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UKERC response to the PRASEG Inquiry – Renewables and the Grid: Access and Management

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Lead authors: Phil Baker (University of Exeter) and Modassar Chaudry (University of Manchester)
Contributions from Prof. Catherine Mitchell, Dr Bridget Woodman (University of Exeter), Prof. Nick Jenkins (Cardiff University), Prof. Goran Strbac (Imperial College London), and Dr Jeff Hardy (UKERC HQ)

UK Energy Research Centre
58 Prince's Gate
Exhibition Road
London
SW7 2PG

Submitted on behalf of UKERC by Dr Jeff Hardy
Tel: +44 (0) 207 594 1572
E mail to: jeff.hardy@ukerc.ac.uk
www.ukerc.ac.uk

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UKERC Response

The UK Energy Research Centre welcomes this opportunity to provide input to the PRASEG Inquiry – Renewables and the Grid: Access and Management.

Summary

- Without the adoption of a more holistic approach that addresses BETTA structural reform and network regulation, it is difficult to see how a satisfactory resolution of the transmission access issue can be achieved.
- It is proposed that more strategic and unified development of the onshore and offshore network together with the provision of interconnection would be encouraged through common or at least zonal ownership of offshore transmission assets, while cost-effectiveness and the efficient delivery of assets could be achieved through tendering and outsourcing construction.
- Modern distribution networks are not typically designed to accommodate generation; a number of technical and operational challenges will need to be addressed in order for the connection of significant amounts of distributed generation on these networks.
- The consequences of intermittency or variability of input will need to be managed by a combination of retaining conventional plant and developing demand response. Additionally, interconnection with adjacent transmission systems and improved forecasting of wind resource and maintaining geographic diversity of wind generation could also reduce the impacts of intermittency.
- The role of “smart grids” will be to enhance the capacity and utilisation of the electricity grid (both transmission and distribution) by means other than investing in traditional transmission assets and, via the deployment of smart metering, massively increase the contribution of the demand side to system security and the decarbonisation of the heat and transport sectors.
- UKERC is concerned that a major opportunity will be missed unless there is a timely change to a regulatory regime that encourages objective and cost-efficient choices between investment and smart grid solutions.

1. Transmission: What are the challenges regarding access to transmission network for large renewables?

Concerns over transmission access arrangements have existed for some time. In fact Ofgem's predecessor, OFFER, first raised the need for reform at the time of industry privatisation in 1990, and it is surprising that the existing access arrangements, which seem so at odds with the competitive electricity energy market, have survived for so long.

The failure of the joint BERR (DECC)/OFGEM Transmission Access Review and both earlier and subsequent attempts by industry to agree an enduring access regime which is affordable, cost-reflective and capable of delivering the generation capacity required to achieve the UK's renewable obligations in a secure fashion can, arguably, be attributed to two main causes. Firstly, the reluctance of generators to relinquish what they believe to be "evergreen" transmission access rights together with the possibility of a successful legal challenge to any non-legislative attempt to dilute these rights. Secondly, structural problems associated with BETTA in pricing congestion, reinforced by current network regulation.

If there is to be a satisfactory resolution to the long standing issue of transmission access for generation, Ofgem and DECC will need to take a more holistic approach that considers the impact on transmission access of electricity market design and regulatory incentives, and not the selective and targeted approach adopted to date and which is evident from DECC's consultation on access reform, published in August 2009.

"Evergreen" transmission access rights. Existing arrangements, which allow generators ongoing access to the transmission system for the payment of a single year's use of system (TNUoS) charges with a need to give only a few months notice of relinquishing those rights, seem incompatible with the need to "share" transmission capacity in a situation where connected generation will exceed demand. The arrangements also discriminate against newly connecting generators, who are required to commit to a number of years transmission charges, and are also unhelpful in terms of identifying the need for transmission investment. Some means of addressing the issue of "evergreen" rights needs to be found if an appropriate enduring access regime is to be identified. It is therefore disappointing to note that, of the three access options proposed by DECC in their consultation on "improving Grid Access", published in August 2009, only one option involves any changes to the rights of existing generators, and that this option seems unlikely to be progressed.

Market arrangements, congestion pricing and network regulation. Existing GB electricity market arrangements result in significantly higher costs of resolving transmission congestion than those adopted in some other jurisdictions, including the previous England & Wales Electricity Pool or the old GEGB merit order process. Unnecessarily high congestion costs will discourage arrangements that allow the early connection of generation (i.e. a “socialised” connect and manage access regime) and could also make access models which target the costs of congestion on those causing that congestion prohibitively expensive for both newly connecting and existing generators behind an exporting boundary.

