January 2001

Appeal of resolutions in respect of anomalous prices in the Electricity Pool during 2000

An Ofgem decision document

Summary

This document sets out Ofgem's decision, and the reasons for our decision, regarding an Appeal from British Gas Trading (BGT) of six resolutions rejected at a Pool Members' meeting on 1 November 2000. Two of the resolutions sought to change the rules of the Electricity Pool of England and Wales associated with calculation of the capacity payments element of the Pool price, resolution 1 was to include demand side bidders capacity into the calculation and resolution 2 was a fixed disappearance ratio to be applied to all plant. Two resolutions (3a and 3b) proposed looking into whether the Pool scheduling software could be amended to reduce the occurrence of price spikes in the energy component of the Pool price. The other two (3c and 3d) resolutions proposed changes to the Pool's Market Monitoring Group (MMG) , resolution 3c proposed changing the terms of reference of the MMG and resolution 3d proposed to invite non Pool members to the MMG.

Ofgem invited views from all interested parties on the merits of the Appeal, in writing, in November 2000. In total, Ofgem received 19 responses from interested parties. Of these respondents 9 supported all of the dissentient Pool Member's Appeal resolutions, 4 respondents opposed all elements of the Appeal, and 6 respondents supported some, opposed some or did not object in principle to the resolutions. Ofgem's decision has been informed by additional analysis of the expected effects of the resolutions, in the light of responses from interested parties.

The respondents who supported the two resolutions designed to address problems associated with the capacity payment mechanism, argued that it had consistently failed to deliver price signals that reflect underlying market conditions and highlighted the weaknesses in the rules that the resolutions were designed to address. Respondents not supporting these resolutions argued that the proposed changes could reduce generator availability and liquidity in contract markets by increasing regulatory uncertainty.

NGC in particular suggested that the capacity payment mechanism, for all its faults, had helped maintain security of supply by providing a strong financial incentive for generators to keep plant available on the day (if not scheduled to operate) when the system margin was relatively tight. NGC went on to express concern that the effects of upholding either (or both) of the resolutions designed to address problems with the capacity payment mechansim would be to significantly reduce or effectively remove

capacity payments for the remaining life of the Pool. NGC argued that although the effect was uncertain, it might result in some reduction in the amount of generation offered to NGC. NGC reported that this year it had experienced significant volumes of generator redeclarations that appeared to be in response to lower market prices. NGC also noted that to date, it had issued Notificiations of Insufficient Margins on 20 days since October 2000, compared with 9 during the same period last year. NGC also argued that the inclusion of unscheduled demand side bidders in to the capacity payments calculation was inappropriate because they could not be dispatched by NGC on the day if required and were therefore not contributing to system security.

A narrow majority of respondents supported resolution 3 (a to d) arguing that the operation of the Pool software had often led to anamolous outcomes and expressing support for the proposed changes to the Pool MMG. However, a number of respondents argued that given the remaining life of the Pool and the time taken to make changes to the software and the MMG any changes were likely to be of limited benefit. They also argued that upholding this resolution might divert valuable resources from the successful delivery of the New Electricity Trading Arrangements (NETA).

The Authority's decisions

The Authority is required, under clause 13.5.1 of the Pooling and Settlement Agreement (PSA) to determine Appeals by reference to whether the interests of a group of Pool Members, including the Dissentient Pool Member have been, are or will be unfairly prejudiced by the failure to pass the resolutions that are the subject of the Appeal, although under clause 13.5.3 it is expressly recognised that satisfaction of that criterion will not in itself entitle the Dissentient Pool Member to a determination in its favour.

Following consultation with interested parties and careful consideration of all of the arguments raised, the Authority has decided to reject five of the resolutions that were appealed by BGT and uphold the other. The Authority has decided to uphold the appeal of resolution 3(d) - that active traders in the forward electricity market, who are not Pool members, be invited to attend the MMG. The Authority has decided to reject the remaining five resolutions.

The Authority continues to believe that the capacity payment mechanism does not produce price signals that reflect the balance between demand and supply on the system, as it was originally designed to do. The Authority believes that experience this summer has demonstrated many of the failings of the capacity payment mechanism. Capacity payments were frequently very high (by historical standards) when the plant margin was not noticably different from previous summers. This was the result of the unrealistic assumptions used in the calculation about the reliability of generation capacity of plant of different ages. The exponential nature of the loss of load probability used to determine the capacity has also exacerbated the problems. When the plant margin has been tighter than in previous years, capacity payments have been an order of magnitude higher. Finally, the complex set of rules used to calculate payments are opaque and difficult to understand, even by market participants with ten years experience of the operation of the Pool.

However, the Authority has decided that given the concerns expressed by NGC, it would not be possible to uphold either of resolutions one and two which were designed to address problems associated with the capacity payment mechanism. The Authority recognises that upholding either resolution would represent a substantial change to the existing arrangements, shortly before the introduction of the New Electricity Trading Arrangements (NETA). Given the recent difficulties reported by NGC relating to capacity redeclarations, and that the consequences of effectively removing capacity payments are uncertain, the Authority does not believe it would be appropriate to uphold either of the resolutions given the relatively short expected life of the Pool before NETA is implemented.

The Authority accepts that given the rules and arrangements associated with the Pool's Demand Side Bidding scheme, it would be unreasonable to include demand side bidders into the calculation. As NGC cannot centrally despatch the demand side on the day, the effective disappearance ratio of these bidders under the scheme is one (as they are unavailable on the day) which is consistent with not including them in the calculation. On resolution two the Authority accepts that the expected effect of upholding this resolution under the Pool would be to effectively remove capacity payments. Given this, the Authority believes that this rule change, in isolation, could risk system security by removing a key financial incentive on generators to keep unscheduled plant available on the day under the current Pool rules.

The Authority's ongoing concerns about the administered capacity payment mechanism under the Pool will be addressed with the introduction of the New Electricity Trading

Arrangements (NETA), scheduled for the end of March, which do not include such a mechanism.

The Authority has decided to reject resolutions 3(a), (b) and (c) because it accepts that upholding these resolutions would be likely to be of limited benefit given the expected remaining life of the Pool. The Authority also accepts that upholding them may divert resources from the successful implementation of NETA, which it does not believe would be in customers interests. The Authority has upheld resolution 3(d) because it will bring additional expertise to the Pool's Market Monitoring Group.

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1. Introduction

Purpose of this document

1.1 The purpose of this document is to set out Ofgem's decisions, and the reason for our decisions, on a number of resolutions appealed to Ofgem by BGT following the decision taken by members of the Electricity Pool, the wholesale electricity market in England and Wales, to reject the six resolutions forwarded at a Pool Members' meeting.

Background and the process so far

1.2 On 13 November 2000 a dissentient Pool Member, BGT, wrote to Ofgem seeking a decision from the Director General of Electricity Supply (DGES) under clause 13.5 of the Pooling and Settlement Agreement (P&SA). BGT asked the DGES to rule that six resolutions not passed at the Pool Members' meeting on 1 November 2000 should have effect on the grounds that the interests of the dissentient and other suppliers would be unfairly prejudiced by the failure to pass the resolutions. Ofgem forwarded the Appeal to the Pool Executive Committee (PEC) and BGT also advised PEC of its appeal.

1.3 A summary of the six resolutions is as follows:

1. To incorporate Demand Side Bidders (DSBs) into the Loss of Load Payment (LOLP) calculation as an increase in generation capacity at fixed Disappearance Ratios (DRs) of 13.5% in the summer and 7.5% in the winter.

2. To fix DRs that apply to all generating plant in the LOLP calculation at 13.5% in the summer and 7.5% in the winter.

3a) To agree that the Settlements System Administrator (SSA) be requested to examine the way in which the Pool's scheduler, GOAL, schedules generation units and to produce a report on the causes of the high System Marginal Price (SMP) values during summer 2000.

3b) To support requesting the National Grid Company (NGC) to report on any potential flexibility in the GOAL scheduling program which could reduce the occurrence of these SMP spikes.

3c) To agree that the terms of the Market Monitoring Group (MMG) be expanded so that they investigate and report on all unusual price features within the Pool, irrespective of whether they are compliant with the Pool Rules.

3d) To agree that active traders in the forward electricity market who are not Pool members be invited to attend the MMG.

1.4 On 17 November Ofgem wrote to all interested parties requesting views on the appeal made by BGT relating to the resolutions rejected at a recent Pool Members meeting. Ofgem has considered all of the views submitted by interested parties in coming to our decision. No request was received for an oral hearing. Since such appeals have previously been considered on written representations alone (including a previous appeal on similar issues) it was not considered necessary to hold such a hearing in this case.

Respondents' views

1.5 In total, Ofgem received 19 responses from interested parties. Of these respondents 9 supported all of the dissentient Pool Member's Appeal resolutions, 4 respondents opposed all elements of the Appeal, and 6 respondents supported some, opposed some or did not object in principle to the resolutions. In addition Ofgem has written to NGC on a number of detailed points asking them to analyse the likely effect of upholding each of the resolutions and to seek further clarification on NGC's views and concerns about the resolutions.

1.6 All of these responses have been placed in the Ofgem library and can be viewed during normal working hours. A series of letters between Ofgem and NGC have been reproduced in full in Appendix 2 given their central importance to the Appeal and the Authority's decisions.

Outline of this document

1.7 This document sets out the Authority's[1] decision on this Appeal. Chapter 2 below sets out the background to the Appeal. Chapter 3 summarises respondents' views for and against the Appeal and Chapter 4 outlines Ofgem's views. Chapter 5 sets out the Authority's decision. Appendix 1 contains a list of respondents to Ofgem's letter to interested parties inviting views on the Appeal. Appendix 2 reproduces correspondence between NGC and Ofgem on the potential impact of upholding the Appeal.

[1] On 20 December 2000, the relevant provisions of the Utilities Act 2000 were enacted and the Gas and Electricity Markets Authority was created, replacing the Director General of Electricity and Gas Supply. Further details are given in Chapter 2.

2. Background

The regulatory and legal framework

2.1 This section outlines both the current and future legal and regulatory framework of the electricity industry. It summarises the current legislative, licensing and regulatory regimes and describes the relationship between the Electricity Act 1989, licences and industry agreements and the Utilities Act 2000.

The legislative framework

The Electricity Act 1989

2.2 The Electricity Act 1989 (The Electricity Act) provided the framework for the functions of the Director General of Electricity Supply (the Director General), of the consumers' committees, and for the licensing to enable the supply (including distribution) generation and transmission of electricity.

The Utilities Act 2000

2.3 The Utilities Act 2000 (the Utilities Act), which received Royal Assent on 28 July 2000, introduced reforms to the gas and electricity markets and the regulation of these markets.

2.4 One of the most important of these changes that has occurred to date is the replacement of the Director General of Electricity Supply and the Director General of Gas Supply with the Gas and Electricity Markets Authority (the Authority) to cover both the gas and electricity industries. On 20 December 2000, the functions of the Director General of Electricity Supply and the Director General of Gas Supply were transferred to, and in the future will be exercisable by, the Authority.

2.5 The Authority's Chairman and Chief Executive is the former Director General, Callum McCarthy. In addition, the Authority will also contain four executive members and six non-executive members.[2]

[2] A list of the Authority members that have been appointed to date can be found at www.ofgem.gov.uk.

2.6 The new principal objective (primary duty) on the Authority is to protect the interests of consumers in relation to electricity conveyed by distribution systems, wherever appropriate by promoting effective competition between persons engaged in, or in commercial activities connected with, the generation, transmission, distribution or supply of electricity.

2.7 Subsequent changes to be enacted include:

- the introduction of standard licence conditions for each type of electricity licence granted under the Electricity Act and provisions for making modifications to standard licence conditions;
- the separation of the licensing of electricity supply and distribution; and
- the creation of an additional power to enable the Authority to impose financial penalties on companies found to be in breach of their relevant licence under the Electricity Act.

Competition Legislation

2.8 The Authority has concurrent powers with the Director General of Fair Trading under the Fair Trading Act 1973 and the Competition Act 1998 (which came into effect on 1 March 2000). Chapter I of the Competition Act prohibits anti-competitive agreements and Chapter II prohibits the abuse of a dominant position. Under the Competition Act, the Authority has powers of investigation, powers to give directions and power to impose financial penalties of up to 10% of turnover of the undertaking concerned on companies infringing the prohibitions under the Act.

Licensing and regulatory duties

The duties of the Authority

2.9 The duties of the Authority are set out in the new sections 3A-C of the Electricity Act comprising the new primary objective and a range of other duties. However, under transitional provisions contained in the Utilities Act,[3] Section 3 as previously enacted, rather than the new sections 3A-C will apply in relation to

[3] Commencement No.4 and Transitional Provisions Order 2000 (SI 2000/3343).

questions referred to the Director General prior to 20 December 2000. The decisions on the Appeal have therefore been taken with reference to these duties.

2.10 Under section 11 of the Electricity Act, the Authority can modify a licence with the licensee's consent (and after consultation). If the licensee does not consent to the modification, the Authority may refer a question relating to the modification to the Competition Commission under section 12 of the Electricity Act 1989. The Authority may, depending on the findings of the Competition Commission, modify the licence following such a reference without the consent of the licensee.

2.11 The Authority will also be able to amend standard licence conditions. Under section 11 the Authority can only modify standard licence conditions if:

- the total number of licence holders objecting to the modification is less than a percentage to be prescribed of the total relevant licence holders and the market share of the objecting licensees is also less than a percentage to be prescribed;[4] or
- no relevant licence holder objects to the modification.

2.12 The Authority will also be able to make references to the Competition Commission in respect of modifications to standard conditions.

Other related documents

The Pooling and Settlement Agreement

2.13 Generators, suppliers and transmission companies are required by their licences to be party to the P&SA. This multilateral agreement contains the rules and arrangements for the current market in wholesale electricity in England and Wales (the Pool). Schedule 9 of the P&SA (the Pool Rules) includes, amongst other things, the method for calculating DRs and the subsequent calculation of capacity payments for electricity generators.

[4] The prescribed percentages will be set out in a statutory instrument which will be laid by the Secretary of State before Parliament. Ofgem is currently awaiting confirmation as to when the different provisions contained in the Utilities Act will take effect.

2.14 It is open to any signatory of the P&SA, known as a Pool Member, to propose an amendment to the P&SA. Such a resolution is normally voted upon by show of hands, but a paper vote may be requested. The P&SA states that a proposal cannot be carried unless 65% are in favour of it.

2.15 It is open to Pool Members to appeal against any resolution under section 13.5 of the P&SA. The Appeal must be based on the grounds that either the interests of the dissentient Pool member would be unfairly prejudiced by the passing or not passing of the resolution or that passing the resolution would breach, or cause the dissentient Pool member to breach, the P&SA, its licence or the Electricity Act.

Process to date

Pool Member's Vote

2.16 On 1 November 2000, a paper (PMM 066/0152) was presented to the Pool Members' Meeting by BGT. The paper argued that Pool prices had, over the past two years, moved so far away from economic fundamentals that they have become meaningless. The paper analysed the reasons for the departure of Pool prices from economic fundamentals and proposed three resolutions, one with four parts, pending the implementation of the New Electricity Trading Arrangements (NETA) and argued that failure to pass the six resolutions would unfairly prejudice it and other suppliers;

Resolution 1

Amend the treatment of demand reduction blocks in the LOLP calculation so that the amount of demand reduction for which payment is received is incorporated into the LOLP calculation as an increase in generation capacity with the following fixed DRs:

13.5% in the summer (April to September)
7.5% in the winter (October to March)

Resolution 2[5]

Modifying the use of DRs such that fixed values are applied to all generating plant in the LOLP calculation. The following fixed values were specified:

13.5% in the summer (April to September)
7.5% in the winter (October to March)

Resolution 3a

The Settlement System Administrator (SSA) be asked to examine the way in which GOAL is scheduling generation units and to produce a report for Pool Members on the causes of high SMP values that have been occurring over this summer.

Resolution 3b

NGC be asked to report if there is any flexibility in the GOAL scheduling program that could be used to reduce the occurrence of these SMP spikes.

Resolution 3c

The terms of reference of the MMG be expanded so that they investigate and report on all unusual price features within the Pool, irrespective of whether they are compliant with the Pool Rules.

Resolution 3d

A representative of non-Pool members who are active traders in the forward electricity market should also be invited to attend the MMG.

2.17 All six resolutions were rejected at the Pool Members' meeting of 1 November 2000 – the votes recorded for each resolution were as follows:

[5] This has been amended from the original BGT resolution following a proposal made at the Pool members meeting by Scottish & Southern Energy.

