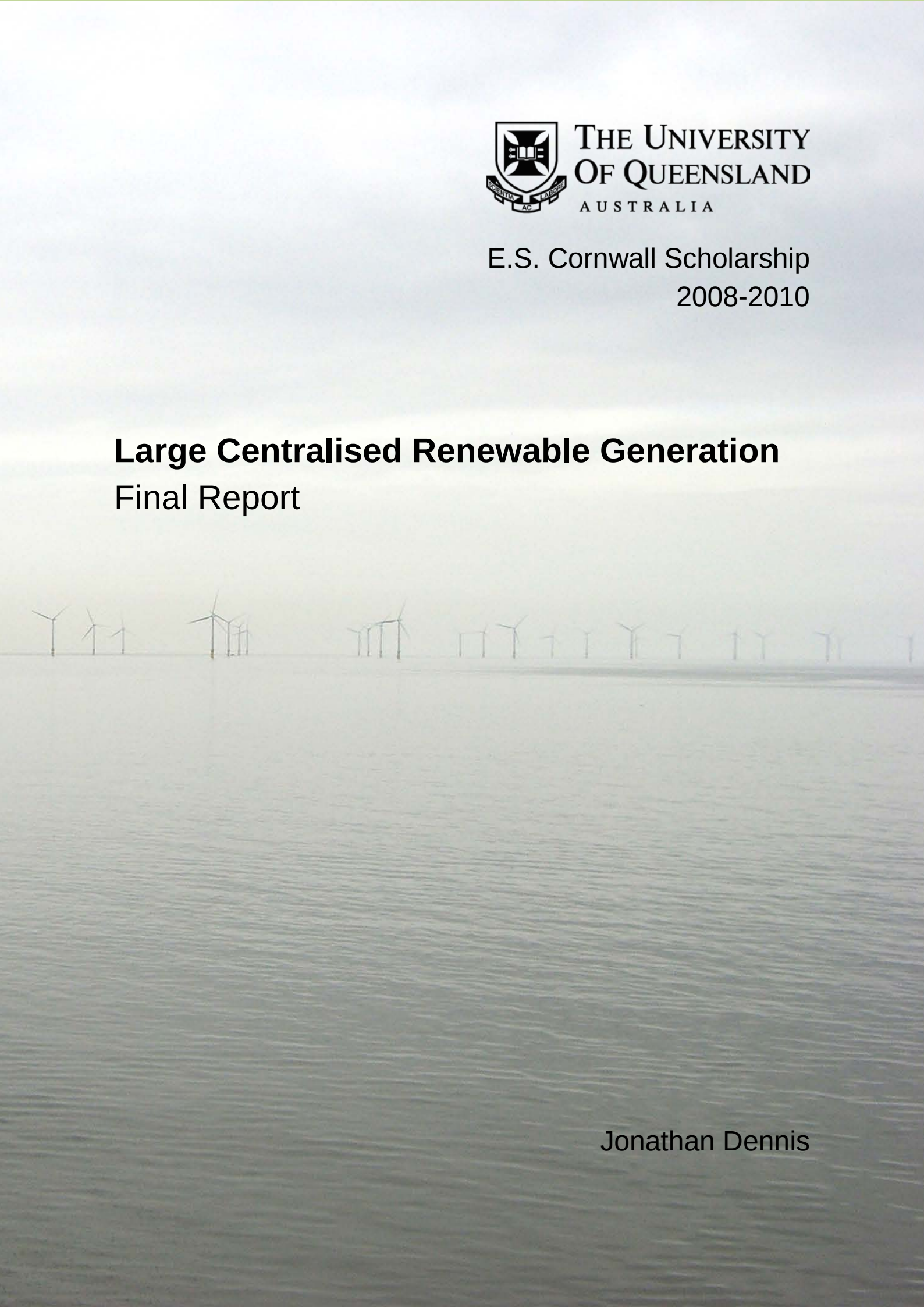

THE UNIVERSITY OF QUEENSLAND
AUSTRALIA

E.S. Cornwall Scholarship
2008-2010

Large Centralised Renewable Generation

Final Report

Jonathan Dennis

I am very grateful for the assistance of many people during tenure of the scholarship. In particular, I would like to acknowledge:

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  - Sigrid Bolik, Manager Power System Analysis (now Principal Engineer at REpower)
  - Simon Cowdroy, Head of Design
  - Patrick Smart, Head of Commercial and Regulatory
  - Guy Nicholson, Strategy & Technical Director (also Head of Grid at RenewableUK)

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  - Richard Proctor, Senior Engineer – Strategy Development
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  - Mark Perry, Manager – New Technology, System Integration and SQSS
  - Paul Plumptre, Manager – Specialist Economic Consultant
  - Jo Zhou, Senior Engineer – System Development
  - Andy Hiorns, Manager – System Strategy

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- And ultimately, I wish to acknowledge my Lord and saviour Jesus Christ, for creating this world including me, and for granting all of the abilities that I have and all of the amazing opportunities I have received. Even more so, for dying for me to take the penalty of my rejection against Him, and calling me into a relationship with Himself. Soli Deo Gloria – to God alone be the glory.

Cover photograph: Burbow Banks Offshore Windfarm, near Liverpool in the UK

Please do not hesitate to contact me to discuss anything contained in this report at:
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I kindly request that you do not copy any information in this report without my consent.

Executive Summary

I used my tenure of the scholarship principally to gain experience in the measures being applied internationally by transmission companies to manage the connection of large centralised renewable generation. To this end, I spent a year and a half working in the British power industry – in both consulting and transmission utility firms. I also gained some insight into the situation throughout greater Europe and North America through technical visits, a couple of conferences, and involvement in an international working group. This report documents the impressions I gained from these experiences and my thoughts regarding how they might apply to the Australian context.

Renewable Turbine Characteristics

Renewable turbine technology has advanced rapidly in recent years in response to evolving grid code requirements. New doubly-fed induction generators (DFIGs) and converter-connected machines are much more 'grid-friendly' than their induction generator predecessors, and provide much finer control over the real and reactive power, improved utilisation, and the ability to ride through system faults. In fact, the controllability of converter-connected machines exceeds that of conventional synchronous machines, and may enable them to provide additional ancillary services to the grid, including oscillation damping, voltage regulation and power quality filtering. As the penetration of these generators increases, their relatively subdued fault contribution could lead to a reduction in system fault levels, deeper voltage drops during faults, and the absence of an 'impulse' at fault inception. These factors need to be carefully considered when designing and setting protection schemes, and when specifying the deepest voltage drop generators are required to ride through. In spite of these advances in turbine technology, older-style machines continue to be installed in markets that have not adopted stricter grid code requirements. Spain's experience with wind power suggests that it is far preferable to proactively review and update grid codes before issues get to the extent that they have major operational consequences, than to take remedial action later on.

Recommendations:

- ➔ Continually review grid code requirements for intermittent generators to ensure that they remain appropriate
- ➔ Ensure that protection schemes will be able to cope with falling fault levels and no impulse.
- ➔ Investigate the opportunities to use ancillary services provided by modern generators.

Executive Summary

Inertia

Engineers are attempting to harness the controllability of converter-connected turbines to provide 'synthetic inertia' by emulating the response of larger synchronous generators to frequency variations. However, because the amount of energy stored in the rotor of intermittent generators is much less than a conventional synchronous equivalent, providing an inertial surge of power significantly slows down the rotor's speed of rotation, reducing the efficiency with which it can extract energy from the wind, leading to a reduction of energy production in the medium term. Therefore, while 'synthetic inertia' might be able to arrest a sudden fall in frequency, other generation will need to be able quickly increase their output to cover the reduction in production from wind in the medium term, as well as to recover the system frequency. This is an area of ongoing research.

Recommendations:

➔ Monitor overseas experience with synthetic inertia. However, the settings developed for use in Britain or continental Europe may not be optimal for Australia's power system, and it may be necessary to re-work international findings to take account of Australian conditions.

Remote Generation

Britain is in the process of a significant adoption of renewable power, especially offshore wind generation. This change in generation is in turn prompting the need for significant new power transmission infrastructure – much of which will be in the form of an interconnected offshore transmission system. Although Britain is much more compact than Australia, their need to use expensive and high-capacitance subsea cables makes Britain's situation electrically and economically similar to Australia's. Therefore, there may be opportunity for Australia to learn from the measures Britain is using to minimise the cost of connecting remote generation:

- Allowing a lower reliability standard in the remote, generation-only areas of the power transmission system so that the network design includes no redundancy but merely limits the amount of generation which can be lost in a single contingency
- Developing a integrated network design that maximises the efficiencies of scale, rather than multiple radial connections to individual generators (along the lines of the present Scale Efficient Network Extensions rule change proposal)
- Designing the network so that it can play a dual role: connecting remote generation to the load-centres when renewable power is available, and providing additional inter-regional and inter-national transfer capacity when it is not.

Additionally, High Voltage Direct Current (HVDC) technology has evolved significantly over recent years – particularly in the area of Voltage Source Converter (VSC) technology. Unlike conventional HVDC technology (line commutated converters), VSC is suitable for connection to relatively weak networks, as would typically be the case when connecting remote generation. Much R&D is continuing into this technology. It is hoped that multi-terminal HVDC circuits will soon be available, making it possible to have tee connections into an HVDC circuit using a converter rated only for the capacity of the tee.

Recommendations:

- ➔ Consider whether Australia's transmission network reliability standard could be relaxed for network which is established to connect remote generation
- ➔ Consider the role that HVDC might be able to play and how the technology could be deployed for maximum benefit. e.g. a HVDC connection between Queensland and South Australia via central Australia could facilitate the development of geothermal and/or solar generation, would itself provide greater inter-regional transfer capacity (closely coupling South Australian wind generation with the Queensland gas generation it is likely to displace when available), and could be used to enhance the capacity of the parallel AC network by providing the active damping of oscillations and transients on the AC network.

Intermittency

Power intermittency is a complex issue. Wind, wave, tidal and solar generators are not only intermittent in nature, but the power generated by like generators in a region is highly correlated. This makes many more operating states possible, and can lead to rapid changes in generation, and hence network flows and voltages. The inability to anticipate wind levels more than a week or so ahead of time will make reserve and outage planning more complicated and less effective. Expansions to the network will increasingly need to be justified on the basis on economic merit, which will require significant additional effort, and given all of the assumptions and trades offs that will invariably need to be made in the analysis, some uncertainty will remain and need to be managed.

Recommendations:

- ➔ Start recording high quality weather data from locations where it is likely that renewable generation will one day develop. Having long-term records of such data provides an objective and confident basis for assessing the correlation of generator outputs.

- ➔ Continue gaining experience with the use of probabilistic economic techniques to justify transmission expansions. It takes time to develop, refine and build confidence with models and the judgement calls that need to be made in the assessment process. It would be good to start this process well in advance of having to make a critical investment decision on the basis of it. Internationally, it has been common-place to run these studies alongside conventional studies for a number of years, initially as supporting evidence but gradually placing more and more weight on the economic modelling as the proportion of renewable generation increases.
- ➔ Develop tools and processes to manage uncertainty in the assessment and approval of transmission infrastructure. This may include establishing mechanisms to consult the wider industry on key assumptions, with a view to agreeing a consensus position.

Cost Effective Power System Characteristics

Although technologies and techniques now exist to manage most of the difficulties associated with intermittent renewable generation, resorting to such remedial measures can be expensive. The well considered deployment of intermittent generation in the first place could reduce the overall cost by avoiding the use of remedial measures, minimising the amount of new transmission required, and minimising the total volume of generation capability required to provide adequate security of supply. In particular, I am concerned that in Australia there are no incentives or signals to promote having diversity in renewable generation (in both geography and fuel source), or to support the development of energy storage. Additionally, I am concerned that just like similar schemes overseas, Australia's Renewable Energy Target (RET) scheme makes the operation of renewable generation very inflexible, which in time could drive generator outcomes that are inefficient and justify the development of more transmission than is truly merited.

Recommendations:

- ➔ Consider how to promote an economic level of diversity in the power system and support the cost-effective deployment of energy storage
- ➔ Consider developing a mechanism to allow intermittent generation to be constrained offline at a cost which is reflective of its true value

(I include proposals to implement both of these recommendations in the chapter)

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Introduction

This report is based on the experience I gained whilst on the ES Cornwall Memorial Scholarship. I used my tenure of the scholarship principally to gain experience in the measures being applied internationally by transmission companies to manage three significant complicating aspects of large centralised renewable generation, being:

- the variability of renewable power availability over time,
- the low inertia, poor fault ride through capability of renewable generators, and
- the remote location of renewable energy sources, necessitating long distance transmission connections.

Apart from the 'context' section of this report, I have deliberately focussed the impressions I gained rather than the circumstances in which I gained them. Please refer to my quarterly reports[1] for more information about the work that I was involved with in each of my placements.

[1] Available online at: www.escornwall.com.au

Context

In this section I have attempted to outline the context from which I have written. This includes a discussion of my two placements, as well as a general introduction to the present state of the British power industry, in which both my placements were based.

United Kingdom Power Industry

Great Britain's power sector is undergoing profound and rapid change in response to the nation's 15% renewable energy by 2020 target. A 15% renewable energy target may initially seem less ambitious than Australia's 20% target. However, the Britain'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 the goal of producing over 30% of the UK's electrical energy from renewable generation by 2020. Whilst there are various ways in which electricity could be decarbonised, the government has determined that in the UK this will principally be achieved through the construction of wind generation, largely owing to the relative maturity of wind technology, the good quality wind reserves available in and around the UK, and the limited availability of other renewable energy sources.

Electricity prices in Great Britain are already high by Australian standards, with generation being the dominant component and transmission accounting for only 1% of a typical bill (compared to 8% in Queensland). England's main 400kV transmission network was mostly constructed in the 1960s and has experienced very modest expansion since then, mostly using techniques to better utilise the existing network such as substation reconfigurations and the use of high temperature conductors. Britain is interconnected to France by a 2000MW high voltage direct current (HVDC) link, and has just commissioned a new 1000MW HVDC link to the Netherlands.

Peak power demand in Great Britain has been steady at around 60GW for several years now – even falling slightly due to the economic downturn. The initial outlook is for the demand to remain at or around this level as efficiency improvements offset any new loads. In the longer term, peak demand is expected to increase to around 90GW, with the conversion of loads presently powered by gas and petroleum to electricity.

The commercial incentive to develop renewable power generation in Britain is provided by the Renewable Obligation scheme, which places a binding obligation on energy retailers to purchase renewable generation certificates in proportion to the energy consumed by their customers. Should a retailer fail to obtain sufficient certificates they must pay the buyout price, with the proceeds recycled to other retailers in proportion to how close they came to satisfying their obligation. Renewable generation technologies which are still in their infancy (e.g. wave and tidal generation) earn certificates at a higher rate than more established technologies (e.g. onshore wind generation) as a means of supporting the commercialisation of new renewable technologies.

The plot below shows how much the proportion of fuels used to produce electricity have varied over the past 20 years (from a starting point fairly similar to Australia today), and how much they are expected to vary by over the next 10 years in order for the UK to achieve its emissions reduction target.

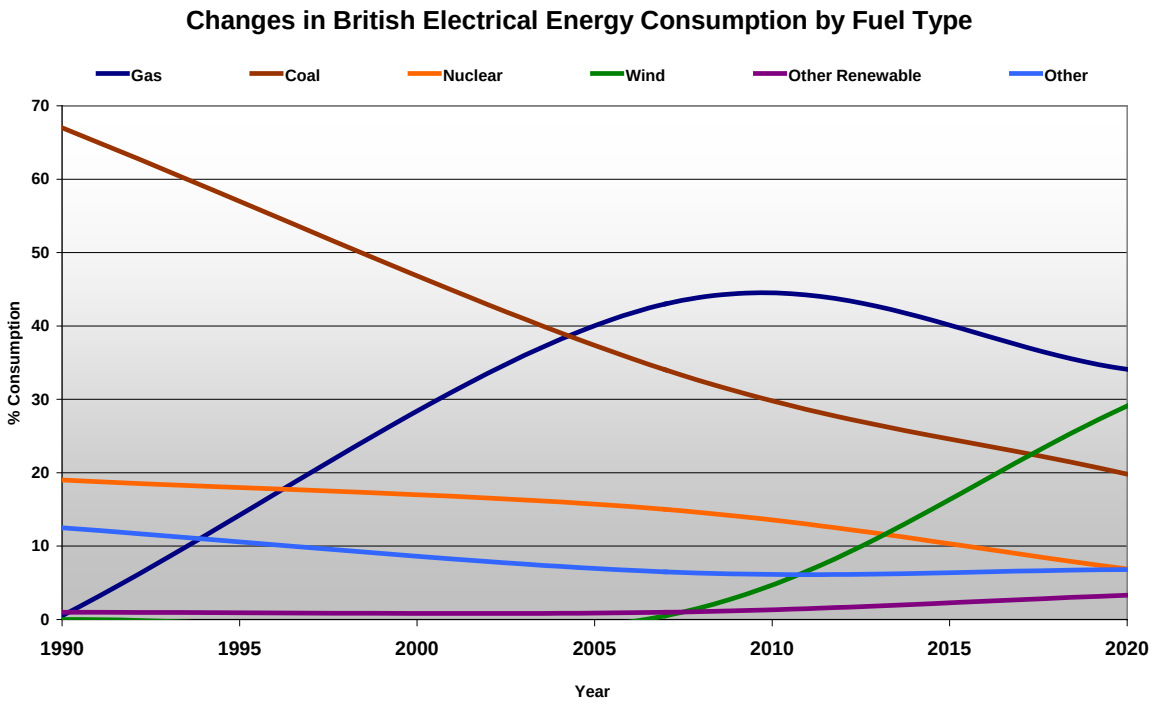


Figure 1 - Variation in the UK's Electrical Energy Consumption by Original Fuel Type [2]

The scale of what the UK and many other European countries are trying to achieve can only be fully 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

[2] 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)

sources will require a renewable *generation capability* closer to 70% of average demand. Bringing about this change is a significant multi-faceted challenge.

Although the volume of wind generation that is presently installed is much lower than what the UK aspires to, wind farms are already a common sight across the UK and the public's 'honeymoon' period with the technology is well and truly past. Wind farms are now considered a blight on the landscape and community groups strongly lobby against any new developments. Although wind farms will continue to be installed onshore (mainly in the north of Scotland), the government has determined that the bulk of the new wind generation will be installed offshore. To facilitate this, the Crown Estate has allocated the right to develop renewable generation in specific offshore locations surrounding the UK. Sites were allocated to developers in a number of rounds of increasing scale and distance from shore. The first round was conducted in 2000 and involved sites located close to shore with capacities up to 90MW. The latest round in 2009 involved sites located hundreds of kilometres offshore and capacities up to 12GW. In each round, sites were awarded to developers through a competitive tendering process on the basis of which developers were deemed most commercially and technically capable of developing the sites. The map on the following page shows all of the awarded offshore development sites. The combined wind generation capacity of the allocated sites is 47GW.

Regardless of whether wind generation is located onshore in the north of Scotland or far offshore, significant new transmission capability will be required to transport the power it produces to the main load centres in central and southern England. Much of this transmission capability will be provided by a new interconnected offshore transmission system that not only connects the offshore generation to the mainland, but also provides additional transfer capability between different regions of the UK, and additional interconnection with other European countries.

Presently, the British energy regulator (Ofgem) intends to develop the offshore transmission network in stages, using a competitive bidding process to award licences to develop and own different sections of the network. To prevent anti-competitive behaviour, the process Ofgem has developed to allocate transmission licences involves strict restrictions about communication between parties during the network design and tendering stages. This approach is intended to maximise the value of competition to consumers but there are concerns about the inefficiencies that will result from a lack of coordination (not least from National Grid, who has a vested interest in developing the offshore network itself).

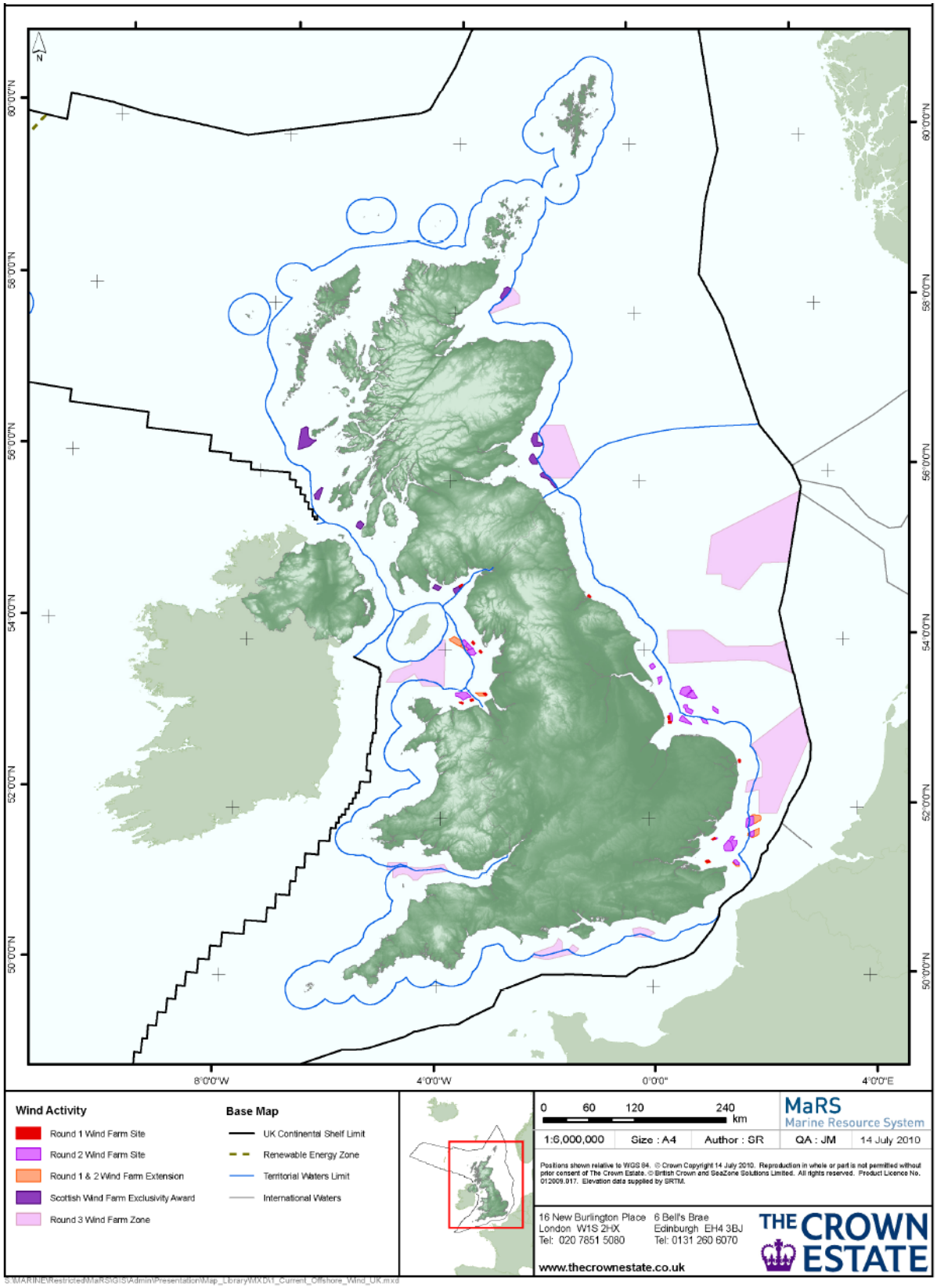


Figure 2 – British Offshore Wind Generation Locations [3]

[3] Taken from the 2010 Offshore Development Information Statement, National Grid, September 2010, Available online at: http://www.nationalgrid.com/uk/Electricity/ODIS/

My Experience

Whilst in the UK, I spent half a year working for the consulting firm Senergy Econnect, and then a year working for the electricity transmission company National Grid. I was also able to visit a number of other companies and participate in a couple of conferences in Europe and North America.

Senergy Econnect is a consulting firm that specialises in resolving issues related to the connection of renewable generation to the grid. Their workload includes network studies to assess the feasibility of connection options, negotiating with utilities on behalf of developers, detailed design of electrical connection infrastructure, project management, model development for turbine manufacturers, and advising on the commercial and regulatory issues associated with renewable generation. Working for the company provided a general insight into all of these areas, and a particular insight into my main areas of work:

- Studying the impact of new renewable generation on distribution and sub-transmission networks in order to assess the adequacy of different grid connection options
- Designing on- and off-shore transmission connections and turbine collection arrays
- Applying to and liaising with distribution network operators for new grid connections
- Assisting project developers to prepare the technical component of their tenders for the Crown Estate's competitive bidding process for allocating offshore renewable generation sites

Overall, I believe that working with Senergy Econnect afforded a good insight into the changes occurring in the British power system from the perspective of both large and small scale generation developers.

