The Extent to Which Economic Regulation Enables the Transition to a Sustainable Electricity System

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April 2009

Executive Summary

The UK's contribution to the new, legally binding, EU renewables target is to provide 15% of energy consumption from renewable sources by 2020. In addition, the UK has adopted, via a Climate Change Act, a unilateral and statutory target of reducing carbon dioxide emissions by 80% from 1990 levels, based on an updated understanding of the consequences of climate change. These statutory targets are extremely ambitious and achieving the 2020 target alone will require a 10 fold increase in the use of renewable energy compared with the situation in 2006.

The electricity sector is the largest producer of greenhouse gas emissions within the broader energy sector and will therefore be required to make a significant contribution to the achievement of the UK's new renewable obligations and longer term climate change goals. In order to deliver this contribution, there will be a need to transition to a "sustainable" electricity system that can accommodate the necessary renewable and low-carbon generating capacity in the timescales required.

Today's electricity system has been designed around large, flexible fossil-fired and nuclear generation. Generation plant margins over demand have historically been relatively modest at around 20 -24%, reflecting the controllability and high-availability of conventional generation in meeting peak demands. Essentially, the transmission system has been designed to accommodate the output of all generation simultaneously to meet peak demand and is therefore relatively constraint-free.

Electricity trading occurs on a bilateral basis between generators and suppliers, ignoring physical transmission system limitations and with the costs of resolving any resulting system congestion being "socialised", i.e. spread across all users of the system. Transmission network investment requirements have been relatively predictable to date and are undertaken on a centrally planned basis, using long-standing deterministic security-based rules. Network regulation has historically reflected this predictability, with investment requirements

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determined ex-anti and the regulatory focus being very much on driving efficiency and implementing agreed investment programmes in a cost-effective manner.

A “sustainable” electricity system will, however, have very different characteristics. It will need to accommodate sufficient renewable and low-carbon generation to deliver the UK’s renewable obligations and goals and will be effectively decarbonised, i.e. only using fossil fuels as a last resort when insufficient renewable or low carbon resource is available. The “replacement” role of renewable generation and the need to retain conventional generation as “back up” to cover periods of reduced renewable output, implies increased margins of generation over demand and the consequent need for available transmission capacity to be “shared” between renewable and conventional plant, in order to avoid inefficient transmission investment. In other words, rather than building a transmission system that in capable of accommodating the output of all renewable and conventional generation simultaneously - an impossible scenario given the limited amount of demand to be supplied - a finite transmission capacity would be utilised by renewable generation when renewable resource was available and by conventional generation when renewable resource was reduced.

Under current market arrangements, the sharing of transmission capacity between renewable, low carbon and conventional fossil fired generation could give rise to significant congestion in some areas of the network. Although the zero or low marginal cost of many renewable and low carbon generating technologies should result in that generation replacing fossil-fired plant, the disposition of generation around the system and the integrated nature of generation and supply businesses coupled with the lack of any centralised scheduling process, is likely to result in renewable and conventional generation competing for scarce network capacity. There would appear to be two approaches to addressing this issue. Either renewable and low carbon generation would be given the “priority access” to the electricity markets that decarbonising the electricity system would appear to demand and that current EU legislation[2] requires in terms of generation dispatch, or the existing, non-discriminatory, electricity market could be maintained with reliance on carbon pricing etc to indirectly achieve the same outcome.

Transmission investment required to accommodate numerous, often remotely connected, renewable generation projects with relatively short development timescales will be significant but less predictable and more dynamic than has been the case to date. Notwithstanding the urgency of climate change and the need for a rapid reduction in carbon emissions, future regulation will need to recognise the increasing uncertainties in identifying the need for specific transmission investment and focus on maximising the use of available transmission assets while encouraging objective and efficient investment in order to achieve a sustainable electricity system in the most cost-effective fashion.

Demand will also have an enhanced role to play in delivering a sustainable electricity network. While energy efficiency measures will be effective in minimising overall energy consumption and therefore generation capacity requirements, fuel substitution - for example the introduction of heat pumps - can be expected to increase electricity demand and require increased levels of renewable generation to meet energy-based renewable targets. The deployment of intermittent or variable output renewable technologies such as wind and tidal generation will result in

[2] Article 7 of the Directive on the Promotion of electricity from renewable Energy Sources in the Internal Electricity Market (2001/77/EC).

increased price volatility and the use of "smart" appliances and fuel substitution together with exposure to real-time electricity prices, will allow electricity demand to respond to fluctuations in the availability of renewable resource. In response to electricity prices, electricity demand would increase to accommodate additional renewable generation during periods of abundant renewable resource and decrease when the availability of renewable resource is reduced. The introduction of locational electricity pricing, which would reflect the degree of network congestion by increasing energy prices in generation-deficit areas and reducing energy prices in areas of the network where generation was in surplus, would allow demand to have a role in mitigating that congestion and reducing the need for transmission investment.

Objectives

The objective of this report is to review aspects of existing regulation, electricity market arrangements and industry practice in order to identify barriers in making the transition to a sustainable network.

1. As a first step, the renewable generating capacity that will be required to commission in order to deliver the electricity sector's contribution to the UK's renewable obligations is considered, together with that conventional capacity that might need to be replaced in order to maintain traditional levels of security.

2. The report then goes on to consider the need for that generation to obtain early access (i.e. before the construction of necessary transmission capacity) to electricity markets and the associated need for access reform. Related electricity market-related issues including the impact of congestion pricing and the potential need to explicitly reward generation capacity are discussed, as is the prospect of having to curtail wind output due to energy constraints as renewable deployment increases.

3. The scale of transmission investment needed to deliver the UK's renewable obligations is then considered, together with the role of regulation in ensuring that investment is efficient.

4. Finally, the report goes on to consider current transmission network charging methodology and the issue of whether that methodology constitutes a barrier to the deployment of renewable generation discussed.

Given the objectives of the paper, and the general context of existing regulation and preference for competitive electricity markets, the comments and changes proposed by the paper are largely tactical in nature and represent an incremental approach to the development of arrangements that are compatible with the achievement of the UK's new renewable obligations and goals. However, a more strategic approach will be required to identify the fundamental change required to deliver a truly sustainable electricity system that would be both fully decarbonised and capable of delivering security of supply, though fuel diversity, the maintenance of a mixed generation portfolio of adequate capacity and appropriate industry practice; and quickly enough. This is to be the subject of another report by the author in Phase 2 of UKERC.

Generation capacity required to deliver the UK's new renewable obligations.

The contribution to be made by the electricity sector to delivering the UK's new renewable obligations will depend, to some extent, on the contributions made by the other main energy-consuming sectors, heat and road transport. However, as the largest contributor of green-house gasses within the energy sector, the electricity sector will be required to make a major contribution and, based on an analysis of feasible build-rates and technology development (SKM, 2008 & BERR, 2008) suggest that between 32% and 40% of electrical energy will need to be produced by renewable generation by 2020. Other sources suggest that the electricity sector contribution will need to be at the high end of the range proposed by SKM/BERR, with the UKBCSE (2008) and Renewables Advisory Board (2008) suggesting that 40% and 47% of electrical energy will need to be sourced from renewables, respectively.

How this electrical energy contribution translates into renewable capacity will depend on the effectiveness of energy saving measures[3] and, to a lesser extent, on the balance of technologies deployed. In this context it is worth noting that the European Action Plan has a non-binding target to reduce energy demand by 20% by 2020 from projected levels.

A review of analysis carried out by SKM, BERR and the UKBCSE suggests that, assuming no change in demand and energy requirements from current levels, a 2020 energy contribution of between 32 and 40% will required between 37 to 55GW of total renewable capacity, compared with the current capacity of around 6GW.

In addition, there is likely to be a need to replace some existing conventional generation capacity expected to decommission by that time. Taking account of the probable impact of the Large Combustion Plant Directive and anticipated nuclear decommissioning, it is estimated that at least 22GW of conventional plant will close by 2020, with a further 7 GW of nuclear generation due to retire by 2030 (see UKBCSE 2008). Due to the limited ability of variable-output renewable technologies such as wind to replace conventional generation capacity, and assuming that measures set out in the Climate Change Programme[4] result in energy and peak demand remaining unchanged over the period, it is likely that around 10 - 14 GW of decommissioning conventional plant would need to be replaced. This would be sufficient to maintain a margin of generation over demand at historic levels of around 20-24%, although it should be noted that plant margins are currently somewhat higher than historic levels at the present time.

The need to replace conventional plant expected to decommission by 2020 could, however, be reduced if energy efficiency measures are effective in deducing peak electricity demands over the period. In fact, in their analysis for Greenpeace/WWF, Poyry (2008) suggest that the need

[3] As the renewable target is energy-based, the reduction of demand through energy efficiency will reduce the renewable capacity required to deliver that target. The decarbonisation of the heat and ultimately transport sectors is, however, likely to increase electrical energy demand over time consequently increasing the amount of energy to be sourced from renewables. While an increased contribution to the achievement of the EU target from the transport and heat sectors could reduce the contribution required from the electricity sector, maintaining that requirement would enhance the decarbonisation of the energy sector as a whole.

[4] http://www.defra.gov.uk/environment/climatechange/uk/ukccp/index.htm

to commission new base-load coal or gas fired plant would be pushed back into the mid-2020s, if the ambitious energy efficiency targets set out in the UK's national Energy Efficiency Action Plan (see Defra, 2007) were to be achieved. However, assuming that electricity demand and energy targets remain broadly unchanged over the period to 2020, it is expected that a total of somewhere between 44– 58 GW of new generation capacity will need to be commissioned by 2020. It is likely that almost all of this capacity will be transmission-connected, with only around 4GW of biomass, some smaller wind developments and micro generation connecting to the distribution networks. This represents an average connection rate of up to 6 GW/pa from now until 2020, to be compared with the average generation commissioning rate of just over 1GW/pa achieved since the privatisation of the electricity supply industry in 1990.

Need for enhanced and early access to the transmission network

If, therefore, the UK's climate change obligations and goals are to be achieved, it is clear that the arrangements for connecting generation to the electricity system and allowing access to the electricity markets will need to be improved. The emergence of a 12GW renewable generation connection queue in Scotland with some projects having connection dates beyond 2018 together with similar, if less onerous problems elsewhere in E&W, suggests that existing access arrangements are a real impediment to the achievement of the UK's renewable obligations. While the disappointing growth in renewable generation to date cannot be laid entirely at the door of current network access arrangements, with planning consents and supply-side constraints also impeding progress, changes to existing access arrangements will be necessary if the required renewable generation capacity is to be connected by 2020.

Current arrangements for generation to access the transmission system are a refinement of the centralised planning regime which existed before the privatisation of the industry in 1990. National Grid Electricity Transmission (NGET) as GBSO[5] and the Transmission Owners (TOs)[6] continue to operate a "predictive" (SEDG, 2007a) approach to the development of the transmission system, applying demand and contracted generation information to long-standing investment criteria, set out in the GB Security and Quality of Supply Standards (GBSQSS)[7], to determine what transmission developments are required. Once all necessary reinforcements have been commissioned, and not until that time, a connecting generator will be allocated "Transmission Entry Capacity (TEC)", which gives the right to export to the transmission system and participate in the electricity markets. In other words, the GBSO and TOs are said to operate an "invest and then connect" approach to transmission access, whereby access to be electricity market is only allowed once network compliance with the investment criteria set out in the GBSQSS has been fully achieved.

[5] As GB System Operator (GBSO), NGET is responsible for the operation of the transmission system in Scotland, England & Wales.

[6] NGET owns all transmission assets in England and Wales. Transmission assets in the North of Scotland are owned by Scottish Hydro Electric Transmission Limited (SHETL) and in the South of Scotland by Scottish Power Transmission Limited (SPTL).

[7] The GB Security & Quality Supply Standards (GBSQSS), contain, inter alia, criteria which govern the operation of the transmission system and define the need for reinforcement. The GBSQSS can be viewed at http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode

These arrangements, which focus on allowing controllable, conventional generation contribute to meeting peak electrical demand, result in a transmission system capable of accommodating the almost simultaneous operation of all generation. Although appropriate in their day, these arrangements are not consistent with the concept of a sustainable electricity system, where the "replacement"[8] role of renewable generation requires available transmission capacity to be "shared" with conventional plant and where far more generation will be connected transmission system than the system has the capability to accommodate. Moreover, current arrangements result in a situation where incumbent fossil fuel generation has indefinite access to the electricity markets at the expense of new renewable generation, which is the polar opposite of what is required to deliver the Government's goal of a decarbonised, sustainable electricity system.

Other concerns over the suitability of the current access arrangements going forward relate to the inability of generation to connect until all necessary reinforcements have been completed and the lack of any economic signals as to the short-run value of access which would allow objective decisions to be made as to the for investment in new transmission capacity.

Developing an enduring (i.e. long term) access regime, consistent with the delivery of the UK's new renewable obligations

The need to address the issue of transmission access was recognised in the 2007 Energy White Paper, which initiated a review of the current arrangements, the "Transmission Access Review (TAR)", led by Ofgem and BERR. The Review, which is still ongoing, has considered three basic options for reform and Ofgem will identify a preferred option for development in the summer of 2009. In summary, the options considered are;

- "Connect and manage", whereby all generation is offered a guaranteed connection date, irrespective of whether any necessary system reinforcement has been completed or not. In its basic form, connect & manage would continue to "socialise" the cost of resolving any resulting system congestion across all users of the transmission system.
- An "evolutionary" approach, whereby the allocation of TEC continues to be limited by system capability and where newly connecting generators would be required to exchange or trade scarce TEC with incumbents. In contrast to the situation today, generation without TEC would be allowed access to the electricity market, but would bear the costs of any additional congestion.
- A variant of the evolutionary approach where the initial allocation of TEC is auctioned by price.
- A hybrid "Capacity Pricing Mechanism" which would allow generation to connect in advance of transmission reinforcement, with the costs of resulting additional congestion targeted on all generation, incumbent and new, contributing to that congestion.

It is as yet unclear which of the possibilities considered by TAR will emerge as emerge as the preferred option for reform. Although a "connect & manage" approach has the virtue of

[8] Replacement role of renewable generation. Variable-output renewable generation such as wind replaces the output of conventional generation when its primary resource is available, but conventional generation needs to be retained to operate when the renewable availability is reduced.

simplicity, could be quickly implemented and is most likely to deliver the capacity of renewable generation in the timescales required, Ofgem clearly has concerns over the potential increase in network congestion and the lack of cost-reflectivity. On the other hand, detailed arrangements for access trading, possibly augmented by a multi-stage auction process, required for the "evolutionary" approach would take time to deliver and, taken together with an already complex electricity market, would represent an overwhelmingly difficult environment for small players. As discussed later, there are also concerns over the impact that the existing methodology for computing congestion costs might have on the affordability of early access with an "evolutionary" approach and its consequent effectiveness in delivering the required renewable capacity.

The Capacity Pricing mechanism proposal would target the costs of resolving network congestion on all generation contributing to that congestion and therefore would expose newly connecting generation to less cost than would be the case with an the evolutionary approach. However, all generation would be required to enter in a multi-stage auction, imposing an additional level of complexity which would effectively discriminate against small players. Furthermore, future generation projects unable to take place in the initial annual round of auctions when available transmission capability would be allocated, would be exposed to a far higher cost of access.

Given the difficulties of developing an enduring access regime capable of delivering the renewable generation capacity necessary to achieve the UK's new renewable obligations and the need to address associated electricity market issues referred to below, a two-stage approach to access reform is proposed. Initially, a connect & manage regime would be adopted to "kick-start" the connection process in order to make progress towards achieving the UK's renewable obligations and to ensure that consented renewable projects are allowed access to the electricity networks within the timescales of their planning consents. These interim arrangements would allow time for issues such as the computation of congestion costs, which threaten to undermine successful access reform, to be resolved and an enduring access regime based on sound foundations and capable of delivering a decarbonised electricity sector to be developed.

In developing an enduring access regime, consideration would need to be given to how priority for renewable and low carbon generation in accessing the electricity, necessary to deliver a decarbonised electricity sector, is to be achieved. This could be done either directly by requiring that renewable and low-carbon generation has priority in both dispatch (a statutory requirement for renewables under EU Directive 2001/77/EC) and access to the electricity market, or by ensuring that the shadow price of carbon was sufficient to allow an electricity market that did not discriminate between generation technologies, to consistently deliver the same result. A direct approach would seem to be incompatible with the bilateral electricity trading arrangements we have to date and would seem to imply the need to return to an electricity pool, based to some degree on a "minimum carbon" merit order. On the other hand, and as demonstrated by recent movements in carbon pricing, relying on factors external to the electricity market to guarantee decarbonisation would seem to be optimistic..

Electricity market issues

The "socialisation" of congestion costs

Bilateral energy trading via the BETTA forward electricity markets is "unconstrained" and takes no account of the physical limitations of the transmission system. Any transmission system congestion resulting from this unconstrained trading is resolved by the GBSO in real time via the Balancing Mechanism[9]and the associated costs are "socialised", i.e. spread across all users of the transmission system.

It is concluded that where network congestion is limited, the socialisation of congestion costs is probably acceptable. However, with the increase in network congestion and associated costs likely to occur as a result of connecting the renewable capacity required to meet the UK's climate change goals and the consequent need to "share" transmission capacity to a significant extent, the socialisation of congestion costs would appear less acceptable going forward. Alternative methodologies which allocate the costs of resolving congestion to those parties responsible for causing the congestion (both incumbent and new generation), and therefore apply appropriate signals in terms of both operation and location, would seem more suited to situations where congestion volumes are significant.

The Balancing Mechanism and the costs of resolving network congestion

Targeted congestion costs will only apply appropriate locational and operational signals if those costs are computed correctly. There are concerns that the methodology used by the Balancing Mechanism leads to the resolution of congestion being unnecessarily expensive and certainly more expensive that was the case with the Electricity Pool rules[10], which preceded the introduction of NETA/BETTA.

Apart from the implications for consumers, who ultimately bear the costs of resolving congestion, the fact that costs are higher than necessary could negatively impact on the deployment of renewable generation for two reasons. Firstly, options for allowing early access for generation are undermined due to concerns over the high costs of resolving the additional network congestion that would result. Secondly, unnecessarily high congestion costs result in a bias in favour of transmission investment when justified by cost benefit analysis, potentially inflating the volume and cost of investment required to accommodate new renewable generation. Resolving congestion via the Balancing Mechanism tends to be more expensive than alternative arrangements because of opportunities for generators to exploit commercial opportunities and also because of structural issues involving the recovery of generation fixed costs.

It is a real concern in the context of moving to a sustainable electricity system that the early connection of renewable generation is likely to be hindered by unnecessarily high costs of resolving congestion and that more transmission investment will be required to accommodate the renewable generation capacity required to deliver the UK's climate change goals than would be the case if alternative market arrangements, such as the Electricity Pool, were in place.

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[9] Balancing Mechanism, the mechanism within the BETTA electricity trading arrangements by which energy imbalances and system congestion are resolved.

[10] A summary of the Electricity Pool rules can be seen at http://www.elecpool.com/about/about_f.html

Rewarding generation capacity

The GB electricity market rewards energy only and provides no explicit reward for generation capacity, with generators having to recover fixed costs through the energy market or through other means such as the Balancing Mechanism or, in the case of peaking plant, through security contracts with the GBSO. While there appears to be no clear academic consensus on the relative merits of rewarding capacity explicitly or indirectly via energy prices, the case for separate capacity payments will become stronger as generation margins over demand increase and the utilisation levels of conventional generation deceases with the deployment of variable-output renewable generation.

Some 25GW of new generating capacity has been commissioned since privatisation of the electricity industry in 1990. However, it is worthy of note that most of this investment occurred during the period when the Electricity Pool was in place, when generation capacity was rewarded explicitly. Less generation investment has taken place since the introduction of NETA/BETTA in 2002 and although there may be other reasons for this disparity, i.e. the "dash for gas" in the early 1990s, it is probably a fair comment that the BETTA energy-only electricity market has yet to be fully tested in terms of its ability to bring forward sufficient generation investment to meet both security and sustainability requirements.

Finally on the issue of rewarding capacity, it seems probable that explicit capacity payments would help address the structural problems of the Balancing Mechanism in that it would no longer be necessary for generators to seek to recover fixed costs via that route.

Energy curtailment

With the growth in variable-output renewable generation such as wind, the likelihood of situations arising when insufficient electrical demand is available to accommodate all generation wishing to operate, will increase. High levels of wind generation output will require increased amounts of conventional plant to operate in order to provide operating reserves and this, together with the output of inflexible nuclear and other low-carbon generation, could result in situations where total potential generation exceeded available GB electrical demand, for example overnight during summer when demand levels are particularly low. In these situations, the output of wind or other zero-marginal cost plant would need to be curtailed, causing energy prices to collapse. Furthermore, energy prices could enter negative territory as wind and other renewable generation sought to retain access to ROC[11] income by continuing to operate. The prospect of wind curtailment and consequent negative energy prices would damage not only on the economic viability of wind and other renewable generation, but also high-capital cost technologies such as nuclear.

