Mr Jonathan Dennis
22 Colombo Square, Worsdell Drive
Gateshead NE8 2DF
Tyne and Wear
United Kingdom

21st April 2009

Mr Simon Bartlett
Chairperson
E S Cornwall Scholarship Advisory Committee
P O Box 1193
Virginia QLD 4014
Australia

Dear Mr Bartlett

E S Cornwall Memorial Scholar – Jonathan Dennis
First Quarterly Report

Please find enclosed the first quarterly report for the E S Cornwall Memorial Scholarship for 2008-2010, which is a requirement set out in the scholarship rules.

My first quarter on the ES Cornwall Scholarship has provided valuable insight into:

- the dynamic behaviour of different types of wind turbines,
- the criteria used to plan and operate Great Britain's transmission system, and
- the measures that have been taken to overcome obstacles to the widespread uptake of renewable generation.

I would welcome the committee's feedback on this report and my aspirations for the next quarter.

Yours faithfully,

Jonathan Dennis

Enclosures:
E S Cornwall 2008-2010 Quarterly Report 1

ES Cornwall Scholarship 2008-2010
Jonathan Dennis

First Quarterly Report

Introduction

My tenure of the E S Cornwall Memorial Scholarship commenced in January 2009 and continues until June 2010. My program is aimed at gaining experience in the measures being applied internationally by transmission companies to manage three main deficiencies of large centralised renewable generation, being:

- variability of renewable power generation over time,
- low inertia, poor fault ride through capability, and
- remote location necessitating long distance radial connections.

This is the first of six quarterly reports required by the scholarship guidelines, and covers the three months from January 5 to April 5, 2009. During this time I have been employed by Senergy Econnect in their Power Systems Analysis team. This report documents the work that I have been involved with, and the impressions I have gained thereby.

Senergy Econnect is a consulting firm that specialises in resolving issues related to the electrical connection of renewable generation. The range of work performed by the company includes:

- initial assessments of the feasibility of an electrical connection for a new development
- completing generation connection applications and negotiating with network operators on behalf of developers
- detailed design of electrical connection infrastructure
- design of offshore transmission networks
- grid code compliance studies and the design of systems to address deficiencies
- project management of the construction of electrical works
- turbine model development for wind turbine manufacturers
- advising on commercial and regulatory issues related to renewable generation

To date, I have worked on several different projects, including:

- high level design of the offshore array and offshore transmission connection for a very large wave and tidal generation scheme in the far north of Scotland
- assessing the capability of the transmission network in Wales and South West England to accept the connection of a proposed multi-gigawatt offshore wind farm
- completing several generator connection applications to distribution network operators on behalf of developers – providing information about the development and the gensets in a form acceptable to each distribution network operator (DNO)

- assessing the feasibility of connecting a proposed wind farm in Northern England to the local distribution network, considering the network's thermal and fault level capability, and the cost of various connection options
- modelling a proposed wind farm in Romania to identify any thermal overloading and voltage rise issues in the local distribution network

The commercial-in-confidence nature of the work I have been involved with means that I am unable to report specific details. However, I can report that involvement in these projects, coupled with discussion with experienced colleagues has afforded valuable insights into:

- the characteristics of different types of wind turbines and the impact of these turbines on the operation of the power grid
- the transmission planning criteria presently used to guide the development and operation of the UK's transmission system
- the wide range of measures that have been undertaken in the UK to overcome the obstacles to the widespread uptake of renewable generation, including:
    - improving the financial viability of renewable generation
    - providing a place to site renewable generation
    - measures to decrease the time taken to acquire planning consent
    - measures to increase the rate at which new renewable generation can be connected
    - development of a high level plans to extensively upgrade the transmission network

This report elaborates on what I have learned in each of the areas listed above.

Historical Development of Wind Turbines

Commercial wind turbines for grid connected applications have existed since the 1980's. Initial wind turbine development concentrated on increasing the output capacity, and a significant increase in capacity was achieved, as can be seen in the diagram below[1].

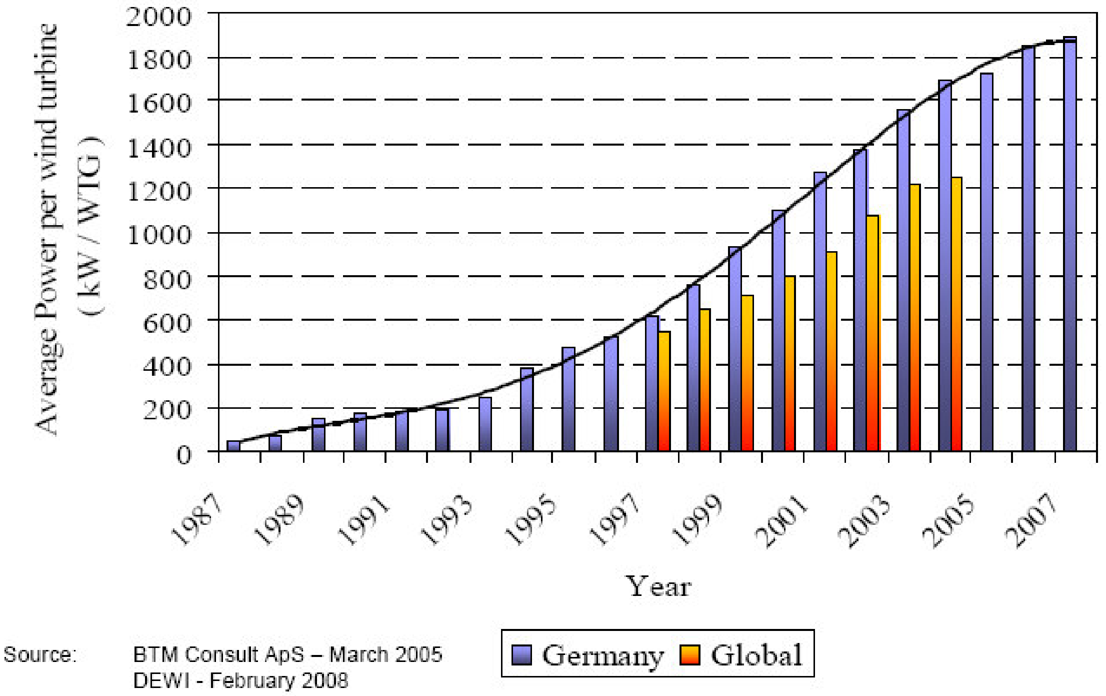


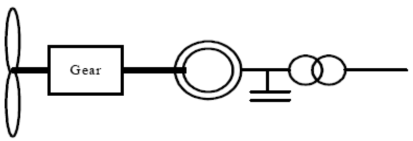
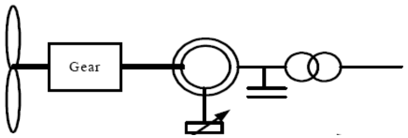
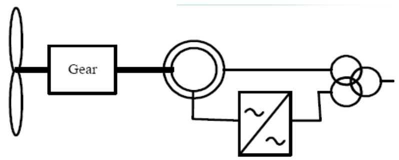
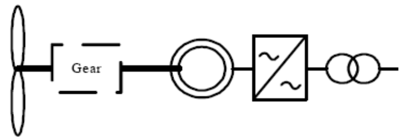
Figure 1 - Variation of Average Wind Turbine Size Over Time

However, since 2000, the increasing volume of wind generation and increased focus on renewable generation has prompted countries around the world to increase the technical requirements placed on turbines. This has had the effect of slowing the increase in turbine size as wind turbine developers channel their R & D into improving the technical performance of their turbines.