National Grid is an umbrella company that includes electricity and gas transmission and distribution companies in both the UK and the USA. The UK electricity transmission company has the dual role of being the transmission system operator (TSO) in England and Wales, as well as the power system operator for all of Great Britain including Scotland (where there are two other TSOs). I was placed in the electricity network investment team which is responsible for assessing the future adequacy of the onshore transmission system in England and Wales, and planning its expansion as needed. Given ENI's central role in the British power system, ENI was also given some industry coordination responsibilities, and

from time to time was called on to advise government departments on matters relating to the development of the power system. Working in ENI therefore offered the opportunity to work closely with some of the UK's leading experts and offered an insight into some of the deliberations that take place behind the scenes about the direction of the industry. Specific responsibilities I was given included:

- Participation in the Fundamental Review of the British transmission planning criteria. This wide-ranging review was initiated in recognition of the significant effect that renewable generation will have on the way the power system operates, potentially making the existing planning criteria sub optimal. The review was organised into a number of working groups, each reviewing a particular component of the planning criteria (including issues such as voltage standards, connection arrangements, secured contingencies, dynamic equipment ratings, oscillation damping rates, use of intertrips, consideration of embedded generation etc.). I worked with each of these groups to finalise their findings and summarise them into a public report for industry consultation.
- As part of the Fundamental Review, I was also allocated to a special working group established to review the criteria that determines the required capability of network boundaries (i.e. cut-sets) to ensure that the existing level of demand security is maintained into the future and the overall cost of operating the power system is minimised. This very significant and highly controversial criterion had been debated for many years with limited progress due to disagreements about the extent to which 'smart' technologies (demand side management, fast generator intertrips etc.) could offset the need for transmission capacity. The working group was established to develop a new criterion which took account of changing power system behaviours and economics without relying on yet-unproven transmission technologies.
- Preparation of the inaugural 'Offshore Development Information Statement' – a public document exploring the future development options for onshore and offshore transmission in the UK with the goal of improving the coordination between the three onshore transmission network owners and a multitude of potential offshore transmission network owners.
- Power flow analysis to assess the issues resulting from the connection of new renewable generation to the transmission system, and the effectiveness of different reinforcement options.
- High level analysis of various government generation scenarios for the year 2050, and their implications for transmission network development.

The following experiences/visits during my time overseas have also been influential in forming my opinion on the matters I discuss in this document:

Meetings with other utilities:

- Spanish TSO Red Eléctrica de España
- Finnish TSO Fingrid
- Swiss TSO Axpo
- Canadian TSO HydroOne
- Scottish TSOs Scottish Power and Scottish Highlands Electricity Transmission

Meetings with equipment vendors:

- ABB's IEC 61850 system verification centre (substation secondary systems)
- Alstom's Technology Development Centre (HVDC technology)
- Psymetrix (wide area phasor monitoring)
- RePower (wind turbines)
- Siemens (wind turbines)

Participation in the following conferences:

- 2009 Cigre B4 (HVDC and FACTS) Colloquium
- 2010 Cigre Session and subsequent membership of the Cigre C1 working group 24 on the economic assessment of power systems

Other experiences:

- Participating in the grid code compliance testing of a new wind farm
- Shifts in the British national generation and transmission control centre
- Organising and participating in several GB industry workshops to debate the proposed changes to the network planning standard

My familiarity with the Australian power system is from my work as an engineer with Powerlink Queensland, in network planning, network operations and substation design roles.

Please refer to my quarterly reports for more information about the work I conducted during each placement and what I learned through my various meetings, conferences and experiences.

Context

Turbine Characteristics

This section reviews the historical development of renewable turbines over time with respect to their interaction with the rest of the power system. It concludes that the early problems of wind turbines having no voltage regulation and poor fault ride through have been resolved, provided that grid codes are regularly reviewed to ensure that developers are required specify this functionality in their turbines. The emerging problem of low system inertia is in the process of being resolved. However, as the proportion of modern renewable generators increases, their relatively subdued fault contribution could lead to a reduction in system fault levels, deeper voltage drops during faults, and the absence of an 'impulse' at fault inception. These factors need to be carefully considered when designing and setting protection schemes, and when specifying the deepest voltage drop generators are required to ride through.

In general, the requirements applying to renewable turbines have and will continue to become increasingly similar to those that apply large conventional generators. This is necessary to maintain system security as the proportion of renewable generation increases.

The advanced capabilities of modern renewable turbines mean that they may also be able to be harnessed for other applications including power oscillation damping, power quality filtering, and dynamic voltage support (even when there is no wind).

Although this section discusses turbines for wind generation applications, several of the turbine technologies discussed are also suitable for use with other forms of renewable generation.

For a more detailed comparison of the characteristics of different wind turbines, please refer to Appendix A.

Historical Development of Wind Turbines

Commercial wind turbines for grid connected applications have existed since the 1980's. Initial wind turbine development was most concerned about increasing the output capacity and decreasing the cost of turbines, and so research centred around the use of simple, reliable and low cost induction generators.

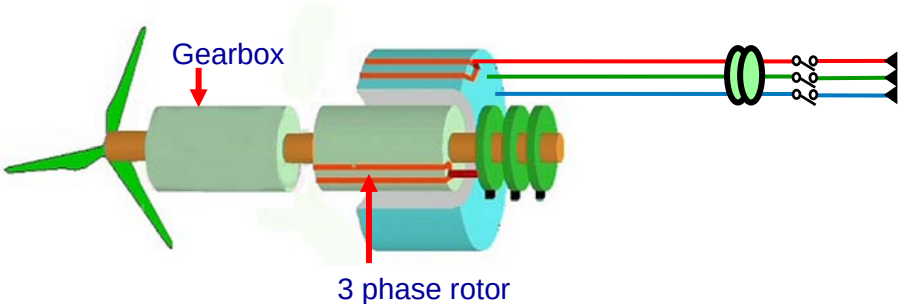


Figure 3 – Straightforward Induction Generator

Using this technology, a significant increase in capacity was achieved, as can be seen in the figure 4 below.

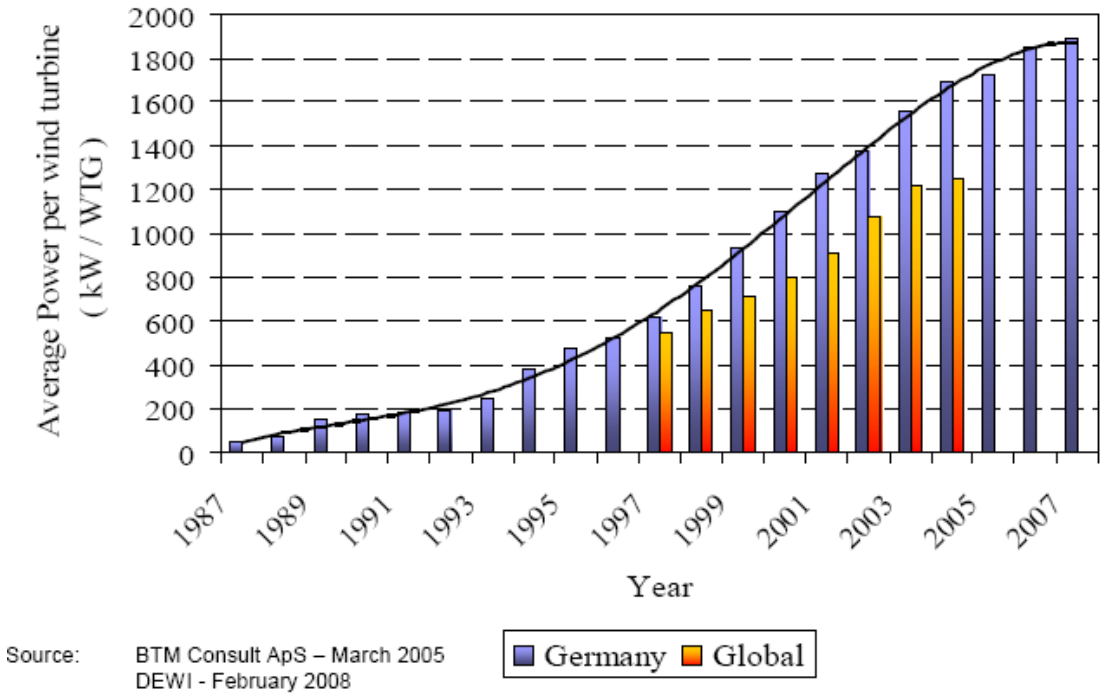


Figure 4 - Variation of Average Wind Turbine Size Over Time [4].

[4] "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

However, induction turbines also have a number of significant disadvantages, especially:

- the consumption of reactive power
- the inability to remain connected to the grid following system faults (i.e. poor fault ride through)
- little controllability

Initially these characteristics were not a significant concern to network operators, given the insignificant scale and low penetration of wind generation. However, as the scale of wind turbines grew and the overall proportion of wind generation in the power system increased, the problems presented by induction generators became increasingly difficult to manage.

Spain was one of the first countries to encounter significant widespread problems with wind turbines. Large volumes of wind generation were prone to tripping offline during system faults, threatening the security of the Spanish power system. In 2005, the Spanish authorities along with a number of other countries introduced additional criteria relating to frequency and voltage regulation and the ability of a turbine to ride through power system faults. In Spain, the government deemed the existing situation to be so serious that they made the criteria changes retroactive, forcing existing turbines to either be retro-fitted to comply with the new requirement or face being constrained offline. Increasingly onerous grid-connection requirements have changed the focus of turbine research and marketing in recent years, resulting in the development of new types of turbines with completely different characteristics to conventional induction generators.

Modern Wind Turbines

A commonly installed solution today is the Doubly-Fed Induction Generator (DFIG). Whilst still an induction generator, a power converter connected to the rotor windings enhances its level of controllability of the turbine and improves its power factor. Additionally, a variable resistance closed-circuit between the rotor windings improves the ability of the turbine to remain connected to the system during brief drops in system voltage. The advantage of this design is that the power converter only has to be rated for part of the machine's overall capability, reducing the cost of power electronics and the losses incurred during operation. The primary disadvantages are the need to regularly replace the rotor brushes, and the still-somewhat-limited extent of controllability, especially when there is a large concentration of such machines at one location.

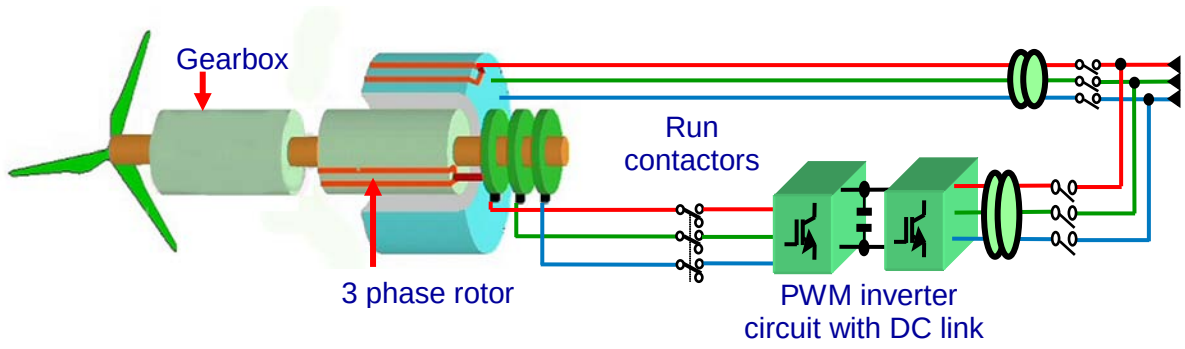


Figure 5 – Doubly-Fed Induction Generator (DFIG)

Increasingly, turbines are being installed that use power converters to completely de-couple the turbine from the grid. The power converter enables any type of turbine to be used and operated at any frequency, including 0Hz (DC). Power can be exported to the grid at any frequency or power factor, subject to the rating of the power converter. It is even possible to export more or less power to the grid than what is actually produced by the turbine for a short period of time, storing or utilising inertial energy in the spinning rotor. However, such machines require power converters that are rated for the full capacity of the turbine, adding additional cost and losses (although power converter costs are decreasing with time). Nevertheless, this would seem to be the general direction that wind turbine technology is heading in, with new lightweight and low maintenance brushless DC direct-drive motors under development, to fully exploit the advantage of having the turbine fully isolated from the AC grid by the power converter.

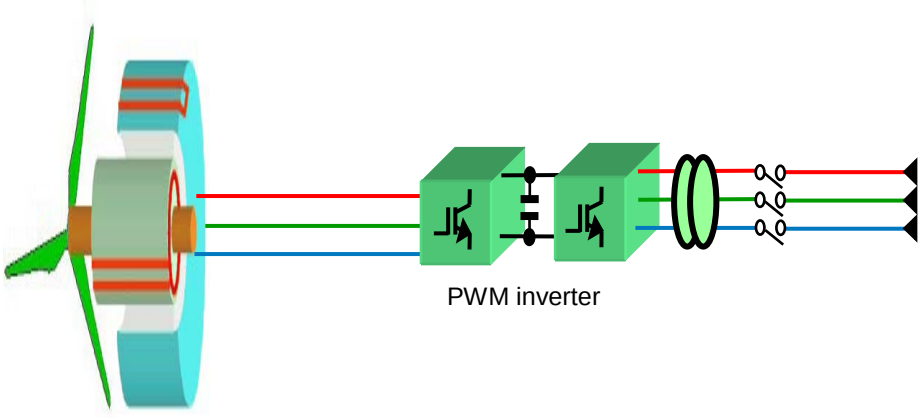


Figure 6 – Converter Connected Generator

Although 'full-converter generators' are most commonly found in wind turbines, they will likely be used for other low-density forms of renewable generation (e.g. wave, tidal, solar thermal), since it permits the turbine designer the flexibility to use any type of turbine and operate it at any speed, to maximise the power extracted from the renewable energy source. Power converters are already commonly used to convert the DC power produced by solar photovoltaic systems to the grid. Increasingly, power electronics are also being incorporated

into loads. Electric-cars are a particularly interesting example since the power converter is combined with energy storage. Therefore, although this discussion is focussed on wind turbines, it is likely to apply equally to other forms of renewable generation and domestic loads.

During my placement with National Grid, I was able to participate in the grid code compliance testing of the Burbow Banks offshore wind farm – the first in the UK to use full scale power converters. It was very impressive to witness the responsiveness of the turbines to a synthetic frequency signal being injected into the central wind farm controller. The only exception to this was when the wind-farm was increasing its output after being forced to operate at a level significantly lower than the power available in the wind – when the power output would recover quite slowly (i.e. over 30 seconds). The representative from the wind turbine supplier indicated that this was due to a lack of confidence in the estimated level of wind power presently available, and the need to not significantly overshoot this level. Were the power converters to extract significantly more power from the turbines than they could recoup from the wind, the speed of rotation could drop to a speed at which energy extraction from the wind would be far less effective, causing the power recouped from the wind to drop further still and eventually causing the wind farm to suddenly drop to zero output. The representative explained that significant R&D was continuing into better equipment and techniques to estimate the level of available wind power, and that with greater confidence in this estimate the rate at which the power level was allowed to increase could be accelerated. An example photograph of the power-output level trace is shown in the figure below. The axes have been deliberately obscured to respect customer confidentiality. The red trace is the MW output of the wind farm, which is responding to a simulated system frequency change (unfortunately not shown). The thick white trace shows the variation in the actual system frequency while the thin white trace shows the voltage at the wind farm terminals.

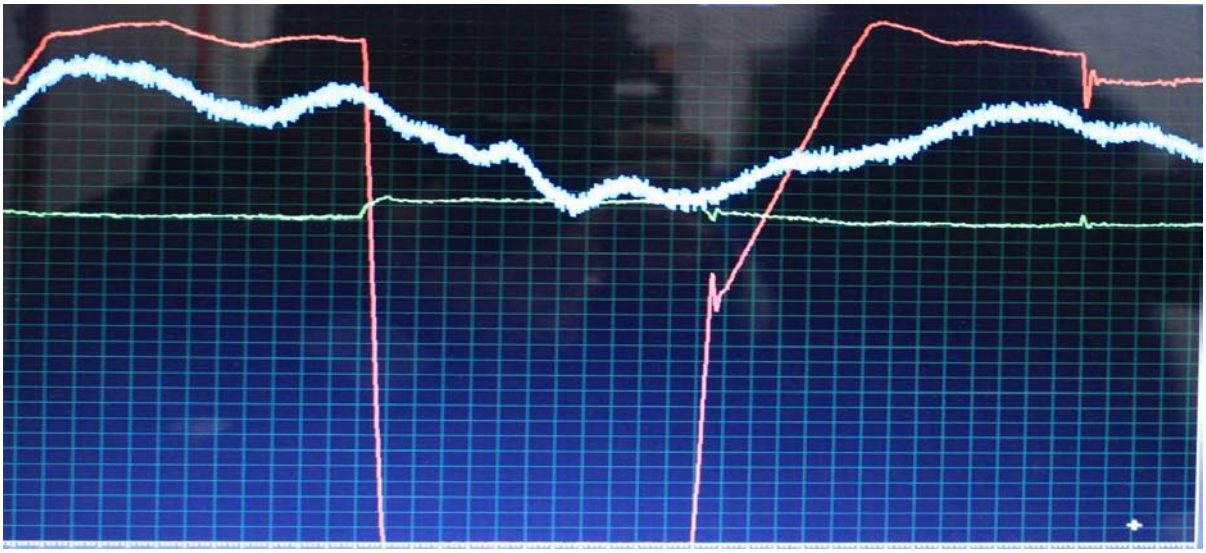


Figure 7 – Controlled Variation in Wind Farm Output (Red Trace)

In the long-term, it is expected that a significant proportion of the wind turbines installed in the UK will be similarly based on a full-converter design. Interestingly, other markets expect to be dominated by DFIG turbines. Ultimately, the turbines which are installed will depend in large part on the grid code requirements in that region. The challenge for utilities to define what characteristics turbines need to have for the power system to be operated securely and efficiently, which will vary from power system to power system.

Fault Ride Through

With the advent of DFIG and full converter turbines, the sudden disconnection of wind turbines during system faults need not be a problem. However, modern turbines are more expensive than straightforward induction generators and turbine vendors still have induction turbines in their product lines for those markets which have yet to adopt stricter guidelines. For example, immediately across the border from Spain, the Portuguese government has so far resisted the TSO's call for stricter requirements and conventional induction machines continue to be installed. In the month before my meeting with the Spanish TSO they had observed a transmission fault resulting in the sudden disconnection of 1500MW of wind generation. Until a requirement to ride through faults is introduced in Portugal, the volume of generation prone to suddenly disconnect there is only likely to increase. It is therefore important that grid codes are activity reviewed and updated as circumstances necessitate, to guide manufacturers R&D and to ensure developers specify equipment appropriately. The cost of retrofitting turbines in Spain was much greater than if the grid code had required the initial functionality upfront. It is always much better to proactively anticipate future problems and continually revise grid codes as required, than to react to a problem only when it begins to have operational consequences. In response to the continuing growth of wind generation in Spain and the resulting fall in system fault levels, the authorities are in the process of enacting even stricter requirements on new wind turbines, including the requirement to ride through deeper voltage drops (down to 0pu voltage) during system faults. This will enable the penetration of renewable generation to continue to increase without jeopardising the security of the power system. When introduced, the new criteria will only apply to generation constructed in the future (i.e. this time the criteria change won't be retroactive).

The present and proposed fault ride through requirements in Spain are contrasted below:

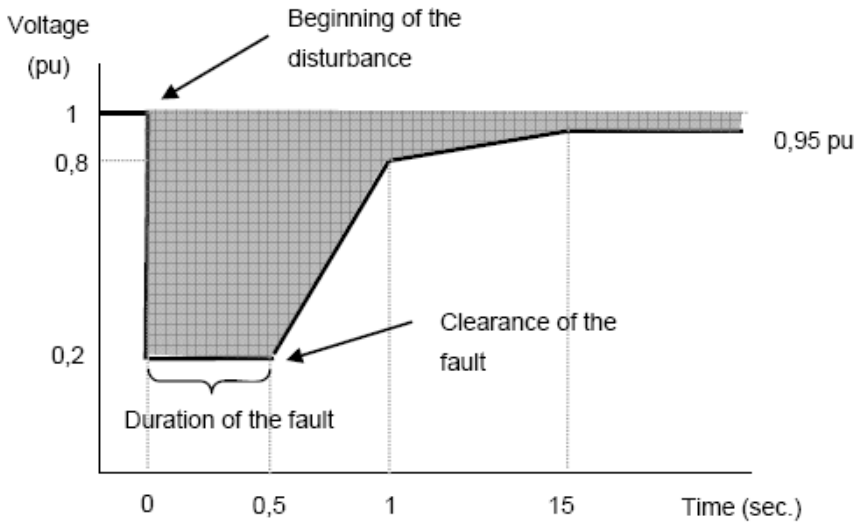


Figure 8 – Existing Spanish Fault Ride Through Requirement

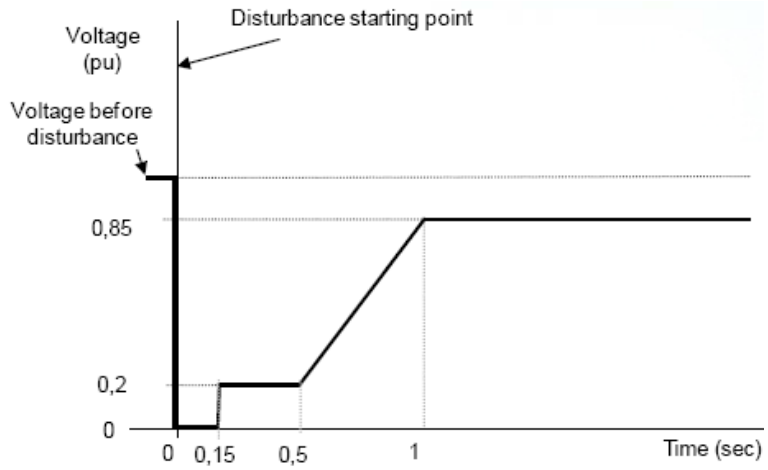


Figure 9 – Draft New Spanish Fault Ride Through Requirement

A legacy of having no fault ride-through requirements prior to 2005 is a significant number of Spanish wind turbines that have not been retrofitted and are still prone to tripping during network faults. A key activity of the TSO's control centre is therefore to continually assess how low the system voltage would fall during faults and how much generation would trip as a result. A screenshot from this application used to perform this assessment is included below. When the amount of generation that could be lost is unmanageable, the control centre constrains this un-retrofitted generation offline.

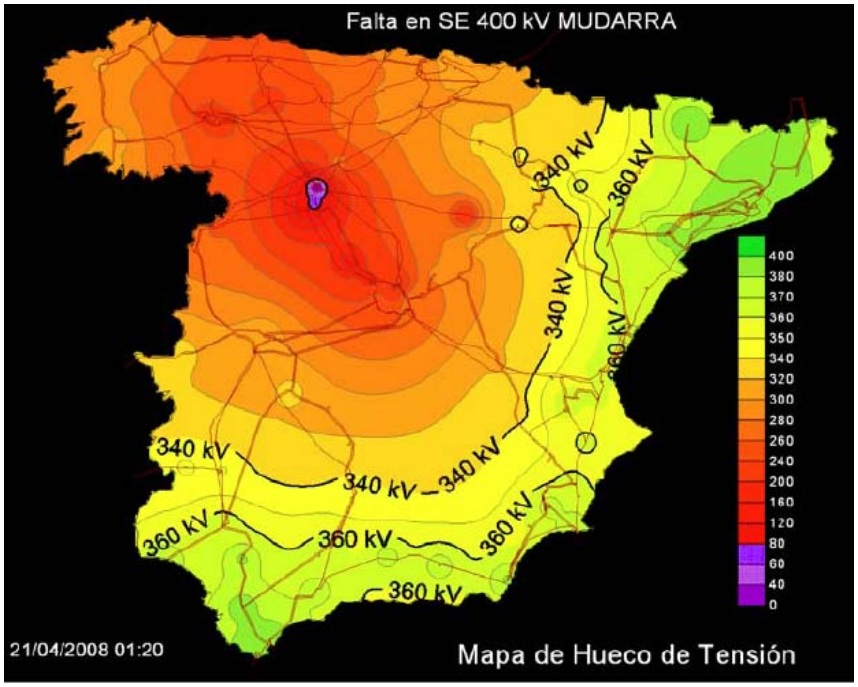


Figure 10 – A screenshot of a tool used to assess the security of the Spanish power system

Inertia

The 'low-density' of many forms of renewable generation means that relatively light-weight turbines are used. Given that relatively little energy is stored in the spinning rotors of such turbines they do not naturally produce/absorb as much power as the frequency varies, and therefore do not produce a significant inertial response to counteract frequency variations as a large synchronous generator naturally would. When low-mass turbines displace conventional high-mass turbines, the overall inertia of the system is lowered, making the whole system more susceptible to collapse. As the penetration of renewable generation increases, inertia is likely to become a significant issue.

Recognising this, work is underway to solve the inertia issue before it becomes a problem. Whilst the mass of the typical wind rotor may be inadequate to naturally produce a significant inertial response to frequency variations of 0.5-2.0 Hz, the rotor does contain enough energy to produce a short term surge of power if the rotational speed of the rotor is permitted to drop significantly. The controllability of a full-converter turbine can be harnessed to make it emulate the inertial response that a larger generator would naturally provide. The turbine can produce a surge up to the magnitude of the converter's short-term power rating (typically 20% above its normal rating), drawing energy off of the rotor, slowing its rotation.

However, this inertial surge of energy comes at the expense of energy in the longer term. The greater the 'surge' and the longer it lasts, the more the speed of the rotor will fall, taking it away from the speed for optimal energy extraction from the wind. If the available wind power exceeds the pre-event output of the turbine (and the turbine was therefore spilling power), the blades can simply be pitched into the wind to try to recover the rotor speed. If, as is more commonly the case, the wind turbine was already extracting as much energy from the wind as possible, slowing the speed of rotation would reduce the ability of the turbine to extract energy from the wind. Following the surge the turbine would need to reduce its power output to below its pre-event value to enable the rotor to recover its optimal speed for power production. The challenge is therefore to identify the optimal balance of energy in the short, medium and longer term to maximise the proportion of wind generation that can be securely accommodated. If wind generators can be relied upon to arrest an initial drop in system frequency, it may provide sufficient time for hydro and other fast responding conventional plant to increase their output and supply the longer term energy deficit.

Additionally, while the characteristic of the inertial response of conventional generation is driven by physics, it is recognised that the power converters could be programmed to respond with any characteristic. The design of the synthetic inertia requirement is therefore seeking to find the most effective response characteristic.

These issues are the focus of significant research in Britain. Although the specific requirements are still being refined, wind farm developers have been put on notice that the grid code will be modified to require turbines being installed offshore from 2015 to support synthetic inertia.