There is some dispute over the level of wind penetration at which the curtailment of output will first become necessary. SKM (2008) suggest that, depending on the availability of interconnector and pump-storage capacity, curtailment may not become significant until renewable deployment approaches 40GW. Strbac (2008b) however, based on an analysis of wind forecasting errors up to four hours ahead, suggests that energy curtailment might occur

[11] Renewable Obligation Certificates (ROC). The means adopted in GB to support developing renewable technologies. A statutory obligation is placed on suppliers to purchase a percentage of their energy commitments from renewable sources or pay a defined "buyout" price. The buy out price for 2007/08 was £34.3 per ROC however, as buyout revenue is redistributed to suppliers according to their renewable purchases, the effective value of a ROC for the period was approximately £53.

much earlier and become a real issue by the time wind and other variable-output renewable deployment reaches 25GW, well within the capacity required to deliver the UK's 2020 obligations. Uncertainty and concern over the potential need to curtail the output of zero-marginal cost plant and the consequent impact on energy prices could undermine investment in both renewable and low-carbon technologies such as nuclear and there is an urgent need to undertake detailed analysis to more fully understand the materiality of the issue and at what point it may first occur.

Happily, measures such as fuel switching, increased interconnection with adjacent electricity systems and increased bulk electrical storage are available as a means of delaying the onset of energy curtailment. There is a history in the UK (Economy 7 tariffs, radio switching etc) and elsewhere of utilising domestic thermal storage to increase electrical demand and the use of intelligent metering would allow fuel switching to be responsive to variations in renewable output. Reducing the need for curtailment by, for example, utilising electricity to provide water or space heating during periods of high renewable output would improve the financial performance and effectiveness of variable-output technologies such as wind and allow a greater capacity to be accommodated.

Increasing interconnector capacity would also be helpful in managing imbalances in generated output and demand, although as weather systems often extend beyond national boundaries it cannot be assumed that adjacent electricity systems would always be effective in accommodating UK surpluses of renewable output. Additional bulk electricity storage could also be utilised to help manage energy imbalances. However the potential for increasing pumped storage capacity in GB is limited and subject to environmental constraints, while other technologies such as compressed air electrical storage (CEAS) or flow cell battery technology have yet to be shown to be commercially viable. In the longer term, the introduction of electric vehicles at scale offers the prospect of significant amounts of distributed storage, which could be utilised to mange energy imbalances via the introduction of intelligent metering.

Chapter 6 deals with the issue of potential energy curtailment in more detail and refers to measures applied in Denmark to avoid the need for curtailment and to stabilise electricity prices during periods of high wind availability.

Transmission Investment

Accommodating the renewable capacity required to delivering the electricity sector's contribution to the UK's climate change obligations will require significant transmission investment. It has been estimated that, in addition to the £4 billion of transmission investment already authorised, in the order of £4.7 billion of additional investment could be required by 2020 - excluding the costs of cable connections to the Western Isles and Shetland/Orkney, (ENSG 2009).

In view of the scale of investment required, there is a need to ensure that the utilisation of available transmission assets is maximised, consistent with appropriate levels of demand security, and unnecessary investment avoided. Chapter 7 discusses the criteria used by NGET as GBSO and the TOs in the day to day operation of the transmission system and to determine the need for new investment. It is concluded that potential exists to increase the utilisation of existing transmission assets by taking a more risk-based approach to system operation, thereby reducing investment need. Furthermore, it is concluded that the criteria currently used to determine the need for transmission reinforcement could lead to over-investment. Taken together, there appears to be some danger that the application of current criteria for the operation and reinforcement of the transmission system could lead to the need for transmission investment required to accommodate variable-output renewable generation being over-stated. It is important, therefore, that the ongoing review of the GBSQSS, which is assessing the validity of the current standards in the light of the deployment of new renewable generating technologies and the implications of transmission access reform, develop proposals that allow the utilisation of existing transmission assets to be increased and support objective investment decisions.

Finally in relation to investment, Chapter 7 discusses the need for infrastructure developments critical to enabling the UK's renewable obligations to be undertaken on a "strategic" basis rather than in response to specific customer need in order to ensure delivery in the required timescales. Ofgem's proposals to encourage Transmission Owners to "anticipate" customer need through adjustments to the Price Control risk and reward profile are reviewed and the importance of developing appropriate rules to determine the utilisation of transmission assets and the efficiency of investments, identified.

Regulatory incentives to encourage efficient investment

The transmission business, as a natural monopoly, needs to be regulated in order to ensure that high standards of service are delivered efficiently and at minimum cost. Since privatisation in 1990, NGET as owner of the transmission system in E&W and the Scottish TOs have been subject to a form of price cap regulation via a series of periodic "Price Control Reviews". NGET as GBSO is also subject to separate regulation, the System Operator (SO) incentive, focusing on the day to day external costs of operating the GB transmission system.

Developments in Transmission Price Control methodology over time have increased incentives on TOs to undertake investment at least-cost. However, it is not clear that the Transmission Price Control and the SO incentive, in combination, provide sufficient incentives to maximise the utilisation of existing transmission assets and ensure that transmission investment is truly efficient. Currently, the regulated income that TOs are allowed to recover is a function of the value of their asset base and there is therefore an incentive to grow that asset base by building as much transmission as can be justified over a Price Control period. On the other hand, the GBSO incentive encourages NGET to outperform an operational cost baseline set for the year in question and is to all intents and purposes independent of Transmission Price Control. Taken together, there is no overall mechanism which would allow NGET or the Scottish TOs to benefit from forgoing investment opportunities and associated long-term increase in revenues if that decision resulted in a risk of an increase in system costs.

It is therefore concluded that transmission regulation currently encourages investment over the adoption of operational alternatives and that this is reflected in the TOs and GBSO taking a cautious, low-risk, approach when making operational and investment decisions. It is proposed that, given the transmission investment challenges ahead and uncertainties over the disposition and timing of renewable deployment, enabling the long-term development of a sustainable electricity system in the most cost-effective and efficient fashion will require more attention to be given to ensuring that regulation encourages the maximum, secure, utilisation of available network assets and that investment is objectively justified against operational alternatives.

At a higher level however, the issue remains that Ofgem's current primary duties place efficiency and competition above sustainability. Whether this position is consistent with the delivery of a truly sustainable electricity system is questionable. As proposed by the Sustainable Development Commission (2007) in their report "Lost in Transmission", what might be required are primary duties which require Ofgem to develop a sustainable electricity system as efficiently as possible, rather an efficient electricity system as sustainably as possible.

Transmission charging

Chapter 8 discusses the extent to which the current investment cost-related pricing (ICRP) based mechanism for charging users of the transmission system might represent a barrier to the delivery of the UK's renewable goals or discriminate against renewable generation required to locate in remote areas of the network. Although Transmission Network Use of System (TNUoS)[12] charges are higher in Scotland, where the majority of onshore renewable generation is currently locating, SKM/IPA (2008) suggests that investment returns on renewable projects are sufficient to support those higher charges. It is concluded therefore that the principle justification for the proposal by the Scottish companies, supported by the Scottish Government, that current charging arrangements discourage the deployment of renewable generation in Scotland and that uniform, non-locational, use of network charges should apply, is not supported by available evidence.

Although current charging methodology might not represent an unreasonable barrier to the deployment of renewable generation, work carried out by the Centre for Sustainable Energy & Distributed Generation (SEDG, 2007a) suggests that the methodology is not cost-reflective. SEDG demonstrate that in exporting areas of the network where generation exceeds local demand, renewable generation generally drives the need for transmission investment less than conventional generation and therefore, with an ICRP-based charging methodology, should not be exposed to the same level of charges. Conversely, due to limited ability of variable-output renewable generation to contribute to the security of demand and therefore replace the need for transmission, renewable technologies such as wind should not be credited with the same level of negative network charges in importing areas as applied to conventional generation. As the allocation of access rights via TEC is indifferent to generation technology, and TEC is the basis on which TNUoS charges are applied, differential charging on the basis of generating technology is not possible with the current access/network charging regime.

Delivering a sustainable electricity system

This paper has considered what changes to regulation, electricity markets and operational procedures may be required to deliver the UK's new 2020 renewable obligations. The changes proposed by the paper are with reference to the arrangements and preference for competitive markets which exist today and are therefore largely tactical in nature. However, rather more fundamental changes may be required to deliver the ultimate objective of a fully sustainable electricity network, which would be essentially decarbonised and capable of delivering security of supply through fuel diversity, maintaining a mixed generation portfolio of adequate capacity and appropriate industry practices.

[12] TNUoS charges. The charges applied to users of the transmission system (generators, suppliers & interconnectors) to cover the allowed costs of providing a transmission service. A description of current use of system charging methodology and actual charges can be seen at http://www.nationalgrid.com/uk/Electricity/Charges/chargingstatementsapproval/

In order to understand what these fundamental changes may be, a common understanding needs to be established of what market, regulatory and operational arrangements would best accommodate this ultimate objective of a fully sustainable electricity network. Would, for example, ensuring that renewable and low-carbon generation assume the necessary natural priority over any supporting conventional generation that needs to be retained be best achieved via a combination of a non-discriminatory electricity markets, carbon pricing and obligations on suppliers as now, or by directly assigning priority? Is bilateral electricity trading compatible with reliably minimising carbon emissions or will it be preferable to move to an electricity pool with centralised dispatch that could more accommodate a "carbon-minimising generation merit-order"? How best to maintain a diverse generation portfolio where generation margins will approach 100% and conventional generating plant will see much reduced load factors? Only once these and other questions have been addressed and an understanding achieved of what electricity market, regulatory and procedural arrangements will be required to deliver a sustainable electricity network, will the real scale of change be identified. The question then to be addressed is can that change be delivered by a regulatory authority whose primary duties relate to cost-efficiency delivered via competition, and is required only to have regard to sustainability in discharging those duties, or whether those primary duties need to be recast with the delivery of a sustainable electricity system at their heart.

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1 Introduction

1.1 Background

The UK has agreed with its EU partners to a legally binding target that 20% of the EU's energy consumption must come from renewable sources by 2020. It is proposed that the UK's contribution to meeting this target should be to source 15% of total energy consumption from renewable sources by that time. In addition, the UK has adopted a unilateral and statutory target of reducing carbon dioxide emissions by at least 60% relative to a 1990 baseline by 2050 with the Committee on Climate Change (2008) recently recommending that this should be raised to 80%, based on an updated understanding of the consequences of climate change. The delivery of these statutory and proposed targets will be extremely challenging and achieving the 2020 target alone will require a 10 fold increase in the use of renewable energy compared with the situation in 2006.

As the largest contributor of greenhouse gas emissions, the electricity sector will be required to make a significant contribution to meeting the UK's climate change obligations and longer-term goals. Just how large the electricity sector contribution will need to be depends to some extent on the contributions made by other sectors such as heat and transport. However, it seems likely that the electricity sector will be required to supply between 32 to 47% of electrical demand from renewable sources, implying the need to commission between 30 to 48 GW of new renewable capacity by 2020.

Most of this capacity, by virtue of its size or remote location, will need to connect to the transmission system, which has evolved over time to accommodate large, centralized, flexible generation. The challenges to be overcome in transitioning to a future, sustainable, transmission network that can accommodate a mixed generation portfolio consisting of diverse generation technologies having quite different dynamic characteristics and operating patterns, are considerable.

1.2 Objectives

The objective of this report is to define some of the challenges that will need to be faced in transitioning to a "sustainable" transmission network, i.e. a network that is capable of enabling the delivery of the UK's climate change obligations and longer-term goals. The report also attempts to identify those aspects of current industry practice, electricity market arrangements and network-related regulation that could hinder progress in developing a sustainable transmission network and makes proposals for change.

1.3 Report structure

The report is structured as follows;

- Chapter 1 reviews various estimates of the capacity of renewable and conventional generation that will be required to deliver the electricity sector's contribution to the UK's climate change obligations, while at the same time maintaining traditional levels of supply security.

- In the context of these generation capacity estimates and the limited timescales available for delivery, Chapter 2 considers the need for increased and early access to the transmission system and identifies problems with existing access arrangements.

- Given these problems, Chapter 3 proposes some characteristics of an enduring or long-term transmission access regime, designed to accommodate the required level of generation commissioning. Options for access reform being considered by the ongoing Ofgem/DECC Transmission Access Review are discussed in the context of these characteristics and a way forward proposed.

- Chapter 4 considers some aspects of the electricity market in relation to network access, in particular the impact of the Balancing Mechanism in resolving transmission system congestion and providing signals for investment. The issue of whether an electricity market that does not explicitly reward capacity will be capable of supporting the margin of generation capacity over demand required to enable the UK's climate change obligations, is also discussed

- Chapter 5 considers the possible need to curtail the output of wind as renewable deployment proceeds and whether this is likely to become a significant issue in terms of the economic viability of high-capital cost technologies such as wind and nuclear.

- Chapter 6 considers the issue of transmission investment required to deliver the electricity sector's contribution to the UK's climate change goals and the need for that investment to be efficient and timely.

- Chapter 7 considers the role of regulation in ensuring efficient transmission investment and that objective decisions are made in relation to trade-offs between investment and operational alternatives.

- Finally, Chapter 8 considers the issue of transmission charges and whether current arrangements discriminate against renewables or are fully cost reflective.

The analysis undertaken within the report is made with reference to the arrangements and preference for competitive markets which exist today and are therefore largely "tactical" in nature. However, rather more fundamental changes will be required to deliver the ultimate objective of a fully sustainable electricity network. This is to be the subject of another report by the author in Phase 2 of UKERC.

2 Generation required to deliver the UK's renewable obligations.

Chapter summary.

Chapter 2 considers the contribution that the electricity sector is likely to be required to make to the UK's new 2020 renewable obligations and the implications in terms of generation capacity required. The need to replace conventional generation expected to decommission by 2020 is considered and an estimate made of the total generation capacity required to commission by that time together with the implied commissioning rate. This is compared with the rate of generation commissioning achieved since privatisation of the electricity sector in 1990.

2.1 Electricity sector contribution.

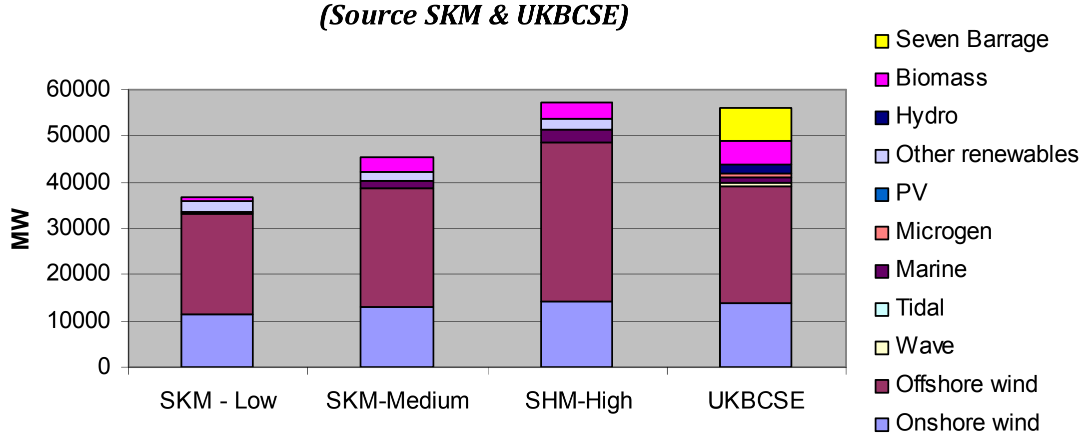
Delivering the UK's contribution to the new, legally binding, EU renewables target and longer-term climate change goals will require major initiatives across the main energy consuming sectors, electricity, heat and transport. It is not clear at present what contribution the electricity sector will be required to make, however, as the largest contributor of green house gases, it is likely to be significant. Based on an analysis of feasible build rates and technology development, SKM (2008) & BERR (2008) refer to a number of possible outcomes in terms of achieving the UK's obligations, suggesting that between 32% to 47% of electrical energy would be sourced from renewable technologies by 2020 depending on the contribution made by the heat and transport sectors. The lower estimate assumes that the heat and transport sectors will deliver contributions of 14% and 10% respectively, compared with less than 1% at present. The higher estimate of the contribution to be made by the electricity sector assumes reduced, but still challenging, contributions of 6% and 8% from the heat and transport sectors respectively. Other studies suggest electricity sector contributions towards the high end of BERR/SKM's range of outcomes will be required if the UK's contribution to the EU renewables target is to be achieved. For example the UKBCSE (2008) and Renewables Advisory Board (2008) suggest that 47% and 40% of electrical energy will need to be sourced from renewables respectively.

2.2 New renewable capacity

How this electrical energy contribution translates into renewable capacity will depend on the effectiveness of energy saving measures[13] and the balance of technologies deployed etc. A review of analysis carried out by SKM (2008) and the UKBCSE (2008) suggests, assuming no change in demand and energy requirements, that a 2020 energy contribution of between 32 and 40% will require between 37 to 55GW of total renewable capacity, compared with the current capacity of around 6GW. How this capacity may be delivered in terms of individual renewable technologies is shown in Figure 2.1

[13] See note 2.

Figure 2.1 Renewable Capacity to deliver 2020 renewable Target
(Source SKM & UKBCSE)



2.3 Replacing conventional generation

In addition to connecting new renewable generation, there is likely to be a need to replace some existing conventional generation capacity expected to decommission. Taking account of the impact of Large Combustion Plant Directive and anticipated nuclear decommissioning, it is estimated that at least 22GW of conventional plant will close by 2020, with a further 7 GW of nuclear due to retire by 2030 (UKBCSE, 2008). Even assuming zero growth in energy and peak electrical demand, a considerable proportion of decommissioning plant will need to be replaced as wind generation, which will dominate the growth in renewable capacity in the medium term, is capable of making only a limited contribution to capacity needs[14].

Depending on the precise make up of the 2020 renewable portfolio, and assuming that measures set out in the Climate Change Programme[15] result in energy and peak demand remaining unchanged over the period, it is likely that around 10 - 14 GW of decommissioning conventional plant would need to be replaced in order to maintain a margin of generation over demand at historic levels of around 20%, noting that plant margins are currently somewhat higher than 20% at the present time. Table 1 sets out the total renewable capacity required by the SKM/BERR high, mid and low energy scenarios, together with total conventional generation requirements and the convention capacity that needs to commission by 2020 to replace plant expected to close by that time.

[14] There is considerable uncertainty over the capacity value of wind generation, i.e. the extent to which it can replace conventional generation. However, at penetrations consistent with the achievement of the UK's 2020 renewable targets, there is some consensus (SKM SEDG, UKERC etc) that wind generation will have a capacity value in the range 10-20%, depending on geographic diversity. Clearly, as wind penetration increases, geographic diversity will decease and capacity values will fall. The likelihood of wind capacity in the UK being developed in specific onshore and offshore locations suggested that diversity could be limited and the capacity values could be toward the lower end of the proposed range.

[15] http://www.defra.gov.uk/environment/climatechange/uk/ukccp/index.htm

If however, energy efficiency measures were successful in reducing future energy requirements and peak demand, the need to replace decommissioning generation would reduce. In fact, in their analysis of future plant requirements carried out for Greenpeace/WWF, Poyry (2008) conclude that no new coal or gas plant would need to commission by 2020 if the Government were to achieve their own ambitious targets for energy efficiency set out in the UK's National Energy Efficiency Action Plan (Defra 2007) .