There are now a range of different turbine types with vastly different capabilities. The four principle types and their characteristics are described in the following table.

[1] "The impact of Grid Codes on the development of wind turbine technologies", Dr Sigrid M Bolik http://www.senergyworld.com/UserFiles/Documents/econnect/papers/TheimpactofGridCodesonthedevelopmentEC-SigridBolik.pdf

Wind Turbine Types & Capabilities

	Type A - Fixed Speed	**Type B – Limited Variable Slip**	**Type C – Variable Speed with Partial Scale Converter**	**Type D – Variable Speed with Full Scale Converter**
Description	Uses an asynchronous squirrel cage induction generator directly connected to the grid via a transformer. Multiple speed gearboxes or star/delta switchable generator connections can be used to provide multiple fixed speeds of operation. 	Uses a wound rotor induction generator with a variable rotor resistance. Varying the rotor resistance varies the slip and subsequently provides up to 10% variation in rotor speed. 	Uses a wound rotor inductor generator whose rotor windings are connected to the grid using full bridge power converter rated at approximately 30% of the nominal generator power rating. Alternatively known as a doubly fed induction generator (DFIG). 	Connects any type of generator (including non wind turbines) to the grid via a full-scale full-bridge power converter. The converter effectively de-couples the generator from the grid and enables operation at any speed. 
Usage	The "traditional" wind turbine and perhaps the reason for wind energy's poor reputation amongst utilities. Many such turbines exist although the new installation of these turbines is uncommon.	Were increasingly popular to install during the 1990s until type C turbines were developed, after which their usage had dropped.	Since their development in the late 1990's, type C turbines have dominated the market for new turbine installations. By 2003 they were the most common type of wind turbine in use.	Type D converters have maintained approximately 15% of the market share since the mid 1990s. In the last 2-3 years, reductions in the cost and improvements in the reliability of power converters, combined with increasingly onerous grid connection requirement have seen their usage increase significantly.

Information in this table is adapted from "Wind Power in Power Systems", Edited by Thomas Ackerman, 2005, John Wiley & Sons

	Type A - Fixed Speed	Type B – Limited Variable Slip	Type C – Variable Speed with Partial Scale Converter	Type D – Variable Speed with Full Scale Converter
Reactive Power Control	No control of reactive power. Inducing a current in the rotor windings naturally consumes reactive power from the grid. The resulting power factor typically varies in the range -0.80 to -0.92. These turbines are often used in conjunction with capacitors to offset reactive power consumed and provide some form of reactive power control.	Like type A turbines, there is no control of reactive power, and reactive power is consumed from the grid with a typical power factor of -0.80 to -0.92. Type B turbines are likewise often used with separate reactive compensation.	The full bridge converter enables control of reactive power, typically between - 0.80 pf and + 0.95 pf. Depending on grid code requirements, type C turbines may also be used on conjunction with additional reactive compensation.	Full bridge power converters can produce energy over a wide power factor range and are only limited by their current rating and the amount of energy produced by the turbine.
Real Power Control	Three common variations: A0: The only 'control' is that the blades are designed in such a way that they will stall (and power output will drop) if the wind speed gets so strong that the turbine would become overloaded. A1: The blades can be pitched to adjust to slow variations in the wind speed and extract the maximum amount of wind power – or to try to maintain a constant power output. However, the pitch mechanism is not fast enough for sudden gusts of wind, resulting in large power output variations. A2: Employs 'active stall control', a pitching mechanism that can quickly stall the blades and reduce power output variations with wind gusts.	Although any of the power control options that exist for type A turbines could be applied, historically only pitch control has been used, in order to maximise the amount of energy extracted from the wind.	The partial scale power converter enables smoother control of the power output and operation over a wider range of wind speeds (typically -40% to + 30% of synchronous speed). Type 3 converters are commonly also fitted with blade pitch control to optimise the speed of rotation for maximum energy extraction in different wind speeds or to try to follow a power output set point. The partial but rapid control of the power converter can be coordinated with the slower acting pitch control to provide a fair degree of overall controllability of the turbine.	The full scale power converter provides complete and rapid control over the power output. Sudden variations in the wind speed can change the rotor's rotational speed but need not vary the power output at all. Additional control logic can also be applied, such as maintaining a constant power (equal to or less than the available wind energy), varying the power output in response to changes in the grid frequency or power oscillations, or quickly reducing power output after a fault and restoring full power output after it is cleared.

	Type A - Fixed Speed	Type B – Limited Variable Slip	Type C – Variable Speed with Partial Scale Converter	Type D – Variable Speed with Full Scale Converter
Fault Response & Contribution	A typical contribution during a fault is: Peak: 8 x rated current (compared to 10 x for a synchronous machine) RMS: 6 x rated current (compared to 8 x for a synchronous machine)		With additional fault ride through enhancements, fault contribution reduces to approx 3 x rated current for peak and 1.5 x rated for RMS	The fault contribution is limited by the current rating of the power converter, typically 3 x rated for peak and 1.5 x rated for RMS
	Grid faults tend to induce large currents in the rotor windings and cause large oscillating torques on the generator shaft. If these parameters exceed the turbine's capabilities, protection will trip it. If the generator is still connected to the grid when the fault is cleared, they can consume large amounts of reactive power.	The turbine's response is very similar to that of a type A turbine, except that the variable rotor resistance is set to full during the fault to reduce rotor currents and subsequently rotor torque, improving the turbine's ability to ride through the fault.	During a fault, the rotor side power converter acts to dampen oscillations in rotor currents (and therefore reduce rotor torques) improving fault ride through, or may block completely to protect itself causing the turbine to behave as a type A turbine. The grid side power converter acts as a STATCOM to support the grid voltage. Post fault the rotor side converter restarts quickly to resume normal operation.	After detecting a grid fault, the converter quickly reduces real power output but increases reactive power output to full to support the grid voltage. Once the fault has cleared, the converter re-synchronises and resumes normal operation. This process can take several seconds for a large wind farm.
Advantages	Simplicity and robustness	Speed variability improves the utilisation factor over type A turbines	Much greater control of the active and reactive power, improving compliance with grid codes. Increased control of wind speed improves utilisation factor.	The ability to control both active and reactive power, and largely decouple the operation of the actual turbine from conditions on the grid, plus the ability to use any type of generator operating at any speed.
Disadvantages	Complete lack of control	Additional complexity and a corresponding drop in robustness and reliability	The use of vulnerable power electronics increases the cost and reduces the reliability of the turbine. The use of slip rings (to connect the power converter to the rotor windings) necessitates more frequent maintenance.	Significant use of power electronics increases the cost and reduces the reliability of the turbine. Losses in the power electronics reduce the overall efficiency of the turbine.