A related area of research is in the design of nuclear generators. Historically nuclear generators have been designed for efficient baseload operation and have been very inflexible, either operating at full output or coming offline altogether. Once offline, it can take days or weeks for them to resume normal operation. However, the next generation of nuclear plant in the UK are being designed with a 'low output state' in which they can remain online at ~25% of their rated output. Nuclear plant will therefore be able to make way for the wind generation when it is available while still contributing their inertia to the system, and be able to quickly resume normal operation as the wind generation falls.

Impact on System Fault Level

As is common in life, the solutions implemented to solve one set of problems often create additional problems of their own. Although converter-connected turbines greatly assist fault ride through and inertia, they are also contributing to a drop in system fault levels.

Just as power converters enhance the controllability during the normal operation of the turbine, so they also influence the fault-characteristic of the turbine. Because power converters have a finite current limit their fault response is relatively subdued when compared with conventional synchronous generators. Typically a converter's output is limited to its normal rating, and perhaps a 10-30% short-term overload capability. A conventional synchronous generator can produce several times its normal output in the first few milliseconds following the introduction of a system fault.

Unlike synchronous generators, inverter connected generators do not have an inherent fault characteristic behaviour, and can be programmed to respond to faults in whatever fashion is desired. In the UK, a requirement has recently been introduced for converter-connected generation to produce maximum reactive current during a fault, plus real-power in proportion to the retained voltage. However, other responses are possible. In some European countries for example, there is a requirement for full reactive power during the fault but no requirement for real power. In some cases, embedded converter-connected generation has been known to be programmed to provide no fault contribution (i.e. to stop all output during a fault), to avoid overloading the fault rating of local switchgear. While a low fault contribution may sometimes be advantageous from local perspective, the aggregate effect on the power system as a whole (especially when the proportion of intermittent generation is high) could have significant implications.

The consequence of lower fault contributions has been the focus of some studies in the UK. The typical *fault contribution* from a synchronous generator (blue trace) and a UK compliant wind farm comprised of inverter-connected wind turbines (pink trace), is compared in the following figures, both for a small capacity installation (left) and a large installation (right).

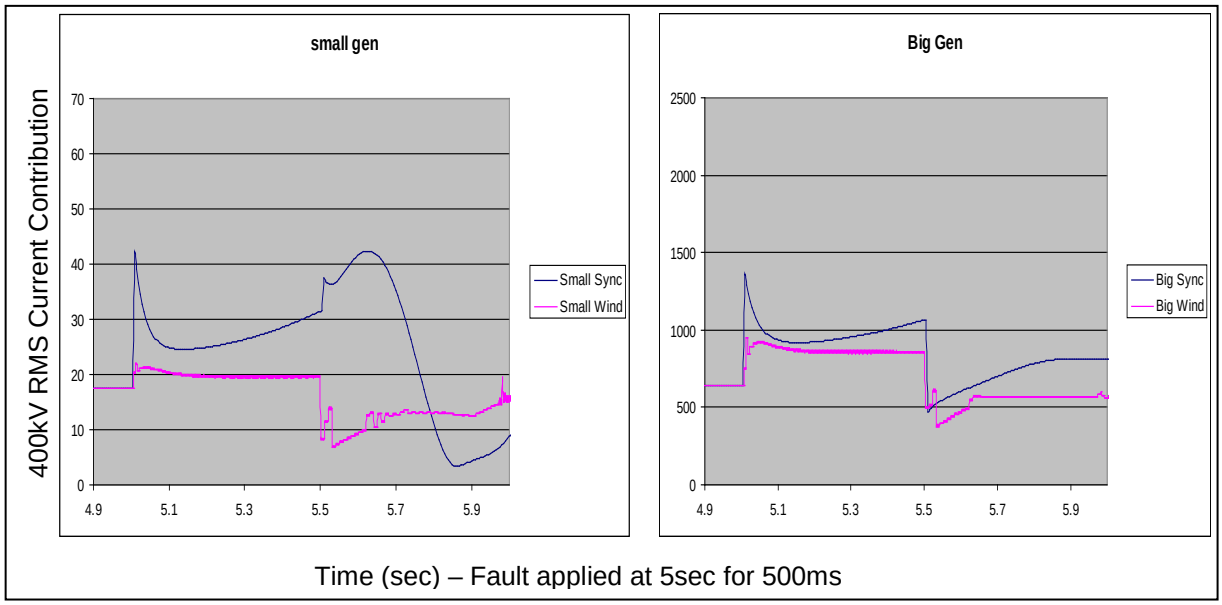


Figure 11 – Comparison of the fault contribution of a typical synchronous generator and a typical converter-connected renewable generator

In the extreme event that all of the generation in the system were supplied by inverter-connected wind with a characteristic as above, the *fault-current measured by protection relays* would probably resemble the trace in the plot below.

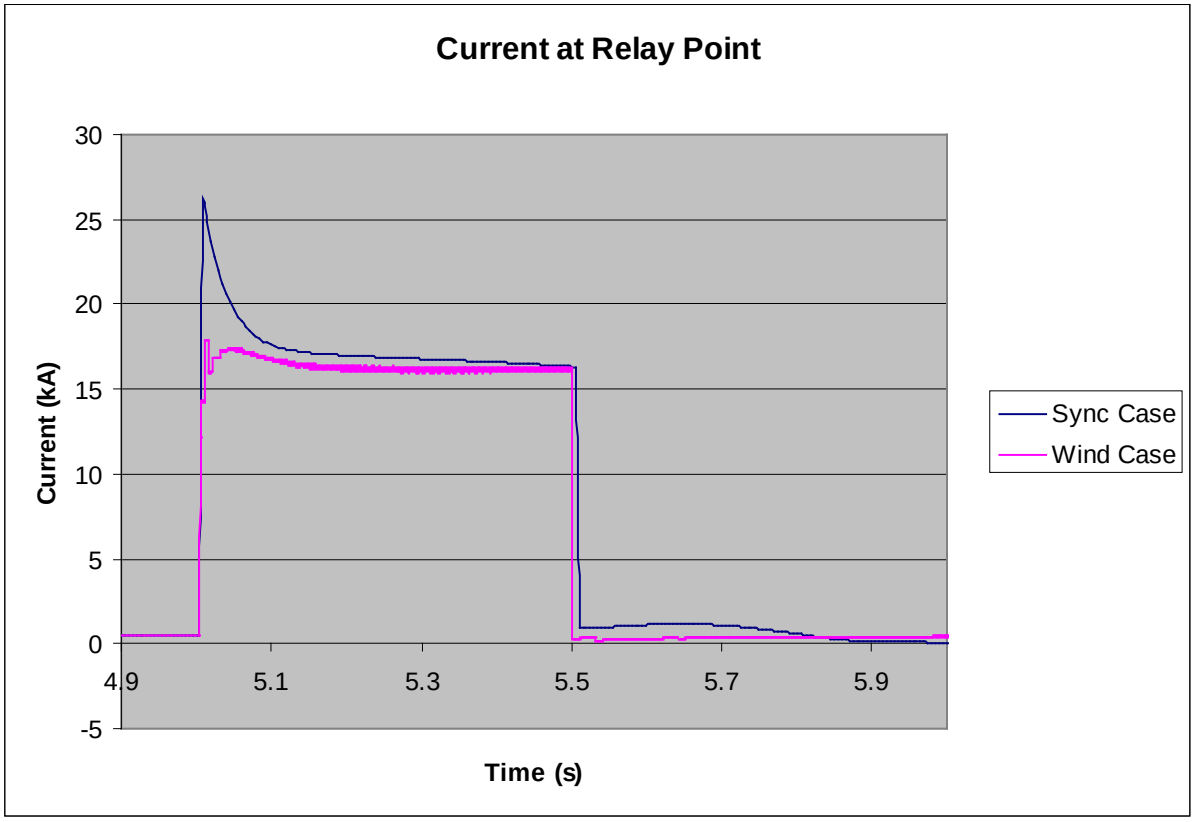


Figure 12 – Comparison of the fault current observed by a protection relay in a power system dominated by large synchronous generators or small converter-connected generators

The one clear difference in the measured fault current is the absence of an initial impulse. Depending on the specific circumstances in the local network, the fault level could also be much lower that what it presently is with entirely synchronous generation. This has several implications.

1. Future fault level studies will need to take account of the different fault contribution from inverter-connected generation.

2. Given the relatively long lifetime of HV infrastructure, consideration should be given now to the capabilities that protection systems will be required to have in the future. A review of National Grid's standard protection design concluded that to ensure that schemes are still fit for purpose in 20 years time, relays should be procured that can have any impulse functionality disabled, and it may be advantageous to make greater use of differential protection – even using dual differential protection (with distance

backup). This could be a more significant issue for distribution networks, which have historically used over-current relays for protection.

3. Consideration should also be given to the impact of a low fault level on any 'classic HVDC' links, since these require a certain fault level to be able to commutate. In areas of the network where the proportion of inverter-connected generation could be very high, it may become necessary to intervene to prevent the fault level from becoming too low. This could be done by:
   - requiring inverter-connected generation to have a higher short-term rating
   - installing synchronous compensators
   - using operational power system constraints (already being used in Denmark to maintain adequate fault levels in high-wind low-demand situations)

Other Advantages of Full Converter Turbines

The controllability of full converter turbines can be harnessed to assist a number of other aspects of the power system.

Just as the controllers of converter-connected generation can be programmed to respond to frequency deviations, so too can they be programmed to detect power system oscillations or respond to an external signal, and vary the power output of the turbine in a manner that dampens the oscillation. Given the very fast response time that is possible with power electronics and the direct control over real power production, this could potentially be highly effective, if configured optimally. This function would only be available while the turbine was producing power, but this would not be problem in the not-unlikely situation where additional grid transfer capacity is only required during periods of high wind generation.

Converter-connected generation can also provide the same reactive power compensation and power quality filtering services that a STATCOM can provide. A number of wind turbine manufacturers have recently released offerings that can provide these services even when the wind is not blowing (and the real power output is therefore 0MW). This is achieved by adding an auxiliary power supply to the DC bus of the power converter, as there would be in a STATCOM device.

Whilst converter connected generation has the potential to provide important services to the power system, a number of steps need to be taken to realise this potential:

- The value of converter-connected turbines needs to be assessed against the additional cost of the technology, especially if another solution would otherwise suffice. If the net value is positive, mechanisms may need to be put in place to incentivise or force

developers to utilise the technology – otherwise they have no reason to incur the additional cost for such features (e.g. National Grid's requirement for synthetic inertia). An alternative may be to create another ancillary service, e.g. for power quality/oscillatory stability services. Ideally this arrangement would allow for the converter's programmed response to be updated from time to time as the power system changes, or ultimately, be configurable/selectable in real-time with input from a wide-area monitoring and control system.

- The benefits of converter-connected generation will only be realised if the controllers are configured appropriately. Studies therefore need to be undertaken to define the response that such turbines should provide. The optimal response may vary from power system to power system, region to region, and at different voltage levels – and so the findings obtained in the UK may not be optimal into the Australian context.
- The response of converter-connected turbines needs to be taken into account when performing system stability studies. Therefore, procedures need to be established to develop models of the programmed response of such turbines, and to verify the response during commissioning.

For a more detailed comparison of the characteristics of different wind turbines, please refer to Appendix A.

Turbine Characteristics

Remote Location

One characteristic of most renewable forms of power generation is that the electricity must be produced at the source. Unlike other fuels, it is not possible to transport it by pipeline or train to a more convenient location. Often, those locations where renewable power is most abundant are the harsher environments remote from the load centres.

This section reviews how the remote location of much of the UK's wind energy reserves is being managed. It concludes that the use of HVDC technology, the thoughtful application of lower reliability standards, coordinated scale-efficient network design, and developing the network in a manner that interlinks radial connections to provide inter-regional transfer capacity can all help to minimise the cost of connecting remote generation.

Offshore Transmission in the UK

Although the UK is quite compact by Australian standards, the fact that most of their renewable generation is being installed offshore and will need to be connected by subsea cables makes their situation similar, both electrically and economically, to the use of long radial overhead-line generator connections. Therefore, in a lot of ways, the development of offshore generation in the UK is akin to the development of generation in Australia's interior. It will therefore be valuable for Australia to monitor developments in the UK in coming years and to learn from their experience.

Recognising that the economics and engineering of offshore transmission would be different to onshore transmission, the British energy regulator commissioned an extensive study to develop planning criteria that would minimise the overall cost of offshore transmission and take account of the intermittent nature of wind generation and the small number of demand connections offshore (just auxiliary loads). The study found that the very high capital cost of offshore infrastructure meant that it was not cost-effective to provide any redundancy (compared to the N-2 redundancy used on the onshore network). Rather, the study found that it was most cost-effective to merely limit the amount of generation that could be lost as a result of a single contingency. AC connections with a capacity greater than 90MW can lose a maximum of 50% of their capacity for a credible contingency, up to a maximum of 1000MW. HVDC connections are simply limited to a maximum loss of 1000MW following a single failure. This limit aligns with an existing criterion applying to the onshore network that limits the amount of generation which can be lost as a consequence of a generator trip and select transmission failures (e.g. bus coupler circuit breaker faults). An additional relaxation is the wider voltage ranges which are permitted at offshore connection points, which reduces the amount of reactive compensation which needs to be installed in offshore platform substations, where space and weight are at a premium.

Another key measure to minimising the cost of offshore infrastructure is the development of an integrated offshore transmission network, rather than lots of individual connections to shore. Significant cost is incurred laying any cable regardless of its capacity, and so it makes sense to install high capacity cables to marshalling points offshore. Additionally, there has been extensive thinking about how an offshore transmission system could play a dual role, of carrying wind power to the British mainland and to continental Europe when the wind is available, and providing additional interregional transfer and import capability when it is not. Example 'radial' and 'integrated' network designs are contrasted in the following figures.

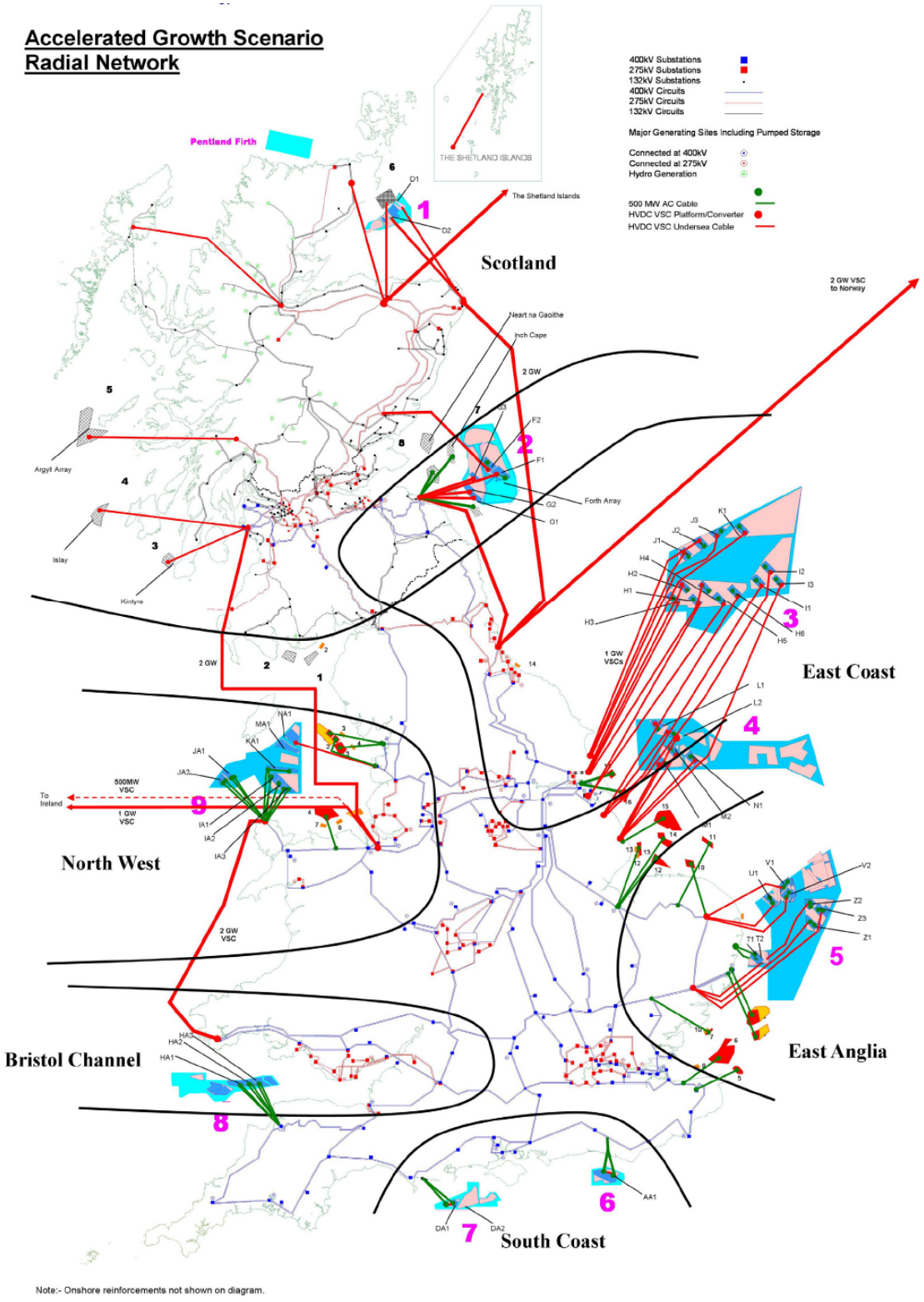


Figure 13 – Indicative offshore network design with a radial design philosophy [5]

[5] Taken from the 2010 Offshore Development Information Statement, National Grid, September 2010, Available online at: http://www.nationalgrid.com/uk/Electricity/ODIS/

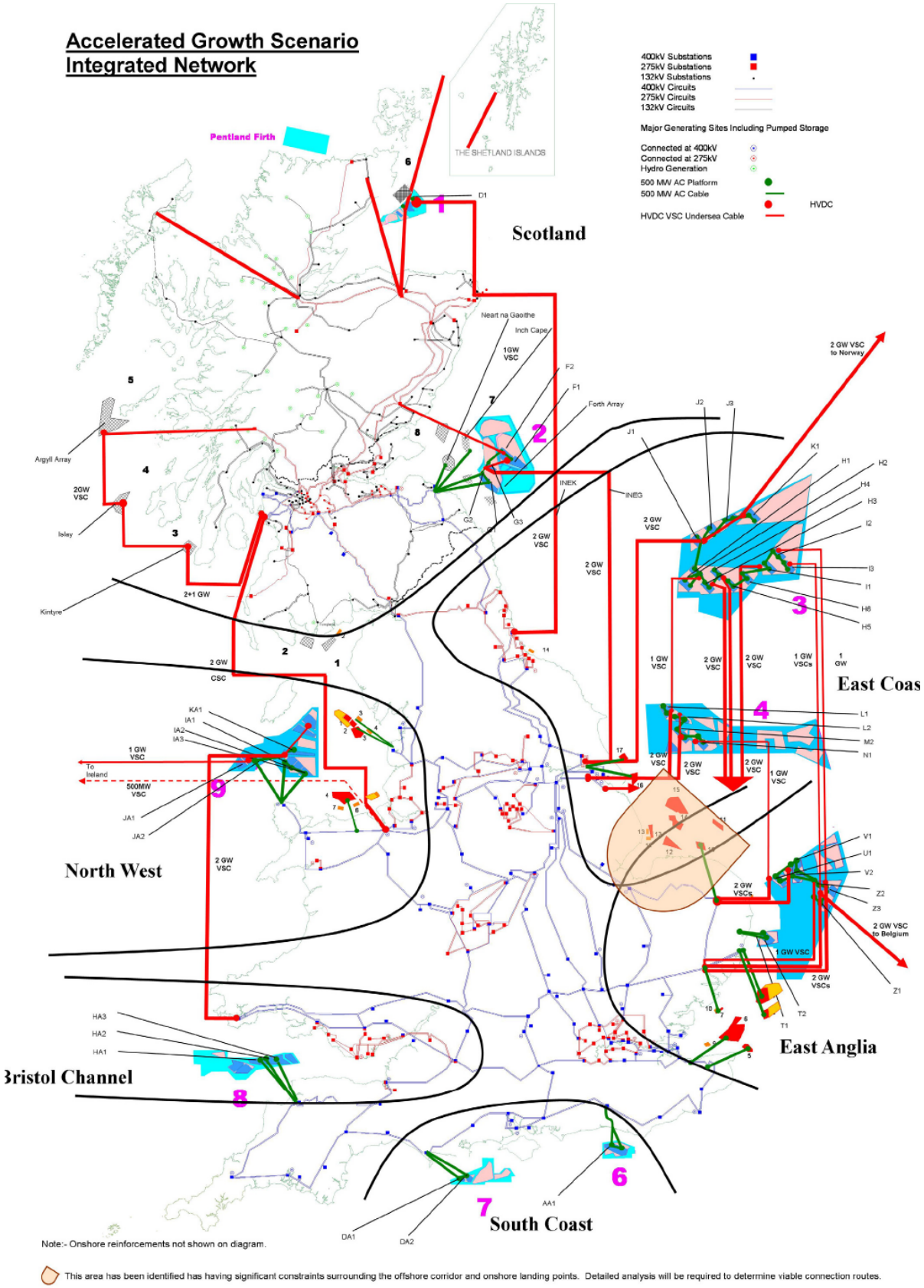


Figure 14 – Indicative offshore network design with an integrated design philosophy

High Voltage Direct Current (HVDC) Technology

HVDC technology is obviously well suited for long distance subsea transmission, as it removes the need for intermediate platform substations solely to manage the voltage and power factor, maximises the utilisation of a conductor, and minimises losses. Additionally, the controllability of HVDC is very helpful when designing a network that is not redundant. Conventional line commutated HVDC technology takes up far too much space for a converter station to be installed on an offshore platform, requires a high fault level at the remote end, and makes it necessary to use oil-impregnated cable. New designs developed over recent years have significantly lower power conversion losses, enable the use of overhead lines as well as cables, and utilise modular standard components (as opposed to a bespoke design with custom-built components) which should make asset management easier, less expensive and ultimately more reliable. However, the very high cost of HVDC converter stations means that the technology will still only be cost-effective where long distances need to be traversed or where there is a need to use cables over moderate distances.

The advent of multi-level voltage source converter (VSC) HVDC technology has significantly reduced the scale of converter stations, with no need for harmonic filtering, reactive compensation or a high fault level. Its ability to reverse the direction of power flow without reversing polarity enables cheaper and more flexible XLPE cables to be used. VSC HVDC also opens up the potential for tee-connections into the cable with a converter rated only for the capacity of tee – enabling a high capacity cable to connect a number of small wind farms along its route. In practice, no multi-terminal VSC HVDC connections have been developed yet. The main hurdle to their development is having control systems which can ensure that a multi-terminal link behaves as a coordinated system. However, given the significant efficiencies that such an arrangement could provide, multi-terminal schemes are under serious consideration in a number of European situations and are the focus of much R&D.

For more detailed information about HVDC technology and its potential role in connecting remote generation, please refer to Appendix B.

Remote Generation in Australia

The development of generation far inland to access Australia’s geothermal resource is analogous to the development of offshore networks in the UK, as expensive new transmission infrastructure will be required predominantly for the connection of new generation to the main transmission system. Whilst cheaper overhead lines should be able to be used instead of underground cables, the circuit lengths required will be much longer, and

so the cost of developing this infrastructure will be similarly expensive. Because of the long circuit lengths, HVDC technology is a strong candidate as it is for offshore networks.

Given the similarities, some of the measures undertaken to facilitate offshore networks in the UK could be considered for Australia:

- Certainly it would be more effective to coordinate the development of an inland transmission network rather than constructing dedicated connections for each inland generator. The Scale Efficient Network Extensions rule change proposal may go some way to facilitating this.
- There may be value in developing a different reliability criteria optimised for the higher cost of infrastructure and small number of loads inland. For instance, permitting a certain volume of the generation infeed to be lost following a contingency, perhaps linked to the amount of FCAS normally run, or the size of the largest generator unit (Kogan Creek, 700MW). Practically, this could be achieved by using intertrips to selected generators. For any small loads connected to the network, it may be more economic to pay a capacity payment to keep any existing generation operable for use following a contingency instead of providing a redundant connection. The commercial and operational consequences of not providing a redundant connection would need to be worked out.
- Given that connections to Australia's interior would likely need to be built from several coastal locations, if these connections were joined in the middle they could be utilised to boost the transfer capability between different coastal locations.

However, the following issues would need to be carefully considered:

- Coordination would be required to ensure that the development of an inland network is done in a co-optimised and efficient manner
- Although little or no load may be supplied directly by the inland network(s), as more generation is connected to the National Electricity Market (NEM) via less reliable inland links, it could impact on the overall security of the NEM.
- Given that geothermal generation is likely to run baseload, a different connection reliability may be economical than what was identified in Britain for intermittent offshore wind generation. A detailed assessment would be required to determine the optimal design.

Power Intermittency

Another unique characteristic of most renewable power sources is their intermittency, and this can have a profound impact on how the network needs to be planned, designed, and operated.

This section discusses the experience and research of several European TSOs into this issue. It concludes that:

- the issue is very complex and there are no straightforward solutions,
- recording detailed weather data now will help to inform future decision making,
- there may be value in TSOs starting gaining experience in economic assessment of power systems ahead of when it is absolutely necessary, and
- infrastructure decision making and approval processes will need to become more resilient to uncertainty.

While much of the discussion relates to wind generation, the principles are applicable to other forms of generation where the availability of the fuel source is variable.

Intermittency

The variation in renewable power generation is a function of both the intermittency of renewable power availability and the characteristics of the generators.

The characteristic of a typical wind turbine in shown in the figure below. There is a cut-in speed below which it will produce no power (~2m/s), and a cut-out speed above which the generator must shut down to avoid damaging itself. Between these extremes, the power output increases smoothly but non-linearly with the available wind/water speed.

