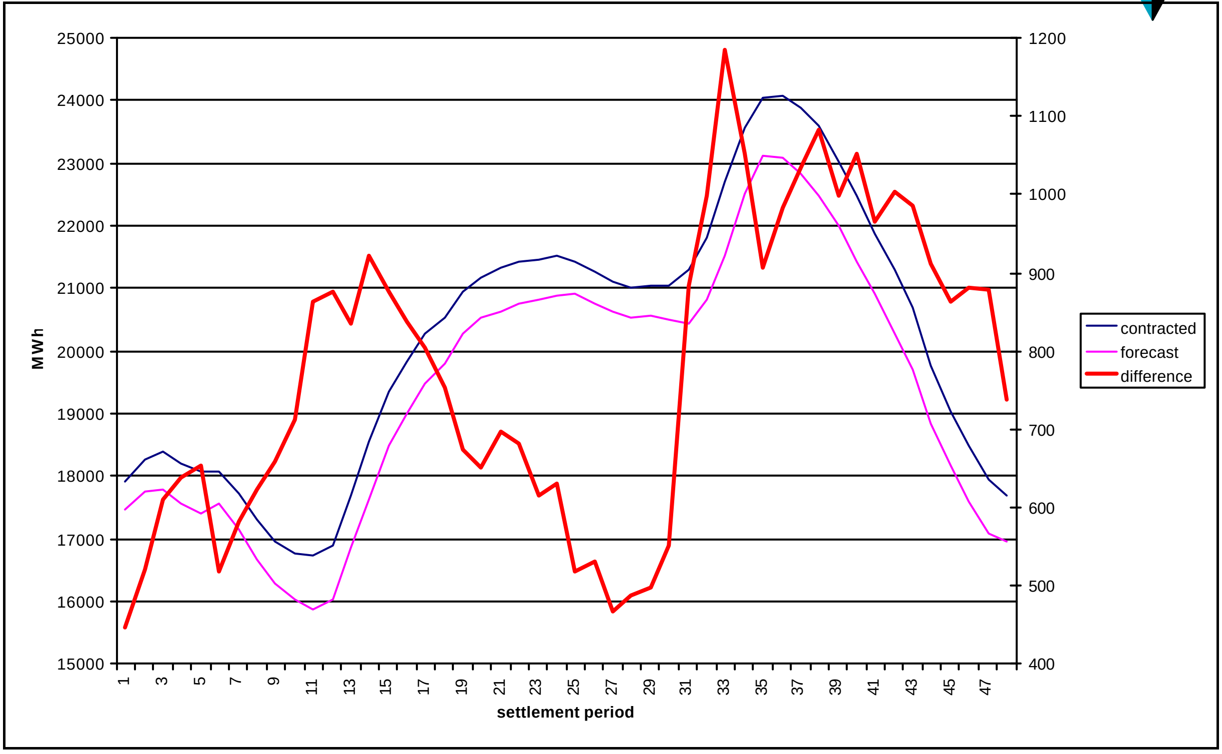
Settlement data is not readily available to highlight the shape of supplier contract positions. However, it is reasonable to assume that net generator FPN positions will mirror supplier contracts. In this section, the extent to which supplier contract shape has matched predicted demand shape as published by NGC as indicative generation is examined.

The specific data used are as follows:

- Forecast demand issued by NGC at the day ahead stage – the shape to which parties should be contracting
- Summated FPN data at gate closure – the level that parties will have contracted to.

The period covered is 1st November to 28th February.