Table 1. Renewable & Conventional Generation Requirements to meet 2020 Renewable Obligations (SKM/BER Scenarios)

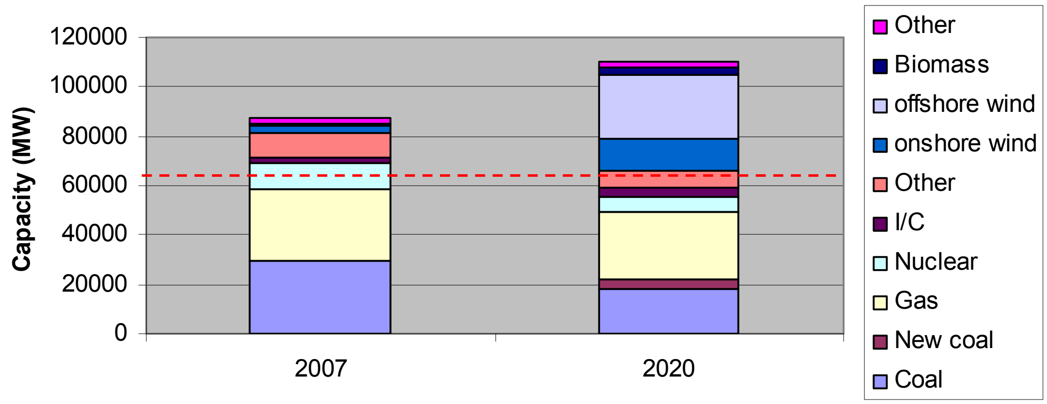
	Higher	Med	Lower
Assumed (%) contribution from renewables, consistent with 15% overall target -			
Heat -	6%	10%	14%
Road transport -	8%	10%	10%
Electricity	47%	38%	32%
Renewable capacity (GW)			
-Wind -	49	39	33
Other	6	5	4
Renewable capacity contribution (GW)[16]	12	10	8
Conventional capacity (GW) to maintain 20% margin of generation over demand	67	69	71
Conventional capacity (GW) required to replace that expected to decommission by 2020	10	12	14

2.4 Total generation requirement

Summating the need for additional renewable generation capacity with the need to replace at least some of the conventional plant expected to close in the next decade, suggests that somewhere between 45– 59 GW of *new* generation capacity will need to be commissioned by 2020. It is likely that almost all of this capacity will be transmission-connected, with only around 4GW of biomass, some smaller wind developments and micro generation connecting to the distribution networks. This represents an average connection rate of up to 6 GW/pa from now until 2020, to be compared with the average rate of just over 1GW/pa achieved since the privatisation of the electricity supply industry in 1990. Based on analysis carried out by SKM (2008), a possible breakdown of total generation commissioning required by 2020 is shown in Figure 2.2

[16] Capacity value for wind assumed to be 15%, 80% for other renewables

Figure 2.2 Growth in Generation Capacity to 2020
(*Source SKM - Mid scenario)*



3 Need for early access to the electricity networks

Chapter summary.

Given the six fold increase in average generation commissioning rate required to deliver the electricity sector's contribution to the UK's renewable obligations, this chapter considers the need for reform of current transmission access arrangements.

Current transmission access methodology is briefly described and a number of problems identified, relating to a failure to recognise the replacement role of variable-output renewable generation or the associated need to share available transmission capacity and the absence of any signals as to the short-term value of transmission capacity which would allow objective decisions to be made between the need for transmission investment and operational alternatives.

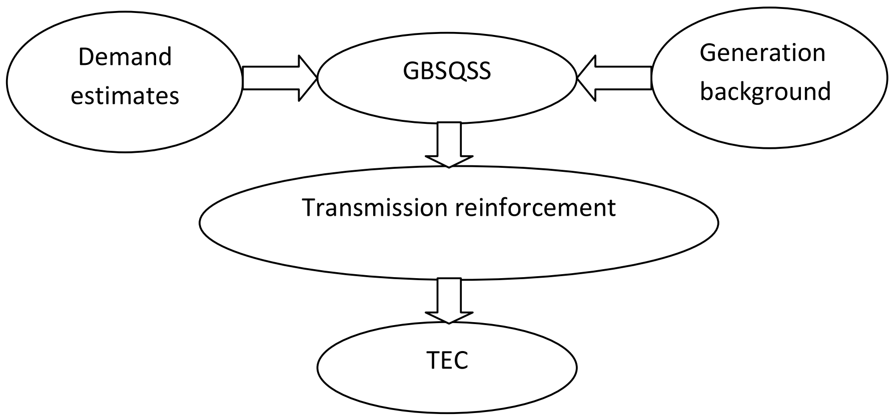
As discussed in chapter 2, delivering the UK's renewable obligations while maintaining traditional levels of generation adequacy will require a significant and sustained increase in the rate at which generation connects to the transmission network. The rate at which new renewable capacity becomes available to connect will of course be influenced by supply-side and consenting constraints, however these issues operate "in series" with that of transmission access and all three need to be addressed if real progress towards achieving our renewable obligations is to be made.

Evidence that existing transmission access arrangements (see Box 3.1) are inadequate in terms of delivering the renewable capacity required to meet the UK's renewable obligations is clear. Currently, there are some 3.2 GW of consented wind projects, mostly in Scotland, awaiting access to the electricity network. A further 9GW of unconsented projects, all with connection agreements, are awaiting connection - some having projected connection dates beyond 2018. For reasons associated with the development of the connection queue in Scotland[17], failure to

[17] As part of the transition to the GB electricity markets in the form of BETTA, any project wishing to connect in Scotland was required to submit a connection application by 31 December 2004 in order for that connection

Box 3.1. Existing transmission access arrangements[18]

The arrangements to be negotiated by generation wishing to connect to the transmission system and participate in the electricity markets date back to the pre-privitisation era, when responsibility for transmission development and generation planning lay with a single entity, the CEGB, and total coordination between the two processes was possible. NGET as GBSO and the TOs continue to operate a "predictive" (SEDG, 2007b) approach to the development of the transmission system, applying demand and contracted generation information to long-standing investment criteria, set out in the GBSQSS, to determine what transmission developments are required.



Once all necessary reinforcements have been commissioned, and not until that time, a connecting generator will be allocated "Transmission Entry Capacity (TEC)", which gives the right to export to the transmission system and participate in the electricity markets. It should be noted that exports to the transmission system above the defined (MW) level of TEC allocated are prohibited. In other words, the GBSO and TOs are said to operate an "invest and then connect" approach to transmission access, whereby connection is only allowed once network compliance with the investment criteria set out in the GBSQSS has been fully achieved.

Annual charges for using the transmission are allocated per kW of TEC, rather than on a commodity or utilisation basis. This, together with exports in excess of TEC being prohibited, tends to discriminate against technologies such as wind generation. There is no option but to contract for TEC up to the maximum output likely to be achieved, even through wind generation will normally operate well below its maximum output.

was to be contingent on transmission works in Scotland only. Applications for connection received after this date would require any necessary transmission reinforcement in E&W to be completed before connection. This deadline resulted in a rush to submit applications (in excess of 16GW) for connection, many of which where speculative or made earlier than appropriate. Queue position was dependent on the date at which an application was received and this has resulted in viable projects, many with planning consents, being "blocked" by speculative projects or those at an early stage of development. Ofgem have recenltly indicated that they are minded to revisit the December 2004 deadline.

[18] A detailed description of the current access regime is contained within the Connection & Use of System Code (CUSC) at http://www.nationalgrid.com/uk/Electricity/Codes/.

obtain planning consents and natural attrition, many of these projects will fail to materialise. It is therefore difficult to imagine more than, say, 7-8GW of onshore projects currently residing in the Scottish queue and elsewhere in E&W actually proceeding to completing and, given that any new onshore wind projects seem most unlikely to connect this side of 2020 under existing access arrangements, total wind connections seem certain to fall considerably short of the 15GW capacity assumed in terms of delivering our renewable obligations.

It is perhaps surprising, given the move to competitive energy trading with privatisation of the electricity supply industry in 1990 that a predictive, centralised, non-market approach to accessing those energy markets has survived for so long. No doubt this is in part due to the relative success of these arrangements in connecting some 25GW of conventional generation since 1990. However, the current arrangements have proved less successful in dealing with smaller, more risky and often remotely connected renewable generation projects which, once consented, can be constructed in rather shorter timescales than traditional coal or gas fired generation projects, or the associated transmission reinforcements.

Concerns about transmission access, particularly the fact that the current arrangements sat uncomfortably with the new energy markets, have existed for some time. In fact, Ofgem's predecessor, Offer[19], first raised the need for reform at the time of industry privitisation in 1990. More recently, concern over mounting delays in connecting renewable projects and the potential of the current arrangements to jeopardise the delivery of the UK's renewable targets, led to transmission access and related issues being highlighted in the Energy Review of 2006 and the Energy White Paper published by BERR in May 2007. In the latter document, a joint BERR/Ofgem review of the current arrangements, TAR, was announced, the final conclusions of which were published in June 2008.

3.1 Problems with existing access arrangements

Underlying the obvious concerns that existing access arrangements are a barrier to the delivery of the UK's renewable obligations and do not allow access to transmission system in timescales that are consistent with generation project development, are a number of more fundamental problems, including;

- an inability to recognise the replacement role of renewable generation or embrace the concept of "shared" transmission access,
- inadequate information concerning the need for transmission investment
- the absence of any signals concerning the short-run value of transmission.

3.1.1 Limited opportunities to share transmission capacity.

The methodology set out in the GBSQSS for determining the need for transmission reinforcement is based on the premise that all generation generally needs access to the electricity network at the same time, i.e. to contribute to meeting peak demand. While this assumption is valid with for conventional generation, it is less so when considering a mixed generation portfolio that includes a significant proportion of variable-output renewable generation.

[19] Offer, Office of Electricity Regulation. Gas and electricity regulation was combined with the creation of the Gas & Electricity Markets Authority and Ofgem via the 2000 Utilities Act.

Renewable generation such as wind has a predominately replacement role, i.e. it will operate when its primary resource is available and replace energy that would otherwise have been produced from fossil fuels. However, intermittent generating technologies cannot be guaranteed to be available at any specific point in time and wind output has been shown to have a poor correlation with peak demand (Oswald, 2007, SKM 2008). The ability of wind to replace conventional generating capacity is therefore limited and most conventional generation will need to be retained in order to ensure that traditional levels of generation adequacy are maintained.

The consequence of an increasingly mixed generation portfolio will be that far more generation will need to be connected to the transmission system than the system has the capacity to accommodate. The transmission system will need to be sized to satisfy demand rather than attempt to accommodate the output of all connected generation simultaneously. In other words, connected generation will be required to "share" available transmission capacity on the basis of need. Renewable generation such as wind will utilise available transmission capacity when its primary resource is available, with conventional generation taking up that capacity when the availability of renewable resource is reduced.

Unfortunately, the present arrangements for allocating TEC prevent the sharing of transmission access to any significant degree. As indicated previously, no generator is allowed to export to the transmission system until it is awarded TEC and this does not occur until the transmission system has been reinforced and is capable of accommodating the totality of access rights awarded. Because of the particular application of the GBSQSS, which assumes that wind generation has an unrealistically high load factor (60% compared with 83% for conventional generation), only limited sharing of transmission capacity is possible, resulting in a system that is essentially designed to accommodate all generation all of the time.

3.1.2 Inadequate transmission investment signals

The allocation of TEC incurs a liability to pay TNUoS charges for one year ahead only, in exchange for the right to renew the arrangement on an indefinite basis. Currently, therefore, incumbent generators are able to "reserve" transmission capacity into the future at the cost of one year's payment of TNUoS charges. This, together with the need to give only very limited notice of decommissioning[20], creates uncertain signals for transmission investment. Without some knowledge of the intentions of incumbents and their future need for transmission capacity, it is difficult for the GBSO and TOs to make efficient investment decisions. Although, in pursuing their "predictive" approach to identifying future requirements, the GBSO will have access to some intelligence about generation decommissioning, for example whether or not a generating station has signed up to compliance with the Large Combustion Plant Directive, the lack of any requirement for incumbent generators to commit in advance for transmission access makes efficient transmission investment decisions problematic.

These difficulties are exacerbated with the growth of renewable technology projects such as wind, which are often more uncertain in nature than large conventional generation projects. A predictive "invest then connect" methodology is less effective in dealing with smaller, less certain generation projects which often have considerably shorter development timescales than

[20] Section 5 of the CUSC requires 6 months notice of decommissioning. However, in practise much less notice is necessary as only 5 days notice of a reduction in TEC is required.

the transmission infrastructure required to accommodate them. Because of the long lead-times that can be associated with transmission development and the limited timescales of generation project planning consents, projects are often required to seek connection agreements at a very early stage - well before planning consents have been obtained or even sought. At this stage in their development, small generation projects can be very uncertain. However the current methodology employed by the GBSO assumes that all projects that have signed a connection agreement will commission and transmission reinforcement is planned on that basis.

3.1.3 No signals as to the real value of transmission.

In the GB electricity market, energy trading and transmission access are largely separated. A generator may contract to sell his output within the constraints of his TEC allocation without any regard to the costs that may be imposed on the transmission system. Access rights associated with TEC are financially firm and if a generator is required to constrain his output in real time in order to avoid network overloading, the constrained energy is paid as if it had actually been produced. Any constrained energy will be replaced through the Balancing Mechanism, and the resulting costs are spread across all users of the transmission network via the payment of Balancing Services Use of System Charges (BSUoS)[21] charges.

Generators are therefore shielded from exposure to the real short-run value of transmission (the value of additional transmission in avoiding the costs of constraining energy) by obtaining TEC, bought at the predicted cost of incremental network capacity via TNUoS charges. As there is no option to export without TEC, there is no mechanism to reveal this short-run value or allow new entrants access prior to the completion of all necessary transmission works. This failure to reveal the short-run costs of transmission and the consequent inability of generators to choose between exposure to those costs or avoidance through obtaining additional TEC via investment, could well lead to inefficient network investment and locational decisions.

4 Developing an enduring access regime compatible with the delivery of the UK's new renewable obligations

Chapter summary.

Building on the review of existing transmission access arrangements set out in Chapter 3, this chapter considers what characteristics an enduring access regime, capable of delivering the UK's new renewable obligations, might require.

Progress with the ongoing Transmission Access Review (TAR) is discussed, and the options for change being considered are reviewed against the characteristics that it is proposed an enduring access regime might require. Based on these options for change, and taking account of the need to address electricity market deficiencies that threaten to undermine the development of an enduring access regime, a possible way forward is proposed. This would involve the introduction of an interim arrangement to "kick-start" the connection of consented renewable projects while at the same time allowing time for appropriate market reform. Once these

[21] Balancing Services Use of System (BSUoS) charges cover the costs incurred by the GBSO in energy balacing, resolving network constraints and procuring a range of other services related to the secure operation of the transmission system. Charges are levied on all users on the transmission system on a per kW basis.

market deficiencies had been addressed, a robust enduring access regime could then be introduced.

4.1 Characteristics of an enduring access regime

In addition to ensuring that traditional levels of security are maintained, an enduring transmission access regime will need to allow generation early and affordable access to the transmission network to enable the delivery of the UK's renewable obligations and address the deficiencies of the access current regime set out in 3.1. Taking these requirements together, it is proposed therefore that an enduring access regime would need to;

- Allow the timely connection of renewable generation, consistent with both individual generating project development timescales and the overall delivery of the UK's climate change goals,
- Recognise the replacement role of renewable generation and allow the utilisation of transmission assets to be maximised by sharing available capacity on the basis of temporal need,
- Provide choice in access products and ensure that those choices are fully cost-reflective,
- Ensure the delivery of strong and cost-reflective signals for efficient and timely transmission investment and that traditional levels of security are maintained.

In order to achieve these requirements, particularly ensuring optimum levels of investment and maximising the utilisation of available transmission assets, it will also be necessary to address certain electricity market and regulatory issues referred to in Chapters 5 & 8 respectively. Although not strictly part of an enduring access regime, the need to ensure that general regulatory incentives encourage appropriate trade-offs between capital and operational expenditure and that price signals emerging from the electricity market accurately reflect the true short-run costs of transmission, is crucial if investment is to be efficient and the utilization of assets maximized.

4.2 Transmission Access Review

The "final" conclusions the Transmission Access Review (BERR, Ofgem 2008a), initiated by the 2007 Energy White Paper, were published in June 2008 setting out high-level principles that should underpin an enduring access regime capable of delivering the UK's renewable goals, together with three options for further development. These options where described as "connect & manage", a "market-based or incremental approach" and a "locational marginal pricing (LMP)[22]" model.

However, the TAR process continued with the development of a suite of modular amendments to the standard industry contractual arrangements, as set out in the Connection & Use of System

[22] Locational Marginal Pricing. An electricity market methodology which involves the centralised computation of electricity prices at each node of the transmission system. The nodal prices contain both an energy element and an element representing congestion costs. Therefore, in the presence of congestion, nodal prices will differ across the system. For a brief description, see 5.2

Code (CUSC)[23], via established industry governance processes. Using these modular CUSC amendments as building blocks, any of the three high-level proposals set out in the TAR Final Conclusions document, together with a fourth "auction-based" alternative, could be developed. The modular amendments were progressed by a number of working groups established by the CUSC Amendment Panel, which oversees modifications to the CUSC document, and have now been presented to Ofgem with recommendations.

Using the suite of proposed CUSC amendments, Ofgem is now tasked with constructing an access regime which will deliver the contribution to the UK's renewable objectives required of the electricity sector and which is consistent with both the relevant objectives of the CUSC which relate to the Gesso's legal obligations and the facilitation of competition, and Ofgem's primary objectives. Ofgem is to publish its conclusions in the summer of 2009.

Notwithstanding the "deconstruction" process adopted by the CUSC Panel in progressing the various amendment proposals, two of the three high-level models identified by the TAR Final Conclusions Document, together with auction-based alternatives favoured by Ofgem, effectively remain the primary candidates for selection as an enduring access regime. The third model identified by TAR, which was a derivation of the "locational marginal pricing or LMP" approach adopted in parts of the US (PJM & New England electricity markets) and elsewhere, was rejected by the CUSC Panel as representing too great a development challenge in the timescales available.

The key features of the three re-constructed candidate access models and variants that emerged from the CUSC development work and which are currently sitting with Ofgem for determination, are described in the following paragraphs.

4.2.1 Connect & Manage.

Under this model access rights in the form of TEC would be user-defined rather than system-defined as now and, potentially, there would be no limit to the amount of firm access rights issued. Generators would be given a guaranteed connection date, possibly three or four years ahead, and could connect at this point irrespective of whether any associated transmission developments had been completed or not. Access rights would be firm, in other words a generator would be compensated in the event of output being constrained for network-related reasons and the cost of those constraints would be "socialised" i.e. recovered form all users of the network via BSUoS charges as now.

As the totality of access rights issued could exceed the capability of the network by some margin leading to increased network congestion, there is concern over the potential costs of implementing a connect & manage regime. To address this concern, the CUSC working group developed a variant of connect & manage, which targeted the increased costs on the newly connected generation causing the increase in congestion. This model begins to look very much like "overrun" as described in 4.2.2, with the exception that costs would be calculated ex-anti, and would therefore be more "bankable" in terms of project finance.

[23] The Connection and Use of System Code (CUSC). The code which sets out the contractual arrangements for using the transmission system. The CUSC is a modifiable document and the modification process is overseen by the CUSC panel, which recommends modifications to Ofgem to endorse or reject.

4.2.2 Evolutional change/finite access rights.

With the “evolutionary change” model, access rights remain “system defined” as now, i.e. the allocation of TEC would be limited to that which could be supported by transmission system capacity. Existing generators would be required to specify the number of years for which access was required and would commit to the payment of TNUoS charges for that period. New generators would be awarded TEC once all work required to ensure compliance with GBSQSS standards had been completed, but would be allowed to export to the system as soon as physical connection could be achieved. A newly connected generator could then trade TEC with incumbent generators or “overrun” in the period before full access rights where awarded on completion of any necessary reinforcement. If a generator chose to export to the system in excess of any firm access rights held in the form of TEC, i.e. to “overrun”, it would be exposed to the any costs associated with resolving congestion caused by that overrun.

4.2.3 Capacity auctions

A similar approach to “evolutionary change”, but with finite access rights allocated via auction rather than “grandfathered”, which arguably discriminates in favour of incumbent generators. Both incumbent and newly-connecting generators would bid for access for the required number of years. Bids would be stacked in descending price order and allocated on a pay as bid basis up to the point at which transmission system capacity was fully utilised. Any unfulfilled bids would be tested to identify whether incremental capacity release via investment would be justified. Unsuccessful bidders would have the opportunity to seek access from successful bidders via secondary trading or to rely on overrun.

An interesting alternative to a price-based auction considered by CUSC was that of a capacity and duration-based auction. With this arrangement, all generators would declare their total requirement for access. This would be met in full, consisting of a pro-rated TEC element reflecting the physical capacity of the network, with the remainder effectively considered as “overrun” or “over-allocation”. The overall price of the awarded access would consist of the pro-rated element bought at cost (i.e. TNUoS charges) with the “over-allocation” to be bought at a price reflecting the estimated costs of resolving the associated network congestion. In subsequent auction rounds, generators would be able to adjust their capacity bids to reflect their willingness to pay the composite access price.

4.3 Comparison of alternative access models considered by the TAR

In 4.1, it was proposed that a long-term access regime capable of accommodating the renewable and low-carbon generation capacity required to deliver the UK’s renewable obligations would need to have a number of specific attributes. The following paragraphs consider the extent which the three models developed via the CUSC Amendment process compare in terms of these attributes and the extent to which they overcome the deficiencies of the current access arrangements.

