NGC Report on the Second Tender Round for Obligatory and Enhanced Reactive Power Services

EXECUTIVE SUMMARY

- This is the report on the second Reactive Power Market tender round, for contracts to commence on 1st October 1998. This report reiterates much of the equivalent report on the first tender round.

- Tenders were received in respect of 10 gensets at 6 power stations. 3 generating companies tendered, with gas, coal and oil fuel-types represented. 5 tenders were received from gensets which were unsuccessful in the first tender round. Over both tender rounds, NGC has received a total number of 95 tenders for Reactive Power Market contracts, from a total of 154 eligible centrally despatched gensets.

- Assessment of tenders was in accordance with the evaluation criteria specified in Appendix 6 of Schedule 5 of the Master Connection and Use Of System Agreement ("MCUSA Schedule 5"), and was entirely consistent with that used for tender round one.

- The range of assessment outcomes was much narrower in this second tender round, than in the first round; this is shown in Figure 1. This may indicate an encouraging convergence of generator and NGC understanding of contract value within the Reactive market.

- Five tenders have proceeded to contracts with NGC. Four contracts will pertain to the period 1st October 1998 to 30th September 1999, and one tender has been accepted for the period 1st October 1998 to 30th September 2000.

- Over tender rounds one and two, NGC has received nine tenders for Enhanced Reactive Power Services ('ERPS') at three stations; there are as yet no contracts in place.

- Combining contracts from tender rounds one and two, signed Market Agreements now in place for winter 1998/9 now represent some 36% of the eligible lagging capability available.

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DOCUMENT NOTE

The bulk of this report reiterates the Report on the First Tender Round, because the assessment methodology has barely changed. Accordingly, significant changes from the First Report are highlighted by bars | thus in the left hand margin.

INTRODUCTION

i) This Report details the assessment undertaken of Reactive Power Market tenders received by NGC for contracts to commence 1st October 1998. This was the second tender round, since the Reactive Market arrangements commenced on 1st April 1998, and is the first to take place mid-way through a financial year.

ii) The arrangements for provision of either an Obligatory Reactive Power Service or an Enhanced Reactive Power Service were initially explained at a seminar held at the Raven Hotel, Droitwich on 27th September 1997, prior to NGC holding the first tender round. In preparation for the second tender round, NGC conducted bilateral discussions with Users and established a telephone hot-line service, and a workshop was held on the 19th May to detail the outcome of the first Reactive Market tender round, and inform Users on the preparation of tenders.

iii) This report details the cumulative contractual position, following both the first and second tender round for the financial year 1998/9; the second round contracts contribute for the later six months of the year. The next Reactive Market tender day by which time new tenders should be submitted (known as the "Market Day") is 3rd December 1998. The next Market Day pertains to new contracts commencing 1 April 1999, for the third Reactive Power Market tender round. Invitation To Tender packs are available for any eligible provider to submit a tender.

iv) MCUSA Schedule 5 states that the ratio of total default moneys paid out on reactive Capability : Utilisation is intended to decline from 50:50 for year 1998/9 to 25:75 for year 1999/0 (this is known as "the staircase"). This was the central case considered in the assessment. Consideration was given to a sensitivity case, that MCUSA Schedule 5 is varied to retain "50:50" for a further year 1999/0 - this is to be debated by the Transmission Users Group ('TUG') in November 1998.

BACKGROUND

v) Following work undertaken by the Reactive Power Market Working Group (RPMWG), a working group with pan-industry representation, new payment arrangements for reactive power procurement have been agreed. These provide a "safety net" or default payment arrangement for eligible generators, together with opportunities for potentially economic providers of reactive power services, to submit a tender for a reactive market contract (known as a "Market Agreement"). These arrangements are enshrined in a new Schedule 5 to the Master Connection and Use of System Agreement (MCUSA Schedule 5).

vi) The National Grid Company plc (NGC) held the second Reactive Power Market tender day on 10th June 1998. This enabled relevant Users (defined as a person using the NGC Transmission System) providing the minimum Grid Code Obligatory Reactive Power Service (ORPS), to offer alternative payment terms to the default payment arrangements over a contracted period, for the provision of voltage support to the NGC Transmission System in the contracting period commencing 1 October 1998. This alternative market arrangement also presents Users with the

opportunity to tender reactive power capability in excess of that required by the Grid Code obligations - a so-called "Grid Code Plus Enhanced Reactive Power Service". Furthermore an Enhanced Reactive Power Service (ERPS), can be offered by any other eligible service provider, who does not provide an ORPS.

vii) This report describes the tenders received and the subsequent selection process that led to Reactive Market contracts being struck for the contracting period commencing 1st October 1998. These tenders related to ORPS only, with none tendered for ERPS. One tender was for 24 months duration, with the remaining tenders all for a minimum 12 month contract period.

