ENERGY POLICY REVIEW

SUPPLEMENTARY SUBMISSION
FROM NATIONAL GRID

28 September 2001

1 INTRODUCTION

1.1 In National Grid's initial response to the Energy Policy Review of 29 August 2001, we identified a number of areas of particular importance and on which we believe we could provide expert input to the process. These areas were:

i) security of supply:

a) real time balancing;

b) network investment in the long term;

c) fuel diversity;

ii) role of transmission with a major renewable generation base:

a) requirements for transmission capacity;

b) impact of cost-reflective charging;

c) transmission and distribution interfaces and active distribution;

d) intermittency.

1.2 In our initial response we indicated that the requirement for a high voltage transmission system will continue to be an integral part of a sustainable energy policy both now and in the long-term. We explained that the transmission system will remain a significant and efficient enabler of both security of supply and fuel diversity. In addition, major new long-term developments in renewable energy, are likely to boost the need for an enduring transmission system, both in facilitating bulk power transfers and in ensuring real-time operational security of supply.

1.3 Subsequent to the preparation of our initial response, the Performance and Innovation Unit (PIU) produced further, more detailed scoping notes, which raise a number of questions relating to the areas identified above. In particular, the Electricity and Gas Networks Scoping Note raises issues concerned with cost-reflective pricing, network investment (including interconnectors with other systems) and issues concerning the development of active distribution networks. The Renewable Energy Scoping Note raises issues associated with the intermittency of some forms of renewable generation and the Scoping Note on Security of Supply raises issues relating to real-time balancing on which we wish to make a few additional points.

1.4 While National Grid's initial response set out our views on principles related to these issues, the purpose of this note is primarily to respond in detail to points raised in the PIU scoping notes. For this reason, it is arranged in the following way.

i) Cost-Reflective Pricing of Networks

This covers issues and questions raised primarily in the Electricity and Gas Networks Scoping Note.

ii) Regulation and Investment in Networks

This covers questions raised in the Electricity and Gas Networks Scoping Note and relates to the need to continue to provide transmission capacity to contribute to the delivery of security of supply and to meet the requirements of a significant expansion of renewable energy sources.

iii) Interconnectors

The issue of investment in interconnectors was dealt with briefly in our initial submission in the context of diversity and security of supply. This submission sets out more detailed answers to the specific questions raised in the Electricity and Gas Networks Scoping Note on the role of Interconnectors.

iv) Intermittency

Our initial response indicated that we were preparing a fuller paper on the interaction between intermittent energy sources and operation of the transmission system. This section sets out our views on issues raised in the Renewable Energy Scoping Note and sets out in Appendix II some further analysis on wind intermittency that we have undertaken.

v) Transmission and Distribution Interface and Active Networks

Our initial submission indicated that we would be submitting further information on this issue. Questions were also raised in the Electricity and Gas Networks Scoping Note on the possibility of significant changes to the role of the transmission and distribution networks in the longer-term. This section sets out our response and, in Appendix I, our more detailed thoughts.

vi) Real Time Balancing and System Security.

This section deals with two issues raised in the Scoping Note on Security of Supply, which are additional to those set out in our initial response

2 COST-REFLECTIVE PRICING OF NETWORKS

2.1 The issue of network charging is raised directly or indirectly at a number of points in the Electricity and Gas Networks Scoping Note; directly, at Paragraph 4.3 and indirectly at Paragraphs 6.7, 7.6 & 7.7. In addition, questions are also raised in that Scoping Note about specific aspects of existing network charges and proposed alternatives (eg, at Paragraph 4.11 and 4.13).

2.2 In the case of National Grid, the broad principles of charging for connection to and use of the transmission system were initially set in 1990 when National Grid was established. However, there have been a number of reviews and revisions as a consequence of requests by the Regulator (either Offer or Ofgem). In particular, substantive changes were made in 1993 to use of system charges and in 1997 to connection charges and use of system charges. Furthermore, at the present time, Ofgem has been undertaking a consultation exercise on transmission access and losses which could have, potentially, a substantial impact on the transmission charging structure.

2.3 However, throughout all these reviews and revisions, the overarching aim has been to reflect as accurately as possible in charges, the costs which are incurred in meeting transmission system users' requirements, ie, the charges should be, as far as practicable, cost-reflective. The extent to which this objective has been achieved is, of course, open to debate, as, indeed, is the precise meaning of cost reflection. Debates have taken place as to whether the charges should reflect short-run or long-run costs or whether they should reflect sunk-costs or only incremental costs, for example.

2.4 At one level, this emphasis on cost-reflective charging derives from National Grid's statutory duties and from the duties placed on it by the Licence under which it operates in England & Wales. Essentially, these relate to:

i) duty to develop and run an economic and efficient transmission system;

ii) duty not to discriminate between users;

iii) requirement that connection charges to users should reflect the costs incurred.

2.5 At a more fundamental level, if charges are not cost-reflective, costs incurred by National Grid in meeting the requirements of one customer or user have to be met, in effect, by other customers or users. For example, if the investment costs incurred by National Grid in connecting a new power station development are not met by that customer they will have to be met by other customers leading to inefficient decisions by users of the system on where to locate, inefficient development of the system and, in principle, cross subsidy of one customer by another.

2.6 As indicated above, there have been, and will undoubtedly continue to be, debates about the extent to which transmission charges are currently, or could be, made more cost-reflective. However, we believe that to attempt to reflect costs in charges as a broad principle is consistent with efficiency and avoidance of discrimination and, as such, is required by our duties under the Electricity Act and under the Transmission Licence.

2.7 Turning to the specific questions concerning cost-reflective pricing which are raised in the text of the Electricity and Gas Networks Scoping Note, we have identified four questions which affect the principles.

Is it appropriate that, where practicable, network users should pay different prices depending on the cost they impose on the networks? If not, why not and what could be alternate proposals (Network Scoping Note, Paragraph 4.3)?

2.8 On the basis of the above, we take the view that it is not only appropriate but necessary. One alternative to cost reflection is flat, postage-stamp type charges which we would find unacceptable for the reasons identified above. A second alternative would be to find a mechanism to identify the relative value to users of different locations, through an auction process rather than base charges on costs. This is considered further below in response to the relevant question on capacity auctions.

Should network access and trading arrangements be technology blind? If not, why not and how could environmental considerations be incorporated in a fair and transparent manner (Network Scoping Note, Paragraph 6.7)?

2.9 The issue of trading arrangements will be dealt with below. In terms of network access and related connection and use of system charges, the application of the principle of cost-reflective charging means that access and charging arrangements should not differ according to the generation technology but only in respect of the costs imposed, which will vary primarily according to size and location of the generating plant. We recognise that cost-reflective charging may bear particularly heavily on some renewable energy sources which are remote from centres of demand and which require reinforcement of, or the establishment of, additional transmission or distribution capability. In order to access such resources it may be necessary to consider other approaches specifically targetted at renewables. However, a general move from cost-reflective charging would require, as indicated above, fundamental changes.

Would current approaches to network regulation, based on cost-reflective pricing and investment to meet user requirements, deliver the non-marginal changes required? Would it be able to do so if the costs of carbon abatement were internalised in electricity prices (Network Scoping Note, Paragraph 7.6)?

2.10 This question relates to the desirability of radical changes to the nature of the transmission system with more localised generation and, possibly, a limited requirement for a transmission network. Issues related to this are discussed further in Section 6 and Appendix I. However, as a direct answer to the question raised, requirements for transmission capacity will be determined by the requirements of users. Given cost-reflective prices, a scenario such as that envisaged in the Scoping Note at Paragraph 7.6 could emerge as a result of the economics of large versus small generation. However, we do not agree that prices for transmission should be adjusted away from cost-reflection to achieve such an end as a matter of policy. Nor do we see that internalising the costs of carbon-abatement to electricity prices would lead to such an outcome as such a policy would not necessarily radically alter the economics of generation and transmission to make local distributed generation more attractive.

Should network reinforcement to accommodate large remote sources of power be disadvantaged in order to provide stronger incentives for local generation? (Network Scoping Note, Paragraph 7.7)

2.11 As indicated in paragraph 2.5, we believe that cost-reflection in charges provides the most appropriate incentive for all network users.

2.12 The scoping document also introduces the issue of capacity auctions and access rights (at Paragraph 4.11). Our views on the merits of auctions and access rights have been set out in detail in response to the recent Ofgem Consultation Document on these issues – “National Grid’s Response to Ofgem’s Consultation on Transmission Access and Losses Under NETA, July 2001.” In summary, our views contained in this document are:

i) capacity auctions as envisaged by Ofgem are likely to be expensive and complex;

ii) on a strongly interconnected network, they will inevitably represent a compromise between accurate constraint resolution and the efficient discovery of access prices.

iii) they are unlikely to provide a basis on which to invest in transmission capacity, although in certain limited circumstances, they could provide additional signals to National Grid on where to invest.

iv) investment in the transmission system should continue to be determined by assessments of users' needs to maintain security of the system.

v) auctions would reduce the scope for small generators to use aggregation to manage the energy market risks associated with their individual fluctuation.

2.13 In our Response on Transmission Access and Losses, we suggested some simpler and cheaper alternative developments which would address concerns with the present arrangements and reduce the risk of distortions occurring in the future.