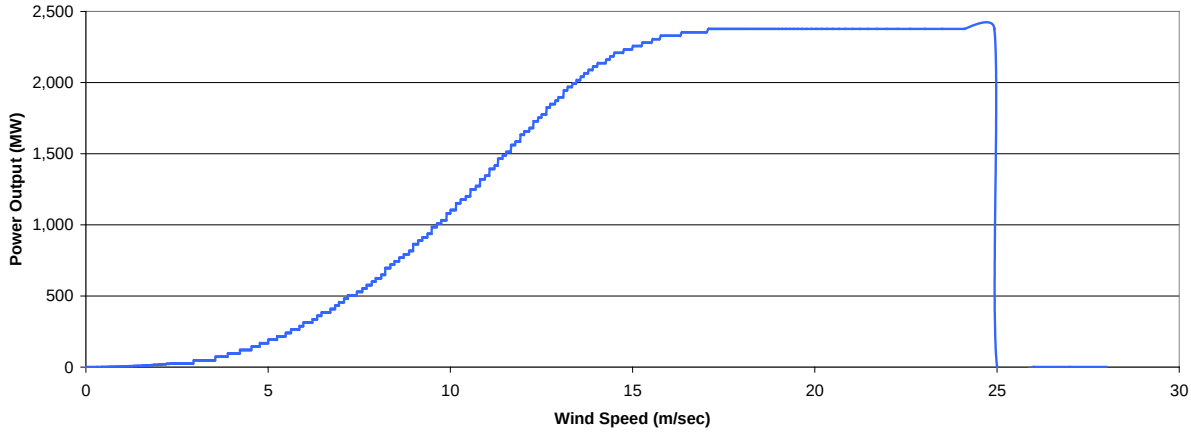


Figure 15 – Typical Wind Turbine Operating Characteristic

A consequence of the output profile is that the greatest sudden changes in network power flows due to renewable generation are likely to result from wind speeds exceeding the cut-out speed of the turbine and suddenly disconnecting. The following trace is from the Spanish power system, and shows the impact of a storm front on national wind power production.

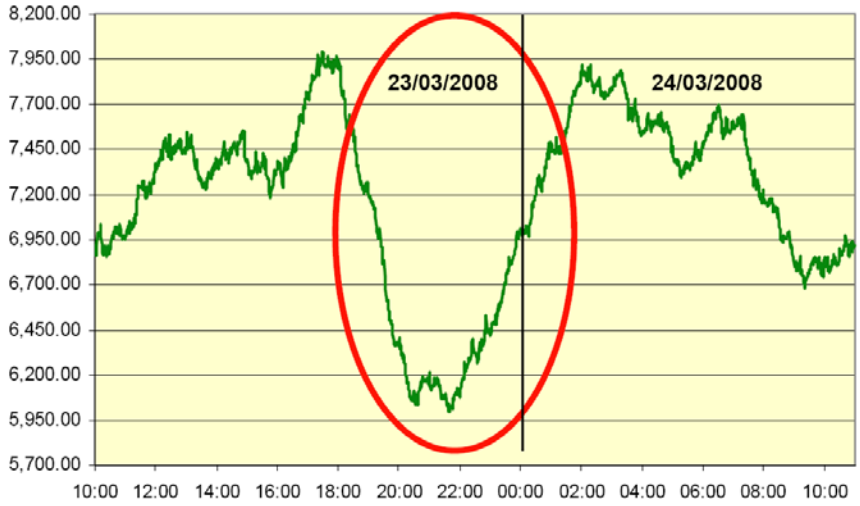


Figure 16 – Recorded reduction in Spanish wind generation with the arrival of a storm front

The day to day power output of a wind generator obviously also depends on the availability of wind. The frequency distribution curves from typical, well-located onshore and offshore generators (in the UK) are shown in the figures below. The wind is generally stronger and more consistent offshore, and the effect of this can be seen in the more even distribution of power output levels. The peak at 100% power output is due to the range of different of different wind speeds at which the wind turbine can produce 100% of its rated output.

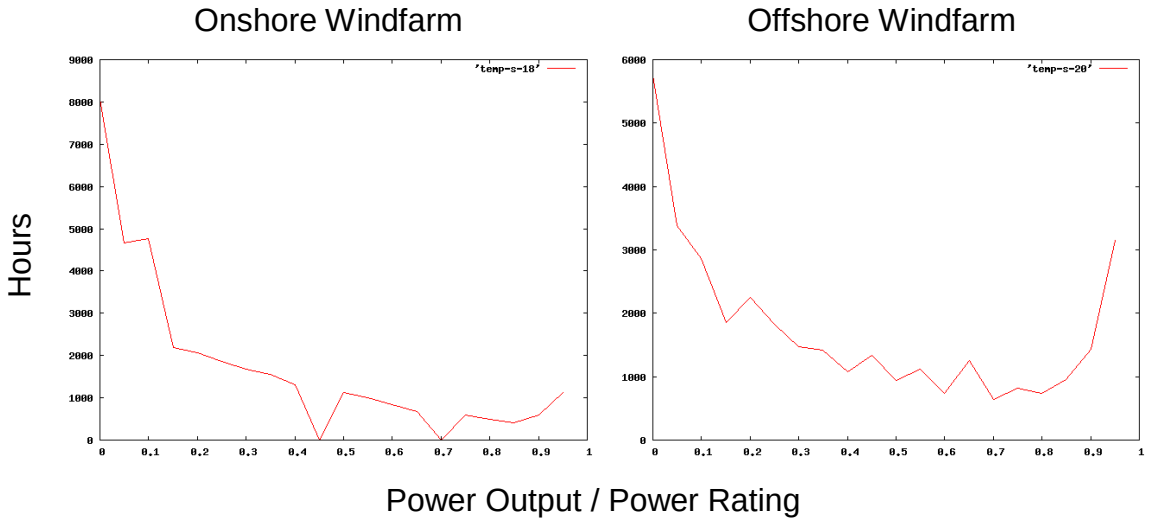


Figure 17 – Generation utilisation distribution of a typical onshore windfarm and a typical offshore windfarm in the UK

When averaged out over a wider region, the overall probability distribution assumes the typical S form. The following figure shows the recorded profile of wind generation in the Spanish system for each year from 2005 to 2009.

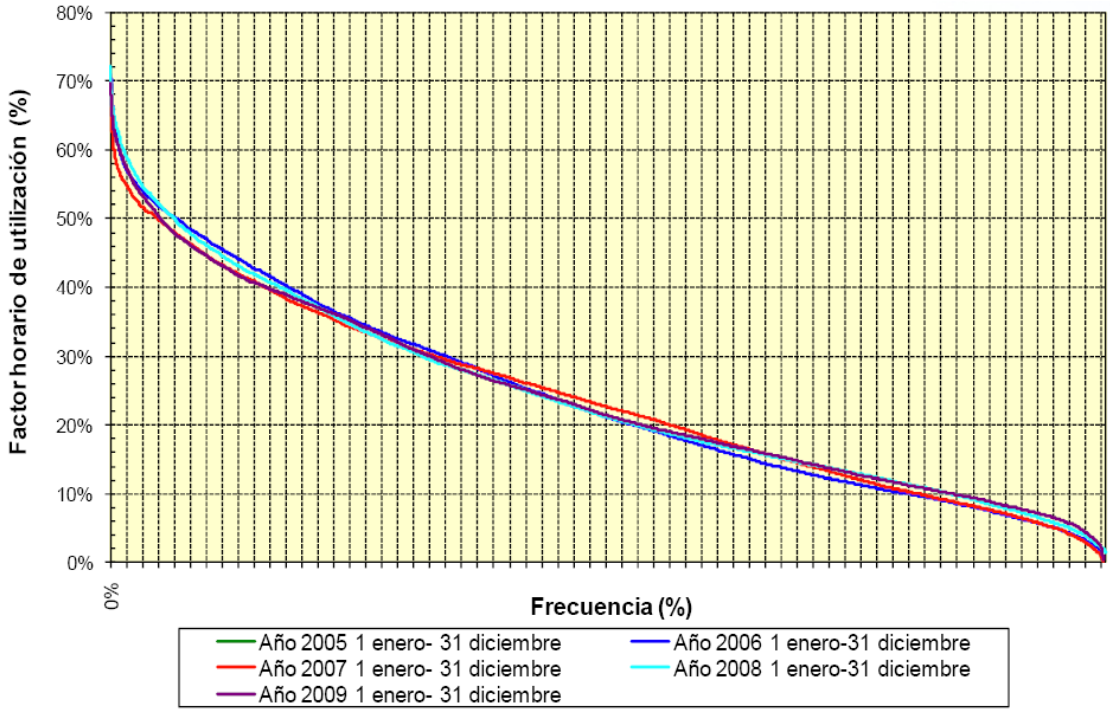


Figure 18 – Spanish wind generation utilisation profile over recent years

Although each form of intermittent renewable generation has a typical capacity factor (i.e. the area under the graph: around 20% for onshore wind, 35% for offshore wind, and 25% for the entire Spanish system), a generator will often produce much less than this level, and will sometimes produce much more than this. The incentive payments that renewable generators presently earn from producing power make them expensive to constrain offline (especially in Britain), and so regulating their output is generally not a viable option. The power system must therefore be designed to accommodate the full range of possible outputs.

Geographical Correlation

Another aspect of renewable generation intermittency is the geographical correlation of multiple generators. The weather systems that power the turbines have quite a large scale and will have a similar effect on all of the renewable generators in a region. A study into the correlation of wind farm outputs in the UK was conducted using eight years of historical wind data. The following relationship between the geographical separation of turbines and the correlation of their output was obtained.

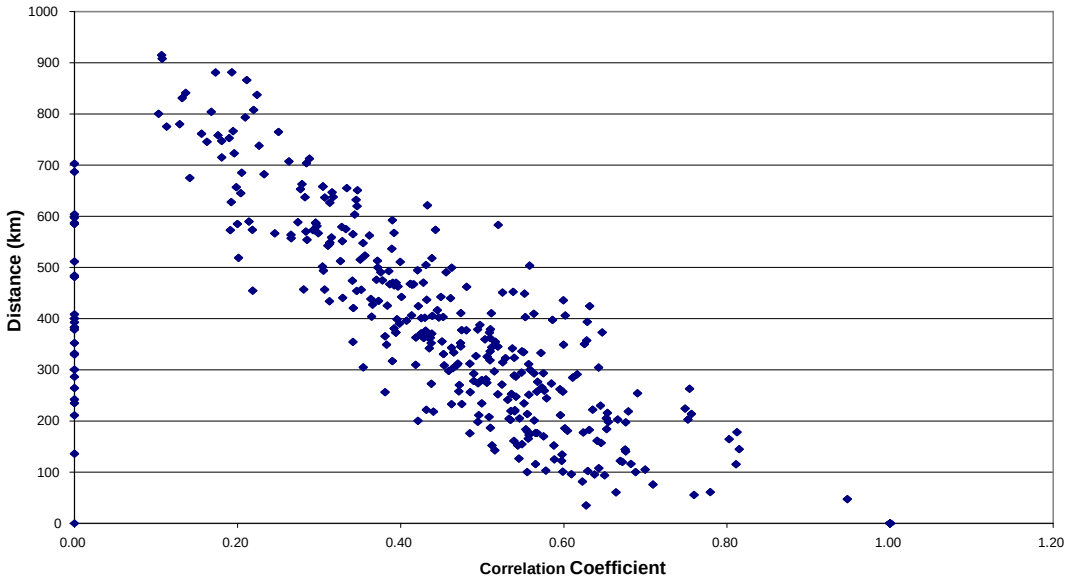


Figure 19 – Relationship between Generator Proximity and Generator Output in Britain

Further analysis interrogated the data to understand any common patterns in the correlation to inform the development of generation scenarios to be used in network planning. The relative weights of the different patterns identified are shown in the plot below. One was found to be dominant, and two or three others were less significant but still clearly discernable above the level of 'noise' in the data.

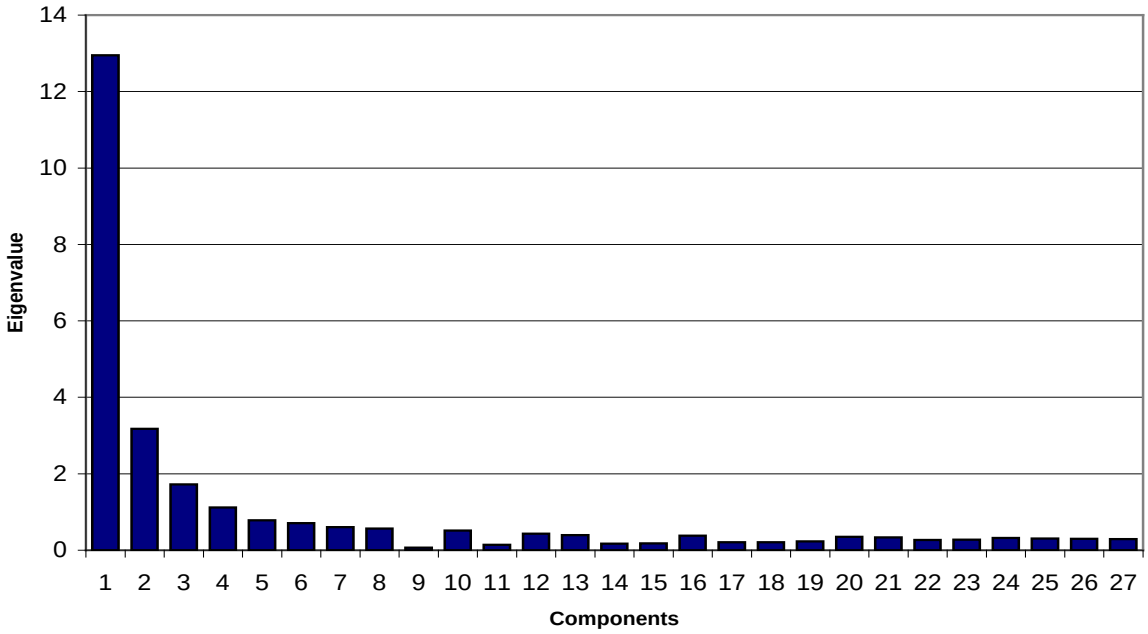
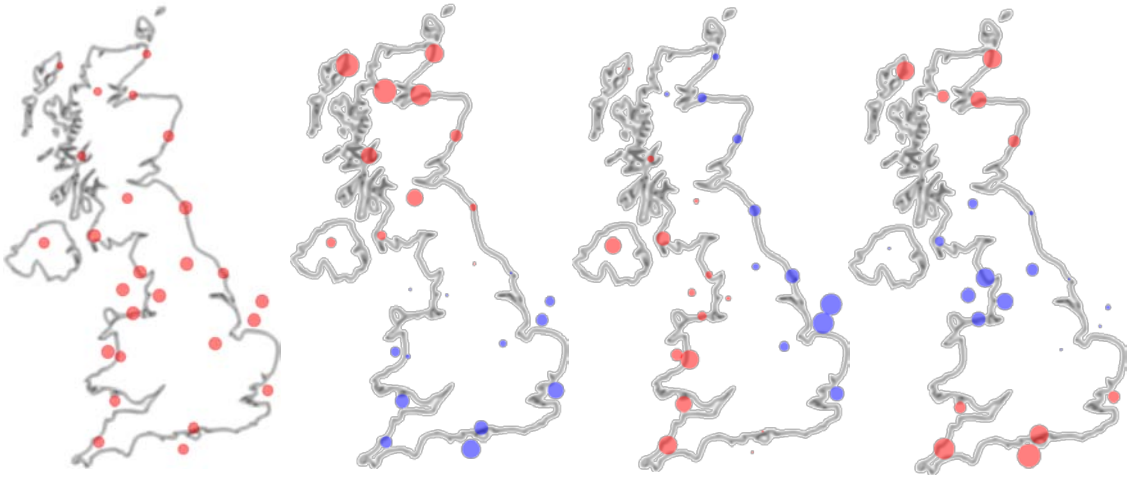


Figure 20 – Relative scale of various components in the British wind generation output data

The scenario corresponding to each of the four most significant components is illustrated in the plots below.



Eigenvalue: 12.3	Eigenvalue: 3.2	Eigenvalue: 1.8	Eigenvalue: 1.1
Windy throughout the UK	Windy in the north of the UK and calm in the south (or vice-versa)	Windy in the west of the UK and calm in the east (or vice-versa)	Windy in the far north and south of the UK and calm in the centre (or vice-versa)

Figure 21 – Dominant wind patterns in the United Kingdom

It should be pointed out that the east-west and north-south components could be understated in the above results, since the underlying data was based on the average wind speed over each hour, and weather systems can move over the UK from west to east quite quickly. Nevertheless, it is clear that when it is windy in the UK, it is usually windy throughout the entire UK. The reciprocal is also true: when the wind is calm, it is most likely to be calm throughout the UK. The implication is that the UK is too small (compared to the size of the weather systems that affect the wind) for there to be any significant diversity between the output of different wind farms. The overall amount of power generated from wind will therefore tend to swing between quite high values and quite low values.

The impact of this correlation can perhaps be seen most vividly in the following plots, which show what the wind farms that are planned to be built by 2020 would have generated during the winter months of 2000-2003. It is especially interesting to note:

- the variability of wind power production from day to day – it is quite possible to have 25GW of generation one day and none the following day
- the variability of wind energy production from year to year

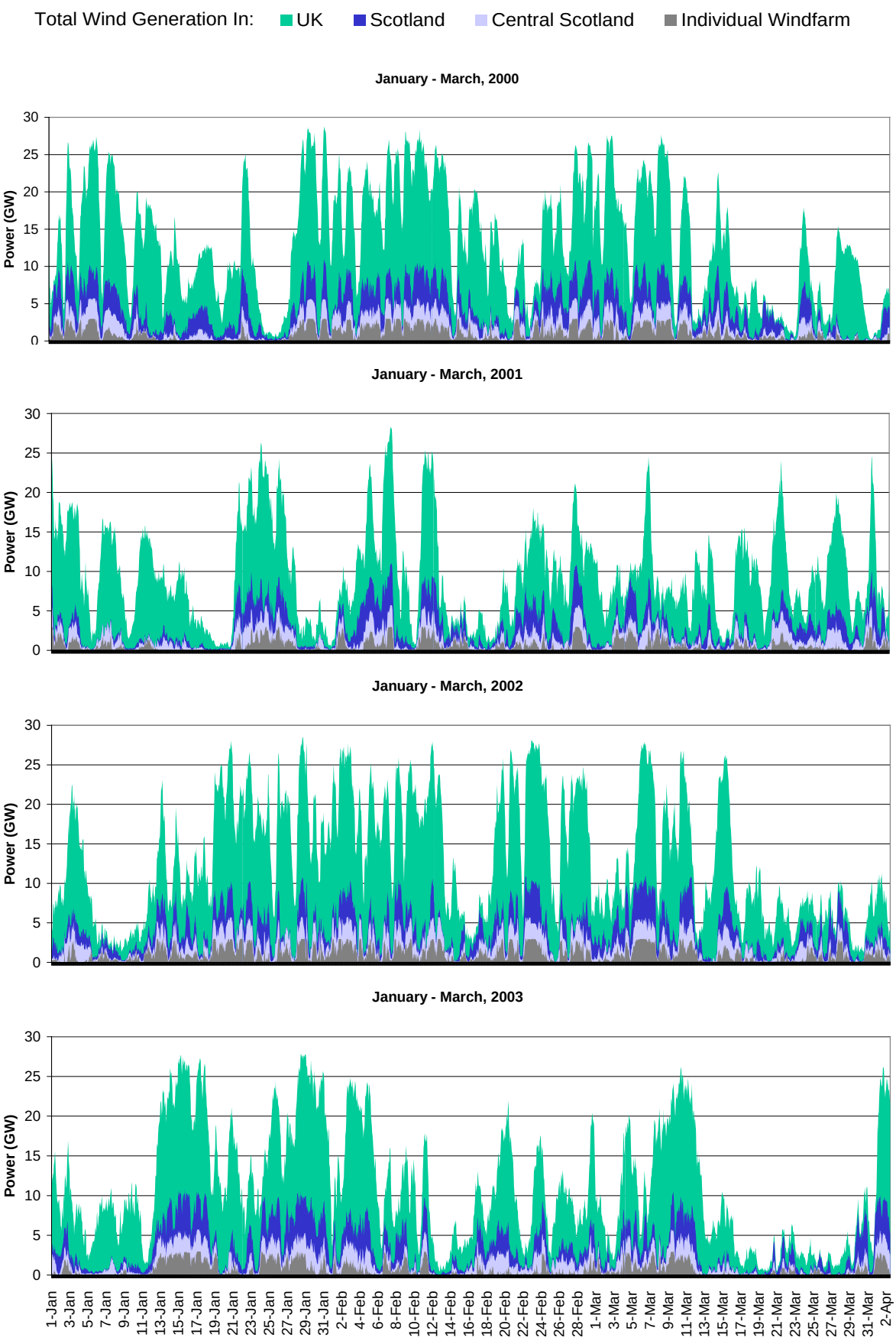


Figure 22 – Simulated wind generation in Winter 2000-2003, based on recorded wind data and the wind farms planned to be built by 2020

Resulting Generation Variability

The intermittent and correlated nature of most forms of renewable generation means that generally they cannot be used to secure demand. A consequence of this is that introducing renewable generation to the power system does not do away with the need for much conventional generation. As such, the ratio of generation of maximum demand can increase significantly. The proportion by which the generation capability exceeds maximum demand is referred to as the 'plant margin'.

This effect can be observed in the Spanish power system, as shown the figure below. There is a significant increase in generation capability between 2005 and 2010 (especially renewable and combined cycle generation) with only a modest increase in both maximum demand and annual energy consumption. The plant margin increases from 66% in 2005 (already quite high by historical standards) to 121% in 2010.

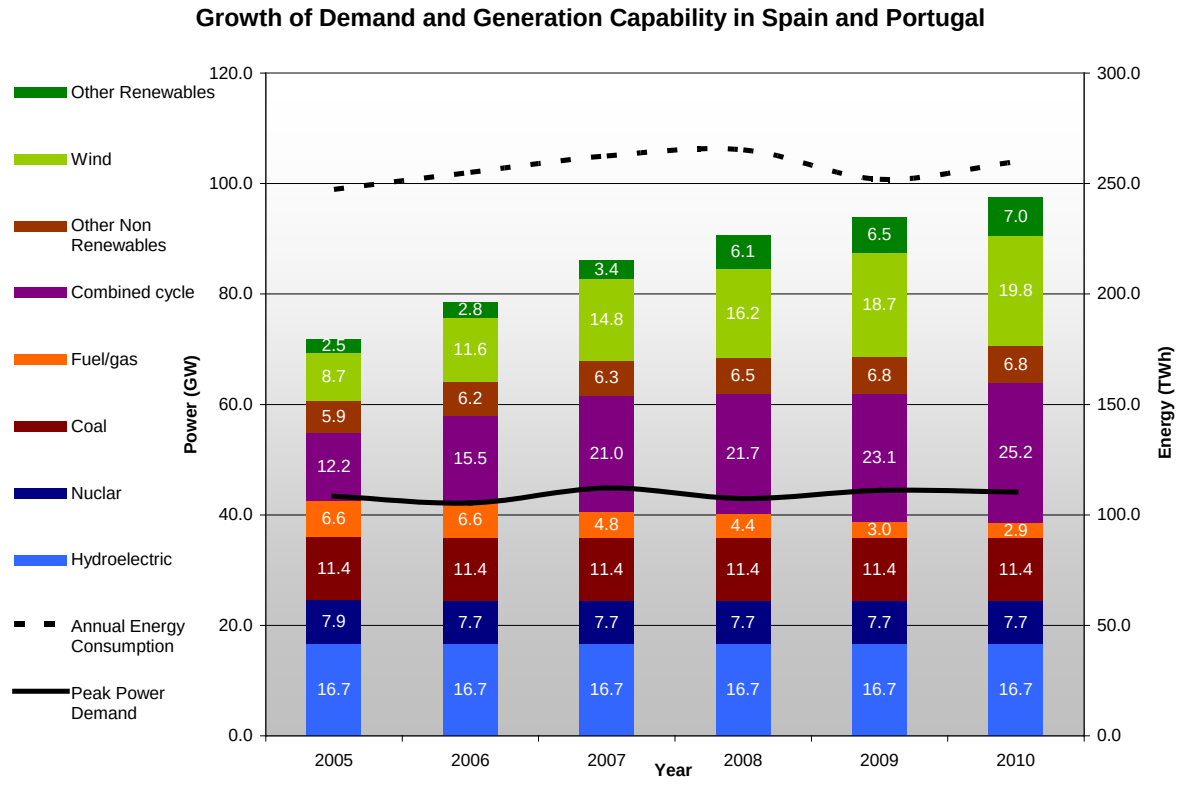


Figure 23 – Growth in Spanish Generation Capability and Demand [6]

An increase in plant margin results in much greater generation variability in the day to day operation of the power system. In a mature market, the merit order of conventional generation is generally quite stable, and the actual dispatch usually just moves up and down

[6] Prepared using information published in 'The Spanish Electricity System – Report 2009', and 'The Spanish Electricity System – Preliminary Report 2010', Red Eléctrica de España,
Available online at: http://www.ree.es/ingles/sistema_electrico/informeSEE.asp

this merit order to meet demand. The range of common system states could therefore be simplistically represented as a line, with only a single dimension of variation. More accurately, there is some irregularity in the generation dispatch due to plant outages and fuel price variations, but the requirement to maintain a minimum level of reserve limits the scale of this second dimension of variation. Additionally, power system economics mean that there is likely to be greater uncertainty at moderate levels of demand. When the demand is very high, almost all generators will need to be running, and at very low levels of demand there are not many generators which would accept a very low spot price to remain online. The space representing the possible range of operating states could therefore be represented as a narrow triangle, as illustrated in brown in the diagram below.