Implications of Recent Turbine Developments

From the above table it can be seen that the dominant wind turbines being installed today (types C and D) are a relatively recent development and have characteristics that are very different from earlier technologies. Although two wind farms may physically look alike, they may use different generator types and therefore have completely different electrical behaviour. One may be completely acceptable to the grid operator while the other may not.

Although increasingly strict grid code requirements are likely to necessitate the use of type C and D turbines for AC connected wind farms, there is still an application for type A and B turbines in proposed large offshore wind farms that are to be connected to the mainland grid via an offshore HVDC transmission network. An HVDC connection, which may already be necessary because of the long length of subsea cable required, has the additional benefit of decoupling the entire wind farm from the AC grid, in the same manner as the power converter in each type D turbine decouples the generator from the grid. Cost savings and reliability improvements can therefore be obtained without reducing the electrical performance by using type A or B turbines in this context.

Even today, wind turbines are the subject of much ongoing research and development. A key focus of present research is to improve the overall behaviour of wind farms, coordinating and controlling the response of individual turbines so that the wind farm behaves as one machine.

It is my impression that in time, the *dynamic behaviour* of wind turbines (and other renewable generation connected to the grid via a full scale power converter) will be able to effectively match that of conventional generation. Those qualities that renewable generators do not naturally possess (such as inertia) will be able to be mimicked by advanced control techniques. However, the additional equipment required to provide this capability increases the already high capital cost of renewable generation and the practice of operating turbines at a lower level than the available energy and the energy losses incurred in power converters effectively increases the operating cost. Improvements in the robustness and controllability of power networks may be able to facilitate the use of less expensive types of renewable generation and less expensive operating techniques. The challenge for regulators and policy makers is to identify the overall least cost manner of apportioning responsibility for maintaining the dynamic performance of the power system between generators and network operators. At this point in time, extensive network upgrades are still necessary to mitigate the *longer term variability* of renewable energy sources such as solar and wind. Advances in energy storage systems could one day even overcome this problem, but would again raise the issue of the most cost-effective way of incorporating such energy storage into the power system.

Great Britain's Planning and Operation Criteria

In Great Britain, the Security and Quality of Supply Standard (SQSS)[3] outlines the criteria by which the grid is to be developed and operated. It differs at quite a number of points with the Australian Electricity Rules[4] (AER) and planning criteria used in Queensland[5]. Below, I have sought to briefly outline those differences, and my understanding of the strengths and/or weaknesses of those differences.

'Tiered' Levels of Reliability for Demand, Expressed Deterministically

The two main options for defining reliability levels in planning criteria are to use deterministic rules (e.g. N-1) or probabilistic reliability levels (e.g. ability to meet demand 99.998% of the time). Deterministic criteria lead to a uniform level of reliability throughout the network, while probabilistic criteria often lead to a higher level of reliability for core high-capacity parts of the network than for peripheral low-capacity areas of the network. Using a probabilistic approach can be more cost effective overall since investment is directed towards those upgrades that will have the greatest impact on overall reliability. However, using a probabilistic approach is quite difficult in practice since it is not intuitive, and can be highly sensitive to the reliability & availability assumptions that must be made.

The SQSS is a hybrid of these two options, since it expresses reliability levels deterministically for clarity and straightforward application, but defines different reliability levels for different levels of demand. Demand connections less than 60MW do not need to be fully redundant, but capacity must be able to be restored within a timeframe that varies with the demand level. Above 60MW demand connections must be fully N-1 compliant, with different timeframes for restoring demand for a forced outage that occurs during a planned outage. Above 1500MW, demand connections must be N-1 compliant during any planned outage.

It is my view that describing multiple reliability tiers deterministically, provides a 'best of both worlds' approach – providing a high level of cost effectiveness, defining minimum reliability levels, and expressing the criteria in a way that is easy and clear to apply. Were

---

[3] A copy of the GB Security and Quality of Supply Standard can be obtained from National Grid's website: http://www.nationalgrid.com/uk/Electricity/Codes/gbsqsscode/DocLibrary/

[4] A copy of the Australian Electricity Rules can be obtained from the Australian Energy Market Commission's website: http://www.aemc.gov.au/rules.php

[5] A copy of the Powerlink Planning Criteria can be obtained from the Australian Energy Regulator's website: http://www.aer.gov.au/content/item.phtml?itemId=693265&nodeId=e056d8a0305cd23083d9fa5c9c8f1a4d&fn=Powerlink%20planning%20criteria%20policy.pdf

electricity reliability levels in Queensland ever to be reviewed, it is my view that the use of tiered levels of demand reliability be considered.

Infeed Loss Risk

Unlike the AER, the SQSS sets an upper limit of the amount of generation capacity that can be lost due to a credible contingency, which is linked to the amount of spinning reserve (FCAS) that is contracted. This limit influences the design of the transmission network and sets an upper limit on the size of generator units. Situations where one particularly large unit increases the amount of FCAS required by the market most of the time (such as Kogan Creek Power Station in Queensland) are therefore avoided. The infeed loss limit is also 'tiered':

- the loss of a single transmission circuit or busbar section should lead to no loss of infeed
- the loss of a single generator or generation circuit should not result in a loss of infeed greater than 1000MW,
- the loss of any two transmission circuits (either together or the forced outage of one circuit during the planned outage of another), a double circuit generation connection, or two adjacent busbar sections should not result in a loss of infeed exceeding 1320MW.
- (A recent review has recommended that the 1000MW and 1320MW values be increased to 1320MW and 1800MW respectively, to accommodate proposed nuclear generation units and offshore transmission networks).

Because FCAS is usually a grid-wide requirement paid by the market, I feel that there may be value in establishing a consistent infeed loss limit across the NEM to avoid situations where a particular generator or network branch is increasing the FCAS cost borne by all.

Contingencies Considered Credible

Like the AER, the SQSS considers the forced outage of a single circuit or piece of reactive plant to be credible. Unlike the AER, the SQSS also considers the forced outage of busbar sections and double circuit transmission lines to be credible in the planning timeframe. The consequence of this classification is:

- the increased use of bus sectionalising circuit breakers
- more parallel transmission circuits (at least two double circuit transmission lines to each region of the country)
- a higher level of reliability

The increased number of transmission circuits must obviously come at a considerable cost to the consumer, and this classification is therefore only likely to be cost effective for compact and meshed networks (such as the UK's) or the meshed portions of broad networks. For less meshed, radial portions of networks, this classification is not only likely to be prohibitively expensive but it is also less necessary since a non-credible fault is likely to cause the network to break at a weak point and subsequently cause any islanded sections of the power system to collapse. Provided the transmission system breaks 'cleanly' it is then relatively straightforward to rebuild the collapsed section of the power system outwards from the breakpoint (e.g. the North Queensland outage on January 22, 2009). However, for the highly meshed portions of networks, a non-credible contingency could initiate a cascading failure that could outage not only the meshed portion of the network but also any radial sections connected to the meshed section. Such an expansive outage would make rebuilding the network more complicated and time consuming.

In my experience, although relatively infrequent, busbar and double circuit line faults still occur with enough frequency that could warrant the introduction of a tiered standard that considers such faults to be credible in the meshed areas of the Queensland/Australian network that occur around the major load centres. Operationally the loss of a double circuit line is already declared to be credible when there is an electrical storm or fire in close proximity to the line. Given that these phenomena are quite common at the time of year that peak demand is expected, I believe that there is a strong case for considering such faults to be credible in the planning timeframe.