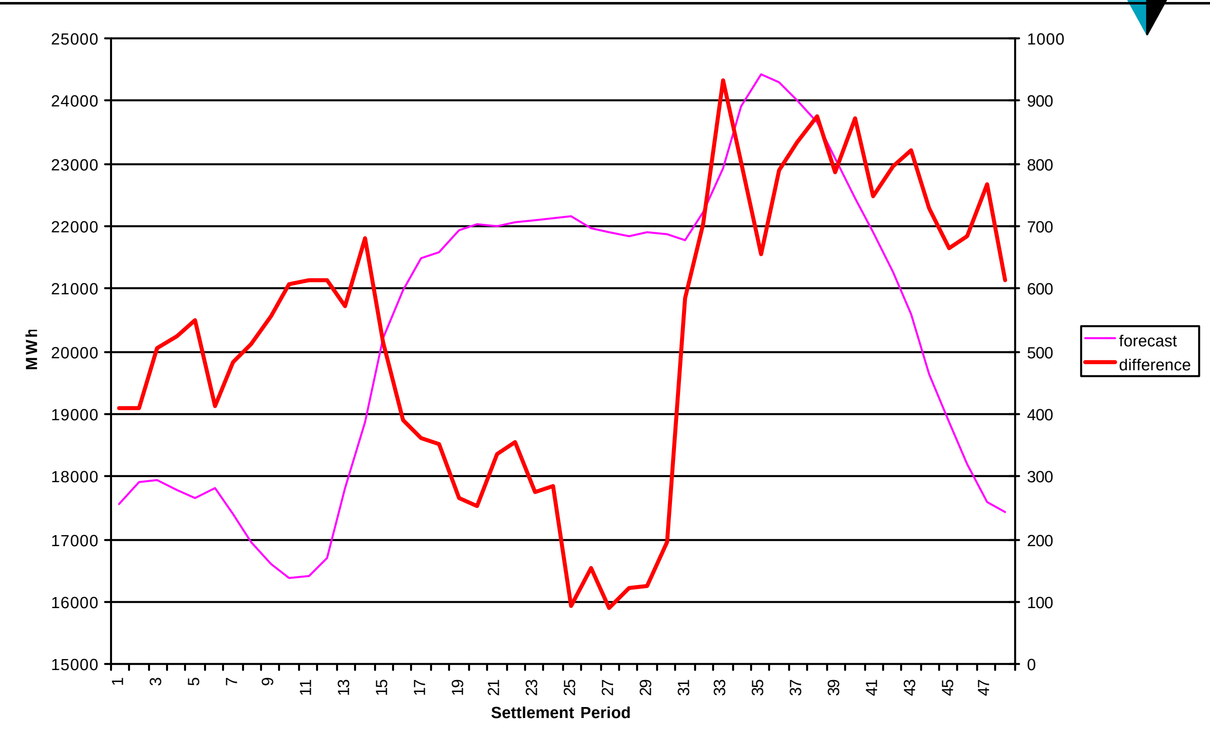
Figure 4: Match between contract level and forecast demand



It is acknowledged that, to the extent that FPNs incorporate trips that are known before gate closure (i.e. a genset that is contracted out but then trips), they will not fully reflect the level of supplier contracts. However, in the absence of actual contract data, it is reasonable to assume that there will be a reasonable degree of sub-contracting by generators to cover these trips and that any mismatches should not show a specific pattern).

If parties are contracting to balance then differences between forecast demand and contract level should not show a specific daily shape. As is demonstrated in Figure 4, Figure 5 and Figure 6, this is far from the case.

Figure 5: Match between contract level and forecast demand – weekdays only



The figures indicate a persistent shape to the extent of over-contracting. This tends to be associated with crude load shape contracts, excess purchase of tea-time cover ensured that suppliers were particularly long over that period and they only slowly eased off over-night.

Suppliers remained pretty long overnight and only reduced length after the morning pick-up, most closely matching to forecast over the middle-day period. This is especially marked when looking at the weekday-only data.

The average level of over-contracting appears to peak around period 33 with 932 MWh over-contracted, which is about 4% of demand on weekdays. The lowest level of over-contract is period 27 at 89 MWh, which is 0.4% of demand on weekdays.

For non-weekdays, the level of over-contracting increases markedly, averaging nearly 8% of throughput.

These data show a definite pattern of contracting without full regard to the shape of demand that is being balanced against. For vertically integrated participants, there is a strong probability that changes in forecast demand from settlement period to settlement period can be reasonably closely matched by changes in level of generation. Therefore suppliers operating without vertical integration are likely to show an even more marked tendency to contract without significant regard to demand shape. This cannot, however, be demonstrated without access to settlements data.

It is reasonable to conclude form this information that suppliers are not managing their balances to match expected demand but are using less-shaped contracts and going longer at certain times of the day.

Figure 6: Match between contract level and forecast demand – non-weekdays

A6 Impact on emissions

There is no direct measure of emissions used in this analysis. However, by employing standard conversions for coal oil and gas, a reasonable indication of level of emissions is available. Output of SOX and NOX have increased in line with the increased output of Carbon but, for convenience, this analysis concentrates tonnes of pure carbon emitted using the following conversion factors (based on DUKES 2000):

Coal	0.263 tonnes Carbon per MWh generated
Oil	0.268 tonnes Carbon per MWh generated
Gas	0.119 tonnes Carbon per MWh generated

A6.1 Estimate of additional emissions from scheduling of part-loaded coal plant

In a dynamic environment, level of useful reserve is hard to be certain on. NGC could provide estimates of the level of reserve they would have scheduled. This analysis is considerably cruder. It is assumed that part-loaded capacity would have been replaced by fully loaded capacity of the same type.

The measure of reserve held on the system is MEL > FPN at any point. This has been summated as an energy total in a settlement period.