Table 2.1 – Voting at the Pool Members' Meeting

Resolution	Votes For	Votes Against
1	16	33
2	23	33
3a	6	28
3b	7	28
3c	7	34
3d	17	32

Appeal to Ofgem

2.18 On 13 November an Appeal was lodged by a dissentient Pool Member, BGT, with the Director General seeking a ruling that the failure to pass the six resolutions at the Pool Members' Meeting unfairly prejudiced the dissentient and other suppliers. Ofgem forwarded a copy of the Appeal to the PEC and BGT and also advised the PEC of its Appeal.

BGT's referral

2.19 BGT claims that, over the past two years, Pool prices have moved so far away from economic fundamentals that they have become meaningless and that there is now no longer any sensible correlation between price and demand. BGT argues that, with a plant margin of 25.3 per cent for 2000/01 and a registered capacity of 66 GW, the Pool prices experienced over the summer are sending price signals to encourage new plant to be built, rather than reflecting the actual overall capacity margin. BGT also argues that the SMP spikes of around £40-£50/MWh experienced over the summer seemed to be caused by GOAL scheduling relatively small increments of 'expensive' generation to meet minor increases in forecast demand.

2.20 BGT claims that the lack of apparent correlation between demand, supply and cost has resulted in Pool prices that bear no relationship to economic fundamentals. BGT argues that this is detrimental to customers on Pool related contracts, unhedged suppliers and traders who attempt to trade on the basis of reasonable expectations of market behaviour.

2.21 In support of its Appeal BGT argues that the capacity payments experienced in September 2000 were the highest monthly average recorded in 2000. Total capacity payments for September 2000 totalled over £500 million – double the total for September 1999 and some one hundred times higher than the September figures for 1997 and 1998. BGT claims that the high capacity payments distorted the Pool Purchase Price (PPP) and increased uplift via unscheduled availability payments, a cost borne by all suppliers that cannot be effectively hedged.

2.22 BGT argues that the capacity payments mechanism appears to get triggered too early and respond too quickly when there is no real shortfall in capacity due to defects in the capacity payments calculation. BGT claims defects in the high capacity payments calculation include the following:

(a) The LOLP calculation considers only the absolute difference between generation and demand, not the relative difference – therefore a generation margin of 5000 MW would create the same price signal in summer troughs and winter peaks, although the absolute level of demand might be 250 per cent different.

(b) The logarithmic component of the LOLP calculation which results in capacity payments increasing by a factor of ten for each 2000 MW of capacity reduction.

(c) The failure to incorporate the contribution of DSBs within the LOLP calculation although they receive availability payments as 'pseudo generation.' BGT claims this increases the unscheduled availability cost for supplies.

(d) The DRs applied to gensets as an adjustment to genset availability. BGT claims the current system, whereby the highest offered availability of each genset over the previous seven days (XMAX_0) is used, with the daily DR calculated as the sum of variances between actual availability (XP) and XMAX_0, underestimates the amount of capacity actually available and despatched at peak due to varying XP values. BGT argues that many Combined Cycle Gas Turbines (CCGTs) have multiple gas turbines which might not all be available simultaneously, leading to lower XP values off peak and a subsequent distortion in the whole plant's DR.

2.23 BGT concludes that deficiencies in the LOLP calculation, in particular the value of DRs, systematically underestimates the amount of capacity actually available by between 4,000 and 10,000 MW, with the effect larger in the summer due to plant maintenance.

2.24 Given the limited remaining life of the Pool, BGT suggests a pragmatic but fair solution must be looked for to address the issue of unrepresentative capacity payments. BGT suggests that such a solution would be to incorporate the amount of demand reduction for which DSBs are paid into the LOLP calculation, either as an increase in generation capacity or a reduction in forecast demand or reserve. BGT also suggests that an additional solution would be to change the DRs used in the LOLP calculation. Following an amendment tabled by Scottish and Southern Energy (SSE) at the Pool Members' meeting, the following DRs were put forward in an amended resolution.

Table 2.2 – Proposed disappearance ratios

	Winter	Summer
All Plant	7.5%	13.5%

2.25 The rationale behind the DRs proposed is based on the difference between XMAX_0 and XP (as currently used) but only at periods of peak demand, with the XP of demand side bidders excluded from the calculation. Using this methodology will limit the impact of varying daily XP values and partial outages.

2.26 In addition to problems with the capacity payments mechanism, BGT also claims that there have been many occasions this year when the value of SMP has 'spiked' in a manner which does not correspond with supply/demand fundamentals. BGT claims that it is counter intuitive that the highest SMP does not systematically occur at the time of highest demand and asserts that the scheduling software, GOAL, appears to be selecting expensive marginal generation to meet minor increases in the forecast of demand. BGT claims that it is detrimental to Supplier Pool members if GOAL, whilst seeking to minimise its objective of 'lowest production cost,' is setting artificially high SMP values because of the content or structure of some of the generator offer data.

2.27 BGT argues that the resulting SMP spikes raise the cost to customers on Pool contracts and increase the overall level of SMP, which feeds through to the forward market raising the cost of forward contracts and hedges. BGT also asserts that the random nature of the SMP spikes increases the uncertainty of non-baseload pricing, leading to a reduction in liquidity in traded markets.

2.28 BGT proposes that Pool Members ask NGC to produce an analysis of the causes of the current SMP spikes and explore the possibility of flexibility within GOAL to reduce the occurrence of the spikes. BGT also proposes to expand the terms of reference of the MMG to investigate and report on all unusual price features within the Pool and those Non Pool members who are active traders in the forward market be invited to attend the MMG.

2.29 On the basis of the arguments outlined above BGT asked the Director General to rule that the six resolutions not passed by Pool Members should have effect.

3. Respondents' views

3.1 Ofgem has received 19 responses from interested parties. Of these respondents 9 supported all of the dissenting Pool Member's Appeal resolutions, 4 respondents opposed all elements of the Appeal, and 6 respondents supported some, opposed some or did not object in principle to the resolutions. The following table shows the number of respondents who support, oppose or who do not object in principle to the resolutions. One respondent did not comment on resolutions 3c and 3d.

Table 3.1 – Summary of respondents' views

Resolution	Number of respondents that support the Resolution	Number of respondents that oppose the Resolution	Number of respondents that do not object to the Resolution in principle
1	11	6	2
2	10	8	1
3a	10	7	2
3b	9	9	1
3c	10	7	1
3d	10	5	3

Arguments supporting the appeal

3.2 The main arguments given in support of the Appeal were:

- the LOLP mechanism is flawed;
- failure to include demand side participation in the LOLP calculation prevents the system achieving a balance between supply and demand and breaches the principle of the system whereby DSBs are paid availability payments;
- the LOLP mechanism over exaggerates the likelihood of generation capacity being unavailable to meet demand;

- the value of DRs fails to reflect the risk that plant will not be available to meet demand on the day;
- the operation of the LOLP mechanism over the summer led to suppliers facing uncertain capacity related costs that could not be hedged; and
- the complexity of the Pool Rules results in uncertain outcomes.

The LOLP mechanism is flawed

3.3 Some respondents claimed that the capacity payments mechanism is fundamentally flawed. One respondent argued that the operation of the LOLP mechanism was resulting in very high Pool prices at times when the plant margin remained significantly above the levels of both forecast and actual demand. Others suggested that the LOLP calculation also allowed generators to manipulate prices.

Failure to include demand side participation in the LOLP calculation prevents the system from achieving a balance between supply and demand and breaches the principle of the system whereby DSBs are paid availability payments

3.4 A number of respondents argued specifically for the inclusion of demand reduction blocks into the LOLP calculation using fixed DRs. In support of its argument, one respondent argued that demand side participation plays an important role in maintaining a balance between supply and demand and stated that the current system (whereby demand reduction offers receive capacity related payments from the Pool equal to generating plant but are not included in the LOLP calculation) prevents the system from achieving a least cost supply/demand balance.

3.5 One respondent claimed that a stated principle in the design of the Pool's DSB scheme was to treat the DSBs in a manner as closely comparable to generation as possible. This respondent argued that has not been the case and, as a result, consumers who are not amongst the 39 participants in the DSB scheme are disadvantaged because of the failure to include DSBs in the LOLP calculation. The respondent argued that failure to take into account DSBs capacity to reduce demand when determining capacity used in the LOLP calculation, which is then compared with demand to estimate a plant margin, breaches the principle intended for the DSB scheme. The respondent claims the inconsistency has persisted, despite being raised at PEC, because of the perceived difficulty surrounding the agreement of relevant DRs for the DSB sites. The respondent concludes that, although the 39 DSB participants receive approximately £20 million a year of capacity related payments, this sum is not ameliorated by the inclusion of all demand reduction capacity within the LOLP calculation. This increases the costs of supply and is not offset by the few instances where the DSBs bids are less than SMP and demand reduction is called.

3.6 Another suggested that, as DSBs receive payment through the Pool for their availability, it should be assumed they would reduce their consumption in the event they are called upon to do so. Given this assumption, the availability of this plant to reduce demand reduces the probability that load will be lost (i.e. they reduce the LOLP value). As a result, the DSBs should be incorporated into the LOLP calculation.

The LOLP mechanism over exaggerates the likelihood of generation capacity being unavailable to meet demand

3.7 A number of respondents commented on the current mechanism used for calculating DRs and suggested that it systematically underestimates the amount of capacity available and therefore overestimates LOLP. One respondent argued that, although the LOLP calculation is intended to determine the probability that there will be insufficient generating plant available to meet demand, the calculation grossly over exaggerates this probability. To support its claim, the respondent carried out a series of calculations using historical half-hourly LOLP data to determine the probability of insufficient generating plant availability over longer time periods. The respondent concluded that, taking the maximum LOLP figure for each day and summing them gives the expected number of occasions when demand should exceed capacity. The calculation suggests that generation shortfalls should have occurred on eight occasions over the past three years. In practice no shortfall occurred. Taking into account periods of non-peak LOLP values, the probability of no generation shortfall occurring during the previous three years is virtually zero. The respondent argues that its calculations provide compelling evidence that the historical figures used for LOLP are over exaggerated.

3.8 Another respondent compared the Pool's day ahead estimation of expected available capacity in the peak demand period of the following day with actual re-declared availability in the peak demand period of each day and concluded that, since 1 April 1994, actual available capacity had been underestimated by over 1200 MW. The result was an overestimation of LOLP and therefore inflated capacity payments. The respondent claimed that the source of this underestimation of expected available capacity is the DRs for generating units.

The value of disappearance ratios fails to reflect the risk that plant will not be available to meet demand on the day

3.9 A number of respondents argued against the current application of DRs. One suggested that a system of fixed DRs for both existing and newly commissioned plant would give a more balanced reflection of plant performance, which would result in a more balanced pricing mechanism. Another suggested that DRs do not reflect the risk that generation plant will be unavailable to meet demand on the day.

3.10 One respondent argued that the present application of DRs does not reflect the reliability of most plant on the system, but instead serves to artificially reduce the amount of available plant which enters the LOLP calculation, inflating capacity payments. Another supported this view by outlining the current DR calculation – DRs are calculated by comparing the actual availability of a genset in each period with the value of XMAX, where XMAX is the maximum availability of that genset at the day ahead stage over the previous seven days. The DR calculated is 1-XP/XMAX, where XP is the actual availability over the day. The monthly DR is the average of the half-hourly DRs. The respondent claims that the weakness in the current calculation relates to the lower availability of some plant in low demand periods, such as overnight and at weekends. The respondent argues that some units of a generating plant might chose to be unavailable in low demand periods in response to low Pool prices. However, the DR calculated reflects a lower apparent reliability based on the plant's lower overall availability. The DR does not therefore reflect physical plant reliability but also includes unavailability for commercial reasons.

3.11 In general those respondents who commented, concluded that the calculation of DRs overestimates the probability that a unit will fail, decreasing the estimation of available capacity which results in an increase in the estimation of LOLP and thereby capacity payments.

The operation of the LOLP mechanism over the summer led to suppliers facing uncertain capacity related costs that could not be hedged

3.12 A number of respondents pointed to the distortions apparent in the Pool price over the summer, with one pointing to 'unnecessarily high' capacity payments. One respondent claimed that over the summer suppliers faced unexpected and unhedgeable capacity related costs of £284 million while generators received massive windfall profits. Similarly another respondent suggested that the operation of the LOLP calculation has inflated uplift costs, including unscheduled availability costs in a manner that cannot be justified on the basis of underlying demand and supply fundamentals.

The complexity of the Pool rules results in uncertain outcomes

3.13 Some respondents argued that the operation of the Pool's scheduler and the Pool Rules leads to unpredictable outcomes and that an examination of the scheduler's operation would aid comprehension of price setting and increase market confidence. One suggested that the complexities surrounding the interaction of the Pool Rules resulted in uncertain outcomes to changes in the Rules. Others suggested that SMP commonly does not correspond to supply and demand fundamentals and that generators are able to create SMP spikes because of the de-linkage between the Pool scheduling process and SMP setting.

3.14 One respondent suggested that the operation of the scheduler, SuperGOAL, is resulting in SMP spikes as, although it schedules units to produce a lowest cost production schedule, price spikes result as SuperGOAL schedules output for short time periods from flexible generating units. The respondent argues that the size of the demand forecasting error by NGC can result in a price spike resulting from a potentially erroneous increase in demand. Other respondents also suggested that NGC's daily demand forecast is invariably too high with implications for both SMP and capacity payments.

Arguments opposing upholding the appeal

3.15 The main arguments given in opposition to resolutions appealed were:

- the motivation behind BGT's resolutions and subsequent appeal;
- the impact on the volume of capacity payments;
- the impact on participants' market positions and contract market liquidity;
- DSB sites are fundamentally different from generation;
- DRs should reflect plant reliability;
- an examination of the scheduler is unnecessary;
- any changes to the scheduler will have little effect given the time taken to implement them and the introduction of NETA; and
- there would be no benefit from extending the role or membership of MMG.

The motivation behind BGT's resolutions and subsequent appeal

3.16 A number of respondents questioned the motivation behind BGT's resolutions at the Pool Members' meeting and subsequent appeal to Ofgem, suggesting that the main motivation behind BGT's action was its commercial position which had exposed it to the high capacity payments. Some pointed to the often volatile nature of Pool prices and claimed that the Pool's propensity to price volatility was well understood and any active market participant should enter hedging contracts accordingly.

3.17 One respondent claimed that, if capacity payments were substantially reduced, BGT would benefit due to its retail position, but end-user customers would be virtually unaffected, as most retail sales for the winter 2000/01 period have been fixed by contract.

The impact on the volume of capacity payments

3.18 A number of respondents claimed that the consequence of fixing DRs for all generating plant at 7.5 per cent for the period October to March would reduce capacity payments to virtually zero, if there was no compensatory change to plant availability. Some argued that Ofgem should reject resolution 2 on the basis that it would result in zero capacity payments as Ofgem had concluded in a previous appeal that it was not reasonable to set DRs to zero.

3.19 Some respondents argued that the impact of very low capacity payments would be to substantially reduce the income, and potentially the availability, of low load factor plant over the winter period. Others suggested that reducing capacity payments might reduce demand side participation as capacity payments for DSBs will be reduced and their incentive to participate similarly reduced. One respondent also suggested that arbitrarily restricting one element of the Pool price without properly compensating for the imbalance would distort the electricity market. Several suggested that NETA was the solution to any problems with the Pool and that fundamental changes to the Pool Rules in advance of NETA were inappropriate.

3.20 A number of respondents argued against BGT's assertion that high capacity payments should always coincide with periods of high demand. In support of their argument they pointed to the summer when plant availability is habitually reduced due to maintenance schedules influenced by low expectations of Pool prices. The result, it was argued, can be low plant availability in periods of relatively low demand and subsequently high capacity payments. In support of this argument a number of respondents pointed to the 19 days on which notices of insufficient supply margin (NISMs) had been issued by NGC over the summer. One also suggested that in the summer, when demand is relatively low, it may be difficult for NGC to cope with the unplanned loss of generation, as each generating unit represents a larger proportion of the total load on the system. Some pointed to Ofgem's investigation into high capacity payments in September, highlighting Ofgem's conclusion that an unusually high proportion of plant was unavailable due to unplanned plant outages.

The impact on participants' market positions and contract market liquidity

3.21 Some respondents claimed that, if the resolutions were upheld, those participants who have properly managed their exposure to capacity payments through hedging instruments would be unfairly prejudiced, while those who had not managed their exposure would be rewarded. Some also suggested that if DRs are fixed and capacity payments subsequently reduced, a number of contracts may become stranded, requiring a lengthy and costly renegotiation process.