4.3.1 The timely and affordable connection of generation

Both connect & manage and the evolutionary change proposals have the potential to provide earlier generation connection than the access current regime. However, the cost consequences of early entry under the two alternatives would be quite different and this is likely to affect the extent to which generation will consider early access to be an attractive option.

With connect & manage, any generator wishing to connect to the transmission network would have a firm connection date and access would be bought at cost, i.e. via the payment of TNUoS charges reflecting the long-run marginal cost of connection. Early connection under the evolutionary change approach could be achieved by purchasing firm access rights via an annual auction (the auction variant), via secondary trading or, on a non-financially firm basis, via overrun. No matter which route is taken, obtaining early access for a renewable generator would be more expensive than with connect & manage, where the consequences (i.e. the costs of managing additional congestion) of early access are socialised. If the overrun route is taken, then the cost of any increased congestion caused would be borne by the overrunning generator, together with a local connection charge and the residual proportion of the wider TNUoS charges[24]. For the reasons explained in chapter 5 of this report, the intended use of Balancing Mechanism price signals to determine the costs of overrunning implies that those costs will be high and also uncertain as they will be calculated ex-post. The alternative to overrunning would be to purchase firm access rights from via auction or from an existing holder. However, the auctioned or traded cost of access would be influenced by the avoided cost of overrunning and would also be high.

There is therefore a real concern that, although an evolutionary approach may appear to offer the opportunity for renewable generation to obtain earlier access to the electricity network, the cost of early access may be prohibitively high and uncertain. The effectiveness of the approach in terms of actually delivering early connection is therefore likely to be diminished and certainly less effective in this regard than "connect & manage". An exception to this may be case of incumbent conventional generators who also have adjacent renewable projects. For example, with the evolutionary change approach where access rights are "grandfathered", generating companies operating in Scotland who have both conventional and renewable generation would be able swap access at zero net cost, while independent renewable generators would face the full costs of obtaining firm access.

There is also a general concern that the evolutionary change approach would inherently place wind and other intermittent generation at a disadvantage. Variable-output generation would require access to the transmission system at a time when constraints were active, short-run costs high and hedging these costs through the purchase of access, expensive. On the other hand, variable-output generation would tend to sell rights held when they were unable to operate due to lack of resource, constraints more likely to be inactive and the value of access low. The converse would of course be true for conventional generation. While this is arguably a penalty of being an intermittent generator, when taken together with the complexity and general cost of the approach, the overall outcome might be that a market-based mechanism may not be a comfortable environment for variable-output generation and therefore be less effective in delivering the increase in renewable generation connection required.

4.3.2 Sharing network assets and recognising the replacement role of renewable generation.

Both connect & manage and the evolutionary change models recognise the replacement role of renewable generation and would allow network assets to be shared according to need. Connect & manage would achieve this by allowing more generation to connect than the network had the

[24] As an overrunning generator would require physical connection, local TNUoS charges would be payable. The residual portion of the wider TNUoS charge would also be applied as this is paid by all connected generation. .

capability to support and would allow renewable generation to replace the output of conventional generation whenever its primary resource was available. The evolutionary change model would achieve the same outcome by allowing renewable and conventional generation to trade access according to need or by allowing generation to overrun. As discussed in 4.3.1 however, there are concerns of the potential costs of those options.

4.3.3 Signals for efficient and timely transmission investment

A connect & manage regime would provide clear and strong investment signals. As access rights would be guaranteed by a specific date, a generation project would apply for connection only once planning consents had been obtained and financial closure achieved. Projects applying for connection would therefore be firm and the GBSO would be able to plan ahead with confidence. In other words and as described by Strbac, Ramsay & Pudjianto (SEDG 2007b), a connect and manage world would allow the GBSO to "observe" actual generator connection activity and plan accordingly.

An evolutionary approach to transmission access should also provide clear signals for network investment. Where transmission capacity was scarce and constraints active, short-run costs would be high. Generators would be encouraged to purchase firm access rights from incumbents or via an auction to hedge short-run costs and to seek the release of additional transmission capacity in the longer term via investment. Alternatively, where transmission capacity was plentiful, short-run costs would be low and generators would have little incentive to seek additional capacity though investment. The evolutionary approach could therefore be expected to amplify locational signals and therefore offer more encouragement for generators to connect in unconstrained areas, leading to more efficient transmission utilisation and investment. Over the longer term, transmission development should allow short term value and long-term cost to converge.

4.3.4 Cost reflectivity

Subject to the concerns express in 4.3.1, the evolutionary change model potentially scores well in terms of cost reflectivity. The increase in short-run network costs resulting from the connection of new generation are focussed on those generators and, as indicated above, locational signals would be amplified. However, as the increased level of congestion is a result of the operation of both existing and newly connecting generation, it could be argued that all generation should bear the increased congestion cost. This issue is addressed by the "volume & duration" variant of the Auction model which targets increased congestion costs on all generation in a constrained area of the network, not just on the newly connecting generation.

Connect & manage does not fare so well in terms of cost-reflectivity. As connecting generation would be guaranteed firm access rights with a specific timescale, irrespective of whether associated transmission reinforcements had been completed or not, network congestion would almost certainly rise. As the resulting costs would be socialised across all users of the system, some argue that a cross subsidy would be created in favour of newly connecting generators. However, it can be argued that connect and manage would do no more that place connecting generators on the same footing as existing generators, i.e. in exchange for the payment of use of system charges, both existing and connecting generators would receive firm access rights and see the consequences of their operations socialised.

4.4 A way forward

Connect & manage appears to more likely than the evolutionary change approach to deliver the renewable generation capacity required to deliver the UK's renewable obligations in the timescales available. It also has the considerable virtue of simplicity and could be implemented at a relatively low cost. The evolutionary change approach on the other hand would involve complex and expensive trading arrangements operating close to real time, possibly preceded by a multi-round auction process, which would add significantly to the burden faced by generators, particularly small generators, in having to deal with already complex energy trading arrangements.

If it were not for concerns over the lack of cost-reflectivity and the potential for excessive network congestion, connect & manage might seem the obvious choice for an enduring access regime. However, connect & manage would be no worse than current arrangements in terms of cost-reflectivity, while the concern over the costs of resolving excessive congestion may, partially at least, be misplaced.

Analysis by SEDG and Poyry (2008) suggests that the costs of resolving congestion may be relatively modest in the early years but would then escalate with increasing renewable deployment. In the absence of transmission reinforcement, the application of connect & manage in its basic form would result in renewable generation becoming increasingly constrained with ROC income recovered though the Balancing Mechanism, resulting in increased bid-offer spreads and an increase in the cost of resolving those constraints. A similar conclusion can be drawn from Ofgem's analysis of CAP 148 (2008a), suggesting modest growth in congestion costs up to 2015, a steep increasing in the following three years with costs then reaching a plateau as onshore wind development slows. Analysis carried out by the CUSC working group charged with developing the connect & manage amendment (see CUSC Panel, 2008), suggests that, taking account of the cost of carbon, connect & manage is likely to produce a net benefit in the years prior to 2014, after which rapidly increasing congestion costs prevail.

There is a therefore a general consensus that connect & manage would result in a modest increase in congestion costs in the early years, but that costs would rise significantly in the middle of the next decade as wind generation becomes increasingly constrained due to lack of transmission system capacity. This suggests that a more "intelligent" form of connect & manage could be applied which gave newly connecting generation firm access rights in guaranteed timescales, other than in situations where the connection of that generation would lead to existing wind generation being significantly constrained. There seems little point in connecting additional renewable generation where there was no significant benefit in terms of progress towards the UK's renewable targets and where ROC payments would effectively paid twice – once for renewable energy produced and once for constrained renewable energy via Balancing Mechanism payments.

This "intelligent" variant of connect & manage was that originally envisaged by Ofgem and BERR and referred to in early TAR documentation (see BERR, Ofgem 2008b & c), but for some reason has not been specifically progressed by the CUSC work streams. The variant was, however, effectively considered by CEPA (2008) in their analysis of connect & manage carried out for the BWEA which suggested that, taking the cost of carbon into account, a small negative NPV would accrue over the years to 2017/18. Furthermore, if the cost of constraining wind and ROC costs associated with increased renewable commissioning are removed from Ofgem's CAP 148 analysis, connect & manage actually shows a modest positive NVP in three of the five scenarios considered.

Early connection of consented renewable projects needs to be achieved if the UK's renewable obligations are to be met. Given the concerns over the ability of an evolutionary access model to allow early access at and affordable costs and the difficulties of designing an enduring access model without first addressing fundamental issues relating to the operation of the Balancing Mechanism, it seems appropriate to adopt an intelligent form of connect & manage. This could be achieved rapidly and at little cost, giving time to develop a more cost-reflective enduring access regime based on sound market and regulatory foundations.

Ofgem and BERR in fact have gone some way in this direction by acknowledging the need to implement a "form of connect & manage" (see BERR, Ofgem 2008a) prior to the implementation of an enduring regime. However, what is being implemented is not in reality connect & manage where access would be user-defined, but allows a limited amount (approx 400MW so far) of renewable capacity to connect in Scotland by granting derogations from GBSQSS criteria, where this can be shown to be cost neutral.

5 Market issues

Chapter summary.

This chapter considers aspects of the GB electricity market arrangements in the context of delivering the UK's new renewable obligations.

The implications of "unconstrained" bilateral trading and "socialising" the costs of resolving system congestion are considered, given the likely increase in congestion resulting from the need to accommodate increased margins of generation over demand and the consequent need to share available transmission capacity.

The current Balancing Mechanism methodology is compared with alternate arrangements for resolving network congestion is discussed. The relationship between the cost of resolving congestion and the value of transmission is considered and it is shown that Balancing Mechanism methodology results in the value of transmission being overstated.

The implications of the GB electricity market only rewarding energy are discussed. The issue of whether explicit capacity payments will be required to support the increased generation margins associated with a mixed conventional and renewable generation portfolio and where conventional capacity will experience reduced utilisation, is considered. Finally, the possibility of capacity payments partially resolving the issue of the Balancing Mechanism overvaluing transmission is noted.

5.1 The GB electricity market.

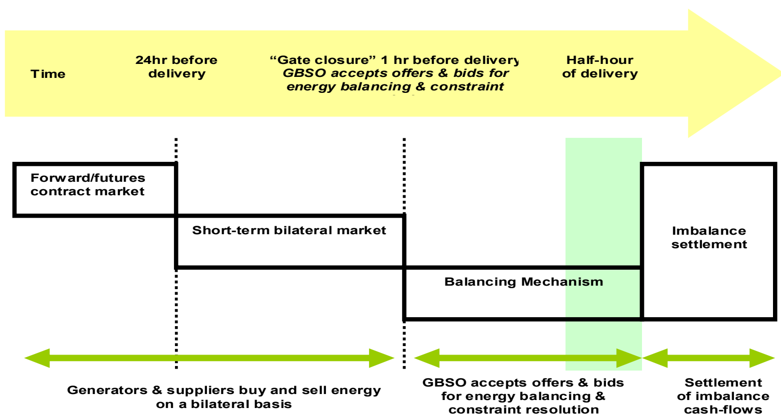
The current electricity trading arrangements were introduced in England & Wales in 2001 to replace the Electricity Pool and were extended to include the Scottish electricity market with the introduction of BETTA in 2004. Unlike the Electricity Pool, BETTA is an energy-only market, with no explicit recognition of or reward for generation capacity. As described in Box 5.1, the majority of energy is traded bilaterally in forward and short term markets on an "unconstrained" basis, i.e. no account is taken of any physical transmission system capacity constraints when striking contracts to supply or receive energy.

Box 5.1. BETTA Overview

Bilateral forward and short-term markets

Generators, suppliers and traders can enter freely negotiated contracts to sell or buy electricity in much the same way as any other commodity market. The bulk of electricity is traded via power exchanges or via bilateral contracts, covering timescales from several years ahead down to "gate closure", 1 hour ahead of real time. At gate closure, when parties are required to declare their final contracted position, down to real time, a "Balancing Mechanism" is available to permit NGET as GBSO to maintain an energy balance in each half-hourly settlement period and resolve any transmission congestion arising from the forward energy trading. Finally, an "imbalance settlements" process allows notified contractual and physical positions to be reconciled after the event and cashed out. An overview of the BETTA market structure is given in figure 5.1.

Figure 5.1. BETTA Market Overview



Balancing Mechanism & Counter flows

The forward and short-term bilateral markets assume a commercially infinite transmission system and market participants can trade energy without needing to consider the physical capability of the transmission system, or the implications that might result from their trading activities in terms of congestion or energy losses.

Where the net electricity flows resulting from the trading process exceed the physical capability of the transmission system, the GBSO will establish appropriate counter flows by utilising the Balancing Mechanism. Participation in the Balancing Mechanism, which is optional, involves generators or demand takers submitting 'offers' (proposed trades to increase generation or decrease demand) and/or 'bids' (proposed trades to decrease generation or increase demand). The GBSO will accept offers and bids to establish appropriate counter-flows so as to ensure that the transmission system can be operated within its physical capability.

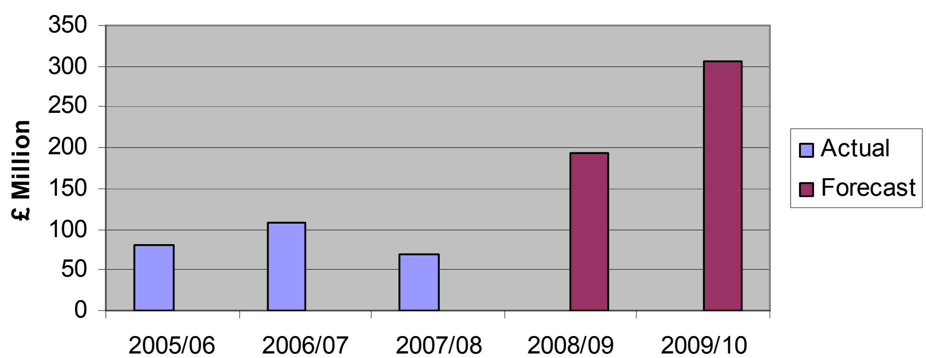
5.1.1 Unconstrained trading and the socialisation of system congestion costs

The "unconstrained" nature of the forward electricity markets, together with the "socialisation" of congestion costs effectively shields individual users of the transmission system from the real consequences of their operations. In other words, by purchasing TEC at the incremental cost of transmission reinforcement via TNUoS charges, a system user will avoid the direct cost of any congestion that may result from fulfilling an energy trade which, if transmission capacity is scarce, may be significantly greater than the incremental cost of reinforcement.

While network congestion volumes are comparatively low, as has been the case until recent years, the socialisation of constraint costs may be acceptable given the complexity of alternative arrangements required to allocate the costs of resolving constraints to those parties causing that congestion. Furthermore, and as discussed in Chapter 3, the potential for excessive constraint volumes and costs is mitigated by the current "invest and connect" approach to transmission access, which prevents generators connecting to the network and obtaining TEC until all necessary transmission reinforcements are completed. However, an "invest and connect" approach is incompatible with the need to allow early access to renewable generation and seems certain to be replaced with the introduction of enduring transmission access arrangements developed via TAR that will allow far more generation to be connected than the transmission network has the capacity to accommodate simultaneously.

The potential is, therefore, for constraint volumes and costs to rise as more renewable generation connects in order to meet the UK's climate change obligations and figure 5.2 indicates that process has already begun. The question arises, therefore, as to whether the market assumption of a commercially infinite transmission network and the socialisation of constraint costs will continue to be appropriate or whether a more cost-reflective, albeit more complicated, market arrangement would be justified where all generators would be exposed to the short-run costs of transmission.

Figure 5.2. Constraint Costs since Introduction of BETTA (*source National Grid*)



5.2 Locational marginal pricing (LMP)

One such arrangement would be locational marginal pricing (LMP) as increasingly practiced in the US and elsewhere. There is an abundance of literature describing the theory and practice of LMP (see for example Hogan 2008, Hausman et al 2006) and a detailed description is beyond this report. However, in principle, an LMP market would aim to minimise the cost of producing energy by utilising the least-cost set of available generators and identifying the incremental cost of energy at each major node on the network. This would involve the GBSO computing electricity prices for each major network node via a security-constrained economic despatch algorithm, based on generator bids. The computed nodal prices would consist of an "energy" element and an element that represented the impact of network congestion. Where no congestion existed, nodal prices across the network would be uniform, however the existence of congestion would cause nodal prices to diverge.

A feature of LMP pricing in the presence of network congestion is that more income is recovered from demand takers than is paid to generators. Furthermore, it is possible to associate this surplus revenue with particular constraints. The surplus revenue is therefore available for reallocation to the owners of "Financial Transmission Rights" (FTRs), auctioned by the System Operator to the level of available network capacity and purchased by market entities as a hedge against the cost of congestion. A generator who owned a FTR would be immune to costs of network congestion up to the capacity of the FTR and, as the instrument is a "financial" rather than "physical" right, would receive income whether he generated or not.

Unlike the current BETTA electricity market and associated access regime, where locational signals are restricted to those applied via TNUoS charges, LMP pricing exposes all market entities to the costs that their operations impose on the network. While these costs may be hedged by the purchase of FTRs, the prices paid via auction would reflect the scarcity value of transmission. In theory, therefore, FTR prices would be a strong signal as to the need for additional transmission capacity to be released via investment; however there is some concern as to the extent to which, in practice, LMP has delivered the required level of network investment. In their review of the LMP-based PJM and New England electricity markets, Synapse Energy Economics (2007) conclude that LMP has not been successful in providing the necessary incentives for optimal investments in transmission, due to a number of factors including the lack of a clear mechanism for assuring adequate returns on that investment.

Despite concerns over the extent to which LMP electricity markets bring forward new transmission, which may not be so relevant in GB given the prospect of regulated returns for efficient investment, LMP appears to be an increasingly popular market design. In his review of transition in the US electricity systems, Hogan (2008) notes the IEA view that LMP serves as the benchmark for market design - "the textbook ideal that should be the target for policy makers". However, moving from the current GB bilateral energy trading arrangements to an LMP model would be a radical and costly process. In contemplating any change, there would need to be a common and clear understanding that the long-term benefits outweighed the costs and disruption of implementation. However, one clear and obvious advantage of an LMP-based model over the current BETTA arrangements would be in dealing with transmission constraints, as discussed in the following section.

5.3 Does the Balancing Mechanism over-value transmission?

5.3.1 The value of transmission

In order to address the question of whether BETTA and the Balancing Market overvalue transmission, it is necessary to consider what the perceived value of transmission is. Originally, transmission in the UK developed on a regional basis to allow local power plants to supply local demand. Over time, transmission expanded to link local networks and allow the economies of building larger, more efficient, centralised power stations sited near their sources of supply, to be captured. Expanded transmission and the interconnection of separate local networks also allowed a major reduction in the level of reserve generation that needed to be held in order to maintain adequate levels of generation adequacy. Historically therefore, the value of transmission has been principally been the reduction of energy costs through generating efficiency and reduced plant margins.

With the highly integrated nature of the GB transmission system, it is unlikely that additional transmission investment will bring any further gains in terms of reliability or the increased sharing of reserve. The value of additional transmission is therefore likely to be restricted to increasing competition and reducing the marginal costs of generation.

In an attempt to describe the value of transmission, consider the topical example of the transmission capability between Scotland and E&W, which is currently in need of reinforcement in order to accommodate power transfers which could potentially exceed that capability. Consider the consequences of connecting a large, say 500MW, efficient generator in Scotland. Being competitive, this generator would contract its output via the bilateral energy markets and displace an equivalent amount of generation. If it is assumed that the "optimum" amount of generation existed before the arrival of the new Scottish generator, the displaced generation would eventually decommission. As power flows almost invariably from Scotland to E&W, it must be concluded that generation in Scotland is more competitive and that, in the absence of system constraints, generation in E&W would decommission. However, as the circuit capacity between Scotland and E&W is constrained and can accept no more energy, generation in Scotland must close, unless of course transmission capacity is increased to accommodate increased power flows.

The value of transmission is therefore the difference in costs of these two outcomes, decommissioning generation in E&W or Scotland. Expressing generation costs in terms of fixed costs (depreciation, transmission charges etc), and fuel costs, the value of transmission is therefore the difference in fixed costs + fuel costs of the two outcomes. Furthermore, if like for like technologies are assumed, i.e. the choice between closing coal-fired generation either in Scotland or E&W, then the fixed costs of generation are likely to be similar (if fact the fixed costs of generation in Scotland may be higher due to larger TNUoS charges). The value of transmission therefore approximates to the difference in fuel costs of the two outcomes.