While Ofgem have recognised the potential difficulties that are caused by higher than necessary congestion costs, they believe that the cause is due predominately to the exercise of market power[1], rather than to the existence of any structural defect within BETTA. While the exploitation of market power may well result in the costs of resolving congestion being higher than would be the case in a truly competitive market, UKERC proposes that a more fundamental issue is the methodology used by BETTA to deal with transmission congestion.

National Grid propose to resolve transmission congestion by seeking bids and offers via the Balancing Mechanism or by striking security contracts with specific generators to reduce or increase generated output as appropriate. Generators making offers to replace constrained energy via the Balancing Mechanism or via these security contracts will have been excluded from the energy market and will therefore seek prices that recover both variable (fuel) and fixed costs. Generation bidding to reduce output will however only offer up (at best) the costs of fuel saved and, as the cost of resolving a transmission constraint is essentially the sum of the costs of constrained and replacement energy, it will include an element of fixed generation cost together with the differential fuel cost. This situation can be contrasted with that which applied under the old England & Wales Electricity Pool, where the cost of resolving congestion was essentially the difference between generator offers to run made at the day-ahead stage and, for similar technologies (i.e. coal), would typically be in the order of £1-5/MWhr. With BETTA, the costs of resolving transmission constraints can significantly exceed £100/MWhr.

Electricity market & regulatory incentives for transmission investment. In addition to discouraging efforts to allow for the early connection of generation, the unnecessarily high costs of resolving congestion, which are a feature of BETTA, also over-incentivise transmission investment. Generators are prevented from making objective decisions between the need for non-financially firm access with exposure to short-term transmission (congestion) costs, or financially firm access, where the short-term transmission costs are avoided by contributing to the long-term costs of investment. Unnecessarily high costs of resolving congestion will always make investment in infrastructure look relatively inexpensive and will result in generators opting for financially-firm access. Ultimately, however, this will lead to the inefficient utilisation of existing capacity and unnecessary transmission investment at a time when investment requirements are already at historic highs.

Current regulatory arrangements reinforce BETTA’s built-in investment bias. With a Transmission Owner’s income linked directly to the size of the Regulated Asset Base (RAB), there is an incentive to invest in order to increase the RAB and little or no incentive to avoid investment by releasing additional transmission capacity via operational means. In fact, existing network regulation does not consider and is unable to deal with the fundamental question of whether the level of network capacity released to network users in operational time scales is delivering good value for money to users. There are no mechanisms that provide assurances to all parties (network users, network operators and the regulator) that an appropriate balance is being struck between release of network capacity in real time and the provision of additional infrastructure. This significantly compromises the economic efficiency of system operation and represents a major barrier to the innovation necessary to enhance increase network utilisation and ensure efficient development.

i). What do you believe is the best model for the provision of access to the transmission network for large renewables, bearing in mind the various options under the 'Connect and Manage' model as laid out in the recent DECC consultation on 'Improving Grid Access'?

As indicated previously, without the adoption of a more holistic approach that addresses BETTA structural reform and network regulation, it is difficult to see how a satisfactory resolution of the transmission access issue can be achieved. A fully socialised connect & manage approach is likely to be ruled out as an enduring option due to the potentially prohibitive costs to be borne ultimately by electricity customers[1] While the "hybrid" approach apparently favoured by DECC pragmatically attempts to reduce the impact of full socialisation, it lacks rigour and patently discriminates in favour of existing generators. Conversely, access options such as Ofgem's favoured "fourth model" or National Grid's proposals for locational BUSoS charges[2], which partially address the issue of "evergreen" rights and allocates congestion costs on those generators causing the congestion, seem likely to impose costs which could seriously undermine renewable deployment in Scotland and also cause difficulties for existing Scottish generators.

However, if changes to BETTA methodology were introduced that reduced the costs of resolving congestion to the levels which would apply if mandatory pool-type arrangements applied in GB (i.e. the old E&W Electricity Pool, or market arrangement that have been adopted in New Zealand or parts of the US) then these alternatives may become more acceptable[3]. The additional costs implied by National Grid's locational BUSoS proposals set out in GB ECM18, which arguably

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[1] "Enduring Transmission Access Reform". Report 70/09, Ofgem, 25 June 2009.