3.22 Some respondents argued against the BGT's assertion that unscheduled availability payments are unhedgeable, claiming that hedging contracts for the capacity element of pool price are available (known as LOLP contracts).

3.23 One respondent argued that a liquid forward market is crucial to the success of NETA and that market liquidity can only develop if traders believe the market is open and competitive and not prone to ad hoc regulatory intervention. The respondent claims that, should it uphold resolution 2, Ofgem would be avoiding its responsibility to ensure that a liquid forward market is available to participants for NETA.

DSB sites are fundamentally different from generation

3.24 A number of respondents, while not directly opposed in principle to the inclusion of DSBs in the LOLP calculation, suggest that inclusion is practically inappropriate as demand reduction capability is difficult to verify and the demand forecasting process includes demand reduction through the extrapolation of historic demand. It is argued that, unlike generation, DSBs cannot be centrally despatched by NGC, as a result it is difficult to verify if DSBs have shed load if scheduled to do so. In estimating demand, NGC extrapolate historic demand patterns, therefore any demand reduction on behalf of DSBs has been taken into account in the demand forecast and so including DSBs in the LOLP calculation would be double counting.

3.25 Several respondents also argued that the DRs forwarded by BGT for the inclusion of DSBs into the LOLP calculation were inappropriate. In support of this argument it was claimed by some that the DRs forwarded by BGT are based on the performance of generation units and that the characteristics of generation and demand are so fundamentally different, in terms of market participation, that specific DRs should be calculated for DSBs.

DR's should reflect plant reliability

3.26 A number of respondents argued that DRs should reflect plant reliability and expressed concern that the presentation of the figures, included as an amendment to BGT's paper at the Pool Members' meeting, contained no analysis. One respondent, who in principle supported the application of fixed DRs to generation units, voiced concern over the proposed DRs in BGT's appeal, suggesting that insufficient examination of the proposals presented to Ofgem for determination had been undertaken.

3.27 Others suggested that the application of blanket fixed DRs is inappropriate as the probability that a plant may fail varies by plant – a point, it was argued, which Ofgem made in a previous determination. One respondent suggested that live DRs do actually reflect plant performance, in particular the impact of redeclarations, and that fixing DRs would result in capacity payments bearing no relation to actual availability.

3.28 Others suggested that, although the present application of DRs had some features that are difficult to justify (such as fixed DRs for pre-vesting plant) making wholesale changes to all plant DRs would have unpredictable effects. One suggested that focusing only on the value of DRs is arbitrary and that it would be more appropriate to reconsider the entire capacity payments mechanism.

An examination of the scheduler is unnecessary

3.29 Several respondents argued that an examination by the SSA of the way in which SuperGOAL schedules plant is unnecessary, as the Pool's MMG has already undertaken a similar investigation in the summer to understand the reasons for high SMPs. One respondent argued that BGT had not sought to query the MMG's report into summer SMP through its association with Accord Energy who sits on the MMG. Another respondent argued that the scheduling programme has previously been reviewed and modified in response to concerns raised by Ofgem and market participants about observed price spikes.

3.30 Some respondents suggested that BGT's proposals illustrated a misunderstanding by BGT of the scheduler's primary objective, which is to find the lowest overall cost schedule for the 24-hour period. This may include scheduling more expensive, flexible plant to run for short periods to meet demand peaks. Another argued that it is not and should not be the purpose or function of the scheduler to reduce the occurrence of SMP spikes. Others suggested that price spikes are a natural consequence of markets and cannot be removed.

3.31 Some respondents pointed to overall SMP levels in summer 2000 and argued that, as average SMP was in real terms at its lowest level ever, there was little justification for BGT's resolution. Some also suggested that, as a Pool Member, BGT could commission its own reports from the SSA on the operation of the scheduler.

Any changes to the scheduler will have little effect given the time taken to implement them and the introduction of NETA

3.32 Several respondents raised doubts over the benefit to Pool Members of undertaking historic reporting on the workings of the scheduler given the limited remaining life of the Pool. Others suggested that any changes to the scheduler would require a commercial evaluation to assess the impact on historical SMPs and that previous changes to the scheduler have taken at least three months. Given the proposed March 2001 go live date of NETA, it was suggested that any change to the scheduler might therefore have a life of less than one month.

There would be no benefit from extending the role or membership of the MMG

3.33 Several respondents argued that the terms of reference for the MMG were debated at length when the group was first established and that no changes to the terms of reference have since been agreed. Some suggested that the MMG already examines unusual price features. Others suggested that the extension of the role of the MMG proposed would give it a responsibility which is currently undertaken by Ofgem via its market surveillance.

NGC's views

3.34 NGC responded to the Appeal with a number of observations and concerns about a number of the proposed resolutions. Given the concerns that NGC highlighted in its response, Ofgem asked NGC a number of more detailed questions and also asked NGC to undertake a more detailed analysis of the likely impact of upholding a number of the resolutions. Copies of the correspondence between NGC and Ofgem are reproduced in Appendix 2.

3.35 In its initial response NGC suggested that the capacity payments mechanism had helped maintain a high level of security of supply under the Pool. NGC argued that although the current market signals from LOLP have been partially distorted due to seasonal disappearance ratio calculations and the 8 day smoothing effect. NGC argued that it was difficult to predict the response of generators to a reduction in capacity payments following a rule change. NGC went on to argue that as the effect on plant availability was uncertain, this could make securing the system more difficult.

3.36 NGC said that the decision not to include a capacity payments mechanism in NETA had been made only after consideration of many factors influencing security of supply. This included moving from a day-ahead market to a market where prices were set closer to real time better reflecting the actual demand and supply balance at that time. NGC therefore cautioned against making changes to the capacity payments mechanism for the remaining life of the Pool.

3.37 In commenting on resolutions 3a and 3b, NGC argued that the SuperGOAL scheduling programme has been previously reviewed and modified in response to concerns expressed by market participants. While acknowledging that SuperGOAL will occasionally schedule more expensive generation to run for short periods as it endeavours to minimise calculated cost of production, NGC cautioned against the diversion of resource from NETA to investigate further modifications to SuperGOAL.

3.38 In order to explore NGC's argument that that the DRs put forward in the Appeal were arbitrary and their application might compromise security of supply, Ofgem asked NGC to provide the analysis NGC had undertaken in reaching this conclusion.

3.39 In response NGC reiterated its view that market signals should be maintained to encourage generators to make capacity available to meet demand and suggested that the adoption of the DRs in the appeal would reduce the level of capacity payments excessively. In reaching this conclusion NGC calculated that adopting a fixed DR of 7.5 per cent for all generating plant, and including 1 GW of demand side bidders (DSBs), would increase the total capacity modelled in the LOLP calculation from 50 GW to 54.5 GW for a typical winter day. This, NGC argued, would reduce LOLP by 95 per cent, as increasing the LOLP margin by 1 GW reduces capacity payments by a factor of around 3.

3.40 NGC recommended that further analysis be undertaken before any decision was made to include DSBs into the LOLP calculation. NGC argued that DSBs are not subject to central despatch and that this limits the extent to which they contribute to system balancing and therefore their inclusion in to the LOLP calculation would not provide NGC with capacity it could call upon when balancing the system on the day.

3.41 NGC argued against the introduction of a fixed DR calculated using only peak demand which, it suggested, was probably the methodology used to calculate the DRs forwarded in the appeal. In support of its argument NGC claimed that the capacity payments mechanism can provide incentives for plant to be made available at times of the day when demand is relatively low, but when a demand increase might combine with the withdrawal of plant. NGC was unable to replicate the 7.5 per cent DR forwarded in the appeal and concluded that analysis based on average live disappearance ratios would result in a winter DR of 14.6 per cent and a summer DR of 18 per cent.

3.42 NGC concluded that the adoption of fixed DR's would be more appropriate if they were based upon average historic DR values. This methodology, NGC argued, would give DRs of 13.5 per cent in the winter and 15 per cent in the summer. NGC suggested that these DRs might remove some LOLP volatility whilst maintaining an effective market signal at times when plant margins are tight. However, NGC also suggested that any changes to the LOLP mechanism should not be introduced before February 2001, after the winter peak.

3.43 Ofgem asked NGC to provide further clarification of its arguments, including an assessment of the capacity margin prevailing when the LOLP calculation would provide positive incentives for generators to make plant available under two scenarios: one using DRs of 7.5 per cent and the other DRs of 13.5 per cent. Ofgem also asked NGC to provide an assessment of the total capacity margin it would consider adequate to maintain security of supply and a breakdown of the volume of reserve NGC holds that could be called upon to meet its energy balancing needs if the capacity margin became tight. Ofgem also asked NGC to explain why, in the absence of capacity payments, it appears to believe that some generators who relied upon availability payments might not declare themselves available, potentially jeopardising security of supply.

3.44 In its response NGC concluded that adopting a DR of 7.5 per cent instead of 13.5 per cent would increase modelled availability, and thus plant margin used in the LOLP calculation, by around 3.5 GW. This, NGC claimed, would reduce LOLP by a factor of 25-30, resulting in capacity payments of around £0-3/MWh, as opposed to £10-100/MWh with a DR of 13.5 per cent. NGC concluded that it is not possible to identify an absolute point at which LOLP payments start to provide incentives to generators to remain available on the day. However, NGC suggested that comparable capacity payments would only be achieved using a fixed DR of 7.5 per cent instead of 13.5 per cent when the plant margin is reduced by 4 GW.

3.45 NGC suggested that, in order to maintain security of supply over the winter period, it considers that a day ahead plant margin of 10.5 GW is required, allowing 3 GW for relatively unreliable commissioning plant. In addition, NGC claims that it holds an effective total of contracted reserve of around 1.4 GW. NGC also argues that the interaction between its standing reserve contracts and the capacity payments mechanism is such that the standing reserve contracts increase the incentive on plant to bid availability into the Pool, contributing towards increasing the plant margin and limiting capacity payments.

3.46 NGC clarified that it was not arguing that in the absence of capacity payments some generators who had relied upon availability payments rather than energy payments for income would definitely declare themselves unavailable on the day. NGC made clear that they could not be certain that this would be the effect of a reduction/removal in capacity payments.

3.47 NGC also made clear that it had questioned the rationale of changing one element of the capacity payments mechanism in isolation prior to the introduction of NETA when the response of generators would be difficult to predict. NGC reiterated that it would prefer substantial changes to the capacity payments mechanism to be delayed until the end of January 2001, after the winter peak.

3.48 Given NGC's estimate of a necessary plant margin of 10.5 GW to maintain security of supply over the winter period, Ofgem asked NGC for its assessment of the cost of securing an additional 10.5 GW of reserve capacity under contract, rather than through the capacity payment mechanism. Ofgem also asked NGC for its assessment of the impact of including the DSBs into the LOLP calculation and NGC's LOLP forecast in the absence of changes to the capacity mechanism.

3.49 NGC qualified its response with a number of observations. It reminded Ofgem that NGC has no role in ensuring that there is sufficient generation capacity and suggested that, if it contracted for 10.5 GW of reserve as an alternative to capacity payments, NGC would be underwriting a significant proportion of generating capacity. NGC claimed that its reserve contracts exist to provide rapid flexible response given the total capacity provided by the market and that, in the absence of capacity payments, 10.5 GW of reserve might not be sufficient to maintain plant margins. Unlike the current capacity payments mechanism, reserve contracts do not provide a signal to all plant to maintain plant margins, since unlike the current capacity payments mechanism it does not provide a signal to all plant to maintain availability. Thus plant without a contract may chose to make itself unavailable. Finally, NGC advised that contracting for 10.5 GW of reserve might take two to three months. Notwithstanding these observations, NGC estimated that the cost of contracting for 9 GW of reserve capacity (10.5 GW minus 1.5 GW already secured) would be around £15/kW, giving an annual cost of £135 million.

3.50 NGC reiterated its view that DSBs do not provide NGC with capacity it can call upon at short notice to balance the system - most DSBs are not subject to central despatch and only contribute towards system balancing if called to do so in the unconstrained schedule at the day-ahead stage. However NGC suggested that it would be reasonable to include the quantity of demand reduction called in the unconstrained schedule in the LOLP calculation as these DSBs had contributed towards reducing demand. NGC argued that including all DSBs into the LOLP calculation would imply that the demand side makes available to NGC the same short term balancing services as generation. NGC suggests a DSB cannot currently provide the same balancing service as a centrally despatched generator due to the lack of appropriate communications and metering. NGC concluded that including DSBs into the LOLP calculation would be likely to reduce capacity payments by 50 per cent.

3.51 In response to NGC's comments about the potential inclusion of DSBs into the LOLP calculation, Ofgem asked NGC to clarify whether in practice all DSBs are excluded from the LOLP calculation. NGC explained that when forecasting demand it takes into account all demand reductions notified to it, but is unable to account for the contribution of unnotified demand reductions. As a result, NGC's demand forecasts are independent of the impact of historic demand side bidding and those offered or called day ahead, therefore including DSBs into the LOLP calculation will not lead to double counting.

3.52 However, NGC also reiterated that DSBs are not subject to central despatch and including DSBs into the LOLP calculation might not provide NGC with capacity it could call upon to balance the system. NGC concluded that it would be reasonable to include only those DSBs that were called in the unconstrained schedule in the LOLP calculation.

3.53 In the light of NGC's responses Ofgem asked NGC for its assessment of the balance of probability that, if the basis for calculating capacity payments were changed by upholding either or both of the Appeal resolutions, it would have a material adverse effect on the system security if the changes are implemented prior to 1 February 2000.

3.54 In response, NGC summarised the results of its analysis to date and set out its assessment of the likely impact of upholding either or both of the resolutions on the capacity payments.

Table 3.2: NGC's assessment of the impact of upholding the resolutions on capacity payments

	Potential reduction in (XMAXmean – TGSD#) margin modelled in LOLP calculation	Likely proportionate reduction in Capacity Payments
RESOLUTION 1 (inclusion of all Demand Side Bidders)	1000MW	X 0.33
RESOLUTION 2 (fixing of disappearance ratios to 13.5% summer/ 7.5% winter)	3,500 MW	X 0.05
RESOLUTIONS 1 & 2	4,500 MW	X < 0.05

3.55 NGC argued that it was the response of generators to any change in the level of capacity payments that will determine whether or not there is a material risk of an adverse effect on security of supply. NGC continued to argue that the response of generators was uncertain and that it was not possible to make a quantified assessment of their likely reaction to either or both of the resolutions being upheld.

3.56 NGC went on to report that it had experienced significant volumes of generator redeclarations this year that appeared to be in response to lower market prices. Assuming that this represents a link between offered availability and the absolute level of Pool prices, NGC argued that a market rule change that further reduces Pool prices might result in some reduction in the amount of generation made available. NGC noted that since October 2000, it had issued 20 NISMs, including 3 High Risk of Demand Reduction notices compared with 9 notifications in total for the same period over the winter of 1999/2000.

- NGC also produced some correlation analysis, in response to Ofgem's request, showing the relationship between capacity payments/PPP and the volume of generation redeclared as unavailable on the day during the last two winters. NGC argued that although the relationship is complex, the analysis suggested that higher levels of redeclarations do take place when capacity payments are at, or close to, zero.

4. Ofgem's views

4.1 Ofgem has carefully considered the arguments raised by BGT in lodging its Appeal and the arguments raised by respondents. In this chapter we set out Ofgem's views on the arguments raised both in favour of and against each of the six resolutions.

Arguments supporting the Appeal

The LOLP mechanism is flawed

4.2 OFFER and more recently Ofgem have consistently expressed concern over the operation of the capacity payments mechanism over the life of the Pool. Concerns surrounding the operation of the capacity payments mechanism were highlighted in the first report on Pool prices in December 1991.[6] This document found that generators had been re-declaring plant unavailable for commercial reasons to increase capacity payments. The Pool rules were subsequently amended to try to prevent this form of manipulation. In January 1995[7] another OFFER Pool price investigation concluded that the main reason for the high prices experienced at the time was the level of capacity payments. OFFER unsuccessfully attempted to amend the capacity payment mechanism to take into account the increased reliability of generation plant commissioned since privatisation. In June 1998,[8] OFFER suggested that the systemic inverse relationship between SMP and capacity payments suggested that the capacity payments mechanism was not working in the way it was expected or intended.