VOLTAGE REQUIREMENTS

viii) NGC manages the voltage of the supergrid system, to meet Transmission Licence requirements for secure and stable power transmission and to ensure quality of supply to customers. Voltages are largely determined by the flows of reactive power on the system. NGC ensures:

a) that reactive power resources are provided on a local basis to meet the constantly varying needs of the system, and

b) that there is sufficient reactive power reserve made available to meet contingencies.

(An introduction to the basis of the need for reactive power to support voltages on the transmission system is given in NGC's Seven Year Statement, Appendix C.6.)

ix) Generating units provide reactive power capability, and the ability to vary their reactive power output, as a requirement of the Grid Code. The power system itself has inherent reactive gains and losses, which vary in accordance with changes in the power flows and voltage. NGC installs reactive compensation plant in parts of the system where there is insufficient generator reactive capability to meet requirements and voltages cannot be regulated effectively or economically by other means. NGC may also contract for generator reactive power capability in excess of that required by the Grid Code, or for other services where economically viable, to help manage the voltage characteristics of the NGC transmission network.

1. Nature of Tenders Received

1.1 For the second Reactive Power Market tender round, tenders were received from 10 gensets at 6 power stations. This represented reduced market involvement from eligible providers than in the first Reactive Power Market tender round. 3 generating companies tendered, and gas, coal, and oil fuel-types were represented. Over both rounds, NGC has received a total number of 95 tenders for Reactive Power Market contracts, from a total of 154 eligible centrally despatched gensets, for services within the financial year 1998/9.

1.2 In the second round, all tenders were in respect of centrally despatched gensets, and none were from non centrally despatched sources. In addition, nine tenders were for the minimum period of 12 months 1st October 1998 to 30th September 1999, and one tender was submitted for a 24 month contract period from 1st October 1998 to 30th September 2000. Five of the tenders submitted were for gensets which had been unsuccessfully tendered in the first Reactive Power Market tender round.

1.3 All tenders ultimately met the stringent rules for data consistency and alignment with Grid Code provisions, as set out in MCUSA Schedule 5. The Grid Code defines technical performance at genset LV terminals at Rated MW. This must be translated for market purposes into the equivalent capability at the HV commercial boundary at Genset Registered Capacity. It was at this stage that one tender, having fulfilled the compliance criterion within its tender for market participation, was evaluated to be infeasible, due to the unusable nature of the HV range of breakpoints submitted.

1.4 Where applicable, all tenders had identical or similar tender data for all gensets at a station; this simplified the assessment process. No tenders were received for the provision of enhanced reactive power services (ERPS) for the second Reactive Power Market tender round.

1.5 Of those tenders received, the majority appeared to be seeking greater remuneration of their reactive power capability. Only one tender appeared to be seeking a similar split of reactive payment moneys between Utilisation and Capability, as provided by the default payment arrangements for 1998/9 and 1999/00; under these provisions of MCUSA Schedule 5, reactive payment moneys overall are currently split within the provisions 50:50 Utilisation: Capability for year 1998/9 and 75:25 Utilisation: Capability for 1999/00.

1.6 Under the default payment arrangements, shortfalls of reactive power capability are subject to payment reductions calculated on a quadratic basis. A few tenders opted for a simpler structure of reactive power capability payments, reflecting a more linear payment rate per Mvar of reactive power available. However, most tenders for this round included a more 'kinked' structure of payment (based around steeper incremental prices at ascending breakpoints), under which the genset loses a greater proportion of money for a small shortfall in reactive power capability.

1.7 All tenders included capability prices for hours available only; no tenderers wished to be paid capability money in part on the basis of hours synchronised also.

2. Assessment Process

2.1 NGC assessed the second Reactive Power Market tender round by the same process as that which applied to the first Reactive Power Market tender round. The Second tender round took place across financial years and across the respective Default Payment Mechanisms and indexation effects, pertinent to those financial years. NGC therefore found it was required to conduct its core analytical processing in six-monthly segments, in order to correctly capture and examine the mid-financial year effects. In the case of tenders submitted for a period of 12 months, this required two tables of data to be utilised. A further two tables were utilised for the single 24 month tender, in order to correctly analyse the second year of contract operation.