2.14 The scoping document also raises the related issue of the attribution of transmission losses to users (at Paragraph 6.5). Ofgem has also indicated that it is considering significant changes in this respect in the market arrangements. If this were to be done, or, indeed, if capacity auctions were to be put in place, this would have a considerable impact on the current structure of National Grid's transmission network use of system charges. The current structure sets use of system charges on a long-run cost-reflective basis. The introduction of access auctions would introduce short-run charges reflecting the value users place on locational transmission capacity and it would be necessary, if such charges were to be introduced, to reconsider the locational elements in the existing tariffs to see whether they were still appropriate. The introduction of transmission loss charges on a locational basis should also lead to a similar reconsideration.

2.15 The scoping document asks five questions related to these issues. Based on our views set out above, our responses are as follows:

Is there a need for more market based instruments to allocate existing capacity and improve investment decisions and, if so, how could they be introduced? (Network Scoping Paper, Paragraph 4.11)

2.16 Capacity auctions have been put forward as a way of fulfilling this perceived need for market rather than cost-derived charges. Our views on these are as set out above.

Are the costs of introducing such measures likely to outweigh their potential benefits? (Network Scoping Paper, Paragraph 4.11)

2.17 Our view, without undertaking a full cost benefit analysis, is that costs are likely to outweigh the benefits under current circumstances.

Are capacity auctions and tradable access rights appropriate instruments and, if not, what other instruments could be used? (Network Scoping Paper, Paragraph 4.11)

2.18 As indicated above, we have significant concerns over their introduction.

Has the balance of network charges tended to favour producers in Scotland and northern England to a greater extent than warranted by variation in costs? (Network Scoping Paper, Paragraph 4.13)

2.19 Generators in Scotland exporting to England & Wales and generators in the north of England currently pay substantially higher transmission network use of system (TNUoS) charges than generators located further south. A generator in north-east England pays some £18 per kW per annum more in TNUoS charges than a generator in south-west England. For a 1,000 MW station this represents a relative additional cost of some £18 million per annum. This relative charge is based on our current long-run cost-reflective charging structure and, we believe, reflects the additional investment costs incurred by National Grid to meet its requirements. Our statements of detailed charging principles and current tariffs are available on our web site. Charges are reviewed annually.

3 REGULATION AND INVESTMENT IN NETWORKS

3.1 In the period since its establishment in 1990, National Grid has invested just over £3 billion in today's money in the transmission network in England and Wales. This has been both to connect some 22,000 MW of new plant and to disconnect a similar amount of old generating capacity ; to replace parts of the system which have come to the end of their technical life ; and, to increase the capability of the system to meet increased power flows. We have increased the capacity to transmit energy by some 23 %.

3.2 This has been undertaken against a background where National Grid has been subject to RPI-X regulation, which has resulted in substantial reductions in transmission charges, in excess of some 30% since 1990 in real terms. In the Scoping Note on Electricity and Gas Networks a number of issues and questions are raised concerning the basis on which networks are regulated, the potential effects of such regulation on investment and the basis on which investment should be undertaken. Our responses to these questions are set out below.

Are the approaches used by Ofgem to tackle information asymmetry between regulator and regulated appropriate? Are there better ones? (Network Scoping Note, Paragraph 4.7)

3.3 The PIU notes that Ofgem has mainly used two methods to address the problem of information asymmetry in setting price controls for network utilities. Specifically:

i) it has set (RPI-X) controls which incentivise companies to become more efficient and, in the process, reveal information about the scope for future efficiency improvement;

ii) in the distribution sector, it has used benchmarking techniques to reveal an 'efficiency frontier', which can then be set as a target for companies, judged to fall well short of it.

3.4 Both of these techniques have their problems as means for revealing information, especially in the way which they have been used to date. In particular:

i) RPI-X controls, based on forecasts of the scope for future cost reductions, are inherently a 'trial and error' method. This will have potentially negative consequences for the operation of networks if there is a systematic bias towards assuming too high future cost reductions. The question of whether there has been such a bias is addressed below. There is also a problem if the regulator's approach is to progressively squeeze revenue at successive price reviews until there is a manifest problem. As the experience with other networks shows, once a problem has become obvious, it is likely that that problem has gone well beyond the stage of speedy remedy.

ii) the use of benchmarking techniques, as in previous distribution price reviews, has been problematic because the distribution businesses do not collect (nor have been required to collect) information in a form which would give the technique an acceptable reliability. Because companies do not collect the required information, they have been required to **allocate** costs to cost-categories specified by Ofgem. As a result, attempts to construct an idealised 'efficient' distribution business, by aggregating the lowest costs from each cost category, have largely aggregated (different) allocation methodologies, rather than actual costs. The result of the benchmarking exercise in the 1999 distribution price review was to produce an unrealistic estimate of efficient costs for distribution businesses. Ofgem itself recognised the problem but did not effectively address it (and could not have done so, given the information available at the time).

3.5 Given the above issues, Ofgem could move in at least two directions. Specifically:

i) it could refine the collection of information from companies, not least through requiring companies to submit highly disaggregated information on a common basis. This is, to some extent, the approach being adopted by Ofgem through its Draft Regulatory Accounting Guidelines for distribution businesses. However, this approach will almost certainly fail to provide the required information. This is because the companies all have different organisational structures, which themselves are continually changing. To submit costs in the categories required by Ofgem will therefore continue to require a substantial amount of cost allocation. This will, in turn, leave Ofgem with the problem of dealing with allocation methodologies which will inevitably be different, at least in detailed application;

ii) more reliance could be placed on **aggregate historic** cost information – for example, by setting that part of regulated revenue which is designed to cover a company's operating costs annually and on the basis of a moving average of operating costs in past years. On the assumption that companies can continue to reduce operating costs, albeit more slowly than has been achieved in the period since privatisation, this approach would mean that:

a) price reviews would be simpler and would largely focus on required capital expenditure (which is, by its nature, less amenable to extrapolation from the past than are operating costs);

b) companies would have the same incentive to reduce operating costs, wherever they were in the price review cycle (whereas, incentives to reduce costs are currently greater immediately after a price review than towards the end of a price control period);

c) the chances of 'getting it wrong' for an individual company would be much less than with current price review practice.

Is Ofgem striking the right balance between seeking cost (and hence price) reduction and investment and maintenance of the quality of service? If not, what are the implications for the approach to network regulation? (Networks Scoping Note, Paragraph 4.7)

3.6 Historically, and particularly when presenting its price review proposals, Ofgem has placed more emphasis on price reductions than on other aspects of price reviews. This is understandable for a variety of reasons:

i) one of the main objectives of privatisation was to improve efficiency - and lower prices were expected to be an outcome of improved efficiency;

ii) the level of company profitability, in the wake of privatisation, was a major political issue;

iii) quality of network service was not a major issue across the electricity and gas sectors as a whole.

3.7 However, the situation now is somewhat different. In particular:

i) privatisation has delivered major improvements in efficiency and substantial reductions in costs and prices;

ii) successive price reviews have dealt with post-privatisation levels of profitability;

iii) **future** quality of network service **is** an issue.

3.8 Ofgem has recognised that simply driving down costs would eventually cause problems for quality of service. A variety of initiatives have been used to redress the balance. These include:

i) the System Operator (SO) incentives scheme for National Grid Company;

ii) a similar scheme for Transco, supplemented by more explicit incentivisation of network investment; and

iii) the Information and Incentives Project (IIP) for distribution businesses.

3.9 However, all of the above are on the fringes of the main price controls. Creating an appropriate balance between costs and quality of service will require addressing the main building blocks of these price controls, particularly:

i) the means by which Ofgem deems a company's efficient operating costs

ii) the means by which Ofgem deems a company's efficient capital expenditure (addressed in our answer at paragraph 3.15 below); and

iii) the means by which Ofgem estimates a company's cost of capital (also addressed in our answer at paragraph 3.17 below). Whatever assumption is made at a price review about required capital expenditure, the incentive to spend the money will be prejudiced if the rate of return on that spend (which has been incorporated into setting the price control) is too low and/or the company expects continuous future squeezing of that rate of return over the life of what are very long life assets.

Is Ofgem's approach to measuring network quality in terms of numbers and duration of involuntary interruptions appropriate? (Networks Scoping Note, Paragraph 4.7)

3.10 Measuring quality in terms of number and duration of involuntary interruptions is currently limited to gas and electricity distribution networks. This is appropriate given the relatively small contribution of transmission networks to interruptions.

3.11 As living standards increase and technology becomes more accessible, customers become more dependent upon reliable gas and electricity supplies. Further work is needed to determine how customers' requirements are changing to enable appropriate incentive schemes to be designed.

3.12 When designing incentive arrangements it is important that a balanced scheme is created using appropriate measures and targets. Otherwise perverse incentives may be created, leading to deterioration in performance. For example, a focus only on immediately customer-facing measures (like frequency and duration of interruptions) could discourage the taking of maintenance outages and have negative effects on the underlying condition of the network.

3.13 Ofgem is seeking to address these issues through requiring companies to report on a wider variety of measures of system condition. However, it is not clear what incentives this gives because it is not clear how Ofgem will react to movements in, for example fault levels – whether, for example, penalising increased fault levels at a subsequent periodic review or using such trends as the basis for allowing higher capital expenditure in the next price control period.