4.3 In July 1999,[9] Ofgem again expressed concern about the operation of the capacity payments mechanism after a period of very high capacity payments that did not appear to reflect underlying market conditions. In October 1999[10] Ofgem reiterated concern about the capacity payment mechanism and announced the intention to ask the Pool to consider changes to the capacity payment mechanism. In December 1999, Ofgem wrote to PEC asking it to

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[6] 'Report on Pool Price Inquiry', OFFER, December 1991.
[7] 'Pool Prices and the Undertakings on pricing given by National Power and PowerGen', OFFER, January 1995.
[8] 'Report on Pool price increases in winter 1997/98.', OFFER, June 1998.
[9] 'Consultation on rises in Pool Prices', Ofgem, July 1999.
[10] 'Rises in Pool Prices in July: An Ofgem decision document.', Ofgem, October 1999.

conduct an impact assessment of Ofgem's proposed changes to the capacity payment mechanism.[11]

4.4 Ofgem subsequently wrote to the Chief Executive of the Pool seeking an assessment of the impact of implementing fixed disappearance ratios within the settlement system. The Pool responded in January 2000 with an assessment that the overall cost of the project would be £300,000 and the time required to implement the changes would be 4 months. Ofgem decided that given the costs and delivery time it was not prudent to divert resources away from other workstreams including the NETA programme.

4.5 Most recently in October 2000, following an investigation into the high capacity payments persisting at the time, Ofgem issued a press release[12] in which it concluded that the high capacity payments were not the result of underlying market conditions as the supply/demand margin was not particularly tight. Ofgem concluded that the high capacity payments experienced were the result of the complex formula used to determine capacity payments which, in Ofgem's opinion, contained unrealistic assumptions that resulted in capacity payments which are very sensitive to the withdrawal of particular types of plant. The greater proportion of more recently commissioned generation capacity and the unplanned outage of older plant, appeared to be resulting in disproportionately large capacity payments. This was the result of the rules used in determining capacity payments that arbitrarily assume that plant commissioned before 1990 is more reliable (assigning them fixed disappearance ratios) than plant commissioned after 1990 (which are assigned live ratios).

4.6 The Review of Electricity Trading Arrangements published by OFFER in July 1998[13] noted that capacity payments do not respond to short term changes in capacity margin, are a poor signal for the long term, and are not working as intended. Explicit capacity payments are not included in the new electricity trading arrangements.

[11] 'Pool Prices in July Statutory Consultation on Proposed Licence Amendments', Ofgem, December 1999.
[12] 'No action against generators after unplanned outages', Ofgem Press Notice 109, October 2000.
[13] Review of Electricity Trading Arrangements: Proposals, July 1998.

Failure to include demand side participation in the LOLP calculation prevents the system achieving a balance between supply and demand and breaches the principle of the system whereby DSBs are paid availability payments

4.7 Ofgem notes the concern of some respondents who suggest that the exclusion of DSBs from the LOLP calculation prevents the system from achieving a balance between supply and demand. Ofgem has frequently highlighted the limited participation of the demand side as a weakness with the operation of the Pool throughout its life[14] where demand side participation is restricted to, and largely benefits only, the 39 DSBs.

4.8 Ofgem accepts that the 39 DSBs who bid into the Pool are, in principle, available to reduce demand on the day and therefore should, in theory, be included in the LOLP calculation. For example, under the Pool Rules a DSB who is scheduled in the unconstrained schedule at the day-ahead stage is required to reduce its demand during the periods in which it is scheduled. DSBs have tended, however, to bid in such a manner that they are not scheduled in the unconstrained schedule. There have also been concerns that DSBs have offered availability in excess of their maximum demand and this has led to the Pool putting in place monitoring arrangements.

4.9 However, as NGC argues, if a DSB is not in the day-ahead schedule it cannot be called by NGC on the day in the same manner as centrally despatched generation, if for example, a scheduled generation unit fails or if there is an unexpected increase in demand. Under the current arrangements, DSBs are not subject to central despatch by NGC and NGC cannot monitor DSBs directly to ensure that they reduce demand (there are over 100 sites). In practice, DSBs are not therefore available on the day to reduce demand, in the same manner as a centrally despatched generator unless scheduled in the day-ahead schedule.

4.10 Under the Pool Rules, capacity payments are set at the day-ahead stage to reflect the plant margin, given declared availability day-ahead and forecast demand. The application of disappearance ratios to declared availability attempts to model the probability that capacity declared at the day-ahead stage will not actually be physically available on the day, if required. In Ofgem's view, because DSBs cannot be called on the day by NGC under the current arrangements, they are effectively unavailable with an implicit disappearance ratio of 1.

4.11 It is clear in our view that the DSB scheme in place under the Pool has a number of weaknesses,[15] although the benefit of any changes now, given the expected remaining life of the Pool, is likely to be very limited.

The LOLP mechanism over exaggerates the likelihood of generation capacity being unavailable to meet demand

4.12 Ofgem continues to believe that many of the assumptions used to determine capacity payments are unrealistic and results in a capacity payments mechanism that is very sensitive to the withdrawal of particular types of plant. The live DRs applied to newer post-vesting plant result in DRs for this plant which are often greater than those applied to pre-vesting plant. As a result, as the proportion of more recently commissioned capacity on the system rises and older capacity is withdrawn, capacity payments may rise significantly above levels previously reached for a supply and demand position. This effect is exacerbated by the exponential nature of the calculation used to determine capacity payments, which means that very small changes in the assumed plant margin can lead to disproportionate changes in the level of capacity payments.

4.13 Although NGC issued a number of NISMs over the summer and autumn, the days when NISMs were issued did not always coincide with the days when capacity payments were highest. This seems to reinforce a number of respondents' arguments that capacity payments do not appear to reflect underlying market conditions and therefore do not provide a useful short-term price signal to generators when capacity is tight.

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[14] For a summary of OFFER's views see the 'Review of Electricity Trading Arrangements: proposals', OFFER, July 1998.

[15] These weaknesses have been well documented and have been the subject of previous OFFER determinations on Pool Appeals. For example, in rejecting an Appeal in March 1997 on the creation of a Load Management Agency, the Director General urged the Pool to consider improving the Demand Side Bidding Scheme and to include the demand side in the LOLP calculation with the application of suitable disappearance ratios. In January 1998, PEC initiated a project to look into the improving the arrangemenrs but the project was cancelled by PEC in July 1998 as NETA would render the scheme redundent.

The value of DRs fails to reflect the risk that plant will not be available to meet demand on the day

4.14 Ofgem has previously expressed concern over the apparent failure of some plant live DRs to reflect the actual risk that plant will not be available to meet demand on a given day. In terms of DRs allocated to newly commissioned plant, Ofgem is not concerned with the basis on which DRs for new plant are set as this reflects the high probability of plant failure during the initial commissioning phase. However, Ofgem is concerned that a newly commissioned plant's DR does not fall at a rate that in our view adequately reflects its improving reliability. The unrealistic assumptions used in determining plant DRs are likely to lead to higher capacity payments, other things being equal, which do not necessarily reflect underlying market conditions and the real plant margin on the day.

The operation of the LOLP mechanism over the summer led to suppliers facing uncertain capacity related costs that could not be hedged

4.15 Ofgem understands that liquidity in LOLP related contracts is very limited, which might impede the ability of participants to hedge against LOLP volatility. Ofgem considers that the complexity and volatility of the LOLP calculation may explain the thin trading of LOLP-related hedging contracts to date. A number of market participants have reported that the accuracy of their LOLP forecasting has deteriorated significantly over the last year and participants have found it increasingly difficult to accurately forecast the LOLP payment for any assumed plant margin.

4.16 Any moves to simplify the assumptions underlying the calculation could make it easier for industry participants to forecast LOLP accurately to enable suppliers to hedge some of their risk.

The complexity of the Pool Rules results in uncertain outcomes

4.17 Ofgem accepts the arguments made by respondents, but is also conscious of the limited remaining life of the Pool and the risk that detailed analysis of the operation of the Rules and the Pool scheduling software could divert resources away from delivering NETA . Also, amendments to the Pool software take considerable time to develop and implement. It is therefore questionable whether any modifications would actually take effect before the introduction of NETA.

Arguments opposing upholding the Appeal

The motivation behind BGT's resolutions and subsequent appeal

4.18 Ofgem does not consider that arguments relating to BGT's motivation are relevant in determining whether to uphold or reject any of the resolutions.

The impact on the volume of capacity payments

4.19 Ofgem has asked the SSA to assess the impact on capacity payments of fixing DRs at the levels outlined in BGT's appeal on the days of highest capacity payments in September and October. Table 4.1 shows the results of the analysis undertaken by the SSA for four different scenarios. The first scenario is actual capacity payments on the days in question. The second shows capacity payments recalculated with the DRs outlined in the appeal applied to all generation units. The third shows capacity payments recalculated with DSBs included into the LOLP calculation at the DRs outlined in the appeal. The fourth scenario shows capacity payments recalculated with the DRs outlined in the appeal for generation units, together with DSBs included in the LOLP calculation.

Table 4.1 - Capacity Payments (£/MW)

	Scenario 1 (Actual)	Scenario 2 (Fixed DRs for all generators)	Scenario 3 (Inclusion of DSBs)	Scenario 4 (Fixed DRs and inclusion of DSBs)
6 Sept	43.87	12.39	17.18	4.75
7 Sept	55.24	14.5	21.6	5.35
11 Sept	43.33	10.98	17.45	3.5
14 Sept	42.86	11.54	17.13	3.74
18 Sept	57.42	12.36	23.04	4.18

27 Sept	41.84	10.13	15.91	3.52
3 Oct	10.39	0.0	2.83	0.0
16 Oct	7.75	0.0	0.0	0.0
30 Oct	26.16	0.03	9.18	0.0
31 Oct	37.74	0.06	13.59	0.01

4.20 As table 4.1 shows, in September, applying the fixed DRs proposed in the appeal (resolution 2) to all generation units would have reduced capacity payments by around 75 per cent (scenario 2). If DSBs are included into the LOLP calculation (resolution 1) capacity payments would have been reduced by 60 per cent (scenario 3). A combination of applying the fixed DR to all generation units and including DSBs into the LOLP calculation (resolutions 1 and 2) has the most dramatic impact, reducing capacity payments by around 90 per cent.

4.21 In October, under both scenario 2 and scenario 4 capacity payments declined by almost 100 per cent. Including only the DSBs into the LOLP calculation at the fixed winter DR reduces capacity payments by an average 65 per cent.

4.22 Ofgem notes the arguments of respondents but does not believe that whether upholding the appeal will effectively lead to zero capacity payments is directly relevant. One of the purposes of the capacity payment mechanism is to send short-term price signals to generators of the value of capacity. If the margin is relatively high it would be expected that the capacity payment should be zero. There have been frequent incidences of zero capacity payments during the life of the Pool when there has been abundant capacity. The relevant question is therefore whether upholding the Appeal would lead to zero capacity payments when the plant margin was tight and whether this could endanger security of supply by removing an incentive for generators to remain available under the existing rules.

4.23 Ofgem also notes the argument that we should reject resolution 2 because we previously concluded that setting DRs to zero was inappropriate within the framework of the capacity payments mechanism. Ofgem does not accept this argument as the resolution does not propose to set DRs to zero but to fixed values that BGT believe more accurately reflect the 'actual' DRs of the plant in question.

The impact on participants' market positions and contract market liquidity

4.24 Ofgem acknowledges the issues created by changing market rules in traded markets and the potential contract re-negotiation between industry participants should resolutions 1 or 2 of the appeal be upheld.

4.25 However, Ofgem and a number of market participants have clearly signalled their concerns about the operation of the capacity payments mechanism. It is also clear that the Pool Rules can be developed and modified over time with the agreement of Pool members, and on Appeal. It is not unreasonable to expect therefore that market participants should have factored in the possibility of rule changes, particularly relating to the capacity mechanism, when taking traded positions.

DSB sites are fundamentally different from generation

4.26 Ofgem recognises the differences between generation units and DSBs in the scheduling process, in particular the apparent inability of NGC to centrally despatch most DSBs due, in part, to the lack of effective communication between NGC and DSBs.

4.27 In terms of the DRs applied to DSBs, Ofgem recognises that the DRs proposed in resolution 1 are calculated with reference largely to generation units and are not specifically related to DSBs. While the calculation of specific DRs for DSBs would be more appropriate, there are practical problems with such a calculation. There is limited empirical evidence surrounding the performance of DSBs compared to generation units due, in part, to the lack of relevant metering and central despatch information.

4.28 Ofgem acknowledges the concerns surrounding the consideration of DSBs in NGC's demand forecast. However, as discussed previously, Ofgem does not consider that double counting would result if the DSBs were included into the LOLP calculation.

DRs should reflect plant reliability

4.29 As discussed above, Ofgem has previously expressed concern over the apparent failure of some plant DRs to accurately reflect actual plant reliability, leading to an overestimation of the LOLP calculation. Ofgem believes that simplifying the LOLP calculation through the application of fixed DRs for all generating plant, rather than the current system of fixed and live DRs, might be appropriate.

4.30 Ofgem asked the SSA to independently verify the DRs proposed in the Appeal. The SSA concluded that in calculating the DRs proposed in the appeal, the methodology outlined at the Pool Members' meeting did not appear to have been adhered to. The SSA calculated DRs using the 'correct' methodology, i.e. adhering to the methodology outlined at the Pool Members' meeting, and concluded that an average summer DR would be 10.9 per cent, and a winter DR 5.7 per cent. NGC also attempted to reproduce the figures proposed in the appeal and concluded that an average summer DR would be 18 per cent and a winter DR 14.6 per cent. However, NGC did not use the methodology outlined at the Pool Members' meeting, in particular it did not exclude the actual availability (XP) of DSBs and therefore a direct comparison is not possible.

An examination of the scheduler is unnecessary

4.31 Ofgem has previously raised concern over the operation of the scheduler, in particular the impact on the system marginal price of scheduling small increments in generation. As a result of the concern expressed by Ofgem and market participants, changes were made to the scheduler in 1999. More recently the Pool's MMG investigated the causes of high SMPs in the summer and the company responsible for the high SMPs was asked to provide an explanation of its bidding strategy, to the satisfaction of the MMG.

4.32 Ofgem accepts the argument that given the limited remaining life of the Pool and the impending introduction of NETA, analysing the scheduler would be of limited value and might deflect resources from the NETA programme.

Any changes to the scheduler will have little effect given the time taken to implement them and the introduction of NETA

4.33 While Ofgem has expressed its desire for the Pool to operate as an orderly market in the run up to its replacement by NETA, Ofgem does not consider changes to the scheduler appropriate given the limited remaining life of the Pool. Any changes to the scheduler are unlikely to be implemented speedily given the need for system development and will divert industry resources from work surrounding the introduction of NETA.

There would be no benefit from extending the role or membership of the MMG

4.34 Ofgem considers the MMG's terms of reference are adequate – in particular the objectives to:

- 'identify the occurrence of anomalous prices – i.e. those not explained by market fundamentals; and
- identify the causes of anomalous prices – in particular whether particular bidding structures are responsible.'

4.35 Ofgem considers that the membership of the MMG, which comprises largely industry participants with physical positions and includes only one trader without a physical position, would benefit from an extension to include suitable experts from other trading companies.

NGC's views

Security of Supply

4.36 Ofgem agrees that a high level of security of supply has been maintained over the life of the Pool and acknowledges the view that the capacity payments mechanism has contributed to this. However, Ofgem also considers that the capacity payments mechanism does not operate in the way which was intended and that the result has been higher prices for customers.

4.37 Ofgem is clearly mindful of NGC's argument that a fixed DR of 7.5 per cent for all plant in the winter might compromise security of supply by reducing the level at which capacity payments will provide sufficient incentives for generators to make plant available by some 4 GW. As part of its assessment NGC suggested that capacity payments of £0-3/MWh might provide too weak a signal to generators to make plant available.

4.38 Ofgem notes NGC's assessment that it requires a plant margin of around 10.5 GW in winter to maintain security of supply, but also notes that NGC argues that a margin in the range of 7.62 and 12 GW has recently been observed to be acceptable. Ofgem also notes that NGC considers that a DR of 13.5 per cent might provide an acceptable level of supply security over the winter period, but that a DR of 7.5 per cent would not.

4.39 Ofgem is also concerned about the potential impact of upholding the appeal on maintaining security of supply in the absence of a market abuse licence condition. Ofgem has frequently expressed its concern about the scope for abuse by short-term withdrawal of generation capacity under the Pool.[16]

4.40 Higher prices will benefit the rest of a generator's portfolio and this form of market abuse can be leveraged in the contract market by taking a long position before the plant withdrawal. Following the rise in prices, the contracts can then be sold on at a profit.

4.41 In our view, in the absence of a MALC, capacity payments provide a financial incentive on generation not scheduled to remain available throughout the day. If capacity payments were very low or zero, generators would have a greater incentive to withdraw plant on the day to ensure that more expensive plant is called to run by NGC. NGC have recently experienced operational problems on certain days when plant has re-declared itself unavailable on the day in response to low prices and capacity payments.