Assumed Generation and Network Transfer Background

When assessing the need for network upgrades, it is necessary to assume a generation and demand background. The demand is generally assumed to be the peak demand forecast for each load point in coming years. Deciding a generation background is more difficult since there may be several different ways in which the generation can be dispatched to meet the load. It is often unclear how to assume the extent to which local generation is available to meet local demand and the amount of demand which should be supplied from distant generation via the transmission network. The present planning criteria in Queensland uses an N-1 approach, assuming all but the single most significant generator are fully available, plus defined levels for the energy limited hydro units.

The approach described in the SQSS is more involved. Different types of generation are allocated a different availability percentage based on historical availability of that type of generators at the time of system peak demand. Additionally, a ranked list of all of the existing and committed new generators on the network is produced, ordered by the expected likelihood of each generator to be operating at the time of system peak. Units are then dispatched in this order, each to their availability level, until the total level of generation is 120% of the peak demand, including losses and exports. The generation of all generating units is then backed off proportionally until the total generation equals the overall demand. The resulting generation and transfer levels are collectively known as the ‘planned transfer condition’ and are taken to represent ‘average’ network conditions at peak demand.

Allowance for non-average conditions is provided for by variations to the planned transfers, known as an ‘interconnection allowance’. The size of the interconnection allowance between two regions is a function of the amount of demand and generation in the smaller region, as per the plot below. The more load or generation there is in a region, the more the variations of individual generators and loads will average each other out. The necessary interconnection allowance therefore increases at a decreasing rate and peaks at just under 4% of the UK peak (average cold spell, ACS) demand. The planned transfer condition plus the interconnection allowance defines the ‘required transfer capability’ across a boundary.

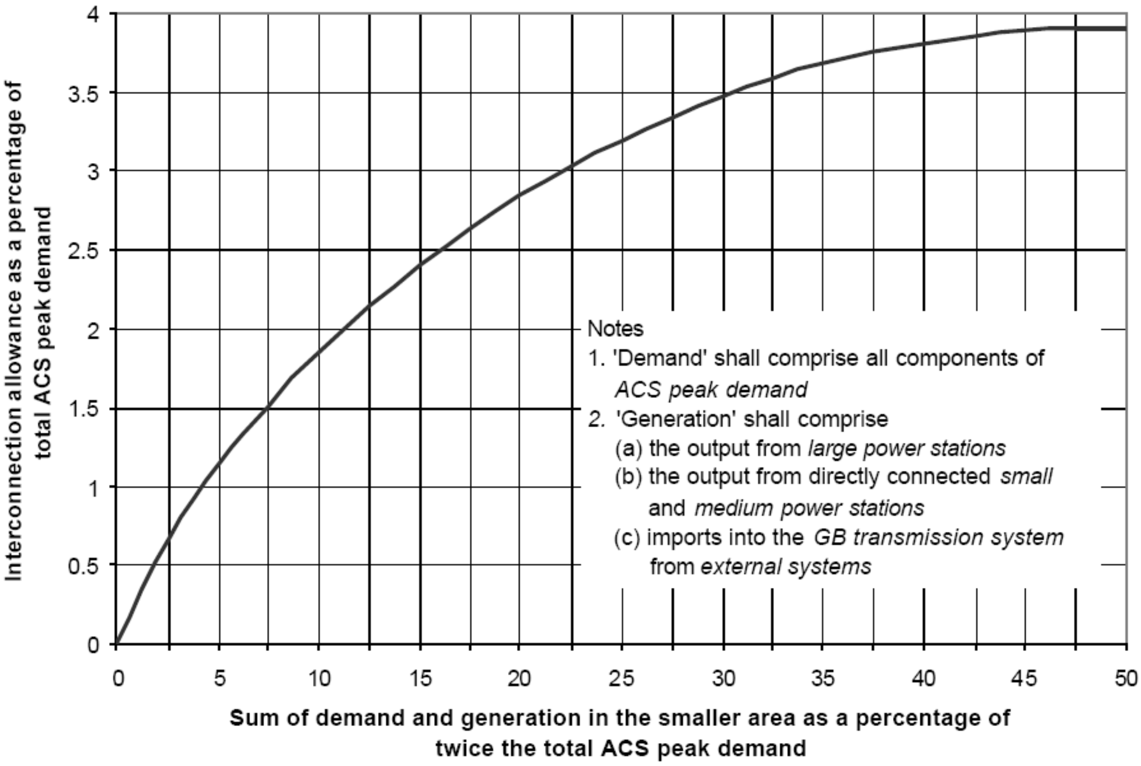


Figure 2 - Interconnection Allowance as a Function of Generation and Demand

The required transfer capability anticipated for future years can be compared to how the actual capability of the transmission system is expected to vary, to identify whether and when additional network augmentation may be necessary. National Grid is required to publish a rolling seven year outlook of such information in their Seven Year Statement. For completeness, on these plots National Grid also publish a representation of the range of transfers that they consider likely to occur, considering the typical operating pattern of generators, variations in demand growth, new generator openings or closures etc. An example plot[6] below illustrates the planned transfer condition (red solid line), required transfer capability (red dashed line), boundary transfer capability (blue line) and probabilistic transfers (green shading). In this example, the network would need to be upgraded in four years time as the required transfer capability exceeds the actual anticipated capability.