2.2 As for the first tender round, NGC divided the process of assessing the reactive power tenders into several stages, which were addressed as follows.

2.3 (i) *Tender Receipt and Registration*: the tenders were opened, in the presence of a separate witness, and all tender data was transcribed onto a suite of pre-formatted tender database tables.

2.4 (ii) *Tender Data validation*: All database entries were then separately checked back to the original tender sheets. Prepared software checks raised a number of minor data queries that were all resolved.

2.5 (iii) *Obligatory Reactive Power Service Assessment*: The tenders were assessed against likely outgoings, taking into account the many interacting factors associated with each tender acceptance decision, as described in MCUSA Schedule 5, Appendix 6 (see Appendix C of this report). This involved, amongst other factors, evaluation against projections of expenditure and availability of service against historic and forecast Mvar and Mvarh data, to produce central views of the moneys payable under the default payment arrangement or under a Market Agreement. Details of this particular element of processing are described in section 3. below. The overall assessment was supported by an examination of many credible sensitivities around the central view, and these are described in section 4. below.

2.6 (iv) *Enhanced Reactive Power Service Assessment*: Had NGC received any ERPS tenders for the second Reactive Power tender round, these would have been conducted on a case-by-case basis, against possible alternatives, such as NGC constraints and investment.

3. Core Analytical Processing

3.1 Tender assessment takes place in the context of uncertainties and interactions of factors affecting reactive uplift payments and transmission requirements. To initiate the assessment of the overall value of each tender, it is necessary to prepare a central view of future payments so that the relative impact of the factors influencing the economic evaluation of tenders can be fully addressed. As six monthly assessments have been performed for this second Reactive Market round, the core comparisons for each six month assessment were combined to give the overall core comparison by genset for each tender period submitted.

3.2 For each genset tendered for 1998/9, the process was as follows:

3a. Firstly, NGC utilised the Zonal Weighting Factor ('ZWF') tariff for 1998/9 and a "central view" of the 'ZWF' tariff for 1999/00 and 2000/01. The ZWF extrapolation used for the 1999/00 and 2000/01 periods was a direct average of previous years, and the results of this method will be published before subsequent tender rounds. In the subsequent overall analysis, these 1999/00 ZWFs were placed with significant uncertainty, (in the order of at least ±0.5 £/kvar/year), on each default ZWF. This was however moderated by the level of certainty present in the 1998/9 Default arrangements, and by the fact that the materiality of ZWF uncertainty decreases as the staircase ramps down to a 25% weighting on capability moneys in 1999/00 and 0% in 2000/01.

3b. The default capability money was then set at Grid Code rated capability multiplied by normalised ZWF (namely, that weighted by the appropriate staircase factor taken from MCUSA Schedule 5, pertinent to the financial year of analysis).

3c. Forecast Mvarh generated, in each band by reactive Mvar breakpoints, were set by extrapolations from historic observations and forecast load factors. The historic observations covered representative days over 1997 and 1998, and came from the Ancillary Services records against which reactive power utilisation is currently paid.

3d. The default utilisation money was set at forecast Mvarh multiplied by the assumed final national utilisation price of 1.24 £/Mvarh (weighted by the appropriate staircase factor taken from MCUSA Schedule 5, pertinent to the financial year of analysis).

3e. Market Agreement capability moneys were set at tendered price multiplied by tendered capability, allowing for break-points, multiplied by forecast hours both available and synchronised.

3f. Market Agreement utilisation moneys were set at tendered prices, multiplied by the same forecast Mvarh as in 3c, respecting the tendered break-point bands of Mvarh utilisation.

3g. The core comparison of default payment arrangements versus Market Agreement payment simply compares the sum 3b + 3d with the sum 3e + 3f. Reactive power assessment is however, by no means as simple as taking the cheapest apparent option. As will be seen in the following section, a full understanding of the factors influencing reactive power requirements on the NGC Transmission System must be taken into account to provide a complete economic assessment of tender value.