4.42 On balance, and given the considerable uncertainty surrounding the impact of very low capacity payments on generator availability, Ofgem is concerned that this resolution may increase the scope for abuse by generators by removing a financial incentive to remain available throughout the day when not scheduled. Given the operational concerns raised by NGC any reduction in generator

[16] See Ofgem's submissions to the Competition Commission available on the Ofgem website at http://www.ofgem.gov.uk/customers/competition.htm.

availability could raise security of supply issues under the current trading arrangements.

Demand Side Bidders

4.43 Ofgem notes NGC's claim that a lack of effective communication channels between it and DSBs and lack of DSB metering capability prevents NGC from relying on them on the day, if required. However, Ofgem also notes that DSBs receive availability payments for offering demand reduction capacity, but that this capability is not taken into account in the LOLP calculation.

4.44 On balance, Ofgem accepts that under the current Pool arrangements, which are clearly deficient, the effective disappearance ratio of a DSB if not scheduled day ahead is 1, as it cannot be despatched on the day, if required.

Re-evaluating GOAL

4.45 Ofgem agrees with NGC's view that further investigation into the operation of and potential modification of the SuperGOAL scheduling programme will be of limited value and may divert resources from the NETA programme.

5. The Authority's decision

5.1 The Authority is required, under clause 13.5.1 of the PSA to determine Appeals by reference to whether the interests of a group of Pool Members, including the Dissentient Pool Member have been, are or will be unfairly prejudiced by the failure to pass the resolutions that are the subject of the Appeal, although under clause 13.5.3 it is expressly recognised that satisfaction of that criterion will not in itself entitle the Dissentient Pool Member to a determination in its favour. The Authority must apply its statutory duties in reaching its decision.

Resolution 1

5.2 The Authority recognises that the present provisions in respect of the failure to include DSBs in the LOLP calculation may adversely affect Pool Members including the Dissentient Pool Member. However, NGC raised a number of concerns regarding DSB's which the Authority has had to take into account in reaching **its** decision whether to uphold the resolution. In particular, the Authority has considered the following factors:

- unlike centrally despatched generation, under the current arrangements DSBs cannot be called on the day by NGC and are only despatched if they are included in the day ahead schedule;

- under the Pool Rules, availability payments are calculated on the basis of the estimated capacity margin at the day-ahead stage based on forecast demand and declared availability. A disappearance ratio is then applied to capacity offered which is the probability that declared capacity offered at the day ahead stage will not be available on the day;

- the implicit disappearance ratio of DSBs not scheduled is 1 under the rules, as unscheduled DSBs are not available to NGC on the day and cannot be called if required because of a lack of effective metering and communication infrastructure between NGC and DSBs;

- it would be unreasonable and illogical, within the current arrangements to assume that the DR of DSBs not scheduled to run is anything other than 1, which is equivalent to not including them in the LOLP calculation; and

- in respect of this resolution and resolution 2, the uncertain effect on security of supply of implementing the changes proposed in the short period expected prior to the implementation of NETA.

5.3 Within the framework of the capacity payment mechanism and given the current rules associated with the DSB scheme the Authority therefore considers that the rejection of the resolution does not unfairly prejudice the Dissentient Pool Member and that it would be unreasonable having regard to the uncertain effect on security of supply within the current arrangements to allow the Appeal.

Resolution 2

5.4 The Authority recognises that the present provisions in respect of the DRs of generators may adversely affect Pool Members, including the Dissentient Pool Member. However, it notes in particular the views of NGC regarding the possible adverse effects which the resolution could have on security of supply and the following additional points:

- the effect of upholding the appeal would be likely to lead to very low or zero capacity payments for the remaining life of the Pool and there is considerable uncertainty about the impact this would have on generator availability;
- in the absence of a market abuse licence condition to act as a deterrent, Ofgem is concerned that very low or zero capacity payments may increase the incentive on generators to withdraw plant on the day to ensure that more expensive plant is called to run;
- there is some evidence of lower generator availability as a result of increased redeclarations when capacity payments are zero and/or Pool prices are low, as evidenced by the increased number of NISMs issued in recent months; and
- as a result, upholding the appeal might adversely affect the plant margin both at the day-ahead stage and on the day and could affect NGC's

ability to ensure adequate security of supply for the remaining life of the Pool.

5.5 The Authority therefore considers that the rejection of the resolution does not unfairly prejudice the Dissentient Pool Member and that the risks to security of supply during the winter are such that it should not allow the Appeal.

Resolution 3a

5.6 The Authority does not consider that rejection of resolution 3a will prejudice the interests of the Dissenting Pool Member. This is based on the following factors:

- upholding resolution 3a will be of limited benefit given the anticipated remaining life of the Pool which is due to be replaced by NETA on 27 March 2001 and the likely time required for system development; and

- examining the way in which generation units are scheduled and producing a report for Pool Members on the causes of the high SMP values during summer 2000 will require considerable analysis and divert industry resources from the implementation of NETA. Ofgem does not believe this would be in customers' interests.

5.7 The Authority therefore determines that it should not allow the Appeal in respect of this resolution.

Resolution 3b

5.8 The Authority does not consider that rejection of resolution 3b will prejudice the interests of the Dissentient Pool Member or other suppliers. This is based on the following factors:

- examining the potential flexibility of the scheduling programme to reduce the occurrence of SMP spikes and producing a report for Pool Members will require considerable analysis and divert resources within NGC from the implementation of NETA. Ofgem does not believe this would be in customers' interests;

- considerable time and effort has already been spent improving the scheduling program - in 1999 it was modified to limit the ability of generators to produce unrepresentative price spikes with particular bidding strategies. Ofgem does not consider the price spikes in summer 2000 sufficiently anomalous to warrant further modifications to the scheduler; and

- any potential modifications to the scheduler following the production of a report are unlikely to be implemented significantly before the proposed NETA go live date of 27 March 2001 because of system development lead times.

5.9 The Authority therefore determines that it should not allow the appeal in respect of this resolution.

Resolution 3c

5.10 The Authority does not consider that rejection of resolution 3c will prejudice the interests of the Dissentient Pool Member or other suppliers. This is based on the following factor: Ofgem believes that the existing terms of reference for the Pool's MMG are adequate for the limited remaining life of the Pool.

5.11 The Authority therefore determines that it should not allow the Appeal in respect of this resolution.

Resolution 3d

5.12 The Authority considers that rejection of resolution 3d will prejudice the interests of the Dissentient Pool Member and other suppliers. This is based on the following factor: the membership of the Pool's MMG would benefit from an extension to include suitable experts from trading companies as well as existing members.

5.13 The Authority therefore determines that this resolution should have effect. Since the resolution does not specify a date from which it should apply it will take immediate effect.

Eileen Marshall

Managing Director Competition and Trading Arrangements

Gas and Electricity Markets Authority

26 January 2001

Appendix 1 List of respondents to the consultation

1.1 The following parties responded to the Ofgem letter. Copies of those responses can be viewed in the Ofgem library.

Company

Accord Energy

Amerada

BNFL Magnox

British Energy

Dynegy

Economy Power

Edison Mission Energy

Enron

Innogy

London Electricity

National Grid Company

PowerGen

Scottish & Southern Energy

Scottish Power

SEEBOARD

Teesside Power Ltd

TXU Europe

UK Electric Power Ltd

Yorkshire Electricity

Appendix 2 Copy of correspondence between NGC and Ofgem on the likely effects of upholding the Appeal

23 November 2000

MD/NGC/MR/RJB

Dr Eileen Marshall
Deputy Director General
Competition and Trading Arrangements
Office of Gas and Electricity Markets
9 Millbank
London SW1P 3GE

Dear Eileen

APPEAL OF DISAPPEARANCE RATIOS RESOLUTION

Further to the letter from Steven Smith inviting comment on the appeal made by British Gas Trading against the recent Pool Members meeting decisions, I would like to take the opportunity to provide a number of observations on the changes being proposed.

- The capacity payment mechanism is one of a number of elements of the existing Pool arrangements which come together to encourage the provision of sufficient generation to meet uncertain demand levels. Since Vesting, a high level of security of supply has been maintained and capacity payments have played their part in achieving this. The decision not to include a capacity mechanism as part of the New Electricity Trading Arrangements (NETA) was taken only after considering all of the factors influencing the collective security of supply framework in the new market, and the inclusion of more reflective pricing signals closer to real-time. I would therefore caution against making changes to the current capacity payment mechanism in isolation, ahead of the introduction of NETA.

- Although the current market signals from LOLP are partially distorted due to seasonal Disappearance Ratio calculations and the 8 day smoothing effect, historically the capacity payment mechanism has acted as a reasonable short term market signal indicating low plant margins. When actual plant margins have been eroded capacity payments have provided an incentive for all Generators to make additional plant available. Indeed, capacity payments represent the principal mechanism for remunerating redeclared availability above the offered level on high merit plant. Setting disappearance ratios to an arbitrary, fixed level could act to blunt this mechanism and it is important that these short-term signals are not weakened in the period prior to the introduction of NETA.

- The GOAL scheduling program has previously been reviewed and modified in response to concerns expressed by market participants and as a result of observed price spikes. However, it is recognised that in arriving at optimal generation schedules, GOAL will on occasion schedule more expensive, flexible plant to run for short periods to meet demand peaks. This effect is known and understood. At this time I would caution against the diversion of key industry resource to investigate further modifications to the GOAL program since it would inevitably divert effort that is focussed on delivering the systems required to facilitate the new market arrangements.

I hope that these observations are helpful. However, if you require anything further please do not hesitate to contact me.

Yours sincerely,

Jeff Scott

28 November 2000

Mr Scott
Director of Market Development
The National Grid Company plc
National Grid House
Kirby Corner Road
Coventry CV4 8JY

Our Ref:
Direct Dial: 020 7901 7436
Email: lisa.woolhouse@ofgem.gov.uk

Dear Mr Scott,

Pool Appeal

Thank you for your letter of 23 November in which you outline why NGC considers that Ofgem should not uphold a number of resolutions within British Gas Trading's Appeal in respect of anomalous Pool prices during 2000.

In your letter you suggest that the capacity payments mechanism has helped ensure that sufficient generation capacity has been made available to meet uncertain demand and ensure a high level of security of supply. You also suggest that the decision not to include a capacity payments mechanism in the New Electricity Trading Arrangements (NETA) was made only after consideration of many factors influencing security of supply, including more reflective pricing signals closer to real-time. You indicate that, although the current market signals from LOLP have been distorted, the capacity mechanism has acted as a reasonable short term market signal to generators to make plant available and suggest that setting disappearance ratios to an arbitrary fixed level could act to blunt this mechanism.

To be clear – the current Pool appeal does not propose the abolition of the capacity payments mechanism which some of your arguments appear to suggest. Instead it proposes the inclusion of demand reduction blocks into the LOLP calculation and changing disappearance ratios to a fixed level to capture plant disappearance from the highest level seen over the previous week (XMAX). I am not clear how including demand reduction blocks into the LOLP calculation and changing the current combination of fixed and live disappearance ratios to a single figure, using the methodology outlined above, will compromise security of supply.

In order to clarify your assertion that, in upholding the appeal, Ofgem may compromise security of supply it would be helpful if NGC provides Ofgem with the analysis it has undertaken in reaching this decision. Your analysis should include an assessment of the impact on the LOLP calculation of both; including the demand reduction blocks into the LOLP calculation at the disappearance ratios outlined in the appeal (13.5 per cent for summer and 7.5 per cent for winter), and; fixing the disappearance ratios of all plant at the levels outlined in the appeal.

It would also be helpful if NGC provides Ofgem with the rationale underpinning its assertion that the disappearance ratios outlined in the appeal are arbitrary. In your response you should include an assessment of why the proposed disappearance ratios are potentially more arbitrary than the current system of fixed and live disappearance ratios, when the current fixed disappearance ratios are based on pre vesting plant performance.

In order to assist Ofgem in its decision making process your response should reach our office by no later than 5p.m. on 5 December.

If you have any queries regarding this letter, please do not hesitate to contact me on the number above, or on my mobile (0777 161 2087).

Yours sincerely

Lisa Woolhouse
Head, Wholesale Market Operations

5 December 2000

MD/NGCC/MR/RJB

Lisa Woolhouse
Head, Wholesale Market Operations
Competition and Trading Arrangements
Office of Gas and Electricity Markets
9 Millbank
London SW1P 3GE

Dear Lisa

APPEAL TO DISAPPEARANCE RATIOS RESOLUTION

Thank you for your letter of 28th November in which you outlined some concerns with the contents of my 23rd November letter. I have attempted in this note to respond to your questions and provide further clarification on the points that you raised.

First of all, my letter was written to re-iterate a number of observations that we have made when comments have been sought previously on potential changes to the process for deriving capacity payments in the Pool. Whilst we are unable to predict the potential response of the generating companies to any change to the market rules, it is important that market signals are maintained to encourage generators to make capacity available to meet demand at all times, especially when plant margins are tight.

The proposal to the Pool Members Meeting comprised two main elements, namely a suggestion to fix disappearance ratios and the inclusion of demand side bidders (DSB) in the LOLP calculation. Looking at this proposal in more detail:

- on a typical winter day with say 58 GW of modelled plant availability (Xmax), using a disappearance ratio of 13.6% would result in some 50GW of generation being modelled in the LOLP calculation process;

- the inclusion of 1GW of DSB and applying a disappearance ratio of 7.5% (the figure proposed by Scottish and Southern Energy) across all capacity in the model would suggest a modelled availability of 54.5 GW, an increase of some 4.5GW;

- in previous analysis that we have shared with you, we found that increasing the margin in the LOLP calculation by 1000 MW reduced capacity payments by a factor of about 3;

- in this scenario, a 4.5GW increase in the margin is likely to reduce LOLP by 95%; and

- similarly, whilst the effect is likely to be less in summer, increased margins in excess of 2 GW can be anticipated in the model.

This approximate analysis would suggest that the proposed Pool resolution is likely to reduce the level of capacity payments excessively. (A more robust analysis would require ESIS, as administrators of the LOLP algorithms, to undertake a detailed assessment of the proposed changes.)

Looking specifically at the inclusion of DSB in the calculation of LOLP it should be noted that, whilst they do currently receive capacity payments, they are not subject to central despatch; they only contribute to system balancing if called to do so in the unconstrained schedule. As a result, their inclusion in the LOLP calculation, whilst putting downward pressure on capacity payments, would not necessarily provide corresponding capacity that we could call upon when balancing the system. We would therefore recommend that more detailed analysis be undertaken to understand fully the impact of this modification before any decision to include DSB is taken.

It is worth noting that since generation plant returned to service following the summer outage period, capacity payments have diminished significantly and are now at typical levels for this time of the year. However, recognising the potential attraction of fixing disappearance ratios to remove some the volatility observed over recent months, careful consideration needs to be given to the specification of the fixed value in order to ensure that market signals are maintained. Current generator disappearance ratios, whilst comprising a mix of fixed and calculated figures, do relate in some way to either recent or previous performance of the generator in question. The fixed values proposed appear to remove this link and, as illustrated by our analysis above, will effectively eliminate the market mechanism that encourages plant to be made available when margins are tight.

I have attached analysis of historical disappearance ratios and "real" disappearance ratios (i.e. calculated for all plant using the same basis 1-XP/XMAX). It is interesting to note that the "real" disappearance ratios are actually higher at 14.6% (winter) than the average historical disappearance ratio for the winter period, which is 13.6%. This value is somewhat higher than the "peak only" figure of 7.5% proposed to Pool members. We would caution against the introduction of a "peak demand" disappearance ratio since:

i) the capacity payment mechanism currently acts across all day types and all periods of the day; it can provide additional incentives for plant to be available at weekends and overnight where, particularly at this time of the year, we can encounter significant demand increases combining with the withdrawal of plant for ad-hoc maintenance or as a result of gas arbitrage; and

ii) we have not been able to replicate the 7.5% figure using the data that we have access to (although we suspect that it may consider only the peak half-hour for each weekday).

Our analysis suggests that the adoption of fixed values based on average historic disappearance ratios (13.5% winter, 15% summer) would remove some of the LOLP volatility observed whilst maintaining an effective market signal at times when plant margins are tight. However, to minimise any risks that may be associated with an uncertain outcome (e.g. in terms of generator reaction) from modifying the current process for calculating LOLP, we would prefer the introduction of any changes to wait until the beginning of February 2001, after the winter peak period has passed.