5.3.2 Investment signals derived from BETTA.

The linkage between BETTA and the value of transmission therefore occurs though the operation of the Balancing Mechanism in resolving transmission constraints. When resolving an active constraint, the GBSO will seek bids from generators to reduce output on the "export" side of the constraint and corresponding offers to increase output on the "import" side. Generators whose bids are accepted are paid via the energy markets as if they had generated at their "prebid" output, while generators whose offers are accepted receive their offered price, which will generally cover both fixed and variable costs.

The cost of reconciling a particular constraint is therefore the product of the constrained energy volume and the sum of offer and bid prices. At best (assuming perfect competition), bid prices will only reflect the fuel saved (in practice a bid may actually be negative if for example a generator wishes to retain some avoided cost as profit or signal a desire not to reduce output). Conversely, offer prices will presumably include both fuel and fixed costs, as offers will be made by generation excluded from the energy markets and who will therefore take the opportunity to recoup those fixed costs. The net cost of resolving a network constraint is therefore likely to include the fixed costs of the "constrained on" generation plus the differential in fuel price and is therefore quite different to difference in fixed costs + fuel costs, which underpins the "real" value of transmission.

Figure 5.1 Accepted BM Offer & Bid Prices & Market Index Price

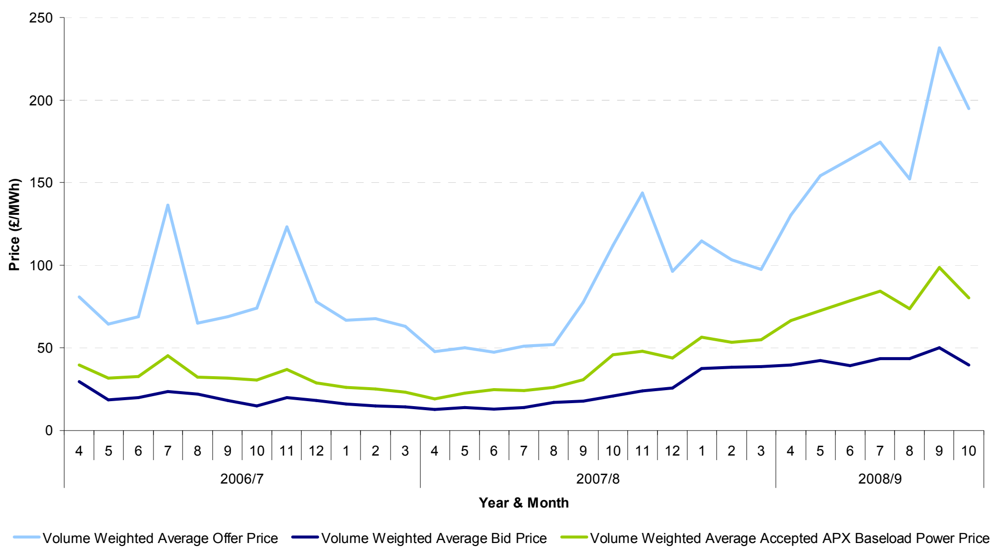
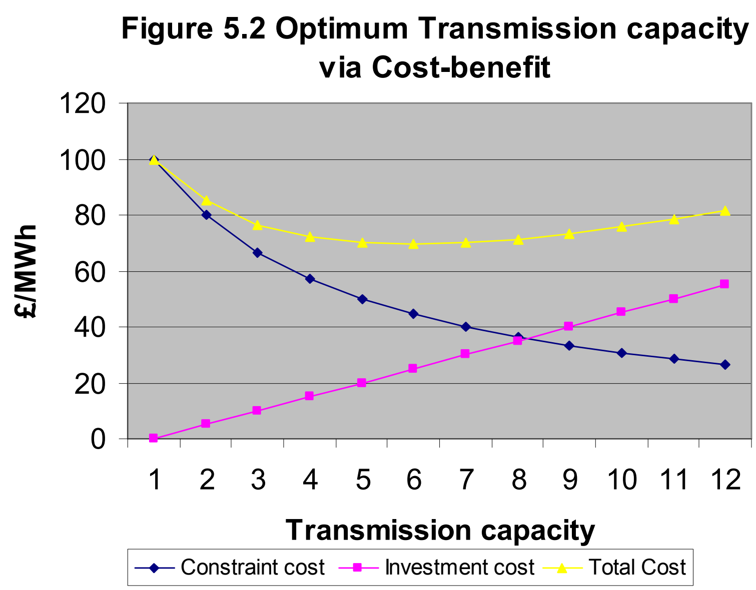


Figure 5.1 (NGET 2008a) shows the relationship between accepted Balancing Mechanism offers and bid prices and base load market power price over recent years. It can be seen that, although all three prices have risen due increases in fuel costs, bid prices have been less volatile than offer prices. According to NGET, this is in part due to the "market" for bids being more liquid due to the predominately "long" nature of the energy market and the consequent need to require generation to decrease output. The offer "market" is by nature less liquid as the need to accept offers to increase generated output via the Balancing Mechanism is generally restricted to constraint resolution or the need to increase reserve. With generators displaced from the energy markets needing to recoup fixed costs over a reduced number of running hours, it is expected that offer prices will exceed average base load energy prices. However, the margin by which this occurs suggests that the illiquid nature of the offer market is being exploited, particularly given that offers will normally be made by "marginal" generation, i.e. generation that is included in the energy market, but operating at part load and able to offer additional output via the Balancing Mechanism. It is also worthy of note that, according to NGET (2008a), bids prices in Scotland are less that the average volume-weighted values shown in Figure 5.1, again suggesting some exercise of local market power.

5.3.3 Establishing the optimum level of transmission via cost-benefit

When considering the need for transmission investment, the GBSO will carryout cost benefit analysis, weighing the potential savings in congestion costs against the cost of reinforcement required to achieve those savings, see Figure 5.2. By using signals emanating from the Balancing Mechanism, the GBSO will therefore include the fixed costs of generation in making a case for transmission reinforcement. This seems inappropriate as, in a system where there is the correct amount of generation to satisfy demand and provide an adequate generation margin, building transmission will not lead to other than a marginal reduction in generation fixed costs. In other words, any generation which closes on the import side of the constraint as the result of increased transmission capacity, will need to be replaced on the exporting side.



The treatment of congestion costs under BETTA, and the implications for valuing transmission, can be contrasted with the treatment under the Electricity Pool, which preceded the current market arrangements. Under Electricity Pool rules, an "unconstrained generation schedule" was compiled at the day-ahead stage, which established a marginal energy price. A generator's inclusion in the unconstrained schedule effectively conferred firm access rights as, should the generator be constrained off in the event, the marginal price for its constrained energy would still be received, minus the original bid. Generation constrained on to replace that energy would be paid at bid. Consequently, the cost of satisfying an active constraint would be the product of the difference in bid prices and the energy volume. As both bids would presumably cover a generator's fixed and variable costs, the resulting constraint cost would be a function of the differential of those fixed and fuel costs.

It can be seen from the above that the treatment of constraint costs under BETTA and the Electricity Pool are quite different and lead to quite different conclusions as to the value of transmission. Under BETTA, where for example bid–offer spreads for marginal gas and coal plant are in the range £75-£90/MWh (NGET 2008b) and might, according to Figure 5.1 on occasion be much higher, cost benefit analysis might suggest transmission reinforcement economic in order to avoid constraint costs. However, under Electricity Pool rules, where constraint costs would presumably reflect fixed and fuel cost differentials in the order of £1-10/MWh (SKM 2004), the same transmission reinforcement may well not appear economic. This leaves us with the uncomfortable conclusion that more transmission will be required to accommodate the UK's renewable obligations under BETTA than would have been the case if the old Electricity Pool rules still applied.

5.4 BETTA only rewards energy

The need to retain sufficient flexible conventional generating capacity to maintain reliability and generation adequacy at times when the availability of renewable resource is reduced, raises the issue of how that capacity is to be paid for. As the deployment of intermittent and variable output generation technologies increases, conventional generation will be increasingly displaced from the energy market and experience decreasing load factors, reducing the opportunity to recover fixed costs and profit. Strbac (2008c) suggests that, with an installed generation capacity of 100GW incorporating 30GW of wind generation (a capacity broadly consistent with achieving the UK's new obligations for 2020), some 20GW of conventional generation will operate at load factors of less than 10%. With energy markets that only reward energy, as is the case with BETTA, the need for conventional plant to recover its fixed costs and profit margins during the increasingly limited periods when it has access to those energy markets, i.e. during periods when renewable output is low, will result in increased volatility in energy prices.

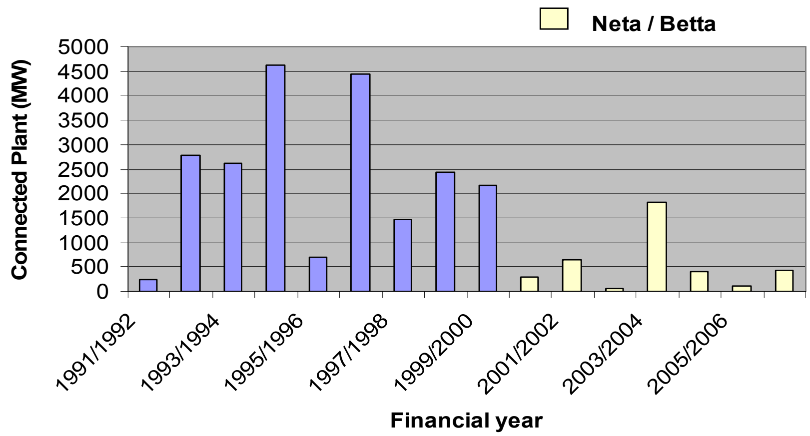
As Oren (2000) and others have suggested, while in theory allowing energy prices to reflect imbalances in supply and demand will produce market signals for capacity expansion, there is concern that increases in electricity prices when capacity is scarce may not be sufficiently high or certain to produce adequate investment in generation. There is also concern about the possibility of regulatory intervention to suppress high energy prices, even when they legitimately reflect the degree of capacity scarcity, resulting in the inability of existing generators to adequately cover their fixed costs and discouraging future investment. Kirschen and Strbac (2007) come to a similar conclusion, i.e. that the uncertainty of returns will discourage risk-averse investors from investing in generating plant.

In a UK context, it is worthy of note that NETA/BETTA has not yet been tested in terms of its ability to ensure adequate investment in new generation capacity. As discussed by Rouqes et al (2005), while the connection of new generation capacity remained at high levels following privatisation in 1990, connection activity declined significantly with the introduction of NETA (figure 5.3). The events of winter 2003/04[25], when forecast capacity margins fell dramatically but recovered in the event is cited by Ofgem as evidence of the markets ability to respond. However, Roques et al dispute this conclusion, suggesting that the eventual outcome was more to do with the GBSO's efforts to procure additional operating reserves via the reactivation of mothballed plant and demand side action, than an adequate market response to forward price increases. It remains an open question therefore, whether the current UK market arrangements are capable of responding adequately to the expected 22GW of conventional plant

[25] During the summer of 2003, forecasts for the coming winter indicated low plant margins of around 16% and the possibility of demand interruptions in the event of cold weather or further plant losses. Following pressure from Ofgem, NGET conducted a tendering exercise to obtain additional reserve capacity. The tender process resulted in some 850 MW of additional reserves being procured.

decommissioning expected by 2020 or of retaining significant levels of low-load factor conventional plant as a back-up to intermittent renewable energy sources.

Figure 6.2 Generation Commissioning 10991/92 to 2006/2007 (*source National Grid*)



The alternative to rewarding energy alone would be to recognise that, with a mixed generation portfolio containing significant amounts of intermittent and variable output generation that offers relatively little capacity, there are two distinct electricity products, energy and capacity, and to reward them both. The different arrangements used internationally to reward capacity are reviewed by Arriga et al (2002). Regulators can either define a price for capacity and let the market determine the amount of capacity to be provided, or define the amount of capacity and let the market define the price. The former mechanism was applied as part of the E&W Pool arrangements which preceded NETA/BETTA, while the latter is applied in some US markets and elsewhere. The E&W Pool arrangements liked capacity payments to the product of LOLP[26] and the difference between VOLL[27] and a generator's bid price.

Much has been written about the relative merits of rewarding capacity through the volatility of energy prices or of rewarding capacity separately. Roques et al (2005) contend that there is as yet no clear academic consensus on the market design which provides the least-distorting long-term investment incentives. However, given the importance of a reliable electricity supply to the general health of the economy, the predictable increase in price volatility with the introduction of intermittent renewable sources and the importance of retaining adequate levels of supporting generation which will experience decreasing load factors suggests that the calls to explicitly recognise the value of capacity will become more strident.

5.4.1 Impact of an energy-only market on constraint costs

In addition to removing the need for excessive energy price volatility and providing more stable investment signals, the explicit recognition of capacity would also reduce the need for mid-merit plant to recover capacity constraints via the Balancing Mechanism. As discussed in 5.3.2, the recovery of fixed costs via accepted Balancing Mechanism offers inflates the costs of resolving congestion, thereby polluting transmission investment signals and potentially leading to

[26] LOPL, Loss of Load Probability. A measure of the probability that demand will exceed available generation.
[27] VOLL, Value of Lost Load. The value placed by customers on avoiding losses of supply. Value obtained by surveys.

unnecessary and unjustified investment. The weakness of the Balancing Mechanism in dealing efficiently with congestion and the tendency to over-value transmission is already a significant problem, as can be seen from Figure 5.2 and the recent letter from Ofgem highlighting concern over the increase in congestion costs (Ofgem 2009a). With the increasing deployment of intermittent renewables and reduced utilisation seen by mid merit plant to access the forward energy markets, there could well be an increasing dependence on the Balancing Mechanism to recover fixed operating and investment costs. This could further inflate the costs of resolving congestion and, by implication, the apparent value of transmission.

6 Energy constraints

As the deployment of renewable technologies such as wind progresses to meet the UK's climate change goals, the possibility of having to curtail the output of renewable generation due to insufficient demand to be served, will at some point arise. Electrical demand in GB varies on a seasonal and daily basis between a minimum of around 20 GW during summer nights and a winter peak of some 63 GW. As the capacity of variable-output renewable generation such as wind and marine increases, the possibility arises that periods of high renewable availability will coincide with periods of low electrical demand, resulting in the need for curtailment. The probability of needing to curtail renewable output is increased due to the inflexible nature of some plant, for example CHP generation whose operation is driven by process heat requirements or nuclear plant, where economics or safety issues require continuous operation.

In addition, there is a need for flexible conventional plant to operate at reduced output in order to provide both upwards and downwards operating reserve[28] to support wind output. In providing this reserve, conventional plant will take up available energy and further reduce the headroom available for renewable generation. With the increasing deployment of intermittent technologies such as wind, reserve requirements will clearly increase and the combination of reduced demand, inflexible plant, and high wind output with an associated requirement for additional reserves held on conventional plant, will increase the probability of needing to curtail renewable plant when periods of high renewable output coincide with periods of reduced demand.

There appears to be some uncertainty over the level of wind generation deployment that will trigger the onset of curtailment. In their report to BERR, SKM (2008) suggest that, depending on the availability of interconnection with Europe and pump storage capacity, significant energy curtailment will not occur until wind deployment approaches 40GW. However, Strbac (2008b) suggests that curtailment might become first become required at wind penetrations of around 16GW. Other estimates suggest that curtailment might first become apparent at wind penetrations as low as 10% (approximately 12GW) and become significant at penetrations of 20% (approx: 25 GW), when 10% of wind energy might need to be curtailed (Holttinen 2004). For higher wind penetrations, studies carried out in the CEGB era suggest that curtailment could be very significant. For example, Halliday et al (1983) suggest that an installed wind capacity of approximately 30GW might require up to 45% of wind energy to be rejected while Gardener

[28] Flexible conventional generation such as coal-fired or CCGT units will be required to operate at reduced output in order to provide upwards reserves to cover reductions in wind output. Flexible generation will also be required to operate with sufficient downwards regulation to cover for sudden deductions in demand (e.g. loss of Dinorwig pumping demand).

and Thorpe (1983) suggest that a wind generation fleet of around 35GW could result in excess of 50% of wind energy being rejected.

The difference between the Strbac and SKM conclusion can be partially explained by assumptions concerning the additional reserve requirements required to support variable-output. SKM assumes that, at a half-hour resolution, the reserve requirement necessary to manage the variability of "net demand" (demand – wind output) is little different to that required to manage the variability of demand alone and therefore that is no significant increase in reserve requirements. On the other hand, Strbac points out that, at resolutions of 2-4 hours, there is a significant increase in reserve requirements with increasing wind deployment and the need for additional synchronised generation to provide these additional requirements will eat into available energy. The need to consider timescales out to 4 hours arises as this is the time typically required to synchronise warm conventional plant. As within timescales of up to 6 hours ahead, persistence forecasting theory[29] provides the best estimate of wind output, variations in wind output occurring within these timescales cannot be cleared by the market and will therefore need to be covered by reserve held on synchronised, part-loaded, generation.

Assuming an installed wind capacity of 26GW, the increased variation in wind output with time is shown in Table 6.1. The GBSO will assume 3 standard deviations when setting reserve requirements, suggesting that reserve requirements will need to rise from the current level of around 1200MW to some 7200MW to cover wind generation variations at a 4 hr time horizon.

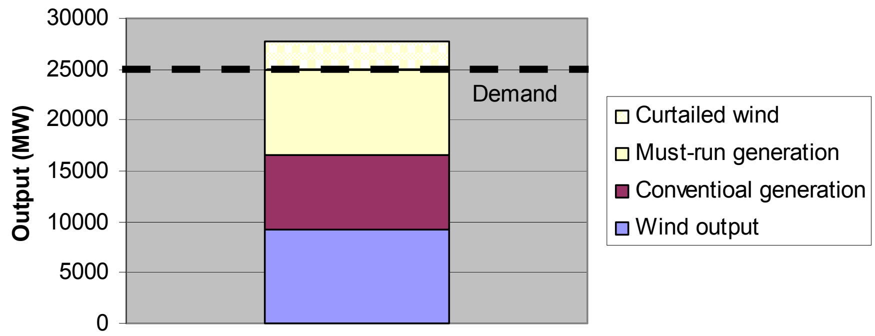
Lead Time (hrs)	Standard Deviation (MW)	Maximum Change (MW)	Extreme Change (MW)
0.5	360	1,090-1,450	2,600
1	700	2,100-2,800	3,950
2	1,350	4,050-5,400	6,550
4	2,400	7,200-9,650	13,500

Table 6.1 Variation of Wind Output with Lead Time (SEDG)

A "snapshot" example of potential wind curtailment is depicted in Figure 6.1. Given an installed wind capacity of 26GW generating 12 GW, a reserve requirement of 7200MW (see table 6.1 above), a GB demand of 25GW and assuming the presence of 8.4GW of must-run plant (i.e. nuclear, CHP & inflexible conventional plant), it can be seen that it would be necessary to curtail some 2700 of wind output.

[29] Using persistence theory, the forecast output of a wind generator will be its current output. Persistence theory is generally thought to give the most accurate forecasts up to 6 hours ahead.

Figure 7.1 Snap-shot of Wind Curtailment with 26GW Installed Wind Capacity & 25GW Demand



Clearly, more work needs to be undertaken to understand the materiality of the curtailment issue and the level of wind generation deployment at which energy-related constraints on output are first likely to appear. When there is a possibility of zero-marginal cost generation such as wind being constrained, there is the potential for energy prices to collapse and even go negative, as wind operators recover ROC income via the Balancing Mechanism or spill energy. The potential of low or even negative energy prices, even for limited periods, could have a detrimental impact not only on the commercial viability of wind, but on the viability of other capital-intensive, low marginal cost technologies such as nuclear and CCS, whose commercial viability will depend on high-load factor operation and high energy prices. As suggested by EdF Energy (2008), the prospect of highly volatile electricity prices, occasionally falling into negative territory, will encourage investment in low capital cost, flexible fossil-fuel rather than zero or low-carbon generating technologies, therefore undermining the achievement of the UK's renewable obligations and a transition to a sustainable electricity network.

6.1 Mitigation of energy constraints

Although more work is required to understand at what point in the deployment of variable-output renewable generation the issue of energy constraints will become material, the issue will arise at some point. It is therefore worthwhile to consider what mitigating actions may be available. Options include the provision of additional interconnector capacity to allow excess energy to be exported to adjacent electricity systems during periods of high renewable output. Additional interconnection would also provide capacity support during periods of low renewable output, thereby reducing the requirement for generation capacity. However, it is worth noting that weather systems often extend beyond national boundaries, potentially reducing the extent to which adjacent electricity systems may be able to provide support during periods of high (or low) renewable output. .

