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ELECTRIC POWER SYSTEM PLANNING WITH THE UNCERTAINTY OF WIND GENERATION

Working Group
C1.3

April 2006

cigré

Scope and Layout

This work was requested by CIGRE Study Committee C1 and sanctioned by the Technical Committee. The brief required the Working Party to consider the effects on power system planning of the uncertainties associated with wind-powered generation and like technologies. This has been interpreted to mean planning for the uncertainties in power serving and in technical performance of new technologies.

The Working Group considers that the main uncertainties which are introduced by wind generation are:

- uncertainty about the rate of installation of wind generation, and its location (see Section 2);
- uncertainty about the effects of the intermittent nature of wind generation (see Section 3);
- uncertainty about the technical characteristics of wind generation, and the interaction with the electricity system (see Section 4).

To set the background, Section 1 summarises the factors which are driving the expansion of renewable forms of generation, and wind generation in particular.

This Scope forms one of three works expected. The second is to deal with planning with uncertainty posed by the market in traditional generation. The third is to deal with planning with uncertainty around the use and development of interconnection.

The objective of the report is to support policy makers in their decision making with regards to wind energy and to be a reference for CIGRE Engineers.

The Working Group

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Summary

The Report deals with the uncertainty that faces system developers and operators resulting from the rapid increase in wind farms.
There are strong carbon abatement and fuel diversity drivers for increased penetration of wind farm power stations (see projection in Figure.1). So far, all predictions even from wind associations have fallen far below the outturn growth in installed wind farm capacity.

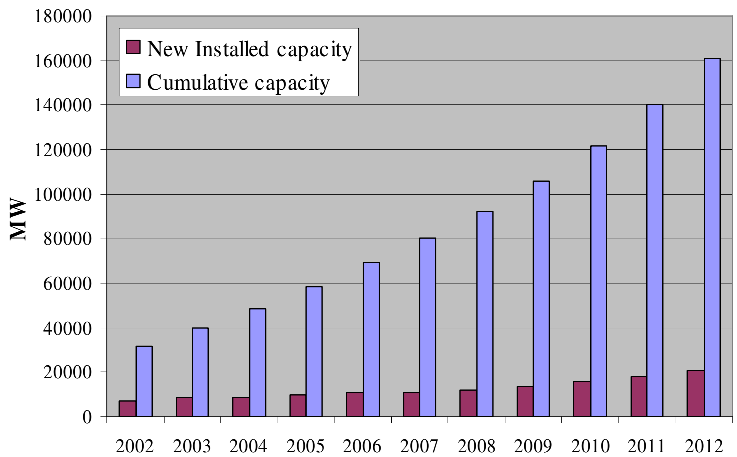


Figure 1 - EWEA[1] long term forecast for global wind power development

There are several Appendices to the report. One deals with administrative arrangements and incentives schemes to encourage wind generation. Another shows the wind farm penetration position in a number of countries and provides commentary on the issues facing these countries.

Individually, wind farm outputs are highly variable. Output variability needs to be balanced but it is uncertainty which terrifies System Operators. Variability is measured by the change in output over a fixed time interval and is expressed on a statistical basis. Uncertainty is the difference between forecasted output and outturn production.

Maintaining energy balance is a significant issue for systems with a high penetration of wind farms. In continental sized systems the problem is greatly reduced by geo-diversity of wind farm outputs.

Variability – Correlation of Wind Farm Outputs

One study by RISØ[2] has estimated that the output of wind farms a few hundred kilometres apart is correlated by about 80% whereas at 2500km apart the output is almost uncorrelated. Figure 2 shows the highly correlated output of three wind farms spread by about 40km on an island system. Figure 3 shows a number of wider spaced wind farms in the US. Studies in this subject are facilitated by well correlated data.

[1] European Wind Energy Association
[2] RISØ is National Laboratory under the Danish Ministry of Science Technology & Innovation

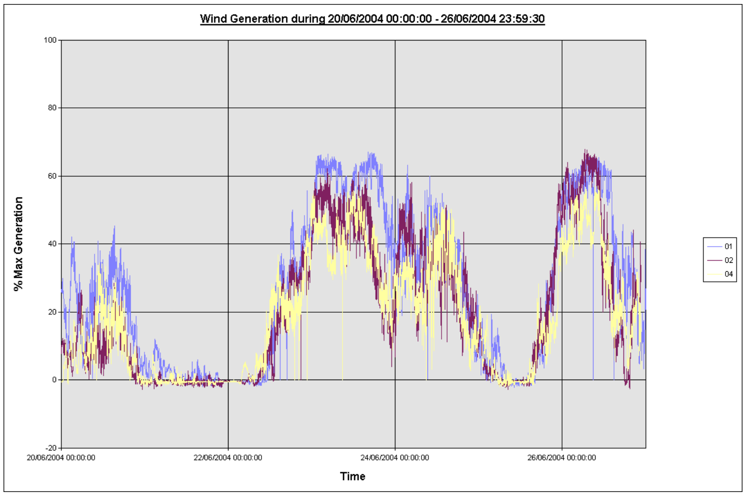


Figure 2 – Three Days Output of Three Wind Farms 40km Apart (Northern Ireland)

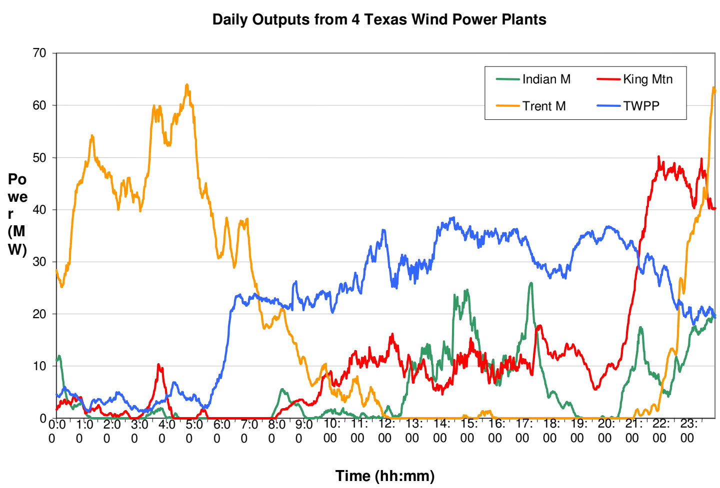


Figure 3 - Daily output of Four Wind Farms in Texas separated by between 40kM and 490km

Continental and Island Systems

Also on continental systems, wind farm output variability can be shared among many actors using interconnection. In some places eg US this use of interconnectors is moderated by financial penalties based upon area control errors.

On island systems the nature of the balancing resources is significant if wind power is to be accommodated without worsening security of supply. Hydro-generation, pumped storage and rapid start plant are all useful. In future, energy storage devices will play a part. It is important to study the variability from wind farms individually and system-wide to project the balancing requirements as penetration increases. Figure 4 is illustrative of the characteristics of wind variability. The vertical axis is a measure of confidence in output and the horizontal axis is in percentage of installed capacity.

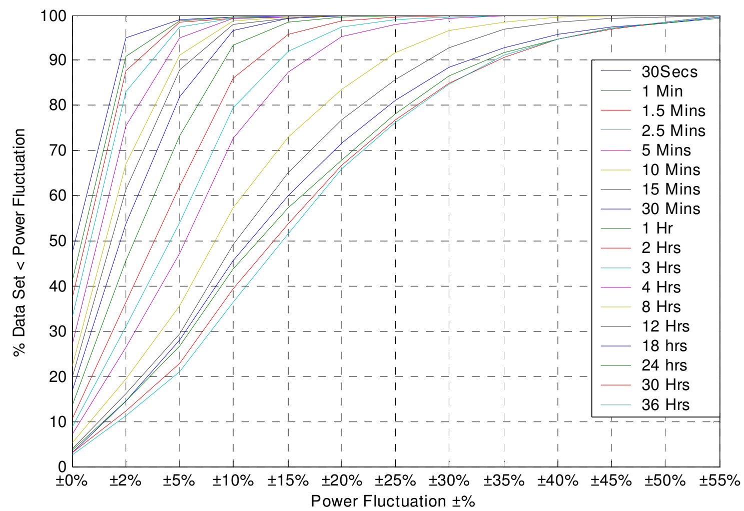


Figure 4 - Variability as a percentage of installed capacity for a small island system (150 days in summer)

Uncertainty in Wind Output

High quality forecasting and confidence in the forecast are necessary to aid management of balancing energy from traditional plant.

The present basis of forecasting systems is that the first hour is assumed to be about the same as the present output (persistence), the next period up to about 6 hours is managed on the basis of past trends, statistical variation and physical models. The longer periods (days) are managed using meteorological forecast data. The quality of meteorological forecasts is not yet good enough to allow accurate prediction on individual sites. Hybrid systems are being developed and meteorological forecasting accuracy is being improved by reducing the granularity of the forecast. Forecasts should be accompanied by confidence curves.

Management of extreme wind events requires study. It is necessary to separate these events from routine wind variability and manage the consequences in a different operational way. (Figure 5 shows a sudden loss of wind farm output).

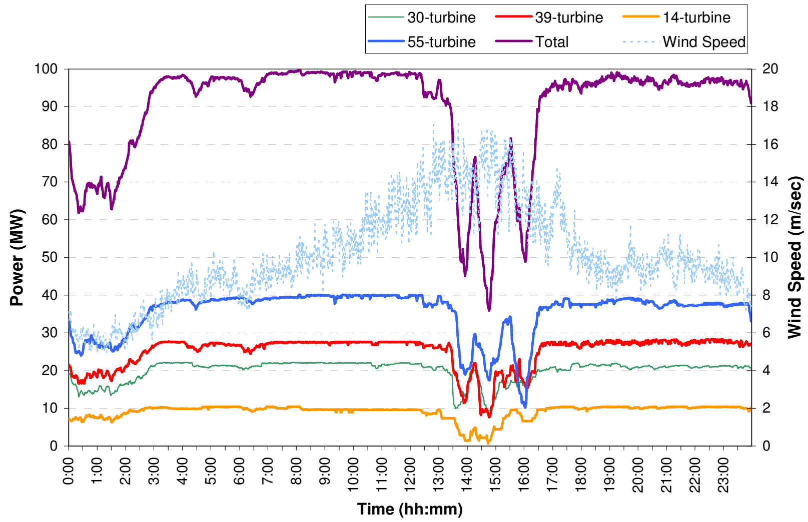


Figure 5 - (NREL Report) shows a rapid loss of output from a number of wind farms

In summary of the variability and uncertainty issues, high penetrations of wind farms are more easily accommodated on continental systems than islands. In continental systems the tendency is to use markets and interconnectors to achieve energy balance. The efficiency and security aspects of this policy need to be investigated. In many cases the load factor on interconnector links will be poor and flow volatility may pose risks. On island systems good forecast and balancing plant available in a range of sizes and timescales are critical resources.

Other Technical Uncertainties – Grid Code

The Report also considers the need to manage the technical uncertainties of high penetration of wind farms. It recommends placing Grid Code requirements on wind farms wishing to connect. The Grid Code requirements should reflect the needs of the system, but the following topics require attention:

- plant tolerance to voltage and frequency variation
- plant capability regards
  - tolerance to system faults and performance during and after faults
  - reactive power
  - active power management
  - power quality

- control capability to manage
  - power ramping up
  - response
  - voltage and power factor control

- Real time information and control including the provision of modelling information.

Importantly the Report recommends that wind farms must comply as real plant and not just as theoretical models. There is a requirement for accurate standardised dynamic modelling and for compliance testing.

In network development terms the Report suggests the need to review standards for connection and suggests that wind farm curtailment could be used to reduce backbone network development. It also lists a wide range of further work that is required.

The WG believe that the wind farm development environment is changing so rapidly that it will be necessary to update this Report in one year to 18 months time.

1. Introduction

The management of variability of wind energy takes place in the real time operating environment. Normally system planners consider developments, economics and standards with a lead time of years ahead. It is however a pre-requisite for planning with the uncertainty of wind energy to understand how and to what extent the system can be managed in real time with increased levels of variability in generation input. This report aims to address issues which many planners would see as closer to real time but which are nonetheless necessary to inform the planning process.

It sets a wide agenda for further work.

2. Overview of the Growth in Wind Power

Signatories to Kyoto protocol to control greenhouse gas emissions

The Kyoto Protocol was signed in 1997 by the parties to the United Nations Framework Convention on Climate Change. There were 38 signatories. The joining of approximately 55% of CO2 emission world wide are now to be regulated in 2004 means that this Agreement sets binding emissions reduction targets for developed countries (or groups of countries such as EU). The first commitment is for the period 2008 – 2012 when e.g. EU is to reduce the output of a basket of greenhouse gases by 5% below 1990 levels. Actions are required in energy, transport and industrial sectors. A Burden Sharing Agreement between EU member states was formed giving rise to the Renewable Energy performance requirements in Table 1.1. Each Member State has thus been set an individual stretching target.

European Legislation & Targets

The Agreement is implemented through a Renewable Energy Systems Directive which forces Member States to comply with the targets and creates a future community framework to meet the aim. To achieve legal compliance, each Member State was required to enact national legislation by Oct 2003. The legislation must cover a mechanism for establishing the origin of renewable energy, plant authorization procedures, access to networks and reporting by Member States.

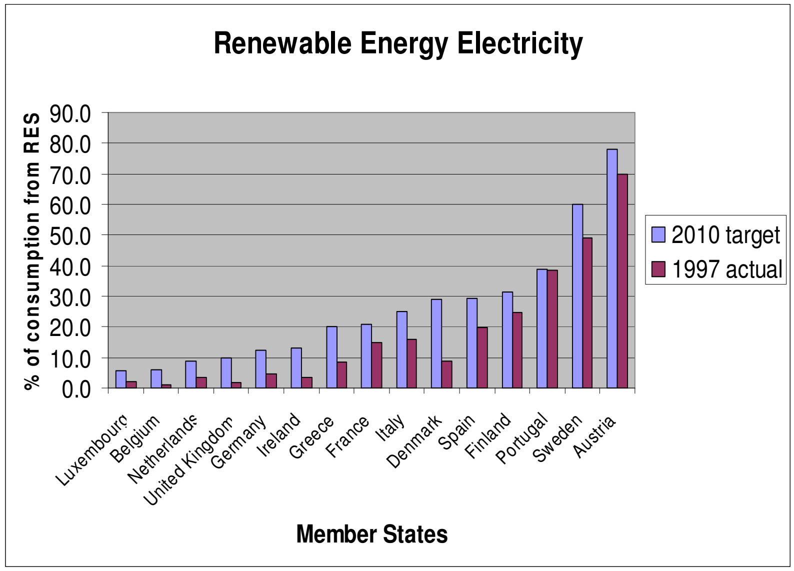


Figure 2.1 – European Renewable Energy Plan

Other parts of the Triad of nations may have approached their response in a less coordinated fashion, nonetheless, in many places the renewables development response will be as great as in parts of the European sector of the Triad.

History and scope of renewable technologies

The use of renewable technologies is not new, hydropower being among the oldest technologies and geothermal being well developed, but particularly wind generation technology and fuel cell technologies are fast developing. Other areas of renewable technological improvements and maturity involve ocean resources (i.e. tidal, wave and salinity gradient), biomass, forestry waste conversion and gasification techniques for graded municipal waste. There are continuing improvements in large and small scale direct and indirect solar energy conversion.

2.1 Drivers for Renewable Energy Source Development

The following points highlight the drivers for renewable energy source development worldwide;

Emissions Control on pollutants

- **Greenhouse Gases e.g. CO_2, NOx and SOx Emissions**

Politically, the issue is simple … Lower emission of greenhouse and noxious gases like (NOx and Sox) is a "good" and will be paid for. Power planners have to learn to manage with the uncertainties posed by less predictable and less well understood technologies and sources of energy.

Renewables have higher capital cost /MWh, but future may be different

- **Cost of Energy**

The capital cost/MWh of this energy can be very high, due to the technology being relatively new. Some can claim to match the installed cost of traditional generation/MW capacity, but instead of about 95% load factor for traditional generating plant, for wind the capital cost must be spread over say 25-40% load factor. As renewables plant becomes fully depreciated the total cost of a unit generated will be very low, there being no fuel cost. Most wind farms are unmanned sites.

Mandates help initial investment

- **Mandates/Incentives**

Initial incentives in the form of levies, green taxes, renewable certificates and/or market advantage are used in many countries to encourage development and help with the high cost of the renewable investment. The position in a number of countries can be found in Appendix 1.

Wind has no economic fuel risk

- **Fuel Price – Risk of change**

Investing in an energy project that is reliant on a particular fuel type can be risky. The price of the fuel can vary dramatically in both the short and long term. This variance, unless hedged will be felt directly by the plant operator, whereas with renewable energy there is no fuel cost-hence fuel price risk is eliminated.

Creates local employment

- **Economic Development (of a region)**

In under developed countries, the balance between high capital investment/MW and reduced energy costs may be off-set by local manufacture and construction of the equipment. Because labour rates are low this reduces the first-off cost.

2.2 Barriers to the Expansion of Wind Generation

The following section highlights the barriers that wind developers come up against when considering their investment.

Wind generation development constrained by the cost of transmission

- **Transmission Constraints**

In some cases, wind developers may avoid an area because they believe that a major network extension would be necessary, which would cost more than any single project could afford. This can be avoided if a 'shallow charging' or shared cost principle is adopted.

Environmental permissions can

- **Location**

restrain planners from trying to build for the future. Network development not proactive.

Siting decisions are taken by a wind project developer based on many factors. Wind resource is important, but other factors must be considered, such as the likelihood of gaining necessary permits, planning permission, the cost and timescale of network connection. It is usually possible to define areas where wind developments are likely, but it may not be possible to do so with sufficient accuracy to plan extensions to electricity networks. Network extension may therefore be carried out in reaction to requests for connection.

2.3 Rate of Expansion of Wind Power

Rate of wind development unpredictable

The rate of expansion of wind generation in a system operator's area is hard to predict, as it depends on many factors including price incentives, permitting risks, and the perceived 'bankability' of projects.

To provide some guidance, current forecasts for the expansion of wind generation are given here.

2.3.1 – Global Overview

2003 – 40GW
2008 – 95GW

Expansion greatest in Europe
America next

The global market for wind power is set to grow significantly from the current total of 40 GW (end 2003), with an expected 55 GW of new capacity being added over the next five years, to give a total of 95 GW by the end of 2008 (reference: BTM Consult ApS, *World Market Update 2003,* March 2004, ISBN 87-987788-5-4). The bulk of the expansion is expected in Europe, already the market leader, with the Americas making up a significant proportion of the remaining share. The AWEA is forecasting a total of 20,000 MW of wind capacity installed in the US by 2010, compared to 6,400 MW today. An increase in demand from Asia is expected, primarily led by Japan and India, and African demand is also expected to begin increasing in the next 5-10 years as a result of Egypt and Morocco's interest in renewable energy.

Global Forecast (EWEA)

A more general long term global forecast from the European Wind Energy Association (EWEA, *Wind energy - the facts*, February 2004) is shown below in Figure 2.3 based on a 15% average annual growth in cumulative capacity in the years between 2007 and 2012. This is lower than the average annual growth of 20.6% predicted in the years between 2002 and 2007 and represents the inability to continue to produce turbines at the required rate, and restrictions due to replacement rates for existing generation.

EWEA wind forecast

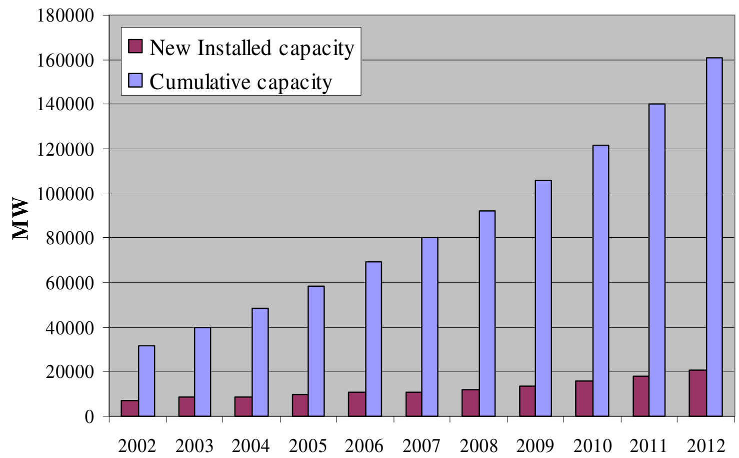


Figure 2.3 EWEA long term forecast for global wind power development

It is predicted that the current trend towards larger turbine manufacturing companies is set to continue with increasing participation in the market from established conventional energy companies.

2.3.2 – Specific Market Commentaries

Europe

Europe is predicted to retain the dominant share of the wind market in the near future. BTM Consult expects the European total of 29 GW (end 2003) to increase to 66 GW by end 2008. Major installations by the market leaders Germany (increase from 15 to 28 GW) and Spain (increase from 6 to 13 GW) are expected, along with increases in the emerging markets of the UK and France. Denmark, well known for its large share in the market, has already achieved 20% penetration. The energy agreement in the Folketinget (the Danish parliament) of March 2004 includes approx 750 MW more wind power within the next years. It includes two sections of offshore wind farms each of 200 MW to be in operation in 2008. It also covers a replacement scheme where the wind turbines up to 450kW can be replaced by double power. The upper limit is 350 MW. Growth in onshore installations in Germany is set to decline but will be supplemented by an expected boom in offshore development. In the UK, offshore, rather than onshore, wind may make up the bulk of the development over the next 5 years.

Canada & USA

The market in the US and Canada is set for significant growth in the next 5 years. The Canadian Wind Energy Association has announced an ambitious installation target of 10 GW by 2010 under their "10 x 10 plan". Despite the country's excellent wind resource, ability to cope with high wind penetration and large amounts of available space, this target may be hard to achieve due to limited availability of grid connections and the current legal framework. A tax credit scheme, similar to that implemented in the US, has been proposed to encourage development and this has produced high levels of interest in several states.

The US market is prone to large fluctuations in annual installed capacity due to repeated policy changes regarding the Production Tax Credit (PTC). The typically short term extensions to the PTC, combined with the knowledge that Congress has allowed the PTC to expire twice in recent years, is discouraging developers from long term investment in the country. If the PTC were to be given a long term extension of 7 or 10 years then it is likely that the US market would grow significantly more than is currently predicted. Despite the uncertainties regarding the PTC, however, a steady market growth of 1000+ MW per annum is expected from 2005 (see Figure 2.2). Presently the American Wind Energy Association (AWEA) has a target of 6% of electricity generation being achieved by wind power by 2020. This would require the industry to maintain an 18% annual growth in installations, to achieve 100,000 MW by 2020.

India

Other markets worth mentioning include India and Australia. After an initial 'rush' to install wind turbines in the mid-to-late 1990s, the Indian market has now reached a more slow and controlled state. The gross potential of wind energy in India has been estimated at 45 GW by the Ministry of Non-conventional Energy Sources and the present installed capacity of 2 GW leaves much room for development. Slow but steadily increasing growth is expected to take place here over the next few years with a projected new capacity of 2,800 MW being added by 2008.

Australia

Australia, like Canada, has an excellent wind resource and large amounts of unused land. Unfortunately, like Canada, grid connection issues and the fragmented nature of the grid as a whole may pose significant problems. Despite this, and the relatively modest level of current development, significant future projects representing several GW are planned.

Italy

The Italian electric sector after the liberalization

The Italian power system has progressively deregulated, under the new "Electric Law", the so-called Bersani Decree 79/99 of 31/03/1999.
The previous monopolistic Vertically Integrated Utility ENEL was unbundled.
The Demand Market has been opened to clients having consumptions > 0,1 GWh/yr in March 2003 and according to the new EU Directive 2003/54/EC of 26/6/2003, the liberalization *for the industrial and commercial consumers* took place since 1/7/2004. **The full opening** of the market to include, domestic clients included, is foreseen **by 1/7/2007.**

The Italian market (IPEX) began its operation on 31th, March 2004; the market is two-sided (supply & demand) since 1/1/2005. Italy has an Independent Regulator for Electricity and Gas.

The total Italian demand for 2004 was 325.3 TWh; the final sales, netted from T&D losses, were 304.5 TWh: 156.3 TWh (51 %) for the captive market and 148.2 TWh (49 %) to the free market (127.1 TWh + 21.1 TWh of self consumption).
Wind capacity installed at the end of 2004 was ***1265 MW*** and ***wind production 1.84 TWh***, with an **increase 2004/2003 of 26.7%.**

The target under EU "Renewable Directive" 2001/77/CE is to promote, by 2010, a renewable electricity production in the European Internal Market of 22.1% against a 1997 baseline of 13.9%.

Italy was given a very ambitions burden sharing : 25% of the demand by 2010 against a 1997 baseline of 16%.

The contribution of wind production is **expected to grow** from the present 1.8 TWh up to **5- 6 TWh by 2010.**

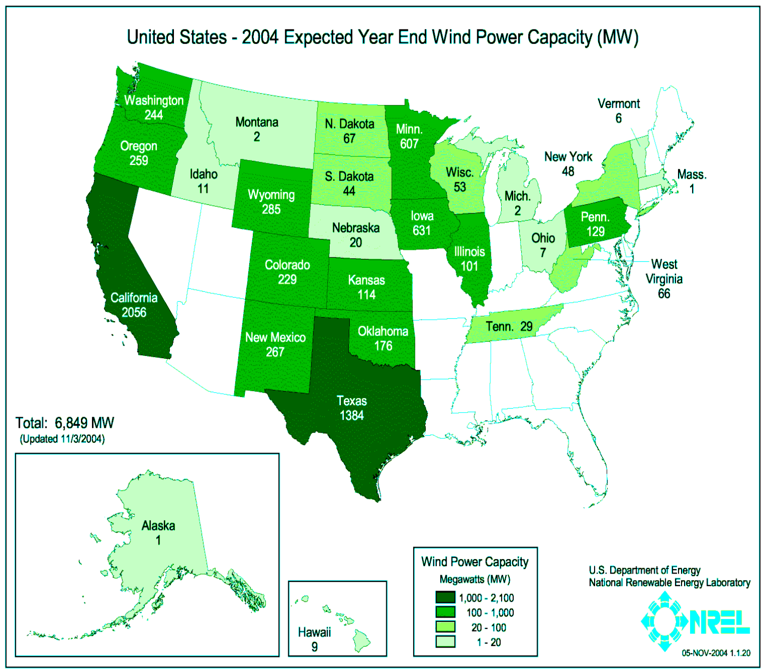
Presently the **major problems** for the wind source development are not the price paid to the Developers but the **capability of the grid**, which is not always sufficient to absorb the energy produced by the wind plants **extremely slow licensing procedures**.

Notwithstanding a "Framework Decree" (387/2003) ruling a simplified licensing procedure, that should allow the developers to obtain with a single administrative act the licence after a maximum of 180 days from the application, the average time by which a project is completed is more than three years. In some cases (eg Sardinia Island) Regional Laws put a moratorium to the construction, until the regional energy plans are not developed. Since there are no national standards, rules for building wind farms vary from Region to Region.

Offshore wind market to grow Projects up to 1200MW

2.3.3 – Offshore Development

Offshore generation is likely to take an increasingly larger share of the global wind market as the technology is further developed and suitable land based sites become scarcer. BTM Consult expect that 16% of the new capacity installed between 2004 and 2008 will be made up of offshore projects and that by 2008 offshore wind farms will make up 10% of the wind market. Major developments are expected in Germany, the UK, Spain, Belgium, Sweden and the Netherlands. There are plans for the construction of projects up to 1,200 MW in size.



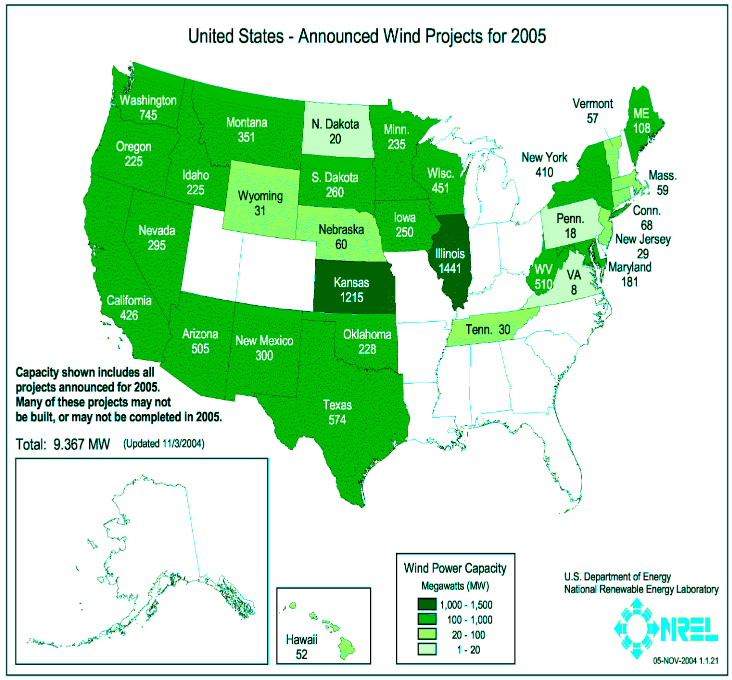


Figure 2.2 – 2004/05 Wind Installed Capacity

3. How To Manage Variability

P.S. Planners have a role in informing Stakeholders about the characteristics of variability

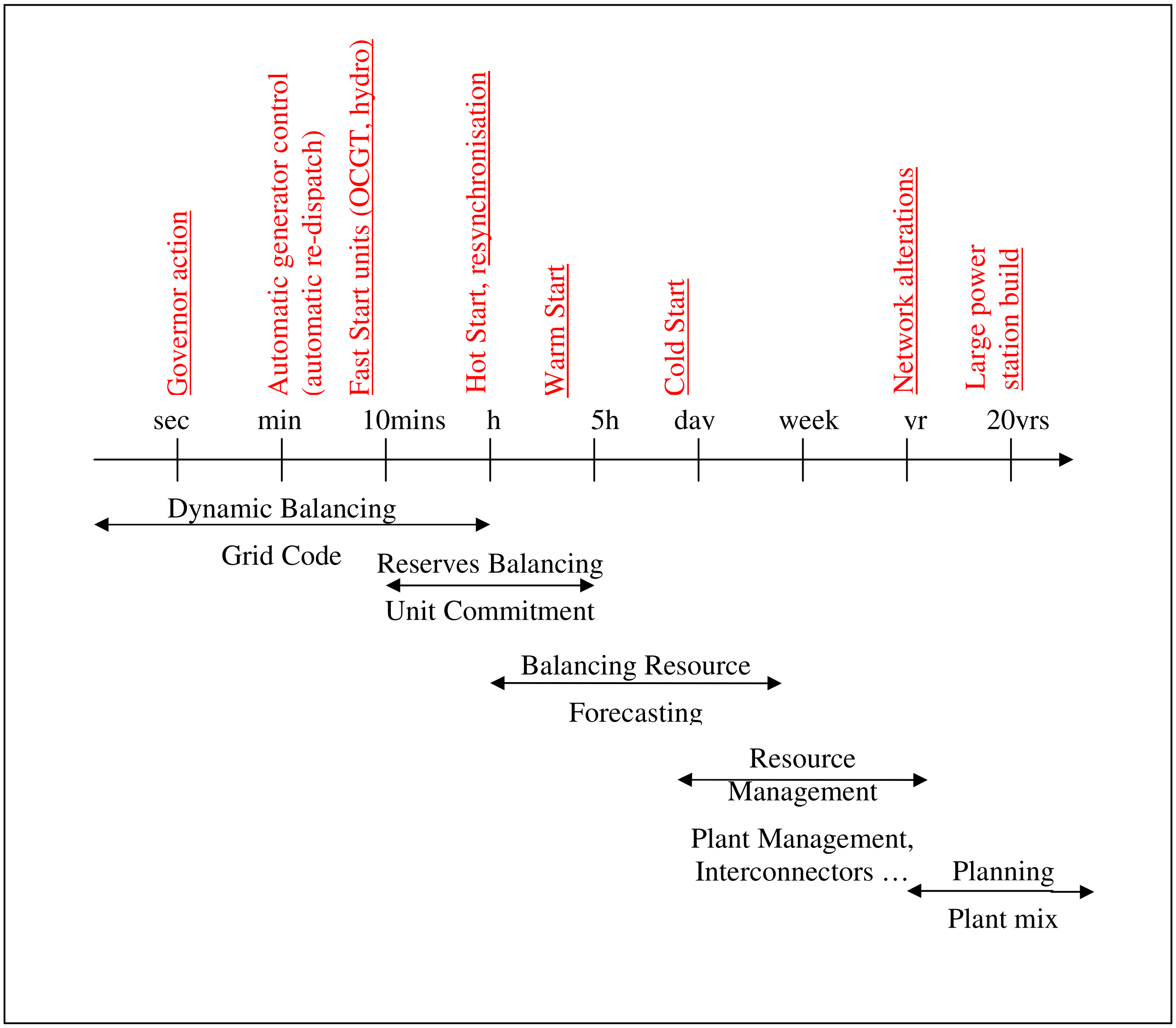
As wind farm power station penetration increases, a major uncertainty faced by both system planners and operators is the uncontrollable variability of Wind Energy Converters (WECs). Planners need to provide guidance and inform stakeholders of the role for traditional plant in managing increasing variability. Operators need to find ways of utilising existing resources to maintain the energy balance with increased uncertainty and to do so economically.