4. Tender Assessment

4.1 The principal role of the overall tender assessment was to quantify and evaluate consistently the many factors that NGC and the RPMWG had agreed should be included in the assessment of all tenders. These factors are those referred to in 5.3(e)(ii) of MCUSA Schedule 5 and were cross-referred in section 2.12 of the Invitation to Tender pack. The NGC evaluation team developed and implemented a process enabling these factors and associated uncertainties to be methodically considered.

4.2 The RPMWG had accepted at the outset that aspects of the evaluation process would be subjective in nature. It was therefore important to establish a framework within which this subjectivity could be exercised in a consistent fashion across all tenders.

4.3 The NGC evaluation team developed and implemented such a framework, enabling these factors and associated uncertainties to be methodically considered against the background of NGC's Licence and statutory requirements for economic purchase and economic, efficient operation and the intentions of the RPMWG for the development of the market. Specific questions were asked of each tender of the nature:

- would a Market Agreement (central case assessment) give a reduction in payments?

- would a Market Agreement be robust against:
**the envelope of credible outturn ZWF's*
** expected individual variations in utilisation due to:*
** a new station opening nearby*
** an existing nearby station closing*
** trends in local reactive power demand*
** freezing the 'staircase' at 50:50, rather than moving to 25:75 for 1999/0*

- would a Market Agreement enhance the incentive on the Generator to maintain his Grid Code capability?

- how would a Market Agreement affect operational despatch?

- to what extent might a Market Agreement potentially offset NGC investment?

- would a Market Agreement for ORPS enable a desired contract for ERPS?

4.4 All other criteria in MCUSA Schedule 5 paragraph 5.3 are covered by this methodology.

4.5 In the evaluation, NGC recognised the current discussions within RPMWG regarding the possible freezing of the staircase arrangement of the Default Payment Mechanism. NGC is obliged to assess tenders in accordance with the criteria of the MCUSA Schedule 5; this includes an explicit economic comparison of each tender against the Default Payment Mechanism, specified by the factors X and Y currently set out in MCUSA Schedule 5. NGC viewed the possible freezing of the staircase as a sensitivity on the core analytical processing, and required this uncertainty to be methodically considered in concert with all the other factors

detailed above. In this way, NGC considered whether its contracting decisions were robust against the sensitivity of the staircase being frozen at the 50:50 utilisation: capability ratio.

4.6 The following paragraphs highlight some issues involved in some of the most marginal contract / non-contract decisions of the first and second tender rounds.

4.7 All the marginal cases from the first assessment round had tendered prices such that NGC perceived no significant difference in forecast reactive power payments under the default payment arrangements or under Market Agreements, after consideration of the uncertainties. The judgment applied to this basic economic assessment is such that, if the forecast payment under the Market Agreement differs from that under the default payment arrangement by more than say ±25%, and this difference is broadly robust to NGC's range of views on utilisation and ZWF, then the contracting decision will not be marginal.

4.8 In respect of the second tender round, the majority of tenders submitted were of a marginal nature; and of these, many whose core comparisons indicated a level of undesirability, were made marginal by consideration of the incentive on the generator to maintain reactive power capability. Under the default payment arrangement, a shortfall in reactive power capability of 5% results in a reduction in capability payments on a quadratic basis, thus by 10%. A number of the marginal tenders had been priced with a highly "kinked" price curve for reactive power capability across the full range of contract breakpoints, and thus - in the above example - would see in excess of 10% reduction in capability payments. This meant that the Market tender had placed a superior incentive upon the generator than that given by the Default Payment Mechanism. NGC perceives there to be value in the reactive power market in the provision of capability, and thus the incentive to maintain it; so in a number of the marginal cases, this consideration had the potential to influence the decision whether to accept or reject a Market Agreement. In cases where capability considerations are material, a genset's previous record of reactive shortfalls may also be a factor considered in tender assessment.

4.9 Many of the marginal cases had tendered a utilisation price less than the default payment arrangement, and thus in some cases considerations of possible savings from "swinging" the despatch of Mvarh did arise. ("Swinging" means the re-despatch of Mvarh from dear to cheaper sources that are electrically proximate.) However the level of available utilisation anticipated from the tenders concerned, generally lessened the likelihood of significant savings being achieved, as most of the tenders submitted were perceived by NGC to operate in low merit during the contract period.

4.10 In all cases, NGC continued to consider interaction with forecast transmission constraints. In no cases were significant interaction with constraints identified.