Additional electrical storage capacity could also be effective in either boosting or reducing demand in response to variations in the availability of renewable energy, However, the opportunity for developing additional large pumped-storage storage facilities in the UK are limited and likely to be environmentally contentious. Other energy storage technologies such as Compressed Air Electrical Storage (CAES) or flow-batteries, which could potentially offer energy storage at utility-scale, are at an early stage of development and its is unclear whether they have the potential to make a material contribution in the timescales available.

While additional interconnection and possibly increased storage capacity are likely to contribution to some extent in delaying the point at which energy curtailment becomes necessary, a more promising option appears to be that of demand-side options such as "fuel switching". As described in Box 6.1, fuel switching from gas to electricity in Danish district heating facilities appears to have been remarkably effective in both stabilising spot electricity prices while at the same time allowing the increased utilisation of wind resource and reducing gas consumption.

Box 6.1 Demand Substitution in Denmark

Demand substitution has been used successfully in Denmark to reduce the incidence of low to zero electricity prices during windy periods, when excess wind energy would otherwise be exported to Germany or Norway, or been curtailed.

In December 2005, the Danish Parliament legislated to allow electricity to be used for heating in district heating schemes and participation of these schemes in the electricity market has already impacted the incidence of low or zero spot prices, by switching from gas to electricity consumption. The impact on spot electricity prices in West Denmark during periods of high wind output can be seen by comparing figures 6.1.1 & 6.1.2, which compare spot prices and wind output on the West Danish system in February 2004 and 2006 respectively. Figure 6.1.1 shows how electricity price falls and become more volatile during periods of high wind in the absence of any response from district heating schemes. Figure 6.1.2 shows how switching from gas to electrical heating in these schemes smoothes price volatility during high wind periods and how electricity prices are stabilised.

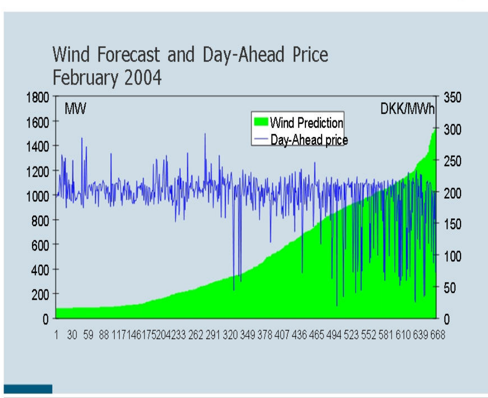


Figure 6.1.1

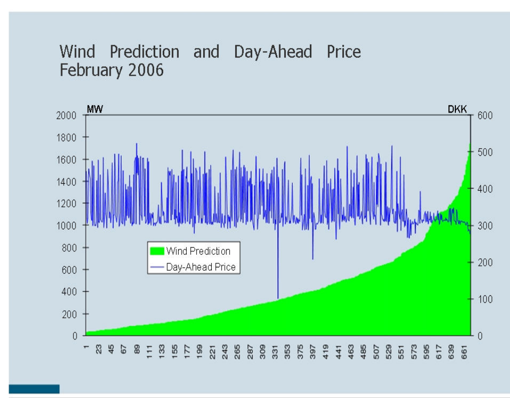


Figure 6.1.2

In the UK, district heating schemes are limited to hospital and industrial facilities and only around 1-2% of domestic housing is connected to heating networks (BERR 2008). However there is the potential for a considerable expansion of district heating and the capability to utilise electrical energy directly in these schemes could mitigate the need to curtail wind and stabilise electricity prices as in the case of Denmark. In fact, the ability of district heating to contribute in this fashion could add to the attraction of the option in the context of a strategy to achieve the UK's renewable goals. In addition, there is currently around 6 GW of CHP heat-driven electricity capacity in the UK, some of which may have fuel switching potential. It may be possible to replace gas consumption by electricity to provide heat during periods of low electricity prices in some CHP plants, thereby increasing electricity demand at the same time as reducing total generation output and allowing the increased use of renewable resource.

A further possibility suggested by EDF Energy (2008) is the development of Air Source Heat Pumps (ASHP), a technology not considered by BERR in their Renewable Energy Strategy consultation. The deployment at scale of electrically-driven ASHP technology, which does not suffer from the ground-area constraints likely to limit the deployment of ground-source heat pumps, in replacing conventional gas-fired boilers would have the effect of increasing the contribution made by the heat sector to the UK's renewable obligations. This in turn would reduce the renewable energy contribution required from the electricity sector, while at the same time increasing electrical energy consumption and reducing the probability zero or low-carbon output having to be curtailed.

7 Transmission investment

Chapter Summary

Delivering the electricity sector's contribution to the UK's climate change obligations will require significant transmission investment. A recent estimate by the TOs for the Electricity Network Strategy Group (ENSG) suggests that delivering the UK's new renewable 2020 obligations will require £4.7 billion of transmission investment, in addition to the £4 billion already authorised.

Given the scale of the investment challenge and uncertainties around the location and timing of renewable deployment, attention will need to be given to ensure that existing transmission assets are fully utilised and that transmission investment is fully justified. The importance of recognising the replacement role of renewable generation and sharing available transmission capacity in terms of efficient network use has already been discussed in chapter 3. This chapter continues this theme by considering the role of the GBSQSS in determining the extent to which existing transmission assets are utilised and the scale of investment required.

Notwithstanding the importance of ensuring that transmission investment is efficient and fully justified, it is clear that a major programme of reinforcement and extension will be required. Given the mismatch between the timescales associated with network developments and those of individual renewable projects, there is a need to focus on achieving the UK's renewable obligations and not rely entirely on customer demand. Major infrastructure developments will therefore need to be planned on a "strategic" basis rather than in response to specific customer need, in order to ensure that investment is delivered in a timely fashion and that renewable and low-carbon generation can contribute to the delivery of the UK's renewable objectives.

7.1 Transmission investment required to accommodate the UK's 2020 renewable obligations

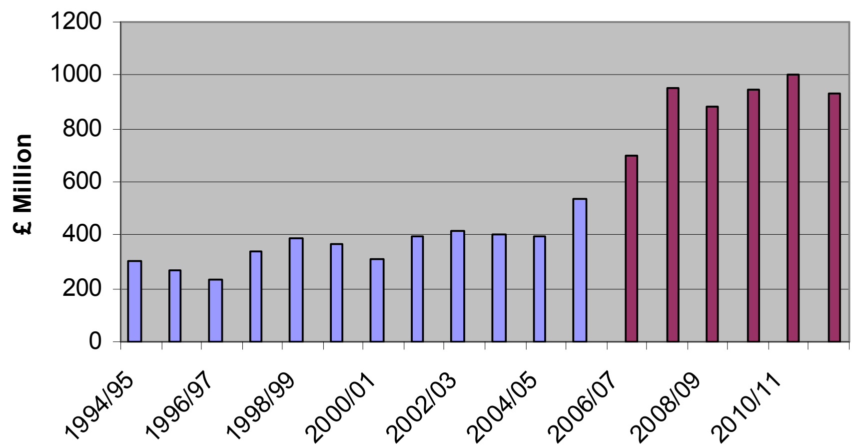
Delivering the electricity sector's contribution to the UK's 2020 renewable obligations system will require a significant programme of transmission network investment. Whereas new nuclear capacity and any conventional generation required to replace that likely to decommission by 2020 is likely to be sited in areas where the transmission network is relatively strong, new renewable capacity, particularly technologies such as wind, will predominately connect in areas where the transmission network has limited capacity or, in the case of offshore wind generation, where no transmission network currently exists. Major investment will therefore be required to extend the transmission system to those areas where the new renewable technologies locate and also to increase general infrastructure capacity in order to accommodate the increased power transfers that will result from the connection of that renewable generation.

An initial assessment of the cost of connecting the renewable generation capacity necessary to deliver the UK's new renewable obligations together with new conventional generation was given is as around £12.6 billion by SKM in a report to BERR (2008). More recent work carried out by the TOs for the ENSG (2009), suggests that in addition to the £4 billion of investment already authorised and excluding investment required to reinforce the connections to the Western Isles, Orkney and Shetland, an additional £4.7 billion of investment will be required by 2020. In other words, the investment needed to deliver our renewable obligations and climate change goals could, in total, exceed the current regulated asset valve (RAV) of the transmission networks, which currently stands at some £6.7 billion (Ofgem 2008b)

7.2 Need for efficient investment

When the need to extend and reinforce the transmission networks is taken together with the need to refurbish and replace existing assets that are nearing or have reached the end of their useful life, it is clear that we have entered a period where capital investment will dominate TO revenue requirements (see figure 7.1). This growth in investment, which coincides with a period of economic turbulence during which financing capital projects may be more difficult, will see the costs associated with providing a transmission service increase, reversing the trend seen since privatisation. With the cost of increased investment outweighing revenue reductions accrued through efficiency savings, regulation will in future need to increasingly focus on ensuring that the utilisation of available transmission capacity is maximised and that investment is fully justified and efficiently carried out.

Figure 7.1 - GB Transmission Investment Actual & Forceast (Ofgem, National Grid)



7.3 GBSQSS Investment and operational criteria

The criteria used by NGET as GBSO in the day to day operation of the transmission system and by the TOs to determine the need for transmission investment are set out in the GBSQSS. The nature and application of these criteria, which are deterministic in nature and remain essentially unchanged from those introduced by the CEGB in the 1970's, is therefore a crucial element in determining both the utilisation of existing transmission assets and the investment required to accommodate the renewable generation capacity necessary to deliver the UK's renewable obligations.

7.3.1 Investment criteria.

The original aim of the transmission investment criteria set out in the GBSQSS was to ensure that the ability of generation to contribute to supplying winter peak demand was not unduly restricted. Work carried out by SEDG (2007a) suggests that the additional loss of load probability (LOLP) attributable to a GBSQSS-compliant transmission system is approximately 5%. In other words, taking the now obsolete (but still used as a general guide in terms of judging the adequacy of generation plant margins) CEGB Generation Planning Standard of a 9%[30] risk of winter peak demand exceeding available generation capacity, the additional risk of transmission failures might raise overall LOLP from 9% to 9.5%.

The format of the deterministic investment criteria set out in the GBSQSS defines the transmission capacity to be maintained between any two areas of the transmission system (providing the smaller has a demand equal to or exceeding 1500MW) in the event of certain "credible" defined equipment outages. A "planned transfer" is defined as the transfer across the boundary with all generation (de-loaded to a degree to take account of the margin of generation over demand) operating to meet anticipated peak demand. An "interconnection allowance" is also defined which represents divergences from "planned transfer" observed generally on the transmission system over time. If the boundary capacity equals the "planned transfer plus

[30] The 9% CEGB Generation standard risk was usually interpreted as equating to winter peak demand exceeding available generation in 9 years in a century.

"interconnection allowance" with any one boundary circuit out of service and the "planned transfer" plus ½ "interconnection allowance" with any two circuits out of service, the boundary is considered compliant and no reinforcement is required. Additional reinforcement over and above these "deterministic" criteria may, however, be justified on the basis of cost-benefit analysis, in other words if the net present value of the additional investment is outweighed by the net present value of avoided costs, i.e. the costs of avoided network congestion.

7.3.2 Operational criteria.

The operational criteria set out in the GBSQSS are also deterministic in nature and define the permitted consequences of a number of "credible" fault contingencies, such as the loss of a double-circuit overhead line or a single cable. The contingencies that need to be secured are dependent on the size of the demand group being considered and for groups in excess of 1500MW, "main interconnected system" or MIS rules apply which require, inter alia, that a double circuit fault should not result in any loss of demand or unacceptable voltage or frequency conditions.

The application of the GBSQSS operational criteria will determine the utilisation of transmission assets and the extent to which the output of generation has to be constrained in order to restrict boundary flows. As an example, the flows across the four circuits that form the "Cheviot" boundary between England and Scotland will have to be restricted to around half their nominal capacity in order to cater for the very unlikely event of the loss of two of those circuits, with the unequal pre-fault sharing of the four circuits further reducing permitted power flows. Although operational measures, such as the use of short-term circuit ratings[31] or intertripping[32] can increase pre-fault flows, there is often a need to establish counter-flows across the boundary via the Balancing Mechanism.

7.4 Justifying transmission investment

Until recently, the investment criteria set out in the GBSQSS have proved to be a good proxy for economic assessment as, historically, little if any additional investment has been shown to be justified by cost benefit analysis. However, the introduction of NETA/BETTA increased the cost of resolving transmission congestion compared with the Electricity Pool market arrangements it replaced, as discussed in 5.3.1. In addition, the increasing deployment of zero marginal-cost renewable generation with access to ROC income will also cause congestion costs to rise, where that generation has to be constrained. In combination, these two factors will increasingly result in cost-benefit analysis justifying investment over and above that identified by the application of the deterministic investment criteria. In other words, the GBSQSS operational criteria summarised in 7.3.2 will play an increasingly important role in determining the need for transmission investment.

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[31] Short-term ratings. The capability of a transmission circuit is limited by thermal considerations and, provided a circuit is not fully-loaded, its output may be increased above its "continuous" rating for a short period. This allows the pre-fault capability of a transmission boundary to be increased, provided action is available post-fault (such as increasing the output of generation) to reduce circuit flows to within continuous rating.

[32] Intertripping. Generation is tripped instantaneously on the occurrence of a particular fault. This allows the capability of an exporting transmission boundary to be increased, effectively allowing the assumption to be made that the output of the generator was zero pre-fault.

7.4.1 The GBSQSS intermittency review

Concerns over the approach taken by NGET to integrate intermittent renewable generation into a GBSQSS methodology primarily designed around conventional generation, promoted in a review of those standards in 2006. This "intermittency" review confirmed NGET's approach to the treatment of intermittent generation (essentially applying a capacity factor for wind of 72%) to be basically sound (see NGET 2008b Appendix 8, page 97). However, this conclusion is of some concern as SEDG in their earlier work on the application of the GBSQSS and in their response (see SEDG 2008) to NGET's Consultation demonstrate that the rationale supporting a 72% capacity factor for wind to be flawed, as it leads to the illogical position that more transmission capacity should be installed for less-secure generation. SEDG's analysis using objective assumptions suggests that capacity factors for wind in the range 30-35% are justified, depending on the extent of wind penetration.

One of the assumptions giving rise to this divergence of view is the cost of resolving congestion. As discussed in Chapter 5, NGET relies on bid and offer prices emerging from the Balancing Mechanism in performing cost benefit analysis, which inflates the value of transmission reinforcement. Other concerns raised by SEDG over the methodology used by NGET relate to the need for multi year-round assessment over the life of the proposed assets, adequate representation of the daily and seasonal variation wind output and the need for objective assumptions about generation running patterns, availability and merit orders. Overall, SEDG (2008) conclude that that the methodology and assumptions used by NGET consistently give rise to the need for higher transmission boundary capabilities than would be the case with arguably more objective assumptions.

7.4.2 The GBSQSS "fundamental" review.

NGET's intermittency review has now been overtaken by a more fundamental review of GBSQSS criteria and methodology. This "fundamental" review is driven by concerns expressed by the Transmission System Operational Review Group (see Ofgem 2007) established by Ofgem, increased interconnection capacity, the possibility of lager generating sets (1500MW and above) connecting to the transmission system but, primarily, by interactions with the Transmission Access Review.

The outcome of the TAR could have far-reaching implications on the means of determining the need for transmission investment and on the GBSQSS generally. Whereas, currently, the GBSQSS is the means of converting generation requests for connection into system capacity requirements and the possible need reinforcement, this may not be the case in future. For example, if system capacity were in future to be allocated by auction, then unsuccessful bids for existing capacity might be tested to see if additional capacity was justified on a cost-benefit basis. Similarly, with the "evolutionary change" approach envisaged by TAR, the price paid by generators for short-term access or as a result of "overrunning" might be an indicator for the need for addition system capacity over and above that required to support requests for long-term access rights, which might still be identified by the GBSQSS. It is concluded therefore that the development of revised access arrangements via TAR could result in the current, deterministic, GBSQSS investment criteria being replaced, at least partially, by pure cost-benefit analysis. If this the case, and it seems inevitable that cost- benefit will have an increasing role in justifying the need for reinforcement given the introduction of zero marginal-cost technologies such as wind, it is clearly important to establish an objective, robust and transparent cost-benefit process, which is supported by all stakeholders.

The “fundamental” review will also look at the case for a more risk-based approach to the GBSQSS operational criteria which are deterministic in nature. As indicated previously, any justifiable relaxation in the GBSQSS operational standards would result in both increased transmission system utilisation and a reduction in investment justified by cost benefit analysis. There are a number of opportunities that the GBSO could exploit in an effort to reduce the costs of resolving congestion and increasing network utilisation. For example, the fact that a significant majority of network faults are weather related could be exploited by relaxing operational standards during periods of fair weather, without any significant increase in operational risk. Other examples would be the increased use of intertripping, which disconnects generation instantaneously in the event of specific network faults and allows pre-fault network utilisation to be increased, or the exploitation of the synergy between high wind speeds/high wind generation output and enhanced circuit ratings.

More fundamentally, the review is considering the case for a more cost-benefit approach to operational standards, in which the savings to be made in reducing congestion would be set against the cost of potential unsupplied energy following a transmission[33]. This approach would imply that increased operational risk would be justified in order to avoid curtailing the output of technologies such as wind, which have zero-marginal cost and are expensive to constrain.

7.5 The need for strategic investment

In order to obtain a connection date, a renewable project must enter into a connection agreement with the GBSO and provide some form of security or financial commitment to the transmission works associated with its connection, which will escalate as those works proceed. However, as discussed in 3.1.2, it is often difficult for renewable generators to provide adequate “customer commitment” when required by the GBSO, given the mismatch between generation project and transmission infrastructure development timescales. Until planning consent has been obtained, a renewable project will have difficulty in justifying any substantial financial commitment and early entry into the planning process is unlikely to be an option as consents once obtained will require construction to commence within a specific time frame, currently three years in Scotland. As the timescales for delivering major transmission projects may be considerably longer than this, as evidenced by many Scottish renewable projects having connection dates approaching 2020, a catch 22 situation arises with generation projects unable to provide the financial commitments required to initiate the transmission reinforcements necessary for their connection.

In addition to being an issue for individual renewable projects, the current requirement for transmission investment to be supported by customer commitment could seriously hamper the delivery of transmission infrastructure necessary to accommodate the renewable generation capacity required to deliver the UK’s renewable commitments. This possibility was recognised by the TAR (BERR, Ofgem 2008a) and subsequently Ofgem (2008b) consulted on arrangements designed to address those aspects of existing access methodology that discourage Transmission Owners from anticipating customer demand and initiating work on necessary transmission reinforcement.

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[33] The potential cost of unsupplied energy would e calculated as the fault probability x load lost x value of lost load (VOLL), currently estimated at around £x/MWh

As an interim measure to ensure that immediately critical transmission development is not delayed, Ofgem is proposing arrangements to free-up funds for pre-construction activities. In addition, it is proposed that transmission projects identified as being necessary to facilitate the delivery of the 2020 renewables target and where there is a clear requirement to commence work in advance of specific customer need, should be authorised with regulatory income guaranteed. This is a similar approach to that used to initiate some £560 million of investment in Scotland, including the Beauly-Denny line and Scottish interconnector upgrades (Ofgem 2004). There is, however, no proposal to relax the requirement for customer commitment for local transmission works, which would appear to leave the issue of generators being unable to support the associated financial commitments at least partially unresolved.

For the longer term, Ofgem's proposals are not yet well developed. However, in principal, it is suggested that TOs be encouraged to take on the risk of anticipating the need for transmission development ahead of customer commitment by allowing an enhanced rate of return on investment efficiently incurred. Transmission developments that are initiated ahead of customer commitment would attract some, yet to be decided, level of enhanced rate of return provided that they ultimately become fully utilised. Any investment that did not become fully utilised would, however, be subject to a reduced rate of return. The proposed arrangements in principal are illustrated by Figure 7.2.