Study variability in different time frames

The Working Group considers that both planners and operators derive advantage by studying variability in different time frames. These time frames are chosen to relate to traditional plant capability. The pattern of variability will depend upon the characteristics of prevailing winds and where examples are given here they cannot be generalised, rather they are set down to help create a system of analysis.

System Energy Balance Required

Successful operation of an electrical power system requires continuously achieving a balance between generation output and system load plus losses. This delicate balance must be maintained over periods ranging from instantaneous to years ahead. Such a wide boundary encompasses machine and system transient response, automatic governor action, automatic generator control and re-dispatch, unit commitment, capacity procurement and infrastructure developments. The continuum is illustrated in the diagram below:



(Appendix 2 provides an outline of the characteristics of the balancing characteristics of traditional plant).

The Working Group has not found any harmony of definition in the terms used to describe the availability of energy production capacity in the various time periods. Appendix 6 shows some terms used by different organisations.

Traditional Balancing Resources

Balancing resources, include:

- Hydro & Pumped Hydro
- CCGT
- Traditional Thermal Plant and some Nuclear Plant has been adapted for load following duties since 1980's.
- Wind under curtailment (i.e. operating below its maximum available output)
- Demand Side Management (including in future hydrogen production plants)
- In future, newer technology energy storage devices will contribute, but they are still expensive and of modest size

3.1 0 to 10 Minute Period

3.1.1 Managing the Period

0-10 Minutes Self Managing

10 minutes has been selected as the end of the first period because after that time, reliance can be placed on rapid start plant. It is here assumed that the 0-10 minute period must be self-managing.

There are two processes within the period:

- Dynamic response
- Primary response

Dynamic response is an innate characteristic of the inertia or spinning mass of traditional plant and lasts for some seconds.

Primary response (or reserve) is available when plant is not fully utilized. The response is activated automatically.

Plant Performance is a Grid Code requirement

Plant performance in the 0-10 minute period is a Grid Code requirement, mostly encompassed in clauses related to response and control systems for active and reactive power. Section 4 gives guidance in relation to Grid Code provisions for WECs.

Geospread helps smooth outputs. As few as 3 wind farms saturate benefits

Recent unpublished work by the convenor et al and by UCD (Professor Mark O'Malley et al) based on recorded data has shown that benefits from geo-diversity saturate quickly in an island situation. As few as 3 geo-dispersed wind farms may achieve 90% of the geodiversity wind output averaging benefits. O'Malley says this can be achieved by about 150MW on a 5000MW system. Studies are required to determine the saturation characteristics of wider landmasses.
The following charts show plots of raw data for a number of wind farms in an island situation.

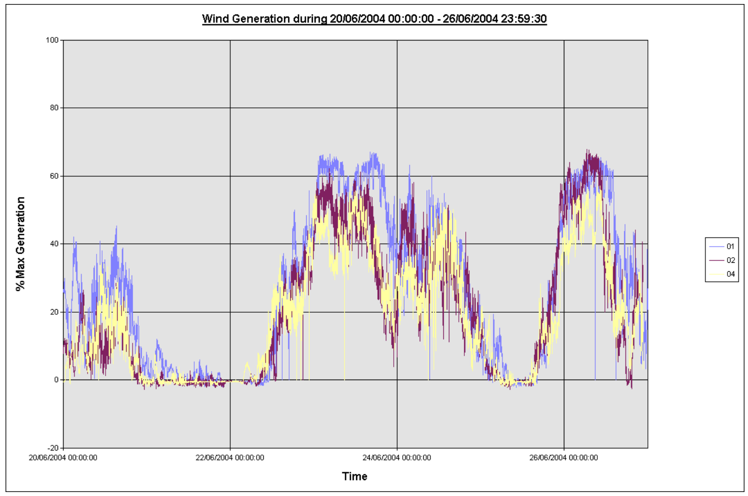


Figure 3.1 - Shows lack of geo-diversity on 3 wind farms circa 60km apart

The next chart gives some insight into the effects of geo-diversity for a larger land mass. The data is taken from an NREL report (Ref. 7) and presents monitoring results over a 24 hour period for four wind plants located in Texas, with the distances between them ranging from 40 km to 490 km.

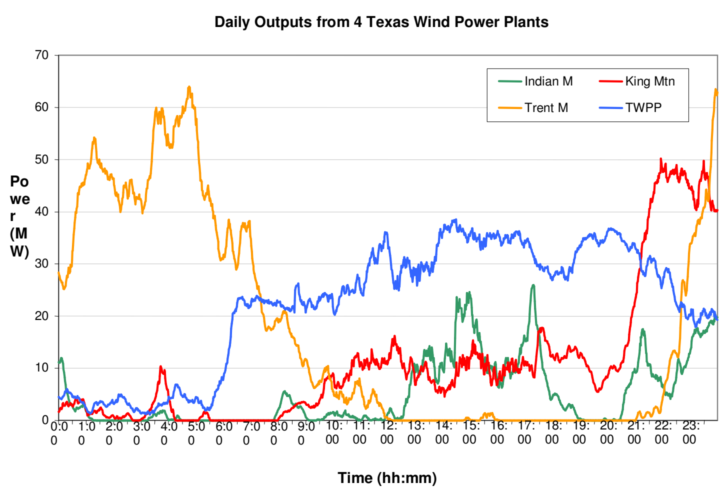


Figure 3.2 - Shows daily geo-diversity on 4 wind farms in Texas

The following table shows the monthly average value of the associated correlation coefficients among the four wind plants. It can be seen that the output of three of the four plants is more highly correlated than with the fourth, but there is still a fair degree of diversity among the four Texas wind plants.

Further analysis in the NREL report looks at the combined output of two wind plants on the Buffalo Ridge, approximately 1300 km from the

Texas wind plants, which had an hourly output of zero for 191 hours during a 12 month period. When combined with the Texas wind plants, the number of zero output hours was reduced to five for the same period. This analysis points out the value of geo-diversity, and the need for synchronized time series data for performing analyses of this type.

Average 12-Hour Correlation Coefficients with Hourly Data Series						
2003	King Mountain Indian Mesa	King Mountain Trent Mesa	King Mountain TWPP	Indian Mesa Trent Mesa	Indian Mesa TWPP	Trent Mesa TWPP
January	0.42	0.30		0.29		
February	0.48	0.17		0.20		
March	0.53	0.27		0.22		
April	0.58	0.30	(0.04)	0.31	(0.09)	(0.05)
May	0.33	0.29	0.05	0.16	0.08	(0.02)
June	0.54	0.28	0.03	0.28	0.06	0.02
July	0.61	0.40	0.20	0.50	0.10	0.17
August	0.61	0.35	0.08	0.47	0.13	0.06
September	0.54	0.25	(0.03)	0.32	(0.12)	0.05
October	0.36	0.30	(0.01)	0.43	(0.01)	0.06
November	0.37	0.30	0.03	0.12	(0.08)	(0.08)
December	0.44	0.30	0.18	0.23	0.19	0.06
Year	0.49	0.29	0.06	0.30	0.02	0.03

Figure 3.3 - Average 12 hour correlation coefficients with hourly data series for a number of sites in US

3.1.2 Events in the 0-10 Minute Period

Three types of energy event are envisaged.

Spinning Reserve increase consider wind and load variability together

Normal wind variability
This is catered for using spinning reserve. The level of spinning reserve is set to cover the loss of a major generating source + an amount for load following. It may be necessary to increase the load following reserve to account for the combined effects of load and wind uncertainty. In assessing the level of reserve, planners / operators should have regard to the co-incidence of load and wind patterns.

Rare – only happens when high concentration in one location

Sudden loss of wind generation
High concentrations of wind generators in a single location can be subject to sudden loss of output due to storms or a single network outage. It is for utilities to assess the frequency of such occurrences and their impact on energy balance and network voltage.

The following figure provides an example of partial wind plant outage due to high wind speeds, taken from the NREL report. The 1-minute average power output is plotted with an average wind speed over a 24 hour period. It can be seen that the output of the four groups of turbines begins to decrease as the highest wind speeds are achieved, and to increase as the wind speed drops.

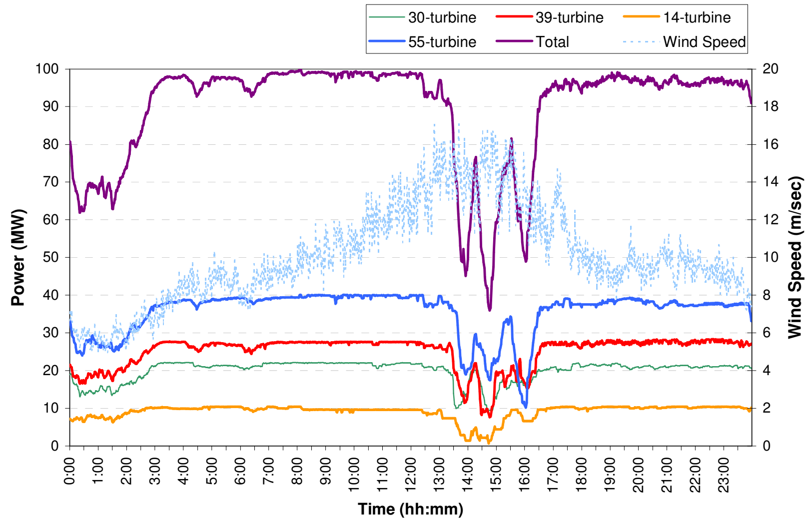


Figure 3.3 - Wind Power Example During High Wind Period

Individual turbine behavior can be seen in the 1-second power data below. Because of the micrositing considerations, it is unlikely for all of the turbines to experience the same wind speed simultaneously.

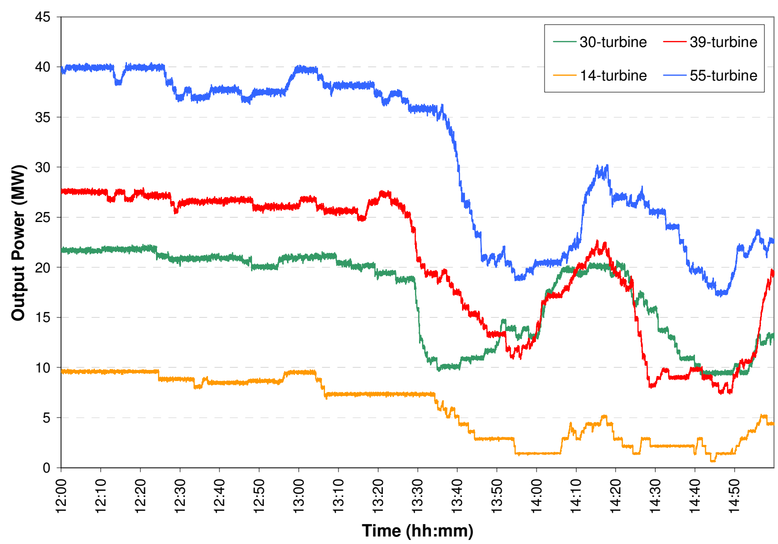


Figure 3.5 - Detail of Turbine Cut-out with 1-second Power Data

Reduce wind farm output before a storm

Clearly either adequate spinning reserves need to be constantly maintained, (which may be uneconomic) or on the approach of a storm, wind farm output is reduced and traditional generation increased. The very rare events may be managed by temporary load reduction according to agreements with customers. The load would then be recovered by non-spinning reserves. The time frame for load recovery is a cost / benefit analysis for stakeholders.

In small systems wind generators may need to spill wind and carry reserve at light load

Sudden loss of traditional plant

This is "business as usual" for system planners and operators, however high concentrations of wind generators on small systems may pose special problems at times of light load. The problem will be more acute for small system with large generating unit sizes. It may be necessary on such systems for wind generators to participate in carrying reserve. Before such a maximization of output from wind generators can be adopted, other factors need to be considered e.g. will system inertia be high enough at high wind, low load periods? Will fault level be high enough to operate protection and maintain voltage performance?

Fault Ride Through Required

Network Events

Unplanned circuit events also occur in this period. They are managed by Grid Code responses like fault ride through. (See 4.2.4 later)

3.1.3 Tools and Analysis Techniques

Statistical Wind Analysis

Most authorities now agree that energy issues in this period are best analysed by statistical methods based upon sample data. An example of such an analysis is included. This is based on work done on the island of Ireland by the convenor et al.

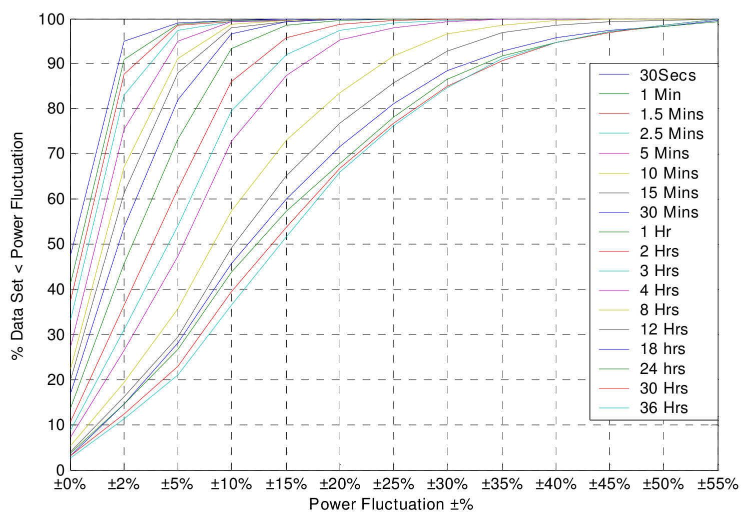


Figure 3.6 – Variability in different time periods

3.2 10 Minute to 2 Days Period

3.2.1 Managing the Period

Options for Balancing

System Operators faced with balancing variability over a period from 10 minutes to 2 days have options. The options have different costs and emissions implications (Appendix 2 refers). In summary:

See Figure below.

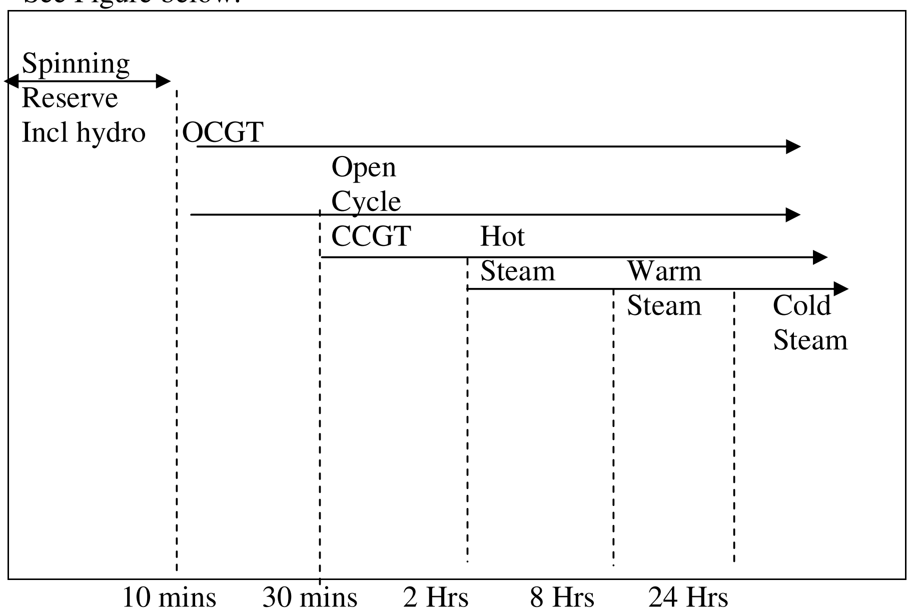


Figure 3.7 - Availability of System Operator Balancing Mechanisms

Figure 3.8 represents a stylised wind power confidence curve which could be constructed for a particular weather type and wind direction.

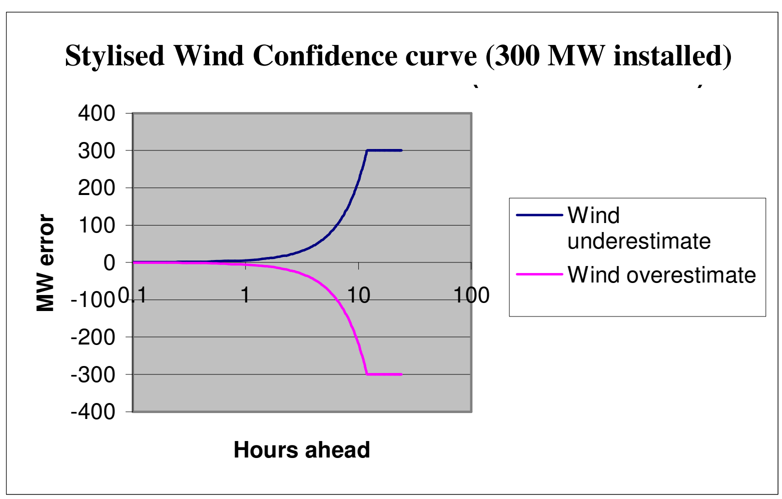


Figure 3.8 - Stylised Wind Confidence Curve

The following diagram shows a wind confidence curve superimposed on the availability time of plant.

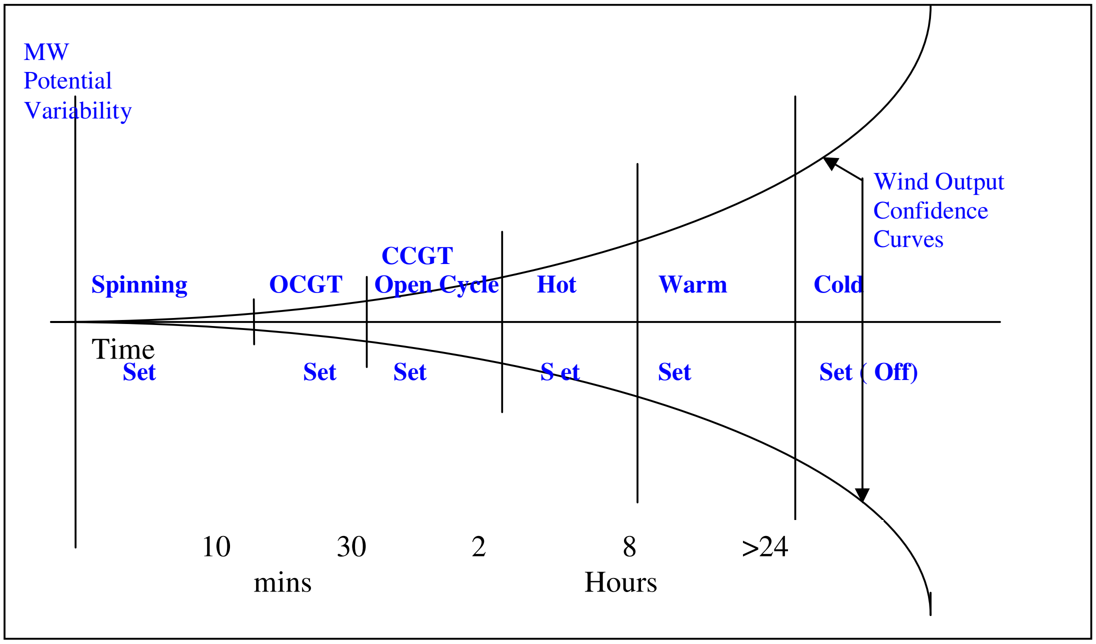


Figure 3.9 - Diagram showing the Operator's Decision Dilemma

Operators will want plant available

This stylized diagram (Fig. 3.9) illustrates the operator's dilemma. Confidence in the persistence of wind reduces with the length of period to be predicted. At the same time, there are windows of opportunity to commit or re-commit generating units. If the output of windfarms is high now but confidence is low in a prediction 24 hours ahead, then the operator will want to commit traditional plant rather than reduce its readiness state. Where balancing markets exist, signals will be required. If new technology energy storage systems become economic they can be used to lessen ramp rates.

The following factors affect the shape of different wind power confidence curves:

- Weather Factors
- Power Generation Factors

Wind confidence is affected by these factors

<u>Weather Factors</u>

- Location of country i.e. prevailing patterns

- Present weather type
- Local weather patterns caused by terrain

Present Weather Type
Investigation of this is likely to commence with analysing the predictive confidence in stable and unstable airflow types and reflect such effects as wind speed at high and low levels. Greater refinements will add accuracy and complexity to the analysis.

The following example shows the accuracy of forecasts up to 36 hrs ahead for a half year data sample from the UK Met Office.

On average wind forecasts are good

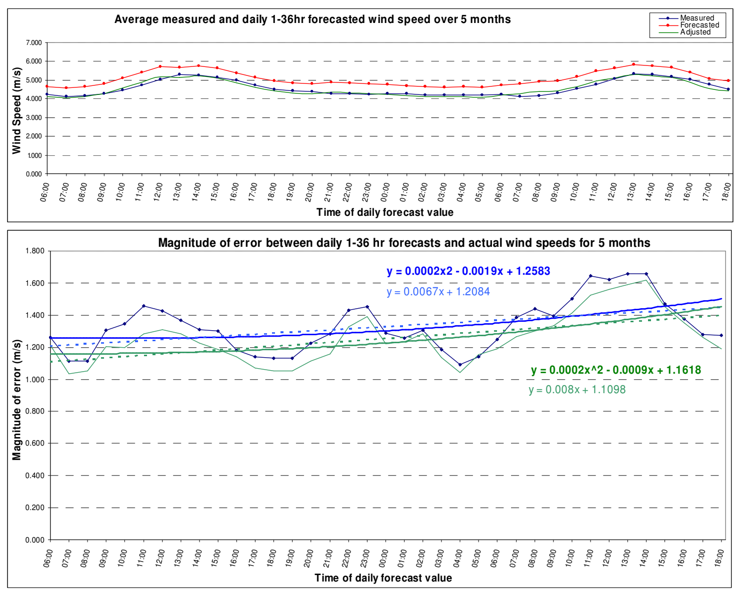


Figure 3.10 – Average Error of 36 hour forecast for 151 days – Northern Ireland

In the above example Fig. 3.10, the diagrams show the accuracy of wind forecasts with 12 km grid scale. The forecast is based on a 1000m numerical prediction model with an outputs based translation model to adjust the forecast to hub height. The top figure shows a systematic error 0.5 M which, when removed, shows the corrected average over 151 days. The weather forecast is, on average, very closely correlated with reality for up to 36 hours ahead.

On any one day, that conclusion cannot be drawn; some days the forecast is optimistic and days pessimistic. The bottom diagram, trending the accuracy over 36 hrs (and removing the systematic error) shows a slight increase in

A range of forecasting technology is available

predictive error as time to forecast increases.

Local Weather Patterns caused by Terrain.

Weather forecasts are derived from global high level climatic information which is refined in stages to determine the continental and ultimately local effects of ever reducing grid square size. Translation between even a local general forecast of wind speed and duration to a forecast of wind conditions on a wind farm site is required. It is also necessary to determine the accuracy and factors affecting and the accuracy of local weather forecasts.

Choices of Forecasting Technology and its Integration

A variety of forecasting techniques can be used – at various levels of sophistication, price and resulting performance. As stated above, close in forecasts are more reliant upon statistical methods based upon recent trends, persistence and statistical deviation. As time increases, metrological data has an important part to play in improving forecasts. Self-learning programmes based upon neural networks and similar technologies improve forecast performance. Studies carried out by the Anemos (anemos.cma.fr) project clearly demonstrate these points.

The method of integrating the individual wind farm forecasts for overall system operation will also make a difference, and this is critical since the impact on operating costs is largely at this level.

Power generation factors

- Geospread of windfarms
- Wind speed to power conversion relationship of windfarms
- Weather Patterns

Geospread

It is clear that, in the short term, a tightly confined group of wind turbines will have less output diversity than a number of plants which are widely spread. This implies that a large off-shore wind farm will give rise to a reduced prediction confidence curve relative to similar capacity which is terrain based and widely spread.

The following curve drawn in a report by RISO National Laboratory in May 2000 shows the effect of distance in output correlation. A correlation coefficient of 1 means that the time series are perfectly correlated, and hence go up and down in exactly the same fashion. A coefficient of 0 means that the time series are randomly distributed.

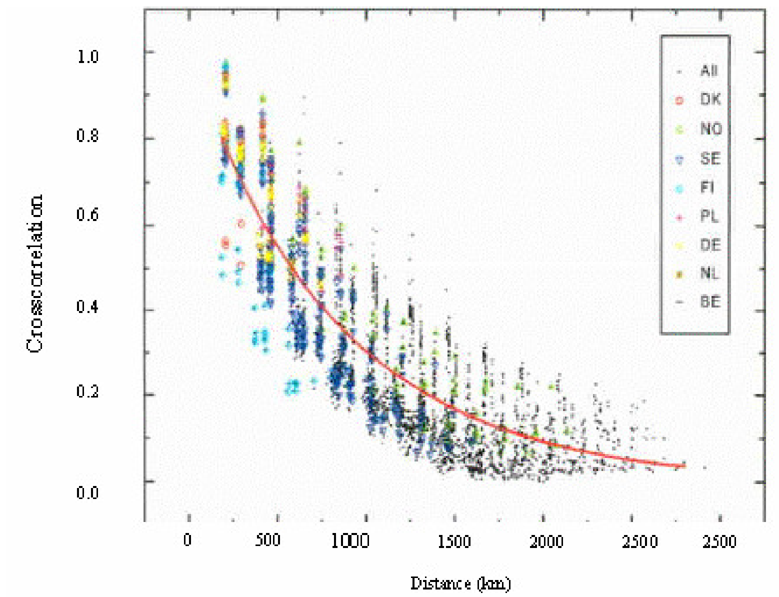


Figure 3.11 – Effect of distance on correlation

In the US work has been done on correlation between close (200km and distant sites (490km) (NREL Aug 2004)

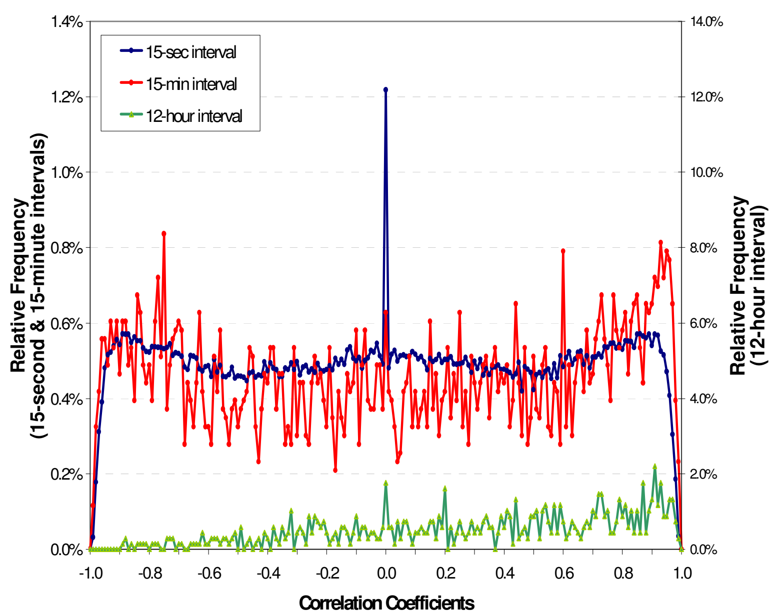


Figure 3.12 - Distribution of correlation coefficients between Ruthton and Storm Lake

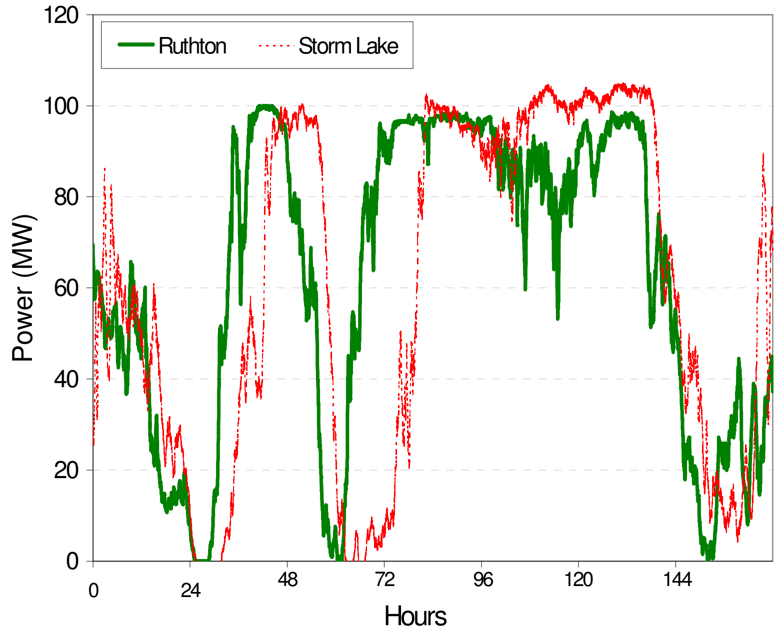


Figure 3.13 - Example of weekly 1-minute average power from Ruthton and Storm Lake

In Fig. 3.13 a temporal shift can be seen between the wind farms. Fig. 3.14 shows 4 wind farms in Texas for a 24 hour period separated by 40km to 490km.