Introducing intermittent generation increases the scale of this second dimension of variation, and in so doing, significantly increases the range of potential range of operating states. The support schemes offered to renewable generators means that they are incentivised to generate even when demand is very low, with the potential to drive the spot price significantly negative (down to the negative value of renewable generation certificates). In such a situation, it could be highly uncertain which generation would remain online. Also, because the availability of intermittent renewable generation is continuously varying, the magnitude of this effect would also vary. The ‘narrow triangle’ of potential system operating states has been expanded to a large and complex volume.

In operations, the extent of generation variability will be limited by the finite capability of the transmission network (particularly in Australia where long distances lead to high network infrastructure costs and make relatively high levels of congestion cost effective). Network planners however need to analyse the full range of potential operating states to assess how much network capability is warranted – an issue which is discussed further in the ‘Network Planning’ section below.

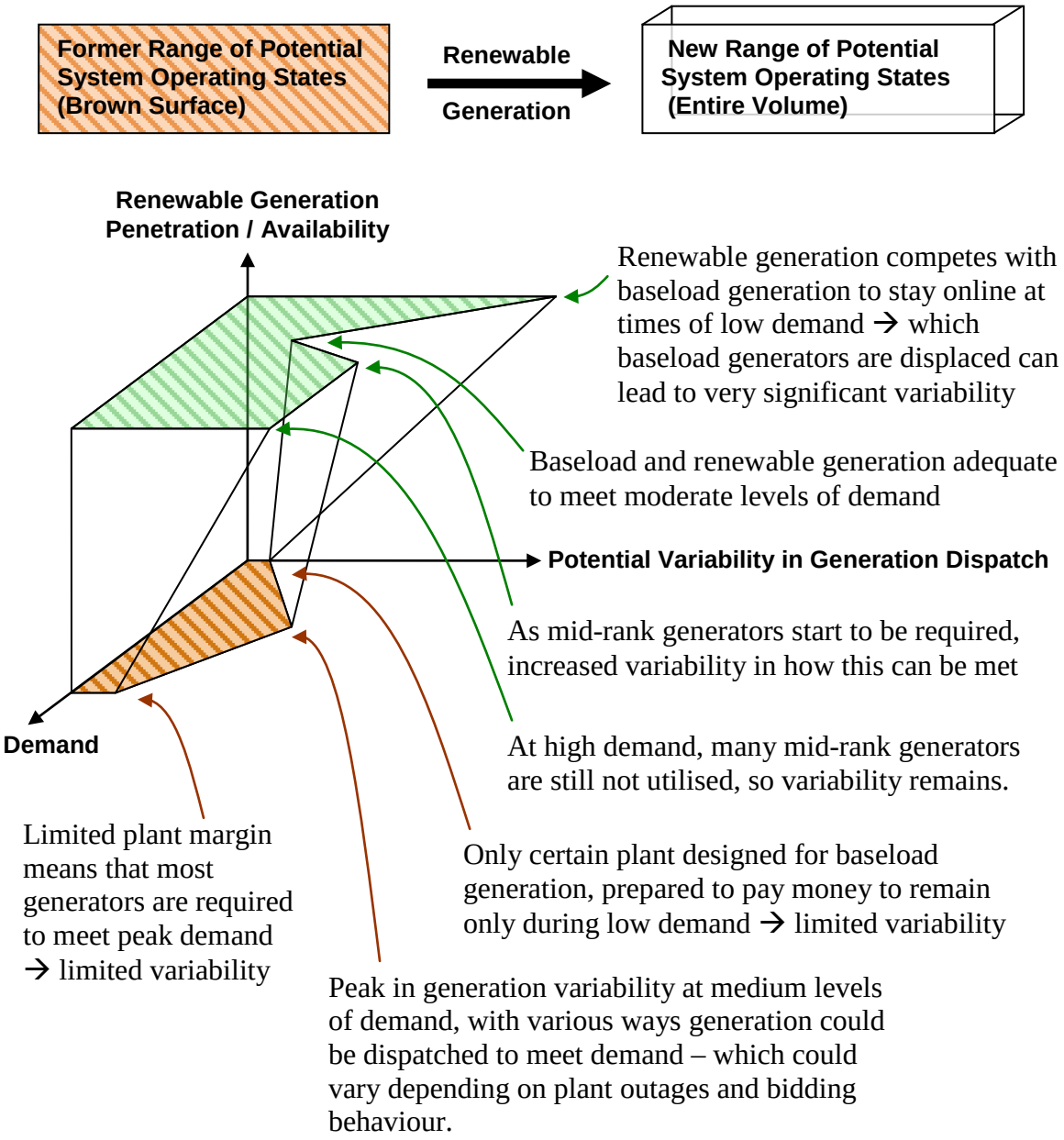


Figure 24 – Graphical Representation of the Potential Power System Operating States With and Without Renewable Generation

Additional Challenges for System Operators

Like demand variations, generation intermittency necessitates both the re-distribution of generation as well as the management of network flows and voltages. This process needs to be managed by power system and transmission network operators. System operators are familiar with managing variations in demand, have mature tools to forecast how it will vary, are experienced in handling the existing rates of change in the power system, and are familiar with a fairly consistent merit order of generation.

The broader range of system states will make it more difficult for controllers to develop an intuitive understanding of the network in each situation (e.g. critical contingencies, voltage management etc.) and may therefore make operators more reliant on aids such as contingency assessment.

An increasing volume of intermittent generation is also likely to increase the rate of change – both directly by putting varying amounts of power into the system, and indirectly, by making market prices more variable and leading to greater fluctuation in interconnector flows as a consequence. It is likely that more system controllers will be required to manage the faster rates of change, and additional tools may need to be developed to assist them.

Having reliable generation availability forecasts is important to inform the decisions of system operators generally, and especially when planning generation reserves. A number of European TSOs have produced and utilised wind forecasts for some years. However, because the power produced by wind farms is influenced by a number of complex factors such as the height of the turbines, the layout of the wind farm and interaction with the surrounding landscape, producing an accurate forecast is quite a difficult task and may take years of refinement to get right. The figure below is from the Spanish TSO's benchmarking of its wind generation forecasts, and shows how its accuracy has improved over time.

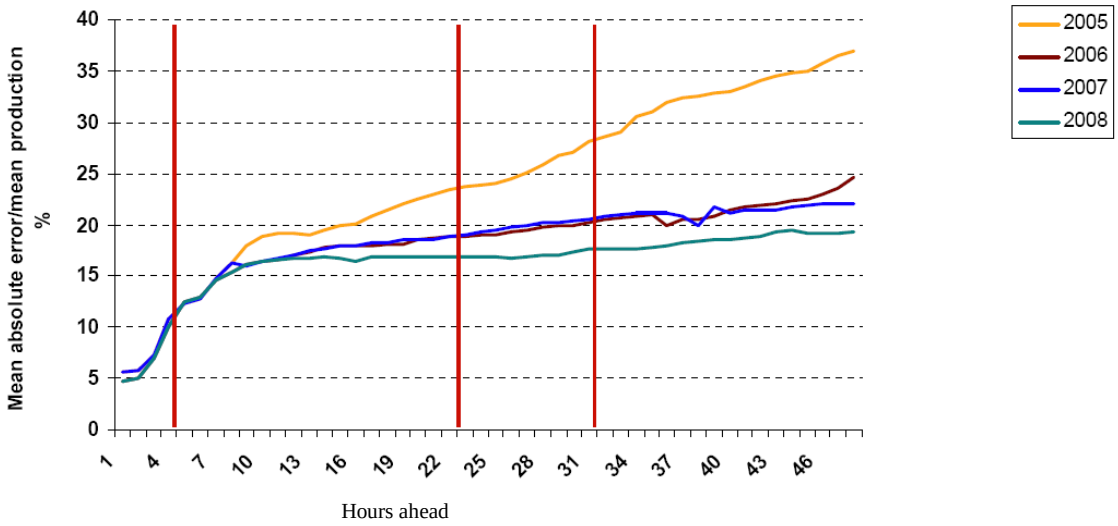


Figure 25 – Spanish wind forecasting accuracy over time [7]

After four years of refinement, there is still significant uncertainty when more than ~10 hours out. To accommodate this uncertainty in the day ahead planning of generation, the tool also provides confidence intervals - the upward reserve is planned based on the 85% confidence interval and downward reserve is planned based on the 15% interval.

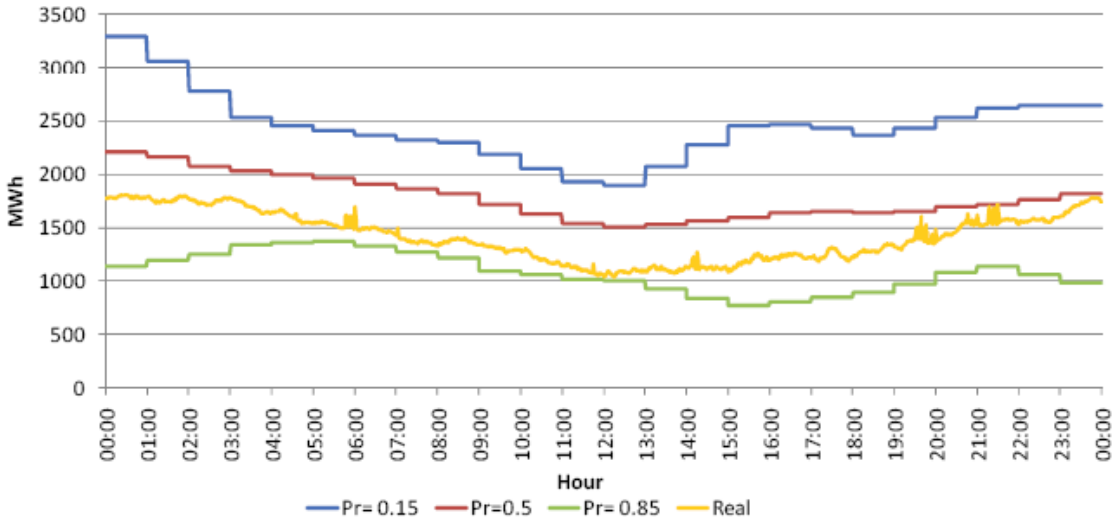


Figure 26 – Spanish wind forecasts with different confidence intervals

Managing generation reserves is a key challenge, especially when the penetration of wind generation is sufficient to start displacing generation which may take a significant amount of time to come back online. It can be very expensive to constrain wind generation offline, but

[7] Information provided by Red Eléctrica de España. Reproduced with permission.

the more inflexible other generation is, the more confident that operators will need to be that it will have sufficient time to restart or ramp-up in time for when it is needed. The problem is likely to first show up during low-demand situations, when historically the only plant left online have been designed for base load operation.

Large volumes of intermittent generation also make it difficult to schedule outages opportunistically. Because demand varies seasonally and with the time of day, it is often possible, years or months in advance to anticipate a suitable opportunity to take an outage, minimising its impact on the operation of the power system. This is not possible with renewable power generation. To manage this dilemma, the Spanish TSO has decided to categorise its outages into two groups:

- Outages related to the important maintenance of HV equipment and implementing the capital program are part of an annual outage plan. These outages were deemed to be too important and disruptive to constantly reschedule to minimise their impact on wind generation. These outages proceed regardless of wind conditions.
- Flexible outages relating to vegetation management or short outages that have a fast return to service. These are programmed days beforehand using wind forecast information to try to minimise disruption to the market. Maximising the organisation's ability to flex around the wind's availability requires broadly-skilled staff as well as flexible business processes.

Another issue for system controllers is the practicality of managing a large number of relatively small generators. In Spain for instance, there are now over 640 wind farms with a capacity greater than 10MW. Not only is communicating with this number of wind farms logistically difficult, but many of the wind farms are not large enough to warrant having a dedicated 24-hour control team, and so system operators could find themselves waking people in the middle of the night who would then take time to dial into the wind farm to implement any changes.

To manage all of these additional challenges associated with intermittent generation, the Spanish TSO has established a dedicated renewable energy control centre, co-located with their main power system control centre. The main functions of the renewable control centre are to:

- aggregate data from all of the individual wind farms
- forecast future generation
- assess the system's ability to cope with the generation
- if necessary, issue constraints to generators (sent automatically by SCADA)

Figure 27 – Spanish transmission & generation control room, with the dedicated renewable control desks visible on the far left [8]

Additionally, there is a requirement for every wind farm to be monitored and controlled by a continually staffed generation control room. Most wind farm developers have contracted out the monitoring, operation and bidding of their wind farm to one of 23 privately owned wind generation control centres. The system operator therefore liaises and interfaces with these control centres, instead of each individual generator.

Network Setting Design

The much wider range of possible network generation backgrounds must also be taken into account when determining network settings including protection relays, generator excitation controllers and power oscillation dampers in FACTS and HVDC devices.

Of particular concern to protection design are low fault level situations that may occur when wind turbines displace larger synchronous generators. Ensuring that distance relays will adequately protect a wider range of backgrounds may necessitate reducing the relay limit, reducing the achievable capacity of an asset. For this reason, unit/differential protection will likely become more commonly utilised in areas of high wind penetration, as it can provide protection regardless of system conditions.

[8] Photograph obtained from REE's public website: http://www.ree.es/ingles/operacion/regimen_especial.asp

Network Planning

The intermittency of renewable generators has a significant impact on network planning because of:

- the need to use market/economics-based analysis to identify and justify reinforcements
- the much wider range of background conditions which must be considered
- the distortion that the incentive payments to renewable generators have on power system economics/behaviour.

Economic Assessment of Power System Reinforcements

Intermittent generation, by nature, cannot be relied upon to secure much demand. Given sufficient volumes of generation with significant geographical diversity, some demand could potentially be secured, but the real value of renewable intermittent generation is offsetting the fuel and carbon costs associated with most forms of conventional generation at times when renewable energy is available. Therefore, once there is a significant volume of intermittent renewable generation in a power system it is inadequate to use planning techniques that focus solely on demand security. The challenge for planners is to consider the benefit of offsetting carbon pollution (or its reciprocal, the cost of constraining renewable generation) and identify the transmission network design which minimises the overall cost of operating the power system.

This is especially applicable to the main interconnected sections of the transmission system where there is the potential for greater variability in flows. On a local and regional level, the relatively small number of generating units means that diversity cannot be relied upon in the same way as in the power system at large – and conventional reliability-driven transmission planning criteria are likely to still be the most cost-effective way to develop the network. But for large scale reinforcements inter-connecting regions with significant diversity, the likelihood of the most extreme operating conditions is sufficiently small and the cost of reinforcements is sufficiently high that a detailed assessment is required to judge what power system conditions the network should be designed to accommodate without constraint.

Studies related to power system economics are far more involved than studies based on conventional reliability criteria. In situations when generation cannot be utilised due to transmission congestion, the cost of constraining that generation must be weighed against the cost of a transmission augmentation. To make this assessment, it is not adequate to study a couple of specific situations. Rather, planners must consider all of the different states that the power system could be put into and evaluate the likelihood and cost associated with each state. Only then can the aggregate operating costs be properly determined. Given that the cost of a transmission reinforcement will continue to be paid for the next 40-50 years,

planners need to be confident that the constraint costs would otherwise continue for long enough to justify the investment. Repeating the analysis for various transmission reinforcement options (with different costs and network capacities) enables the merits of different options to be compared.

A typical result of an economic assessment is illustrated in the figure below. The constraint costs (i.e. operational costs above the optimal dispatch) generally decrease as additional transmission capacity increases, while the cost of providing the transmission infrastructure (represented as an annualised cost) must obviously increase with the capacity that is provided. The summation of these two categories of cost will generally result in a curve, whose minima corresponds to the network capacity that minimises overall cost of operating the power system. As the figure below was produced as part of the development of a new planning standard, the cost of transmission was represented as a linear 'price per MW per kilometre' function. In practice, transmission augmentations come in large steps (in both cost and capacity), and so the 'curves' for a specific project would be more punctuated.

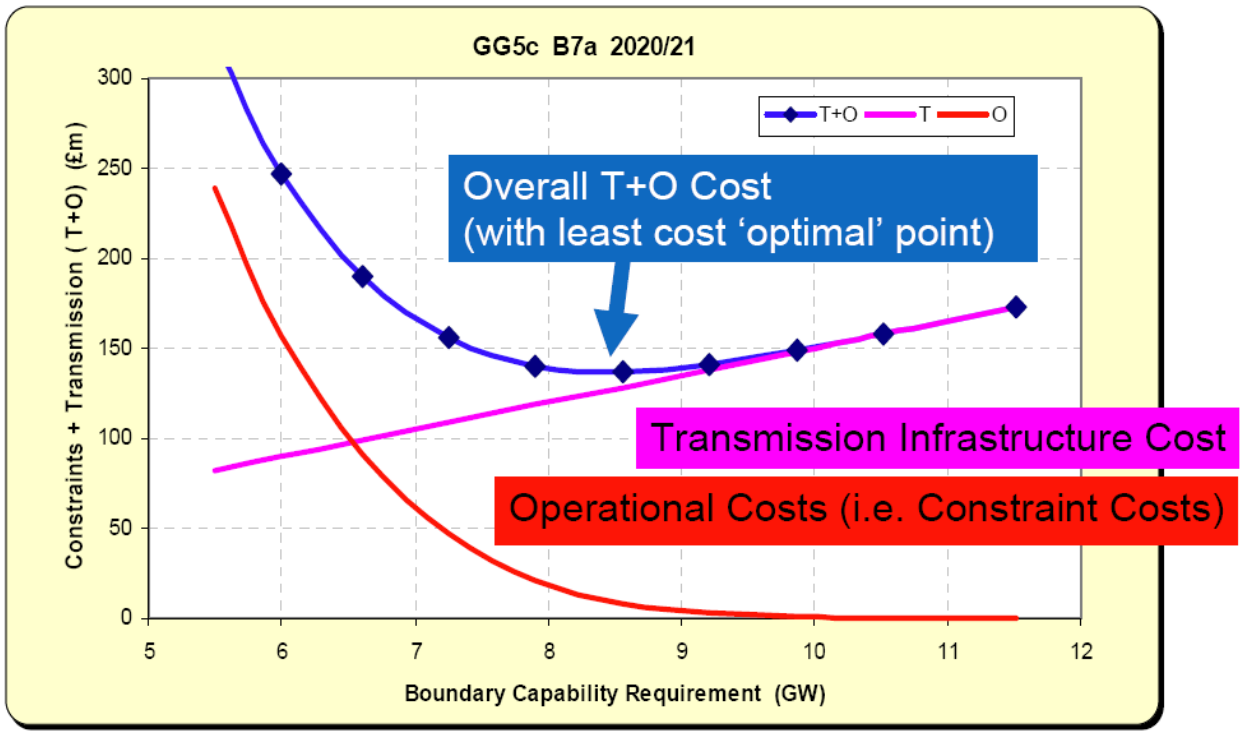


Figure 28 – Illustration of the transmission capacity that minimises the net cost to consumers

Given the interconnected nature of transmission networks, it is common practice to speak of the network's capacity in terms of its cut-sets i.e. its ability to transport power across the boundary between two adjacent regions. Additionally, system analysis tends to focus on specific boundaries as a means of breaking a larger problem down into its discrete components. However, when performing economic analysis, it is important to consider the

power system as a whole. Reinforcing a particular cut-set can merely transfer constraint costs onto neighbouring cut-sets. Depending on how the analysis is performed, this effect could either under-state or over-state the benefit to be gained by a particular reinforcement.

Additional Difficulties Particularly Associated With the Economic Assessment of Intermittent Generation

Economic analysis must be performed whenever a project is to be justified on the basis of its benefit to the market. However, the process becomes much more complicated when the power system includes a significant proportion of intermittent generation:

- We have already noted how the introduction of intermittent generation increases the plant margin, and significantly increases the range of states that the power system could operate in. The implication of this is that there are many more conditions which need to be evaluated, each with a much lower likelihood of occurring.
- Although modern wind turbines are technically some of the most flexible plant on the system, the very high value of the credits earned from producing green energy means that in practice they are extremely inflexible and will always run to their maximum extent when wind is available. When the penetration of wind generation is high this can lead to some 'abnormal' effects - as very high constraint costs will be incurred from displacing firmly baseload generation, or paying renewable generation the value of their renewable generation certificates plus energy not to generate (e.g. a substantially negative spot price). Even though particularly high wind availability situations may only occur very infrequently, if the costs incurred during them are sufficiently high, they could be sufficient to justify large scale transmission augmentations. However, a need case based on extreme operation conditions is highly sensitive to input assumptions which are impossible to predict accurately and very difficult to defend objectively (e.g. whether >90% combined output from all wind generators in a region occurs 0.1% or 0.2% of the time could significantly alter the need case for a transmission reinforcement).
- It is not just the volume of generation that is significant but also its location. Therefore, generator behaviour assumptions need to be set on an individual basis. Often the most difficult generator assumptions to make are which generators are most likely to be offline when wind is abundant – especially in the situation where wind generation can supply much of the off-peak demand and historically baseload generators must go offline to make room. In this case, whether more generators in one region go offline than in another region can greatly affect the interregional flow of power. In practice, which generators come offline could vary from instance to instance. Setting assumptions is both subjective and commercial sensitive, as generation companies may be commercially affected if it becomes known that the utility considers their generators more likely to be displaced by wind than a competitor's fleet, it is unlikely that the input assumptions

could be published, making the process non-transparent. A workaround would be to use the same probabilistic profile for all generators of a particular type – but there would still ambiguity in setting the profile for each type of generator, and ultimately the validity of the study findings would be related to the quality of the input data. 'Vanilla' inputs are likely to result is sub-optimal outcomes.

- Unlike conventional generators, the behaviour of renewable generators can be correlated due to the scale of the weather systems which affect their output. This very-real and very-influential effect needs to be taken into account. For accuracy and defendability, studies ought to be based on historical measurements recorded over a long period of time, with measurement sites in the correct locations and at the same height above ground as the wind turbines. Often, comprehensive wind records do not exist, adding additional subjectivity to the study process.
- There are many other uncertain external factors which could significantly impact the future operation and economics of the power system:
    - Demand changes over time
        - efficiency improvements vs. more loads being powered by electricity (e.g. electric space heating/cooling)
        - different consumption patterns (e.g. charging electric cars overnight)
    - Different power generation/storage technologies (carbon capture and storage, molten-salt energy storage, hydrogen, etc.)
    - Future commodity prices and availability
    - Political decisions about carbon reduction levels, acceptable fuel sources, inter-regional connectivity
    - Assumptions regarding how users will value electricity into the future
- Given all of the dimensions to the problem, simplifications and trade-offs need to be made in the assessment process to ensure that the problem is still solvable. Judgement is therefore needed to discern which factors are most influential. Unfortunately, even the 'less influential' factors can still significantly affect the answer.
- Because of all of the subjective assumptions which need to be made, the procedure is likely to yield inconsistent results over time.
- The economic analysis of power systems with a large volume of intermittent generation is internationally an evolving area and as yet there are no well established norms or 'industry best practice' to point to in defence of a particular approach.
- The analysis work requires a significant amount of expertise in statistics and computer science – areas in which transmission companies and power engineers historically have had limited expertise.

There is no easy workaround to these problems that I can perceive, as the assessment is merely trying to reflect to complexities of reality and the future is genuinely uncertain. The paradox (which I clearly observed in the UK) is that it could be widely accepted that something ought to be done, but impossible to objectively define and defend what specifically needs to be done, and as a consequence nothing is done. Individual parties with a vested interest (either against a project or in favour of an alternative option), can use the ambiguity in the study process to argue against the project or a particular option.

Nevertheless, there are measures that I believe could be implemented now to help to manage the difficulties:

- Start recording weather data in areas likely to experience the development of renewable generation. Having a detailed and long term record of weather will provide an objective basis for the study of correlation factors and utilisation rates.
- At the end of an exhaustive study, the findings will only be as accurate as the assumptions which have been made at the start of the process. The decision making, approval and funding processes for transmission augmentations therefore need to become tolerant to an increasing risk component. In the UK, the investment risk is presently borne entirely by consumers and the regulator has been exploring means of sharing this risk with utilities (e.g. linking the rate of return on assets to how necessary they are deemed to be each year) and this trend may in time be adopted in Australia. In this case, individual transmission companies will need processes and guidelines to evaluate and manage this investment risk. A higher average rate of return may be required from the regulator to fund the costs of borrowing for a riskier investment. Alternatively, if the present risk sharing arrangements remain, the criteria which are used to approve a reinforcement will need to be expanded to provide more explicit guidance about how to quantify and manage the risk, and specify an acceptable threshold for the project to proceed. These issues are very complex and suggestions which initially sound reasonable often break down when working out the details (e.g. how to assess the necessity of an individual component of the transmission network). In Great Britain, the regulator has presently reverted to assessing each major renewable-driven reinforcement on a case by case basis, releasing funding each year to incrementally progress the design and pre-construction works (i.e. reserving final approval until the last possible moment). It is possible that other regulators may follow the British regulator's lead.
- Continue to minimise the time it takes to implement projects, potentially implementing long-lead time and relatively low-cost aspects ahead of final approval. The later investment decisions can be made, the more opportunity there is for assumptions to be tested and refined ahead of final commitment. However, given the 40-50 year economic life of most infrastructure, significant risk would remain.