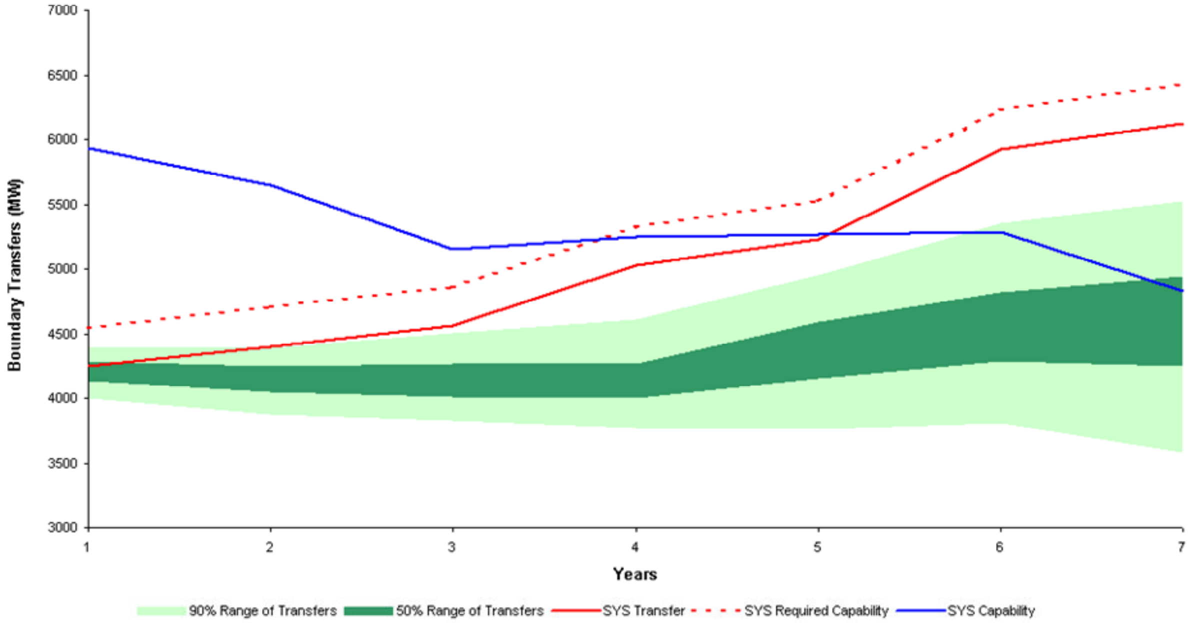


Figure 3 - Example Boundary Transfer Forecast, Requirement and Capability

The SQSS approach is obviously much more involved than an N – 1 approach. However, I feel that there is merit in considering the operating characteristics of different types of generators, and defining the amount of variability to make allowance for. This will become increasingly important as the volume of renewable generation connected to the grid increases, since it is almost always online but may have a relatively low utilisation factor (typically 40% for a well situated wind farm). Additionally, it is widely recognised that increased interconnection and interregional transfer levels will be needed to average out the variation in energy production from higher levels of renewable generation and ensure a reliable supply. A SQSS-like planning criteria may be necessary to highlight the reliability driven capacity increases that will be required on the main transmission network.

Another key strength of defining required boundary transfers is that this provides much greater clarity to electricity market participants about the baseline capability that the network will be designed and planned around. Whilst this doesn't completely remove the uncertainty regarding each participant's ability to generate or consume power, it does make the planning process more transparent.

[6] GB Seven Year Statement – May 2008, National Grid Plc, Available online at: http://www.nationalgrid.com/uk/sys_08/

Consideration of Operational Matters

The SQSS distinguishes between the design and the operation of the transmission system, and provides separate criteria for each. In general, the requirements which apply to the design of the network are more onerous than the requirements which apply to its operation. For example, the voltage range within which the network can be operated is wider in an operational timeframe than in a planning timeframe. During the planning timeframe, the SQSS also explicitly requires that planners ensure that all anticipated planned outages are able to take place at the times of year that access would normally be required. Regard must also be given to the typical power station operating regimes, and demand cycles (peak and minimum demand) likely to occur over the course of the year.

The planning criteria which presently exists in Queensland focuses on being able to securely meet the forecast peak demand. It is assumed that if the network is able to meet peak demand with the most significant transmission element and generator out of service then it will be flexible enough to meet less onerous conditions and be able to accommodate any necessary outages. However, I contend that this is not always the case, as some network issues (e.g. overvoltage) only manifest themselves in light loading conditions. Additionally, although the network may be designed to handle any single outage, in reality several different planned outages must happen on the network concurrently in order to adequately maintain and upgrade the network. Furthermore, planned outages are required on elements of the network for which the forced outages are not considered credible (e.g. busbars) and therefore have not been considered during the planning phase.

It is difficult to define how much operational flexibility should be designed into the network. However, I feel that in Queensland that there is greater scope for operational issues to be considered during the planning and design phases, and for the capital cost of different development options to be weighed against the potential operational cost savings (although the later is difficult to quantify). The value of operational flexibility is likely to increase as the level of renewable generation increases. When delivering a project, there are often small and relatively inexpensive measures that could be undertaken to significantly improve operational flexibility, such as increasing the negative VAr range on certain static var compensators to manage overvoltage issues, or including additional circuit breakers and/or isolators in the design of a substation.

Ongoing Review

The SQSS is a living document, and is subject to ongoing review. A significant change which is currently in the process of being finalised is a separate set criteria to guide the development of the offshore transmission networks which will be used to connect the significant amount of offshore wind, wave and tidal generation that is expected to be constructed in coming years (discussed further below). While similar in form to the requirements for the existing onshore network, the requirements for offshore networks have been relaxed to take account of the higher cost of infrastructure and the absence of demand connections. For example, up to 50% of an offshore generation scheme's capacity can be lost following the trip of a circuit, up to the infeed loss limit.

A fundamental review was initiated last year to assess the ongoing suitability of the SQSS given the significant increase in renewable generation that is expected to occur in the UK resulting in much higher volumes of generation with much lower average levels of utilisation. One of the members of the SQSS Review Group, Brian Punton, has offered to meet with me to discuss the scope and progress of this review, and I therefore hope to be able to write more about this in my next report.

Overall Impressions

Although the SQSS is designed for Great Britain's compact and highly meshed transmission system and would not be cost-effective to directly apply to the Queensland/NEM context, I feel that there are several aspects of it which should be considered when the Queensland planning criteria is next reviewed and if a NEM planning criteria (under AEMO) is developed. There may be merit in adopting a similar approach or form of expression in certain areas, although the specific thresholds and requirements should be re-worked to be optimal for the local context.

Addressing Obstacles to Renewable Generation

The UK's 15% renewable energy target by 2020 may initially seem less ambitious than Australia's 20% target. However, the UK's target addresses all forms of energy consumption and not just electricity production. To allow for the ongoing use of petroleum based fuels in portable applications, the UK government has set itself a goal of producing over 30% of the UK's electricity from renewable generation by 2020. The plot below shows how much the proportion of different fuels used to produce electricity have varied over the past 18 years (for a starting point fairly similar to Australia today), and how much they are expected to vary by over the next 12 years. The full scale of what the UK and many other European countries are trying to achieve can only be appreciated when one remembers that the utilisation factor of renewable generation is typically less than 50%. To produce 30% of the UK's electrical energy from renewable energy will require a renewable generation capability closer to 60% of average demand. Bringing about this change is quite obviously a significant multi-faceted challenge.