Is there a risk that current and proposed regulatory approaches would lead to inadequate investment in the networks? If so, why and what is the appropriate means of securing adequate investment? (Networks Scoping Note, Paragraph 5.4)

3.14 Current and proposed regulation of gas and electricity networks will mainly impact on future network investment through the following routes:

i) the method for estimating capital expenditure requirements at price reviews;

ii) the current and expected cost of capital assumptions embedded in the calculation of the main price controls; and

iii) the operation of initiatives targeted specifically on incentivising network investment.

Estimation of Capital Expenditure Requirements at Price Reviews

3.15 As with the estimation of future operating costs, the main divide in the method for estimating capital expenditure requirements is between those companies which Ofgem has sought to benchmark against each other (distribution businesses) and those which do not have obvious benchmarks (National Grid, Transco). For the latter, price reviews involve detailed evaluation by Ofgem of the companies' capital plans. There may be disagreements between company and regulator about Ofgem's final conclusions but the basic approach is reasonable. In future, these discussions are also likely to be informed by a shift of relative emphasis from cost cutting to the need for adequate investment.

3.16 In so far as there are technical issues about how capital expenditure requirements are assessed at price reviews, it is arguable that there have been more issues for distribution businesses. In particular, it is arguable that the same benchmarking philosophy, which has been applied to distribution operating costs, has also led to insufficient attention to the specific capital expenditure requirements of individual distribution businesses.

Estimation of Companies' Costs of Capital

3.17 Successive price reviews have led to progressive squeezing by Ofgem of estimates of network businesses' costs of capital. A number of points arise from this:

i) has Ofgem correctly estimated cost of capital for the energy network companies?

ii) even if it has done so, has Ofgem taken sufficient account of the point, made most recently by the CAA (as part of its work on the current round of airport price reviews)[1] that, if there is to be an error in either direction on cost of capital, then it should err on the side of generosity because of the greater social costs of getting the number slightly too low, rather than slightly too high?

iii) if, as has sometimes been implied in Ofgem's price review proposals, that future estimates of cost of capital are likely to be even lower than those embodied in current price controls, then this will further discourage investment in assets which can expect to earn back their cost over a period of 40 years or more;

iv) either way, Ofgem's estimates of network businesses' costs of capital are significantly lower (on a like-for-like basis) than estimates made by the Competition Commission, with notable disagreement on non-industry-specific parameters of the cost of capital calculation (notably the 'risk free rate' and the 'equity risk premium').

3.18 Overall, estimation of cost of capital (particularly the estimation of the cost of equity) is inherently contentious. However, the differences between Ofgem and the Competition Commission in this area suggest that Ofgem is, at the very least, trying to do a finer calculation than would be implied by the CAA's philosophy and, as such, is doing little to encourage network investment through this route. Closer adherence to the CAA/Competition Commission line on cost of capital would be positive for network investment.

Specific Initiatives to Incentivise Investment

3.19 Ofgem has recently made proposals specifically targeted on the incentivisation of investment both for National Grid and for Transco. Without discussing these proposals in detail, two overall points are worth making:

[1] ['The Cost of Capital. CAA Position Paper. June 2001]

i) if the main point of these proposals is to offer network companies an additional incentive to spend over and above what has been assumed at the previous price review, while allowing this extra spend into the company's regulatory asset base at the next review, this is likely to have a positive effect on economic network investment;

ii) however, if it is the long run intention to expose past network investments to continuous market testing (e.g. through capacity auctions which affect the total revenue received by the network owner), then this is likely to deter network investment, especially if there is no commensurate adjustment to the company's assumed cost of capital to compensate for the higher risks.

Is there a case for a deliberate regulatory policy to encourage over-sizing of networks on precautionary grounds? If so, how should this be done, to what extent, and who should bear the costs? (Networks Scoping Note, Paragraph 5.4)

3.20 Electricity transmission systems are designed against security standards prescribed by Ofgem. A degree of margin is included in transmission designs in order to meet security requirements in these standards. The security and quality of supply standards for transmission were revised in November 2000 following widespread consultation amongst all users and consumer groups and therefore we do not currently see a need for higher standards of security and therefore a higher margin.

3.21 In planning future transmission requirements, a probabilistic view of future generation and demand patterns is derived. This aims to include all potential projects, with a view taken on the likelihood and timescales in which they will proceed, and will consequently identify a degree of uncertainty over future plans. Due to the size and impact of large generation projects, system extension investment is undertaken on the basis of firm contractual commitments. For the small incremental changes arising from changes in consumer demand and embedded generation, forecasts (both internal and customer) of future operating behaviour are used on which to commit investment.

3.22 The Scoping Note identifies some potential, radical scenarios for development of electricity generation sources involving possibly widespread growth of renewable energy and associated increases in embedded generation. In the context of investment in the transmission system, our approach to planning should enable such trends to be identified if they were to occur and their impact on transmission capacity requirements to be identified and acted upon. If such trends lead to a reduced requirement for transmission capacity then investment can be appropriately reduced. Conversely, such developments could lead, in some scenarios, to increased requirements for transmission capacity. To ensure that the system can be developed to meet these requirements, it is important to recognise that extended timescales can be involved in transmission reinforcements as a consequence of the need to gain planning consents. The streamlining of the consent process and the identification of transmission requirements at the time of consideration of generation developments are important aspects in this process. Similarly, it is important that sufficient information continues to be provided via Grid Code submissions on potential developments.

Is uncertainty created by regulatory changes currently being considered, causing medium term security risks? If so, how can these risks best be dealt with? (Networks Scoping Note, Paragraph 5.4)

3.23 Since privatisation, the basic 'regulatory deal' for network utilities has been to balance:

i) a relatively low ex ante rate of return (i.e. the cost of capital used in setting price controls); and

ii) a relatively low risk environment through allowing assets into the companies' 'regulatory asset bases' (RABs), with the expectation that these assets would be remunerated through price controls over specified 'regulatory asset lives'.

3.24 This required balance could be negatively affected by the changes referred to by the PIU, notably the creation of firm tradable access rights for transmission capacity. However, the impact of such proposals on transmission investment would depend less on the creation of such rights, per se, than on the linkage between the newly created market and the determination of total network revenue for National Grid, in particular on the extent to which the new market created risks in excess of any adjustment of ex ante regulated rates of return. The overall argument for creating a market in firm tradable access rights in electricity transmission capacity may have to do more with the overall cost of introducing such a market, relative to the likely benefits, than specifically and necessarily with the impact on network investment.

4 INTERCONNECTORS

4.1 National Grid's initial response to the Review referred briefly to the role of interconnections with other systems in providing diversity of energy supply and, because of the economies of scale in terms of sub-sea electrical interconnectors, the need for a robust transmission system with which they can connect.

4.2 The scoping note on Gas and Electricity Networks raises some additional points concerning interconnections and the related subject of the boundaries of networks providing common carriage as against those where access is provided as a negotiable third party arrangement. Our views are set out below with respect to electricity interconnections.

Is it appropriate to apply Common Carriage access to the main networks and NTPA to other wires and pipelines?

Where do the natural monopolies end and how can the boundaries be justified:

a) in respect of off-shore gas pipelines; and

b) in respect of smaller, on-shore gas and electricity systems?

(Networks Scoping Note, Paragraph 2.7)

4.3 While the above question is specifically related to the issues of off-shore gas pipelines and small on-shore gas and electrical systems, we believe it raises a wider issue which is relevant to the development of interconnectors with other systems and, as such, raises issues related to questions raised in Paragraph 5.6 of the Scoping Document concerning how new interconnections should be financed and charged for. In particular, it raises the issue of whether interconnectors between countries should be considered to be natural monopolies or be open to entrepreneurial investment but, of course, subject to appropriate procedures for allocation of capacity which may be by NTPA or, indeed, auctions.

4.4 Whereas interconnectors are defined as the connections between two systems which are subject to different control or to a different local market, there can be other characteristics which distinguish them from the network element that would usually be considered part of a natural monopoly. Interconnectors which comprise DC submarine links, or, peninsular AC links, may have a very high investment cost and it is possible to identify the individual users of the interconnector. Interconnectors which are part of a heavily interconnected AC system can have loop-flows which can enter and leave the same boundary and users cannot be individually identified. In our view, where investment in a new interconnector is identified as desirable, then two routes for financing and remuneration exist ; namely entrepreneurial[2] and price controlled.

Entrepreneurial Approach to Interconnectors

4.5 In an entrepreneurial approach to interconnector development it remains a fundamental principle that, after the construction of the new interconnector, there remains sufficient price differential between the two markets to cover the operating costs of the interconnector and to provide sufficient returns to justify the investment. On this expectation, direct or indirect participants in the project can support their investment case. Capacity can be allocated through NPTA or by the use of auctions or other market means. The degree to which these will establish the value of the interconnector concerned depends on the nature of the markets on either side of the interconnector. An open and competitive energy market is required on both sides of an interconnector for the true economic benefit to be established by market users.

4.6 Construction cost and actual trading opportunities will determine whether the project was well founded and the investors benefit from, or bear, the consequences. Where projects are seen to be highly profitable then this may lead to further interconnector developers entering into the market and in principle, this is no different from any other market where above-normal returns will lead to increased investment driving down returns to normal levels.