- Utilities may be required to agree any ambiguous inputs in consultation with the regulator, system operator and/or industry in general. Additionally, there may be opportunity for the industry to voluntarily or compulsory submit information that could feed into the study, such as minimum stable generation output levels, or a generation portfolio operator's merit order. These processes/assumptions will take time to negotiate and establish, and there may be merit in voluntarily starting to seek industry input into key assumptions and trying to build a consensus position.
- Begin developing experience with the use of economic market modelling techniques ahead of when they are actually needed to justify augmentations. It takes time to develop, refine and build confidence with models and the judgement calls that need to be made in the assessment process. It would be good to start this process well in advance of having to make a critical investment decision on the basis of it. Internationally, it has been common-place to run these studies alongside conventional studies for a number of years, initially as supporting evidence but gradually placing more and more weight on the economic modelling as the proportion of renewable generation increases. It may be possible to engage outside firms to perform the work, but the detailed and subjective nature of the process means that the entity that ultimately bears responsibility for the investment would typically want to perform the assessment itself or at least have sufficient expertise to be able to critically appraise the assessment.
- Additionally, I believe that there are some changes to the incentive schemes which could improve the efficiency with which renewable intermittent generation can be integrated into the power system, which would have implications on the planning process. These are discussed in the following section.

Efficient Power System Design Principles

A key conclusion from my time on the E. S. Cornwall Scholarship is that most of the problems associated with intermittent renewable generation have been solved or are in the process of being solved. However, some of the solutions have a substantial cost, and resorting to them may not necessarily be the best outcome. The challenge facing engineers is not merely to de-carbonise power generation, but to do so as cost-effectively as possible. In my view, there may be ways to develop intermittent generation that reduce the need to resort to expensive 'remedial' measures. In this section I review the characteristics of power systems which I believe will minimise the cost of integrating generation. I then go on to suggest ways that Australia's existing incentive schemes and arrangements could be modified to encourage these characteristics in the Australian power system. Some of the principles of efficient power system design are contradictory to a certain extent and so a compromise must be reached.

Characteristics of Cost-Effective Power System Design

The additional costs that are incurred when renewable generation is introduced into the power system fall into a number of categories:

- building and operating new renewable generation (including the additional cost of providing enhanced controllability/characteristics),
- retaining and developing controllable forms of generation to ensure security of supply to consumers
- providing greater network transfer capacity
- managing power quality issues or providing ancillary services historically provided by generation, or made necessary by renewable generation

The most efficient adoption of renewable power generation will occur if all of the various costs are considered, and the balance that minimises the net cost is pursued. Practically, I believe that there are a number of characteristics that can be built into power systems to minimise some or all of these costs:

Both generation and network costs can be minimised by:

1. reducing energy demand through efficiency improvements
2. improving demand-side management to smooth the demand and enable it to track renewable energy availability
3. strategically increasing the amount of energy storage in the power system to regulate net power generation and network flows
4. where possible, design transmission reinforcements to serve the dual role of opening up new areas for renewable generation and providing additional inter-regional transfer capability, and hence minimise constraint costs

Generation infrastructure costs can be minimised if:

5. renewable generation is located in areas where renewable power is most abundant and reliable, minimising the renewable generation capacity which must be constructed to fulfil renewable energy targets
6. renewable generation is dispersed as widely as possible to maximise its diversity and minimise the amount of conventional generation needed to maintain acceptable levels of demand security
7. transmission reinforcements tightly couple regions that have diverse forms of generation, allowing them to offset each other

Network infrastructure and system operating costs can be minimised if:

8. renewable generation is located close to the generation which it will displace
9. the volume of renewable generation installed in a particular region is limited to what the network can efficiently accommodate
10. the forms of intermittent technology installed in area are mixed, to reduce the likelihood of all or no intermittent generation being available at any given moment.
11. transmission developments are coordinated with renewable generator interest to maximise the effectiveness of transmission expenditure
12. technology developments are utilised as appropriate to minimise the cost of providing additional transmission capacity
13. operating criteria enable the network to be utilised to its maximum extent
14. mechanisms are in place to allow renewable generation to be constrained offline at reasonable cost so that it does not inappropriately distort market operation or transmission cost-benefit analyses

A number of these characteristics are already being encouraged through a combination of :

- incentives (e.g. subsidies to encourage energy efficiency, time of use tariffs),
- legislation (e.g. the 'Scale Efficient Network Extensions' rule change, ceasing the sale of domestic incandescent lighting, the regulatory test for new transmission infrastructure),
- trials (e.g. Energex's Cool Change trial and many similar demand side management initiatives)
- market structure providing natural incentive (e.g. the ability for companies to maximise profits through good site selection)

Of course, there may yet be opportunity to further enhance the effectiveness of some of the present arrangements (e.g. Australia's N-1 secure operating criteria is already strongly biased towards cost effectiveness, but as discussed previously, if this could be relaxed for the radial connection of remote intermittent generation to simply limiting the amount of generation that could be lost for a credible contingency, this could significantly reduce the network cost with only a very slight reduction in demand security).

However, I believe that there are some characteristics (3, 6, 8, 9, 10, and 14) which are not being addressed at all, relating to the expansion of energy storage, the optimal mix and location of intermittent generation, and constraining intermittent offline at an appropriate

cost. Without any mechanism to support these characteristics, they are unlikely to be considered. If appropriate signals/structures can be developed for the industry, these factors can start to be taken into account alongside the existing considerations when the investment decisions for new renewable generation are made.

Below I suggest some practical means to address these presently un-supported characteristics.

Optimal Location and Mix of Intermittent Generation

Because of the nature of intermittent generation, the power system operates more efficiently if it is located:

- close to the generation it displaces
- close to energy storage
- over as wide an area as possible

Additionally, it is beneficial if the forms of renewable generation in an area are mixed, further improving the diversity.

A power system with these characteristics will require less generation and transmission infrastructure. If these characteristics can be obtained at a lower cost than the additional infrastructure that would otherwise be required, the overall cost to electricity consumers will be less.

I propose that it may be possible to provide an appropriate signal by adjust the existing Renewable Energy Target (RET) scheme. This scheme provides credits to renewable generators for the renewable power they produce, which the generator can then sell to electricity wholesalers to provide additional revenue. Electricity wholesalers have a legal obligation to obtain credits in proportion with the national targets set each year and the size of their customer's load, or be faced with paying the shortfall price. Normally, 1 MWh of renewable energy production is equivalent to 1 credit, but a multiplication factor is presently applied to energy produced by small scale photovoltaic generators.

Presently, renewable generators earn credits at the same rate regardless of where they are located and whichever form of renewable technology they employ (with small scale photovoltaic generation being the only exception). If the earning rate were to be varied slightly by location and generation technology to reflect the marginal benefit of installing the generation in one region over region, or by using a different technology, this would send a

clear signal to generation proponents. The factors could be balanced so that overall the cost of introducing the margin would be negligible (i.e. a 1.1 scaling factor in an underdeveloped and beneficial location could be offset by a 0.9 scaling factor in an already congested region). Generation developers could then consider whether the superior availability of renewable power in an already congested region would be sufficient to keep developing that region, or whether it would become cost-effective to develop generation elsewhere.

AEMO is probably best placed to determine the scaling factors through an evaluation of the generation and transmission infrastructure savings that could be achieved were renewable generation to locate in different regions or use a different energy source. The scaling factors could be static numbers reviewed periodically, or could be consist of tiers to automatically account for the commitment of additional generation in the region (e.g. first 150MW of wind generation at 1.03, the next 150MW at 1.02 etc.). This scaling would only apply to new generation, and the scaling factor that applied when the plant was committed would be locked in for the life of the plant (as it is with the solar credits from small scale photovoltaic installations). A high standard would need to apply to when the rate was 'locked-in' to prevent developers from locking in a high factor but not immediately developing the generation.

The scheme could be coordinated with other initiatives, such as the 'Scale Efficient Network Extensions' rule change to further reduce the disadvantage of being the first to develop a new region and to ensure that new transmission investments are effectively utilised. By providing clear signals to industry about the benefit of different types of renewable generation in different regions, the scheme would enable individual generation developers to make decisions which further the development of an optimal, lowest cost power system. If, for example, the quality of renewable power in a particular region justifies expanding the transmission network capacity into the area and whatever remedial measures may be necessary, then the margin established by the scaling factors should not be sufficient to dissuade generators from developing that region. If however, an alternative region with ample capacity to accommodate more renewable generation was available and the value of avoided transmission works exceeded the value of reduced renewable generation, then the margin that is created should be sufficient to change the generation's business case in favour of the alternative location.

Expanding Energy Storage

Energy storage can reduce the overall cost of utilising renewable generation technology, as it can reduce the amount of conventional generation that needs to be retained to ensure demand security. Depending where the energy storage is located, it can also regulate network flows

and defer the need for transmission augmentation. Energy storage facilities make money from buying (and storing) energy when the price is low, and then selling this stored energy when the price is high. In Spain, they have found that this buying and selling of power is not sufficient to offset the large capital outlay required to develop large scale energy storage, but they have also found that the cost energy storage is more than offset by the value of the benefits it provides to the power system. The government has therefore decided to subsidise the construction of new energy storage (pumped hydro), to facilitate the ongoing increase in renewable generation.

It is plausible to assume that increased energy storage could have a similarly positive impact on the Australian power system, and similarly stand in need of government support to make it viable. However, it would not make sense for the government to provide support beyond the value of the benefit it provides. I can therefore envisage a further role for AEMO to quantify the value that energy storage could provide at different locations in the power system, which could form the basis of a support scheme. The evaluation would need to consider how large an installation would need to be, both in terms of its power rating and its energy storage capacity. Given that energy storage would need to participate in the energy market, it would likely need to be operated by a non-regulated commercial entity.

Historically pumped hydro generation has been the only cost effective form of large-scale energy storage, and there are very limited locations where such facilities could be constructed. However, various new energy storage technologies are under development that may be more scalable and flexible.

Cost Effectively Constraining Renewable Generation

Although modern renewable generators are technically some of the most flexible plant in the power system, present commercial arrangements make them very inflexible in practice. Given their very low operating cost and the value of the RET credits they receive to make them viable, they can continue to make money with a substantially negative spot price and can therefore under-bid all other generation. While the penetration of renewable generation is still low this is unlikely to cause significant problems or lead to any additional costs for consumers. However, as the penetration of intermittent generation increases, without a mechanism to constrain renewable generation offline at an appropriate cost, renewable generation could be developed without regard for the other generation already present in a region. This could lead to situations that greatly distort the normal operation of the power system, uneconomically justify transmission expansion and increase the cost of electricity to consumers (as discussed in the previous chapter).

The challenge comes from the fact that the RET incentive payments presently needed to make renewable generation viable are presently greater than the value of carbon displaced by the generation (i.e. the payments made to them are greater than their true economic value). Although the cost of renewable generation is incurred almost entirely as an upfront cost, the incentives are paid back to the generator by artificially increasing the value of the electricity they produce. Whilst this is reasonable during system normal operation, in an uncommon operating state such as extremely high wind availability, it would seem inappropriate for this artificially increased value to the basis upon which other generation are displaced (for forced to pay very significant costs to remain online) or transmission reinforcements are assessed. Given that the primary function of renewable generation is to offset the production of carbon dioxide from conventional generation, I propose that it would be far more appropriate to use the value of the carbon displaced as a measure of the value of keeping renewable generation online in such circumstances.

One possible means of implementing this could be to limit the minimum spot price of semi-scheduled generators (i.e. RET supported intermittent renewable generators) to the negative value of carbon displaced by their operation, while retaining the ability for fully-scheduled generation to bid down to -$1000/MWh. This would ensure that the true value of intermittent generation is used as the basis of constraining other plant offline, and hence as the basis for evaluating the cost of transmission constraints and the merit of transmission augmentations.

During system normal operation when renewable generation is not constrained offline, renewable generators would continue to earn RET credits according to what they actually generate. In the hopefully rare instances where renewable generators are constrained offline, AEMO could estimate the certificates that they would otherwise have earned (based on their pre-constraint output levels and AEMOs renewable generation forecasting tool) – and credit these certificates to their accounts. This would prevent the generators from being unfairly penalised by the pricing restriction placed particularly on them and would ensure the RET scheme continues to function unaffected. A renewable generation, if constrained offline, would however miss out on the sale of power – as would any other generator in that situation. This would act as a deterrent to knowingly developing renewable generation that could frequently be constrained offline. Ideally this would be coupled with an incentive scheme which provides a lower rate of incentive to new generation in an area that already has a high concentration of such generation.

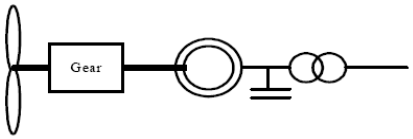
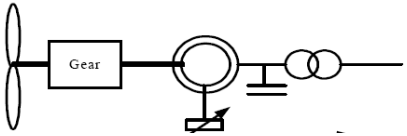
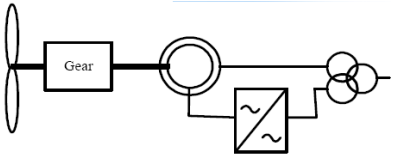
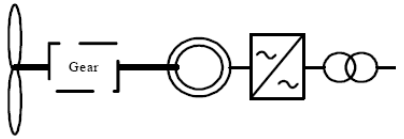
Appendix A – Renewable Turbine Types and Characteristics

Since the early 2000s, 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.

Although the discussion relates to wind turbines specifically, the same turbines (especially type D) are increasingly being used in various other forms of renewable power generation. As wind is the most mature renewable generating technology, it has tended to drive the development of technologies which have subsequently been adopted by the other forms of renewable generation.

Appendix A – Renewable Turbine Types and Characteristics

	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

Appendix A – Renewable Turbine Types and Characteristics

	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.

Appendix A – Renewable Turbine Types and Characteristics

	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.

Appendix B – HVDC Technology

High Voltage Direct Current (HVDC) technology has evolved rapidly over recent years. This appendix summarises the proceedings of the last Cigre B4 Colloquium on HVDC and Power Electronics, held in Bergen, Norway in 2009. The review includes information about:

- the current state of the technology,
- recent international experience with it,
- an appraisal of HVDC's pros and cons, and
- proposals to better coordinate and leverage dynamic grid equipment for maximum benefit

Appendix B – HVDC Technology

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HVDC Converter Technologies

There are two basic types of HVDC converters available today: Line Commutated Converters (LCC) and Voltage Source Converters (VSC).

Line Commutated Converters

LCC is the 'traditional' and mature form of HVDC, with the first installation energised in 1950. Commercially it is often referred to as 'classical' or 'conventional' HVDC. It uses thyristor switches, which block the flow of current until they are closed ('fired') at a controllable point on the voltage waveform. Once fired, the thyristors remain closed until a zero crossing in the current waveform when they naturally commutate open. Large specialized reactors and other filtering are required at the AC terminals of a LCC converter to restore a sinusoidal waveform. LCC converters consume reactive power (approx 60% of the real power transferred, with limited ability to control this value) and therefore require shunt capacitor banks to be installed on the AC terminals, which are often integrated with the filters. The AC network's fault level at the converter must be maintained at a high enough level (typically 2.5 times the rating of the converter) for the thyristors to reliably commutate open at the end of each cycle. If the fault level drops below this, a commutation failure can occur, interrupting the transfer of power. In order for the direction of power flow to be reversed, the DC polarity must also be reversed. If cables are used, a time delay must be integrated into the polarity reversal during which the system is unable to transfer power. Both underground cables and overhead lines can be used, although the need to reverse voltage polarity prevents polymeric (e.g. XLPE) cables from being used. LCC converters have been used with voltages up to 800 kV and capacities up to 3000 MW.

Voltage Source Converters

The recent development of high voltage and high capacity Insulated-Gate Bipolar Transistors (IGBTs) has enabled the use of VSC converters. Commercially, VSC converters are known as HVDC Light or HVDC Plus. IGBTs can be switched both on and off very rapidly, making additional designs and features possible. VSC converters can independently control the flow of active and reactive power. The direction of power flow is controlled by adjusting the voltage phase angle rather than the polarity, which permits continuous operation and makes the use of lighter and cheaper XLPE cables possible. The flow of reactive power is controlled by adjusting the voltage magnitude at each terminal. VSC converters do not require a high fault level to operate, enabling the connection of weaker nodes, reducing the likelihood of the

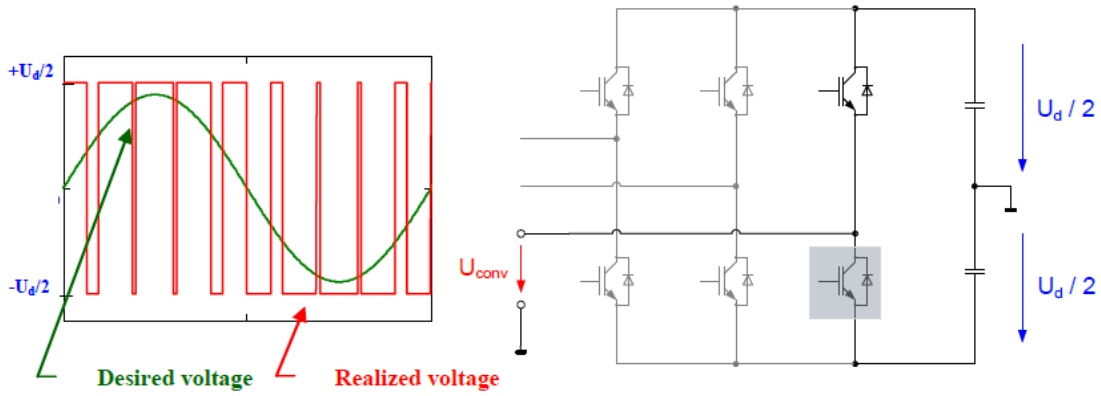
power transfer being interrupted by commutation failures 'in sympathy' with other network contingencies, and allowing the link to be used for black start. Presently, VSC converters cost more; have higher losses and lower voltage (300kV) and power capabilities (500MW) than LCC converters. However, there is much ongoing research and development into the design of VSC converters and their design and capabilities change frequently. For instance, until recently, it was not possible to use VSC with overhead lines, but recent design changes now permit this.

There are two broad architectures of VSC converters: two-level and multi-level converters.

Two-Level VSC Converters

Two level converters were the first to be developed for VSC HVDC, and are still used in the ABB HVDC Light offering. These use a large central DC bus capacitor to maintain a steady DC bus voltage. Two switching units are used to adjust the AC voltage between plus and minus the DC bus voltage. Pulse width modulation is used to control the average magnitude of the AC voltage. A large specially designed AC reactor, star-delta converter transformer and shunt filters connected to each AC phase then act to filter out the high frequency components leaving a (mostly) sinusoidal waveform.

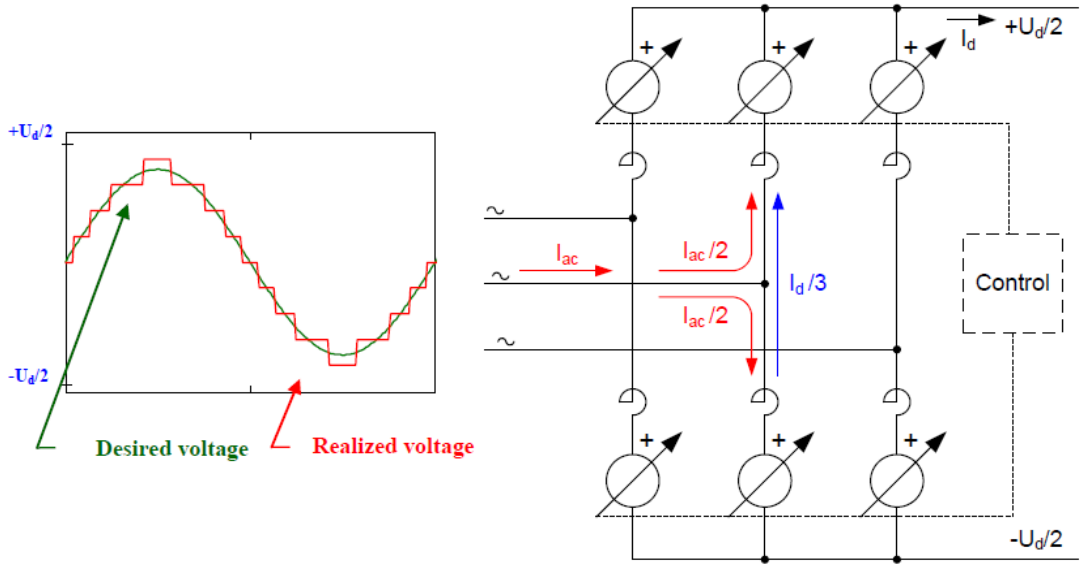
Large water-cooled air-cored reactors were observed at the ABB Light converter visited during the conference's technical tour.



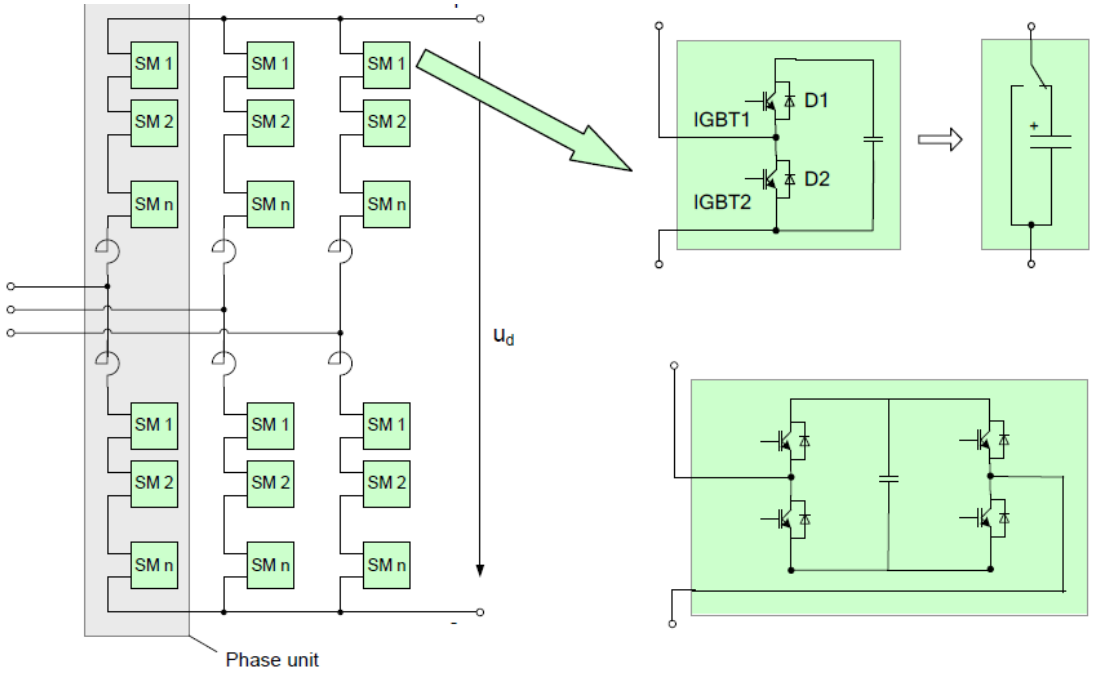
Multilevel VSC Converters

Siemens have recently switched to using a multilevel VSC converter in their HVDC Plus offering, and Alstom have just commercialized their own multilevel VSC converter. Multilevel converters use a large number of DC capacitors, each of which can be switched

independently such that the AC voltage is built up from small steps. The more levels that are used, the closer the voltage waveform will resemble a sinusoid.



The Siemens and Alstom designs are based around the use of standard submodules, each containing switching elements and a DC capacitor. A different number of submodules can be connected in series or parallel to meet design requirements of a particular project. Faulted submodules are automatically short circuited to allow the system to continue functioning until they can be replaced. Reactors are installed on each converter branch to damp the flow of balancing current and minimize the magnitude of the current that would flow following a DC circuit fault.



The main disadvantage of multilevel converters is that for the same DC voltage level, a multilevel design requires almost twice as many semiconductor switches (which require a larger footprint) and a much higher the level of DC capacitance than a two-level converter.

However, there are several advantages of multilevel architectures over two-level architectures:

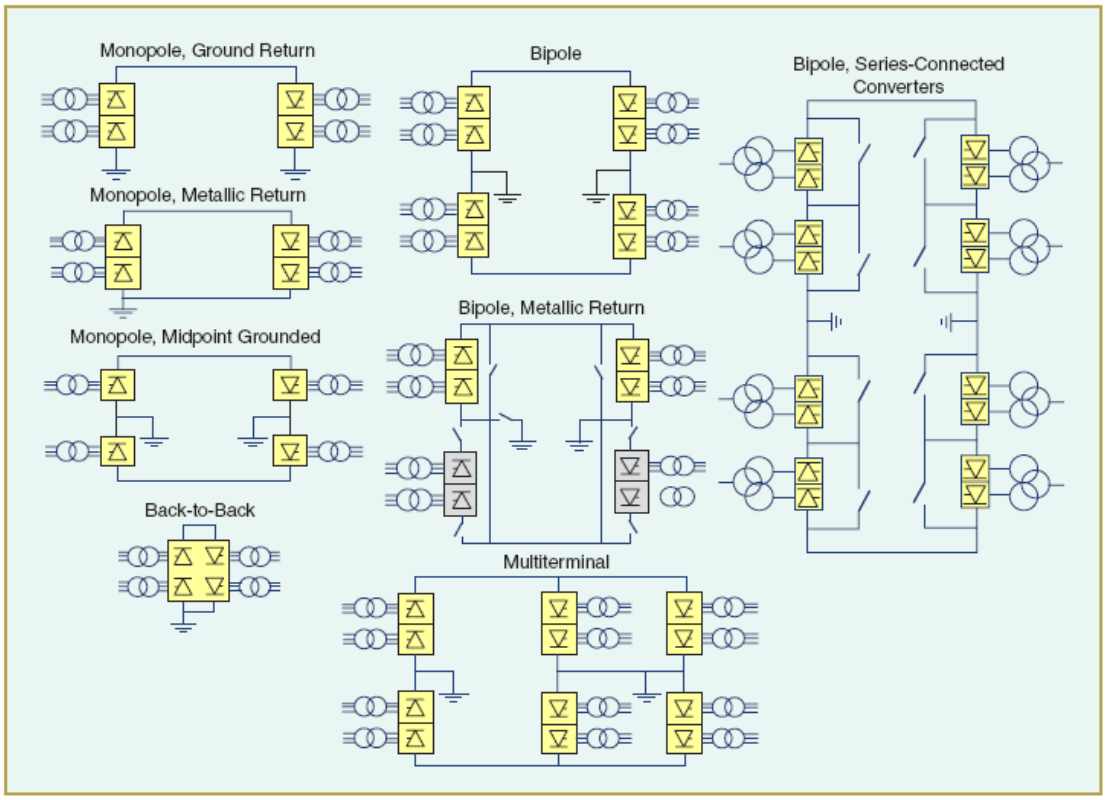
- Because the voltage waveform is naturally much closer to a sinusoid:
  - Smaller, standard AC reactors can be used
  - Less or no AC harmonic filtering is required (reducing the footprint of the AC switchyard)
  - Standard AC step-up transformers can be used
- Almost twice the power transfer capability
- The AC fault ride through capability is enhanced with a more stable DC bus voltage.
- Having individual capacitors on each switching element and different switching elements for each branch allows operation with continuous voltage phase imbalance, and improves the ride through of unbalanced AC network faults.
- Maintaining a constant voltage drop across each of the switches is more straightforward, and greater inaccuracy in switching times can be tolerated.