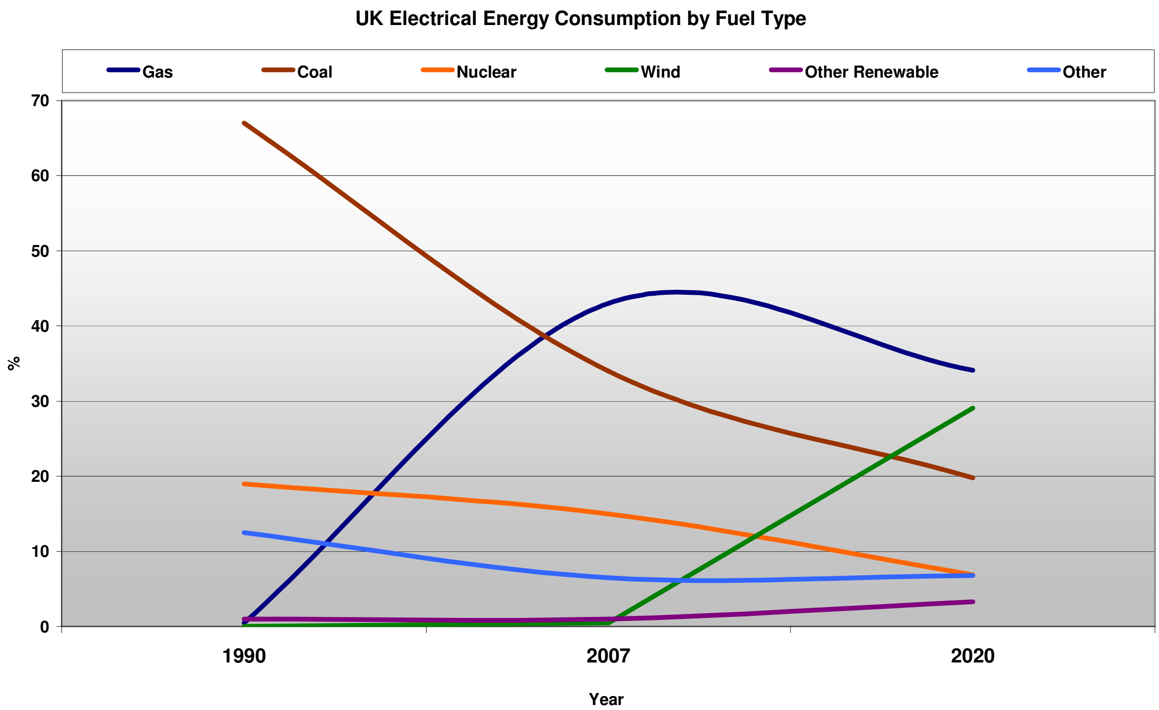


Figure 4 - Variation in the UK's Electrical Energy Consumption by Original Fuel Type[7]

One of my biggest impressions so far from my time in the UK is of all of the policy, regulatory and commercial matters which have needed to be addressed to facilitate this very significant shift towards sustainable generation. In this section, I briefly overview the range

---

7 Produced from information contained in the "UK Energy in Brief July 2008" (http://www.berr.gov.uk/files/file46983.pdf), and "Our Transmission Network: A Vision for 2020" (http://www.ensg.gov.uk/index.php?article=126)

of impediments that have been encountered to date, and the steps the UK has taken to overcome them. The situation in the UK is obviously different to that of Australia. However, I do expect that these issues will similarly need to be overcome and there is value in learning from the experiences of others.

Financial Incentive for Generation Developers

One of the first and most obvious matters needing to be addressed was to improve the financial viability of renewable generation for developers. In 2002 the UK energy regulator Ofgem established a 'renewables obligation' (RO) scheme, requiring suppliers to source a certain percentage of their energy from accredited renewable generation. The required level in 2002 was 3%. By 2008/09, this had increased to 9.1%, with 9.7% expected for 2009/10. By 2020, the UK is seeking to produce 32.4% of its electricity from renewable sources. Should suppliers fail to attain the required level of renewable energy during the year, they are required to make a buy out payment (presently £35.76/MWh) into a fund, which is paid back on a pro-rated basis to those suppliers who met their requirement[8].

The large number of proposed wind, wave and tidal developments in the UK would suggest that the RO scheme has been very effective at making renewable generation financially viable to date. The ongoing success of the scheme is dependent on suitable renewable generation targets and buy-out charges being set each year.

The renewable obligation scheme is very similar in structure to the Mandatory Renewable Energy Target (MRET) scheme in Australia, although the MRET targeted a much lower 2% increase in renewable generation over the 10 years from 2001 to 2010. The Australian Government is in the process of establishing a Renewable Energy Target (RET) scheme, similar in form to the MRET but seeking a more aggressive 20% renewable generation target by 2020[9].

A Place to Site Renewable Generation

Initially, renewable generation development in the UK consisted mainly of relatively small scale wind farms connected to the local distribution network. Growing public opposition to the visual blight of wind farms means that applications for new wind farms, even in rural locations, are often subjected to a protracted planning approval process and increasingly are

---

[8] Various Ofgem Reports available at:
http://www.ofgem.gov.uk/Sustainability/Environment/RenewablObl/Pages/RenewablObl.aspx

[9] MRET Factsheet, Australian Government – Office of the Renewable Energy Regulator, available online at:
http://www.orer.gov.au/publications/pubs/mret-thebasics-0309.pdf

not approved. I therefore expect that prevalence of new small onshore wind farms will decrease, apart from around industrial facilities, where there are significant commercial and good-will reasons to install renewable generation and where aesthetics are relatively unimportant.

To provide a place to site renewable generation, the Crown Estate has and continues to award leases to develop renewable generation on the seabed surrounding the UK. Two rounds of leases have already been awarded and tenders for the third round are currently being assessed. The scale of the developments allowed has increased markedly in successive rounds:

- The first allocation took place in 2002, and consisted of up to 18 sites nominated by developers within 12km of the shoreline. The maximum capacity of each site was approximately 90MW.
- Round 2 took place in 2003 and allocated 15 sites located between 8 and 13km of the shore (to reduce the visual and environmental impact of the wind farms), with a combined capacity of 7.2 GW (approximately 500MW per site)[10]
- Round 3 included 9 government nominated zones, each at least 22km offshore. The capacities of the different zones vary from 0.5GW to 9GW, with a combined capacity of 25GW. Tenders for round 3 closed in March 2009. The Crown Estate has reported significant interest in the offering, receiving 40 zone bids from 18 international companies / consortia.
- Applications for the first round of wave and tidal generation rights in the far north of Scotland close in May 2009.

While locating these massive wind farms offshore avoids public opposition and enables the use of very large wind turbines, connecting the offshore generation to the onshore grid will likely pose a challenge.

Transmission Access

The transmission access and market arrangements presently operating in the UK are quite different to what exists in Australia's NEM. Generators have firm access rights, the guaranteed ability to generate up to a certain level. Contracts are struck directly between generators and retailers. A spot-market balancing mechanism is used to move generators away from their contracted position, either to follow variations in a retailer's demand or to handle congestion in the transmission system. The advantage of this system for market participants is that it removes much of the uncertainty regarding the transmission network's

[10] "Details of Round 3 Bids Announced", The Crown Estate, March 2009, available online at: http://www.thecrownestate.co.uk/our_portfolio/marine/offshore_wind_energy/phases_of_development.htm

capability and effectively provides them with compensation from the transmission company whenever generation capability is constrained by the network. It was thought that this arrangement would provide strong incentive for the transmission companies to plan outages optimally, and promptly develop their networks to meet customers' needs where efficient to do so[11].

These arrangements have however had the unintended effect of slowing the rate at which transmission connections are offered to new generation applicants, since transmission companies do not wish to unnecessarily expose themselves to financial risk by connecting generation before all of the necessary upgrades have been completed. Throughout the UK, there is now over 40GW of connection applications waiting in a queue for transmission connections (although some of this is intended to replace existing generation, and some is considered speculative). The current status of generation in the queue is shown in the figure below.