Analysis to follow

A6.2 Estimate of additional emissions from use of deloaded plant

This analysis proceeds from the section above. The results are a subset of those preceding results. The basic methodology is to review acceptances in the BM. The assumption used is that the plant should not have been scheduled on as it had proved surplus to requirements. The volumes deloaded add to reserve. This is a measure of the extent to which over-contracting has added to inefficiency.

Analysis to follow

A6.3 Extent of peaking capacity used by the system operator

This looks at a subset of specific gensets defined as flexible. These comprise: open cycle gas turbines, pumped storage, demand-side acceptances and interconnector loads (these latter are only partly flexible for contractual reasons).

The underlying theory is that, in a balanced market, such flexible plant will be used when needed. This will be less polluting than use of over-scheduled alternatives that are deloaded to varying degrees in response to demand. If suppliers had traded to a long position equivalent to the expected volume of lost load (consistent with a 50% probability of exposure to SBP – their natural position in a balanced market), then NGC would have scheduled peaking plant for those periods. This is a subset of the lost load analysis in SectionA6.1.

Analysis to follow

A7 Cost targeting estimates comparing TRC and CSOBM

It is not possible to get an accurate estimate of gross imbalances based on public domain data. TRC – the beer fund – is only normally published as an aggregate monthly figure. However estimates can be made using the following methodology

- TRC = Supplier short positions * SBP
  + Generator trips * SBP
  + Supplier long positions * SSP
- TRC = Matched positions * (SBP – SSP)
  + Net system short * SBP
  + Net system long * SSP
- Assume that, on average beer fund is close to zero, which means that, on balance, the cost of short positions (mainly generator trips) is offset by supplier net spill.

- CSOBM is all NGC purchases – all NGC sales

The following statistics from the period 7th November to 31st January are thus derived per settlement period:

Average volume of NGC purchases:	125	MWh
Average cost of NGC purchases:	£7,011	
Average volume of NGC sales:	-6,969	MWh
Average value of NGC sales:	-£615	
Average Net imbalance Volume	-489	MWh
Average Net Imbalance Cost	£42	
Average volume of generator trips	486	MWh
Average trip cost to generators	£18,366	
Average supplier net spill volume	1,449	MWh
Average supplier offset cost	£18,408	

Therefore, in terms of cost targeting, NGC bought 125 MWh at a cost of £7,011

Short parties paid out a total of £18,366

NGC sold 6,969 MWh at a revenue £615

Long parties spilled 1,449 MWh at a revenue of £18,408

These figures are per settlement period and take no proper account of supplier accounts that would have gone short over the period. These figures indicate the extent of leverage between imbalance settlement and actual costs of balancing the system.

A8 Issues raised against single price

In this section, a summary is made of arguments and assertions raised at various times within the process of other Modification Proposals. The purpose is to evaluate the likely validity of the assertions against the evidence and economic arguments presented here. This could contribute to the Assessment Criteria that the Panel could request.

A8.1 Reduced incentive to balance

This has been fairly exhaustively discussed in the foregoing discussions. The incentive on Consumption Accounts in the 2-price proposal is to over-contract and to spill. The economic drivers in a single price proposal is to contract to a level where the expectation is of market balance, which is a better position than the incentive to balance a single account because it manages expected imbalances on Production Accounts.

A8.2 Incentive to contract

It is asserted that parties will cease to contract and will take the “Pool” price resulting from the Balancing Mechanism. It should be noted that this price-taker strategy is reliant on the remainder of the market doing the reverse. If suppliers do not pre-contract generation then generators will await a contract form NGC in the Balancing Mechanism. A perpetual ex post SBP price will result, which should always be greater than prices available in an ex ante market.

To cover against this, parties could contract via CfDs. Any generator with a CfD contract will schedule generation to meet expected energy in the contract and so a CfD will be no less physical than current contracts. All a CfD will be doing is passing meter risk between generators and suppliers, which is an economically efficient trading function.

Pre-NETA, the market was 80% to 90% contracted on CfDs.

It is likely that notified contracts pre gate closure will continue. The effective difference between these and CfDs will be in the credit terms:

- Under a pre gate closure notified contract, the generator will have guaranteed delivery and will need to post credit with the system against imbalance risk. The supplier needs to post credit with the generator to guarantee payment.
- Under a CfD contract (ex post notification) the supplier must post additional credit for systems imbalance and the generator must post guarantees to the supplier that it will pay against the CfD.

The incentive to contract is no less strong under the single-price market because it is based on an improved incentive to balance.

A by-product of the single-price market is that CfD terms can be used in contract to cover notification failures. Under present arrangements, both parties go into imbalance on a notification failure, which greatly increases the risk cost of notification failure. A notification backed up by a CfD option will cover this risk, allowing trading to continue much closer to gate closure (noting that trading after gate closure will not affect the physical position because generators will have scheduled against their notified FPNs).