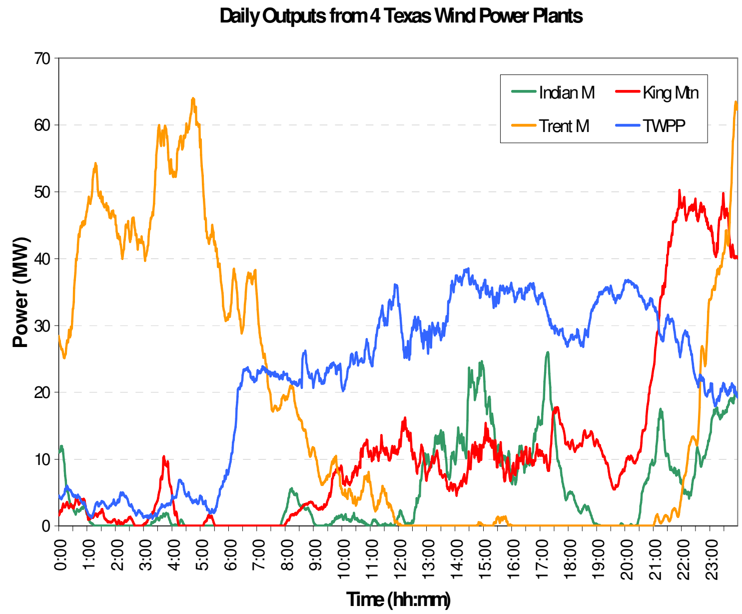


Figure 3.14 - Example daily output profiles of four Texas wind power plants

On islands and small landmasses (within the hours to days timeframe) a single weather front can dominate the entire landmass. Weather patterns are up to 1500 km across. This gives rise to a dramatic loss of diversity in the longer periods.

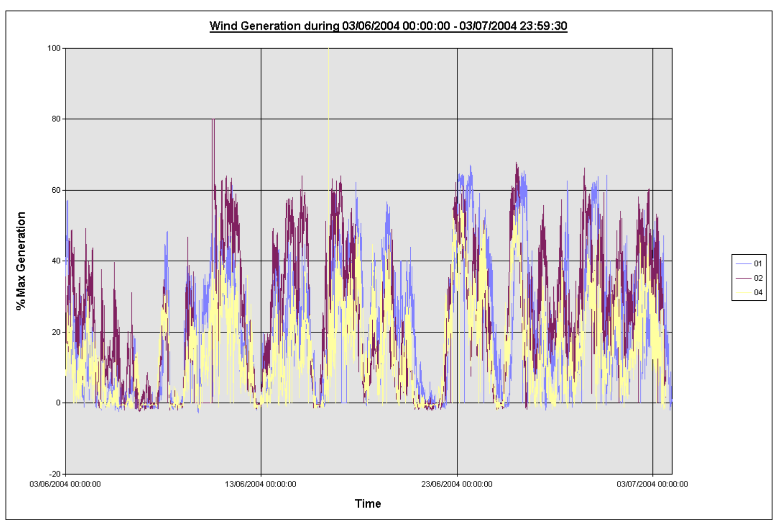


Figure 3.15 - Shows a typical 3 week period for 3 geospread wind farms in Northern Ireland

In shorter time periods more diversity is seen.

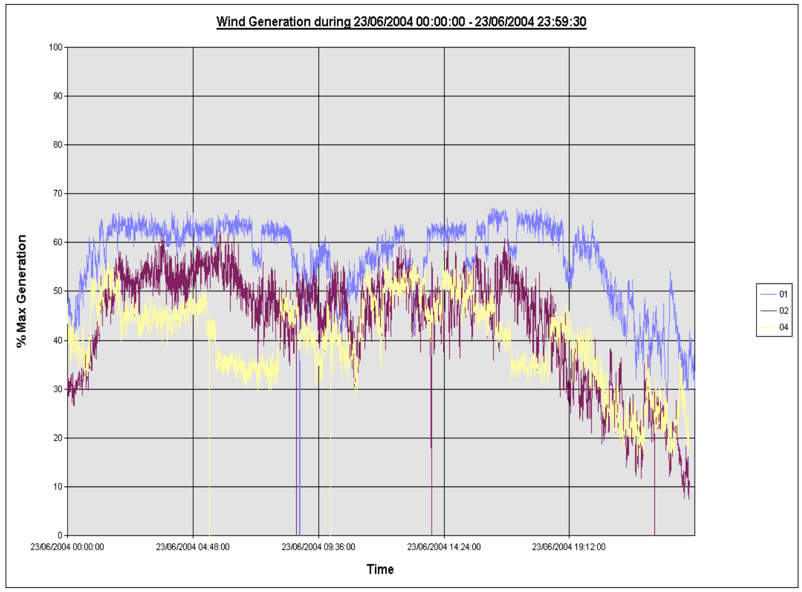


Figure 3.16 – 1 Day Graph

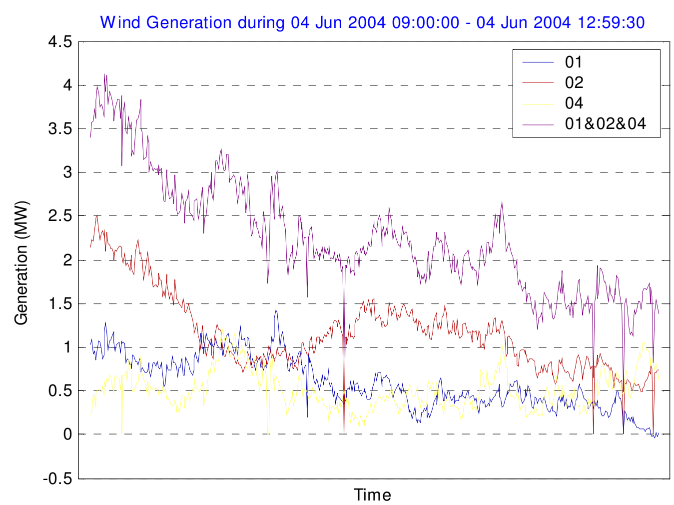
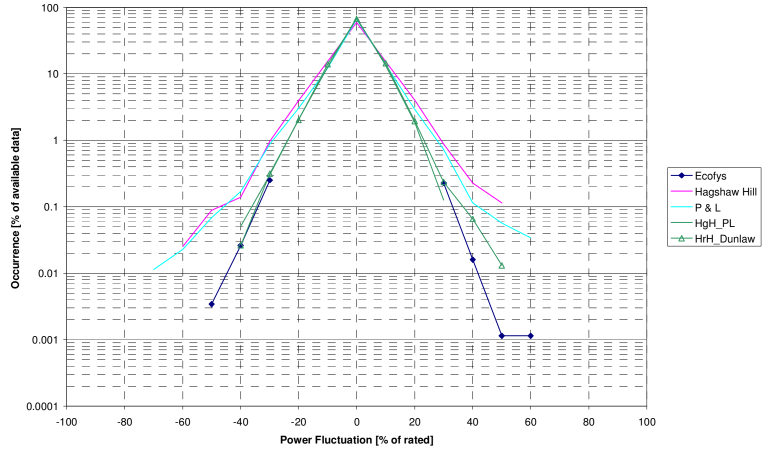


Figure 3.17 – 4 Hour Graph

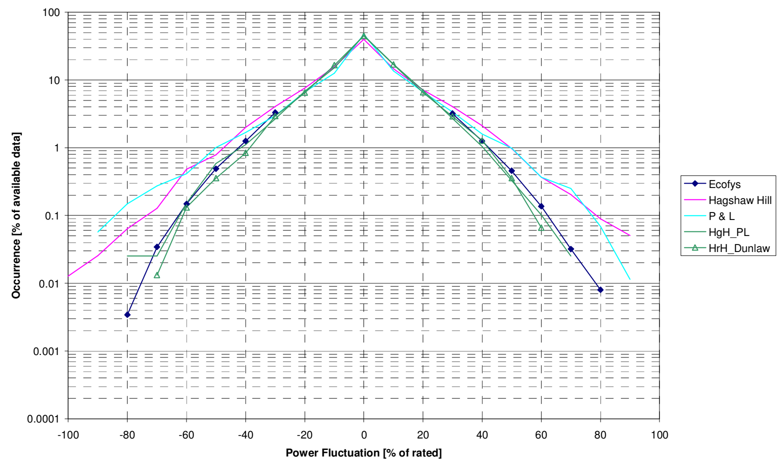
<u>Persistence Analysis</u>

Garrad Hassan, consultants, have analysed actual results (from limited data sets) for some UK wind farms. This uses 10 minute data. The first is a 1 hours interval curve, the second 12 hour and the last a 24 hour curve.

1 hr Variability



12 hr Variability



24 hr Variability

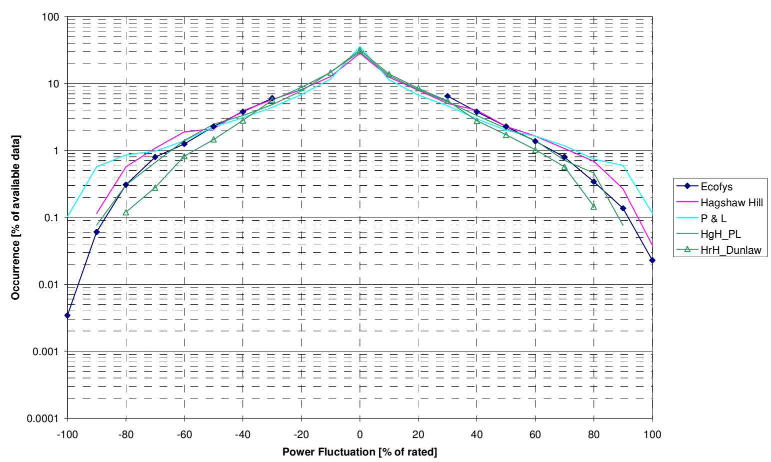


Figure 3.18 - By Garrad Hassan shows the effects of geo-diversity in the UK

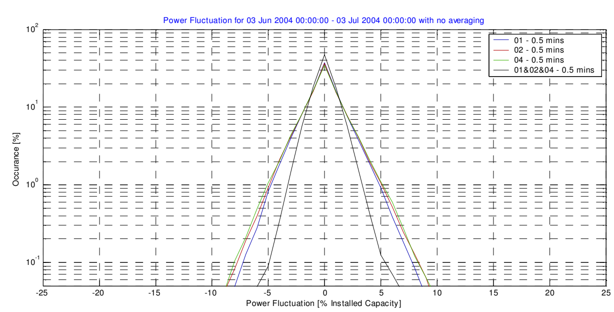
In the above curves, each is plotted to show output variation from the present level. By showing the number of hours per annum against the variation measured as the percentage of installed capacity, it is possible to derive a number of useful statistics related to wind balancing. The family of curves is constructed for different wind farms to show geographical differences. While the recorded output has not been compared with forecast data, the increasing variability with time gives credence to the shape of the forecast confidence curve.

The diagrams are to be read as distribution curves showing that within 1 hr wind farms experience no variation in average output for about 70% of the time but in 24 hrs this falls to 30% of the time. By 24 hrs wind farms have the potential to vary positively or negatively by their entire installed capacity as opposed to only ±50% in 1 hr.

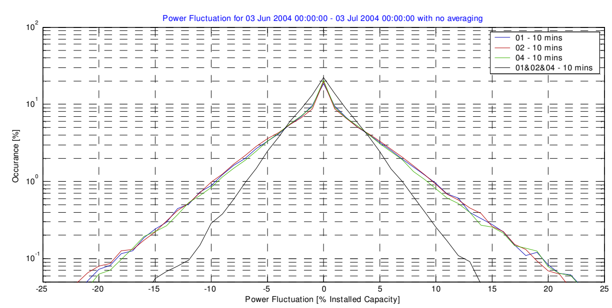
The data shows that 99% of the variations (1% probability) lie within 30% of rated power at the 1 hour interval, 50% of rated power at the 12 hour interval, and 75% of rated power at the 24 hour interval.

The convenor et al has performed a similar analysis using 30 second data. (Different histogram bin intervals have been used).

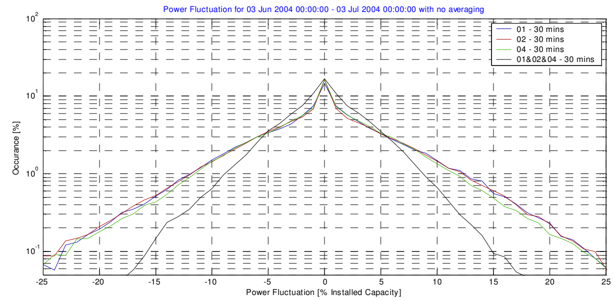
30 Sec variation



10 min variation



30 min variation



Variation over range of time frames

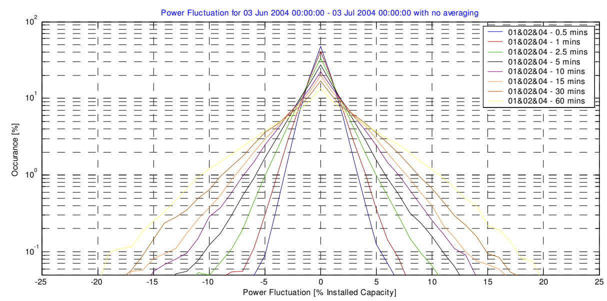


Figure 3.19 – For 3 equal sized wind farms in NI – about 60km spacing

This data shows that 99% of the variations (1% probability) lie within 5% of rated power at the 30 second interval, 10% of rated power at the 10 minute interval, and 12.5% of rated power at the 30 minute interval. An analysis of a similar limited set of data by NREL produced average and maximum 1 second output changes of .1% and 1%. At the 1 minute level, 90% of all step changes were found to be within 1.0% of rated capacity; at the 1 hour level, 94% of the hourly changes were within 20% of rated capacity. The results of the data analysis thus far tend to support the observation that the wind plant output does not change dramatically most of the time, but there are occasional extreme weather events which must be planned for.

RISO (Ernst) have shown (2000) that changes in turbine power over all Germany vary as shown.

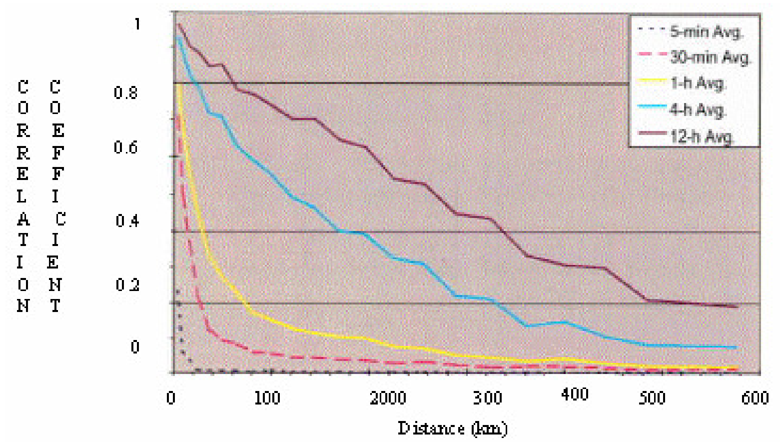
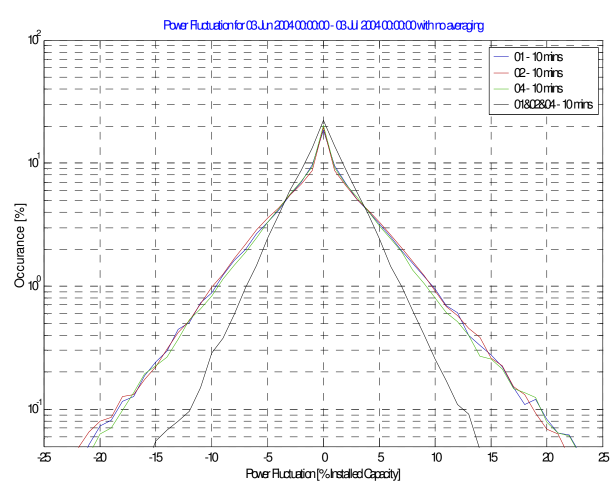


Figure 3.20 – Cross-correlation of changes in turbine power for different averaging times in Germany

In N.I. the pattern has been demonstrated:



Confidence level required depends on the cost of “getting it wrong”

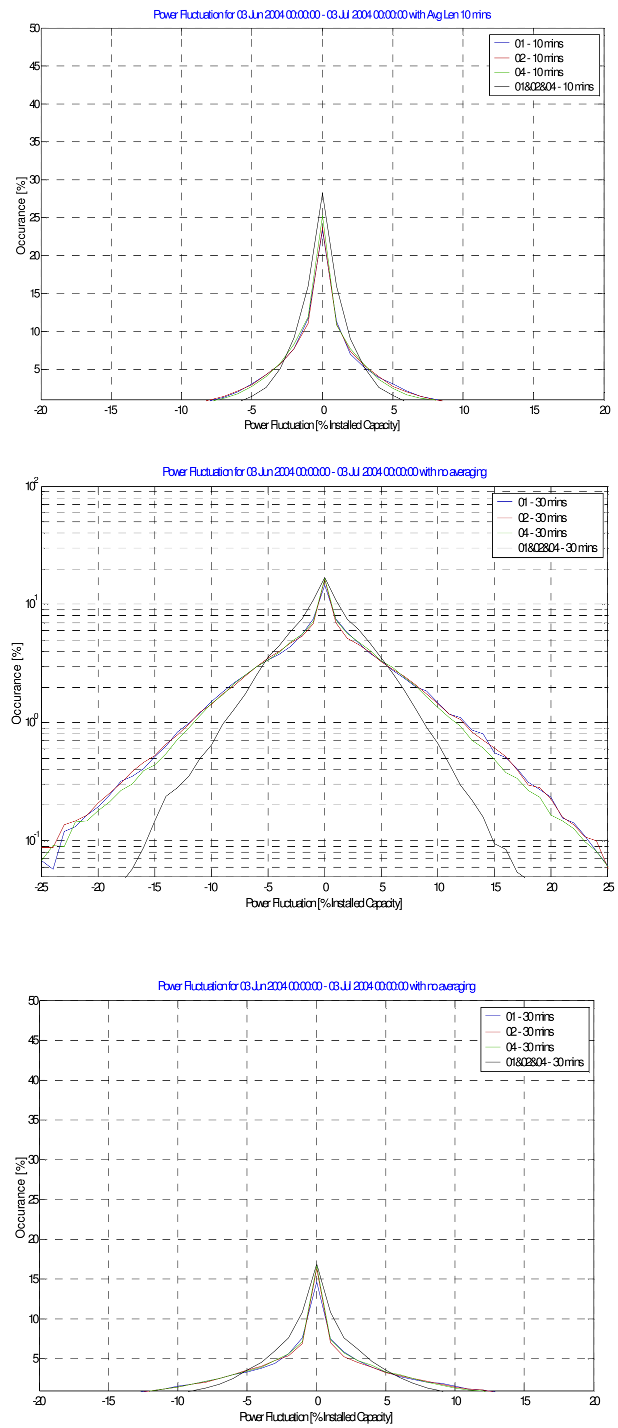


Figure 3.21 – WEC output fluctuation over 10 mins & 30 mins

Wind Speed to Power Conversion relationship of Wind Farms

Both wind speed and direction are significant in determining the output of wind farms. The familiar power curve shown in Appendix 2 is for incident wind on one turbine. The effects of terrain or shielding of other turbines and the mix of turbine types on a site may all contribute to the output for a given wind speed and direction.

Weather Patterns
Weather type (e.g. transient low pressure system) can be associated with different levels of variability and different confidence levels.

Returning to the stylised confidence curve for ease of explanation. The confidence curve shows by how much an estimate of 400MW of wind power might vary from prediction over a number of hours ahead and is drawn for a selected confidence level, e.g. 65% confidence or 1 standard deviation. The selection of confidence level would depend upon the cost of guessing the wind output wrongly. The higher the cost, whether measured in social or financial penalty terms, the higher the wind prediction confidence level that must be sought.

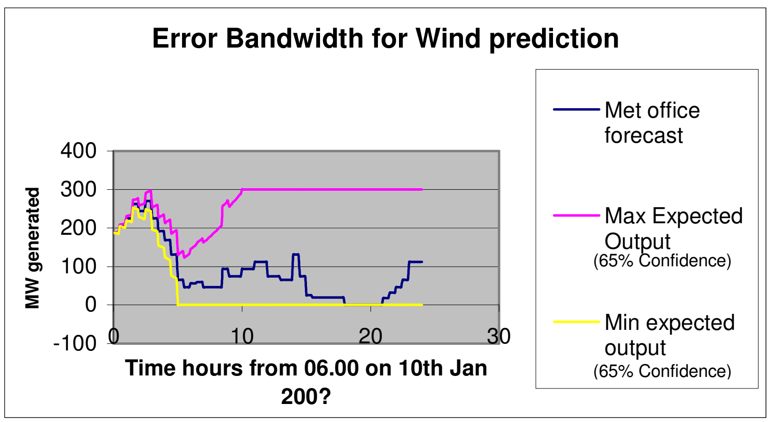


Figure 3.22 - Upper and Lower Confidence curves around a Wind Forecast

Adding load uncertainty to wind uncertainty

To obtain a wind and load variation confidence curve it is necessary to determine the degree of correlation between the wind uncertainty and the load uncertainty. If the two uncertainties are uncorrelated they can be added as orthogonal vectors. This would produce a total management confidence curve.

It is the total forecast error which a system operator must manage, therefore it is against this unintended fluctuation that operating reserve must be retained.

A recent E.ON report identifies that for Germany the load estimation error is about an order of magnitude lower than the wind prediction error. Adding errors by the sum of squares method would therefore make the load estimation error insignificant. Nonetheless where wind penetration levels are low, the two errors need to be considered together, and added as [(sigma wind)^2 + (sigma load)^2]^{½}.

Commit plant to meet the lower confidence curve

Response (spinning reserve) would never be intentionally committed outside this confidence curve since this represents the least cost operating method to achieve the security standard. If there are too many excursions outside the confidence curve, then the confidence curve for that type of weather and that locality needs to be modified.

The response profile would then be as follows, viewed at t=0:

Use reserve/negative reserve to commit units

A system operator could "cover" unpredictability in response (spinning reserve) at t=0 as the difference between the blue and yellow curves. The difference between the blue and yellow curves for times ahead would be factored into unit commitment. As time increases the curve will be redrawn to improve accuracy for later periods. The issue still to be addressed is when to let a traditional generating set that may be needed for balancing go to HOT, WARM or COLD states. Work is required on methodologies. Various market mechanisms determine how units are committed. To simplify the position it is easier to talk about reserve required to manage the difference between the blue and yellow curves. Negative reserve can be used to assess whether the upper confidence curve (red) can be attained without uncommitting a unit.

Gas market may be a factor

On systems that use significant amounts of gas for peaking and balancing, the purchases of gas on the "next day" market may easily become a critical cost factor.

Interconnection can reserve a balancing corridor but it can be expensive

A similar position can be postulated for use of interconnection in balancing. If the market gate closure is 12 hours ahead of a full day trading window, again System Operators need to decide what balancing corridor is to be reserved, especially if the connection is capacity constrained.

Market and trading arrangements will dictate where the costs of energy balancing fall. This in turn will provide the incentives to improve efficiency by reducing unforeseen energy surplus and deficit.

Energy production from wind farms easier to predict over a period

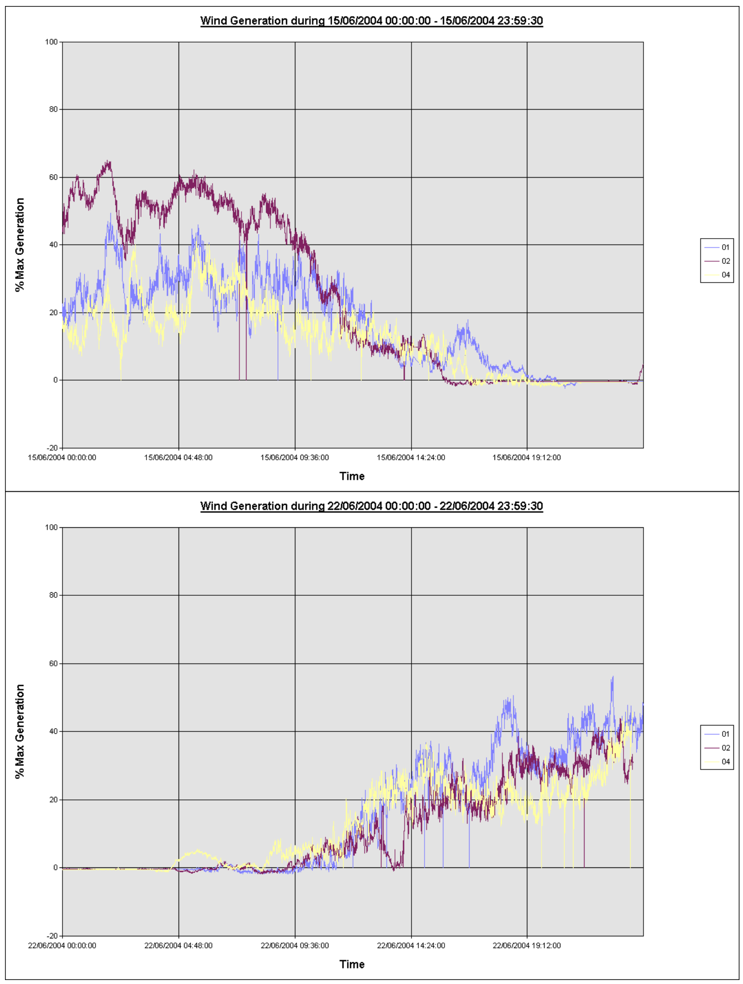
The commercial issue for wind is predicting how much total energy will be provided by the windfarms during the entire period of interest (such as the next day). This is not operationally critical except for a daily 'gas take'. The accuracy of predicting total energy production for the next day is much higher than that of predicting the power output from windfarms at a specific time.

Much of the instantaneous forecast error results from errors in predicting the timing of frontal passages and other peak weather events. Averaged out this has relatively little impact on the energy production for the day as a whole. Energy forecasting accuracy approaches the accuracy of load forecasting.

3.2.2 Events in the Period (10 mins to 2 days ahead)

Typical variability in Western Europe

The significant events in the period are wind patterns. The graph below shows a typical set of wind patterns over 4 days in Western Europe where there is a generally decreasing, increasing, steady or fluctuating wind speed. The three wind farms shown are about 60km apart.



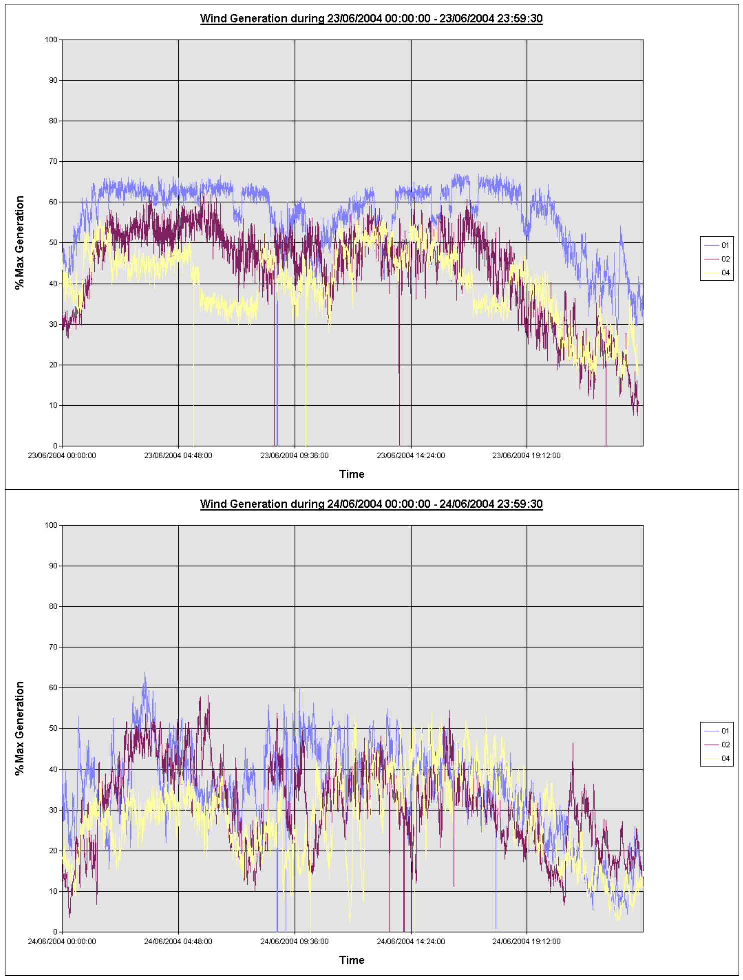


Figure 3.23 – Wind patterns over 4 days – wind rising, falling, steady and unstable

Tools required
- better forecasting
- unit commitment dispatch

3.2.3 Tools

System Operators are already dealing with variability on a continuous basis. Wind energy increases the variation.

Tools required to help System Operators manage wind

Tools are needed to integrate statistical and meteorological forecasts. Improved meteorological forecasts and confidence curves are seen as the way to manage the uncertainty in energy source within this period. American evidence suggests that using information from met masts or other wind farms ahead of the weather front greatly improves predictability in the 10min – 2hr period. Wind farms ahead of weather could perform this function. Work is required on the best response to managing the variability with traditional plant. Traditional plant costs and emissions need to be modelled for a range of variability balancing scenarios.

Tools are needed to minimize the cost and operational impacts on the system.

3.3 2 Days to 1 Year Ahead

3.3.1 Managing the Period

Use of outage planning and demand reduction

Various techniques can be used during this time period to free-up reserve. Such concepts as demand reduction schemes and timely planned maintenance are valuable. Resource allocation can be adjusted in response to trends in this period.

3.3.2 Events in the Period

Outage Planning

The main events in the period are outages in traditional generation and WECs, also planned network outage.

3.3.3 Tools

Statistical tools useful

Meteorological tools are weak in the period from 1 week to 1 year ahead. Statistical tools can be used to assess the output of wind farm power stations, the load pattern and the incidence of unplanned events on an annual basis as a means of pseudo-optimizing wind farm and traditional plant performance. Risk analysis is appropriate.

3.4 1 to 20 Years Ahead

3.4.1 Managing the Period

Review
- plant mix
- plant criteria
- curtailment

During this longer term time period the plant mix comes into consideration i.e. adjustment of the quantity and type of plant that should be installed to enable the system to operate with the planned/predicted amount of wind penetration. Again, this is particularly important for small island systems with high wind penetration levels. For a discussion on expansion of interconnection capacity see Appendix 3. In addition to the plant mix the transmission plan and planning criteria could be re-assessed, taking into account the greater uncertainty of power flows. Concepts such as long-term curtailment of wind power for certain periods may prove viable.