4.7 Where market participants wish to build their own interconnectors then this should not be precluded. However where such infrastructure is to be available to a multitude of users then the rules for accessing capacity need to open, transparent

[2] The term “entrepreneurial” is used in relation to projects that are self financing, funded by charges that users will pay.

and non-discriminatory. Charges for capacity can be determined by market mechanisms (eg, auctions) or using NTPA. Any Licence obligations or regulatory oversight in this area should apply equally to all interconnectors irrespective of the developer.

Regulated Approach to Interconnectors

4.8 The alternative to the entrepreneurial approach is a price-controlled or regulated approach. As indicated in our initial response, transmission networks are available for use by all market participants and so Common Carriage principles are appropriate. These networks are developed to meet Licence obligations and Security Standards and in response to customer requests for connection. The obligation on network owners to develop the network in response to such requests is reflected in their ability, ultimately, to make use of compulsory powers established under statue. Transmission networks are remunerated via regulated revenue, collected from the generality of system users because they benefit all system users.

4.9 This approach can be applied to interconnector investment and in such a case, costs would be recovered irrespective of whether they use such facilities from the generality of transmission system users. The developer would bear no risk if the project proved ill founded but would equally not receive the benefit of a highly successful project.

Can market forces be relied on to provide the appropriate number and capacity of international links, especially if energy market competition is less well developed outside the UK? (Networks Scoping Note, Paragraph 5.6)

4.10 National Grid is currently investigating and developing new interconnectors to Norway (1,200 MW) the Netherlands (1,000 MW) and the Republic of Ireland (500 MW). The total investment involved is likely to be in the region of £600-1,000 million and these projects are planned to be self-financing on an entrepreneurial basis.

4.11 For an entrepreneurial interconnector to be developed it is necessary for there to be a stable regulatory and market framework. This will allow investments in interconnectors (and indeed in all aspects of the energy industry) to be undertaken on a sound basis with an understanding of all the relevant risks. Uncertainty will make investments more costly to finance and ultimately this will result in higher costs to consumers. In extreme circumstances, political and regulatory uncertainty may deter investment.

4.12 An open and competitive energy market is required on both sides of an interconnector for the true economic benefit to be established by market users and National Grid's proposed interconnectors to Norway and the Netherlands are to such markets.

4.13 As to the number and capacity of international links – the market should determine where a new interconnector, or an upgrade of an existing interconnector, is justified.

Is there a case for government or regulatory intervention to promote new links and if so, what form should this take? (Networks Scoping Note, Paragraph 5.6)

4.14 The public sector has an important role in such projects in that it sets the regulatory framework under which any investment will take place. Both Government and regulatory authorities (both at EU-level and nationally) contribute. Unless the framework is transparent and stable there will be a risk that changes in it could alter the economic rationale for an investment. For example, the economic case for an entrepreneurial interconnector could largely be undermined if an additional link is built with public funding, or, which receives a regulated (ie guaranteed) revenue. The original entrepreneurial interconnector would now represent a stranded asset. Where the risk of such intervention exists, then it is likely to be difficult to finance new entrepreneurial projects. There is, however, a role for Government in the form of "pump-priming" with assistance with feasibility study and development costs. If such studies show a new link to be economically viable then the market should be left to undertake the necessary investment. Where this is not the case then clearly the private sector will not invest and arguably neither should the public sector.

5 INTERMITTENCY

5.1 Our initial submission identified that the development of renewable energy sources in line with the Government's targets for 2010 would not give rise to issues in terms of balancing the system and that we were undertaking further work in this area. We concluded in our initial submission that developments more in line with those put forward in some of the scenarios of the Royal Commission on Environmental Pollution may well in the longer-term give rise to the need to develop new market approaches to system balancing, but do not present insoluble issues relating to transmission operation and intermittency.

5.2 Section 7 of the Scoping note on Renewable Energy puts forward the proposition that developments in terms of renewables and particularly intermittency of renewable energy will not be subject to constraints for the foreseeable future. We would agree with this proposition with respect to current Government targets and we are continuing to analyse the issues relating to further substantial renewable development in the longer term.

5.3 In the meantime, we attach as Appendix II some specific results of work that we have undertaken on intermittency of wind power and which was presented to the DTI's Energy Advisory Panel in September 2001.

6 TRANSMISSION AND DISTRIBUTION INTERFACE AND ACTIVE NETWORKS

6.1 The Electricity and Gas Networks Scoping Note (Paragraphs 2.2 and 7.2-7.6) raises the concept of a system of local generation meeting local demand with a minimal, if any, requirement for a transmission system. National Grid's initial response to the Review indicated that we would be making a further submission on the transmission and distribution interface and on issues relating to active networks.

6.2 While a future in which local generation meets local demand is possible, it will depend ultimately on the economics of small-scale local generation versus larger, remote generation. We have also explained that in our view such an outcome would still require a high voltage transmission system, although the required capacity of such a system will depend on the extent of locational balance between generation and demand and the security of supply required.

6.3 No specific questions arise on this issue which are not already addressed elsewhere in this paper. We have, however, considered the issues in more detail in Appendix I.

7 REAL TIME BALANCING

7.1 In our initial response, we raised a number of issues related to our activities in balancing the system minute by minute and issues arising from this for security of supply. In addition to our initial response, there are a number of further issues raised in the scoping notes on Gas and Electricity Networks, Security of Supply and Renewable Energy Sources on which we wish to respond. In addition to the Energy Policy Review, these issues are being taken forward in other forums (eg, Ofgem/DTI Working Group on Security of Supply) to which we are contributing. Nevertheless, two questions in the PIU scoping notes warrrant a specific response here.

Is the current regulatory regime for electricity and gas networks, led by Ofgem, adequate to minimise risks of power or gas shortfalls due to inadequate production capacity or network capacity ? (Security of Supply Scoping Note, Paragraph 7.4)

7.2 In terms of network reinforcement for the transmission system, our views are set out in Section 3 (above).

7.3 In terms of production capacity, the current plant / demand balance is adequate to provide secure supplies of electricity assuming supplies of fuel are available to the power stations. For the longer term, the adequacy of generating capacity at times of particularly high demand caused by cold weather will depend on the willingness of generators to install or to retain generating plant on the system to meet unusually high levels of demand which occur only very infrequently. This willingness will, itself, depend on the expectation of, and achievement of, very high prices in the market for electricity when such events occur, or, the willingness of suppliers to contract for such supplies on an ongoing basis, so as to avoid the risk of such potential shortfalls.

7.4 With the removal of capacity payments with the introduction of the New Electricity Trading Arrangements, (and which were available under the previous Pool system), a potential safeguard in this respect has been removed. It remains to be seen whether the more market-oriented approach to remunerating capacity will continue to provide sufficient generation to meet demand in exceptional weather conditions. As we make clear in para 7.3, the current position does not give rise to concerns in this respect but the position should be monitored regularly by the Ofgem/DTI Group on Security of Supply in order that changes can be made to market arrangements if this is seen as necessary.

<u>Gas / Electricity Arbitrage</u>

What if any, further steps need to be taken to ensure that trading and network arrangements for gas and electricity provide appropriate incentives for arbitrage between the two markets? (Electricity and Gas Networks Scoping Note, Paragraph 5.7)

7.5 We believe that the introduction of half-hourly pricing within NETA has established appropriate arrangements for efficient arbitrage between the gas and electricity markets. The 'firm' nature of NETA and the potential exposure to system buy prices gives desirable assurances to the System Operator when balancing the system. Withdrawal of gas fired generation is likely only to occur either when accompanied by re-declarations of replacement plant of an alternate fuel-type, secured through the power exchange, or, when the anticipated imbalance prices are low, indicating healthy plant margins.

7.6 Arbitrage arrangements have improved with the introduction of NETA. Nevertheless, it is incumbent on both gas and electricity network operators to assess arrangements and forecast behaviour of participants against their respective security of supply obligations.

7.7 Growth in intermittent sources of generation will require additional sources of reliable generation to ensure security of supply. It is therefore important that any changes to NETA imbalance price signals do not remove the long-term incentives for availability of predictable generation

8 CONCLUSION

8.1 In this submission we have concentrated on answering a number of specific questions which were raised in the PIU's topic based scoping notes and which are particularly relevant to electricity transmission. In conclusion we would like to re-iterate four main conclusions from National Grid's Initial Response . Namely :

i) Transmission will remain an integral part of a long-term sustainable energy policy. Transmission has an important enabling role in ensuring security of supply and fuel diversity for the future;

ii) Regulatory stability and appropriate incentives are needed to ensure adequate network investment for the long-term;

iii) It is important for the Review to draw a clear distinction between real-time issues relating to balancing the electricity system and delivering minute-by-minute security of supply, and, a range of longer-term resource-related issues. We strongly support this distinction being made in the PIU analysis.

iv) In terms of significant new development of renewable energy sources in the longer-term, there will be a major and enduring role for transmission – both in facilitating transfers of bulk power and in ensuring real-time operational security of supply.

National Grid
28 September 2001

APPENDIX I

ENERGY POLICY REVIEW
NATIONAL GRID

STRUCTURE OF ELECTRICITY NETWORKS
WITH DISTRIBUTED GENERATION

1. The PIU's Electricity and Gas Networks scoping paper asks whether, in the longer-term, there are benefits in changing the current network model which is described as providing one-way flows from large power stations to consumers. This Appendix discusses how networks might be organised to facilitate the effective use of renewables and CHP generation. Itasks if, given the small scale of many of these generation technologies, small independently managed active networks would be beneficial, albeit with high voltage links to remote energy sources.