[2] Locational BUSoS Charging - GB ECM18, Impact Assessment and consultation". This suggests that a large (500MW) high load factor wind generator in the North of Scotland could expect to pay an additional £6.35 million per year under GB ECM18, while a similar sized conventional power station in the South of Scotland would pay an extra £11.53 million per year.

[3] An indication of the likely reduction in the costs of resolving congestion if they were defined by fuel cost differentials rather than BM bids and offers, can be gained from the report "An assessment of the potential impact on consumers of connect & manage access proposals by Frontier Economics for Ofgem, November 2009, which suggests that the use of differential fuel costs reduces total constraint costs by around two thirds. However, Prof: Strbac in his evidence to the Energy and Climate Change Committee's Report into the Future of Britain's Electricity Networks, suggested that the use of differential fuel costs to calculate the costs of resolving congestion might reduce those costs by a factor of 10.

offers the most promising combination of cost-reflectivity, simplicity and appropriate transmission investment signals, might no longer represent a significant barrier to renewable generation connecting in Scotland or pose unacceptable charges on existing Scottish generators. The same may be true of Ofgem's preferred "fourth model", however, the complexity of the auction process and discrimination between those able to take part in the initial allocation of access and those who come later, seem likely to rule this option out of contention.

ii). Offshore wind: Do you think that the present point to point plans for offshore grid connections is the best way forward for large scale offshore renewables?

The size and location of Round 1 and 2 schemes makes radial connections the most appropriate method of connecting them to the onshore grid. However, the exploitation of high resource areas such as the North Sea will require the development of much larger and remote projects as envisaged under Round 3, which will require a more strategic, networked approach to connection.

The UK seems to have adopted an offshore regulatory regime which is seems neither unnecessary for Round 1 & 2 projects, nor appropriate for Round 3 and beyond. With one possible exception, all Round 1 & 2 projects are to be connected to the onshore grid by their own, discrete, radial connections. These connections will be generation spurs that can in no meaningful way can be described as transmission. They support no demand and there is no possibility of third-party access. Consequently, it is not clear why the connections for Round 1 and 2 projects need to be regulated.

Looking forward to Round 3 and beyond, the current developer-driven approach involving the appointment of individual OFTOs for each offshore project via competitive tender will continue to produce radial connections and seems unlikely to encourage a strategic view. For offshore and onshore network development to be optimised as one, and opportunities to interconnect with adjacent electricity systems exploited, the NETSO will need to take up a strategic, coordinating and pro-active role, with some offshore transmission capacity developed on an anticipatory basis. It is not clear that the current regulatory arrangements, which aim to reduce overall costs through competitive tendering, are capable of encouraging or supporting such an approach. It is proposed that more strategic and unified development of the onshore and offshore network together with the provision of interconnection would be encouraged through common or at least zonal ownership of offshore transmission assets, while cost-effectiveness and the efficient delivery of assets could be achieved through tendering and outsourcing construction.

2. Distribution: What are the challenges facing Distribution Network Operator's in providing access to the grid for distributed generators?

i) Do you think that the existing distribution networks can cope with a large increase in distributed generation?

Although considerable amounts of generation were once connected at distribution voltage levels (132kV and below), modern distribution networks are not generally designed to accommodate generation. Unlike the transmission system, which is dependent on connected generation for security, distribution networks are passive in nature and do not require to be actively controlled. If distribution networks are in future to accommodate significant amounts of generation, which will become an integral part of their security, additional monitoring, control, and communications systems will need to be provided and Distribution Network Operators will need to develop a "system operator" capability. In addition, the connection of significant amounts of generation will require the following specific technical challenges to be addressed:

- *Fault levels.* Synchronous generation will contribute fault current in the event of a network fault and lead to a general increase in network "fault level". This will require the fault rating of distribution network equipment, and that of customer equipment connected to the distribution networks, to be increased or fault limiting devices to be installed. Induction generators, or synchronous generators connected via power electronic interfaces, contribute little fault current and this can lead to fault detection issues.
- *Protection against faults.* Currently, the use of time graded over current protection is widely used to detect distribution network faults. This will become inadequate with the connection of generation.
- *Fault ride through.* Currently, technical standards require distribution-connected generation to disconnect in the event of a network fault, in order to avoid damage to customer equipment in the event of a section of network becoming "islanded". However, once significant amounts of generation become connected, this design philosophy becomes untenable - both from a local network and "system level" point of view. Generation will need to "ride through" local network faults in order to provide local security and also survive transmission system faults in order to avoid the wholesale loss of generation at loss of security at a system level. It is worth noting that the loss of large amounts of wind and other local generation, designed to trip in the event of low frequency, was a significant feature in the widespread loss of supplies that occurred across Europe in October 2006.
- *Islanding.* As indicated above, distribution-connected generation will ultimately become an integral part of network security and need to be able to survive being disconnected from the main distribution network in order to support local demand. This implies the need to be able to operate in accordance with statutory frequency and voltage standards. A good example of this issue is West Denmark, where security problems occur once local generation output exceeds local demand in the event of interconnection to the mainland being lost. The proposed solution to this problem is "cell controllers" with black start/islanding capability.

- *Network voltage control.* Existing arrangements for the control of distribution network voltages are designed on the basis of uni-directional power flows and may not be able to handle the range of voltage variation arising from the connection of local generation. Voltage control mechanism may need to be upgraded and “on-load” transformer tap changers installed on 11kV/medium voltage transformers to accommodate local generation “hot spots”.

3. Variability: How can variability of input to the grid be best managed?

The consequences of intermittency or variability of input will need to be managed by a combination of retaining conventional plant and developing demand response in order to provide capacity support and adequate reserve in operational timescales. Improved forecasting techniques and the deployment of renewable technologies whose output is more predictable would also be helpful. Increasing interconnection capacity with adjacent transmission systems will also contribute, although there is a risk that support from adjacent systems may not be available when required, if for example weather systems affect adjacent systems simultaneously. Maintaining geographic diversity of wind generation will also reduce the impacts of intermittency and the need for capacity and operation reserve, as will improvements in forecasting techniques. Utility scale storage also has the potential to reduce the requirement for backup generation capacity; however, a reduction in cost will be required before dedicated storage becomes a viable option.

As renewable deployment builds and the load factors seen by conventional plant falls, economics may begin to favour a certain capacity of low capital cost/ high variable cost plant such as OCGTs

i) In anticipation of a large increase in renewable energy generation, what do you think are the main challenges involved with backup capacity?

The utilisation of conventional plant retained for backup purposes decrease steadily as renewable deployment progresses and the greatest challenge will be that of financial viability. With the GB electricity market only rewarding energy, back up generation will be increasingly dependent on periods of high energy prices to support its fixed costs. As the incidence of these high energy price periods will vary considerably from year to year, the investment environment will become inherently more risky and financial returns will need to increase. The need to ensure sufficient investment in back up capacity may justify the introduction of some of reward for capacity or capacity obligation; neither option is free of difficulties.

ii) What do you think is the potential for interconnectors to ‘balance out’ intermittency?

The exploitation of areas of high renewable resource such as the North Sea and the general increase in price volatility associated with increased levels of intermittency can be expected to drive an increase in interconnector capacity. Interconnectors will provide access to adjacent markets and provide support in terms of both capacity and dealing with intermittency. However, weather systems which straddle international boundaries or difficulties in adjacent systems may on occasion limit the support which can be provided.

iii) What do you think is the likely impact of negative prices and the effect of this on pricing structures?

Negative prices, which are likely to occur during periods of high wind output coinciding with low demand and when more generation than available demand wishes to operate, could have a negative impact on the viability of high capital cost “must run” generation such as wind, nuclear and CCS. The materiality of the issue will depend on the frequency and duration of negative price periods and there seems to be some dispute about how significant the issue may become. In their report to BERR, SKM[4] 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[5] (2008b) suggests that curtailment might become first become required at wind penetrations of around 16GW.

The expectation of low or negative electricity prices is likely to drive a demand response which should result in some mitigation. The experience of Demark where electric heating has been deployed to replace gas in district heating schemes during periods of low electricity prices is instructive. While the UK is not well endowed with district heating schemes, there is considerable potential for demand response from space and water heating, and, in the future, electric vehicles. In addition to demand response, the expectation of volatile electricity prices can be expected to encourage additional interconnector capacity and possibly utility-scale storage, justified on the basis of arbitrage. In addition to mitigating price volatility, all these measures will allow greater deployment and utilisation of wind and other zero and low-carbon technologies, through the manipulation of energy demand.

iv) What do you think is the relevance of BETTA to new Grid patterns? Specifically, will the bidding system to supply the grid be practicable and affordable for a grid which has variable input.