The market design issues come into play in the time frame also.

3.4.2 Events in the Period

Changing system

The main events in the period are new transmission developments, major change in the penetration of renewable/embedded generation, new generating plant and plant retirement. New or increased interconnection capacity is also possible, as are market and legislative changes.

A number of related developments are occurring in the US, particularly with regard to transmission planning processes. Fundamental changes are taking place in some regions, particularly those regions that have filed for RTO status pursuant to FERC Order 2000. The order requires that an RTO assumes responsibility for transmission planning in its territory, and the process implemented must consider all alternatives, including renewables, demand side options, and distributed generation, to ensure that the least cost option is being pursued. The process is stakeholder driven, and wind development interests are able to participate fully. A good example of the result of such a process can be found in the Midwest Independent System Operator footprint, covering a large portion of the central and upper Midwest region of the Eastern Interconnection of the US.

As part of its first transmission plan produced under this new process, MTEP '03, a base case and three alternative scenarios were defined. The base case was a continuation of business as usual, and the three scenarios were high coal, high gas, and high wind. Total costs of the alternatives were examined. The high wind scenario looked at adding 10,000 MW of wind capacity over the course of the planning horizon. This approach has provided a good framework for identifying the issues and quantifying the costs so that the regulators can make more informed decisions and the public can have some better insights into the process. The process itself is being implemented in other regions of the Eastern Interconnection, including, ISO NE, NYISO, PJM, SPP, and in CAISO in the west.

Non firm access

In the Western Interconnection, where there has been greater resistance to the formation of RTOs, a number of studies have examined the possibility of obtaining transmission capacity for wind energy from existing lines which may be contractually loaded, but physically are lightly loaded for many hours of the year. Both the Seams Steering Group-Western Interconnection (SSG-WI) study and the Rocky Mountain Area Transmission Study (RMATS) have examined flow duration curves for major lines needed to move wind energy from remote regions to market. The studies have found that the congestion on the lines often persists for only 20-50 hours per year. In light of this finding, efforts are underway to examine the feasibility of developing a new transmission product, referred to as "flexible firm". The hope is to be able to enter into a long-term contract for such capacity, with a favourable curtailment position, such that the delivery risk could be quantified and a more favourable environment for project finance could be created.

4. How to Manage Technical Issues - Grid Code Guidance

History of Grid Codes

Grid codes were generally based on the capabilities of conventional generation. New technology generation has different characteristics.
In the early days of experimental new technology generation devices, Grid Operators tended to ignore them. Either they were too small to be required to comply with regulations or their impact on Grids was insufficient. As the amount of wind generation (and other distributed sources) grows rapidly Grid Operators have sought to impose Grid Code requirements on these generators. Two lessons are important here:

Two lessons (see opposite)

- It is unnecessary to impose restrictions when the impact is insignificant
- Restrictions imposed should be based upon network needs not the capability of traditional plant.

No uniquely correct code

For this reason there can be no one international Grid Code, but each code should reflect the needs of the country, region or area to which it applies. Grid Codes should seek to deliver the Grid security requirements equitably amongst users of the Grid.

Two approaches to stability requirements of Grid

Two philosophical approaches can be adopted to delivering grid system stability requirements.

- Regulations (the Grid Code) imposed on all Grid users, perhaps tailored by type of user
- Market mechanisms for ancillary services.

First response is regulated. Later response may be market

In general the first response period is controlled by regulations. This provides initial stability following a disturbance. Thereafter the reserve may be provided in either way. The capability and characteristics of new types of generator (Appendix 4) need to be borne in mind when regulations or markets are being designed.

Wind farms can improve recovery

Not all the effects are negative. Whereas large thermal power stations require many hours after a breakdown before they can resume operation, wind energy converters are able to resynchronise themselves with the network and provide active power in accordance with prescribed index values after a short interval (e.g. after a few seconds) following disconnection's

caused by mechanical failure.
Work is ongoing to determine to what extent wind farms can exist in power islands or participate in a black start regime. The thinking is advanced in Denmark where combinations of CHP and wind farm power stations are being considered for island stability and re-schronisation potential.

On the other hand, wind energy converters do not yet offer system services on the same scale as those provided by conventional power stations that are actively involved with the network regulation mechanism (spinning reserve, power frequency regulation voltage regulation, supply of reactive power, etc).

Conventional power stations are able to make a considerable contribution to short-circuit power over a period of several seconds thanks to their rotating centrifugal masses. This maintains voltage levels on the one hand and ensures network protection functionality on the other.

System performance during faults is a worry

Grids with high penetration of dispersed wind energy generation coupled with an accommodating reduction of conventional generation tend to exhibit more severe voltage drops and frequency fluctuations. There is less short-circuit capacity available leading to both a loss of voltage stability and unpredicted operation of the network protection systems. Special attention must be paid to the dynamic behaviour of wind energy converters in the event of network failures. New grid requirements for wind energy converters are required in the network regulation mechanism. In some cases dynamic reactive power units can assist performance.

The small contribution to fault currents and post-fault recovery from induction generators imposes additional system requirements. In the early stages of penetration WTs were disconnected in case of voltage drops below 80% of the nominal voltage. After some time, disconnected WTs were connected back to the system and returned to their operation point. With increased penetration, the disconnection of WTs for system faults can lead to critical situations. Operation could be close to the stability limits with consequences for the entire synchronously interconnected system (in Europe UCTE). Modern Wind Turbines are thus required to stay connected during a fault which depresses voltage over a wide area.

The lower contribution of Wind Turbines to fault currents will lead to deeper voltage drops in the transmission system in case of short circuits. Two approaches are taken:

- Specify improved fault contribution from WEC's
- Define some conventional power plants as must run units to maintain stable and secure operation of the interconnected system in future.

The remainder of Section 4 deals with a number of Grid Code issues and the report makes recommendations on including obligations in National Grid Code.

4.1 Plant Capability – Grid Code Management

Wind farms should be undamaged by voltage and frequency effects

The transmission system is operated with two main axes of variance, voltage and frequency. All customers of the transmission system should be capable of withstanding anticipated variance in these parameters. Where the effect of plant tripping is not detrimental, this may be a way to allow incapable plant.

4.1.1 Voltage Tolerance

Wind farms to stay connected during voltage disturbances. Output to be unaffected by normal voltage range

Wind farms should be capable of 'staying connected' during normal and disturbed system voltage ranges. The output of wind farms should not be affected by normal fluctuations in voltage. The capability of capacitors with respect to voltage and frequency is a significant factor and needs careful consideration. The graph below (Fig. 4.1) gives details of the ranges adapted by various Utilities.

The Italian TSO, GRTN, is presently discussing the introduction of a new performance for Wind farm having size > 25 MW. The present rules entail immediate disconnection of the wind turbines for voltage drops ΔVn (%) =20%.

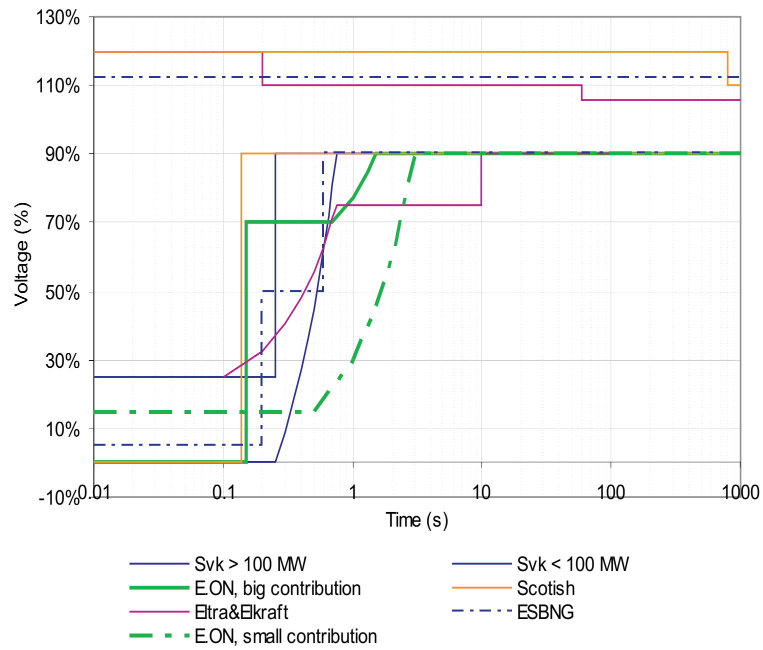


Figure 4.1 - Requirements regarding voltage operation range/ fault ride though definitions in different interconnection standards

SvK = Svenska Kraftnät, TSO Sweden; E.ON = TSO Germany; Eltra & Elkraft (proposed regulations) = TSOs Denmark; Scottish (proposed regulations) = Scottish TSO ; ESBNG (proposed regulations) = Electricity Supply Board National Grid, TSO Ireland; Source: Figure is based on information provided in Chapter 7: Technical Regulations for the Interconnection of Wind Farms to the Power System by J. Matevosyan, T. Ackermann and S. Bolik, in: Wind Power in Power Systems, to be published by Wiley Sons, January 2005.

4.1.2 Frequency Tolerance

Utilities to ensure their required tolerance is realistic

It is unlikely in wide area networks, with large numbers of relatively small generators, that wind farms will be subjected to any significant frequency deviation. The system inertia is simply too large to be affected by the loss of any one in-feed. A major interconnector loss at a time of significant transfer may need to be considered. On the other hand, small island networks, especially with large in-feed sizes are likely to experience wide frequency fluctuations. In these circumstances, plant needs to tolerate a wider band of absolute frequency and a high rate of change of frequency. It is common to place a time limit on tolerance of the more extreme frequency excursions, so that plant may be required to tolerate frequencies close to nominal for an indefinite period but frequencies depressed by 5%-6% for only 20 secs.

The following Fig. 4.2 shows the 2003 Grid Codes position for a number of countries, with respect to frequency tolerance.

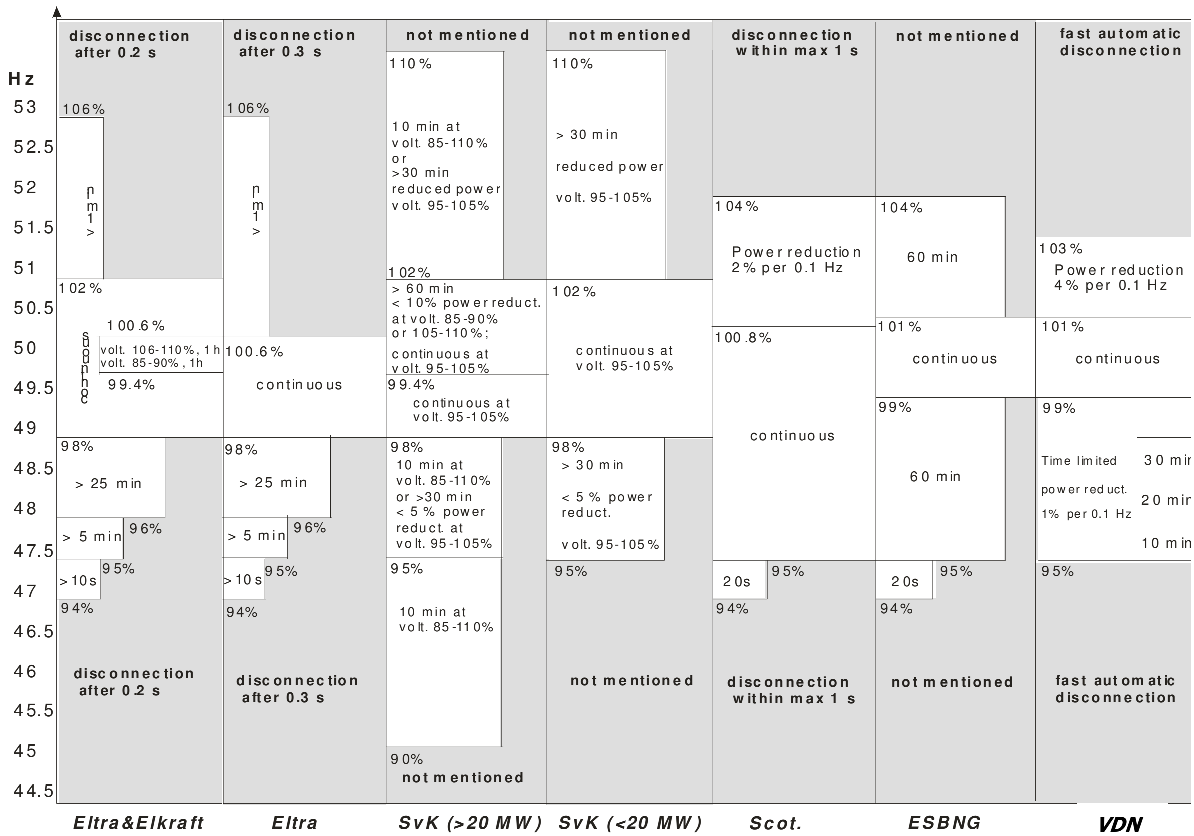


Figure 4.2 - Requirements for frequency range and frequency control

In Italy the dispatching rules are the following: - i) the wind source has a priority dispatch and the TSO must accept the energy produced (with the exception of “network security reasons”); -ii) the wind plants do not take part to the primary frequency regulation; -iii) the wind production does not pay the balancing duty.

The Italian TSO is presently proposing to introduce a requirement of a *primary frequency control* for wind farms having size greater than 25 MW. The possibility of shedding wind plants from centralized remote control is part of the “new package”. This move should help GRTN to solve particular problems in some areas of the country where a large amount of base duty plants with “take or pay” contracts could cause frequency regulation problems particularly during times of low demand. The solution of the issue is still an open question since many commercial problems must be solved.

Eltra & Elkraft (proposed regulations) = TSOs Denmark; <>Eltra (Current regulations) = TSO Western Denmark; SvK = Svenska Kraftnät, TSO Sweden, <>Scot. (proposed regulations) = Scottish TSO; ESBNG (proposed regulations) = Electricity Supply Board National Grid, TSO Ireland; VDN = Association Germany; <>Source: Figure is based on information provided in Chapter 7: Technical Regulations for the Interconnection of Wind Farms to the Power System by J. Matevosyan<>, T. Ackermann and S. Bolik, in: Wind Power in Power Systems, to be published by Wiley Sons, January 2005.

In the US the frequency tolerance is not embodied in a single document which applies to all utilities and generators. The most generally applicable document is NERC Policy 1 – Generation Control and Performance. The concepts are contained in Section A, Control Performance Standard, Introduction.

The CONTROL AREA balance between demand and supply (generation plus INTERCHANGE) is measured by its AREA CONTROL ERROR (ACE). Because supply and demand change unpredictably, there will often be a mismatch between them, resulting in non-zero ACE.

The Control Performance Standard (CPS) establishes the statistical boundaries for ACE magnitudes, ensuring that steady-state frequency is statistically bounded around its scheduled value. Each CONTROL AREA must achieve at least the minimum performance required by the CPS. CPS1 defines the permissible distribution of all CONTROL AREAS' ACEs in an INTERCONNECTION and is based on expected frequency performance within that individual INTERCONNECTION. CPS2 limits the magnitude of the impact that a CONTROL AREA places on its respective INTERCONNECTION.

This is in essence a probabilistic standard.

The Western Electricity Co-ordinating Council WECC have interpreted the NERC guidance to produce the following Fig. 4.3.

Generators connected to the grid that protect for off-nominal frequency operation should have relaying protection that accommodates, as a minimum, underfrequency and overfrequency operation for the specified time frames (Revised 12/5/02):

Underfrequency Limit	Overfrequency Limit	Minimum Time
> 59.4 Hz	60 Hz to <60.6 Hz	N/A (continuous)
<.eq 59.4 Hz	>.eq 60.6 Hz	3 min
<.eq 58.4 Hz	>.eq 61.6 Hz	30 sec
<.eq 57.8 Hz		7.5 sec
<.eq 57.3 Hz		45 cycles
<.eq 57.0 Hz	> 61.7 Hz	Instantaneous trip
This is a typical interpretation.		

Figure 4.3 – WECC interpretation of FERC Guidance

Clearly, from the above discussion, readers must expect island system requirements to be more arduous than continental systems

Recommendation

It is recommended, with respect to voltage tolerance:
Embedded Generation and renewables should be capable of tolerating voltage variations to the same extent as other plant in that area of network.

It is recommended that, with respect to frequency withstand capability:
Since all parts of a network are subjected to similar frequency fluctuations, embedded and renewable generation should be required to tolerate the fluctuations to the same extent as other generation.

System Operators periodically review their requirements. Increased system size, differing plant mix and the advent of interconnection may affect the possibility of large frequency movements or rates of change. The smaller the frequency change requirements the easier it will be to detect wide area islanding using traditional protective approaches.

[In general terms, wind plant will tolerate standard over and under frequency limits].

4.2 Performance

This section deals with the expected performance of the wind farms during these variances, that is, what they should be capable of doing.

4.2.1 Frequency Management

Output should reduce at over frequency and increase at under frequency

Required generated output performance during a frequency excursion period is a matter of debate, but clearly System Operators would be wise to seek reduced output from wind farms at times of over-frequency and best performance at times of under-frequency. Plant design will dictate possibilities.

WEC Plant Differences

Provided that an induction turbine has some degree of pitch regulation, all types of plant are capable of output reduction. The more difficult situation is output increase. The following assumes constant wind speed and describes the frequency performance capability of the different WEC options.

Induction machines – power output tend to reduce with frequency

Pure induction generators will be constrained to operate within about 2% above synchronous speed, therefore if synchronous speed has fallen by close to 4%, the generator's speed will be reduced somewhere between 2% and 4% given a constant ratio gearbox. The blade speed must also fall. This implies a reduction in power output, since any greater increase in the wind energy extraction would advance the slip by a greater percentage and stall the machine.

DFIG's can respond better

A DFIG may respond better since there is a wider range of speed variation. At the inception of the system problem, the DFIG is presumed to have achieved Torque Speed optimisation according to an internal control algorithm. This also dictates the pitch angle of the blades. Again given a constant ratio gearbox, the wind blade speed will naturally be linked to the generator speed, but, by using a system frequency dependant control element, it is possible to change the rotor supply frequency to allow the generator output to be at least maintained or even increased.

HVDC connected generator independent of system frequency

In HVDC connected wind farms the generator is isolated from events on the system. It can continue to deliver its output irrespective of system frequency. Its performance depends on the control algorithm for the HVDC link.

Frequency management can be split into three time fames: rapid (sec), fast (min) and slow (X min)

First Period After Disturbance (Rapid)

Inertia is a natural characteristic of traditional plant

Traditional plant is expected to resist the change in frequency, initially because of its inertia and at a later stage as a result of free governor action. The inertial response is approximately in the 0-3 sec period after a system disturbance. There is no need for a control system, and the response effectively obeys a df/dt function. Since there is no man-made control system, the response of each traditional generator is purely a function of its mass and speed characteristics. The higher the inertia, the lower will be the rate of change of frequency for any given disturbance. At this time, it is unclear whether DFIG & HVDC wind turbines can provide this function. Theory says it can, but no turbine manufacturer has demonstrated it. Work by B Fox et al at Queens University Belfast has shown that pure induction generators have an inertia constant (H) around 3.5. System planners would therefore consider the newer technology plant to have zero inertia and would most likely advise System Operators to respond by increasing the level of rapidly available spinning reserve or to maintain system inertia by keeping units in service at part-load. This may prove an expensive option. Flywheel systems have long been discussed as an alternative form of inertial period spinning reserve. Dynamically configured HVDC links can be considered as inertial equivalent but depend on available capacity. Clearly, again the problem is less important on high inertia systems than on low mass systems.

Inertial response has not been demonstrated in wind turbines

In future, by retargeting the convertor controllers away from the wind speed/output torque optimisation to a maximum short-term energy extraction, inertia may be extractable from wind turbines. The rating of the convertors is a consideration as is the performance in the post inertia extraction period.

Response Period (Fast)

Wind farms need control systems with droop and dead band

Another element of emergency frequency response is spinning reserve. To achieve this, plant must be operating below its capability and have a control system which responds in a predictable manner to frequency deviations. Such a control system is called an automatic governor and it has two major characteristics, droop and dead-band. Droop is a settable value which dictates how the generator shares response with others in providing support for a frequency deviation. When all plants have similar droop settings, they contribute equally in proportion to their size, whereas a plant with a higher setting contributes proportionately less. The dead-band indicates by how much the frequency needs to move before the governor starts to act. This stops plants continually hunting for a stable position. For wind farms to contribute to this frequency management they need to detect the frequency change and have an appropriate control system and settings.

Should wind farms perform this service?

System size important

The debate between System Operators and wind turbine manufacturers world wide is to what extent wind turbines should participate in this service, because to do so they either operate for a time above rating, which is unsustainable beyond a few seconds or they spill a free resource to be able to respond. Once again the system size may have some bearing on the issue. In large systems with many generators, the service may be adequately provided for by thermal or better still hydro plants. In small systems, especially at times of light load, the provision of adequate spinning reserve may be threatened if wind turbines do not contribute. Future developments in wind farms with energy storage may obviate the debate.

Wind farms can carry out frequency regulation by spilling "free" wind geospread importance

All wind farms, with the exception of some stall regulated wind turbines, can carry out this function. The control system required measures the present wind speed and so orders the machine operation to "spill" some energy in order that it is available as rapid reserve. It is likely to be fast response and therefore high quality reserve. The cost of making this facility available is the cost of control. Control could be organised at a turbine level and supervised at a wind farm level. The reserve so obtained, when aggregated over a large enough area, has the benefit of not dieing off after 10 minutes as is common with steam turbine plant when a boiler's constant pressure cannot be sustained until excess firing catches up. Rapidly available traditional plant will then be required to restore the reserve.

The cost of operating the system with reserve from wind, is the cost of spilling free energy. From a wind developers viewpoint there may also be a loss of incentive payments.

Ramp Rates

Maximum Ramp Rate needed to control frequency

Frequency normal band a factor

Controlling the ramp rates of conventional generation for both coming on and off load is a standard procedure and most generators will have no technical difficulty abiding by the requirements as specified by the grid operator. However, wind power which by nature is variable, can only really be controlled when increasing output. A maximum ramp rate should be specified for a wind farm, in order to avoid rapid changes in system frequency. Calculation of the ramp rate will be related to the normal operation frequency tolerance band, the system size and the de-ramping rate of balancing plant. Only frequency rise can be controlled without continuous spilling of the output.

Studies carried out by NREL (2004) in the US shows a typical ramp rate distribution for a single wind farm. The author (Wan) uses the average rate of wind speed change – the speed difference of the sub period divided by the sub period length to represent the ramping rate of each sub period. Two factors are of concern, the ramping period and the ramping rate. For the wind farm investigation the distribution of ramping periods is:-

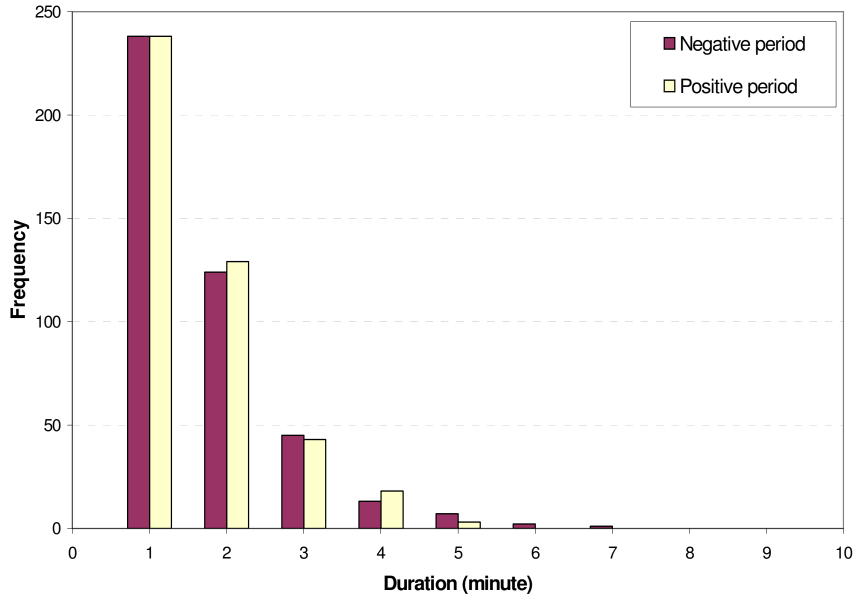


Figure 4.4 - Frequency distribution of wind speed positive and negative ramping periods

For the analysis of ramping rate it is important to study both wind speed and power. Power has a cubic relationship to wind speed. Power ramping can continue after wind ramping has stopped.

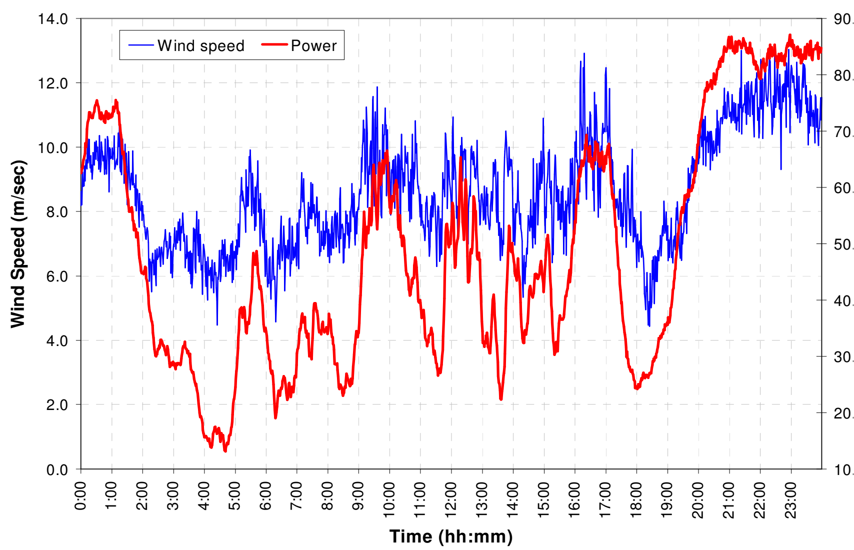


Figure 4.5 - Minute average power and wind speed

The magnitude of ramping is expressed in wind power step change curves similar to the persistence curves already drawn.

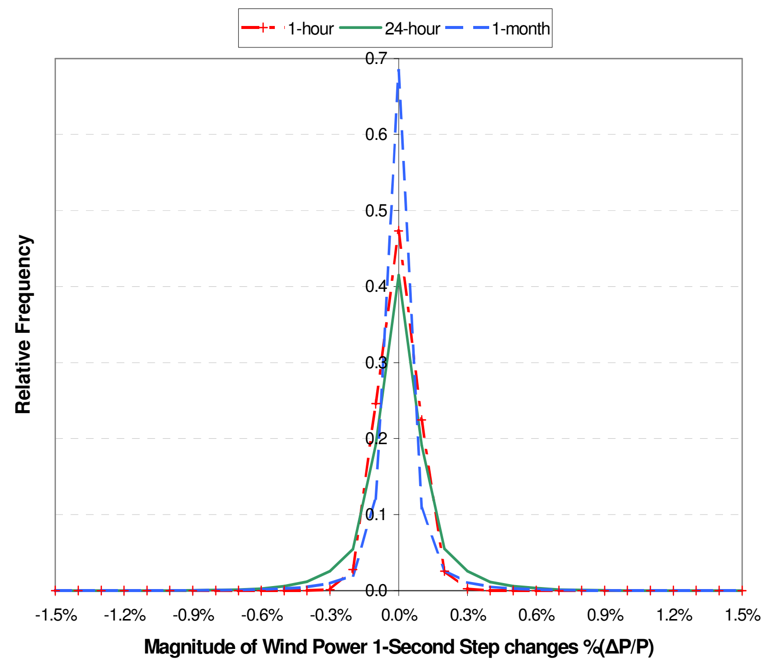


Figure 4.6 - Distribution of 1-second step change values

De-loading in orderly fashion

If wind farms are to be deloaded on the near approach of a storm, then deloading rates should be specified. There is some evidence that wind farms in most locations are not subject to simultaneous shutdown of all turbines, but evidence in America has shown that it may be a feature on a site where the turbines are arranged in a straight line perpendicular to the movement of the dominant weather patterns. Nonetheless in most situations a rapid storm shutdown of all turbines is a rare event.

Recommendation

See Recommendations

It is recommended that System Operators consider the degree of penetration of wind farms likely in the long run and make provision in Grid Codes for future control of frequency using wind turbines, if the penetration is likely to warrant the need inside the life of the wind turbine control systems.

System Operators should consider to what extent any energy regulation element of their Code should apply retrospectively.

System Operators should consider the extent to which control of ramp rate is required to avoid serious frequency fluctuations from the variability of wind farm output. Various automatic mechanisms are available but perhaps the simplest prevents ramping upwards when the system frequency is already high.

4.2.2 Voltage Management

Steady voltage required

A transmission and distribution system is expected to deliver reasonably steady electrical pressure. This is important for both system security and customer loads performance. A voltage profile across a network is achieved through reactive power control.

Balance reactive power

Static and dynamic reactive reserves required

Distributed reactive power preferred

Production and consumption of reactive power must be balanced at all times to ensure a stable system voltage. On the power system this voltage balance is achieved by varying generator excitation, by switching capacitors and reactors, by varying active and reactive power on interconnectors and by the operation of on-load tap changers (OLTCs). In addition sufficient reactive reserve must be carried to limit the voltage rise/drop and to ensure voltage stability following a disturbance. Although active power (MW) can be transmitted over large distances the same is not true for reactive power. Therefore achieving system-wide reactive power balance requires sources of reactive power to be distributed around the network. It is preferable that all generation connecting to the transmission system should be involved in this management.

Wind farms can make requirements of 0.95 lead to lag without additional cost

Capacitors do not provide dynamic requirement

The reactive power ranges requested from Utilities vary depending on system needs. Wind farms have difficulty meeting the same capability as conventional generators, and thus common practice is to adopt a requirement of 0.95 leading to 0.95 lagging at the connection point. It is logical to relate this to plant in service i.e. that the MW being delivered are capable of being accompanied by reactive power of at least 0.95pf weaker systems may require better performance. It also must be noted that wind farms supply this power in many ways. Grid Codes must ensure that reactive power devices do not violate voltage step emissions criteria, that is, that they don't emit frequent reactive power steps, as is the case with switched large capacitor bank units. It is unlikely that capacitors alone would meet a dynamic requirement to manage reactive power.

4.2.3 Power Quality - Harmonics

Harmonics are detrimental to power system and customers' equipment.