2. The issues addressed in this Appendix are :

   i) What are the network requirements of the emerging small scale generation technologies and customers who use them?

   ii) How are these requirements best accommodated in the national context (for example, with some large-scale renewables, international interconnections, pump storage, etc)?

   iii) What are the technical and operational changes necessary to existing networks?

   iv) What are the options for managing these new arrangements?

   In commenting on these issues, we are reflecting a broad overview on network issues. It must be stressed however, that some of these issues are specific to distribution networks. Distribution Network Operators will be more able to comment on distribution-level technical and cost issues.

CONCLUSIONS

3. In summary, this Appendix concludes:

i) A number of significant developments may be required to low voltage networks to enable ‘plug and play’ installation and effective use of desirable new generation technologies. These developments include; standardised electrical interfaces to generation systems, improved network capacity in some areas, and local information/management systems – potentially in the form of local energy and service markets.

ii) Interconnection between all areas of the national electricity system is likely to remain highly desirable in order to maintain quality and security of supply, make best use of available energy resources, and minimise the costs of balancing. Some of these interconnections will support large power flows and a hierarchy of voltage levels will be desirable. In many areas, a flexible homogeneous network structure, which can be readily extended and can evolve from the existing distribution systems, will be preferable to a structure designed to establish and maintain local self-sufficiency.

iii) Major structural change to the technical characteristics of the high voltage transmission network is unlikely. Piecemeal reinforcement and resizing and adaptation will permit the new requirements on the transmission network to be met. On distribution networks, however, rather more wide ranging changes to interfacing standards, capacity, protection and control/information systems are likely to be needed. A number of issues relevant to the transmission/distribution interface have been identified in this paper. Many of these facilitate devolution of active network management activities to the distribution network operators.

iv) There would be major challenges, if not fundamental barriers, to the establishment of a, competitive, market-based approach to the development and operation of an interconnected network. The present structure of regulated monopolies is a workable solution and, on the basis of a proven track record, an option likely to facilitate the network developments required. While there may be some advantages of establishing a system operator for nominally self-sufficient areas, the arguments for adapting the existing networks into a homogeneous structure, together with the efficiency advantages of further distribution operation consolidation, suggests that fragmentation of system operation should not be a policy objective.

4. The remainder of the paper explains the basis of these conclusions.

i) Network Requirements for Small Scale Generation Technologies

Generation Specific Network Requirements

5. The generation technologies which have been highlighted as having particularly attractive characteristics include:

   a) Photo voltaic panels (zero emission energy production near point of use);

   b) Micro and small-scale CHP (giving higher overall energy conversion from natural gas and other fuels – potentially including renewable fuels in the future);

   c) Other small-scale power production from renewable energy sources (wind and bio fuels);

   d) Other energy conversion technologies such as fuel cells, micro-turbines, etc.

6. The features of these technologies which reflect on their network requirements include:

   i. Some of these technologies have the characteristic that their output is intermittent (i.e. more variable than traditional generation) due to either the natural variations in the renewable energy source, or, due to the linkage with other cyclic heat loads.

   ii. Almost all of these technologies will be subject to automatic and decentralised operation. Some will run either when a renewable energy source is available or to meet requirements of nearby energy consumers. Others, however, may have very flexible characteristics and be able to respond quickly and effectively to external signals (be they prices or other signals).

   iii. In terms of development, many of these technologies are likely to be progressively installed by individuals to meet their private or local requirements. They are likely to be standard units to permit economies of production.

iv. Some of these technologies can produce power in direct current (DC) form. With a significant number of appliances requiring or indifferent to DC supply, there is the potential for direct connection of DC power sources to such appliances.

7. These features make the following local network characteristics desirable:

i. The local network should support ‘plug and play’ standardised interfaces for these devices so they can be fitted in a similar manner to load appliances without individual analysis of quality of supply and network capability requirements.

ii. Each link of the local network should be sized so that it has sufficient capacity for its present use and some flexibility for changes (e.g. new power generation devices). Unlike existing local distribution networks, it may not be possible to predict capability requirements with the same confidence. It may be necessary to install information systems that report and permit automatic control of some aspects of network usage – see below.

iii. Network protection, to ensure safety of people and equipment, will need to recognise that there are multiple power sources at the distribution level and two directional flows. This is extremely important.

iv. The network infrastructure provides information which co-ordinates discretionary production or consumption and so can minimise costs, optimise losses and perhaps guard against exceeding limited network capacity at certain pinch points. This information may be in the form of prices or commanded volumes. Such signals could beneficially be integrated with billing systems.

8. These characteristics, and particularly the need to provide information to manage local production, imply a local management structure. It has been suggested that such a structure may be all that is required in the longer-term as decentralised generation technologies become prevalent. However, there are wider network requirements also.

Wider Network Requirements

9. While it is possible that there could be sufficient generation capacity and suitable balancing controls to permit an area to operate independently and disconnected from any other areas, it is likely that interconnection between nominally self sufficient customers or areas will be highly desirable for the following reasons:

i. Security of supply – a number of self-sufficient areas are unlikely to suffer shortages simultaneously and so interconnections reduce the probability of local supply shortages arising from inevitable demand and generation variations. This will be increasingly important as renewable resources such as wind are incorporated because there is significant diversity between sources to be harnessed across the nation.

ii. Economy – interconnections can allow cheaper (or more environmentally benign) energy sources to be used in preference to local energy sources. If an area has a surplus of such plant, the local customers can benefit by exporting such power.

iii. External balancing – as the generation and demand in any particular area are likely to be subject to growth, ensuring that there is sufficient local balancing capability will represent an ongoing technical management and development cost. A simple top up and spill facility to an external system will significantly reduce such requirements.

iv. Quality of supply – the management of voltage distortion on both AC and DC systems is easier as the supply source impedance is reduced (fault level increased). This is a natural consequence of interconnection because it parallels and so reduces the source impedances of a population of power sources.

10. Given the joint requirements of local network management and national interconnection, there is a series of network structures that can be considered:

a. Local networks, with interconnection links to adjacent networks, managed to make best use of local resources and ensure there is sufficient balancing capability to permit operation as power islands should the links fail;

b. Local networks, with interconnection links to adjacent networks, managed to make best use of local resources, but not necessarily self balancing if all interconnections fail (however, local management could assist with islanding in some circumstances and fast black start);

c. A homogeneous interconnected network structure, which does not distinguish between those network links used for local connection of power sources and demands, and those links providing interconnections to more remote sources. Such a structure supports the changing role of links as use of the network evolves. Hierarchical management is required to make best use of local sources within that structure. The management systems should be robust against failure of any particular link, but assumes links are generally sufficiently reliable that multiple failures are not credible.

11. The primary difference between these network structures is the extent to which the local management and control structure is designed to be resilient to failure of key links. In some remote areas with few, and less reliable, interconnections, the better performance offered by the first structure could be worthwhile. In more interconnected areas, the homogeneous structure that meets minimum-security requirements may well be sufficient. In such cases the flexibility of the homogeneous structure may outweigh marginal reliability improvements.

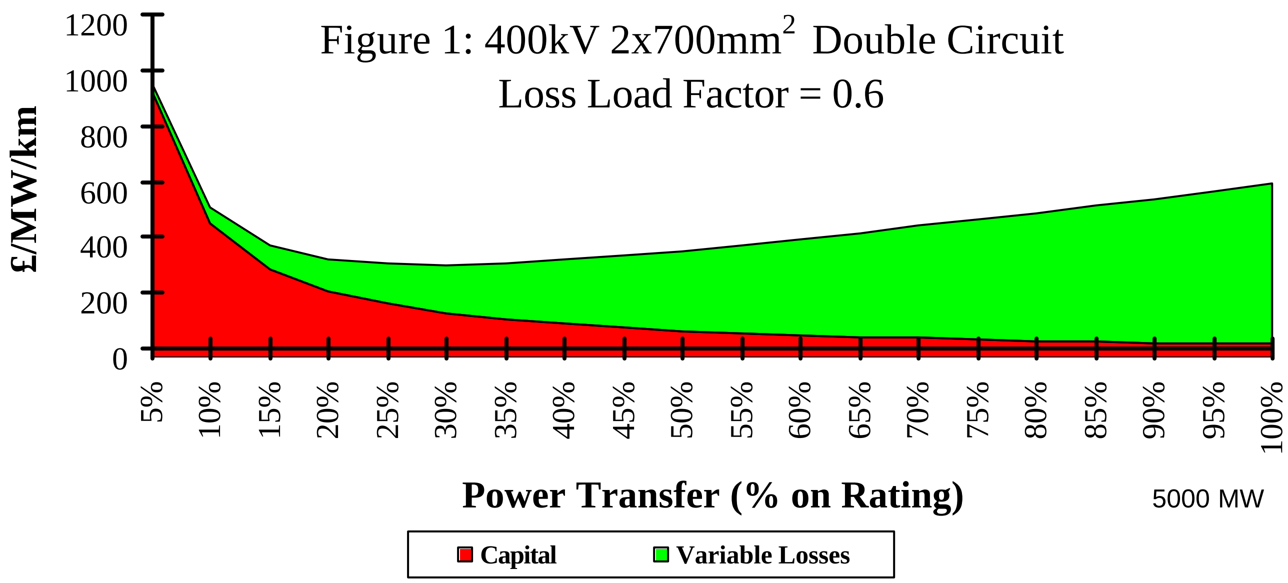
12. Given a structure with each area generally in balance, the size and variability of nearby generation sources and loads will be the dominant factor in determining the capacity required on individual network links. However, it is possible to estimate the total network capacity that will be required between parts of the national network if one area is required to assist another during statistically expected demand and generation variations. For the present system (with peak demand of around 50,000MW), this capacity is in the range 1000MW to 2000MW (i.e. between 2% and 4% of peak demand). In the future, the need for capacity may change. On the one hand, a higher correlation between local generation and demand in an area may reduce this requirement. On the other hand, other effects, such as gas-electricity interactions and intermittency of renewables, may increase it.