The principle concerns about existing electricity arrangements in the context of a generation portfolio that includes a significant amount of intermittent plant relate to the absence of any explicit reward for capacity, a Balancing Mechanism that inflates

[4] Growth Scenarios for UK Renewables Generation and Implications for Future Developments and Operation of Electricity Networks, Report to BERR, June 2008.

[5] Integrating Wind Generation in the UK Electricity system. Presentation 2008 to the Electricity Policy Research Group, Cambridge University, May 2008.

the cost of resolving congestion and penalises energy imbalances and the general illiquidity of the electricity markets – particularly the intra-day market. However, all these issues could readily be addressed and it is not clear that moving to alternate market structures, for example where the System Operator assumes responsibility for centralised generation scheduling and dispatch, would justify the very considerable costs involved.

Capacity payments. Measures to reward generators (or demand) for contributing to capacity requirements could be readily introduced within BETTA and whilst their introduction would no doubt introduce difficulties of their own, there would be clear advantages in terms of a less risky environment for generation investment, a reduction in energy price volatility and a reduction in the costs of resolving congestion (because marginal generators would no longer be justified in recouping fixed costs when offering replacement energy via the Balancing Mechanism).

Balancing & settlement process. The issue of the dual-cash out settlement process penalising energy imbalances, and thereby discriminating against technologies such as wind that have difficulties in accurately forecasting output, could be addressed by the adoption of a single cash-out price. A clear incentive to balance would remain, due to the high cost of imbalances which were in the same direction as net market imbalance. However, the asymmetrical and penal nature of the current settlement arrangements would be removed, with individual imbalances that reduced net system imbalance being rewarded at value.

An alternative to a single cash-out price would be to allow ex-post trading whereby parties where allowed to trade out individual imbalances after the event. Concerns have been raised, however, that ex-post trading would dilute the incentive to balance and be unhelpful to the System Operator.

Market liquidity. The introduction of large amounts of intermittent generation such as wind implies a significant increase in short-term (particularly intra-day) trading to allow intermittent generators to take advantage of increasingly accurate forecasts as real time approaches. It is of some concern therefore, that the liquidity of the GB electricity market is generally poor compared with markets in other jurisdictions. Reduced liquidity has been attributed[6] to the degree of vertical integration in the GB electricity market, lack of firm reference prices, and the fact that the Balancing Mechanism and settlement process may act as a barrier to smaller or non-physical participants. Given the future importance of intra-day trading in allowing intermittent generators to balance their contractual and physical positions, the need for possible measures to improve short-term liquidity and facilitate intra-day trading need to be considered.

Other measures that could be considered in relation to energy balancing and intermittency could include advancing gate closure or changing the basis on which

[6] Liquidity in the GB wholesale energy markets. Ofgem, Ref 62/09, July 2009.

balancing costs are allocated. With gate closure 1 hour ahead of real time, the GB electricity market compares well with other European markets; however, recent data published by Elexon for a typical winter's day (see Figure 1) suggests that significant errors in forecasting total wind generation output still exist even 1 hour ahead of real time. If this be repeated with the wind capacity required to deliver the UK's renewable obligations, the correlation between wind imbalance and market length could result in significant penalties for some wind generators.