Modern systems have to manage 5^{th}, 11^{th}, 13^{th}, 23^{rd}, 25^{th} etc

It is important to understand the harmonic impedance locus of the network. The problem however is that the resonant frequencies may change with network topology and system development. Creating a very small harmonic ripple of a voltage waveform can result in a large harmonic current at a system resonant frequency. Most modern systems struggle to keep 5^{th} harmonic (which comes from customer load) under control and systems with HVDC or large variable speed motors may have issues with 11^{th}, 13^{th}, 23^{rd}, 25^{th}, 35^{th} and 37^{th}. Higher order harmonics are particularly troublesome for telephone interference. Voltage source convertors in wind farms emit harmonics in the telephone range.

Induction generators sink harmonics

Wind farms containing induction generators tend to be a sink rather than a source of higher harmonics and should therefore improve system performance. However, when combined with associated capacitors and cables, they may form a local resonant circuit with harmonics present on the system. In that case the local system will need de-tuning with harmonic filters.

Systems with convertors i.e., DFIGS and HVDC connected plant have the potential to generate harmonics. Many wind turbines use converters based on the Pulse Width Modulation technique (PWM), and therefore generate very little harmonic distortion at frequencies below approximately 2 KHz.

Careful of sub-synchronous oscillations

Induction generators may introduce significant sub-synchronous harmonics, due to wind shadow, and these may be in the range of concern for inter area oscillations.

Recommendations

See Recommendations

It is recommended that Grid Codes should point to standards such as IEL Standard on Harmonics.

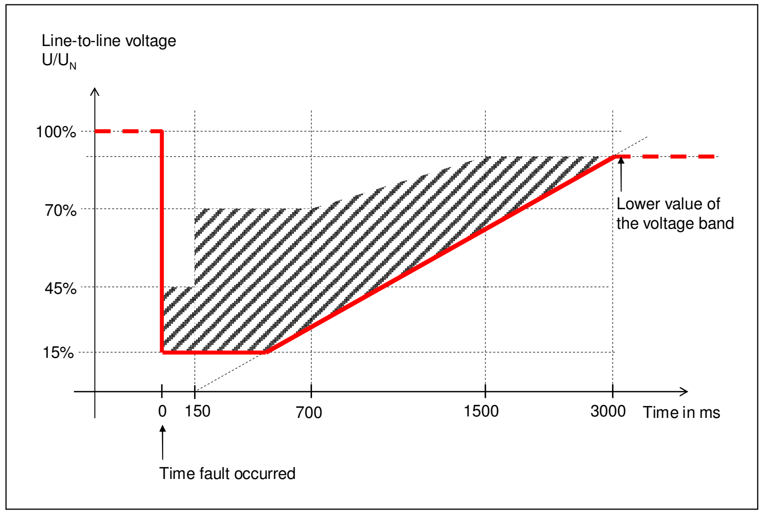
Grid Operators need to understand and communicate the harmonic locus for their networks.

4.2.4 Fault Performance of Wind Turbine Generators

Low voltage ride through Requirement depends on system Specify performance during/following a fault

Fault performance or low voltage fault ride through of generation during disturbances has become an important issue. Again the exact requirements for Grid Codes will depend on the characteristics of the system. It will depend on many factors such as geospread of wind generation, system protection settings, FACTS devices on the system etc. In addition to what is required **during** the fault there is a need to specify what the generators are required to do **following** a fault. System stability and inertia becomes important.

The following type of graph and explanation (developed by E.ON) is often used to describe the requirement for low voltage ride through. This figure is also contained in the guidelines on “REA generating plants connected to the high and extra-high voltage network” (August 2004) of the German association of electricity network operators (VDN – Verband der Netzbetreiber) which have been prepared on the basis of the E.ON Grid Code (August 2003).



Voltage limit curve of a network fault

Figure 4.7 – Fault ride through characteristic (from E.ON Code August 2003)

Near-to-generator three phase short-circuits above the red line should not generally result in generating unit instability or in disconnection from the network. Active power output should resume immediately following fault clearing and be increased with a gradient of at least 50% of the rated power per second. Within the shaded area the active power increase can take place at 30% of the rated power per second.

Additionally the figure below shows the voltage limited curve (at the network connection) above which it is advised that generating units with a low symmetrical short-circuit current component should not be disconnected from the network.

With a disturbed network, the generating units should, in general, support the voltage. If a voltage drop of more than 10% of the root mean square (r.m.s.) of the generator terminal voltage occurs, it is recommended that any power factor or reactive power control in the generation unit be switched over to voltage support. The support of the network voltage needs to be provided quickly (within 20 ms after fault identification) by providing reactive power at the generator terminals. A factor of a minimum 2% of the rated current per percent of the voltage drop is used by VDN (based on E.ON Grid Code). Switching back from voltage control to normal operation is possible after 3 seconds according to E.ON.

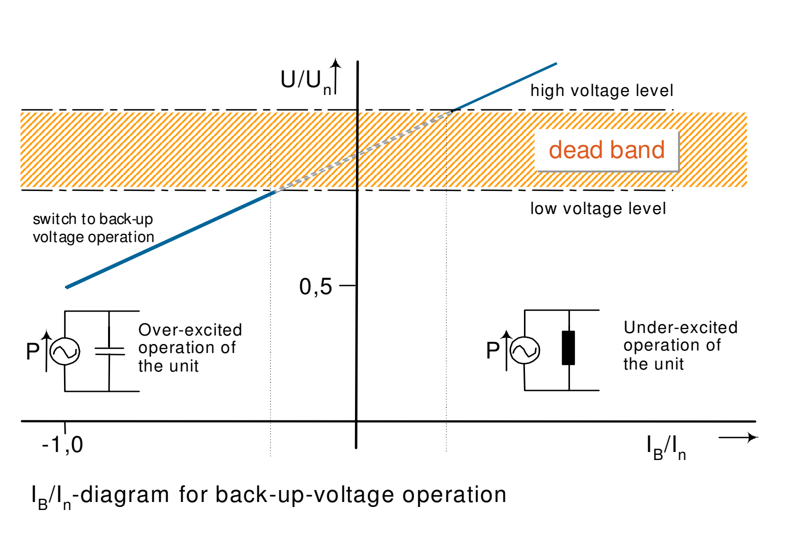


Figure 4.8 – Amount of reactive current feed for voltage support with a fault in the network (Source E.ON)

Experience is required to determine whether this curve leads to option performance.

With far-from-generator three-phase short-circuits, disconnection of the generating unit from the network is not advisable even with fault clearing in back-up time of the network protection. The voltage support should still be adhered to.

For international comparisons the table in section 4.1.1 on voltage tolerance should be consulted. In the US, the AWEA filing with FERC is based upon the E.ON Grid Code.

In the above, wind farms are to stay connected for faults in the grey area. This ensures that a wind farm will "survive" a network disturbance, but does not define performance immediately after the disturbance. Grid Operators faced with high penetrations of WEC's will need to be assured of post-disturbance performance.

This is encapsulated in two concepts:

Rate of return to active power

- Rate of return to full or near full active power. It is often expressed on a percentage return to the wind power curve optimised value in 1 sec.

Not to increase consumption of reactive power

- The consumption of reactive power during the return to active power. It would be desirable that throughout the period, WEC's do not increase their pre-disturbance consumption of reactive power. Even synchronous generators consume reactive power briefly during a fault. The period lasts for some millisecs. Studies are required to understand the stability bounds of consuming reactive power at this time.

4.3 Protecting the System From Islanding

RoCoF and RoCoA principle no longer sufficient

Generation should be capable of detecting islanding situations and promptly disconnecting. It is believed that RoCoF (rate of change of Frequency) or RoCoA (angle) protection settings may not be sufficient and more investigation is required.

4.4 Information Connections & Control

Two types of information are needed:-

- planning data
- real time management data.

Planning and real time data required

Planning data describes the size, type and performance of the plant and interface arrangements. NGT's website shows typical requirements.

Models for load flow fault level dynamics to be verified and validated

Modelling data must facilitate load flow modelling, fault level and transient/dynamic performance modelling. It is required for planning and performance assessment. Models must perform accurately for the purposes for which they are supplied and it is reasonable to hold providers responsible for this. Models must be delivered validated and it is desirable that they are certified accurate. Models should be appropriately documented including block diagrams. Models should slow the effect of ancillary connected apparatus.

There is a need for standard architectural arrangements for models, to enable different controller arrangements and reactive compensation to be attached to standard blocks.

Model architecture to be modular and standard

Model documentation is important and should allow model users to understand the relationships between parameters and should facilitate control improvements. Base machine modelling is critical. As a minimum there should be separate blocks for:

- Turbine generator (i.e. 2 mass model)
- The operation of machine protection including any changes to machine topology
- Control which could be one or more blocks to represent steady state and transient responses

- Unit overall protection

While the WG understands that this represents a large number of programme internal communications (arrays) it is believed that it is necessary to facilitate machine and model performance, and assist in validation.

Standard interface definitions between blocks should be specified and soon.

SCADA required fast monitoring

With regards to the real-time information requirements, it is recommended that wind farms should communicate their input/output at the PCC (point of connection). SCADA (Supervisory Control and Data Acquisition) is the common base for real time communication. However, SCADA may not be the only choice as it may be too slow for monitoring. As it may not be feasible to monitor each individual wind turbine, at least one wind turbine of each type should be monitored (e.g. for ride through faults). Most wind turbines need input signals for control, therefore monitoring signals should not be an issue.

4.5 Compliance

Wind plant development has preceded the development of Grid Codes and has left many System Operators, trying to assess performance of equipment on the basis of inadequate and largely unverified models.

It is strongly recommended that System Operators insist on:-

Compliance to be tested

- model validation
- compliance measurement.

This Working Group believes that if renewable energy is to approach 20% of energy consumption or 40% of installed capacity on networks by 2020, it is imperative that the transient performance of the plant is monitored and understood. Otherwise system stability will be threatened. [A recent CIGRE survey on Confidentiality of Generator Data by Phil Southwell Austrailia states the position].

<u>Recommendations</u>

See Recommendations

It is recommended that for high penetration of wind energy convertors on to power systems:

- *Fault performance is specified as*
  - the ability to ride through disturbed voltage
  - the rate of recovery active power

- a constraint on drawing reactive power after the fault
- a limit on transient performance (adequate damping)

- *Serious work is needed on islanding protection of wind farms required to survive voltage and frequency transients.*

- *Grid codes deal with the control of real and reactive power from wind plants under normal conditions.*

- *Grid Codes deal with mitigating the effects of emergency and storm impacts on wind farm input to the grid.*

- *Requirements are identified and enforced in planning and real time information.*

- *Wind farms are required to comply as real plant not just as models. Performance measurement is required.*

- *Requirements are identified for providing and meeting improved wind plant output forecasts.*

5. Network Issues

In Section 2.2 the W.G. draws attention to the potential issues constraining penetration of wind power.

Typically network is not strong in areas of high winds, because habitation and business avoid these areas.

At a backbone network level the introduction of high penetration levels may reverse flows in networks.

There may be an issue with the level of short circuit power available.

More work required

Many issues emerge and there is a need to research strategies.

- What is the efficient planning standard for wind farm connections?
- What is the efficient planning standard for backbone grids to facilitate wind flows?
- How is network max and min fault level to be managed?
- How will network voltage be managed with a wide range of flow and frequent flow reversals?
- How is such a network to be controlled and protected?

Connections could be rated to "n"

Planning Standards for Connection

It is possible to allow wind farm connections to be made up to the full capacity of an intact network. This is because:

- The amount of time when there is a network outage is not commercially significant.
- The wind farm output can be curtailed.
- The System Operator must plan the system for no wind anyway.

If such a policy is to be pursued then curtailment special protection schemes must be reliable, else, there is a risk of outaging a local load block or damaging equipment.

CIGRE WG C6-2 has produced a Report on 'Connection of Generators and Customers'.

Studies required on back-bone grids but n-1 seems possible. Defence mechanisms to be reliable

Planning Standard – Back Bone Grids

This is a difficult question. Fundamentally planning may be carried out deterministically or on a probability basis. It may be wise to maintain existing planning standards until more is understood about the risks of operating with high levels of wind. It may be that after research n-1 at all times is adequate in that the output of wind farms can be curtailed to allow planned network outages. There is a commercial issue of who funds the curtailment.

Network Voltage

The question here is to what degree will wind farms self manage network voltage, both step change and absolute levels. Newer designs like HVDC connected and DFIG may make a contribution. Older Dutch pattern designs may need SVC, STACOM or similar technologies to deliver this service. Much work is ongoing in this area.

Network Protection and Control

Network protection and control may depend on direction of flow. This must be reviewed with high penetration of embedded generation as reported earlier islanding protection is an issue. Transformer tap changer capability and transformer voltage control systems may need reviewed. As a minimum, unless unit protection is used throughout, protection grading and discrimination will need to be considered.

6. Report Conclusions

- Penetration of Wind Energy Converters (WECs) onto Grids will increase dramatically driven by incentives and rules designed to deliver cleaner energy.
- On islands, variability in instantaneous generation output will be a problem to be managed. This requires improved weather forecasting, tools to efficiently commit and dispatch existing plant to deal with the variability and possibly improved generation mix. In the longer run energy storage is likely to be a feature of high wind penetration systems.
- On continental land masses and some islands, the costs of using interconnectors to balance wind can be significant and must be considered against alternative strategies.
- Plant mix is important. Plant mix changes can have unintended consequences for emissions, efficiency and market performance. Cost and benefit analysis is required.
- Network issues are important and there is a need to monitor how standards and analysis methods are applied and the lessons learnt.
- Network and wind farm stability are important and must be managed regards:
    - tolerance to voltage and frequency as required for other equipment on the grid
    - performance of grid connected wind farms regarding:
        - surviving voltage depression and reactive current contribution
        - rate of recovery of reactive power
        - constraint on increasing reactive power demand
        - ordered response to start up and even emergency shutdown
        - renewable plant may increase the risks of stable network operation and thus reliability assessment is required for different penetration levels.
- Participation in ancillary services.
  This may be critical as penetration levels increase. Provision should be made in new wind farms to facilitate later involvement.
- Deleterious effects should be controlled.
    - Harmonics
    - Sub synchronous oscillation
    - Islanding with loads
- Network plans need to be reviewed to ensure

- Connection standards are appropriate
- Backbone networks standards are appropriate to distributed generation networks
- Network voltage profiles can be maintained
- Special protection schemes (remedial action schemes) are secure
- Fault levels especially minimum fault levels are in an acceptable range
- Protection and control function properly

- Wind farms need to be tested to ensure compliance with standards.

7. Further Work

The following work is required:

- Continuing monitoring of wind power penetration and its effects on system security and stability including the importance of maintaining system inertia and performance of protection systems.
- Monitoring of the changes in the drivers for creating wind farms.
- A report on geodiversity effects in different time periods and different sizes of system/climatic conditions. A useful initial contribution would be a model methodology.
- Development of a methodology for a production of wind power confidence curves.
- Development of real time operating tools to:
  - improve translation of public weather forecasts to site forecasts
  - aggregate site forecasts
  - carry out unit commitment and dispatch with the variability of wind
- Development of system planning tools based on the above.
- Rigorous analysis of capacity values of variable energy sources.
- A standing panel report on:
  - performance of wind farms during major disturbances
  - unplanned outages created by wind farms/embedded generation
  - planning/operating standards applied
  - remedial actions

- A report on wind farm models existing
  - What models exist?
  - How have they been validated?

- What are there shortcomings?
- What should standard architecture be?

- A report in compliance testing of wind farms.
  Such a report should indicate the practice in various countries regards:-
  - What testing phases are adopted
  - What tests are carried out in each phase
  - What performance is acceptable.

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Appendix 1 - Approach to Incentives

Europe

In Europe, a scheme of emissions control is to be applied by issuing to each member state an allowance backed with certificates. Unused certificates may be traded. Projections vary as to what the value of certificates is likely to be, but the principle is that a bad polluter needs to buy certificates to stay in business, whereas a cleaner generator will have certificates to sell. [Most commentators have used €10/tonne of CO_2.

Incentives and taxes used to promote renewable policy are varied, but there is an effort to converge approaches in Europe. The European philosophy is based upon the recognition that each member state will have different starting positions and different factor endowments to help generate energy from renewable sources. It is therefore not the absolute carbon pollution level of each country which is important, but the improvement which is targeted. In the electricity industry, it is the carbon produced for the energy benefit of end users which matters. By reducing demand, end customers can contribute to carbon savings; also reductions can be obtained by more efficient production or by using energy produced from renewable sources.

There are three effects of incentives:

- they stimulate the renewables marketplace;
- they may distort the location of generation
- because they may use different incentive payment regimes or definitions of renewable eligibility, they can create unintended trades and flows across boundaries.

The following represents the position in a number of countries.

United Kingdom of Great Britain and Northern Ireland

There are two primary mechanisms in place, the first being Renewable Obligation Certificates [ROCs] (NI to be introduced in 2004 and tradable in GB in 2005).

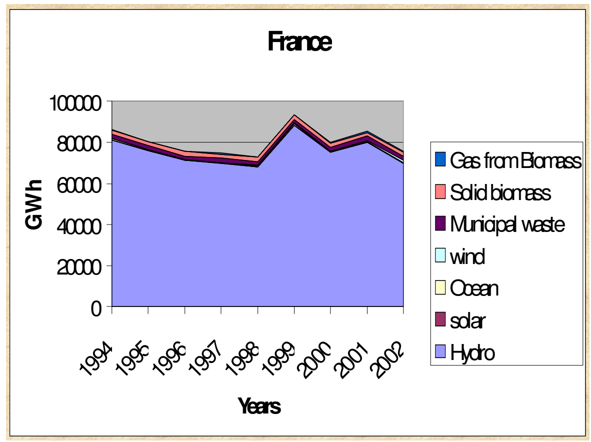
UK – Renewable Obligation Certificate Scheme

ROCs are paper certificates issued to bone fide registered renewable electricity producers and re-collected from suppliers to demonstrate the percentage of energy which each supplier has delivered to customers from renewable sources. Government sets an obligation for a number of

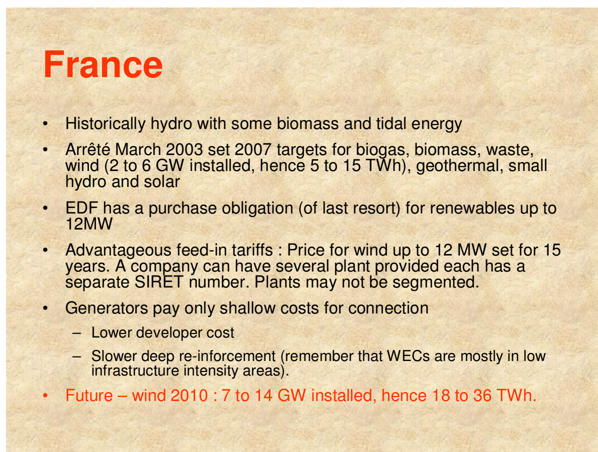
Buy-out price 3p/unit	years ahead, in percentage by consumption of renewable energy. It is mandatory for suppliers to meet this obligation or pay an economic rent for not doing so. This economic rent is called the buy-out price. This has been set up to 2010 at £0.03 / kWh but the money so collected is redistributed in proportion to the percentage which each supplier actually met. This gives rise to a ROC futures market where the price can easily be double the present buy-out rate, based upon the market's perception of the percentage of the target which will be achieved in any year. This inflated ROC value is part of the incentive to drive new producers into the market, but could also be seen as a perverse incentive on existing producers to keep others out and hence hold up the price. The most severe factor limiting development of wind farms and like construction is the Planning consents process. Government have gone some way to addressing this in the recent Energy Act.
Climate Change Levy	The second mechanism at present in place is Climate Change Levy. This is a tax placed on all non-domestic customers levied at £0.0043 per kWh for each unit not bought from renewable sources. Customers who demonstrate substantial carbon reduction can be exempted for a period.
When wind energy is low – renewables supply contracts are frustrated or an energy premium paid	A market issue arose in GB and to an extent in NI, and was solved differently in the two domains. Wind is an intermittent resource and therefore if energy is to be sold to suppliers under contract the seller is exposed to having to cover low wind energy periods with energy bought on the spot market (or in NI from the central procurer). If a renewable producer, mostly produced energy at a time when the energy price is low and then either had no income or worse had to buy top-up energy when the energy price is high, this would lead to a considerable financial exposure. In Great Britain, this is managed by hedging contracts. In NI, where the number of major renewable players is only two, collective hedging would do little to spread the risk, therefore the Regulator introduced a system based upon a Renewable Output Factor (ROF) which bears the cost of hedging on the customer part of the market rather than the producer, but producers pay for this by supplying 120% of the units paid for. It is believed by most stakeholders that management of these risks is crucial to achieving government targets for renewable energy. It is therefore crucial for electricity system planners to recognise that an important obstacle has been removed.

France
Incentive schemes

France



Problems

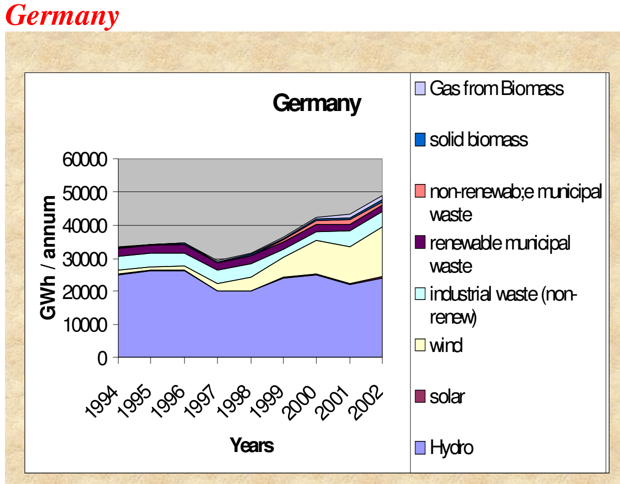


The following note further explains the process.

The main incentive is based on a governmental rule, which guarantees to every wind installation, less or equal to 12MW (and thus connected at HV level), a very attractive buy tariff. All energy produced can be sold, according to the following tariff:

Annual Operation Duration	Tariffs for the 5 first years	Tariffs for the next 10 years
<=2000 hours	83.8 €/MWh	83.8 €/MWh
From 2000 to 2600	83.8 €/MWh	Linear interpolation
2600 hours	83.8 €/MWh	59.5 €/MWh
From 2600 to 3600	83.8 €/MWh	Linear interpolation
Above 3600 hours	83.8 €/MWh	30.5 €/MWh

A second support for the development of wind energy is the use of bidding processes for larger windfarms, greater than 12MW. In 2004 a process was launched for 500MW for off-

	short units (each being less than 150MW) and a second is in preparation for a total capacity of 1000MW of terrestrial units. In these processes, each competitor proposes a buy price, which will be guaranteed to him during a given period of time (15-20 years). The lowest price offer is to be selected. The excess costs of guaranteed tariffs are supported by all the consumers on a basis of annual evaluation by the regulator. Practically, EDF-Producer is requested by the law to buy the electricity produced by the units less than 12MW (wind farms as well as CHP and small hydro) and has responsibility for running generation plants to include these wind farms. Thus, he must manage his other power plants to globally fulfil his consumer demand at any time. As a "balance responsible", his deviations are penalised through the adjustment mechanism. The global "over-cost" (difference between the price of electricity paid by EDF-Producer and the cost of the same electricity which would have been produced by his own power plants) is estimated by the French regulator and is reallocated on each customer invoice at a rate of 0.3 €/KWh (in 2002). This money is paid to EDF-Producer.
Germany Incentive schemes	***Germany*** 

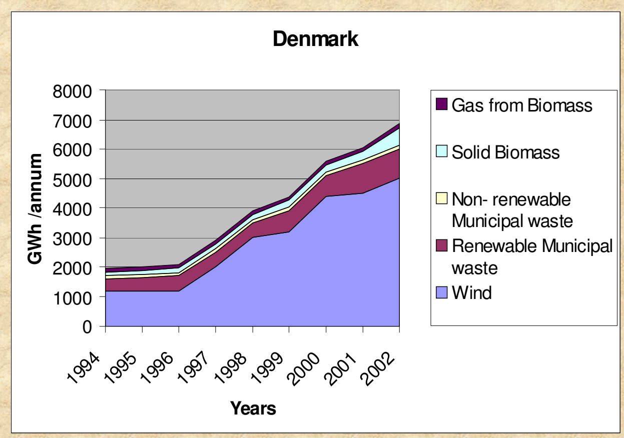
Problems

Germany

- Purchase obligation on distribution and transmission operators (regional variations ironed out by inter-operator compensation schemes)
  - Network operator closest to plant to accept, even if upgrade required
- Obligation on final customers to purchase renewable energy + favourable tariffs for renewables
  - Strong public support
- Hydro, biomass strong and wind 4% (2002) national consumption and 50% of European
- EEG – fixed tariffs for wind projects for 20years (decreasing annually)[9 years for plant more than 3 miles off-shore]
- Shallow network charges for renewables but can recover in TUOS charges
- Connection works contestable
- Government 2002 €30m for research (20 projects)

Denmark
Incentive schemes

Denmark

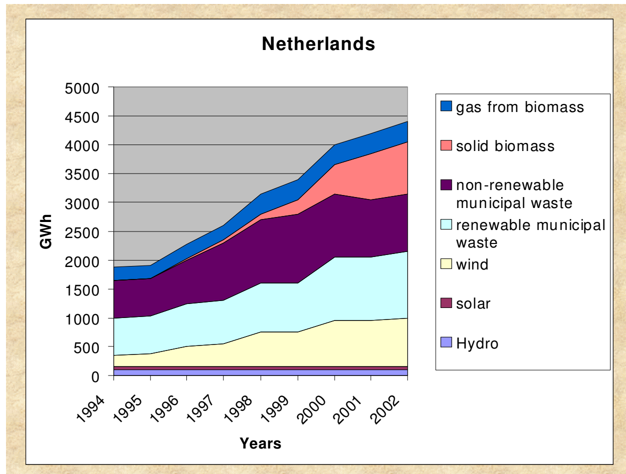


Problems

Denmark

- All electricity customers can choose supplier – to maintain security only part of tariff competitive
  - Open Grid access
  - Small scale only pay distribution connection costs provided they request at 20kV or below
  - Priority access to small scale renewables and CHP
- Green purchase obligation (40%) on all-parties
  - price fixed according to type of plant. Hope to get this down to gas fired CCGT eventually
  - Wind price depends on when the turbine was installed and location (on-shore / off-shore & within Planning designated areas)
- Small scale CHP and hydro under 10MW counts
- 35 small scale waste plants (4PJ electricity and 26PJ heat)
- Green research funding from companies fully tax deductible
- Future may be market related incentives based upon negotiate securities & customer renewable quotas. Securities not implemented until there is sufficient market liquidity by more Member States adopting the system

Netherlands Incentive schemes Problems	***Netherlands***



USA

In the US, the primary incentive scheme to promote investment in wind energy is the PTC, or Production Tax Credit. This is a tax credit of 1.8 cents per kwh for energy produced from a wind plant which goes into service during the period of the tax credit. With the PTC in place in 2003, the wind industry saw a near-record addition of 1,687 MW of new capacity. In mid-2004, the current installed wind capacity in the US is approximately 6,400 MW. It is expected by wind industry sources that if a stable business environment could be created, it could lead to a cumulative capacity of 100,000 MW by 2020.

Because of the lack of consistency in the policy environment regarding the duration of this tax credit in the US, the market has suffered a number of “boom and bust” cycles. The tax credit expired at the end of 2003, for the third time in five years. There were strong expectations that wind capacity

	additions for 2004 could have exceeded the 2003 level if the extension had been signed into law during the first quarter. Minimal new capacity will be added until the extension takes place.

	Appendix 2 - Balancing Resources
	<u>Thermal and combustion engine Plant</u> This type of generating plant is generally based upon one of three principles.
Steam cycle plant needs time to for all parts to expand evenly when starting from cold **Times are dependant on plant design and envisaged duty**	**Steam plant** The most common historical plant was steam cycle equipment where water was turned in high energy steam by burning fossil fuel. The steam is used to create rotational energy by expanding it through a turbine. The boiler exit temperature tends to be about 538^{0}C (oil firing) or 565^{0}C (coal firing) into the high pressure turbine (say 160bar). Where regenerative reheat is used the steam returns to the boiler after expansion in the high pressure turbine and the same temperature is achieved for entry to the intermediate pressure turbine. Any attempt to suddenly admit high pressure steam at these temperatures to either turbine when cold would create metallurgical stress. Also uneven heating of the rotating and stationary parts would cause differential expansion which would result in the blades rubbing on the casing. Different sets are designed for different duties, and the time to run-up a set from cold or warm varies depending upon the duty cycle for which it was designed. There was a move towards larger plants with 200MW 400MW and 660MW being common. The driver was a 20% capital cost saving for each doubling of plant size. Total energy conversion efficiency was about mid 30's%.
	It is this combination of large unit size and long pre-heating time prior to start-up which creates the inflexibility of the type of plant when considering balancing energy.
It can take 30mins to one hour to off-load a steam plant	It takes between 30 minutes and one hour to off-load this type of plant, prior to shut-down. In general, when such plant is taken off the system, it remains HOT for a few hours (depending largely on its level of thermal insulation). For less well insulated plant it could be as little as two hours and for more insulated units it could be as long as 6 hours. Within this period the best response plant can be re-synchronised in 10 minutes and achieve full load after another 20 minutes, but most plants take considerably longer. When a plant passes outside the HOT period, it is defined as WARM and requires preheat time so that full output could be 2 or 3 hours away. Plant which has been allowed to become COLD by being off for in excess of say 24 hours, may take up to a day to return to service.
Steam plant cannot	Steam cycle plant requires large pumps, fans and other

operate at very low output but emissions restrictions may be the first limit	ancillary equipment. The energy requirements of these units make it uneconomic to operate the plant below about 40% of nominal generating capacity. Other limits may come into place first, e.g. emissions control.
Plant state defined as HOT, WARM AND COLD	In summary this type of plant operates between a minimum generation level of about 50% and its maximum declared output. Its operation needs to be planned carefully to avoid sets being allowed to become cold. Merchant plants bid to reflect this and in centrally dispatched merit order systems it is part of the dispatch rules. Plant maintenance schedules are driven in part by the number of HOT, WARM and COLD starts performed.
CCGT **OCGT**	**Combined cycle plant** Gas Turbine Plant fall into two types: • Combined Cycle Plant • Open Cycle Plant.
	Combined cycle plant raises the total energy conversion efficiency from mid 30's to mid 50's% by using two separate thermal cycles. In the first or gas cycle, air is compressed into a combustion chamber were fuel is burnt to expand the gas. The products of combustion are potentially large in volume and drive an expansion turbine on the same shaft as the compressor. The shaft also drives an electrical generator.
	The still hot output gas is used to generate steam and a steam turbine is operated as above, except that the steam conditions are less extreme. One further difference is that the steam turbine is likely to be operated in sliding pressure mode rather than fixed pressure. This increases efficiency by one or two percent but the steam turbine part of the unit then has no response. The steam turbine may have a separate shaft and generator or it may share the same shaft with the gas turbine.
Gas turbine rapidly available but, efficiency poor until the steam turbine is available (hours)	The important feature of this plant is that at mid 50's% efficiency it reduces carbon pollution over traditional steam units and thus for both economic and environmental reasons it tends to be base load plant. It therefore tends to be unavailable for balancing. If it is to be used in this way, the gas turbine alone could be available in between 15 minutes and 30 minutes. The steam turbine could still take 12 hours from COLD. It is common to have to take the gas turbine off-load for a period to run-up the steam turbine. With the gas turbine alone, the unit has an efficiency of 30% or less.
Emissions limits	While theoretically a gas turbine may be operated down to a point where there is no net electricity output, pollution limits

dictate minimum running	usually prevent this and limit operation to about 45% of total CCGT output.
OCGTs available in minutes but expensive and high emissions	**Open Cycle Gas Turbines** These machines are low efficiency compared with CCGTs and therefore high operating cost (between 3 and 6 times CCGT) and high carbon emission plants. They are however available in under 12 minutes from cold to fully loaded. Plants are common up to 200MW.
Diesels – Low speed versus medium speed, rapidly available but expensive and high emissions	**Reciprocating Engines** The most common engine for power systems generation is the slow speed diesel unit. These units can be started and loaded relatively quickly. The other main unit in power systems is the smaller medium speed diesel commonly used as emergency generation in factories and commercial premises. The units are high operating cost and high carbon.
Hydro – very good for balancing wind, but lower the efficiency of one renewable source to make room for another; also there may be dry seasons	**Hydro Systems** Hydro systems are likely to present a substantial benefit as a source of balancing energy. It must however be remembered that when only a little balancing energy is required, even hydro systems will be operating inefficiently. It is therefore at that stage a question of balance between loss of efficiency on one renewable scheme to gain benefit from another. It is also common to find low hydro periods. In run of river schemes there may be very little opportunity to maintain an energy reservoir, while in dammed schemes the judicious use of the stored potential energy of the water greatly affects the system economics. Trends, predictions and Monte Carlo simulations all form part of the process of attempted minimum cost optimisation of mixed hydro and thermal schemes. Adding variable generators to such schemes would require optimisation model modification, but again it can be treated as negative load.