13. This capacity to enable mutual support will need to be shared across the mesh of links interconnecting the country. The location of this capacity will depend on other network requirements discussed below.

ii) National Network Requirements

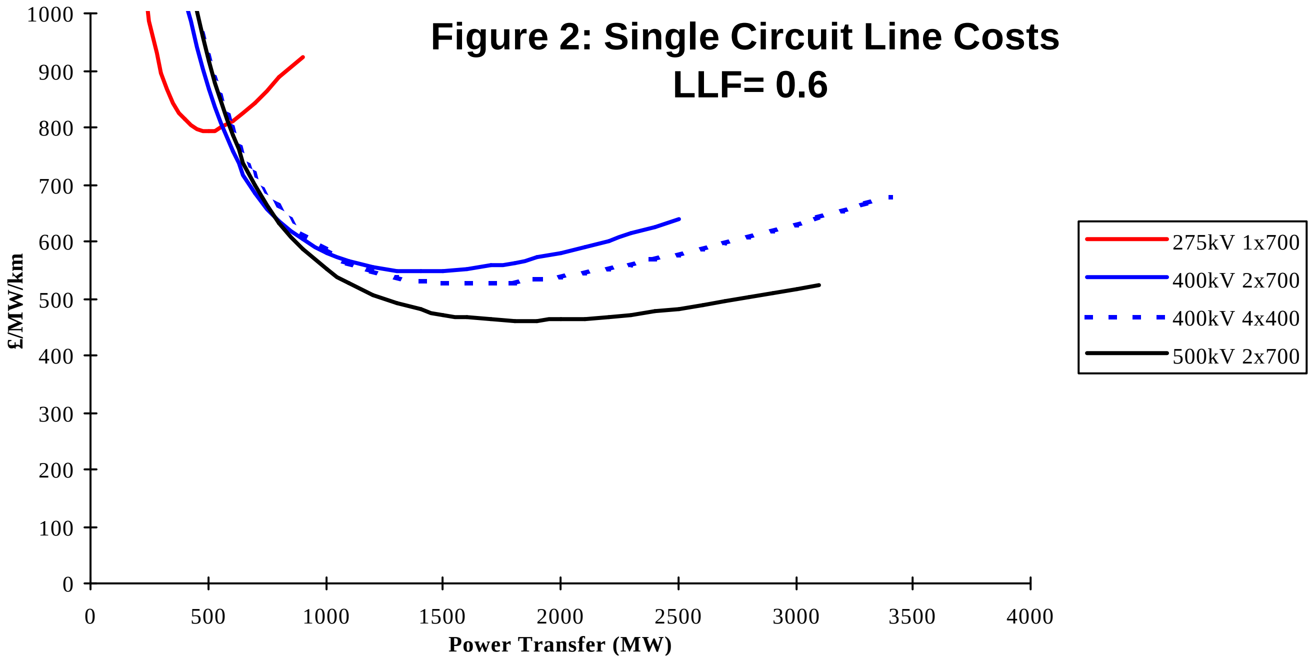
The previous section has examined the network requirements and structure options for a uniform distribution of small-scale generation. In practice, there are a number of energy sources (e.g. wind, wave, tidal, pump storage, and nuclear) that may be developed in the future that may not be uniformly distributed, or due to their individual size, will give rise to bulk power transfers. For example, the Royal Commission on Environmental Pollution examined four different scenarios with varying approaches to energy efficiency, nuclear power and renewable generation. In each case, a high voltage transmission system would continue to be required, and as noted by the Royal Commission, may also need to be extended.

14. Bulk transfers of electricity are most efficiently carried at high voltage because, compared to lines at lower voltages, high voltage lines are cheaper in capital terms per MW and have significantly lower losses (a major proportion of the total life cycle cost of transmission lines). An illustration of the relationship between these life cycle costs and



load level is shown in Figure 1. (This is shown for an AC line but DC transmission lines have a similar characteristic).

15. Figure 1 shows how the capital cost of a transmission line per MW transported reduces as the utilisation of the line increases. However, the capitalised cost of losses increases as utilisation increases. The life cycle cost of losses depends on the cost of energy (assumed here to remain constant in real terms), the cost of capital and the loading pattern (represented in the loss load factor - chosen in these examples to be typical of many circuits on the transmission and distribution networks). It can be seen that transmission lines are most economically operated when their normal loading is about one third to one half of their rating. The remaining capacity is typically used in emergencies only, i.e. when parallel circuits fail.



16. Figure 2 compares the life cycle costs for different transmission voltages and it can be seen that these are significantly higher at 275kV compared to those of 400kV or 500kV. At the highest distribution voltage level, capital costs per MW for 132kV lines (not shown) are typically 3 times higher than at 400kV and the capitalised cost of losses will be around 9 times higher for the same loading. 132KV is the most economic option for flows below around 200 MW per circuit.

17. These approximations of lifecycle costs illustrate the strong benefits of establishing a hierarchical network structure, with low voltages at the point of use to facilitate safe and cheap appliances, and higher voltages to efficiently carry larger flows over distances.

18. In the past, AC technology has been chosen because it is readily transformed between different voltage levels. Advances in power electronics has been bringing down the capital costs of DC systems such that they are often the technology of choice for long point-to-point bulk power interconnections. However, the same power electronics, by providing fast power flow and voltage control devices, has also improved the capability and flexibility of AC networks, reinforcing their position as the best technology for general-purpose use. It is likely that a mix of AC and DC technology, at various voltages, will remain into the foreseeable future on a 'horses for courses' basis.

iii) Evolution and Adaptation of Current Networks

Possible Changes to the High Voltage Transmission Network

19. To service and interconnect all areas of the country, the original high voltage national grid design appears to remain a robust structure for high voltage transmission. As the proportion of generation connected directly to the high voltage transmission network reduces, and new national power interchange patterns emerge, incremental system reinforcements will be required. New technologies are likely to continue the trend of capacity improvements on existing rights of way.

20. If major increases in bulk transfers need to be supported (for example, as a result of major renewable developments in Scotland and the north of England) there is the potential that more substantial network reinforcement may be required. This could be achieved by upgrading some of the existing north to south transmission lines to a DC transmission 'spine'.

21. If, as a result of emerging interchange patterns, certain transmission links appear to require less capacity than their existing 400kV construction on a permanent basis, asset replacement with lower profile single circuit or lower voltage lines may be attractive. A similar piecemeal adoption of new cable technologies would also be possible should they emerge.

Possible Changes to Low Voltage Distribution Networks

22. Work by the DTI/Ofgem Embedded Generation Working Group identified a number of technical and market related issues that would require significant developments on the distribution networks to accommodate the renewable and CHP generation required for government targets for 2010. These developments may be categorised to match the local requirements of the new generation technologies listed above, i.e.:

    i. New standard interfaces for small scale generation technologies (for example, to support 'plug and play' of domestic CHP);

    ii. Resizing of local distribution networks to account for new patterns of use (for example, simultaneous output of surplus PV from 4kW domestic installations);

iii. Developments to distribution network protection; catering for multiple power sources, two way power flows, accommodating potentially higher fault levels, etc.

iv. Information systems for local management. These will certainly include extended SCADA systems with network state estimation and dynamic analysis functions. They may also include; broadcasting of metering and control signals from suppliers/aggregators, market signals for distribution network services, market signals for the aggregation of balancing services needed by the transmission system operator, emergency controls for island operation and black start.

23. The cost and network implications of these developments is beyond the scope of this paper but they highlight a number of issues for the current distribution/transmission interface:

i. Power flows on supergrid points are likely to reduce as a general trend. The capacity required for residual imports or exports and security requirements will be more difficult to forecast on the present 'bottom up' basis as underlying generation and demand will not be observable. Capacity requirements will therefore be increasingly dependent on statistical measurements of sensitivities to weather, gas and electricity prices, and other local trends. The planning criteria for this part of the network may need modification to reflect this.

ii. The range of fault level mitigation measures may need to be extended. As well as high impedance transformers, series reactors and other fault current limiting devices, new automatic and DNO controlled switching schemes may be required.

iii. Revised voltage control schemes may be needed to cope with power swings that include direction changes in power flows and the operation of various generation technologies.

iv. Tighter integration will be required between the extended distribution network SCADA and network analysis facilities and those already in use on the transmission network.

v. Devolution of various network stability and control responsibilities from transmission to distribution network operators.

Options for Managing Change

24. Given the scale of development that would be required to achieve active local networks, the PIU scoping paper questions whether there are more efficient alternatives to having the networks controlled as monopoly entities. The paper makes reference to the barriers to entry for competitive network operators due to the difficulties of establishing rights of way for new lines, particularly near established routes.