IGBT switches also have application in FACTS devices.

HVDC Configurations

HVDC Systems can be configured in various ways, as illustrated in the following figure.

A single link is referred to as a ‘monopole’. As with all electrical circuits, a return path must be provided for the current. When a monopole is used, this return path can either take the form of a parallel metallic conductor or of earth electrodes at each terminal to pass the current through the ground or water. The recently constructed NorNed HVDC link between Norway and the Netherlands (580km, 700MW, +/- 450kW, LCC) was originally proposed as a monopole scheme with sea-electrodes for the return path. However, public concern about EMF, the electrolysis effect it may have on nearby marine infrastructure, the formation of (small quantities of) toxic gases at the electrodes, and the effect that altered magnetic fields may have on navigation of both humans and animals at sea, forced the use of a bipole scheme. Sea electrodes were still installed as a backup for temporary use should one of the conductors fail.



[10]

Two converters are often coupled together to form a bipole. By energizing the return current at the opposite voltage (i.e. same voltage magnitude but in the negative direction), it is possible to transfer power in the forwards direction. This enables twice the amount of power to be transferred for the same amount of conductor (if a metallic return conductor is needed), although it does mean that both conductors must be insulated. Earth electrodes are used to provide an earth reference, to carry any unbalance current, and to carry the return current should one of the conductors fail.

The recently constructed NorNed HVDC interconnector uses a 'simplified bipole' design, which uses only one set of transformers and has the same number of thyristors as a monopole, but they are distributed in six thyristor columns.

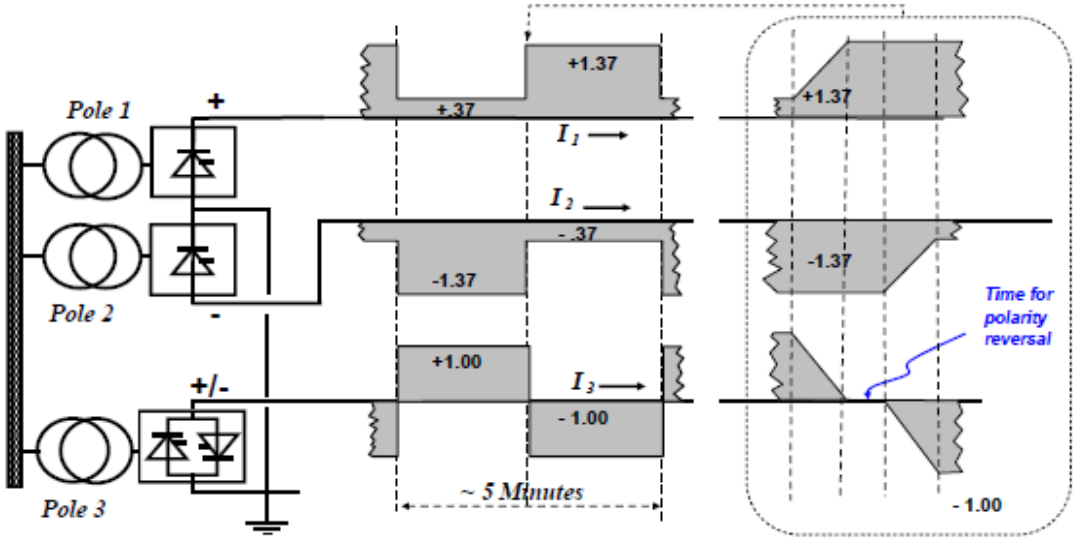
The recently approved Storebælt HVDC link will interconnect the two asynchronous regions in Denmark (600 MW, 400 kV, LCC). It will initially be constructed as a monopolar system but will use an insulated metallic return cable to enable the system to be expanded to a bipole system at a later date.

The use of multi-terminal HVDC schemes is theoretically possible when using VSC HVDC, although this is not yet available commercially. Significant research and development is being invested and many multi-terminal schemes are already proposed (including the UK's 2020

[10] IEEE Power & Energy Magazine March/April 2007 Vol. 5 No. 2

Transmission Network proposal). Please see the HVDC Networks section of this report for more details regarding multi-terminal HVDC networks.

One of the conference presentations was for the conceptual design of a tri-pole HVDC system which could utilise an existing AC line to increase its capacity by up to 70%. The tripole consists of a VSC bipole paralleled by a LCC monopole; both configured and operated to exploit the thermal rating of all three phase positions without causing earth return current. This involves the short term alternate overloading and underloading of circuits, as shown in the diagram below.



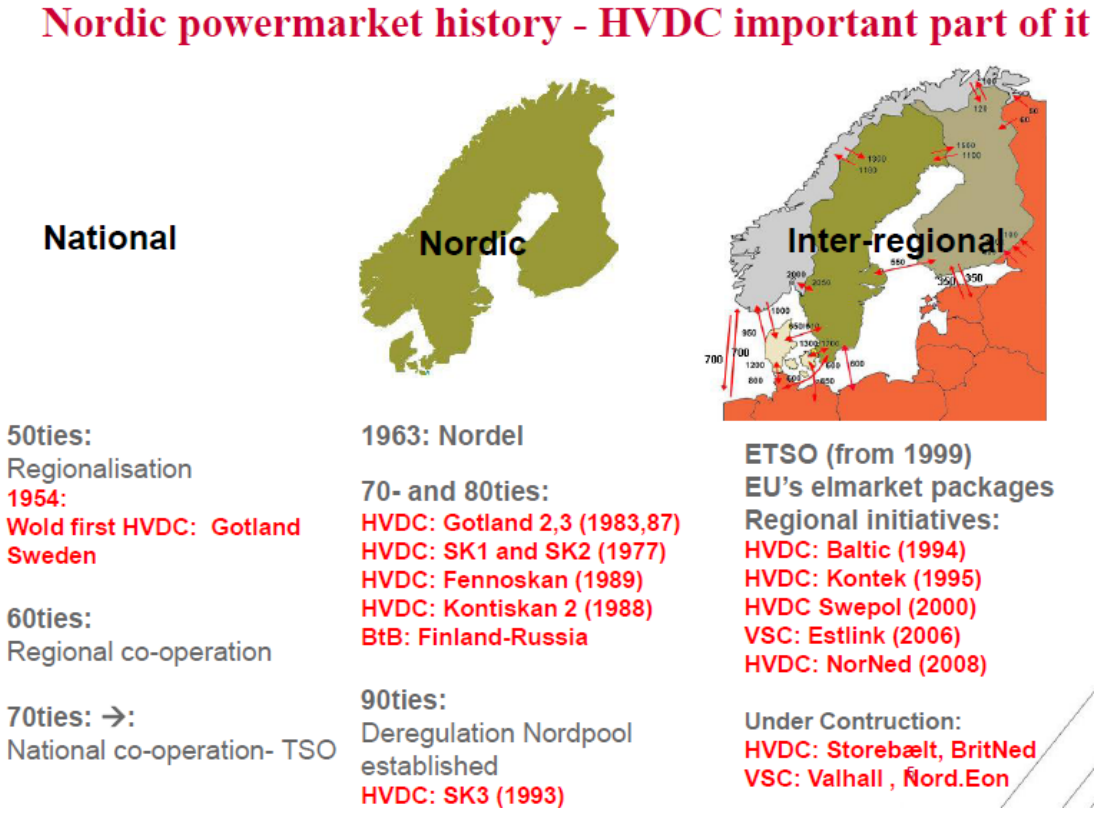
Simplified schematic of tripole operation at maximum loading

Recent International Experience with HVDC

Classical HVDC technology is quite mature with many years of service experience from about 100 installations worldwide, including overhead line and submarine cable schemes, and back to back schemes. Presently the total installed transfer capacity of LCC HVDC schemes in service is about 100 GW. LCC HVDC schemes with ratings up to 6400 MW, and voltages up to ±800 kV are either in service or under construction. In Australia, the 400kV 600MW Basslink interconnector and the 8.3kV 40MW Broken Hill back to back converter are based on classical HVDC.

The first commercial VSC HVDC scheme was commissioned in 1999. In 2009 there were seven schemes in service with a total rating of 894 MW. The largest of these was the ±150 kV, 350 MW Estlink scheme. A further five schemes with a combined capacity of 1678 MW were either under construction or are committed. These include voltages up to ±200 kV and capacities up to 500 MW. In Australia, both the 80kV 180MW Directlink and the 150kV 220MW Murraylink interconnectors are based on VSC HVDC.

Europe, particularly the Scandinavian countries have considerable experience with HVDC. The following slide outlines the various HVDC schemes which have been installed or are currently planned for the region.



The following sub-sections outline the benefits which have been gained and the difficulties which have been encountered (largely by the Scandinavian utilities) through using HVDC.

HVDC Benefits

Some of the benefits of HVDC are well known:

- Because a steady-state DC circuit has no shunt or series reactance, the losses in a DC circuit are considerably less than in an AC circuit, long cable circuits without mid-point reactive compensation (necessary for subsea links) are made possible, and the thermal rating of the circuit can be fully utilised with real power transfers.
- HVDC can be used to connect two asynchronous regions, and can stop the propagation of power fluctuations from one region to another.

However, the controllability of HVDC has other benefits, described below.

Controllable Power Transfer between Distant Nodes

An often overlooked benefit is the ability to control the magnitude and direction of power flow between two distant nodes, regardless of the voltage phase angle at each node. Several of the Transmission Network Operators (TNOs) at the conference cited this as a significant operational benefit, stating that it improved overall network controllability, improved the sharing of power reserves across regions and generally improved the performance of the market by effectively broadening the market and increasing competition. The value of this feature is maximized when an HVDC link couples two regions with different generation and demand profiles. It is likely that the value of this feature will increase as the proportion of renewable generation increases.

The recently constructed NorNed link, between Norway and the Netherlands highlights the value of this benefit. Norway's electricity is generated predominantly from hydro sources while the Netherlands is derived predominantly by fossil fuels. During 'wet' years, surplus hydro power will be exported from Norway to the Netherlands, displacing fossil fueled generators (and vice-versa). Transfer across the 700MW link has been such that the link has recouped almost one third of its €495M development cost in the first 9 months of its operation.

Damping Low Frequency Power Oscillations in Parallel AC Network

It is well known that when HVDC is used to interconnect two regions, in can act as a 'firewall' to power oscillations. However, the lower reliability of HVDC (compared to AC) often means that multiple HVDC links or a HVDC back-to-back installation which can be bypassed, is needed to provide an acceptable overall level of reliability. However, recent studies performed by the Chinese Southern Power Grid have shown that a HVDC link which is in parallel with an AC link can significantly dampen low frequency power oscillations across the AC link. A supplementary control function uses AC network phasor measurements to monitor for any AC network power oscillations and adjust the power transferred by the HVDC link away from the set point value to counteract the oscillations. Therefore, as well as providing additional transfer capability itself, a HVDC link could lessen small system stability constraints on the AC network, releasing additional capacity.

Coordination with AC System Protection

Power transfer across a HVDC link can be rapidly adjusted and could be programmed to respond to system contingencies to reduce their severity. For example, if a HVDC link was operating in parallel with an AC interconnector and the AC interconnector tripped, the HVDC link could very quickly increase its transfer (perhaps using its short term overload capability) to reduce the overloading of any parallel AC circuits and/or minimize any frequency deviations between two newly formed AC islands. This ability could release additional pre-contingent capacity in the AC network.

Black Start

Because VSC HVDC does not require any local reactive power or a certain fault level, it can be used to energise a dead bus. Provided one end of a VSC HVDC link is energized the link could be used to blackstart the AC network at the remote end. The power across the link could then be varied to maintain the nominal frequency, increasing the rate at which load and generation were brought back online.

The 150kV 350MW Estlink VSC HVDC link connects Finland and Estonia, and commenced operation in early 2007. In addition to voltage control, frequency control, reactive power control and damping control, the link also provides black start services to Estonia. The black start capability has been tested in practice and found to be a fast and reliable way of starting up a dead grid. Instead of starting with small units to power up bigger ones, the system can be restored in a matter of minutes from the Nordic power system (a different synchronous area). The link also helps to stabilize the system after the first units have been reconnected into the grid.

HVDC Downsides/Risks

The main disadvantages presently associated with HVDC technology are:

- high converter losses
- poor converter reliability
- high capital cost

Recent utility experience in each of these areas is outlined below.

Reliability

The failure rate of HVDC technology was cited by several of the TSOs present at the conference as a significant hurdle to its increased use. The failures tend to fall into two categories:

- comparatively frequent failures of the power converters or their control system, either causing no immediate forced outage or resolved within a day
- infrequent failure of the cables or transformers, leading to extended outages

Håkon Borgen, Executive Vice President of the Nordic TSO Statnett, summarised his company's recent experience by stating that "conventional HVDC technology has not delivered as required on quality in Scandinavia" in recent years. The NorNed HVDC link was installed towards the end of 2007. During commissioning the project encountered two subsea cable failures and a transformer failure. At least one of the cable failures is believed to have been due to a cable defect that was not detected during factory testing. Since commissioning there has been one 14 day outage due to the failure of a land cable, and several short outages due to problems with the control system and its SCADA interface.

The NorNed experience was said to be representative of the other Nordic cable interconnectors. Notably, the SK3 interconnector also faced severe transformer outages last year. Based on this experience, Statnett representatives stressed the importance of investing in spare transformers and long lead time components for the cable and converters. Over the longer term, Statnett has experienced nine cable repairs since 1976 with the three Skagerrak cables. The 18 repair joints have all survived until now. Single core cables were used in the deep subsea sections of the NorNed link to make any cable failures faster and easier to repair. Double core cables were used in the shallow subsea sections to reduce EMF.

The contract for the converter stations of the new Storebælt Link in Denmark guarantees an uptime of at least 98.5%, with a forced outage rate (FOR) of less than five outages per year.

In 2005, the Nordic oil company StatOilHydro installed an ABB VSC HVDC link to their Troll A offshore platform to supply new variably frequency drives on the platform. StatOilHydro have been very happy with performance of the link, but helpfully provided a list of all of the faults encountered in the previous year:

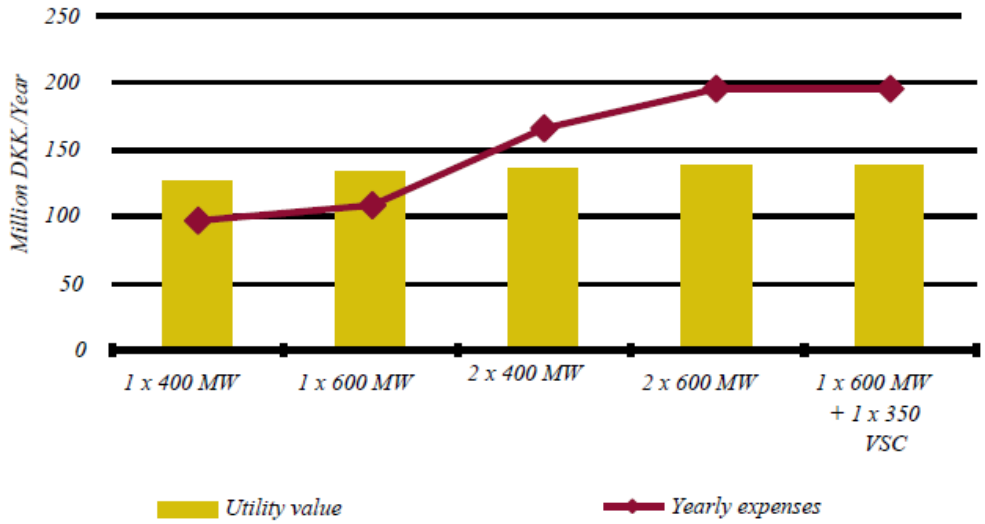
- Hard disc failure in the operator workstation computers at both ends of the link. The discs were changed under warranty.
- Weld leakage on a Swedewater cooling system pipe. Water leaked into the temperature transmitter for the cooling system which raised an alarm.
- 25 IGBTs failed and needed to be replaced. Often this was due to a loose fibre plug.
- Several control system printed circuit board failures. 8-10 cards were changed.
- Several software related failures, including:
    - Cases where the Operator Work Station became “locked” and required a hard reset.
    - Cases where the screen has “locked” (lilac icons on duty/stand-by systems) requiring the Intouch program to be reset.
    - Frozen alarm lists, necessitating a hard or soft reset.

StatOilHydro hastened to add that because of redundancy built into the system, most of these failures did not lead to a forced outage of the entire scheme. Additionally, software upgrades were reducing the frequency of software failures.

Capital Cost

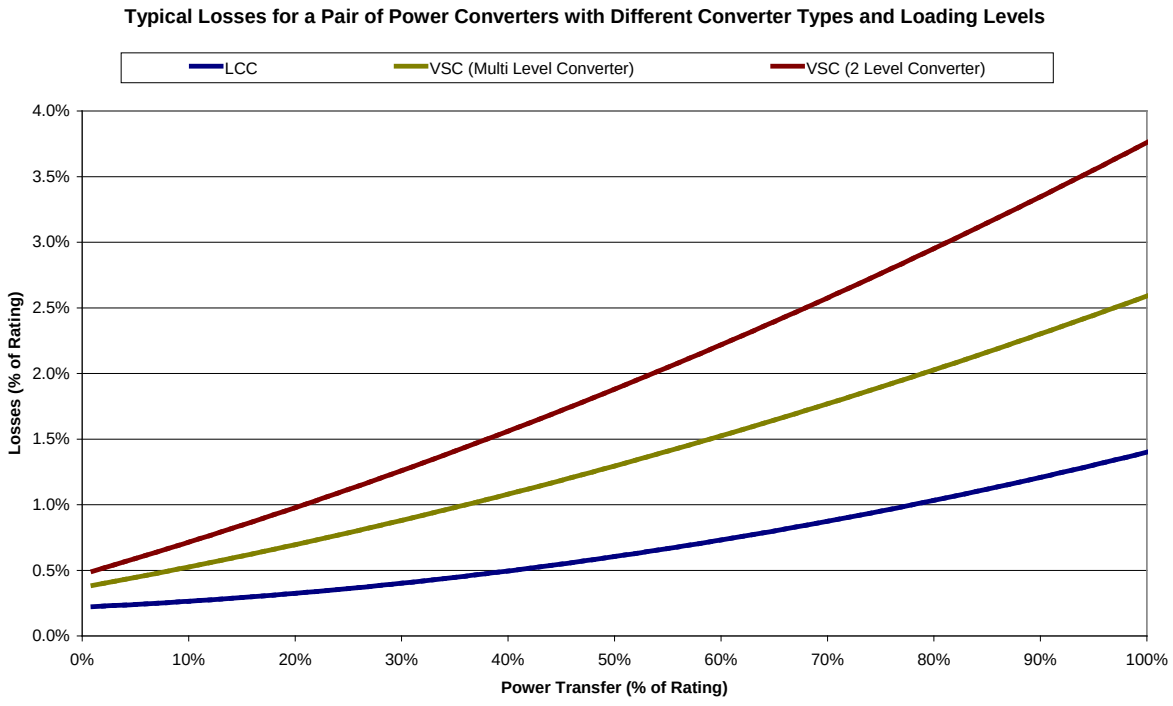
HVDC links can cost a very considerable amount of money. The development of the 700MW LCC 580km NorNed subsea interconnector cost €495 million. The cost was shared equally between Nordic TSO Statnett and Dutch TSO TenneT.

The cost of a HVDC link is highly dependent on different design options. Therefore, a thorough cost-benefit analysis is needed to consider utilization and the cost of construction, maintenance, repair, outages, and losses associated with different design options. The results of such a study for the Danish Storebælt Link are presented in the following figure. It can be seen that some design options are economically viable while others are not.



Losses

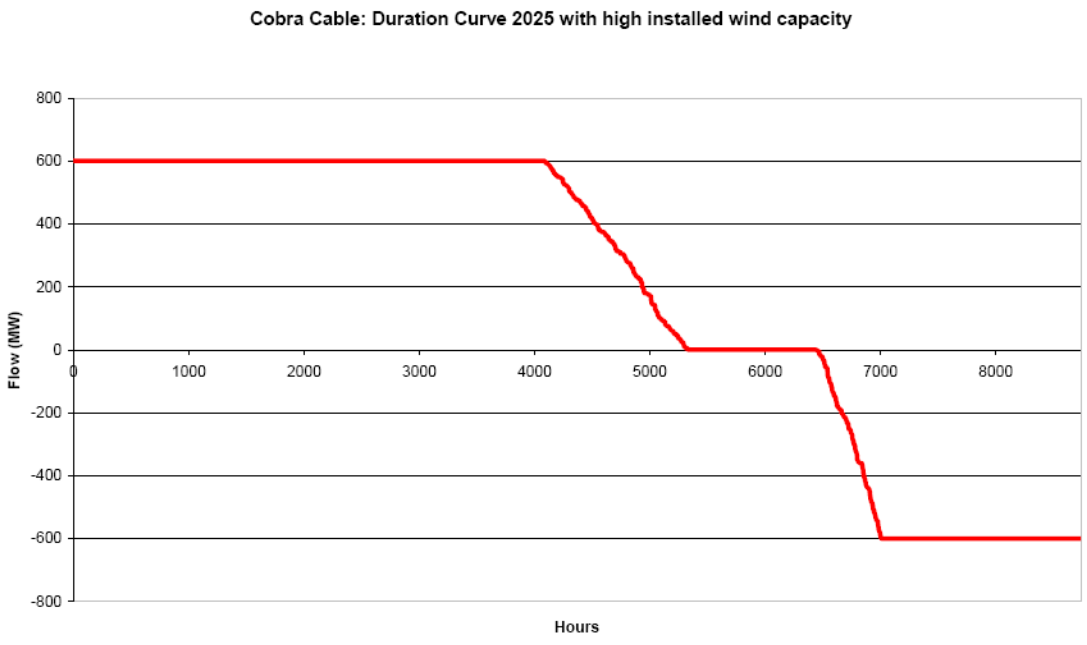
Transmission losses result from AC/DC conversion losses in the converters and from resistive losses in the DC conductors. Because a DC circuit is impeded only by the resistance of a conductor and not its reactance, the conductive losses are lower than AC transmission at the same voltage. However, the losses incurred in the conversion of electricity can be significant. Typical conversion losses are shown in the figure below.

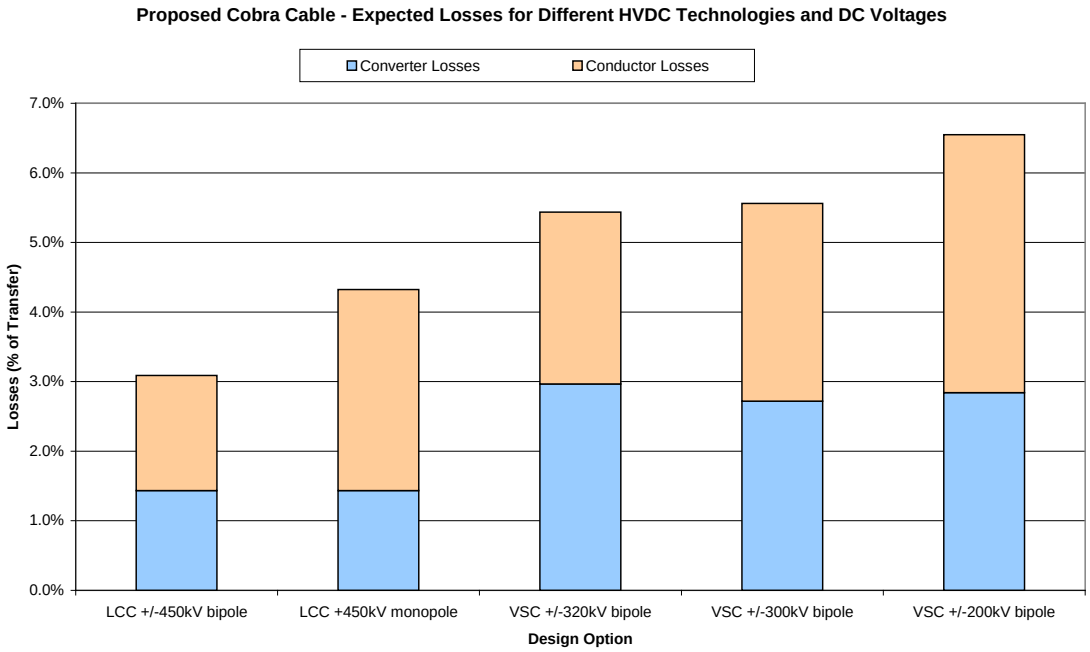


VSC converter losses are higher than for LCC HVDC primarily because the IGBT has a higher conduction loss than a thyristor, and a considerable power loss is incurred during turnoff of the IGBT. Recent development of VSC HVDC technology has focused strongly on the reduction of the power loss. Multilevel VSC converters can be seen to have significantly lower losses than two level VSC converters. The actual losses will depend on the configuration of the link, the type of the converter, and the DC voltage chosen.