A8.3 Incentive to deviate from FPN

It is asserted that parties will observe the system balance position as it develops and will alter generation levels to match a “one-way” bet. This will cause NGC to take balancing actions that need to be expensively unwound, which could also endanger system stability. This type of behaviour has been observed in the gas market.

Against this it should be noted that:

- The gas market is one where “gate closure” occurs near the end of a 24-hour contract day and where physical notification is effectively ex post. Price developments and system balance position is available to trade against during the contract period. This is not the case in the electricity market.
- If Modification P12 is approved then a 1-hour gate closure will give very little time to respond to price developments.
- Even with a 3.5-hour gate closure, near 80% of NGC BM balancing actions have been instructed in close to real time anyway and so the

emerging view of the system imbalance position allows parties little time to deviate from FPN.

- Deviation from FPN is strongly policed under the Grid Code.
- Parties have deviated from FPN to replace tripped generation because of the cost of exposure to SBP – in a single price market, this exposure risk is reduced, which lessens this incentive.
- Generators have an incentive to err on the side of over-delivery because, with ex post losses risk and other variations, they face SBP for any minor under-delivery. This incentive will be lessened.

There is potential for consideration of a non-zero Information Imbalance Charge. This is not part of this Modification Proposal and could more correctly be considered on its merits as a totally separate proposal. However, it should be noted that such a charge could penalise suppliers who have no clear knowledge of their imbalance position as well as tripped generators who face financial loss anyway. There may, however, be potential for a variant of Information Imbalance targeted at Production Accounts that exceeded FPN.

A8.4 Single price does not target the costs of imbalance on those causing it

The 2-price cash-out regime is not good at targeting costs. NGC purchases of imbalance energy in a long market have been for mainly systems balancing reasons (a point acknowledged in the Proposal P78). This sets a cost of going short that is vastly disproportionate to any costs incurred by NGC.

The consequence is that suppliers over-contract and then effectively pay generators to reduce output. This transfer of revenue is a real cost to consumers even where the net effect is well offset in the beer fund.

The single-price proposal rewards reverse-flow imbalance on the basis that it helps reduce the net level of system balancing actions. This fits well with just-in-time scheduling as practiced by NGC.

Noting that the proposed incentive actually gives an incentive for consumption accounts to target system balance (offsetting expectations of trip) this further minimises cost of balancing the system.

A8.5 Supplier spill has reduced the cost of balancing the system

It is correct that suppliers have effectively given NGC excess energy, which they have been able to sell to generators in order to balance the system. However, NGC's incentive is to minimise the cost of managing a balanced system with net system imbalances excluded from the incentive system. Therefore, it is inconsistent to take the low level of BSUoS as evidence of reduced cost of balancing.

A8.6 NETA has led to a reduction in wholesale prices

Certainly, wholesale prices have fallen drastically over the past year. Current EFA prices are some £5/MWh below a Best New Entrant cost of generation. This reflects the over-capacity that had built up in the market. However, as the economic arguments demonstrate, the prices in the current mechanism fail to give an efficient value for security of supply whereas, there is reason to argue that a single price cash-out, by taking account of expected actual market balance (as opposed to individual party balance) in price setting, gives a value to expected generator trip and so sets a more efficient economic price that includes a value for lost load.

A8.7 Single price disadvantages past investment in balance

Certain parties have invested heavily in systems designed to minimise their exposure to system prices. If the risk cost of that exposure is reduced then this investment is potentially stranded.

Against this argument, an efficient market should set correct price signals for imbalance. If those signals are wrong then excess investment in avoidance of imbalance prices will take place. Ofgem has long believed that the Pool set too high a wholesale price, which brought about excess investment in generation capacity. This past investment was not allowed as a reason for maintaining prices inefficiently.

Therefore, excess investment in avoidance of imbalance prices should not justify maintenance of non cost-reflective prices. A single-price cash-out more closely reflects the cost of managing system imbalances by giving correct signals to parties to balance that system.

This reduces the cost of entry into the market for both suppliers and generators, which is a more stable long-term benefit to consumers. Consumers are always better protected when a market that sets prices, which they ultimately pay, is competitive: a level playing field without economically inefficient barriers to entry.

A8.8 The need for regulatory stability

It is commonly argued that parties need to get used to trading under any set of rules and that there is a cost to market efficiency in change to those rules. This argument has never been a very strong one. The whole purpose of competitive markets is to allow parties to take on trading risk, which implies change as markets learn and get more efficient. The justification for acceptance of any Modification is that it leads to a more economically efficient market and this regulatory risk is something that competitors in the market should have taken into account.