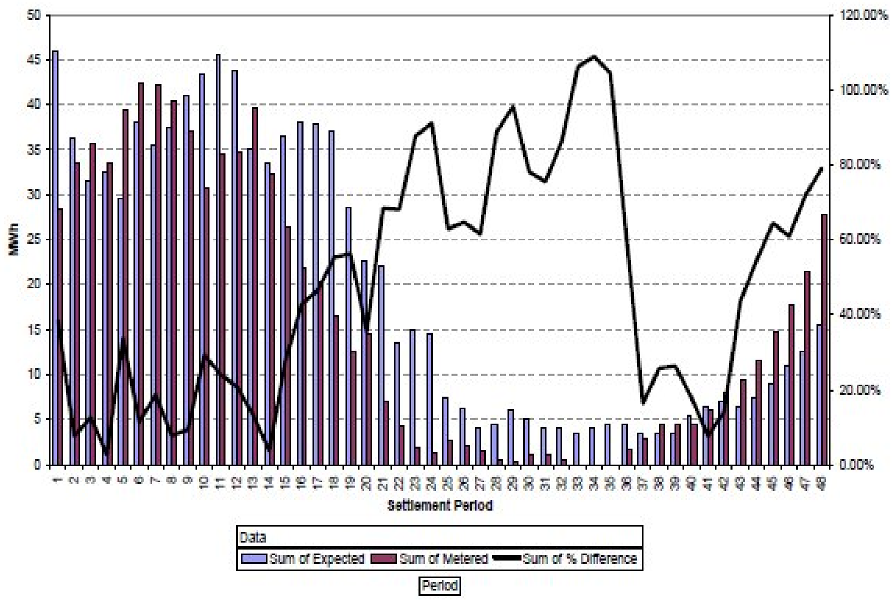

Figure 1: Comparison of 1 hour ahead forecast and actual wind output for a winter's day. Source Elexon.

Given the particular and inherent difficulties in forecasting output from wind generation compared with conventional plant, and the "special" nature of zero-carbon generation, (i.e. its role in replacing the output of fossil-fired generation) there may a case for treating wind and other intermittent technologies differently in terms of balancing requirements. While there is a need to encourage good forecasting performance, the overriding requirement to maximise wind output in the context of reducing carbon emissions suggests that any elements of the balancing and settlement regime that might encourage wind generators to reduce output in order to avoid imbalance charges should be removed.

v) What do you think will be the role of smart grids? How 'smart' will they be? How will smart meters, dynamic demand management, and financial incentives be used to deal with variable generation?

The role of "smart grids" will be to enhance the capacity and utilisation of the electricity grid (both transmission and distribution) by means other than investing in traditional transmission assets and, via the deployment of smart metering, massively increase the contribution of the demand side to system security and the decarbonisation the heat and transport sectors. Attempting the partial decarbonisation of the heat and transport sectors on a "business as usual" basis could, however, incur very significant costs[7] in terms of additional infrastructure and generation capacity requirements. The application of smart grid concepts, through the combination of energy and C & I infrastructures, offers the potential to minimise those costs through enhanced network efficiency & flexibility, customer participation and asset utilisation.

The utilisation of the *transmission system* and its capacity to accept renewable and low-carbon generation capacity through the intelligent application of operational standards and the coordinated application of intertripping and primary devices that can control power flows could be significantly increased while limiting the need for contentious and costly investment in overhead lines and cables etc.

In terms of *distribution*, techniques to increase network capability to accommodate zero- and low-carbon generation and coordinate that generation with network assets and responsive demand, offers increased local and national security and the possibility of replacing services currently provided by centralised generation. Many of the individual technical components and techniques that will contribute to the development of smart grids are already available and, in some instances, already in limited use. The challenge, therefore, is the technical and commercial integration of these techniques and technologies into the operation and management of the electricity grid.

Contribution of smart meters, dynamic demand management and financial incentives to accommodating variable generation. Through the application of smart metering and smart appliances, the demand side will contribute to reducing generation back-up capacity and the magnitude of operational reserves required. Dynamic (frequency sensitive) demand technologies will enhance the "stiffness" of the system response to frequency changes, thereby allowing the more efficient utilisation of reserves held on conventional plant. In addition, smart metering offers the potential to massively increase demand side contribution to grid system security and the enhanced deployment of renewable generation through partial the decarbonisation of the heat and transport sectors. Smart metering also opens up the possibility of offering consumers financial incentives to supply services to the electricity grid.

In addition, smart metering will;

- Allow a move to time related energy pricing
- Provide consumers and suppliers with detailed consumption (and generation) data
- Provide real time measurement of active & reactive power, current, voltage and frequency.

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[7] See "Smart Grids and electric vehicles transport". Presentation to IET by Prof G Strbac, Birmingham 22 October 2009.

- Allow DNO/supplier control of consumer demand (and generation)

4. What other issues regarding access to and management of the transmission and distribution networks do you think will need to be addressed to ensure the UK meets or exceeds its renewable energy & climate change targets?

Current network regulation represents a barrier to the development of smart grid concepts and technologies and therefore to the enhanced utilisation of the electricity transmission and distribution network infrastructures. The key concern is that network regulation, by heavily incentivising investment over operational alternatives, will effectively prevent Smart Grid concepts and technologies (i.e. 'non-network' solutions) from providing an economically efficient alternative to the conventional network asset based solutions. Given the immediate need to release additional transmission capacity to accommodate renewable generation, we are concerned that a major opportunity will be missed unless there is a timely change to a regulatory regime that encourages objective and cost-efficient choices between investment and smart grid solutions.