Finally, I would like to reiterate the final observation in my previous letter, which cautioned against the diversion of key industry resource to investigate modifications to the GOAL program. Such activity would inevitably divert effort that is focussed on delivering the systems required to facilitate the new market arrangements.

I hope that this additional information is helpful. However, please do not hesitate to contact me if you require anything further.

I have copied this letter to Eileen Marshall and Mark Fairbairn in recognition of their recent discussion on the subject of disappearance ratios.

Yours sincerely,

Jeff Scott

cc	Eileen Marshall
	Mark Fairbairn

Attachment – Analysis of Historical Disappearance Ratios

Outline of Method

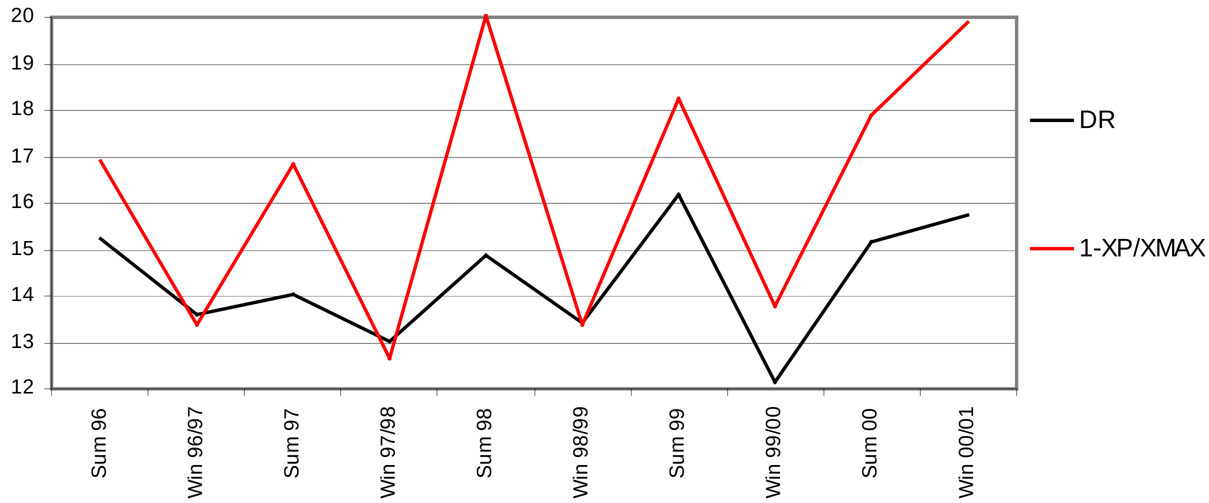
The purpose of the analysis was two-fold:

- obtain a historical profile of average disappearance ratios; and
- provide a method for assessing realistic levels for actual average disappearance ratios.

Live DRs are calculated from the difference between daily proven availability XP and XMAX over some period in the past.[17] In order to provide an indication of what the average DR would have been if all disappearance ratios were based on 'live' performance (rather than the fixed DRs for pre-vesting plant), a monthly analysis has been carried out comparing the total XP and XMAX.

Results

The analysis was carried out using daily data covering the period 1/4/96 to 20/11/00. The Figure below shows results of the analysis, where the monthly results have been



[17] For newly commissioned plant, the calculation is carried out monthly based on the previous month's performance. After 2 years, the Disappearance Ratio is calculated for each standard season (Mar-May, Jun-Aug, Sep-Oct, Nov-Feb) based on the previous standard season's performance. After 4 years, the DR in each standard season is based on the performance in the previous two same seasons (e.g. DR for Jun-Aug 00 is calculated from periods Jun-Aug99 and Jun-Aug98).

averaged for both summer (Oct-Mar) and winter (Apr-Sep). Summary results are shown in the Table.

	Historic average DR (%)	1-XP/XMAX (% - all day)
Summer	**15.1**	18.0
Winter	**13.6**	14.6
Annual average	**14.3**	16.3

The following observations can be made:

- If all DRs were to be 'live', then this will result in a higher average DR. This is consistent with earlier analysis which showed that post-vesting plant (with 'live' DRs) had DRs some 3.5% higher than pre-vesting plant (with fixed DRs). The diminishing fraction of vesting plant may explain the long-term trend of rising LOLP.

- The indicator 1-XP/XMAX shows greater variation between summer and winter than the historical DRs. This could be due to the following factors:
  - DRs for plant less than 4 years old are based on the preceding month / standard season.
  - The four standard seasons used in the DR calculation do not align with the definitions for summer and winter.

Previous analysis showed that an increase of 1000GW in XMAXmean causes the capacity payments to reduce by a factor of about 3. Given that the average level of XMAXtotal in winter is about 58GW, the reduction of average DR by a percentage point would cause capacity payments to reduce by a factor of about 2.

Way forward

If the decision was taken to fix disappearance ratios at the same value for all plant then, based on this analysis and to preserve the availability incentive provided by capacity payments, it would seem appropriate to set the fixed DR at about 13.5% for winter and 15% for summer. This should maintain a proportion of the current level of incentive, but remove some of the volatility that is encountered between months.

7 December 2000

Jeff Scott
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Dear Jeff

POOL APPEAL

Many thanks for your response of 5 December to Lisa Woolhouse's letter regarding the appeal of disappearance ratios. While helpful, your response has raised a number of further issues on which I am seeking clarification. Given the obvious importance of NGC's views on the potential impact of changes to the capacity payment mechanism to security of supply I will need NGC to substantiate a number of the points raised in its response (backed by suitable analysis). As any Ofgem decision could have a significant impact on a number of market participants any response will also need to be placed in the public domain. Given the importance of the issue we will need a prompt response.

In your letter, you caution against the use of a fixed disappearance ratio of 7.5 per cent for the winter, suggesting that fixing disappearance ratios at this level will remove the link from plant performance and eliminate the market mechanism that encourages plant to be available when margins are tight. I am not clear to what extent fixing disappearance ratios at 7.5 per cent will eliminate the capacity mechanism – the mechanism will remain in place, however the capacity margin which triggers capacity payments will fall. We need NGC to provide us with its detailed assessment of the actual capacity margin (in MW) which would need to be reached before the LOLP calculation provides positive values using disappearance ratios of 7.5 per cent and the 13.5 per cent you suggest.

Please can you also provide NGC's assessment of the level of capacity margin (in MW) it would consider adequate to maintain security of supply for an average winter half-hourly demand and a winter peak. Please can you also provide your assessment of the level of capacity margin required across a range of demand profiles typically seen across the winter and spring.

In addition, please supply us with a detailed breakdown of the volume of reserve held under contract by NGC over the anticipated remaining life of the Pool. Please can you also explain the form of the reserve contracts held and indicate those volumes of reserve held by NGC that under the particular contract form would be bid in as available under the Pool and those volumes that would not be bid in but could be called by NGC at sufficient notice to meet its energy balancing requirements in the event that the capacity margin was tight.

Finally, Ofgem would also appreciate a more detailed explanation of NGC's assertion that, in the absence of capacity payments, some generators who previously relied upon availability payments rather than energy payments for income, will disappear from the system. There are a number of electricity systems that operate around the world on the basis of similar rules without the equivalent of a capacity mechanism. Under the proposal, even if capacity levels were very low or zero when the margin was low, it is not necessarily the case that generators would be unavailable to generate at short notice. A generator could, for example, bid in a relatively high price at the day-ahead stage. If that generator was not scheduled in the day-ahead schedule but saw that the margin was tight it might remain synchronised and ready to generate. If called by NGC on the day, it would be deemed to be constrained on under the current rules and would receive its bid price when generating. A generator would therefore be able to command a higher price under the current rules even in the absence of capacity rules.

Given the importance of this issue please can you provide your response by 9.00 am on Monday 11 December by fax (020 7901 7379) and by email. If you have any questions or queries about the information requested in this letter then please do not hesitate to contact me on the number above or Sonia Brown (020 7901 7412).

Yours sincerely

Steve Smith
Director, Trading Arrangements

cc Richard Ball, NGC
Mark Fairbairn, NGC

11 December 2000
MD/NGCC/MR/RJB

Steve Smith
Director, Trading Arrangements
Office of Gas and Electricity Markets
9 Millbank
London SW1P 3GE

Dear Steve

APPEAL OF DISAPPEARANCE RATIOS RESOLUTION

Thank you for your letter of 7th December. In order to provide a prompt response, we have used predominantly prior analysis reviewed and revised to address your specific questions.

Effect of disappearance ratios on plant margins

You sought our views on the impact of using a fixed disappearance ratio of 7.5% and the extent to which it would eliminate capacity payments. As indicated in our previous letter, based on an average XMAX for the winter period of 58GW, a reduction from the current average disappearance ratio of 13.5% to a fixed value of 7.5% would result in an increase to the modelled availability, and thus margin, of about 3.5GW. In previous analysis shared with you, we found that increasing the margin in the LOLP calculation by 1000 MW would reduce capacity payments by a factor of about 3. In this scenario, a 3.5GW increase to the margin is likely to reduce LOLP by a factor of about 25-30, a significant reduction over previous levels.

I have attached the results of our analysis illustrating the relationship between day ahead operational plant margins and capacity payments and between (Xmaxmean-TGSD#) and capacity payments. As a result of the 8-day rule, we can see that there is not a straightforward relationship between day-ahead operational margins and the level of capacity payments. It is therefore not possible to identify an absolute point at which LOLP payments start to provide a short-term availability incentive. However, it is possible to make some conclusions based on average behaviour. As illustrated in the attachment, the same level of capacity payments as in the 13.5% case would only be reached with a 7.5% ratio if the day ahead margin is eroded by an extra 4GW. Given that over the forthcoming winter period we expect to have around 3GW of commissioning generation, a day-ahead margin of the order of 10.5GW is required to meet our requirements (this is explained later in the text). Referring to figure 2 in the attachment, our analysis suggests that, at this margin level, the adoption of a 7.5% disappearance ratio in place of a 13.5% ratio is likely to result in capacity payments of the order of 0 to £3/MWhr as opposed to £10 to £100/MWhr. A much weakened signal.

Margin requirements

With regard to the level of capacity required for NGC to maintain security of supply, we need sufficient margin to enable us to manage the uncertainty associated with maintaining an energy balance from day ahead through to real time and to meet our requirement to provide Ancillary Services. That is, in addition to meeting forecast demand we need to ensure that we have sufficient additional capacity available to cope with unexpected events, such as day-ahead to real-time plant loss, demand forecast error and short-term plant loss. We also require additional capacity to cope with less unexpected events, such as the unreliability of commissioning plant.

The levels of reserve that we hold are adjusted as we approach real time to reflect the increasing certainty of generation and demand levels. Reserve is categorised into various components to reflect this:

- Contingency Reserve is generation that could be synchronised and achieve full output by the next demand peak;

- Regulating Reserve is required to cover short-term generation and demand variations;

- Standing Reserve is plant in a state that can be called upon to meet short term plant shortages, and

- Response (De-load) is that required to enable us to manage system frequency.

The levels of contingency we require, and the level of regulating reserve, standing reserve and response, vary seasonally. The level of additional capacity required to offset the short-term loss of commissioning plant is, of course, dependent on the level of commissioning plant at the time. Typical day ahead additional peak capacity requirements are summarised in the following table:

	GMT	**BST**
Contingency Reserve	3200 MW	3300 MW
Regulating Reserve	1000 MW	650 MW
Standing Reserve	1820 MW	1800 MW
Response Deload	1600 MW	1500 MW
Total:	**7620 MW**	**7250 MW**
Commissioning Plant Cover	0 to 4500 MW	0 to 4500 MW

The above table demonstrates that a winter margin level of between 7.62 and 12GW of plant is required to enable us to maintain security of supply (average around 10.5GW allowing for 3GW of commissioning plant, as indicated above). Virtually all of this plant requirement is in addition to that purchased in the Unconstrained Schedule. Moreover, a significant proportion of plant purchased for contingency reserve and most of the plant capable of providing standing reserve services is of the low-merit fossil fuel or open cycle gas turbine variety. It is this plant that is most likely to be sensitive to reductions in capacity payments.

Contracted reserve

Turning to our contracted reserve; we are holding some 1820MW of standing reserve under contract for winter 2000/01. However, consideration of previous availability and historic performance would suggest that this equates to an effective availability of around 1400 MW, comprising 1110MW of centrally despatched generation and 290MW of non-centrally despatched generation or demand reduction. Of the total contracted volume of 1820MW, 1690MW has a maximum duration of use of less than 5 hours.

The contract form for centrally despatched standing reserve involves National Grid paying an option fee in return for the service provider bidding capacity into the Pool throughout standing reserve windows, which cover 12 hours of peaks of each day, and with a notice to synchronise of less than 20 minutes. In addition, the Pool bid price is hedged by the tendered price for all MWh of reserve exercised. In terms of the interaction between this contract form and the Pool Capacity mechanism, the standing reserve contracts serve to increase the incentive on plant to bid availability into the Pool, thus contributing towards increasing the plant margin and reducing capacity payments.

The contract form for non-centrally despatched standing reserve differs slightly. Service providers receive an option fee in return for making daily declarations to National Grid of MW available for demand reduction at less than 20 minutes notice, and for accepting our monitoring and call-off equipment on their site. They also receive a contract payment for MWh utilised when called. Since these contracts are used to cover short-term plant shortages, they include a maximum period for which we can call on the contracted services. Of the non-centrally despatched reserve, 220 MW is only available for period of up to 5 hours and would therefore not assist replacing sustained plant losses.

Apart from standing reserve, the majority of reserve held is not contracted for availability. Payments are made via Ancillary Service contracts for the utilisation of frequency response, however these contracts do not contain availability obligations.

General observations

I was surprised by your penultimate paragraph since I do not believe you will find any assertion in two previous letters that, in the absence of capacity payments, some generators who previously relied upon availability payments rather than energy payments for income, will disappear from the system. I have stated that the decision not to include a capacity mechanism as part of the New Electricity Trading Arrangements (NETA) was taken only after considering all of the factors influencing the collective security of supply framework, including the opportunity for more cost reflective pricing closer to real-time. I have, therefore questioned the rationale of making changes to just one element of the current rules in isolation ahead of, and so close to, the introduction of NETA.

My position is simply that I consider it difficult to predict the response of generators to the potential effects of modifying the capacity payment mechanism this winter. Given freedom of choice, therefore, I would not invoke substantial changes and certainly not before the end of January 2001.

It is worth noting in your example that, whilst a generator could bid a high price at the day-ahead stage and be ‘constrained on’ at short notice, it would require a significant volume of running to achieve an equivalent level of income to that received from capacity payments.

I hope that this information is sufficient to enable Ofgem to reach a conclusion on the appeal by British Gas Trading, recognising that you will be taking a number of wider considerations into account. I am quite happy for you to place my response in the public domain. Should you do so, for completeness I believe that it would be appropriate to publish my two previous letters also.

If you require anything further please do not hesitate to contact me.

Yours sincerely,

Jeff Scott

Attachment – Analysis of dependence of capacity payments on Disappearance Ratio levels.

This analysis is based on the peak demand periods for all winter days (Oct-Mar) from Oct 1996 to November 2000 (considering only periods with capacity payments greater than £1/MWh). The analysis is based on data for XMAX and TGSD# as well as a regression fit for the relationship between (XMAXmean-TGSD#) and capacity payments (see Figure 1). Analysis was carried out to provide an indication of what capacity payments would have been if fixed disappearance ratios of 13.5% and 7.5% respectively would have been employed. The results are shown as a function of Day Ahead margin in Figure 2.

The following observations can be made:

1) There is no clear link between day ahead margin and capacity payments, apart from the fact that the maximum possible capacity payment reduces as the day ahead margin increases. This can be understood by considering the relationship between Day Ahead Availability and XMAX (Figure 3). Day Ahead availability may be close to XMAX at times, but could be substantially lower due to the 8 day rule for XMAX, for example if a significant level of plant has become unavailable during the preceding week.

2) From the regression relationship of Figure 1 (and hence from Figure 2), it appears that a reduction of 1GW in XMAXmean causes LOLP to decrease by a factor of about 2.6. A reduction of 3.5GW (6% of a typical winter XMAX of 58GW) would cause LOLP to reduce by a factor of about 25-30.

3) Regression analysis on the relationship between Day Ahead Margin and LOLP of figure 2 (bearing in mind that this must be done with great caution due to observation 1) shows that a reduction in Disappearance ratios from 13.5% to 7.5% will result in the same level of capacity payments only being achieved if the day ahead margin is eroded further by some 4GW **on average**.