Appendix 3 - Use of Interconnectors

Use of Interconnectors
Three different interconnection principles are applied in modern power systems and they offer different support to domains with variable generation:

AC interconnectors automatically respond to generation /load balance in various domains

- AC interconnection, where the system which is deficient in energy automatically draws more energy from the interconnected system. Effectively the deficient energy system "wants to" settle to a lower frequency but the higher system drives energy into it to maintain its standard frequency operation. If both are deficient in energy the frequency falls until either a new energy balance is achieved within an acceptable tolerance or load is automatically shed by a defence mechanism.

  It is important to be clear that the transfer across an AC interconnector is a matter of fundamental physics and given two generation profiles in the two domains, the advance and retard angles of the two systems will drive the flow irrespective of the desire of either System Operator. The only way to interfere with the flow is to change the generation dispatch in at least one of the domains.

AC interconnection flows can be controlled by FACTs or transformer based power flow devices

- Powerflow controlled AC interconnectors, are used for a variety of purposes in power systems. The physical characteristics vary with the type of powerflow controllers used. At the slow end, the devices resemble quadrature boost transformers, possibly also with reactive power tap-changers, hence allowing a range of export or import of both active and reactive power. At the fast end, this control would be achieved by power electronics. There are opportunities to use transformers with electronic tap-changers as a medium range device. For the slow devices, they will initially behave as an uncontrolled AC link, allowing the power ramp to be responded to by both systems, but then depending upon the control algorithm applied to the tap-changers they will slowly (minutes) try to restore the original target flows. This controlled flow only works when they are in parallel with other link paths between the domains, else the fundamental physics mentioned above takes over.

	Faster devices can completely block the ramp in one domain from another and can restrain the amount of support which one domain can provide the other, hence acting as an auto-defence mechanism.
DC flows are controlled	• DC interconnection effectively isolates the two domains and the transfer in either direction is independent of the frequency in either domain. Functions can be installed to reflect the market economics associated with provision of response, reserve and emergency assist. Each system can be used to stabilise the other. In essence the link characteristics are selectable and thus completely within the control of the owner / operator.
Interconnectors are used for frequency response and trading; they may be more valuable in these roles	In making an assessment of the economic use of interconnections to balance variable energy sources, it is important to consider the alternative uses of the power conduit. An example serves to illustrate this point:
Example	***Consider a 1000MW AC link between System Operator domain A and B. To simply the discussion, there is always a dominant flow from A→B. The flow is >500MW for 60% of the time and >800MW for 10% of the time, at peak loading time. It is a merchant interconnector, which trades various capacity products differentiated by time and firmness. There is 1000MW of variability to be managed; how should an assessment be made as to the use of the interconnector?*** *In the example, the market will ultimately decide because the interconnector is a merchant plant, but in order to plan the transmission system, it is necessary to guess the market position.* *First assume that the variability is only in domain A. Since the dominant flow is always from A→B, the balancing make-up flow will oppose the dominant flow and hence reduce interconnector net physical flows. In this sense, it is economically free. That is not to say that the interconnector operator may not make a charge, but the charge should economically reduce to just below the cost of the cheapest alternative. In a regulated regime, it might be controlled to the administrative cost of the "superposition" management. To make use of this support with AC interconnection the "A" System Operator would simply dispatch the variable generation as if it was firm for 100% of the time.*

		Power would automatically flow from "B" as needed. With DC interconnection the power order of the link would be changed either manually or automatically. *Now take the more challenging case of the variable generation being located in "B". If make-up balancing power is to flow from "A" it may displace other flows on the interconnector. Economically, had this original energy been available more cheaply in a timely way, from generation located in "B" who would have used the interconnector to transport it? The fact that, in domains with separate capacity markets, traders paid to reserve capacity, shows that prices in "B" are likely to be higher than in "A". To some extent traders are buying a price hedge, but if the risk of high prices was small, they would not have invested in the interconnector capacity. In LMP markets, the actual pattern of interconnector use is driven by the marginal price at the terminal nodes in "A" and "B", so the result is the same. If the capacity is purchased for a year and if for off-peak the interconnector capacity auction price was say half the premium rate, then the peak capacity units need to return the premium supplement part of the auction price over $1/10^{th}$ of the time available to off-peak units. Put another way, traders need to see each unit of 200MW X 876hrs carrying the surplus part of the premium cost, else the traders would buy the energy indigenously.* *The question is, how different is the economics of transferring balancing energy on interconnectors. Supposing variability is such that the generation-loadfactor, allowing for geospread is 55% and the distribution of peaks and troughs is normal, then depending upon the form factor of the energy pattern, there will be very little time when the intermittent generation is close to zero output (say 5%). For this to attract premium rates it has to be concurrent with the system high demand periods which drive the peak charges. For our interconnector this is set at 10% of the time. Therefore if the 200MW of premium rate transfer was to be economic for make-up, it would have to earn premium annual rate over 1/20 of the units sold, i.e. only 43.8hrs. For the remainder of capacity i.e. 800MW, renewable energy flows for 55% of the time, and peak units have been accounted for above, therefore the interconnector price must be recovered by units flowing for 40% of the time.*

	The above form of calculation would need to be adjusted if existing use of the interconnector has a load factor. *In LMP markets, merchant interconector payments are a cost which determines the nodal price differences.*

Appendix 4 - Wind Energy Conversion Technology

Characteristics of wind power generators

<u>Induction Generators</u>

First generation – induction generators squirrel cage rotors

Most wind generators installed at the end of the 20th century were ordinary induction generators, usually with fixed capacitance to correct for the reactive power demands of that type of generator. An induction generator is essentially an induction motor where the slip is negative, i.e. the rotor speed is slightly ahead of the rotating flux in the stator winding. The induction generator has a squirrel cage rotor which draws magnetising current from the stator giving rise to a high reactive power demand when fluxing, as when the generator circuit breaker is first closed.

Only about 2% slip – so really constant speed generator

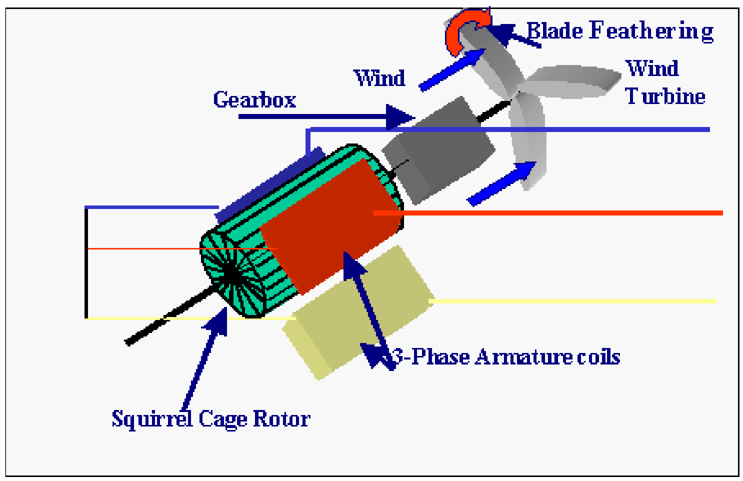


Fig A4.1 - Schematic of an Induction Generator

The useful operating range of the generator lies between synchronous speed and a very small speed increase (negative slip). Thereafter, the torque disappears and consequently the power falls off. The current remains high but will be heavily reactive drawn from the connected system.

Reactive Power varies with slip

The following classic figure shows how dramatically the reactive power demand from the network increases as the generator departs from a tight slip regime.

Capacitors fitted with induction machines

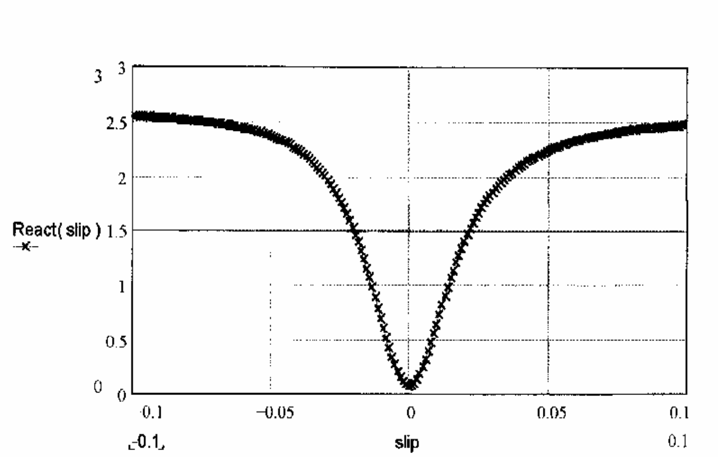


Fig. A4.2 – Reactive Power Slip

These diagrams are also useful in determining how much capacitance needs to be installed to return a machine which can exist at say 2% slip in normal operation back to unity power factor. It is common practice to install mechanically switched capacitors as part of the wind farm and to size them so as to leave the entire assembly slightly inductive as seen from the grid. This inductive bias helps to prevent self-excitation of the generator in the absence of the grid system.

The simple equivalent circuit of the induction machine is shown in Fig. A4.3:

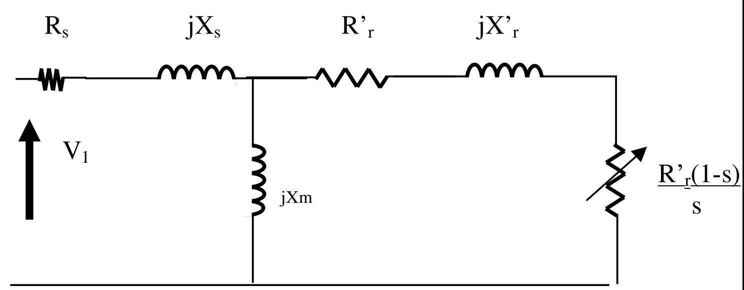


Fig. A4.3

Where
V1 is the supply voltage
R_s is the stator resistance
jX_s is the stator reactance
jX_m is the magnetising reactance
R'_r is the rotor resistance
jX'_r is the rotor reactance
s is the slip in per unit.

Dynamic reactive power devices allow better management

A refinement is the so-called 2-cage rotor model, in which the locked rotor and normal running impedances are modelled separately and placed in parallel. In this 2-cage model the locked rotor impedance can be used to calculate the fault contribution. The model is for steady state or pseudo-steady state calculations only.

At least one manufacturer has replaced the mechanically switched capacitors with a Static Voltage Compensator (SVC) to improve performance. This helps to ride through voltage dips, improves the steadiness of power as the turbine blades pass the tower, and reduces the potential for the system voltage to vary widely in sympathy with the wind. STATCOM is another possibility for this application. These FACTs devices serve to support and smooth the voltage by rapidly injecting and sinking large amounts of reactive power. An SVC may operate from the inductive range through to the capacitive range. Where only capacitance is required, a thyristor switched capacitor is available.

Doubly-Fed Induction Generators

DFIG

The following diagram (Fig. A4.4) shows a hybrid machine called the doubly-fed induction generator (DFIG).

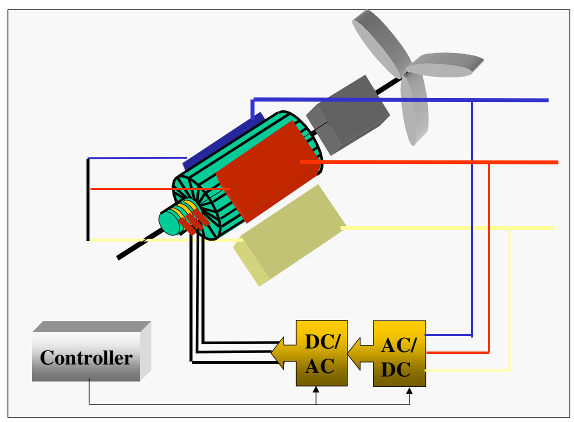


Fig. A4.4

Stator connected directly but rotor wound and controllable

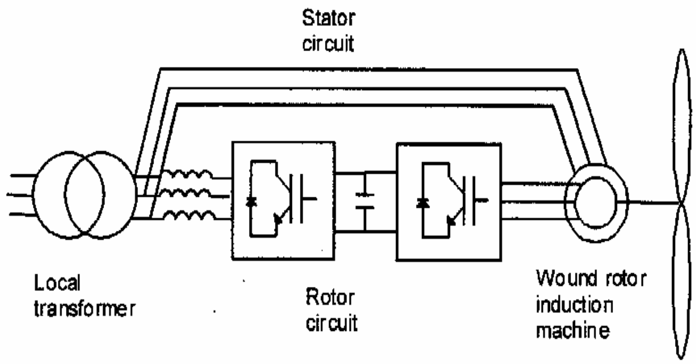


Fig. A4.5

The stator is connected to the low voltage (690V in Europe) side of the wind turbine transformer, but in the case of the DFIG the rotor is a 3-phase coil winding connected with the outside world via slip rings rather than an internally short circuited winding. Active power is drawn from the grid to supply the rotor via an AC/DC and DC/AC voltage source convertor link. The rotor currents can be completely controlled by an IGBT control circuit. The frequency, which the rotor side convertor targets, is that which when superimposed on the rotor speed gives rise to a synchronously rotating field in the airgap.

Add stator and rotor power

The active power exchange with the grid is the sum of the power supplied to the grid from the generator stator and the power exchanged with the rotor (minus the convertor losses). The stator always exports active power to the grid. The rotor can either import or export active power.

Slip range up to ±16% steady state and ± 30% transient

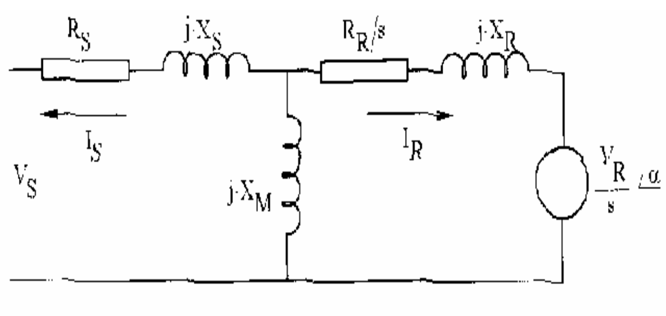
The DFIG machine has a number of advantages over the induction generator. Because the rotor frequency is essentially decoupled from the grid it can operate over a wider slip range - ±10% to ±16% compared to 0% to -2% for an induction generator. The wind turbine is not restricted to a single unique operating speed. This allows the blade tip speed to be varied over a range to better match the wind speed and maintain an efficient operating position for a range of wind speeds.

Flicker reduced

A further benefit of this technology is that by modulating power output using the firing angles of the IGBTs there is a reduction in the power variations caused by the blades passing through the windshield of the turbine tower.

Starting current is active power

Reactive power is controllable. The initial machine magnetisation flux is established from the rotor and the grid

Reactive power generation controllable	side convertor still draws only active power. The reactive power is created by the rotor side convertor by the firing angle and thus the field angle relative to the rotating field in the stator. The stator similarly appears as a unity power factor device even at starting. Where the turbine control system is required to supply or absorb reactive power, the lead or lag of the rotor field can be controlled by the rotor side convertor. Since the synchronous rotor field vectors can be shifted angularly as in the lead and lag of a synchronous machine, the machine can be modelled with direct (d) and quadrature (q) axis components. Fig. A4.6 shows the equivalent circuit for a DFIG.
Equivalent Circuit (From N Jenkins)	 **Fig. A4.6** Where R_S is the stator resistance X_S is the stator reactance R_R is the rotor resistance X_R is the rotor reactance X_M is the leakage reactance s is the slip speed V_R is the rotor voltage and α phase difference. The phase difference and magnitude of the rotor voltage determine the active and reactive power which is delivered to the terminals of a DFIG. In an ideal device, maximum active power exchange takes place at $\alpha = 90^0$ or 270^0 at which time there is no reactive power exchange. Reactive power exchange is maximised at $\alpha = 0^0$ and 180^0. The DFIG can therefore manage active and reactive power independently by controls on the grid and rotor side convertors. It requires a convertor-invertor arrangement, but the maximum expected power through the convertor to or from the rotor is about 25% of the total output power of the generator. Therefore the convertors are cost effective. There is however a downside to the technology. Under serious system fault conditions the grid voltage may be

close to collapse and attempts to meet a target voltage or power factor will drive very high currents into the rotor and hence through the power convertors. The convertors would be thermally damaged by these currents, so the equipment is generally closely protected by an electronic rotor short circuiting mechanism, often called the "crowbar". This can be active within 20ms and is followed immediately by a machine trip. Conventional synchronous generators supply reactive energy to the fault and then on fault clearance they participate in the system recovery.

Recent developments to achieve fault ride through have inserted impedance into the crowbar circuits and/or the DC link.

Fig. A4.7 shows a typical DFIG active and reactive control system modelled by UMIST.

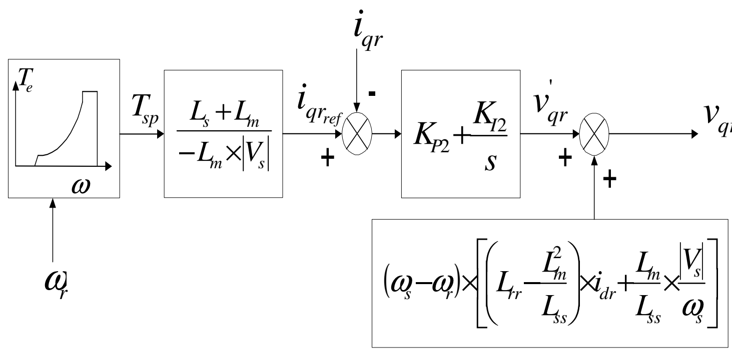


Fig. A4.7 Active Power Control Strategy to optimise wind extraction energy

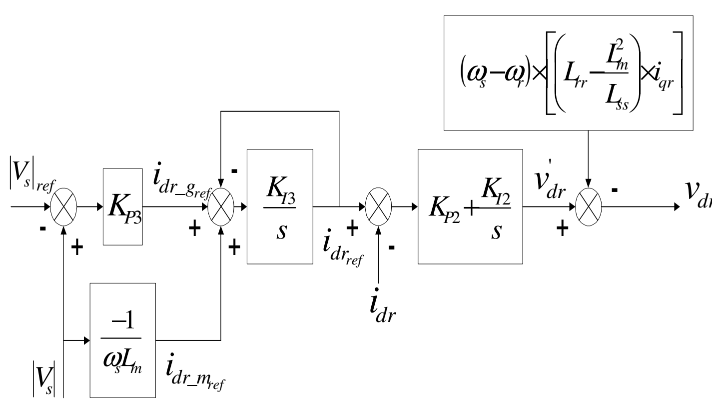


Fig. A4.8 Power Factor / Voltage Control Strategy

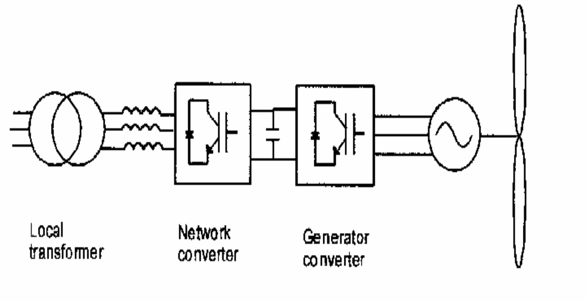
Appendix ## explains these control diagrams.

The DFIG generator can therefore manage active and reactive power independently by controls on the grid and rotor side convertors. It requires a convertor-invertor arrangement between the rotor slip rings and the generator output, but the maximum expected rotor power through the convertor to (or from) the rotor is about 25% of the total output power of the generator. This makes the convertors cost effective. There is however a downside to the technology. Under serious system fault conditions the grid voltage may be close to collapse and attempts to meet a target voltage or power factor will drive very high currents into the rotor and hence through the power convertors. The convertors would be thermally damaged by these currents, so the equipment is generally closely protected by an electronic rotor short circuiting mechanism, often called the "crowbar". This can be active within 20ms and is followed immediately by a machine trip. Conventional synchronous generators supply reactive energy to the fault and then on fault clearance they participate in the system recovery. The challenge has been to mirror this performance using DFIG machines.

<u>Full Range Variable Speed Wind Generators</u>

Direct drive turbines have no gearbox or drive train, and consequently no high speed mechanical (or electrical) components. Such high speed drive components operate at around 1500 rpm, as does the generator. By contrast, all moving parts in full-range variable speed devices turbines, including the blades, rotate at a speed of between 10 and 22 rpm depending on the prevailing wind conditions, which increases the reliability and efficiency of the turbine. Direct drive turbines are also much quieter than gearbox machines as they do not produce mechanical or tonal noise.

Variable speed turbine blades slow down and speed up with the prevailing wind, which enables the turbine to optimise its tip speed to extract maximum energy from the wind resource. They are quieter at low wind speeds than a fixed speed turbine. This is because they will operate at 10 rpm at start up wind speeds, whereas a fixed speed turbine will operate at between 35-40 rpm.

	 **Fig. 4.9** Electrically behave as a source behind a voltage source convertor. The characteristics of the steady state energy output therefore mirror those of the source, assuming that the convertor does not distort the ability of the source to deliver energy. The dynamic and fault level performance are entirely controlled by the convertor control system, but it is reasonable to believe that the convertor delivers almost no fault contribution. In dynamic terms, the convertor may be controlled to provide the required features, and can offer some of the STATCOM facilities related to reactive and selective harmonic control.

Appendix 5

Reference Information on Wind Penetration in Different Countries

Area - Australia

(Main Continental Landmass - 7,692,024 sq. km.)

Geography

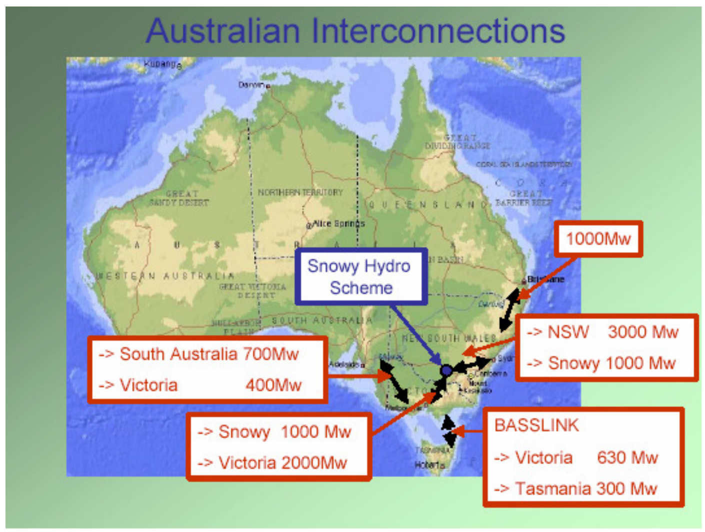


Figure 1 Australian Interconnection

Despite large landmass uncertainty management is difficult due to limited interconnection capacity

The area is a large landmass with loads located along the coast and few limited capacity interconnection.

System Generation & Loading

Hydropower

Coal fired, gas powered & small hydro in all 4 states. Large capacity (restricted energy) hydro in New South Wales (Snowy Mountains).

31.4GW max. demand 10.3GW min. demand

System minimum load (10.3GW) is approximately 30% of system max. loading (31GW). The load is distributed among the States as shown in Table 1:

Table 1 State Loads

State	MW
New South Wales	12400
Victoria	8400
Queensland	7700
South Australia	2900
Total	**31400**

Western Australia interconnected system

There is a separate but interconnected system in Western Australia known as the South West Interconnected System which has a 1000MW minimum demand and a 2700MW maximum demand.

Interconnection

The area is geographically large and well interconnected. AC links operate at 330kV, 275kV and 22kV. Queensland – New South Wales and Victoria – South Australia are HVDC light. Table 2 shows details of the interconnectors.

Table 2 Interconnection in Australia

Interconnection	Type	AC/DC	Capacity MW
Qld-NSW	Double circuit	AC	Qld – NSW 950 NSW-Qld 700
Qld-NSW	DC light Direct Link	DC	180MW
NSW-Snowy	4 circuit 330kV	AC	NSW–Snowy 1150 Snowy–NSW 3200
Snowy - Vic	3 cicuit 330kV	AC	Snowy- Vic 1900 Vic-Snowy 1100
Vic-South Australia	DC Light Murray Link	DC	Vic – SA 220 SA – Vic 120
Victoria-South Australia	Double circuit	AC	Vic – SA 460 SA – Vic 300

Figure 2 shows the location of interconnection.

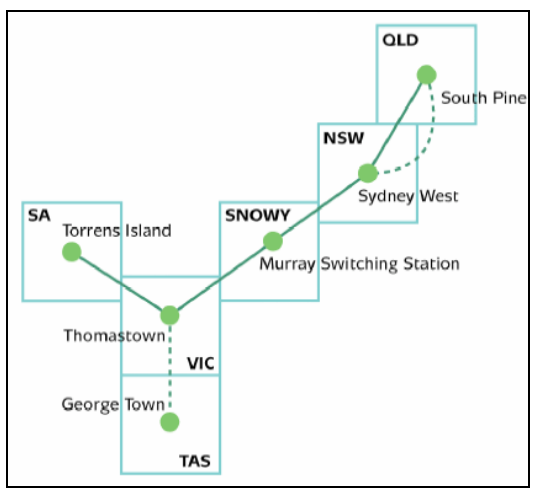


Figure 2 The Regions of the National Grid and the existing (——) and proposed (- - - -) interconnections.

Wind Penetration

2003 – 180MW
envisaged 2.1GW

The 2003 level of wind powered generation on mainland Australia was 183 MW. The envisaged wind penetration is 600MW in 2010. This constitutes 6.7% of system peak or 20 % of system minimum. Likely areas are shown in Figure 3. It is expected that this would give rise to approximately 3.4% by energy consumption. NEM has no formal target for wind but Queensland has a target of 0.5% in 5 years. Western Australia estimates 250MW by 2006-07 (minimum load 1000MW). Western Australia operates 28 small isolated systems based on wind/diesel or wind/reciprocating gas plant.

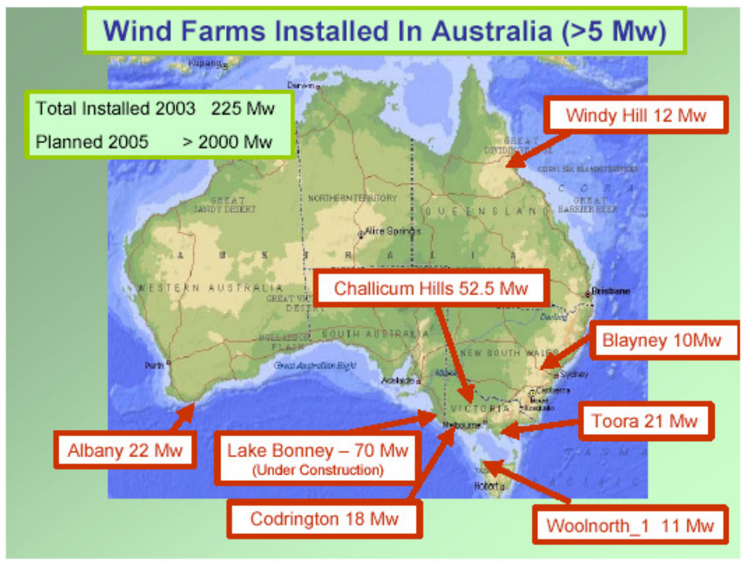


Figure 3 Existing Wind Farms as of 2003

Despite large area of the continent the wind resources are located along narrow coastal corridors. The diversity is often insufficient to eliminate wind fluctuation concerns.

Wind power balancing resources

The region is sufficiently large and well interconnected (Figure 1 and Figure 2) as to be able to reduce the chances to negligible, of sudden loss of wind due to a non-network cause.

In NEM's management area, Hydro-generation (when available) can be used to balance; otherwise thermal plant.

In Western Australia there is 90MW of contracted / interruptible load.

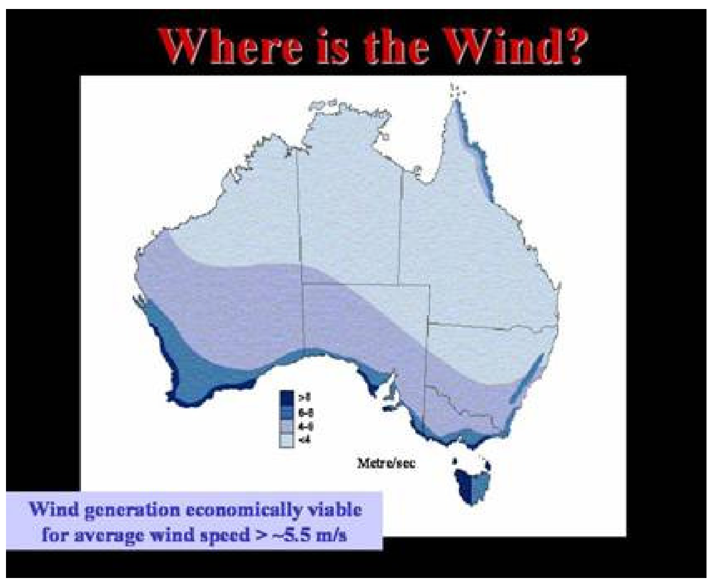
Analysis

Looking at the factors above:

Medium and long term wind prediction errors manageable with hydro

- **Climate**
  Australia does have significant wind resources. The southern section of the continent lies in the path of the westerly flow, south of the anticyclone mid-latitude weather systems in a zone known as the roaring 40's (named after the latitude zone it occupies). These winds reach a maximum around Bass Strait. The passage of low-pressure and associated frontal systems brings most of the wind resource to southern Australia. The position of the weather systems and the strength of the fronts determine how far north these frontal systems penetrate. Strong systems may immerse the entire southern half of the continent, while weaker systems skim the southern coasts. Northern Australia also experiences monsoon and trade wind systems (southeast trades).