4.11 In all cases, NGC considered possible interaction with NGC planned investments. The commissioning in 1998/9 and 1999/00 of new NGC transmission equipment, which includes some reactive compensation equipment, influenced NGCs' view of forecast Mvarh. All of the commissioning equipment is required for compliance with Transmission Licence Standards. Re-phasing of planned NGC investments within a 12 month contract period is barely an option. In the case of the one 24 month ORPS assessment, there happened to be no interaction with

NGC investments, as no compensation equipment is currently planned in the locality of that genset.

5. Assessment Results

5.1 10 tenders were received for the second Reactive Market tender round, of which one tender was not found to be compliant with the evaluation criteria of Appendix 6 of MCUSA Schedule 5. In respect of the remaining 9 tenders, the range of assessment outcomes is shown in a histogram, against the range of the first Reactive Market tender round assessment decisions, in Figure 1. As both rounds were consistent against a common scoring methodology, the comparison of rounds can be considered to be one purely based on the level of tender desirability. The distribution was extremely central in this round, and as such there were no clear-cut decisions to accept or reject tenders. The 6 gensets in the central bar were thus generally influenced by the factors described in detail in paras 4.6 to 4.11 above. The centrality of bids may indicate an encouraging convergence of generator and NGC understanding of contract value within the Reactive Market, demonstrating further success in the operation of the market mechanisms in place.

5.2 Overall the second round led to 3 Market Agreements being signed. These represent 5 gensets from 3 stations owned by 2 different generating companies. Combining these results with those contracts agreed for round one, signed Market Agreements in place for winter 1998/9 now represent some 36% of the anticipated total genset Mvarh despatched and approximately 36% of the overall lagging capability available.

5.3 The total reactive cost for 1998/9, allowing for the above mix of Market Agreements and default payment arrangements, is *forecast* to be lower than if all generators were paid under the default payment arrangements. Of course, the final reactive cost for 1998/9 remains dependent on outturn MWh load-factors, Mvarh generated, capability performance, and outturn ZWF for the year.

6. Concluding Observations

6.1 Any reduction inferred from total forecast cost for year 1998/9 may reflect a success, for electricity consumers, of the reactive power market process. However, NGC views any reduction as a possible 'one-off', and believes that it will take a number of years for the Reactive Power Market process to settle down. The centrality of second round tender assessment decisions suggest that keenly structured bids around the margins of the market are already beginning to take place. A number of generators may bid more aggressively in future tender rounds, and in any event the forecast remains uncertain.

6.2 Overall, the assessment recognised that the interchange of despatched Mvarh between sources by NGC will be limited in the short term. There are a number of reasons; one being the number of stations tendering with the majority of utilisation prices close to the default of 0.62 £/Mvarh. Others are that NGC software capable of auto-despatch remains far from implementation, and manual investigation of possibilities is a resource intensive exercise in terms of control room workloads and priorities.

6.3 Over the immediate years 1999/00 and 2000/01, the default payment arrangement will move to a ratio of 100:0 on payments in respect of Utilisation: Capability, subject to review. NGC perceives value within the reactive market in reactive capability, and will welcome tenders in future rounds which are structured to lower utilisation (£/Mvarh) prices, in return for some capability money. We believe that such tenders will offer greater certainty for both NGC and prospective tenderers in the reactive market.

6.4 NGC considered the interaction of all tenders with NGC planned and putative investments. Offers for ORPS were for one year and as such did not interact with any putative investments. Current planned investments, as described within NGC's Seven Year Statement, are all for compliance with Transmission Licence security requirements.

6.5 None of the three stations who tendered ERPS in the first round, resubmitted in this second round. It is possible that they do not wish to offer ERPS at the price currently available, or that they are waiting to regularise a submission in the third tender round for whole financial years 1999/0 and beyond. Tenders for ERPS are considered to be a valuable component of the reactive market process in that they inform NGC's overall planning process.

6.6 The next Market Day will be 3rd December 1998, and tenders on that day will be for a minimum of 12 months from 1 April 1999 to 31 March 2000. Gensets with Market Agreements in place from 1st October 1998 will not be eligible to participate until the fourth tender round for the period 1st October 1999 to 30th September 2000 at the earliest.

6.7 Together, the first and second tender rounds have seen an encouraging number of participants seeking remuneration through Market Agreements. The wide geographic, owner and fuel-type spread is also viewed as beneficial to the overall evolution of this newly established market.

Fig 1; Population of Reactive Tender Overall Evaluation Results