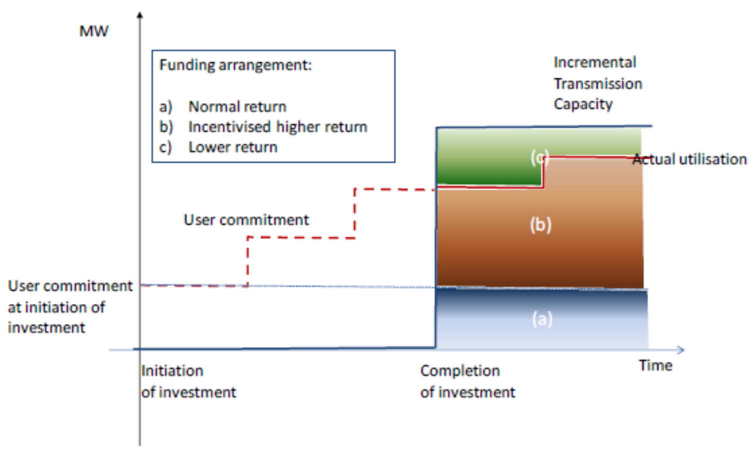


Figure 7.2 Proposed Incentive to reflect utilisation risk. *Source Ofgem (2008b)*

Ofgem's proposals have the potential to allow transmission investment to be anticipated ahead of specific customer demand while at the same time leaving the risk of stranded assets with the TOs, thereby discouraging unnecessary or purely speculative investment. The development of these proposals into effective measures that deliver the necessary investment will, however, depend on the TOs view of whether the potential rewards justify the additional risk to shareholders. There is also the issue of how "anticipatory" investment is ultimately judged to be efficient. Currently, the investment and operational criteria set out in the GBSQSS are used to translate customer commitments into the need for investment and, as discussed earlier in this chapter, there appears to be scope to improve the objectivity of these criteria.

An alternative approach would be for Government, Ofgem and the TOs to collectively agree, on a rolling basis, what transmission investment was necessary to accommodate the UK's renewable obligations and to guarantee a regulated income for the efficient delivery of these investments. This is essentially what Ofgem is proposing as an interim arrangement and would leave the risk of unnecessary investment with end-customers. However, given that renewable developers of wind and potentially tidal technologies are effectively being directed by Government to specific locations, i.e. Scotland, central Wales and offshore, a strategic approach based on the release of renewable resource necessary to deliver the UK's renewable obligations should identify what transmission development is necessary. This approach would require a common agreement as to how those targets are to be achieved in practice and the fact that individual projects may fail and be replaced by others may not be particularly significant if the objective is resource, rather than project, based. The provision of transmission capacity to specific areas would attract developments to those areas and the risk of transmission assets becoming stranded would appear to be low, assuming of course that the UK's obligations are to be achieved.

Whatever approach is taken, and it may be that a combination of both would be appropriate, there is a clear need to ensure that existing transmission capacity is utilised to the maximum and that any investment is fully justified. The review of the GBSQSS criteria currently being undertaken by the TOs represents a unique opportunity to ensure that these aims are achieved through the development of objective and transparent operational and investment standards that reflect the priorities of a sustainable electricity system.

8 Regulation and the need for appropriate investment

Chapter summary

This chapter summarises current GB regulation of network asset ownership and the day to day operation of the transmission system.

It is argued that while regulation encourages least-cost investment once the need for investment is agreed, in combination, the Transmission Price Control process and separate GBSO Incentive may not encourage objective trade-offs between investment and operational alternatives and therefore results in the possibility of over-investment.

It is suggested that, given the scale of transmission investment necessary to deliver the UK's renewable obligations and uncertainties over the disposition and timing of renewable deployment, more attention needs to be given to ensuring that regulation encourages the maximum utilisation of available network, consistent with acceptable demand security. High-level objectives for network regulation to ensure objective decisions in terms of investment and alternative operational measures via the optimisation of total transmission system-related costs, are proposed.

8.1 Existing transmission network regulation

Within a competitive electricity supply industry the transmission and distribution businesses are natural monopolies and need to be regulated in order to ensure that the businesses are run efficiently, costs are minimised and standards of service remain high. In addition, regulation must allow licensees to recover sufficient income to meet their statutory obligations.

Since privatization of the UK industry in 1990, NGET as owner of the transmission system in E&W and the Scottish Transmission Owners have been subject to a form of price cap regulation, commonly referred to as RPI-X regulation, applied though a series of Transmission Price Control reviews, each review normally covering a five year period. RPI-X price cap regulation imposes an allowed revenue stream over the price control period linked to the general inflation index and assumed cost savings accrued via increased operational efficiency.

A modified form of price cap regulation is applied to NGET as the GBSO via the System Operator (SO) incentive. Unlike the Transmission Price Control, the SO incentive is renewed annually and sets an ex-anti target cost of operating the transmission system for the year in question. Subject to a collar and cap, deviations in outturn from the target operational cost are shared between the GBSO and transmission users according to a sliding scale.

8.1.1 The Transmission Price Control.

A detailed description of the Transmission Price Control process is beyond the scope of this report and both the process and current Price Control arrangements are well documented on Ofgem's website[34]. However, it is instructive to consider some aspects of the Transmission Price Control to understand how it might impact on the behaviour of the TOs in relation to transmission investment and operation of the transmission system.

Firstly, it should be noted that the Transmission Price Control process has delivered significant benefits to customers by reducing the costs of electricity transmission, which are currently some 30% (Ofgem 2009b) less in real terms than when regulation was introduced in 1990. However, this was achieved in a period of relatively modest and stable transmission investment, see Figure 7.1, and increased investment requirements are now exceeding anticipated efficiency savings and driving a year on year increase in TO's allowed revenues

Although transmission investment will clearly increase into the future, just by how much additional transmission capacity will be required and by when is uncertain, being largely dependant on the growth and disposition of the renewable generation required to deliver the UK's climate change obligations. This increased uncertainty is managed by the Price Control process through the identification of a "baseline" level of spending designed to accommodate anticipated requirements, supplemented by "revenue drivers" designed to accommodate divergence from the "baseline" assumptions, i.e. to allow for the "known unknowns". In addition, there is the option of a Price Control "re-opener" to accommodate growth in generation connections not foreseen at the time the price control was set, i.e. the "unknown unknowns". An example of a "re-opener" is the "Transmission Investment for Renewable Generation or TIRG" review of 2004, which authorised an addition £560 million of transmission investment to accommodate renewable developments in Scotland and the North of England. A further "TIRG" review seems likely following the recent ENSG report which identified some £4.7 billion of reinforcements necessary to deliver the UK's 2020 renewable obligations.

[34] A detailed description of the current Transmission Price Control can be found at http://www.ofgem.gov.uk/Pages/MoreInformation.aspx?docid=191&refer=Networks/Trans/PriceControls/TPCR4/ConsultationDecisionsResponses

The Price Control process seeks to provide TOs with a revenue stream sufficient to finance capital expenditure, operating expenditure and financing costs incurred by an efficient business. Allowed revenues are directly linked via a defined rate of return on the TO's regulatory asset value (RAV) and, as efficiently incurred capital expenditure is added to the RAV at the end of each Price Control period, there is an incentive on TOs to maximise transmission investment. Although, through the baseline allowances and "revenue drivers", a TO is encouraged to invest at minimum cost[35], their remains an incentive to maximise investment in order to increase revenue allowances.

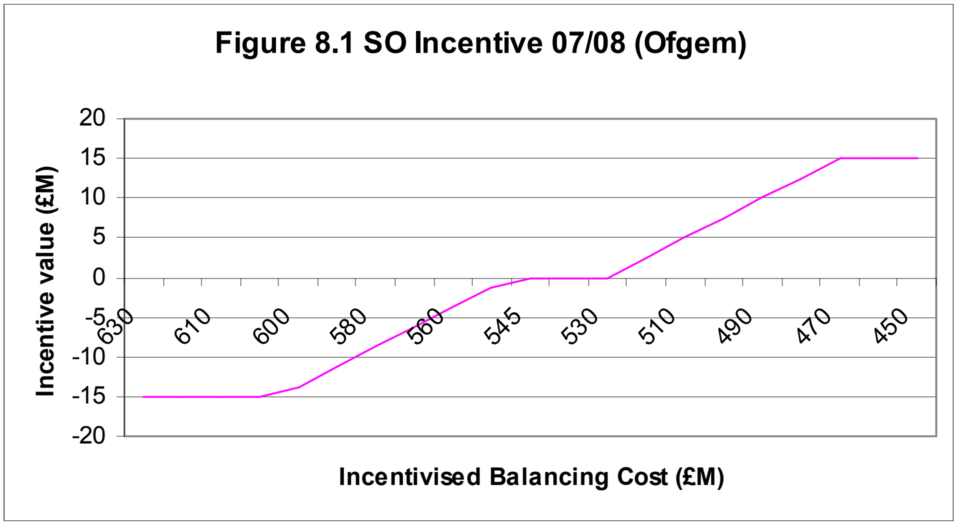
The revenue drivers applying to the three TOs are linked to the capacity of generation that connects by the end of the Price Control period. In addition, a deep infrastructure revenue driver is applied to NGET as TO, linked to changes in power flows across various transmission system boundaries resulting from new generator connection. As these revenue drivers work in both directions, i.e. can reduce baseline capital allowances if the expected capacity of new generation does not materialise as well as increasing capital allowances if more generation connects than anticipated, then there is little to be gained in the TOs inflating the UCAs embodied in those revenue drivers. However, the need for additional transmission capacity to accommodate new generation is directly linked to the operational and investment criteria set out in the GBSQSS and the need for regulation to encourage the development of objective criteria is clearly important in terms of minimising the need for new investment, as discussed in chapter 7.

8.1.2 The System Operator (SO) Incentive

NGET, as GBSO, is subject to a separate System Operator (SO) incentive covering the *external* costs incurred in operating the GB transmission system. These external costs include those incurred in energy balancing and resolving transmission congestion via the Balancing Mechanism, together with the cost of other security services such as the provision of operational reserves, reactive power and black start etc.

Unlike the TO Price Control, the SO Incentive is negotiated with Ofgem on an annual basis. A sliding scale mechanism is used which exposes the GBSO to divergences from an ex-anti target with linear sharing, a dead band and a cap and collar. The current SO incentive exposes the GBSO to any divergence in balancing costs up to a maximum of £15 billion, outside of a dead band of £530 to £545 million, see figure 8.1.

[35] The revenue drivers allow for 75% of actual costs incurred to be "passed through" with the remainder linked to ex-anti Unit Cost Allowances (UCA). This retains the incentive that applies to baseline expenditure, whereby a TO can retain 25% of any under spend and bear 25% of any overspend relative to the UCA. (Ofgem 2008h)



8.2 Characteristics of an optimal regulatory regime.

Barmack, Griffes, Kahn & Oren (2003), suggest that an optimal regulatory incentive mechanism should meet at least two criteria. Firstly, it should encourage the equalisation of marginal congestion costs and the costs of reducing congestion by either short-term operational measures of long-term investment. Secondly, regulatory incentives should not discriminate between capital and operating expenditure in reducing congestion, but rather encourage the pursuit of whichever approach is considered to be most cost-effective.

The fist criteria is only meaningful if short-run transmission cost signals emanating from the energy market, i.e. the costs of resolving transmission, are accurate. As discussed in chapter 5, there are real doubts about the ability of BETTA and the Balancing Market to deliver accurate signals in this respect. Furthermore and as discussed below, there are also concerns over the extent to which the combination of current TO Transmission Price Control and SO incentives that currently form the basis of GB transmission regulation allow the second criteria to be fully achieved – i.e. an objective choice to be made between transmission investment and alternative operational measures. Given the very significant investment programme that Transmission Operators are now embarking on, and the increased uncertainty as to how much generation will actually connect and where, it is clearly important that transmission regulation encourages efficient investment and that available operational alternatives are pursued when justified.

8.3 What needs to change

The incentives built in to current Transmission Price Control methodology encourage TOs out-perform ex-anti estimates of capital costs and UCAs and thereby increase revenues. However, it is not clear that current regulatory arrangements are capable of delivering truly efficient investment or satisfying the criteria proposed by Barmack et al and described in 8.2 Taken together, and as suggested by Cornwall (2008), the combination of revenue cap RPI-X regulation and the separate SO Incentive falls considerably short of achieving an appropriate relationship between short and long-run transmission costs, or of encouraging objective trade-offs between investment and alternate operational measures.

As discussed in 8.1.1, the allowed revenue stream that TOs are allowed to recover is a function of the value of their regulated asset base (RAV) and there is therefore an inherent incentive to grow that asset base by investing in new transmission assets. On the other hand, the SO Incentive encourages NGET to outperform an operational baseline set for the year in question and is to all intents and purposes independent of the Transmission Price Control. Taken together, there is no overall mechanism which would allow the GBSO and the TOs to benefit from forgoing investment opportunities and the associated long term returns that would flow from that investment in favour of alternative operational actions that would be likely to increase external operational costs, i.e. the costs of resolving network congestion.

For example, assume that NGET as GBSO and TO for E&W identified a transmission reinforcement that was marginally justified by cost-benefit analysis. If the reinforcement is progressed, and assuming it was justified as efficient investment, the capital cost would be added to the RAV and would earn additional income over its lifetime. Alternatively, NGET could decide not to proceed with the investment and depend on operational measures to reduce the resulting congestion to a level that made the reinforcement uneconomic. For this to be in its commercial interests, NGET as GBSO would need to agree an increase in the constraint cost baseline that is part of the annually renegotiated SO Incentive on an ongoing basis and be sure that it could regularly outperform that baseline by an amount at least equal to the income forgone. At the very least this would appear to be a high-risk strategy when compared with the comparatively low-risk alternative of investment.

In proposing a form of regulation designed to satisfy the criteria set out in 8.1, Barmack et al suggest that a combined SO and TO entity such as NGET should be exposed to the total costs of operating and investing in the transmission system. NGET would be allowed to collect sufficient revenue to operate and invest in the transmission system as well as cover an ex-anti estimate of congestion costs. The Transmission Operator would therefore be incentivized to minimize the overall costs of investing in and operating the transmission system by equalizing the incremental costs of congestion and the cost of avoiding that congestion – thereby satisfying the first criteria. In pursuit of minimizing overall costs and maximising retained income, the Transmission Operator would presumably select the most cost-effective means of relieving congestion, thereby satisfying the second criteria.

An incentive to minimise total transmission system costs, would encourage NGET as combined SO/TO to ensure that the criteria it applied for investing in and operating the transmission system, currently set out in the GBSQSS, would be objective in nature and not skewed to deliver particular outcomes. A proper balance between operational risk and investment would be encouraged which, from where we currently stand, might result in the increased deployment of operational measures referred to briefly in chapter 7. This could well be an appropriate response given the scale of the investment programme proposed as being necessary to deliver the UK's renewable obligations and the very considerable uncertainties over the timing and location of renewable deployment.

8.3.1 Lessons from gas regulation

The arrangements suggested by Barmack et al are not entirely dissimilar to the regulatory arrangements for gas transmission in GB. National Grid as owner and operator of the gas transmission network (NGG NTS) is obligated to release capacity to shippers via auction and is rewarded for doing so. However the capacity sold by NGG NTS is financially firm and, if that capacity cannot be delivered for whatever reason, it has to be bought back. Remuneration for capacity sold is via revenue drivers for a five year period from the year of provision, after which the actual costs of provision are included in RAV, minus 5 years deprecation. NGG NTS is fully exposed to the costs of buyback for 5 years, until actual costs are built in to the System Operator initiative. Taken together, these arrangements arguably incentivise NGG NTS to maximise its revenue by responding to the capacity requirements of shippers in the most cost- effective fashion.

8.3.2 Control over cost of constraints

While exposing the TO/GBSO to the total costs of operating the transmission system in order to achieve an optimum balance between operational costs and capital investment is theoretically attractive, it may not be so appealing to the companies themselves. Apart from the difficulties of predicting and agreeing appropriate revenues over a price control period, there is a need to recognize that the GBSO has only partial control over constraint costs. While the GBSO can attempt to minimize congestion volumes by appropriate transmission outage planning and coordination with generation outages etc, the actual costs of resolving constraints will be very much influenced by Balancing Mechanism bids and offers made by generators, who may be able to exploit local monopoly power. The situation would be particularly problematic in Scotland where the TO and SO functions are separated, giving NGET less flexibility in terms of rescheduling and optimising outage programmes. The common ownership of generation and transmission assets in Scotland could also present particular opportunities to both increase congestion volumes and manipulate the costs of resolving that congestion.

9 Transmission Network Use of System Charging

Chapter summary.

This chapter considers the role of transmission network use of system charges in the context of developing a sustainable electricity network.

Existing network charging arrangements, which are based on "investment cost-related pricing or ICRP" principles and which apply locational signals to both generation and demand, are briefly described. Consideration is given to whether these arrangements discriminate against renewable generation, which is often forced to locate in remote areas of the network and is therefore exposed to high transmission charges. .

Alternative arrangements, put forward by the Scottish Government as a means of reducing the use of network charges faced by generation in Scotland are considered together with the underlying justification in terms of renewable project financial viability and price volatility.

Finally, analysis undertaken by SEDG that compares a cost-benefit approach to network investment and charging with the current "security" approach is considered, which demonstrates that different generation technologies impose different costs on to the transmission network and that a revised charging regime may be required if discrimination is to be avoided.

9.1 The impact of transmission charging on sustainable development

Current methodology for charging for use of the transmission network (see Box 9.1) is based on "investment cost-related pricing (ICRP) principals, which aim to expose network users to the incremental costs of accommodating additional generation or demand encouraging appropriate locational decisions by customers and, consequently, more efficient transmission investment. The ICRP approach to charging leads to generators in exporting areas of the transmission network paying higher use of network charges that generators situated in areas where there is a more even balance of generation and demand. The reverse is true for demand, as customers situated in exporting area of the network will pay lower transmission charges than customers situated in areas where there is a deficit of generation.

Use of system charging based on ICRP principles is likely therefore to have a negative impact on those renewable projects wishing to locate in exporting areas such as Scotland or where network capacity is sparse or non- existent, such as central Wales or, indeed, offshore. It could be argued, therefore, that ICRP charging acts against the interests of sustainable development insofar as it imposes higher transmission charges on renewable projects, which are often forced to locate in peripheral areas due to resource, technology, consenting or other reasons. In this context, it is useful to note the requirements of Article 7 of the EU Directive on the promotion of renewable energy sources in the internal market (Directive 2001/77/EC), which requires member states to ensure that "the *charging of transmission and distribution fees does not discriminate against electricity from renewable sources, including in particular electricity from renewable sources produced in peripheral regions, such as island regions and regions of low population density*".

Other concerns over the suitability of ICRP–based use of network charges relate to the volatility of network charges, their non-predictability and the fact that investment in conventional generation required to maintain demand security in remote areas of the network, may be discouraged.

Box 9.1. Transmission Charging Methodology

NGET recovers the costs incurred by the TOs in operating, maintaining and expanding the transmission system by levying transmission network use of system (TNUoS) and connection charges on users of the transmission network. Connection charges recoup costs associated with providing transmission assets necessary to connect users to the transmission, while TNUoS charges recoup the costs associated with providing main network infrastructure. In differentiating between connection and transmission network assets, NGET applies a "shallow" methodology with all assets not uniquely associated with a particular generator or demand connection categorised as network assets.

TNUoS charges are set to recover the "maximum allowed revenue" (MAR) set by Ofgem as part of the Transmission Price Control process, and apply to all users of the transmission network, i.e. suppliers, generation and interconnector owners. TNUoS charges are based on ICRP principles and reflect the marginal cost of network reinforcement. Both generation and demand charges consist of a locational element designed to reflect the actual cost of accommodating an increment of generation or demand, plus a residual element designed to ensure a 27/73% split between generation and demand and full recovery of the MAR set by the Transmission Price Control. The rationale for the 27/73% split is not entirely clear.

As the incremental costs of supplying generation or demand vary across the network according to the balance of generation and demand, the network is divided into 20 generation and 14 demand zones, with a separate charge applied to each. Generation charges currently vary from a maximum of £22.26/kW in the North of Scotland to a minimum of -£8.52 in the South West, reflecting the surplus and deficit of generation capacity over demand respectively. Demand capacity and energy charges vary in the opposite generation from £25.22/kW and 0.37p/kWh in the South West to £2.87/kW and 0.37p/kWh in Northern Scotland, reflecting the surplus and deficit of demand over generation capacity respectively.

Generation charges are applied on the basis of TEC, while demand capacity charges are applied according to demand taken during three "triad" demands during the winter period of peak demands. In will be noticed that while generation charges go negative where there is a significant deficit of generating capacity (generation being paid to connect to the network), there are no negative demand charges as this would represent a perverse incentive to increase demand over peak demand periods.

Despite the relatively large differences in generation and demand charges across zones, revenue collected by the locational element of TNUoS is comparatively small, at about £180 million for 2008/09, due to the effect of netting off generation charges and the high residual tariff for demand required to achieve a 27/73% split. The residual TNUoS element accounted for the remaining £1180 million required to recover allowed the MAR of £1360 million for 2008/09.

9.2 An alternative charging methodology

Because of concerns that the current ICRP–based use of network charging methodology could impede the development of renewable projects in peripheral areas of the transmission network, and the consequent implications for the delivery of the UK's new renewable obligations, an alternative charging methodology has been proposed by the Scottish electricity companies, supported by the Scottish Government (NGET, 2008c). Essentially, the Scottish proposal is that a uniform, non-locational, use of network charge should be applied to all generation on the basis of energy produced, rather than connected capacity. It is claimed that such a methodology would provide a simplified, stable, non-discriminatory and cost reflective alterative to the current charging arrangements, and would be more in tune with UK and European renewable policy. These issues are discussed briefly below.