The recently constructed NorNed interconnector (LCC, simplified bipole, +/- 450kV, 580km, 700MW) achieves losses of 4.2 % at full power transfer, which is very low for a 580km link.

Detailed loss studies have recently been conducted for the proposed 'Cobra Cable' subsea interconnector between Denmark and the Netherlands. With an expected transfer duration curve as shown in the figure below, the level of losses were calculated for different converter types and DC voltages, as shown in following figure.





Given that VSC converter technology is changing rapidly, loss estimates may need to be recalculated during the planning process.

Planning Issues

Multi-Infeed Considerations

A LCC power converter is dependent upon a sufficiently 'strong' AC system voltage present at its terminals for the thyristors to commutate at the end of each cycle. If the fault level were to become too low, commutation failure could occur and the transfer of power across the HVDC link could be interrupted. Where there are multiple LCC HVDC systems in a region, care must be taken to ensure that the fault level will remain high enough following the loss of any one of the links to prevent the cascading failure of the remaining HVDC links.

Subsynchronous Damping

HVDC converters have been known to reduce the damping of subsynchronous torsional modes of nearby generator units. Whether this has the potential to lead to inadequately damped oscillations should be studied, and if necessary, subsynchronous oscillation (SSO) countermeasures should be used. SSO countermeasures can take the form of subsynchronous damping controllers (SSDC) incorporated into the HVDC link's control scheme, and/or relays to trip the HVDC link should SSO exceed an acceptable level. It may be possible to develop a

controller or relay that utilizes only local signals, although a recent study conducted for the Fenno-Skan HVDC link in Finland found it was necessary to draw on signals from an external torsional monitoring scheme to work effectively. The torsional monitoring scheme in turn draws on measurements from around the network. Because field testing to verify study findings is not possible, disturbance recording should be incorporated into any torsional monitoring scheme to capture any incidents and help refine the models and improve the effectiveness of SSO countermeasures. It may be necessary to reassess the effectiveness of SSO countermeasures following the connection of new generators or changes to the network.

Project Delivery

NorNed was put into commercial operation on 6 May 2008 after several years of planning and three years of intensive detailed engineering and construction work. NorNed's implementation has been based on seven major independent contracts (one converter contract, one civil construction contract in the Netherlands, two in Norway, two cable supply contracts and one cable installation contract). TenneT and Statnett have taken the resulting interface risk. The contractors have been co-insured under TenneT's and Statnett's construction all risk insurance specially arranged for NorNed. With the mishaps (2 cable failures and a transformer failure) and challenges that were encountered, a contract arrangement more akin to a turnkey structure would easily have created more delay caused by risk aversion. The split in two cable contracts was mainly caused by a maximum 3 year project implementation requirement (cash flow), and the significant time required to manufacture long lengths of cable. This has added to the interface complexity to a degree.

Separating responsibility for cable delivery and installation has led to unresolved liability discussions regarding the cable failures. Therefore it should perhaps be considered whether specific cable field handling limits should be specified by the manufacturer. Both cable manufacturers for NorNed ended up performing a number of repairs to the cable due to mishaps in their factories. It is important to establish a system for inspections and handling of non-conformities in order to maintain full product quality. It is also important to arrange sufficient float in the scheduling to allow for delays caused by the repair of non-conformities.

HVDC Networks

The development of a European 'Supergrid' has been much talked about in recent years. The proposal makes extensive use of multi-terminal HVDC links to interconnect regional AC networks and vast offshore wind farms. With public opposition to onshore wind farms increasing, many of the TSOs present at the conference stated that their governments were

pressuring them to immediately commence development of a supergrid. The disparity between the present capabilities of HVDC and what was needed to develop such a grid became a significant discussion point throughout the conference.

Most HVDC links have only two terminals (i.e. they are point to point), however, two three-terminal HVDC systems do presently exist: the SACOI (Sardinia- Cosrica- Italy) project constructed in 1965 (LCC, 200kV, 200MW), and replaced in 1992 (LCC, 200kV, 300MW) and the Quebec- New England scheme (LCC, 450kV, 2000MW) constructed in 1991. The latter was originally proposed as a five terminal scheme, but the two smallest terminals were later removed from the scheme as disturbances in the ac local network might have caused disturbances in the main transmission of dc power.

In LCC HVDC the DC current can only flow in one direction. To change the power direction requires changing the link's polarity. This is not a problem with two terminals, but becomes more problematic with multi- terminal schemes. VSC HVDC can allow current in both directions and there is no need to change the polarity when the direction of power is changed. This makes building a multi-terminal system with VSC easier than with LCC. Additionally, VSC HVDC does not suffer from commutation failures and is therefore more immune to disturbances in the ac grid.

As well as making multi-terminal links easier, VSC HVDC makes the prospect of meshed HVDC networks closer to being possible. An interconnected HVDC network could offer significant advantages over multiple discrete HVDC links, including:

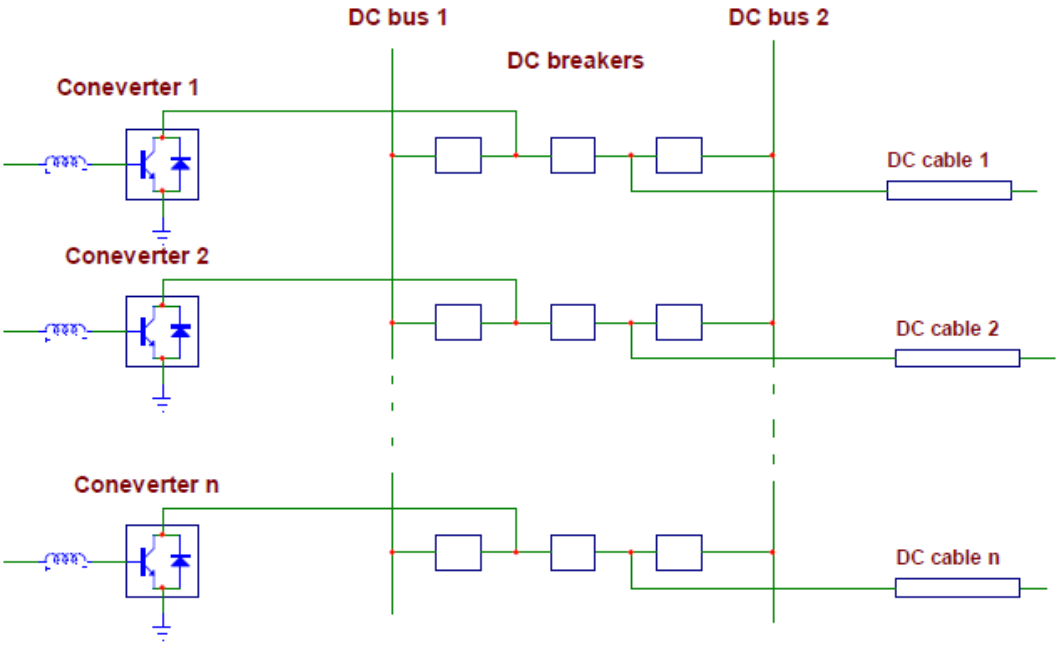
- Improved reliability at a lower cost through shared redundancy (just like a meshed AC network)
- Lower losses, as converter losses would only be incurred at the entry and exit points of the network.

These benefits would be gained at the cost of some controllability. While the power flowing into and out of the network could be controlled by the power converters, like an AC network, the distribution of current between parallel circuits would be inversely proportional to the resistance of each circuit.

Protecting an interconnected HVDC network would be much more complicated than protecting an AC network. Because a DC network does not have any reactance (only resistance), during a fault the fault currents flowing through the network could rise very quickly to very high levels and the network voltage would fall much lower and over a wider area. Suitable protection relays and circuit breakers do not presently exist. The requirements for DC circuit breakers differ from conventional AC breakers on at least two important parameters: they will have to break DC (with no zero crossing), and they will have to operate

much faster. Given the severe consequences of losing an entire HVDC network, protection would need to work very reliably.

Provided protection issues can be overcome, HVDC networks could be constructed in a similar fashion as HVAC networks. An HVDC switchyard would look very much the same as an HVAC switchyard. The figure below illustrates a breaker-and-a-half HVDC switchyard.



To date standardisation has not been a significant issue for HVDC as links have been designed and operated independently. However, the development of an integrated network makes standardization very important. A network will inevitably have to be built in stages and with equipment from different suppliers. While different stages and sections will initially have no contact with each, they will eventually need to be interconnected to form a network. If some design aspects are not standardised such interconnection may not be possible. Issues that will need to be decided by utilities include voltage and capacity levels (i.e. functional issues). Issues that will need to be resolved by the equipment suppliers include protection and control protocols (implementation details). There was a consensus at the conference that an early discussion on standards was required and that the time for that discussion is probably now.

FACTS

Although the conference largely focused on HVDC, Siemens did spend some time explaining how multilevel VSC technology benefits FACTS devices, and there was a presentation by Statnett regarding two recently constructed SVCs.

Multilevel VSC in FACTS Devices

Multilevel VSC converters can also be used in FACTS applications. The VSC equivalent of a SVC is a STATCOM (although Siemens are referring their STATCOM offering as 'SVC Plus'). The main advantages over 'conventional' FACTS devices are:

- lower harmonic distortion, reducing or eliminating the need for harmonic filtering, reducing equipment footprint, and permitting standard modular designs using standard equipment
- the reactive power output capability varies in proportion to the voltage (rather than voltage squared), meaning that smaller devices can be used with the same effectiveness of supplying VARs following a contingency

Siemens has released a 'containerized' version of their SVC Plus product which consists of a ±50MVAr VSC converter and associated control equipment packed within a shipping container. To work, the converter needs to be connected to an external capacitor bank, reactor, transformer, cooling fan bank, and auxiliary power supply.

SVC with Bus Voltage

Statnett presented on its recent experience with the development of two new SVCs. Due to the stringent harmonic performance levels specified, the SVCs had to be designed with three thyristor controlled reactors (TCR) and three filter branches. The system voltage at one of the substations is currently 300 kV, but there are plans for a 420 kV voltage upgrade of the substation. Using a SVC transformer with a 420/300 kV re-connectable primary winding was considered but found to be too heavy to be transported to the substation. The SVC was therefore designed for a 420 kV grid connection, but was commissioned with a 300 kV grid connection. The SVC is expected to be operated with a 300 kV grid connection for 5-10 years until the substation is upgraded to 420 kV. While it is connected at 300kV, the SVC will have a reduced rating.

I later asked the presenter if the SVC was able to meet its harmonic limits at both voltage levels, and he confirmed that it could. This is significant because the LV bus voltage is often

selected to optimise the harmonic filter design, and it is the different LV bus voltage at each SVC which makes it necessary to have 'unique' equipment at each SVC. If using three TCR branches makes it is possible to have acceptable harmonic levels with a widely varying LV voltage, then it may be possible to develop a 'standard' SVC design, usable in several network locations. A common set of spare components could then be held.

The SVCs are equipped with one main circuit breaker, which is situated on the primary (high voltage) side of the step-down transformer. It is therefore not possible to obtain selective disconnection of an earth fault on the secondary side of the transformer, and the whole SVC must trip. Both SVCs are equipped with an Earth Fault Locator, which automatically identifies the earth fault location and commences operation at reduced capacity with the faulty branch disconnected. The method consists of an automatic re-close sequence to connect and energize each branch until the earth fault is located.

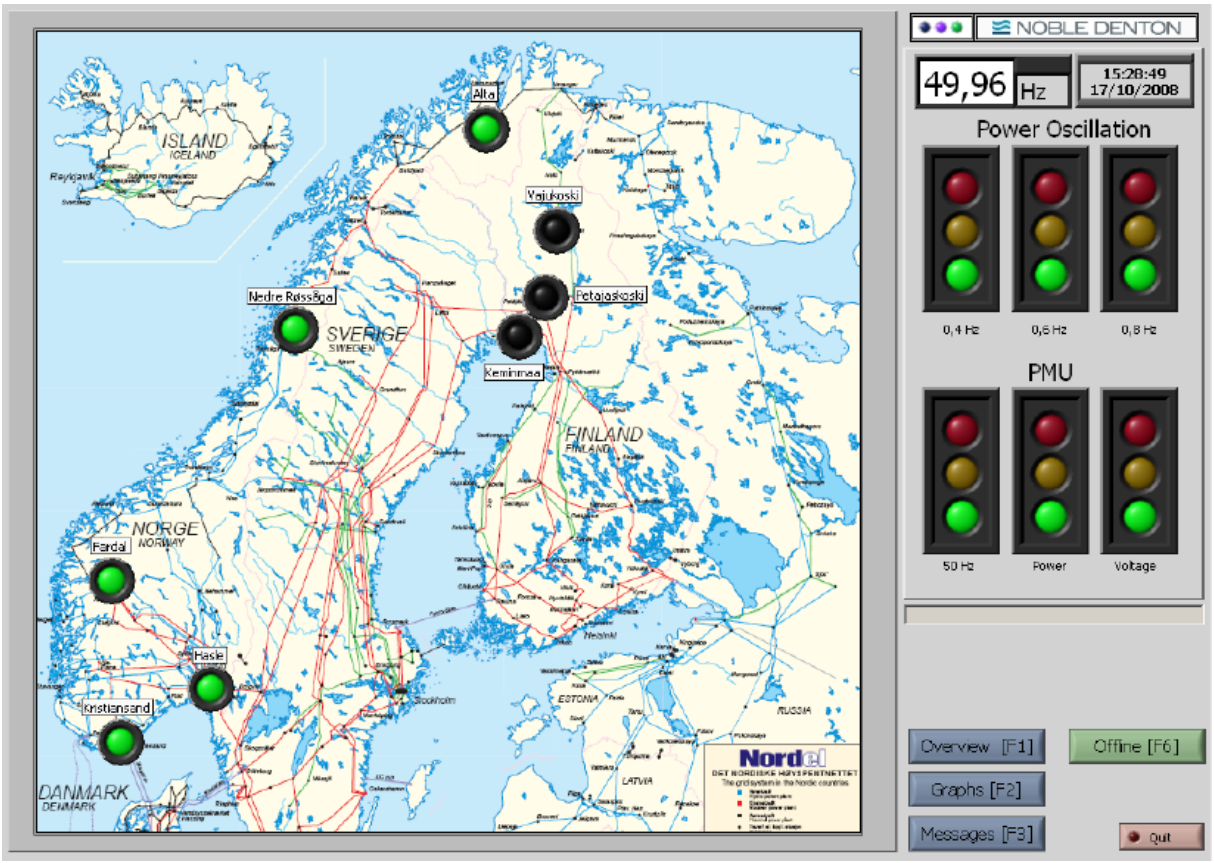
Wide Area Monitoring and Control

In an effort to securely increase utilization of their grid, Statnett are developing a wide area monitoring and control system for their network in collaboration with ABB and the research body Sintef.

The focus from 2005 to 2007 was to develop a wide area *monitoring* system (WAMS). The system collects high speed synchronized information from phasor measuring units distributed throughout the network and uses specially developed algorithms to very quickly identify the level of damping for each mode of oscillation, and monitor any actual oscillation. The system has been quite successful, providing the following benefits:

- More information about the power system state
- Early warning to the operators if a disturbances may cause operational challenges
- Improved data for analysis and verification of faults
- Improved measurements and data for validation of simulation models for the power systems

A screenshot of the operator display is shown in the figure below.



Since 2008, the focus has shifted to developing a wide area power oscillation damper (WA POD) that uses information from the WAMS to control power system elements in a coordinated fashion and actively damp any power oscillations. PSSE simulation shows the WA POD to be quite effective. It will initially be interfaced with one of Statnett's SVCs. If successful, it could be interfaced with more elements. One possibility presently being investigated is interfacing with generator unit power system stabilizers. The system is capable of issuing controls within 10 and 150ms of a power system incident.

Implications for the Australian Power System

A role for HVDC?

Australia's renewable energy resources are spread around the country. Some are close to the major load centers, while others are very distant. Those renewable energy resources which are closest to the existing AC network will be utilized first. However, as the proportion of renewable generation increases, more diversity will be required to maintain a secure electricity supply: diversity in the types of energy sources, diversity of the location of energy sources (particularly for intermittent forms of renewable energy), and diversity in the demand (to reduce its overall variability). To realize this diversity and connect remote renewable generation, a significant amount of new transmission infrastructure will be needed.

The Australian power system has several regions with a strong concentration of generation, and several large load centers. The existing AC network has the greatest capacity between the areas of concentrated generation and the load centers. In order for renewable generation to produce energy, existing generation must be partly displaced for at least some of the time. The generation most likely to be displaced is the thermal generation with strong connections to the load centers. As the proportion of intermittent renewable generation increases, I expect that the use of energy-limited hydro generation is likely to become more strategic (i.e. making up any generation shortfall rather than base load operation). To facilitate this, the capacity of transmission connections to the Snowy Mountains and Tasmania may need to be increased.

Developing high capacity interconnectors between the existing and new generation nodes would allow bulk power to be moved around the country from where it is available to where it is needed, and would allow the existing AC infrastructure to continue to transport the power into each load centre. Such high capacity interconnection could be provided by very high voltage AC links (as in the 500kV NEMLink proposal). However, the small number of nodes and the very long distances involved and mean that multi-terminal HVDC or interconnected HVDC technology could be an attractive alternative, since:

- The overall losses could be far smaller with HVDC than HVAC transmission.
- It could be more cost effective. Over such long distances, the cost of the actual transmission line would be a high proportion of the overall scheme cost. HVDC could provide greater transfer capacity for the same investment in transmission lines. The additional cost of the converter stations would be offset by not needing mid-point substations to correct the power factor and voltage.
- The additional controllability of HVDC could improve the manageability of the power system and therefore improve security of supply.

- These benefits could be realized without having to change existing generator connections. With HVAC networks, the value of a higher voltage level is only fully realized if generation connects directly to that higher voltage.

At present, HVDC technology's level of reliability means that it would be unwise to rely on it exclusively. It is likely that reliability levels will improve as research and development continues. However, because of the additional complexity inherent in HVDC equipment, AC equipment is always likely to be more reliable. Therefore, I believe that there is still a role for a parallel AC transmission network: to transfer power in parallel with the HVDC network, to connect generation & loads along its route, and to provide a base level of reliability. A parallel HVDC network could assist the AC network by:

- Improving small signal stability by damping oscillations in the AC network,
- Enhancing controllability through quickly changing transfer levels following AC network contingencies, and
- Subsequently increasing the secure transfer capacity of the AC network.

Because of the reliability risks with new technology, I do not believe that Australia should be an 'early adopter' of interconnected HVDC networks. Given Europe's shorter distances, greater network redundancy and closer proximity to the equipment suppliers, I believe that European TSOs are better positioned to lead the market. Many European governments have already expressed their eagerness to roll out the technology as soon as it is available. Elsewhere, China is presently in the process of installing several very high capacity LCC HVDC links, to be operated in parallel with their AC network. Australia should monitor and learn from the European and Chinese roll out of HVDC technology before committing to its own significant rollout.

However, I do believe that there is value in discussing the possibilities of HVDC and developing a high level plan of how the Australian system should be developed – using either HVAC or HVDC technology. Developing such a plan is likely to take several years, and implementing the plans will take much longer. Australia is unlikely to be able to meet its emission reduction targets if it waits to observe overseas experience before it commences planning. Having an overall plan is important, as the network development is likely to be delivered in stages over a period of time by different parties. Having a long-term plan will help to ensure that all of the constituent parts will act as a unified system, which is particularly important if a HVDC network is to be used.

Over the page, I have sketched a very high level conceptual HVDC network that is consistent with the reasoning I have explained above. It is my hope that this report and the sketch might provoke some more discussion about the potential role of HVDC in Australia, and more generally, about how the transmission network should be developed to most effectively facilitate the required levels of renewable generation.

Existing Network:

Major Load Centre

Thermal Generation Node

Hydro Generation Node

Strong HVAC Transmission Path (500kV or 4+ 275/330kV circuits)

Intermediate HVAC Transmission Path (2 to 3 275/330kV circuits)

Existing HVDC Connection

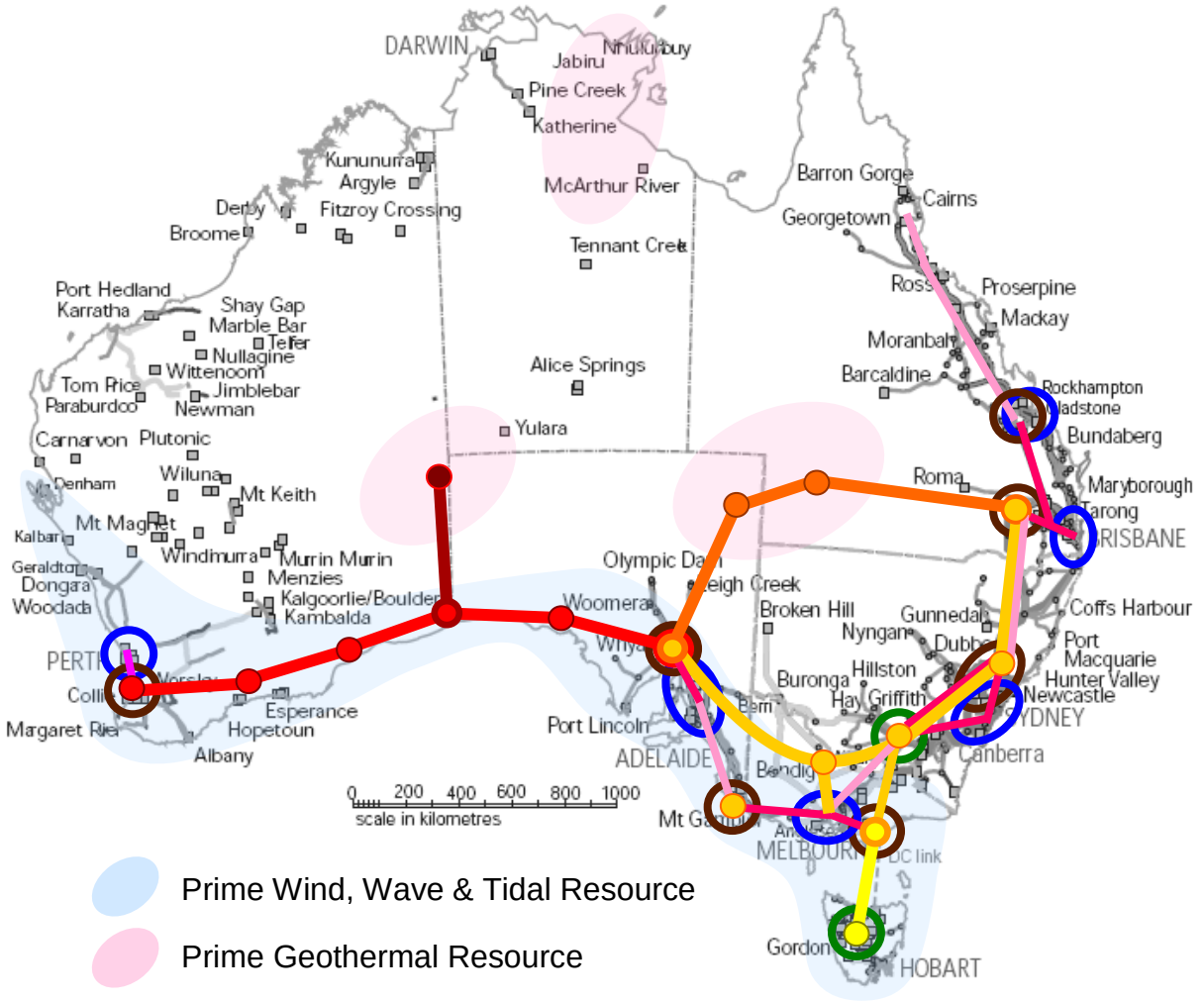
Conceptual Future Network:

1) NEMLink 500kV AC Network Concept or HVDC equivalent, providing improved coupling of generation throughout the NEM

2) HVDC Connection to Geothermal Resource, Additional Renewable Energy Transfer from South Australia into Queensland and Parallel Operation with AC Network to improve its stability and hence its capacity

3) HVDC Connection to Wind & Wave Resource and Improved Load Diversity

4) HVDC Connection to Additional Geothermal Resource



Prime Wind, Wave & Tidal Resource

Prime Geothermal Resource

FACTS Equipment Improvements

Australia is already a keen user of FACTS equipment, and this is only likely to increase as the proportion of intermittent generation increases. At present, each FACTS installation is unique. I believe that there may be scope for more standardization of FACTS installations. Standardization could allow Transmission Network Service Providers (TNSPs) to reduce the total cost of ownership by holding less spares overall, requiring less training for field personnel, and shorter outages following a significant failure by having a more comprehensive set of spares.

Additionally, given the penalties applied to TNSPs for outages and the length of time it can take to repair damaged FACTS devices, it may be cost effective to specify that future SVCs include fault locating equipment and control systems that can operate the SVC (albeit at reduced output) with a faulted limb removed from service.

Wide Area Monitoring and Control

Given the high cost of transmission infrastructure in Australia (due to the long distances needing to be covered) Australia has more to gain from the improved utilization of its existing infrastructure than many other countries. Given that small signal stability is significant issue within the NEM, a Wide Area Monitoring System (WAMS) that could measure the level of damping being applied to each mode of oscillation and record any actual instances of oscillation could afford a better understanding of the secure transfer limit and enable the system to be operated closer to that limit.

Presently, several of Queensland's SVCs run a local power oscillation damper (POD). However, identifying a suitable local signal for each POD is not always possible. With a WAMS, it may be possible to develop a Wide Area POD that utilizes more SVCs (including those SVCs closest to the major load center and therefore the most effective) to improve the level of damping and increase the secure transfer limit.