25. The difficulty in obtaining parallel routes is just one aspect of the fundamental reasons why development and operation of the interconnected network are currently monopoly activities. Even if a workable system of tradable network capacity rights can be established, there are many local market power and monopoly situations that must be resolved so that, in the short-term, assets can be removed from service for maintenance, and in the longer-term, correct development decisions can be made. At present, National Grid suggests that entrepreneurial investment and operation is appropriate and workable in a limited number of circumstances (for example, DC Interconnectors between international markets).

26. The present regulatory framework, in which a sector regulator supervises the network monopolies, is suitable for overseeing the interactions between network issues and a competitive energy market. It is also able to minimise the distortions that network price controls inevitably bring. UK regulatory innovations, such as the system operator incentive arrangements, have been important in achieving the successful delivery of technology changes (e.g. the substantive switch to gas fired generation) and the implementation of a decentralised energy market framework (NETA). On the basis of this proven track record, there is good reason to believe that the present broad regulatory structure would be suitable for facilitating the establishment of the desired new generation technologies.

27. National Grid's experience also highlights the fact that there are considerable benefits, in terms of efficient and consistent incentives and clear internal responsibilities, brought by a combined network owner/system operator organisation. While this may not be achievable in all active distribution contexts, it deserves consideration as the model of choice.

28. The PIU paper also asks whether a system operator should be established for each nominally self-sufficient network area. If the system were to evolve into such a structure, this might be logical. However, the arguments for adapting the existing networks into a homogeneous structure, together with the efficiency advantages of further distribution operation consolidation, suggests that fragmentation of system operation should not be a policy objective.

National Grid
28 September 2001

Appendix II

ENERGY POLICY REVIEW
NATIONAL GRID

INVESTIGATION OF WIND POWER INTERMITTENCY
Discussion Paper to DTI Energy Advisory Panel
September 2001

INTRODUCTION

1. The UK government is committed to putting in place mechanisms to ensure that, by 2010, 10% of electricity supplied in the UK comes from renewable resources. Wind power, one of the UK's most readily available and economically viable renewable resources, is expected to contribute significantly to this target.

2. The intermittent nature of wind power is a potential issue regarding the integration of wind power into the electricity network. This paper summarises work done studying the effects on the interconnected electricity network of a large-scale increase in wind power capacity. The work has concentrated on studying possible short-term output changes of wind turbines and the issues that these might have with regard to:

   - Frequency response requirements to maintain quality of supply and security with unpredictable short-term changes in the output of wind turbines.

   - Reserve and other short-term balancing requirements to manage potential additional volatility of total generation output.

METHODOLOGY

3. A number of scenarios representing possible wind capacity in 2010 were devised and the potential output changes over different timescales modelled to ascertain the effect that this capacity could have on necessary frequency response and reserve levels.

4. The fluctuations in total wind power output were compared to the fluctuations from generation and demand currently accommodated and managed by National Grid in various timescales, as summarised in Table 1 (and more fully described in [1]). It should be noted that National Grid optimises the costs incurred in managing existing power fluctuations and so it is likely that any new additional fluctuations, even if smaller than those currently managed, will require some change in response and reserve holdings, potentially increasing their costs. However, as a first step to assessing feasibility,

comparison of fluctuations from wind with those already managed identifies whether wind represents similar requirements for services or major new challenges.

Nature of Fluctuation	Maximum Accommodated	Mitigation Options
Predictable daily cycle (e.g. national demand cycle on peak day)	Fluctuation < 20% of peak demand (i.e. <10,000 MW)	Purchase additional controllable output as Balancing Services
Unpredictable 1 hour notice generation-demand imbalance	Potential generation loss or demand forecast error of 1500 MW	Purchase additional reserve services
Unpredictable instantaneous reduction in output	Instantaneous loss of 1320 MW	Purchase additional frequency control services

Table 1: Power fluctuations currently accommodated by National Grid

5. The results were then compared with similar work done by a joint German/American study[2], carried out by the National Renewable Energy Laboratory, a U.S. Department of Energy Laboratory. This study utilised output data from the German "250-MW Wind" data project, which analysed data from wind turbines situated all over Germany. In order to qualify the work done, it was considered important to compare the theoretical modelling done with actual analysed data.

SCENARIOS OF UK WIND CAPACITY IN 2010

6. National Grid's demand forecast suggests a total demand in 2010 of circa 400 TWh for England, Wales and Scotland. Adhering to the 10% assumption, this gives a figure of 40 TWh to come from renewables. In 1999 10.2 TWh was generated by renewables. Therefore, if the renewables target is to be met, a significant increase in renewable capacity is necessary.

7. The DTI's consultation document[3] proposes scenarios as to the possible future contributions by various renewable energy technologies. Table 2 below illustrates the three scenarios with regard to the differing contributions toward the renewables target by wind power.

	% of Target by Onshore Wind	% of Target by Offshore Wind	Total %
a) High Wind	26	18	44
b) Medium Wind	21	13	34
c) Low Wind	13	6	19

Table 2: DTI scenarios of wind's contribution to renewable targets

8. The scenarios make a number of assumptions concerning the future development of renewable technologies. The major points with regard to wind are encapsulated below:

a. High Wind

- Considers wind to be the best-resourced, economic and well-developed renewable technology for at least the next decade.
- Similar capacities have been achieved in countries with comparable land use constraints and lower wind resources (Germany 6100 MW, Denmark 2300 MW).
- Assumes large-scale development of offshore wind, due to huge resource, support from government, etc.
- Presumes government support in planning consents.

b. Medium Wind

- Broadly based on existing trends but assumes the saturation of hydro.
- Similar to High Wind scenario but reflects the growth of all renewable technologies supported under earlier NFFO contracts.

c. Low Wind

- Lower Wind development, particularly due to planning problems. (90% of schemes have been rejected so far)
- Offshore wind has not been economically proven.

9. If an average load factor of 30% for wind turbines is considered[4] these scenarios translate to the following approximate necessary capacities for offshore and onshore wind in the UK shown in Table 3.

Scenario	Onshore Capacity (MW)	Offshore Capacity (MW)	Total Capacity (MW)
High Wind	4300	3000	7300
Medium Wind	3500	2100	5600
Low Wind	2200	1300	3500

Table 3: Calculated wind capacities for 2010 scenarios

10. Two scenarios were also devised to represent the geographical distribution of wind capacity in 2010. The UK was split up into 12 regions, based upon the 10 European Union regions with Wales and Scotland also each split into two regions (North and South). Development was then assumed to follow:

i. The Scaled Development Scenario in which the existing geographic distribution of capacity by region was simply scaled up to meet the forecast capacity of each scenario. This represents the possibility that new developers would continue to choose those areas with good wind resource.

ii. The Capped Development Scenario in which it was assumed that, for a number of reasons, capacity would reach saturation limits in some regions. Thus the scenario assumes that new capacity will be considerably more dispersed around the country than is presently the case.

11. In both scenarios, offshore wind capacity was assumed to be located at sites identified by the Crown Estates[5].

MODELLING WIND POWER OUTPUTS

12. Ideally the best method to assess wind power outputs across the country would be to analyse a large set of power output data from existing windfarms, located at various points around the country. Ideally this data would be sampled at fine resolution e.g. 5 to15 minute averages. We are currently in the process of acquiring such data. However, for this study we used Met Office wind speed data, which is immediately available for a number of sites around the country. This data is available as hourly averages.

13. One Met..Office site was chosen in each of the 12 regions and hourly average wind speeds obtained for the five years between January 95 and December 99. These wind speeds were then translated into hourly average turbine power outputs using a standard wind/power curve.

14. It was observed that average wind speed at the Met. Office sites was not sufficient to support a typical turbine load factor of 30%. This is because the wind monitoring stations are not placed in areas favourable for a wind turbine e.g. on top of a hill, hub height of 60m, etc. Therefore it was necessary to scale up all wind speeds to simulate favourable conditions. It was assumed that the distribution of wind speeds would still remain the same.

15. As there are no wind measurements at offshore locations, initially we assumed that offshore turbines would experience the wind measured at the Met Office station in the nearest on-shore region. Assuming all turbines in the region would experience the wind recorded at the Met. Office site, the theoretical average hourly power output of all the

wind capacity in the region can be determined. These regional outputs can be summated to give a total wind power output. A resulting probability distribution for the High Capped Scenario is shown in Figure 1. This illustrates the wide range of total output that would be expected from the population of wind generators, with the mean output around 30% of the total installed capacity. The market will need to provide flexibility (either in direct contracts or through top up from the Balancing Mechanism) to accommodate this variation.

16. The correlations between turbine outputs in different areas are illustrated in Figure 2. This shows moderately high correlations over distances of a few hundred kilometres reflecting the potential for weather systems to affect turbines over a wide area.