Wind farms will not add to firm capacity



- **hydro or pumped storage**
  Large schemes include Snowy Hydro and Southern Hydro.
- **interconnection**
  Management of some interconnections is likely to be a major issue, particularly Vic-SA.
- **rapidly available plant**
  hydro and gas turbines
- **reserve level on traditional plant**
  We have eight frequency control ancillary services markets, and do not use the traditional concept of "reserve" in time-frames of up to 15 minutes. Beyond

that time "reserve" is not dispatched, but the market is informed when it is below set levels for each region. The level for NSW is now negative.

- **size of traditional generators**
  The largest generators in NSW are 660MW (Mt Piper, Vales Point, Eraring, Bayswater), 500MW in Victoria (Loy Yang), 450MW in Queensland (Tarong North) and 478MW in South Australia (Pelican Point). The largest generating units are 660 MW rating, sometimes run above 700 MW. These are black coal fired thermal units.

Taking these factors together it seems that with the large land mass there is unlikely to be a short-time (up to 1 hr) wind variability or total system continuous ramping issue. Nonetheless the system will need to be protected from an unusual ramping event.
As time horizon increases, wind projection is less certain and a weather front may cover a larger area, therefore balancing energy will be required. This energy is likely to come from hydro plants, hence affecting both the efficiency of hydro generation and any hydro/thermal optimised usage plan.
In the ultimate case of total calm or excessive widespread storm, either protracted load curtailment or alternative capacity are required. This is part of the economic cost of wind energy. The risk could be expressed in a Loss of Load Expectation or a Mean Time Between Failure to Supply. In either case, additional cost v firmness is a stakeholder issue.

Geography

Figure 4 Tasmanian Map

The area is an island off the South coast of the Australian mainland. At present this is an isolated system, HVDC interconnection with the state of Victoria will be commissioned in late 2005.

An island electrically connected to Australi

Area - Tasmania

(Medium island - 68,102 sq. km.)

System Generation & Loading

Main generation system hydro

Generation is largely based upon large scale hydro plants, with large storage capability. Hydro generation capacity is 2250MW. One thermal gas fired power station with installed capacity of 240MW providing energy during draft periods. The area often experiences energy short in late summer (March - May)
System minimum load is (1.0GW). System max. load is (1.7GW).

Max load 1.7GW
Min. load 1.1GW

Interconnection

630MW link to Victoria

The area will be linked to mainland Australia by HVDC interconnector called Basslink. The north bound power transfer will be 630MW and the south bound transfer is up to 480MW. Considering the costs of interconnection (300km undersea cable) future interconnections are not planned at this stage.

Wind Penetration

Present 65MW
Envisaged 580MW

The 2003 level of wind powered generation in Tasmania is 65MW. The envisaged wind penetration is 580MW. This constitutes approximately 34% of system peak or 58 % of system minimum. Four principle sites have been identified as having potential as follows:

Woolnorth	130MW
Heemskirk	160MW
Musselroe	120MW

Figure 5 shows stage 1 Woolnorth development.

Figure 5 An operating wind farm - Woolnorth Wind Farm

Other states within Australia have wind generation in service and planned as detailed in Table 3.

Table 3 Wind Generation (MW) in Service and Planned

State	In Service (2003)	Planned
NSW	17	550
Vic	92	921
SA	35	2076
Qld	12	52
WA	28	247

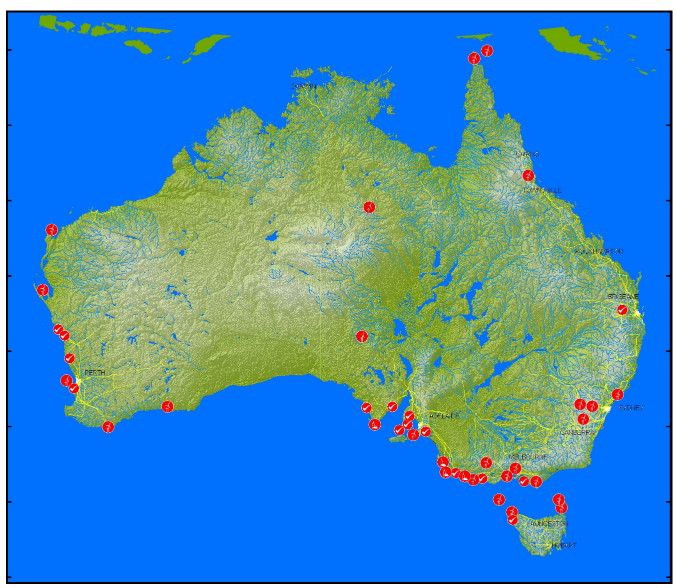


Figure 6 Existing and Planned Wind Farms as at 2003

Ramp rate important
Hydro may manage ramping but accelerated aging

Wind power balancing resources

The region is small hence the maximum ramp from sudden

	wind reduction needs to be assessed. The utility – Hydro Tasmania, is investigating intermittency effects. (See additional comment in New Zealand). **Analysis** Looking at the factors above: • **Climate** The mid-latitude westerlies, a belt of winds squeezed between the subtropical ridge and the sub-Antarctic trough and affectionately known as the Roaring Forties, affect Tasmania directly. The greatest strength and persistence of these winds occur during late winter and early spring, but the speed and direction vary with the passage of high and low pressure systems. In the summer months, when the westerlies are weak, afternoon sea breezes become the predominant wind in most areas. Periods of more humid north-easterly winds are most likely in the summer and early autumn. The highest recorded wind gust in Tasmania are 182 km/h at Cape Grim and 259 km/h at Musselroe. Higher, unrecorded gusts are likely to have occurred about the south-west coast. • **hydro or pumped storage** Most of hydro plant can be available to provide regulating reserves on a costs basis. • **interconnection** The first interconnection will be commissioned in 2005. • **rapidly available plant** Most of hydro station can be started within 5 minutes period • **reserve level on traditional plant** Adequate reserve levels are defined by the System Controller responsible for the system security. The reserves are defined in terms of fast reserves (primary), slow reserves (available in sixty seconds) and delayed reserves (available in 5 minutes). In hydro based system fast rise reserves are at premium. At present hydro plant is operated at maximum efficiency and this results in about 10 to 15% of slow rise reserve. When Basslink is commissioned this responsibility will be passed to NEMMCO. Basslink frequency controller is designed to allow transfer of ancillary services (reserves). With wind generation requirements for additional contingency reserves depends on availability of fault ride through capabilities. Regulating reserves are expected to rise marginally

	The services to cover loss of the largest generating unit or the largest load may increase if necessary to cover the possibility of wind generation changing adversely during the incident. The regulating services ("AGC") are likely to increase to cover wind generation variation. • **size of traditional generators** The largest size of generators is 144MW. This will change due to HVDC interconnection. Monopolar link with export capability of 630MW and import of 480MW will be the largest contingency which will need to be managed using System Protection Schemes.. Taking these factors together it seems that with the small land mass there is a possibility of a short-time (up to 1 hr) wind variability or total system continuous ramping issue. The system will need to be protected from an unplanned ramping event.
Hydro /wind balancing	As time horizon increases, wind projection is even less certain and a weather front may cover the whole island, therefore balancing energy is required. This energy is likely to come from hydro plants, hence affecting both the efficiency of hydro generation and any hydro/thermal optimised usage plan.
Very high wind gusts experienced	In the ultimate case of total calm or excessive widespread storm, either protracted load curtailment or alternative capacity are required. This is likely to come from hydro, providing hydro is available. Wind power means that either more energy from hydro can be profitably exported to Australia or by conserving more water Tasmania may import less in the dry season. This is a special circumstance where the economics may favour wind?

Studies Undertaken and Lessons Learnt

There is a difficulty in connection of new generators to the power system quickly, due to problems and lack of availability of the WTG analytical models and this has been an impediment to gaining connection agreements

WTG technology improvements are required to allow fault ride through, better voltage control and provide a response to frequency deviations.

Treatment of wind as an intermittent small scale form of generation has been found to be no longer appropriate and that regulatory changes are to be made to how wind generation is being treated within the national electricity market.

Reference information on wind penetration

February 2003, Western Power, Western Australia,
Information paper - Technical and Commercial Issues for Access of Renewable Generation to the Western Power South West System, www.westernpower.com.au

November 2003, Outhred, H., *National Wind Power Study - An estimate of readily accepted wind energy in the National Electricity Market*, prepared for the Australian Greenhouse Office, www.greenhouse.gov.au

March 2003, National Electricity Market Management Company Limited, *Intermittent Generation in the National Electricity Market, www.nemmco.com.au*

August 2004, Ministerial Council on Energy - Standing Committee of Officials *Proposed National Electricity Rules Change Process*, Consultation Paper, www.industry.gov.au

May 2004, Transend, *Integration of Large-Scale Wind Generation*, A Report by the Large-Scale Wind Integration Working Group to the NEM Entry Coordination Group, www.transend.com.au

Area - New Zealand (Interconnected islands - 270,535 sq. km.)

Geography

Two islands

The area comprises of two main islands, the North Island and the South Island. The two islands are electrically interconnected via HVDC link and most of wind resource is on the North Island.

System Generation & Loading

63% Hydro; rest mixed.

Hydro generation makes up 63% of installed capacity; coal

See Table opposite for Demands

HVDC interconnection capacity between islands – 1GW

Present 167MW Envisaged 400MW mostly North island

/gas fired, 29%, geothermal 7% and co-generation 1%. Generation in the South Island is 3465MW (hydro only) and there is a net flow to the North Island via the HVDC link. North Island generation is 4882MW (Hydro + Geothermal + coal/gas). Under normal operating conditions the power flow is from south to north, in dry years the flow is reversed.

The system maximum loading in New Zealand is 6.1GW. The minimum is 4.8GW. The following table shows how the load is split between the islands.

	North Island	South Island
Maximum	4.1GW	3.1GW
Minimum	2.1GW	1.7GW

Interconnection

The interconnection between the two island is via an HVDC link which comprises of two poles of different technologies:

Pole 1 Mercury arc 540 MW
Pole2 Thyristor 500MW.

The HVDC transmission line runs from the Central South Island (Benmore) to the lower end of the North Island (Wellington / Haywards).

The 220/110 kV transmission grid runs in the North –South direction and transfers power to the major load centres in the North Island (Auckland) and South Island (Christchurch).

Wind generation developments are predicted to take place largely in the lower part of the North island. Therefore while the inter-island flows will be reduced with the connection of wind power to the grid, it will increase the south – north flow through the main 220 kV transmission trunk in the North Island.

It is expected that the hydro generation will complement the variability of wind generation. When the wind generation is available in the North Island, it will reduce the hydro power generation in the South island and hence the transfer of power to the North Island via the HVDC link.

Wind Penetration

The 2004 level of wind powered generation New Zealand is 167 MW and the developments were limited to only to the North Island. This constitutes 4% of the island peak demand or 8% of island minimum demand.

It is expected that installed wind generation capacity in the country will exceed 400 MW by end of 2006. Likely areas where wind power developments will take place in the future are shown below.

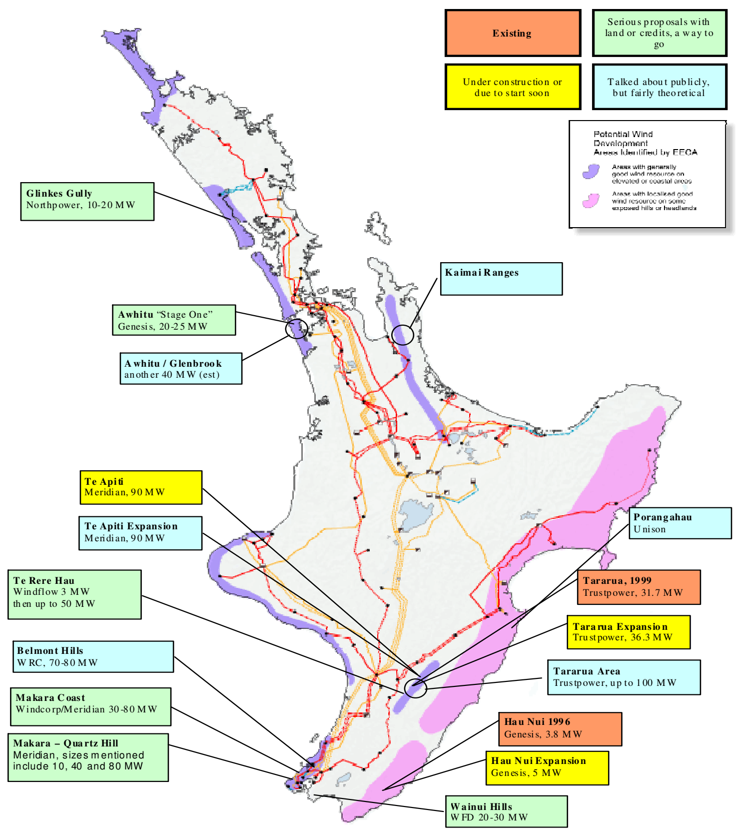


Figure - 1 Wind potential –North Island

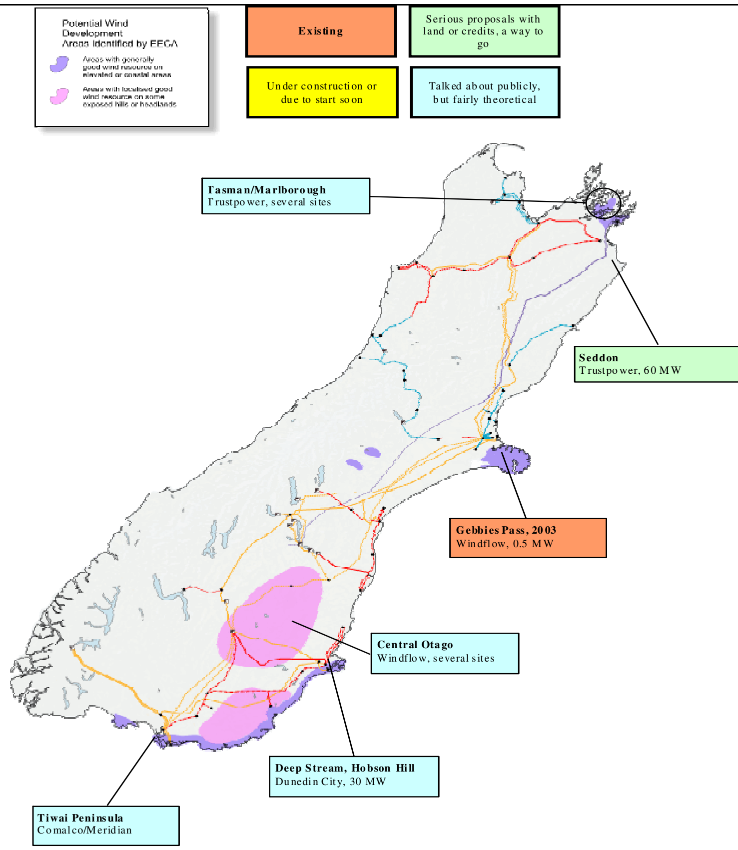


Figure - 2 Wind potential –South Island

Wind power balancing resources

At the present level of wind generation connected to the power system, the variability of wind as an intermittent source has only a very small and insignificant impact on the frequency control ancillary services. Present level of frequency regulating reserve will be sufficient to cover 99% of the deviations expected from wind power generation expected within next two years.

When the diversity of the locations of the wind farms, variations in connected loads, and other embedded generation is considered, the resulting impact due to the variability of the wind power output is further reduced. However, as the level of wind penetration increases the variability of the wind on the frequency control ancillary services as well as on the market pricing and dispatch process needs to be assessed. Further, large quantities of wind power predicted day-ahead may off-set unit commitment of large thermal plants, reducing the amount of stand by reserve (i.e. offered but not dispatched generation) available in the system.

Small wind penetration and hydro quick response, but ramp rate to be checked

Hydro /wind balance for a lot of the time	**Analysis** Looking at the factors above: ○ **Climate** No studies have been yet completed in assessing and correlating the variability of the wind power generation with the geographical diversity of their locations. Studies carried out using the data collected from a small wind farm in the North Island indicated that the variability of wind is not significant and can be managed through the present market and dispatch process. ○ **hydro or pumped storage** While hydro generation is available in both the Islands, there are no plants with pump storage capability. The dispatch is based on the price of the generation offers. However, at present, the wind generation in the North island load is likely to be dispatched prior to the hydro generation form the South Island, if they are offered at the same price, because of the proximity of the wind generation to the major load centre (Auckland) in the North island. ○ **interconnection** The availability of wind power generation is likely to reduce the power transfer through the HVDC link in the northward direction. For most of the time, HVDC has sufficient spare capacity to transfer the ramped up generation from the South island in the event of sudden reduction of wind power generation in the North Island (e.g. shut down during storms) ○ **rapidly available plant** Management of supply security at present requires dispatching of rapidly acting (within six seconds) frequency control ancillary services for covering a tripping of the large single shaft CCGTs (approximately 360 MW). The instantaneous reserves are obtained from partially loaded generators (mostly hydro machines) as well as from controlled demand reductions. It is anticipated that this level of reserve will be sufficient for covering a rapid shut down or tripping of a wind farm. ○ **reserve level on traditional plant** While reserves available from hydro and thermal generation plans are sufficient for

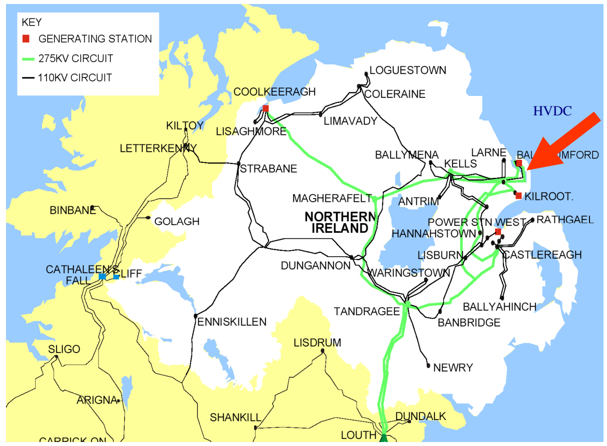
Short term wind fluctuation	covering a loss of approximately 400 MW, any further increase in reserve will displace the available capacity for generation of electricity at any given time. ○ **size of traditional generators** While the largest coal/gas fired steam plant is of 1000 MW (4x 250MW) capacity, the largest generation units consists of two CCGTs of approximate capacity 360 MW. While the geothermal plants (approx. 300 MW) generally runs as base load plants, thermal and hydro plants also take a considerable share of the base load depending on the offer prices. As time horizon increases, wind projection is less certain and a weather front may cover a larger area, therefore balancing energy will be required. This energy is likely to come from hydro plants, hence affecting both the efficiency of hydro generation and optimum and efficient use of the hydro/thermal generation mix.

Studies Undertaken and Lessons Learnt

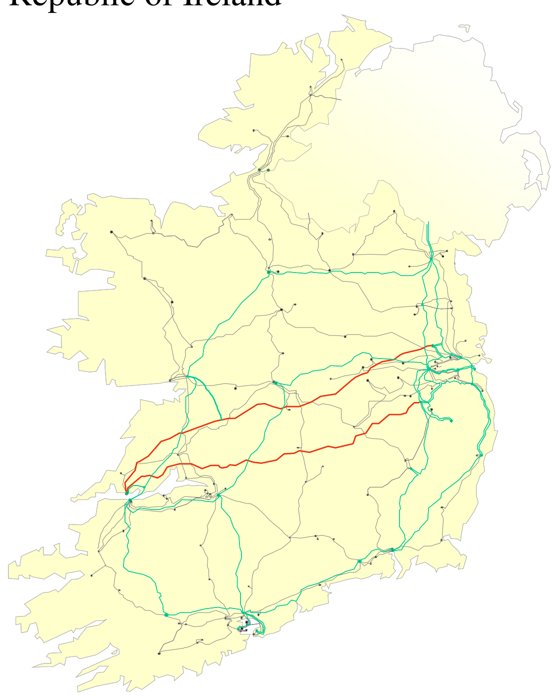
Area - Ireland (Interconnected island - Republic of Ireland (RoI) 65,000 sq. km; Northern Ireland (NI) 10,000 km.)

Geography

Northern Ireland



Republic of Ireland



One island – two states

The area comprises two nation states (Northern Ireland which is part of UK and hence those renewables incentives apply and Republic of Ireland which has separate incentives).

They are electrically interconnected and wind resource is approximately evenly distributed in proportion to the land mass and electrical load of the two states.

System Generation & Loading

NI
Installed Capacity

- Thermal and CCGT 1537MW
- Open Cycle Gas Turbines 232MW
- HVDC 450MW

Load details

- Maximum is 1850MW
- Minimum is 500MW

RoI
Installed Capacity 5282MW

- Coal 855MW
- Gas 2590MW
- Oil 820MW
- Peat 350MW
- Hydro 210MW
- PS Hydro 290MW
- Wind 167MW

Load details

- System max. Demand 4300MW
- System minimum Demand 1430MW

Hydro 7% of island load; rest thermal

Dispatchable hydro generation is present in RoI only and amounts to 500 MW incl. pumped storage (as noted above).

Interconnection

Predicted wind is in proportion to the land mass of the two domains. Interconnection within the island may be useful especially to NI in helping to reduce the short time variation due to wind.

Interconnected between NI and RoI is one 275kV double circuit tower line, each circuit being capable of 600MW + two 110kV links, which would be unstable if operated alone. N-1 standard is applied to the link. On N-2, a limiting factor is rate of change of frequency on sudden loss of the route. Internal networks limit transfers.

- Available capacity 440 N-S including frequency response; 200 S-N including frequency response

Capacity is highly used.

Interconnection between Northern Ireland and Scotland is by dual monopole HVDC link of installed capacity 500MW, but restricted by networks to 450MW winter and 400MW summer. Capacity is highly used.

Small wind penetration and hydro quick response, but ramp rate to be checked Hydro /wind balance for a lot of the time	# Wind Penetration **NI** The 2003 level of wind powered generation in NI was 83MW. Government obligation is 6.7% (4.5% of max demand or 16.6% of minimum) by consumption by 2010, i.e. 280MW (14% of max. and 57% of min.) but while the obligation is mandatory, a softer target of 10% (400MW) (20% of max and 80% of min) has been set; the obligation and target for 2012 is likely to be 12% (500MW) (25% of max and approx. 100% of min.) Clearly there is a need to curtail wind farm operations approaching minimum operation to preserve security and inertia. **RoI** At the end of 2003, there was 167 MW of wind capacity connected in the Republic of Ireland, 128 MW of which was embedded. A further 600 MW wind capacity had signed connection agreements with the relevant system operator, bringing the expected wind penetration to 767 MW within the next few years. EU directive 2001/77/EC on the promotion of electricity produced from renewable sources specifies an indicative target for Ireland's energy production from RES of 13.2% by 2010. Taking account of other renewable sources, this equates to some 985 MW of wind by 2010. This will represent approximately 18% of system maximum or 55% of system minimum. Clearly curtailment will be required.

Fig. 1 Map showing the present wind farms

Wind power balancing resources

The region is small hence the maximum ramp from sudden wind reduction needs to be assessed. Governments have also had an objective of encouraging embedded generation. This is protected by RoCoF relays, therefore inertia or at least response must be controlled if severe generation loss is not to result in cascade tripping. Hydro generation and associated pumped storage are likely to be useful as wind balancing units, but at present they are part of the primary reserve plant, so that duty would need to be replaced.

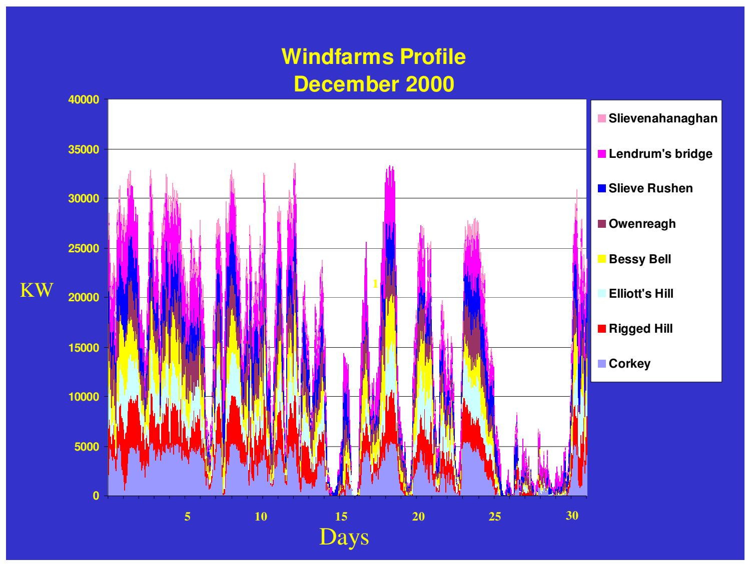
In NI there are 232MW of open cycle gas turbines, used as longer time reserve (7 minutes). These could be of assistance, but they are expensive – 2 to 3 times the cost of base load plant. Also another source of replacement plant would be needed to secure the system against a second thermal trip.

RoI has contract disconnectable load, but this is used as reserve equivalent and would have to be replaced.

Analysis

Looking at the factors above:

- **Climate**
  The Irish climate is notorious for variability - " 4 seasons in one day". A typical month output from all wind farms in NI is shown. Winter output is about 20% greater than summer. Variability of short-term output may vary between seasons, but information is still being gathered. Some very cold nights are calm and some are storm force and above. An Atlantic weather system may be larger than the island. Thus all farms may be becalmed together.



- **hydro or pumped storage**
  Plants exist only in RoI. Some are seasonal run of river stations. There is a 292 MW pumped storage plant, which may prove useful at certain times.

- **Interconnection**
  Internal interconnector capacity is valuable in reducing short time variability. The issue is that there are other competitive uses for the circuits, both in emergency response and trading. Trading or the potential of trades is valuable in curbing market power and hence there may be a significant overt and covert cost to monopolising the corridor for wind balancing.

  If the HVDC link is available to balance wind this would be a useful resource, but may

	prove a costly approach for much the same reasons noted above. ○ **rapidly available plant** The island has 611 MW of rapidly available plant – 232 MW in NI and 379 MW in RoI. This plant performs other functions, is called upon often and may be unavailable in a planning sense to balance wind. Pollution limits are also likely to limit its availability. ○ **reserve level on conventional plant** The parties have agreed a contribution to reserve. Preliminary analysis shows that about 80% of the time there is a margin above that level in Northern Ireland, but only 50% of the time is the margin above 10MW and it falls off rapidly thereafter. ○ **size of conventional generators** Thermal plants in NI are large – they vary from 200MW to 400MW as a single unit. They are therefore cumbersome to balance wind. The issue is that if a 400MW generator is to be operated, it needs to be loaded above about 240MW else it violates NOx omission requirements and below about 180MW it may start to become unstable, unless it can be portioned e.g. by turning off the steam part of a CCGT. The efficiency penalty would then be severe. Taking these factors together it seems with the small land mass there is a possibility of a short-time (up to 1 hr) wind variability or total-system continuous ramping issue. The system will need to be protected from an unplanned ramping event. As time horizon increases, wind projection is less certain and a weather front may cover a larger area, therefore balancing energy will be required. Weather forecasting is frustrated by complex systems which are often temporally disturbed by opposing air flows. This gives rise to delays or advances in actual weather patterns over predicted patterns. Some balancing energy is likely to come from hydro plants, hence affecting the efficiency of hydro generation. An overall hydro / thermal usage plan is not relevant since there is insignificant long term storage. It is certain that not only intermittency but system inertia or

	response will be a significant issue in determining wind farm penetration. Co-operation between Ireland and UK might allow response to be improved at times of low load, hence reducing curtailment, if intermittency can be managed.

Studies Undertaken and Lessons Learnt

Intermittency – Studies undertaken and Lessons Learned
IRELAND

A study was carried out and a report published on "Impact of Wind Power Generation in Ireland". The following is an abstract from the report which describes the principle findings of the study.

Abstract

An increasing amount of Ireland's electricity needs is likely to be met by Wind Powered Generation. This report quantifies the operational and economic impact of large levels of wind generation on Ireland's generation system[3]. It finds that the potential fuel and emissions savings are tempered by the inherent intermittence of wind. For the scenarios studied total generation costs were found to increase significantly. The implied CO_2 abatement cost from this approach, for large wind penetration levels, was found to be in excess of €120/tonne.

As part of the Generation Adequacy Report, an assessment of wind capacity credit was carried out. The following extract from the GAR illustrates the lessons learned.

4.6(a) Wind – An Intermittent Energy Source

The contribution of wind power to generation adequacy has been analysed separately. This detailed analysis is required due to the intermittent nature of wind energy. There is a significant risk that a single source of failure (e.g. very low or very high wind speeds) will result in all wind farms producing practically no output for a number of hours. This has been verified by monitoring the output from wind generation, at quarter hourly intervals, over a number of years. In contrast, the forced outage probabilities for conventional units are assumed to be independent of each other. Therefore, the probability of all conventional units failing simultaneously is infinitesimal when compared to the risk that wind power will be zero.

The methodology adopted for assessing the impact of wind on generation adequacy combines historical wind power performance with wind measurements taken from a proposed offshore wind farm location. By using this combined wind power series (i.e. production pattern) the benefits of diverse wind farm siting are inherently incorporated. This power series is scaled up or down in order to investigate the impact of different wind capacity levels. The capacity benefit for a given wind capacity is calculated by subtracting this wind power series from system demand and performing the normal adequacy calculations using this reduced demand curve. Any decrease in plant requirement, over the case based on the pre-wind demand curve, is therefore attributed to that level of wind generation. From this, the capacity credit curve for wind is generated, as shown

[3] The study has focused on the Republic of Ireland only and All-Island implications are not considered.