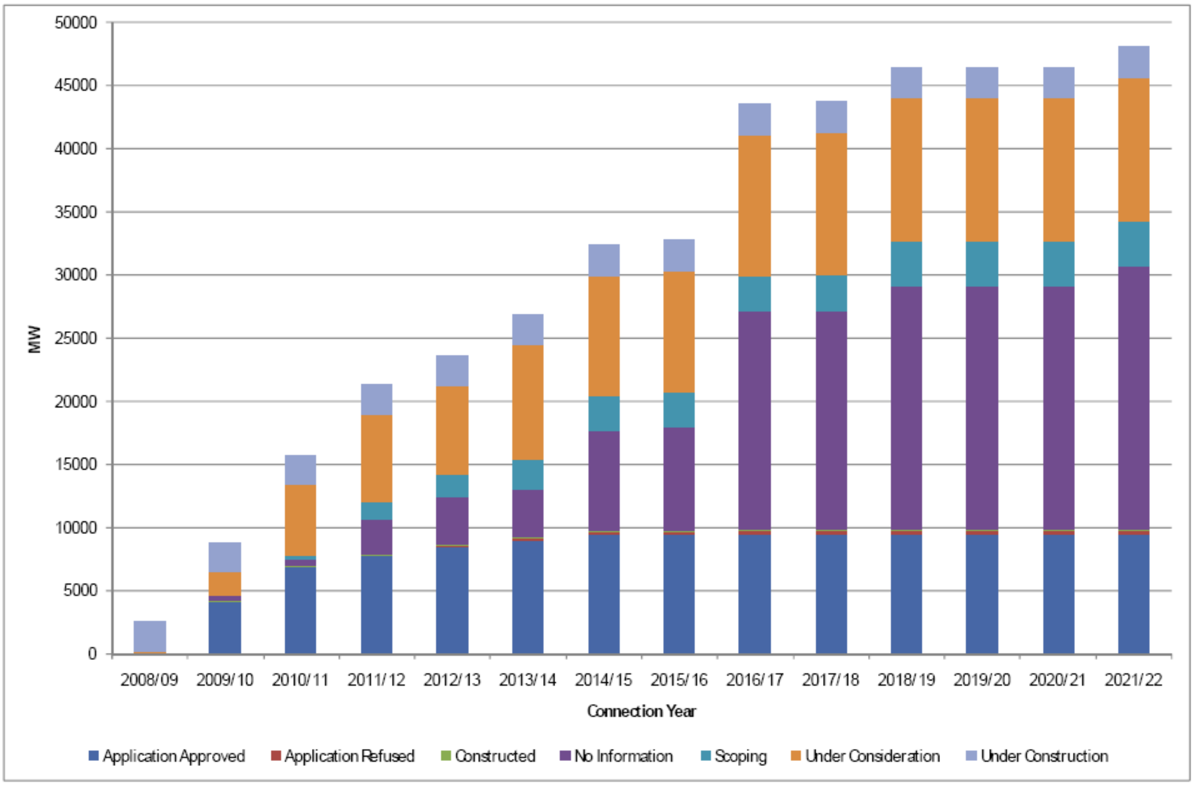


Figure 5 – Overview of the GB Generation Connection Queue in mid 2008 [12]

The UK's commitment to aggressive renewable energy targets creates "an urgent need to have in place grid access arrangements that allow large volumes of new renewable and other essential low carbon and conventional generation to connect quickly. It requires generators

[11] "Transmission Access and Losses Under NETA", Ofgem, May 2001, available online at: http://www.ofgem.gov.uk/Markets/WhlMkts/Archive/101-22may01.pdf

[12] "Transmission Access Review – Final Report", Ofgem, June 2008, available online at: http://www.ofgem.gov.uk/Networks/Trans/ElecTransPolicy/tar/Pages/Traccrw.aspx

to be offered connection dates, which are reasonably consistent with their project development timetables and for early steps to be taken to deliver essential investment in the grid." [12] A recent review of Great Britain's transmission access arrangements has therefore recommended a number of interim measures to help the UK to meet its targets:

- better queue management, demoting unviable of speculative applications and prioritising the connection of renewable generation and those projects which already have planning consent
- select use of temporary violations to the SQSS design standard
- sharing access rights between multiple generators
- use of dynamic line ratings, to free up additional capacity when conditions permit
- improved monitoring of actual transmission system utilisation levels
- reviewing the existing SQSS in light of the increasing volume of intermittent generation
- investigation of faster monitoring and protection schemes, and development of wide area control systems to increase system stability limits (although there is appreciation of the risk of pushing the capabilities of system harder while concurrently making the system more brittle with large volumes of renewable generation)
- incentivising the transmission companies to initiate transmission developments ahead of a firm commitment from generation (exposing them to financial risk) by providing a higher rate of return if/when generation subsequently utilises the new infrastructure, and a lower rate of return if it does not
- immediately releasing funding for the planning and design of network upgrades that are currently anticipated to be necessary by 2020, and applying for planning consent

The review has also outlined the qualities that it will seek to reflect in the enduring access regime which still under development:

- New generation projects should be offered firm connection dates, reasonably consistent with the development time of their project.
- Generators wanting long term financially firm access to the system need to make long term financial commitments.
- Transmission companies need to have appropriate incentives to respond to the long term demand for access signalled by generators. They need the freedom and incentives to invest ahead of full user commitment. They also require appropriate incentives to deliver new connections on time and to innovate so that they can deliver as much capacity as possible from existing assets.
- Access rights need to be more clearly defined and all generators need to be offered choice about how they access the system. This choice will need to include long term fixed price access rights that guarantee long term access in return for a commitment to pay for capacity, and shorter term, more flexible access rights.

- Transmission capacity should be 'shared', particularly as the amount of connected generating capacity increases in relation to transmission network capacity. This will lead to more efficient use of both existing and future capacity.

Transmission Network Development

Granting access to the volume of new generation needed to meet the UK's renewable energy targets will obviously necessitate significant development of Great Britain's transmission network. In 2008 the Electricity Networks Strategy Group initiated a study into options for this development, and published their findings in March 2009.