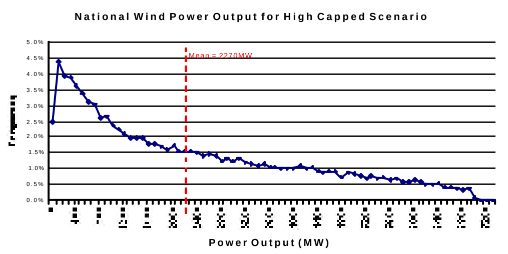


Fig. 1 Distribution of Wind Power Output (High Capped Scenario)

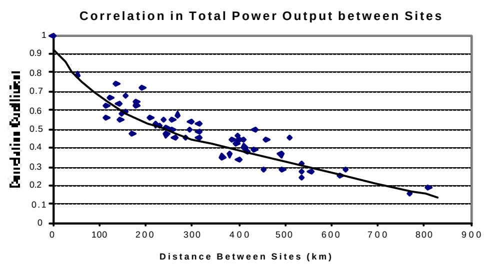


Fig.2 Correlation of wind turbine output between sites

17. To identify the requirements for system balancing for each scenario, we derived frequency distributions of output change over various timescales. Unlike the distributions of total power output, these results suggested that the frequency curves of output change are normally distributed with a mean of zero (see Figure 3). This was consistent with findings in Germany using real wind turbine data (see Figure 4).

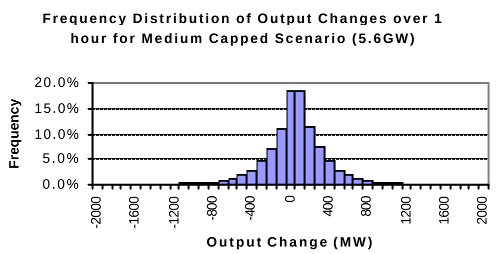


Fig.3 Example of initial distribution of output change over 1 hour

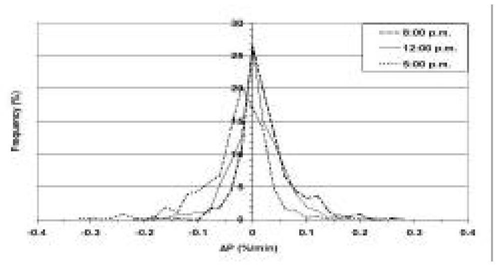


Fig. 4 Distribution of Output Change over 1 hour from German data

18. These preliminary results show the possibility of significant fluctuations from one hour to the next. However, this is partly a result of assuming perfect correlation between all

turbines in a region. When a graph of correlation of output change between sites against distance between sites is plotted, see Figure 5, it can be seen that there is very little correlation even at relatively small distances between turbines. Figure 6 shows similar results have been measured in the German study. (Note this contrasts with the correlation between absolute levels of power output illustrated in Figure 2.) Therefore in reality one would expect much greater diversity in output change.

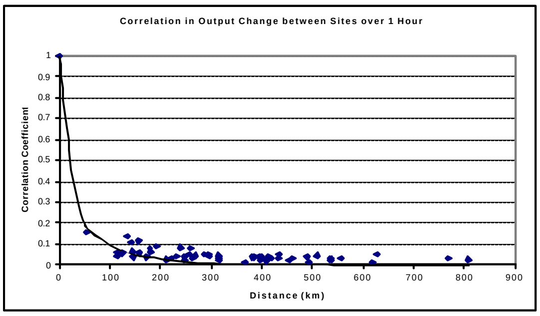


Fig 5 Correlation in output change against distance between sites

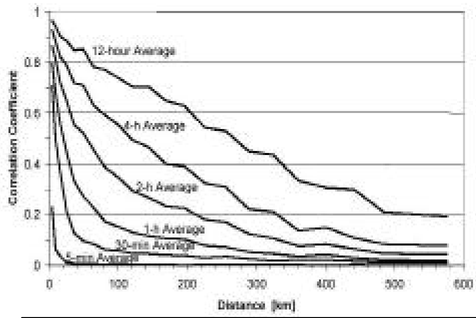


Fig. 6 German data displaying correlation in output change for different average times over the distance

19. The preliminary results were also based on the assumption that all offshore capacity experiences the wind conditions at the closest onshore sites. In reality these offshore sites are likely to be a significant distance away from the Met. Office site. Therefore adding the offshore capacity to the onshore sites means that there is considerably less diversity in output than would actually be the case.

20. To calculate wind variation in a more representative manner, a revised model was devised which incorporated the diversity that would occur in practice. The standard deviation of total wind changes was computed by representing the expected covariances between the output at offshore sites and sub divisions of the 12 regions described above. This model results in significantly reduced standard deviations of total output change curve in each region (see Figure 7) and, when all the regional effects are summated, a similar reduction in the standard deviation of national output change (see Figure 8).

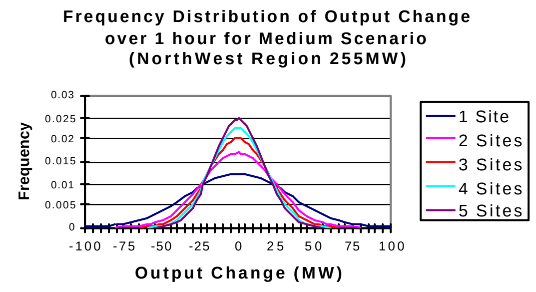


Fig. 7 Effect of number of sites on distribution of output change in a region

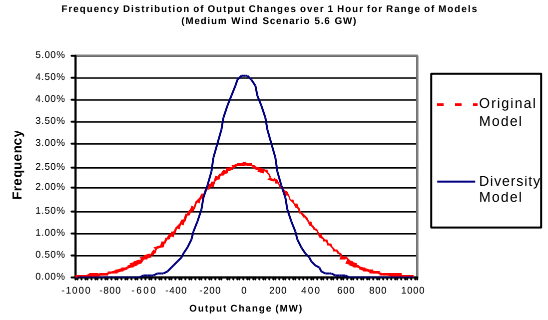


Fig. 8 Distribution of Output Change over 1 hour for two models

RESULTS

21. Using the revised modelling, distribution curves of output change over 1 hour (the finest possible resolution) and 3 hours (closest to NETA gate closure) for all the scenarios were produced. These are illustrated in Figures 9 and 10.

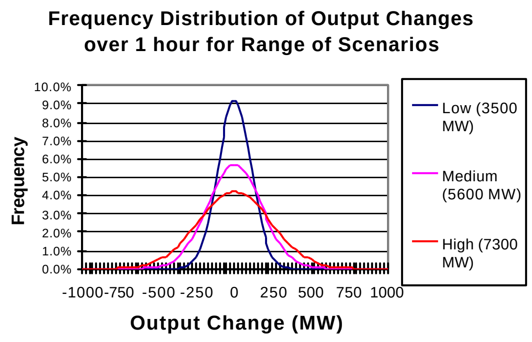


Fig 9 Distribution of Output Changes over 1 hour

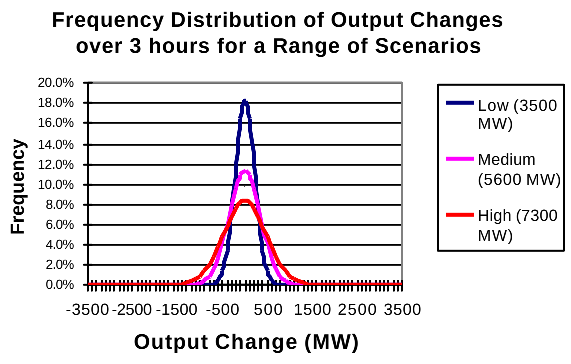


Fig 10 Distribution of Output Changes over 3 hours

22. We found minimal differences between Capped and Scaled scenarios with the same total wind capacity and conclude that, within reason, the distribution of wind development is not a significant factor in establishing sufficient diversity in output changes.

23. Compared to fluctuations currently managed by National Grid (Table 1), the changes in wind output over 1 hour or 3 hours appear to be of a manageable magnitude. While we have not yet been able to analyse UK data that illustrates changes over very short periods, the results from Germany (Figure 7) suggests that even more diversity exists between sites for such fluctuations due to turbulence within the local wind field.

CONCLUSIONS

24. This work has analysed actual wind data for the UK and derived statistical descriptions of the power fluctuations in various time scales that would be expected from different national portfolios of wind turbines. As wind data is not readily available for all possible future turbine sites, models have been formulated to represent the diversity between the fluctuations in wind turbine outputs in different areas of the country. These models are consistent with measurements reported from real wind turbines.

25. A number of scenarios representing possible developments of wind power consistent with meeting Government targets for renewable energy in 2010 have been developed and analysed. These scenarios confirm the expected result that power fluctuations get larger with larger proportions of wind power. However, they also show that the diversity between fluctuations in different areas of the country is relatively insensitive to the location of wind developments.

26. Given the optimisation of services purchased to manage existing generation and demand fluctuations, any additional fluctuations, such as those arising from wind generation, will have the potential to require an increase in the need for services to manage system frequency and balancing. The modelling of wind fluctuations reported in this paper does not permit a detailed assessment of the interaction or independence of wind fluctuations with those already experienced or likely to emerge over the next decade and beyond. More detailed analysis with higher resolution wind output data will be required to estimate potential additional costs and assess at what point beyond 2010 the market for frequency response and reserve services might need to make available more services. National Grid is continuing to collect data and develop models to answer these questions.

27. Nevertheless, comparison of the potential fluctuations from wind power reported in his paper with the size of fluctuations from generation and demand currently accommodated indicates strongly that sufficient frequency response and balancing services would be available to accommodate potential wind developments necessary to meet Government targets for 2010.

National Grid

September 2001

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