9.2.1 Price stability & volatility

As indicated above, a charge often levelled at the current use of network charging methodology is that it results in unstable, volatile charges and the Scottish proposals aims to address that issue by applying a uniform charge to all generation, which would presumably result in less temporal variation. While it is in the nature of ICRP pricing, with its locational cost signals, to gradually reduce zonal cost differences over time though influencing the location of new generation, there is no real evidence that the existing charging arrangements cause excessive price instability or volatility. In fact, Figure 9.1 suggests that the variation in use of network prices in recent years has been quite modest.

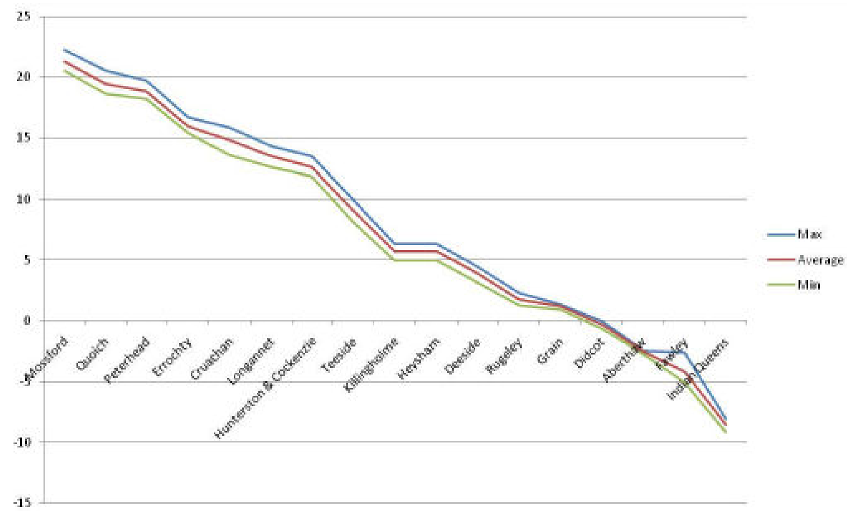


Figure 9.1 Variation in Network use of System Charges since the Introduction of BETTA*. (Source EoN, 2008)*

9.2.2 Discrimination

Whether the alternative pricing methodology proposed by the Scottish Government is more or less discriminatory that the current arrangement probably turns on the issue of whether it is discriminatory to charge renewable or other generation projects on the basis of the costs they impose on the transmission network. Charging a flat, uniform, fee for use of the transmission network will result in the additional costs caused by generation connecting to exporting or peripheral zones being spread across all generators and would, in effect, result in a cross-subsidy in favour of those generators and against those generators situated in more balanced or generation-deficit areas of the network. This situation could also be considered as being discriminatory.

An interesting aspect of the Scottish proposal is that transmission use of network charges should be allocated on a "commoditised" basis, i.e. charged per kWh of energy produced basis rather than per kW of capacity connected. This would, at least in part, overcome a serious deficiency in the existing use of network arrangements, in that there is no recognition of the different demands placed on the transmission network by different generation technologies. A commoditised energy charge would result in lower load-factor plant incurring lower overall use of network charges than higher load factor plant, but would not be technology sensitive and account for the fact that variable-output generating technologies such as wind tend to drive transmission investment less that conventional generation. This issue is dealt with in more detail in 9.3 below.

9.2.3 Discouraging renewable deployment

A flat, uniform, TNUoS charge would clearly reduce costs incurred by renewable generation situated in peripheral areas of the network. However, in terms of onshore renewables, there is mixed evidence as to whether the current charging methodology represents a significant barrier in discouraging investment in remote locations. Currently, there is around 12GW of renewable capacity contracted to connect to the transmission network in Scotland some 5GW of which is to connect in the North of Scotland, which is subject to the highest TNUoS charges under the existing charging regime. The existence of a significant connection queue for connection in

Scotland does not suggest that the existing TNUoS methodology is discouraging investment in areas where high charges apply. Indeed, there is anecdotal evidence to suggest that the more significant disincentive to connect in Scotland is the length of the connection queue and the improbability of new applications to connect obtaining connection dates this side of 2020.

The view that existing ICRP–based TNUoS charging arrangements do not represent a significant barrier to investment in peripheral areas of the network is supported by analysis undertaken by IPA and SKM for BERR (2008) on the issue of whether the limitation of transmission charges in Scotland under section 185 of the Energy Act 2004 would be justified. IPA & SKM concluded that equity returns on capital for Scottish mainland wind projects were likely to be in the range of 11 to 19% under the existing charging regime, which was considered sufficient to attract investment. Even higher returns were anticipated for wind projects located in Shetland and Orkney, due to higher load factors, and these returns were considered by IPA and SKM to be sufficient to overcome the particularly high TNUoS charges that would result from provided a double circuit cable connection to the Islands under the existing charging arrangements.

Whereas a flat use of network charge would tend to increase equity returns for renewable generation projects in Scotland (if not for renewable projects connecting elsewhere in GB), there could be a down-side for renewables in that the connection of additional conventional generation would also be encouraged. Currently there is some 10GW of conventional generation connected in Scotland to support a 5GW peak demand, resulting in the Cheviot boundary (the transmission network boundary dividing Scotland from E&W) being non-compliant with GBSQSS standards and in need of reinforcement. It is of note that of the 31GW of new conventional plant with agreements to connect to the transmission network prior to 2020, none intents to connect in Scotland, suggesting that the locational messages contained within the current charging regime are effective. With a flat uniform use of network charge conventional generation may once again be encouraged to connect in Scotland, increasing competition for scarce transmission capacity, increasing transmission costs and introducing further delays in the connection of renewable projects.

9.3 Cost reflectivity and the need to differentiate between technologies

In developing a use of network charging regime, NGET as GBSO is required by its Licence to ensure that, as far as is possible, reflect the costs in incurred by Transmission Owners in providing a transmission service and is prohibited from discriminating against any user or class of users. NGET interprets these obligations as requiring its charging methodologies to be cost-reflective and non-discriminatory. However, as discussed in 9.2, there are other views as to how these obligations might be discharged

NGET's existing ICRP-based TNUoS methodology attempts to achieve cost-reflectivity by exposing generation and demand customers to the costs of accommodating additional output or demand. However, the existing regime arguably fails to be fully cost-reflective as network charges are applied irrespective of generation technology through the mechanism of TEC and, as discussed in the following paragraphs, different generating technologies can impose different levels of cost on the transmission network.

9.3.1 Security and economics as drivers of transmission investment.

In their analysis of transmission investment and the application of the GBSQSS in the context of the increasing deployment of wind generation, SEDG (2007a) consider alternate investment methodologies based on reliability and economics. As discussed in Chapter 7, the transmission network criteria set out in the GBSQSS are security-based, in that their aim is to allow generation to contribute to meeting winter peak demand, together with an economic "add-on" in that additional investment is allowed if supported by cost-benefit analysis.

The analysis carried out by SEDG shows that, when investment is driven by security, the additional transmission capacity required to accommodate large amounts of wind generation is relatively modest compared with that required to accommodate a similar amount of conventional capacity. The reason for this lies in the limited ability of wind to provide security due to the variable nature of its output and suggests wind generation should incur lower use of network charges than conventional generation. The low contribution of wind to security also implies that, when connected in an importing area of the network, wind generation should not benefit from the negative use of network charges system in the same way as conventional generation as wind generation is not as effective in reducing the need for transmission investment.

When transmission investment is driven by economics however, SEDG show that accommodating wind generation can justify more transmission capacity than when investment is driven by security, due the high cost of curtailing the output of wind, which has zero-marginal cost. In addition, SEDG show that where large amounts of wind generation exist in the presence of limited conventional generation, there may be a case for charging wind higher use of network charges than conventional generation.

The conclusions to be drawn from the SEDG analysis is that different generation technologies drive transmission investment differently and that this fact needs to be reflected in use of network charging methodology if that methodology is to be considered truly cost reflective. As TNUoS charges in GB are applied on the basis of TEC, which does not differentiate between generation technologies, the existing methodology cannot be claim to be fully cost-reflective.

It is also interesting to consider the implications on TNUoS charges in GB, if SEDG's conclusions are applied. In most instances, wind generation would benefit from lower use of network charges and in a number of areas the reduction in charges could be significant. However, in areas where wind generation may ultimately dominate, for example in the North of Scotland, wind generation could expect to pay higher charges than conventional generation. Furthermore, in areas such as the Southwest of England, wind generation would benefit from negative charges as would be the case for conventional plant.

10 Conclusions

This report has considered aspects of current network regulation, the GB electricity markets and industry practice to identify potential barriers to making the transition to a sustainable electricity network, capable of delivering the UK's new EU renewable obligations and longer-term climate change goals.

10.1 Generation capacity requirements

As a first step, the report reviews recent estimates of the renewable generation capacity required to deliver the UK's renewable and climate change goals, together with the extent to which it might be necessary to replace conventional plant expected to decommission by 2020.

It is concluded that some 31 - 49 GW of *additional* renewable plant will be required to be commissioned by 2020, depending on assumptions made about the contribution likely to be made by the heat and transport sectors. As the majority of renewable generation expected to connect to commission will be wind having a variable output, it will be necessary to retain conventional plant to provide support when wind resource and low and it is expected that total generation capacity of around 110GW could be required by 2020. This would represent a margin of generation over peak demand of almost 90%, compared with a traditional level of 20-23%, and implies the need to replace up to 14GW of the 22GW of conventional plant expected to decommission by 2020.

10.2 Access to the electricity network

Achieving the growth in renewable generation capacity required to deliver our renewable obligations will require something like a six-fold increase in the rate at which generation has been connected to the electricity networks in recent years. Although this would no more than match the rate of connection achieved by Germany in recent times, it will require vary significant changes to UK regulation and practice and would need to be achieved in rather more challenging circumstances in terms of supply-side constraints and project costs.

Major changes to the rules governing access by generation to the electricity system will be required in order to ensure that the required renewable capacity can be connected in the timescales available. Individual projects will need to be able to connect in timescales that are consistent with their development programmes and the requirements of their planning consents. Access rules will need to fully recognise the replacement role of renewable generation and ensure that transmission capacity is "shared" between connected generation on the basis of need, rather than encouraging the provision of sufficient capacity to accommodate all installed generation simultaneously.

Developing access rules which embrace the replacement role of renewable generation and the sharing of network capacity will help optimise the requirement for network reinforcement. However, significant network reinforcement will still be required and it will in some instances be necessary for renewable generation to connect before all associated reinforcements are complete. Access arrangements will therefore need to allow early access for generation and to ensure that the rights associated with that access are affordable and bankable in project finance terms.

It is proposed that a two-stage approach to access reform may be required with interim arrangements based on an "intelligent" connect & manage approach, designed to "kick-start" the connection process and ensure that consented renewable projects are allowed access to the electricity networks within the timescales set by their planning consents. These interim arrangements would be replaced by enduring access arrangements, once problems with the mechanisms used to manage network congestion, which threaten to undermine successful access reform and efficient network investment, have been overcome.

10.3 Electricity markets

The Report discussed aspects of the GB electricity market-related that could undermine the timely development of a mixed generation portfolio necessary to deliver the electricity sector's contribution to the UK's renewable obligations and longer-term climate change goals.

10.3.1 Socialisation of the costs of resolving system congestion

Firstly, the expected increase in transmission system congestion arising from increased plant margins and the consequent need for the increased sharing of available transmission capacity, will challenge the current practice of socialising congestion costs. Alternative arrangements which allocate the costs of resolving congestion to the incumbent and newly connected generation responsible for that congestion, would seem more appropriate in situations where congestion volumes are significant.

10.3.2 The Balancing Mechanism, congestion and transmission investment.

While targeting the costs of resolving network congestion on those parties responsible for the congestion should provide generation with appropriate locational and operational signals, it is clearly important that those costs are computed correctly. It is argued that the Balancing Mechanism leads to the resolution of system congestion being unnecessarily expensive and certainly more expensive that was the case with the Electricity Pool, which preceded NETA/BETTA.

Apart from the implications for consumers, who ultimately bear the costs of resolving congestion, the fact that costs are higher than necessary impacts negatively on the deployment of renewable generation for two reasons. Firstly, options for allowing early access for generation are undermined due to concerns over the costs of resolving the additional network congestion that might occur. Secondly, high congestion costs result in a bias in favour of transmission investment when justified by cost benefit analysis, potentially inflating the costs of investment required to accommodate new renewable generation.

It is suggested that resolving congestion via the Balancing Mechanism tends to be more expensive than alternative arrangements because of opportunities for generators to exploit the existence of congestion commercially and also because of structural issues involving the recovery of generation fixed costs.

10.3.3 Rewarding generation capacity

Conventional generation will experience reducing load factors as the deployment of renewable generation progresses and the issue arises of whether an electricity market that only rewards energy can support the conventional generation capacity required as part of a mixed generation portfolio. Generation investment has fallen since the removal of explicit capacity payments with the introduction of NETA/BETTA and the ability of the current GB market arrangements to deliver sufficient new generation capacity has yet to be fully tested. While there appears to be no clear academic consensus on the relative merits of rewarding capacity explicitly or indirectly via electricity price volatility, it seems likely that the case for separate capacity payments will become stronger as generation margins over demand increase and the utilisation of conventional generation deceases. It is also suggested that rewarding generation capacity explicitly would help address the structural problems of the Balancing Mechanism in that it would no longer be necessary for generators to seek to recover fixed costs via that route.

10.4 Energy constraints

The deployment of variable output renewable generation on a scale consistent with the delivery of our renewable obligations will cause energy constraints to occur due at some stage. Just when this is first likely to occur still needs to be quantified, however as some point the combination of high wind generation output and the associated need for spinning reserves to be held on conventional plant, must-run generation such as nuclear and CHP, coinciding with periods of reduced demand will result in an excess of generation capacity and the need to curtail renewable output. Curtailing the output of zero-marginal cost plant will cause electricity prices to collapse and even go negative, with potential consequences for the economic viability of wind generation and for other high capital cost plant such as nuclear, which relies on high utilisation and reasonable electricity prices.

The onset of energy curtailment may be delayed though the deployment of measures such as the provision of additional interconnection capacity and storage and by encouraging fuel substitution in order to boost electrical demand during periods of high renewable output. Fuel substitution, for example by the replacement of electricity for gas in domestic space and water heating and the eventual deployment of electric vehicles, would also be a means of increasing the use of renewable energy in the heat and transport sectors.

10.5 Transmission investment.

Accommodating the renewable capacity required to delivering the electricity sector's contribution to the UK's climate change obligations will require significant transmission investment. It has been estimated by the ENSG that, in addition to the £4 billion of transmission investment authorised by the 2008 Transmission Price Control and excluding the costs of reinforcing connections to the Scottish islands, some £4.7 billion of additional investment could be required by 2020. In view of the scale of investment required, and the potential impact of the increased costs of transmission investment on end-user's bills, there is a need to ensure that unnecessary investment is avoided by maximising the utilisation of existing assets and the adoption of objective investment rules.

In this respect, there are concerns over the application of investment criteria set out in the GBSQSS, with the GBSO/TOs appearing to take a conservative approach to the avoidance of operational risk and the need for investment. There is particular concern over the treatment of intermittent generation by in the GBSQSS and allocation of a 60% "load factor" to wind when justifying the need for reinforcement and the general lack of any transparent and objective rules for undertaking cost benefit analysis. A review undertaken by the GBSO/TOs published in January 2008 worryingly confirmed the approach to dealing with intermittent generation despite other analysis which suggests that load factors in the range 30-35% would be more appropriate. A more general review of the GBSQSS has now been initiated which will usefully explore alternatives to the current deterministic approach to operational and investment criteria and it is hoped that the intermittency issue will be revisited.

Finally in relation to investment, there is a need for critical infrastructure developments to be undertaken on a "strategic" basis rather than in response to specific customer need in order to ensure delivery in timescales consistent with the UK's renewable objectives in the required timescales. The TIRG process undertaken by the DTI and Ofgem in 2004 together with the recent ENSG report proposing transmission investment necessary to deliver the UK's 2020 targets are useful steps in this direction, although someway short of the more structured approach adopted in, say, Germany or Denmark where long-term infrastructure plans are developed, focused on the delivery of energy policy objectives. Complementing the ENSG study, Ofgem's proposals to authorise the costs of transmission developments that need to proceed immediately and encourage the GBSO and TOs to "anticipate" customer need through adjustments to the Price Control risk and reward profile reflect a more strategic approach.

However, it will still be necessary to ensure that overall investment requirements are optimised by the maximising the use of existing assets and adopting appropriate investment criteria.

10.6 Regulatory incentives for Investment

Price cap regulation of the electricity networks has been successful in delivering operational efficiencies to the benefit of GB customers in the form of reduced electricity bills. While there are clear incentives to encourage authorised network developments to be undertaken efficiently, there is concern that the combination of the Transmission Price Control and SO Incentive scheme do not sufficiently encourage appropriate trade-offs between network reinforcement and alternative operational measures. This is a particular concern given very significant uncertainties over the pace, scale and location of renewable generation deployment, which adds to the attractiveness of pursuing operational alternatives, where appropriate.

It is suggested that the optimal trade-offs between investment and operational alternatives would require the GBSO/TOs to be exposed to the *total* costs of providing a transmission service. Lessons could be learned from UK gas regulation, where NGET as network operator is effectively exposed to both the cost of investment in the gas network and the cost of not investing (i.e. buying back capacity when necessary) over the Price Control period. This approach if applied to the transmission system would appear to offer the prospect of a more objective comparison of investment versus operational measures and lead to increased utilisation of existing transmission assets.

10.7 Transmission charging

The existing ICRP- based methodology for charging users of the transmission system is discussed in the context of the extent to which it might present a barrier to the deployment of renewable generation and the delivery of the UK's renewable goals. Although TNUoS charges are higher in Scotland, where the majority of onshore renewable generation is currently locating, analysis by IPA/SKM suggest that investment returns on renewable projects should be sufficient to support those higher charges. It is concluded therefore that the principle justification for the proposal by the Scottish companies, supported by the Scottish Government, that current charging arrangements discourage the deployment of renewable generation in Scotland and that uniform, non-locational, use of network charges should apply, is not supported by available evidence.

There is, however, a concern that the current arrangements for transmission charging, with charges being allocated on a per MW basis with no differentiation between generation technologies, discriminate against variable-output renewable generation and are not truly cost-reflective. It has been demonstrated by SEDG that technologies such as wind generation drive transmission investment less than does conventional generation and should therefore attract a lower level of charge. This effect is not uniform, and a larger discount would be justifiable in exporting areas where both renewable and convention generation co-exist than in areas where renewable generation predominates. However, as the allocation of access rights via TEC is indifferent to generation technology, and TEC is the basis on which TNUoS charges are applied, differential charging on the basis of generating technology is not possible with the current access/network charging regime.

10.8 Delivering a sustainable electricity system

This paper has considered what changes to regulation, electricity markets and operational procedures may be required to deliver the UK's new 2020 renewable obligations. The changes proposed by the paper are with reference to the arrangements and preference for competitive markets which exist today and are therefore largely "tactical" in nature. However, rather more fundamental changes may be required to deliver the ultimate objective of a fully sustainable electricity network, which would be essentially decarbonised and capable of delivering security of supply through fuel diversity, maintaining a mixed generation portfolio of adequate capacity and appropriate operational practices.

In order to understand what these fundamental changes may be, a common understanding needs to be established of what market, regulatory and operational arrangements would best accommodate this ultimate objective of a fully sustainable electricity network. Would, for example, ensuring that renewable and low-carbon generation assume the necessary natural priority over any supporting conventional generation that needs to be retained be best achieved via a combination of a non-discriminatory electricity markets, carbon pricing and obligations on suppliers, or by directly assigning priority? Is bilateral electricity trading compatible with reliably minimising carbon emissions or will it be necessary to operate a "carbon-minimising generation merit-order" administered via an electricity pool and centralised dispatch? How best to maintain a diverse generation portfolio where generation margins will approach 100% and conventional generating plant will see much reduced load factors? Only once these and other questions have been addressed and an understanding achieved of what electricity market, regulatory and procedural arrangements will be required to deliver a sustainable electricity network, will the real scale of change be identified. The question then to be addressed is can that change be delivered by a regulatory authority whose primary duties relate only to cost-efficiency delivered via competition, and who only has to have regard to sustainability in discharging those duties, or whether those primary duties need to be recast with the delivery of a sustainable electricity network at their heart.

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