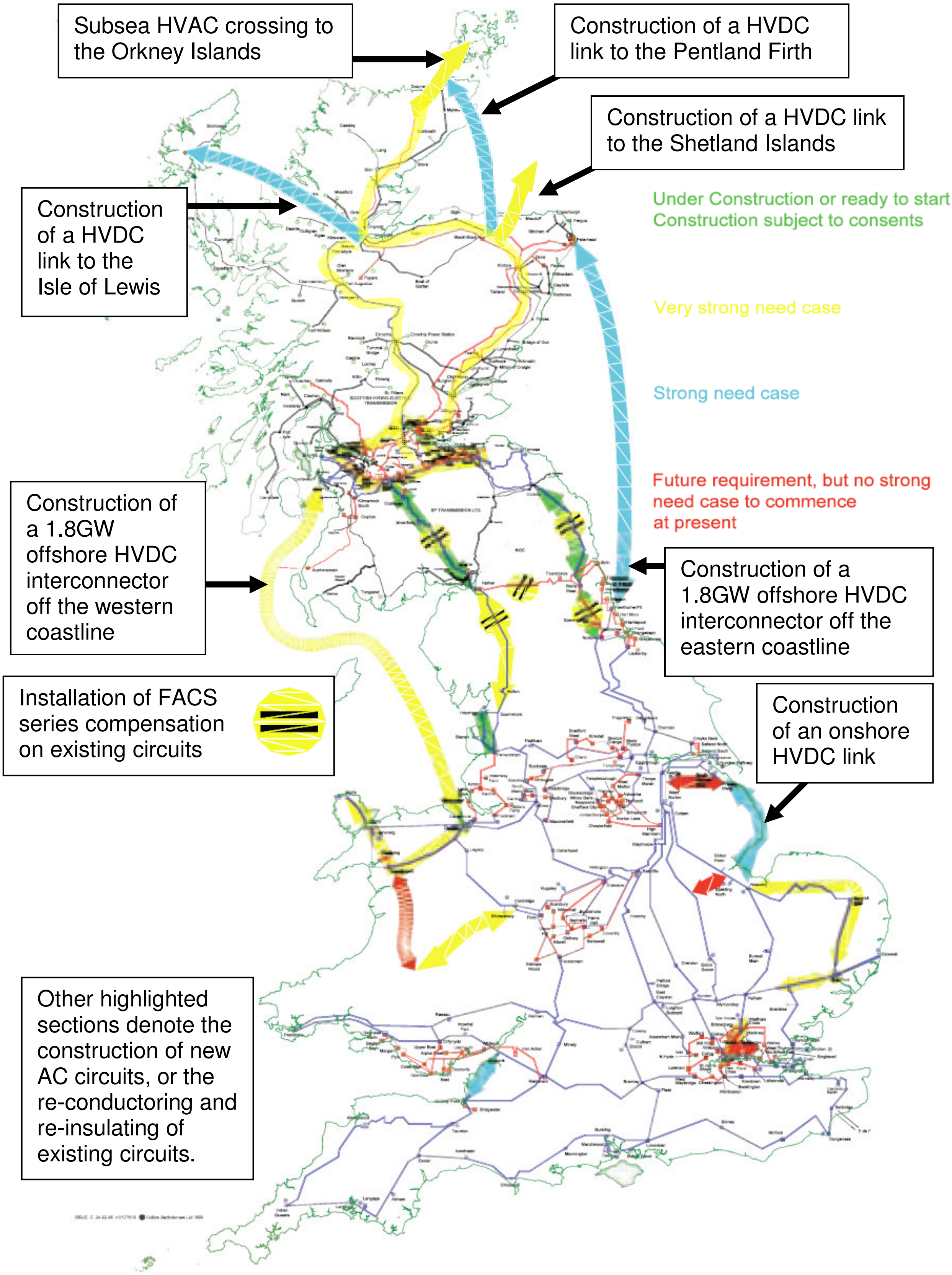
The key recommendations of the study [13] are represented in the diagram on the following page. Although the construction of wind turbines along much of the UK's coastline will necessitate upgrades throughout the network, the most significant increase in generation is expected to occur in Scotland. The bulk of the upgrades therefore relate to improving the network's ability to transport power from the north of Scotland to the main load centre in the south of England.

A novel aspect of the recommendations is the use of offshore HVDC interconnectors along the coastline. There are three main motivations for proposing these:

- Given the public's opposition to new overhead transmission lines, installing cable offshore is far more likely to be achieved within the necessary timeframes.
- The controllability of HVDC will improve the overall controllability of the network.
- As well as transferring power from north to south, it is proposed that teed connections along the interconnectors will be used to connect several of the proposed offshore wind farms to the grid.

Altogether, the network developments are expected to cost £3880M (excluding the cost of the island connections). Ofgem intends to use the report as an input into the revenue determination for each of the transmission companies. The various components of the overall plan are intended to be constructed progressively over the next ten years to match the increase in renewable generation.

[13] "Our Transmission Network: A Vision for 2020", Electricity Networks Strategy Group, March 2009, Available at: http://www.ensg.gov.uk/index.php?article=126


Subsea HVAC crossing to the Orkney Islands
Construction of a HVDC link to the Pentland Firth
Construction of a HVDC link to the Shetland Islands
Construction of a HVDC link to the Isle of Lewis
Under Construction or ready to start Construction subject to consents
Very strong need case
Strong need case
Future requirement, but no strong need case to commence at present
Construction of a 1.8GW offshore HVDC interconnector off the western coastline
Construction of a 1.8GW offshore HVDC interconnector off the eastern coastline
Installation of FACS series compensation on existing circuits
Construction of an onshore HVDC link
Other highlighted sections denote the construction of new AC circuits, or the re-conducting and re-insulating of existing circuits.

Planning Consent

A major impediment to almost any recent infrastructure development in the UK has been planning consent. Obtaining planning consent for transmission lines has been especially difficult since lines often traverse multiple local government areas and require multiple approvals. The most recent transmission line to be built in the UK took approximately 11 years from the initial application in 1991 to the start of construction in 2002.

Recognising that a large amount of new infrastructure will soon need to be constructed in a compressed timeframe, the UK government is in the process of establishing a new framework for the assessment of nationally significant infrastructure projects[14]. Noteworthy aspects of the new framework include:

- The establishment of a national infrastructure planning commission, providing a single point of approval for projects.
- The development of National Policy Statements (NPS) setting out the strategic need for different types of infrastructure and criteria/guidance for the assessment of projects. It is hoped that the NPSs will make the assessment of projects more straightforward and less political – more akin to a court case where the general law is applied to a specific situation.
- A statutory time limit of 9 months for the enquiry and decision.

Although the legislation is now in place, the NPSs are still in the process of being developed. The first two NPSs, 'National Networks' and 'Nuclear', are expected to be published in late 2009 and come into force in 2010.

Manufacturing Capability

The one remaining obstacle to the widespread uptake of renewable generation in the UK is the availability of the necessary equipment, most notably wind turbines, high voltage subsea cable, and HVDC/FACTS equipment.

My interactions with various equipment suppliers would suggest that they are expecting a sharp increase in demand (in the UK and elsewhere) and many are already expanding their production capabilities in readiness. However, only time will tell the extent to which their expanded capabilities will satisfy the demand.

[14] "Infrastructure Planning Seminar – 16 January 2008", Available online at: http://www.rpsgroup.com/Britain/News/RPS-Hosts-IPC-Seminar.aspx

Conclusion

As the various obstacles to the widespread uptake of renewable generation are progressively being addressed, the stage is becoming set for a significant change to Great Britain's power system to occur. The Australian context is obviously very different to that of the UK, and yet all of the same preconditions will need to be met before a similar change can occur.

Some of the impediments to the uptake of renewable generation in the UK were not originally appreciated. In hindsight, the UK's transition could have been more efficient had these problems been envisaged and solutions put in place ahead of time. For example, the length of the grid connection queue may have been smaller had transmission access arrangements been reviewed previously, or less expensive onshore transmission links could have been used had the need for new north to south circuits been identified earlier. Australia has the opportunity to learn from the experience of the UK (and other countries), and address any impediments before they lead to significant disruption or inefficiency.

Moving Forward

My first quarter on the ES Cornwall Scholarship has provided valuable insight into the behaviour of different types of wind turbines, the reliability criteria used to plan Great Britain's transmission system, and the measures that have been taken to overcome the obstacles to the widespread uptake of renewable generation.

During the next quarter I hope to be able to build on this by learning more about the upgrades which are proposed for the GB transmission system, including FACTS series compensation, HVDC, fast protection systems and wide area control schemes. I also hope to further broaden my perspective by learning more about the changes which are taking place across Europe, including efforts to develop a harmonised European grid code, the European Wind Integration and TradeWind studies, and steps towards the development of a European offshore transmission system.

Acknowledgements

I am grateful for the assistance of all of my Senergy Econnect colleagues but would especially like to acknowledge the assistance of Dr Sigrid Bolik, who took considerable time to patiently discuss with me the dynamic behaviour of wind turbines and their integration into the grid.