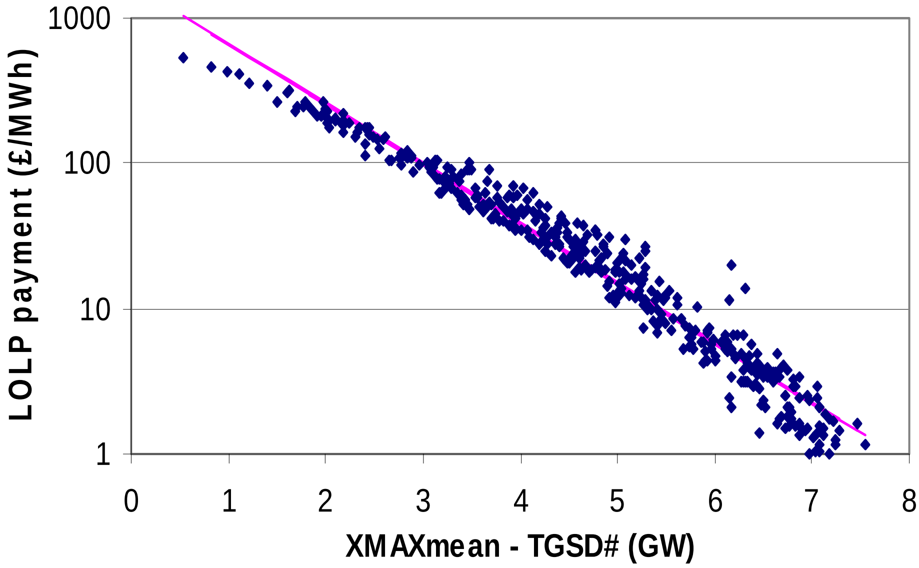

Figure 1 Regression Analysis for deriving LOLP payments from historical XMAXmean margin

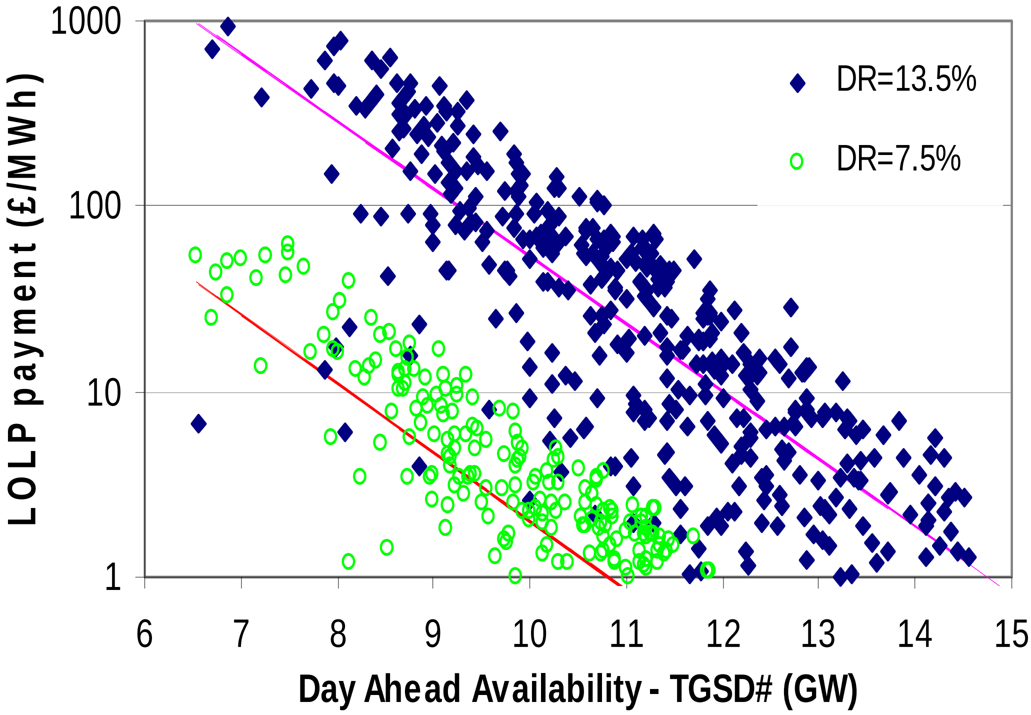

Figure 2 Dependence of capacity payments on Day Ahead Margin

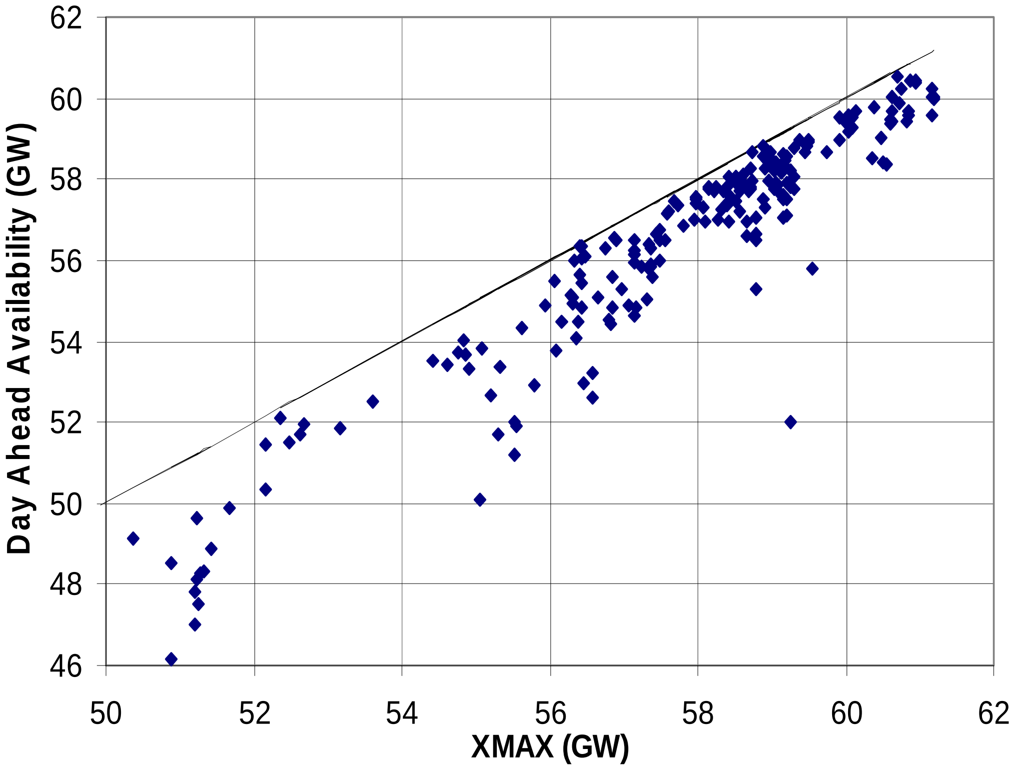

Figure 3 Relationship between XMAXtotal and Day Ahead Availability

14 December 2000

Jeff Scott
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STRICTLY CONFIDENTIAL AND MARKET SENSITIVE

Dear Jeff

POOL APPEAL

Many thanks for your response of 11 December to my letter regarding the current Pool Appeal. Given your reply, our discussions this week and further consideration by Ofgem, we have a number of additional questions to which we require a response from NGC. Again, given the importance of the issue we will need a prompt response.

In your letter you suggest that NGC will require a winter plant margin of some 7.62 to 12 GW in order to maintain security of supply. You also suggest that a large proportion of this requirement will be low merit fossil fuel or open cycle gas turbine which, you argue, is most likely to be sensitive to reductions in capacity payments. You also state that NGC currently has an 'effective' contracted reserve of 1.4 GW.

In your letter, you also acknowledged that the effect of a zero capacity payment on plant availability was uncertain on the basis of experience to date. On this basis you cautioned against upholding the appeal because of the uncertain effects on plant availability and security of supply as a consequence. In the absence of any analysis to determine the potential impact of a reduction in capacity payments on availability we need to be certain that leaving the current capacity payment mechanism in place represents an efficient means of meeting your concerns about maintaining security of supply. Clearly there is a plausible argument that in the absence of capacity payments generators will continue to make plant available at the day ahead stage. Given the limited cost savings they could realise through declaring themselves unavailable they may declare themselves available because of the positive option value this retains if constrained on during the day. However, as we both accept, there is limited evidence to conclude that this would be the case.

Given NGC's assessment of its requirements and the concerns it has expressed to Ofgem over the potential impact on the plant margin should Ofgem uphold the Pool appeal on disappearance ratios, Ofgem would like NGC to provide it with an assessment of the cost of obtaining an additional 10.5 GW of reserve capacity under contract rather than through the capacity payment mechanism. You should provide a breakdown of how you obtained your estimate, with reference to the prices tendered for reserve in 2000/01 under the existing trading arrangements. We need to be reassured that security of supply could not be maintained more efficiently by holding direct reserve contracts for a defined volume of plant rather than by rewarding all available plant through capacity payments.

We would also like you to provide us with an assessment of winter capacity payments (in both £/MWh and £m given assumed plant availability) in the absence of Ofgem upholding the appeal. We also accept that any effective reduction in capacity payments may lead to changes in bidding behaviour and SMP as a result. This could potentially effect NGC's TSS incentive schemes, although in setting the schemes NGC maintained that the level of SMP was not a key driver of the level of uplift costs. Any estimates of the relative costs should therefore be made on a stand-alone basis and without prejudice to the potential impact on NGC's existing incentive schemes. This would be a matter for separate discussion, if necessary, although clearly the operation of the income adjusting event mechanism should provide you with comfort on this issue.

In your letter to me of 5 December you make a number of observations which caution against the inclusion of demand side bidders into the LOLP calculation. You suggest that more detailed analysis should be undertaken to fully understand the impact of including demand side bidders into LOLP before any decision is taken to do so. Please will you provide Ofgem with your assessment and analysis of the impact of including demand side bidders into LOLP. This should include an assessment of the relevant disappearance ratio which NGC considers should be applied to the demand side bidders and an assessment of whether the 7.5 per cent disappearance ratio forwarded in the appeal is appropriate.

Given the importance of the issue, please will you ensure that your response reaches Ofgem by 10 a.m. on Monday 18 December by fax (020 7901 7379) and e-mail. If you have any questions about this letter please do not hesitate to contact me on the usual number or Lisa Woolhouse (0777 161 2087).

Yours sincerely

Steve Smith
Director, Trading Arrangements

18 December 2000
MD/NGCC/MR/RJB

Steve Smith
Director, Trading Arrangements
Office of Gas and Electricity Markets
9 Millbank
London SW1P 3GE

Dear Steve

POOL APPEAL

Thank you for your letter of 14th December in which you posed a number of additional questions arising from the information I have provided in previous letters and the recent discussions that we have had. I have attempted in this note to respond to your questions and provide further clarification on the points you have raised. The analysis provided reflects the prompt nature of the requested response.

Cost of contracting for additional reserve capacity

You asked us to consider the cost of contracting for an additional 10.5 GW of capacity as an alternative to all available plant receiving capacity payments. There are a number of issues I would like to highlight in relation to this conceptual approach:

a) Under the current industry structure, National Grid does not have a role in ensuring that there is sufficient generation capacity on the system. It is the role of the market mechanism to ensure that there is sufficient capacity, both in the Pool and in the future under NETA. Our reserve contracts have always been based on ensuring that, from the total capacity provided by the market, sufficient generation and demand options are available to provide flexible response in short timescales. I feel that National Grid contracting for 10.5GW of reserve as an alternative to capacity payments would put us in the position of underwriting a significant proportion of the generating capacity for the energy market, and could appear to be returning towards central planning of the industry.

b) Substantially removing the availability signal provided by capacity payments would remove the availability incentive on non-contracted plant. Therefore, there would be a reduced signal for in-merit plant, which could lead to an increased likelihood of such plant re-declaring their availability down (e.g. when SMP is low and/or in the event of gas arbitrage opportunities). Therefore, in the absence of an effective availability signal, even contracting for 10.5 GW may not be sufficient to maintain plant margins. The key point here is that contracting for reserve capacity is not equivalent to providing an effective availability signal to all generating capacity.

c) The 10.5GW of required reserve consists of a mix of different types of reserve. Currently, scheduled reserve (which covers regulating reserve and the required response deload) and contingency reserve are generally provided by the "next in merit" plant which can be scheduled and despatched under the Pool mechanisms. Contracting for the availability of this plant in an economic manner would require the development of new contract forms for the required services, tender processes to be arranged and/or bilateral contracts to be negotiated. It would take some 2 to 3 months to establish the capability contractually if we were to do so without compromising our obligations in relation to economic purchasing and non-discrimination.

Notwithstanding these observations, we have attempted to answer your specific question. As noted above, it is difficult to assess the cost/price of contracts for plant availability to provide scheduled and contingency reserve given that these contract forms do not exist at present. The only information available is that from the Standing Reserve tender for 2000/1.

The contract prices for Standing Reserve for 2000/1 (under the Pool) averaged around £10/kW, with a range from £20/kW for high utilisation providers to £5/kW for low utilisation providers. Given that scheduled and contingency reserve are generally higher utilisation services than standing reserve, a price towards the higher end of the range might be viewed as potentially applicable to the additional 9 GW of reserve (10.5 GW minus the 1.5 GW already contracted).

Winter capacity payments

You asked for our view on winter capacity payments in the event that Ofgem did not uphold the appeal. As mentioned in my previous letter, current levels of LOLP are now below average for this time of year as a result of a significant amount of plant having returned from outage. Looking forward, you will appreciate that any forecasts of capacity prices are subject to considerable uncertainty arising from market conditions and the exponential nature of the capacity mechanism. Indeed, the potential range of outcomes is illustrated by comparing the figures for the previous two winters (1998/99 and 1999/2000), our understanding of which is included in the attachment to this letter.

As indicated earlier, capacity payments provide an availability signal to all generation plant, rather than just to the 10.5 GW of plant you might consider we could contract for. It is therefore inappropriate to compare directly the indicative cost of contracting for the availability of additional reserve capacity with any view of potential total capacity payments. Arguably the level of Unscheduled Availability payments would be a more appropriate comparison to the estimated contract costs since it is the plant receiving unscheduled availability payments that provides the margin above the unconstrained schedule.

Demand Side Bidders (DSBs)

We know that, for generators, capacity payments provide an incentive to maintain plant availability in periods when plant margins are tight. Generation can also be called upon in short timescales to maintain security over periods when operational margins are tight, even if they are not selected to generate in the unconstrained schedule. In contrast, whilst DSBs do receive capacity payments, they are not subject to central despatch and current rules only require them to contribute to system balancing if called to do so in the unconstrained schedule.

As a result, including DSBs in the LOLP calculation, whilst putting downward pressure on capacity payments, would not provide corresponding capacity that we could call upon to balance the system. Nevertheless, under the current rules, it would appear reasonable to include the quantity of demand reduction actually called in the unconstrained schedule in the final LOLP runs since, under these circumstances, the relevant DSBs would have contributed towards reducing actual observed demands.

Including all DSBs in the LOLP process would imply that the demand side should make available to us the same short-term balancing services as for generating capacity. This would require the establishment of effective communication channels to despatch DSBs at times of system stress, and their output would need to be metered to a resolution compatible with the second to second despatch of the power system. The appropriate disappearance ratio to use for DSBs in such circumstances would vary from customer to customer, reflecting the characteristics of the particular processes undertaken by each DSB.

Turning to the potential impact of the demand side on LOLP payments. Typically we have an average of about 750 MW of DSBs participating over the winter peak period (out of a potential maximum of around 1GW). In previous analysis shared with you, we found that increasing the margin in the LOLP calculation by 1000 MW would reduce capacity payments by a factor of about 3. Taking the average of 750 MW, our assessment is that including DSBs in the LOLP calculation is likely to reduce capacity payments by 50% (i.e. by half).

I hope that this information is sufficient to enable Ofgem to reach a conclusion on the appeal. I feel that our ability to provide further analysis that would contribute significantly to the debate is limited.

Yours sincerely,

Jeff Scott

Attachment

Historic Winter Capacity Payments

	Average Capacity Price (£/MWh)	Total Capacity Payments (£/kW)	Unscheduled Availability payments (£M)	Total Capacity payments (£M)
Oct 98	0.4	0.3	4	16
Nov 98	2.6	1.9	21	108
Dec 98	1.5	1.1	13	65
Jan 99	0.9	0.7	9	39
Feb 99	0.2	0.1	2	8
Mar 99	0.1	0.1	1	4
Oct 99	0.9	0.7	8	33
Nov 99	2.3	1.7	16	92
Dec 99	2.2	1.7	16	94
Jan 00	6.6	4.9	43	269
Feb 00	1.0	0.7	7	38
Mar 00	0.4	0.3	3	16

9 January 2001
MD/NGCC/MR/RJB

Sonia Brown
Head of Market Surveillance
Office of Gas and Electricity Markets
9 Millbank
London SW1P 3GE

Dear Sonia

POOL APPEAL - NGC DEMAND FORECASTING

Thank you for your fax of 8th January to Jeff Scott in which you seek clarification of our treatment of notified and unnotified demand reductions in the demand forecasts used in the determination of LOLP.

First of all, it is worth noting in considering the PowerGen response, that the current Pool Appeal proposed only the inclusion of demand side bidders (DSBs) in the LOLP calculation process and not other notified/unnotified demand reductions associated with Triad avoidance or commercial demand management.

Secondly, our demand forecasting processes are based on complex analysis of both historic demand patterns and forecast conditions. When processing historic demand data we will account for all demand reductions that are notified to us, although we are unable verify and therefore account for the impact of unnotified demand reductions. Thus our demand forecasts are independent of the impact of both historic demand side bidding and those offered (or called) at the day-ahead stage. I can therefore confirm that should you agree to include DSBs in the LOLP calculation process that there would be no double accounting as a result of our demand forecasting processes.

Nevertheless, as noted in Jeff Scott's letter of 18th December, DSBs are not subject to central despatch and current rules only require them to contribute to system balancing if called to do so in the unconstrained schedule. As a result, including all offered DSBs in the LOLP calculation, whilst putting downward pressure on capacity payments, would not necessarily provide corresponding capacity that we could call upon to balance the system. Thus, under the current rules, it would appear reasonable to include only the impact of those DSBs that were called by the unconstrained schedule in the final LOLP runs since, under these circumstances, they would have contributed towards reducing actual observed demands.

I hope that this information is helpful, if you require anything further please do not hesitate to contact me.

Yours sincerely

Mike Calviou

18 January 2001

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STRICTLY CONFIDENTIAL AND MARKET SENSITIVE

Dear Jeff

Pool Appeal

[Text removed]

…. we have asked you to carry out some further analysis and also answer two simple questions in writing so that we can report your views accurately in the document. You will be pleased to hear that we believe that this analysis and your answers will enable us to take a considered decision on the Appeal.

Therefore, further to Sonia Brown's conversation with Richard Ball earlier today I would be grateful if you could provide a response to the following questions:

1. What is NGC's assessment of the balance of probability that if the basis for calculating capacity payments are changed:

(a) as outlined in Resolution 1;
(b) as outlined in Resolution 2; and
(c) as both 1 & 2;

it will have a material adverse effect on the system security if the changes are implemented prior to 1 February 2000?

2. What is NGC's assessment of the balance of probability that if the basis for calculating capacity payments are changed:

(d) as outlined in Resolution 1;

(e) as outlined in Resolution 2; and

(f) as both 1 & 2;

it will have a material adverse effect on the system security if the changes are implemented after 1 February 2000?

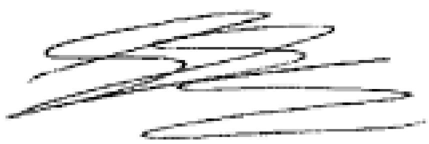
In addition, we would also like you to provide the following analysis for the months of January/February and March 1999 and 2000:

(a) a correlation of capacity payments against the MW of redeclared availability (measured as the difference between the day ahead and end of day availability); and
(b) a correlation of Pool Purchase Payments (PPP) against the MW of redeclared availability (measured as the difference between the day ahead and end of day availability)

Please can you provide a response by 10am on Monday 22 January. Also, as there appears to be a difference in emphasis between different departments within NGC we request that both you and Mark sign the letter.

If you have any questions in relation to this request please do not hesitate to contact me on the above number, alternatively you may contact Sonia Brown on 020 7901 7412

Yours sincerely



Steve Smith

Director, Trading Arrangements

cc: Mark Fairbairn

22 January 2001

MD/RJB/JAS

Steve Smith
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Office of Gas and Electricity Markets
9 Millbank
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Dear Steve

POOL APPEAL

In response to your most recent information request, dated 19th January 2001, the following addresses each of your queries in order:

Impact of Proposed Pool Resolutions

You asked for our assessment of the potential impact of changing the basis for calculating capacity payments as proposed in Resolutions 1 and 2 in relation to the Pool appeal, where our understanding is that:

- Resolution 1 proposed the inclusion of all Demand Side Bidders in the LOLP calculation;
- Resolution 2 proposed fixing disappearance ratios at 13.5% for summer and 7.5% for the winter.

The previous analysis shared with you indicates that both of the Resolutions would have a significant effect on the level of capacity payments arising in the Pool. Resolution 2 has a sufficiently material impact that the result of its application appears little different from the outcome of the two Resolutions applied together.

The following table summarises the results of the analysis that we have presented in previous correspondence by setting out our assessment of the potential reduction in margin modelled in the LOLP calculation, together with the likely proportionate reduction in capacity payments:

	Potential reduction in (XMAXmean – TGSD#) margin modelled in LOLP calculation	Likely proportionate reduction in Capacity Payments
RESOLUTION 1 (inclusion of all Demand Side Bidders)	1000MW	X 0.33
RESOLUTION 2 (fixing of disappearance ratios to 13.5% summer/ 7.5% winter)	3,500 MW	X 0.05
RESOLUTIONS 1 & 2	4,500 MW	X < 0.05

It is the response of generators to any change in the level of capacity payment that will determine whether or not there is any material risk of an adverse effect on security of supply. As I have indicated in previous correspondence, the response of the generators is uncertain and we possess no information that would enable us to make a quantified assessment of their likely reaction to either or both of the Resolutions being implemented. In simple empirical terms the adoption of Resolution 1, by virtue of its lower relative impact on the level of capacity payments, might be considered to be proportionately lower risk than adopting either Resolution 2 or the two Resolutions taken together.

However, as you know, this year we have experienced significant volumes of generator re-declarations that appear to be in response to lower market prices. Assuming that this does represent a linkage between generator availability and the absolute level of Pool prices, it might be anticipated that any market rule change that further reduces Pool payments would result in some reduction in the amount of generation made available to us. It is worth noting that, since October 2000, Notifications of Insufficient System Margin have been in force on 20 days, including 3 High Risk of Demand Reduction notices and 4 notifications issued for off-peak periods. This contrasts with 9 notifications in total for the same period over the winter of 1999/2000.

With regard to the question of pre and post the January peak winter demand period, I presume that your letter intended to refer to 1st February 2001. Traditionally we would expect demand levels in February to be lower than those for January, and therefore the overall risk of there being insufficient capacity available to meet demand would be correspondingly lower.

Correlation Analysis

Turning now to the analysis that you requested. We have plotted on the attached charts the following information:

a) scatter graphs showing capacity payments versus day ahead offered availability minus actual availability for the months of January, February and March 1999 and 2000 (charts 1 and 2); and

b) scatter graphs showing PPPs versus day ahead offered availability minus actual availability for the months of January, February and March 1999 and 2000 (charts 3 and 4).

As previously indicated the relationship between generator availability and capacity payments is complex. However, the graphs do suggest that higher levels of redeclarations do take place at times when capacity payment are at, or close to, zero.

I can assure you that, consistent with my previous correspondence, this letter presents an agreed position on behalf of National Grid. Specifically, our Director of System Operations, Mark Fairbairn, has reviewed it and accords with its content.

Yours sincerely,

Jeff Scott

Chart 1

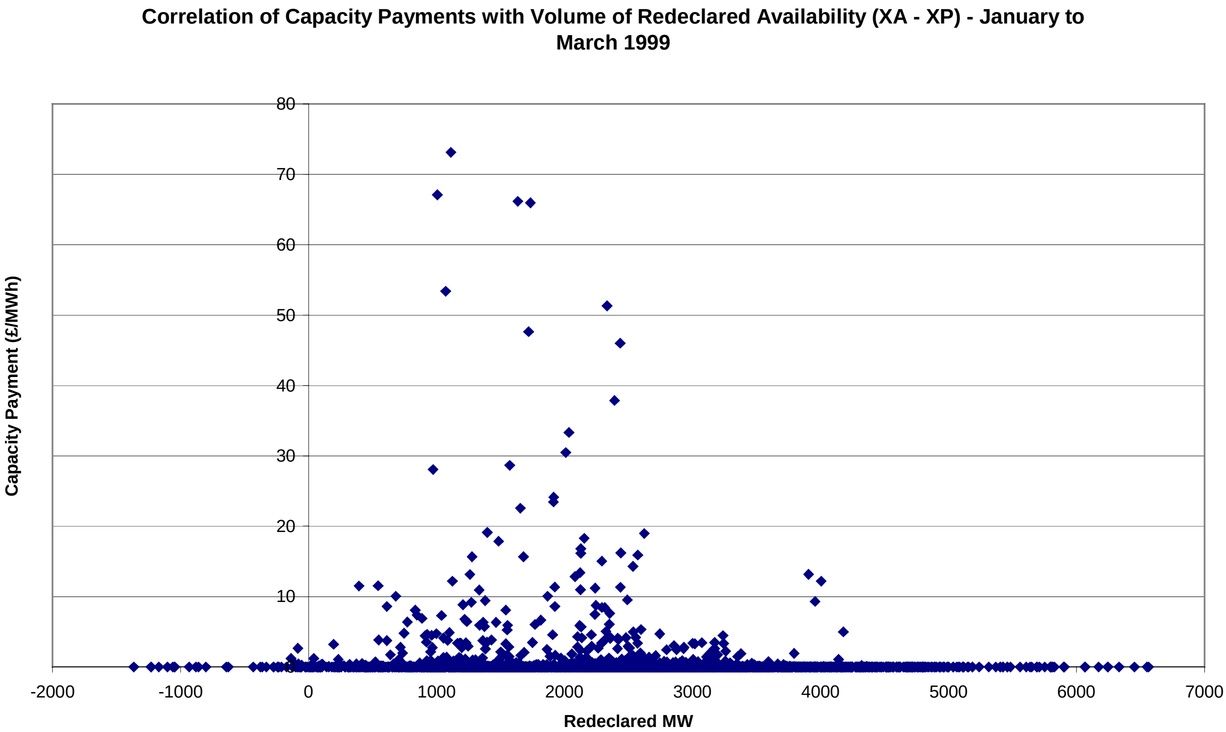

Chart 2

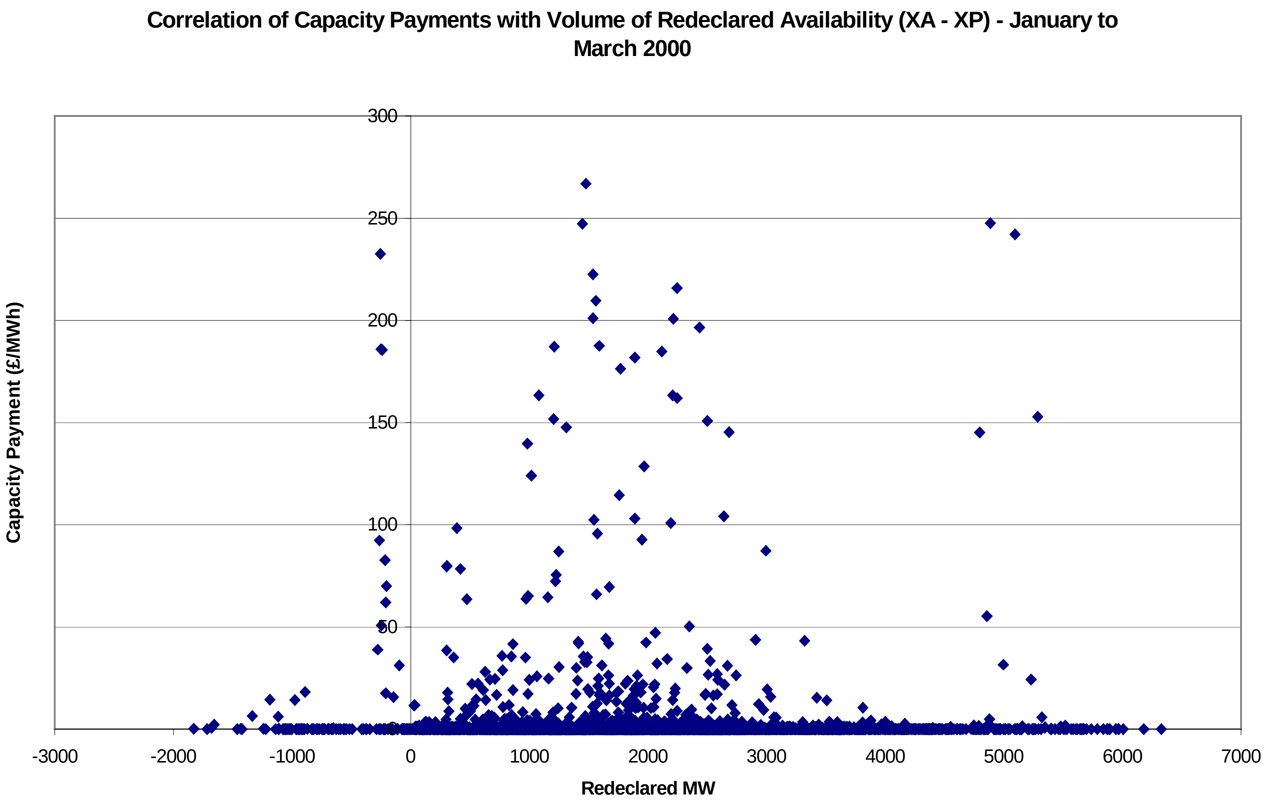

Chart 3

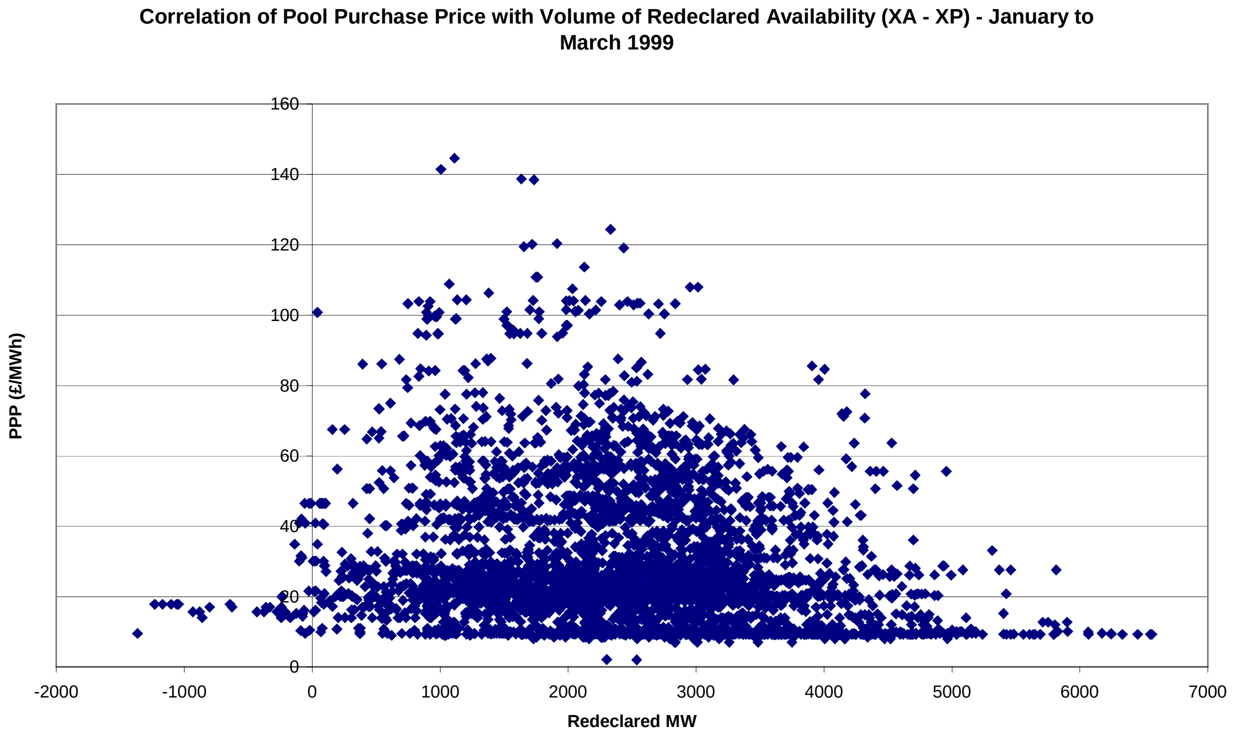

Chart 4