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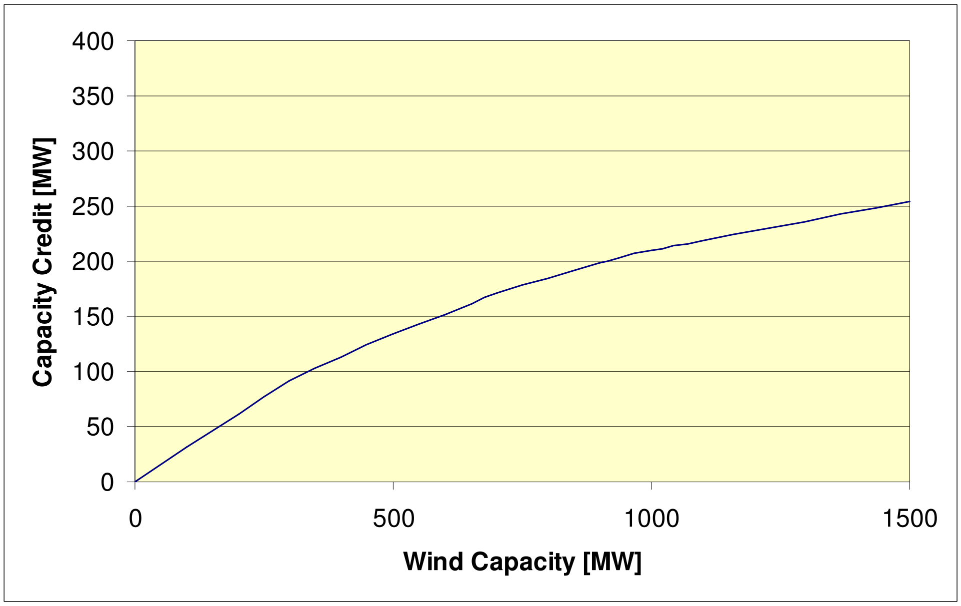


Fig. 2 Wind capacity credit curve

The capacity credit due to wind powered generation is non-linear and diminishes as the installed wind capacity increases. When the total installed wind capacity is below 200 MW, 1 MW of wind contributes just 0.3 MW towards generation adequacy. Above this level of wind penetration the incremental benefit begins to decline and over 800 MW there is only a 0.13 MW capacity credit for each additional MW of wind. This has the significant implication that as more wind capacity is installed, more than the optimum amount of conventional plant must be installed to maintain the demand supply balance. This sub-optimal requirement gets progressively more significant as wind capacity increases (the winds capacity credit saturates). The sub-optimal capacity requirement represents an additional cost which should be considered in any cost benefit analysis of increasing wind capacity.

Both reports are available on the eirgrid website www.eirgrid.com.

A study[4] entitled 'The Impacts of Increased Levels of Wind Penetration on the Electricity Systems of the Republic of Ireland and Northern Ireland' was commissioned by CER and published by Garrad Hassan and Partners Limited, in February 2003. This study raised some important issues and indicated that if wind levels exceed, on an all island basis, 800 MW by 2005 that wind output may need to be curtailed in order to allow conventional generation to operate in a stable manner, that is, above its minimum load levels.

Voltage dips occur mostly on start up of plant. Two situations arise:

[4] This study was jointly commissioned by the Commission for Energy Regulation and the energy regulator in Northern Ireland, OFREG.

- A wind farm starts up either as a planned operation or following a wind gusting shutdown. It is possible to control the wind turbine re-connection so as to manage the voltage dips. A sequence operation can be envisaged in which say only one turbine is allowed to start at one time. Another more sophisticated approach would be to measure the voltage dip and use that as a limit on the number of turbines which can connect. It suits the arrangements at wind farms not to re-connect quickly following an outage and several minutes of outage is not a burden. This allows a deeper voltage dip than would be permitted for the possibility of more rapidly repeated switching.
- A circuit outage can result in the simultaneous re-energisation of all wind farm transformers. This can be treated as an infrequent operation.

Wind turbines vary in the way they are energised. For all large turbines, they are accelerated by wind power until they are close to synchronous speed and then the circuit breaker is closed. Thus even for pure induction generators there is not a large starting current. The order of magnitude is about 1.6 times full load, but this can be reduced to close to full load by anti-paralleling thyristor units ('soft-start' units). The issue is that the initial current is to flux the machine and therefore heavily reactive. This can therefore still lead to voltage depression.

In the case of DFIG devices, the machine is fluxed from the rotor which is supplied by a convertor. The power to the stator side convertor can be at unity power factor with the reactive shift occurring at the rotor side convertor. It is therefore possible to soft start this machine at unity power factor.

HVDC connected machines can be fluxed at unity power factor seen from the power system.

Flicker

Flicker is a disturbing pattern of voltage oscillation. In the case of wind turbines it is mostly caused by power output fluctuations as the turbine blades go into the wind shadow of the support tower. As each blade passes the instantaneous power is reduced towards 2/3. Induction turbines exhibit this phenomenon, but a group of the turbines taken together smoothes the effect. DFIG turbines can correct for the effect by varying the power extraction from the machine to smooth the output. HVDC connected plant tends to be smoothed by the firing of the link.

It is recommended that standards are referred to in Grid Codes to control the level of flicker from wind turbines.

Reference information on wind penetration

Area - Texas (Main Continental Landmass - 740,000 sq. km)

Geography

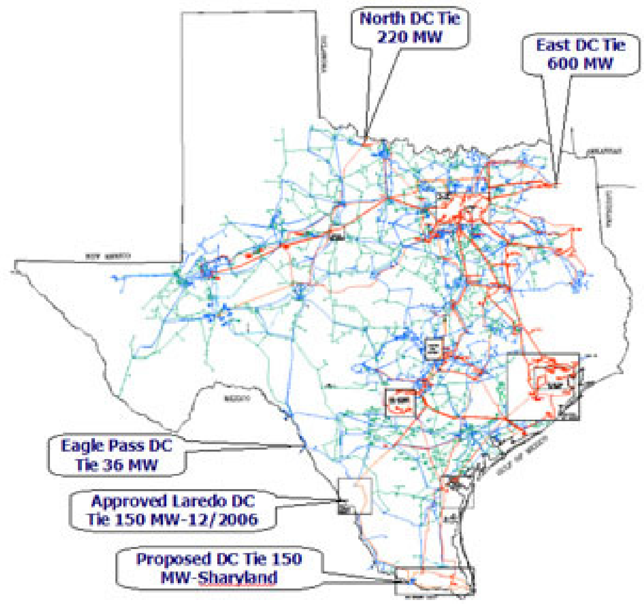


Figure 1 - The ERCOT System

Large landmass helps with uncertainty management

The area is a large landmass and is heavily internally interconnected. It is one of three weakly interconnected grids in the US, located in the south central region of the USA. The Electric Reliability Council of Texas (ERCOT) operates the system, which covers about ¾ of the state.

System Generation & Loading

Diverse mix

Generating capacity consists of coal, gas, and dual fuel (oil/gas) fired fossil plants, nuclear, wind and hydro, as shown in the table below.

Generation	MW
Gas	52,000
Coal	15,000

Dual Fuel	9,000
Nuclear	4,700
Wind	1,300
Hydro	550
Other	400
Total	**82,950**

Table 1 – ERCOT Generating Capacity

60 GW max. demand, 20 GW min. demand

System minimum load (20 GW) is approximately 33% of system max. loading (60GW). The load is concentrated in the eastern region, and wind generation is concentrated in the far western region. Figure 2 below shows the major wind development areas in relation to the transmission system in West Texas.

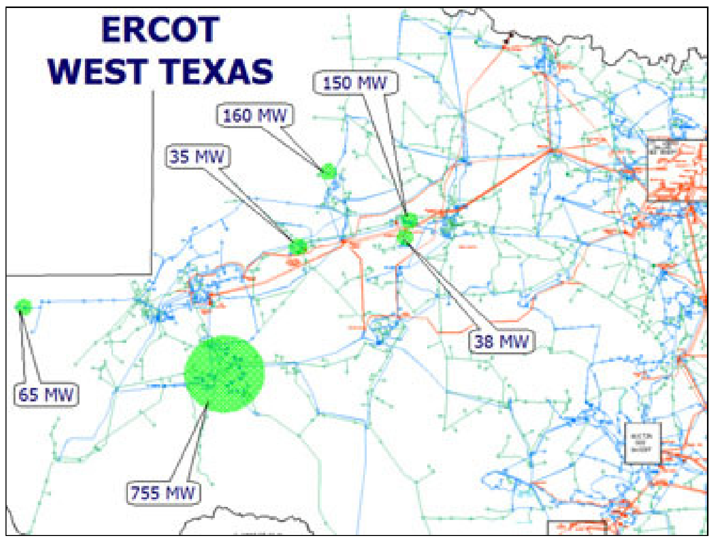


Figure 2 – Major Wind Plant Developments

Interconnection

ERCOT interconnected by DC to rest of US

The area is geographically large and well interconnected internally, although it is only interconnected through three DC links to the rest of the continental US, with two additional links either approved or proposed. The following table describes the interconnections, which are identified in Figure 1.

Interconnection	Status	Capacity
East	In Service	600 MW
North	In Service	220 MW
Eagle Pass	In Service	36 MW
Laredo	Approved	150 MW
Sharyland	Proposed	150 MW

Table 2 – DC Interconnections in Texas

Wind Penetration

CY2003: 1293 MW
Envisaged: 6+ GW

The 2003 level of wind-powered generation in ERCOT is 1,293 MW. The envisaged wind penetration is in excess of 6 GW, based on a very extensive wind resource. This would constitute approximately 10% of current system peak or 30 % of system minimum. It is expected that this would give rise to approximately 5% penetration by energy consumption. The current state RPS calls for 2,000 MW by 2010, but this target is expected to be met in the next few years, subject to the availability of transmission system reinforcement to bring the new generation to load. Approximately 5,000 MW of wind capacity is in the ERCOT interconnection study queue. A map showing current and future planned transmission system reinforcement to accommodate the export of 2,000 MW of wind capacity from West Texas is shown below.

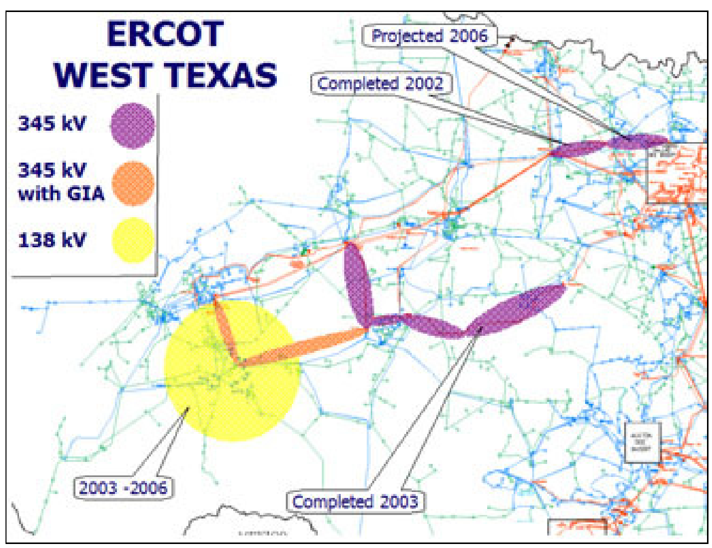


Figure 3 – Texas Transmission System Expansion

Geographical diversity helps	**Wind power balancing resources** The region is sufficiently large and well interconnected that the likelihood of a rapid loss of wind generation due to weather-related causes is relatively small.
Gas helps some	In West Texas, where the wind generation is located, some gas-fired capacity is available to provide balancing services when running. However, that gas-fired capacity is primarily made up of older, less efficient steam units that ordinarily do not operate except during peak summer hours. Otherwise, balancing energy must be provided from outside the immediate area over the transmission system.
	Analysis Looking at the factors above:
Area large enough that short time wind fluctuations not a worry Low capacity value due to lack of coincidence between load and wind	○ **Climate** It can be noted from Figure 2 that there is an excellent wind resource in West Texas. The major loads are in the eastern regions, creating the need for additional transmission. Further analysis of the seasonal wind patterns shows that the winds are lowest in the summer, when the load is at its highest. In addition, the diurnal patterns are such that the winds are lower during the day when the load is at its peak. ○ **Interconnection** The ERCOT system acts as an independent interconnected system, providing its own balancing energy and ancillary services internally. Some scheduled transactions take place with the external DC interconnections to the rest of the US but are not significant. ○ **Rapidly available plant** There are gas-fired plants available in West Texas to provide balancing energy, but they are not always on line. At other times, the balancing energy must be provided from outside the immediate area via transmission. ○ **Reserve level on traditional plant** On an ERCOT-wide basis, there is adequate spinning and operating reserve available (40%) to cover any foreseeable contingency. There was an excess of gas-fired capacity built in the late '90s which should be adequate for some years into the future, depending on load growth and retirement of existing generation.

Medium and long term wind prediction errors manageable with traditional cycling capacity	○ **Size of traditional generators** There is a broad range of size and type of conventional generation available. This range extends from large base-load nuclear and coal plants, to intermediate duty CCGT gas plants, to simple cycle peaking plants and diesels. ERCOT has over 500 generating units. ○ **Hydro Capacity** The small amount of hydro available is primarily used for balancing capacity during periods of the year when water is available, but generation is secondary to water management.
Transmission capacity important	Taking these factors together it seems that with the large land mass there is unlikely to be a short-time (up to 1 hr) wind variability or total system continuous ramping issue. The greater issue is the availability of transmission capacity to provide the required services.
As is balancing energy	As the time horizon increases, wind prediction is less certain and a weather front may cover a larger area, making it more likely that balancing energy will be required from gas-fired plants outside the area. Recognition of the small capacity value in the initial planning process will force the issue of capacity reserves to be dealt with up front. Standard reliability analysis using LOLP and ELCC techniques can be applied.

Studies Undertaken and Lessons Learned

ERCOT has responsibility for the transmission system planning, control area operation, and market operation in the Texas interconnected system. The rapid development of wind generation in West Texas after the Texas RPS legislation was signed in 1999 led to a situation where wind power capacity outpaced the ability of the transmission system to handle it, leading to curtailment of output of the wind plants. Lack of adequate detail in models for the wind turbines and wind plants led to inaccurate results of transmission system studies, which failed to predict the detailed operating conditions that were encountered. This led to ERCOT taking the lead in developing new wind turbine and wind plant models which are being used in transmission planning studies to accurately predict the behaviour of the system and to develop requirements for system performance at the interconnection.

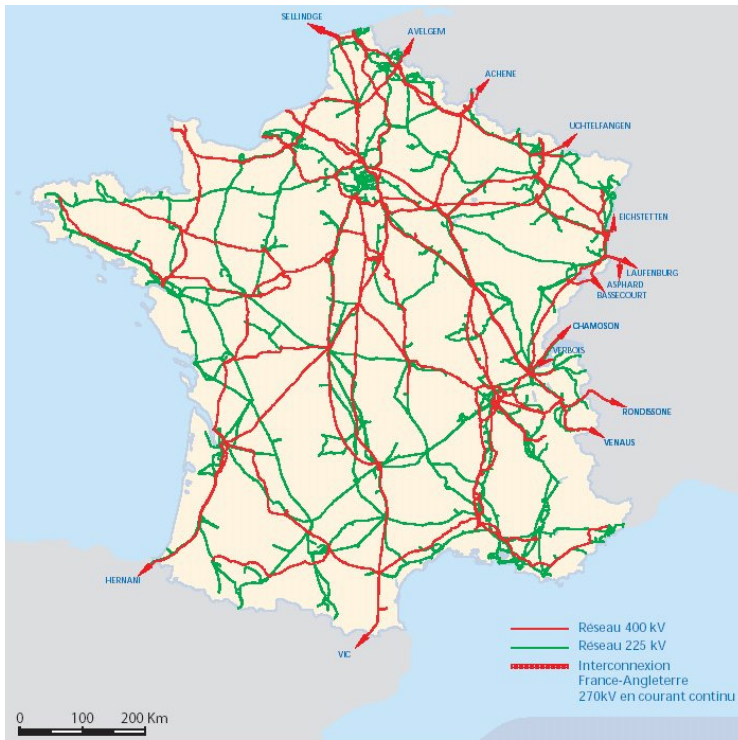
A number of the lessons which have been learned from the initial operating experience with wind plants in ERCOT include:

- a sparse transmission system developed to serve dispersed light loads will likely be inadequate to handle concentrations of wind generation that far exceed the local load;
- new wind generation must provide adequate dynamic reactive capability to provide support in controlling system voltage for the remote region;
- adequate wind turbine and wind plant models must be available to perform transmission system studies, including voltage stability and transient stability;
- understanding the chronological wind plant production profiles on time scales from seconds to years is necessary for comprehensive system planning.

Specific operating problems have recently included high voltages during light load conditions, almost daily restrictions on the wind-farm generation output, and continued operation of three older, less efficient fossil plants under Reliability Must Run (RMR) contracts.

Area – France

Geography



The RTE system is one of the main european systems building UCTE.

System Generation & Loading

Nuclear units have a total nominal active power of 63 GW, and produce about 78 % of total produced energy.
Hydro units have a nominal active power of 24 GW, and produce about 12 % of total produced energy.
Fire thermal units have a nominal active power of 24 GW (4 GW are cogeneration units) , and produce about 10 % of total produced energy.
The system maximum loading is 80 GW. The minimum is 30 GW. The internal consumption in 2002 were 450 TWh and the exportations were near 70 TWh
The system is generally always an export zone, mainly towards Italy, Belgium/Netherlands/Germany, Spain, and England. Nevertheless, the individual situation on each boarder is fluctuant, and importation transits (whereas the

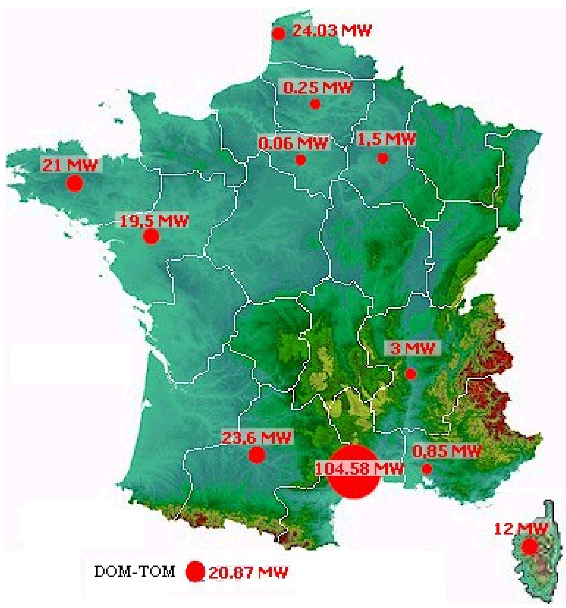
total system generally remains export) happen, mainly from England or Germany.

Interconnection

The system is interconnected with other continental TSOs through 19 AC links (mainly 400 kV) and through a DC link with G-B. The total capacity is around 11 000 MW.

Wind Penetration

The2003 wind installation is about 250 MW.



source : http://www.suivi-eolien.com

The forecast wind penetration is 5000 MW in 2006 and 12 000 MW in 2010. Nevertheless, because of many administrative difficulties for the new installations, it is likely that these values should not be reached in time. These values are required to reach the target of 21 % of renewable electricity in 2010.

There are 3 main zones of important wind development: North of France, Brittany (west) and Languedoc-Roussillon (south). These areas are those with the best terrestrial wind conditions.

Wind power balancing resources

Several thousands of MW on hydro or pumped-storage plants can be quickly adjusted.
Some important consumers can reduce their loads.

All these adjustments are carried out by RTE in the scope of the Balance mechanism where the different actors make offers for positive and negative adjustments. The technical characteristics of these adjustments, such as the duration, are also defined in these offers.

Analysis

Looking at the factors above:

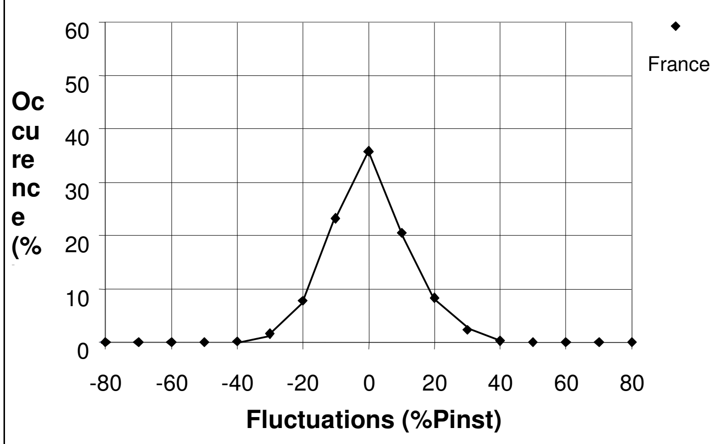
Climate

A recent in-depth statistical study of the characteristics of wind in France has been done, in order to characterize wind fluctuations and expected generated power. It shows that :

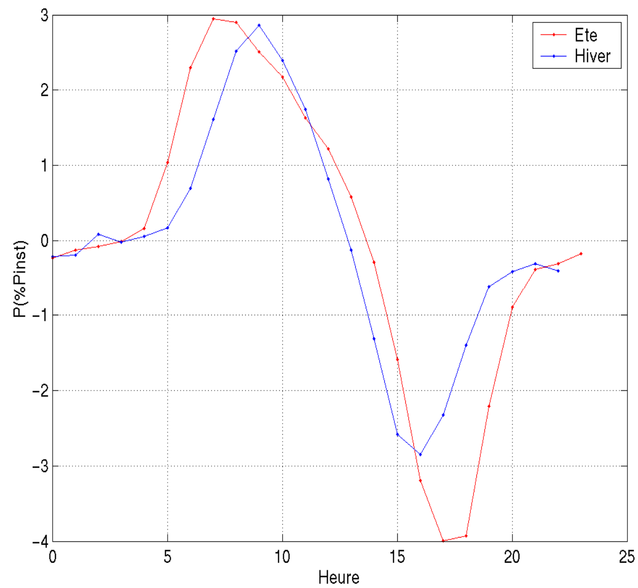
- There is a sort of decoupling between North and South regimes; hence a good spreading of the installations between these 2 areas would be preferable;
- The wind average level is greater in winter than in summer
- The wind level is greater during day than night, increases during the afternoons, and is slightly reducing with temperature in summer;

These trends are stronger in summer than in winter.
The following curves illustrate those results.

Forecast fluctuations of France generated power from one day to the next one for the reference scenario of wind development:



Forecast of the mean of variations on one hour[P(h+1) – P(h)] of the total power for the reference scenario of wind development:



One can see that expected fluctuations in one hour are quite small. This is not the case for larger intervals of time: for a 6-hours interval, these fluctuations could be 20 % and more in 5 % of the cases.

Hydro or pumped storage
Dam and pump-stored hydro energy is available to face important and quick changes.

Interconnection, rapidly available plant and reserve level on traditional plant

The question of reserves is one of the most important ones, and has not yet received an answer, with consideration to the low level of actual installation. Nevertheless, the following items will have to be covered, mainly the last one:

- What about the setting of the primary and secondary reserves (RTE presently applies UCTE rules)?
- What about quick reserves (30 mn ahead): these reserves must be greater than a given threshold, which is defined for the everyday peak load.

One can underline that RTE has already faced some situations of important change of the transits on the interconnections, mainly due to an immediate stop of a big volume of wind generation in Germany.

	Dispatchability Issues The dispatch-ability is a general request for installations connected to HV and EHV networks: the producers make offers in the "balancing mechanism" and RTE uses these offers in real time to balance generation and demand and to maintain system security. Small installations, below 40 MW, are generally exempted from the balancing mechanism and as such the generation output is modulated/stopped by RTE only in exceptional situations. Dispatch-ability specifications are basically applied to generation such as wind farms, hydraulic plants; clearly, not for modification of the generation schedules which are not controllable but for reduction of generation or tripping and for other orders.

Studies Undertaken and Lessons Learnt

Variability and Intermittency issues
RTE has carried out a study on the statistical behaviour of the future wind installed capacity (10000 MW), on the basis of the available recorded characteristics of wind in France. This was intended to get a better vision of the following aspects:

- Impact on variability of the localisation of wind farms on the different areas
- Seasonal, monthly, daily and hourly characterisation of expected variability of the generation at different levels: national, regional, local
- Impact of the sizes of farms, average distance between farms…

Some of the results were given above. Those results will be useful to define the rules to apply concerning reserve handling.

Transient behaviour issues
RTE carried out prospective studies to get better knowledge of the transient behaviour of the different kind of generators potentially inserted in our HVB or EHV networks, taking into account the typical values of these networks : impedances seen from typical connection nodes, response time and other characteristics of protections…
Since there were no effective project on these networks (the first effective realizations were all done on MV networks), these studies were done with some hypothesis for plant models.
The following questions were addressed:
Voltage stability: aptitude to effective voltage control
Dynamic stability: behaviour on voltage dip, reactive load step, stability for small perturbations
Transient stability: behaviour on 3 phase faults, with different possible kinds of clearing sequences

For all these studies, the main point was to appreciate the (in-)aptitude of a set of wind farms in a given area to resist to those perturbations, ie, mainly stay connected (or re-connect quickly) to the network. The main index being the percentage of remaining generators on the network at the end of the transient behaviour.
It clearly appears that this percentage can vary within an important range, depending on :

- The type of wind generator,
- The possible presence and type of control of Mvar shunt compensation resources
- The sizing of the different components of the plant,
- The features and set values of the local protections (over/under voltage and speed)
- The dispersion in terms of locations and working points of wind generators around the fault location;

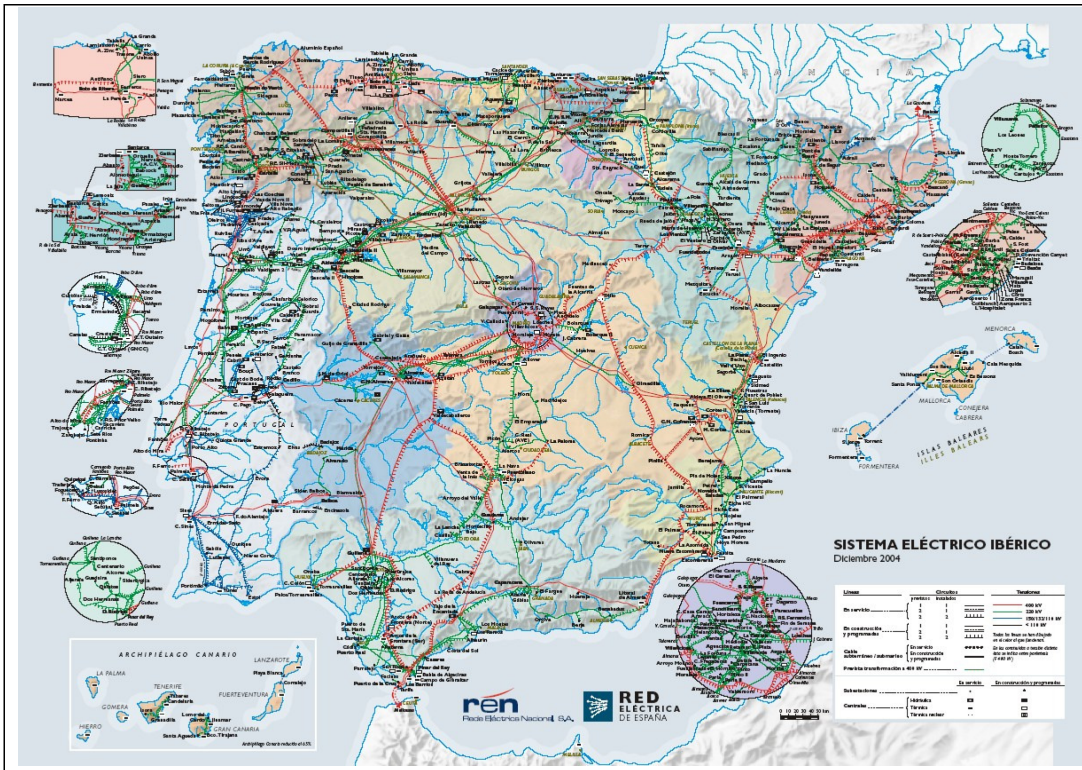
For example, in a studied area with about 1200 MW of installed wind generation (connected in HVA), on a 3-phase EHV default correctly eliminated, depending on the assumptions for those technical choices, this percentage can vary between 20 and 90 %…
Note that these studies have been carried out with a full description of the network and generators.

As a conclusion, a set of defined simulations and studies, dealing with dynamic behaviour, have been defined. For any wind farm to be connected on RTE network, the project responsible is required to realize these studies and give the detailed results to

RTE. One of the necessary conditions required to authorize the connection is that these studies give sufficient confidence concerning the ability of the installation to resist those perturbations and remain connected.

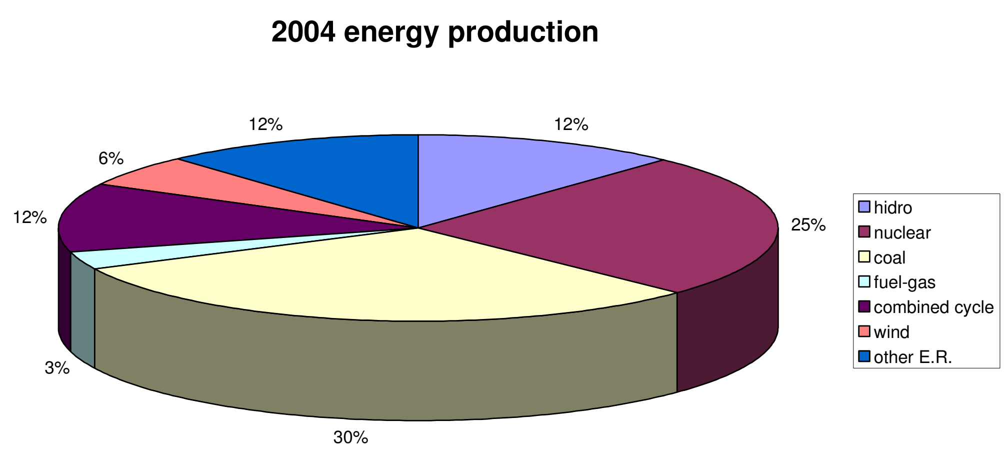
SPAIN

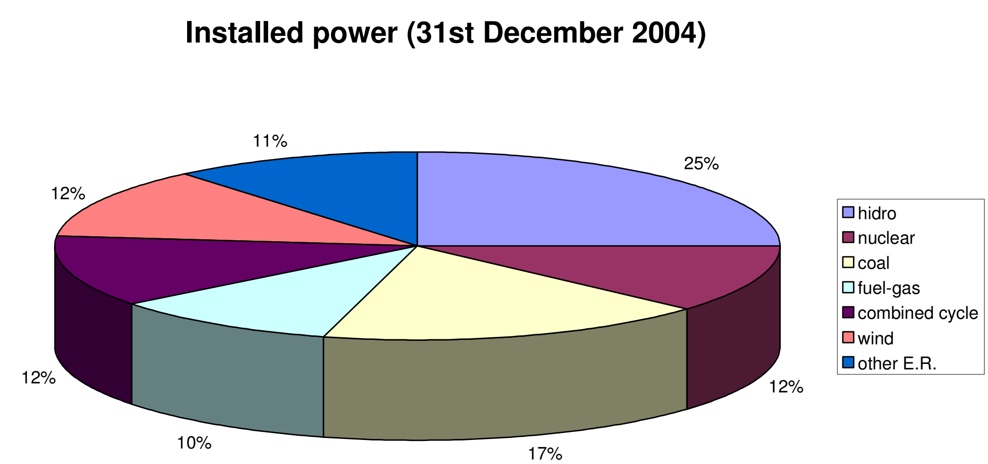
(Provisional 2004 data)

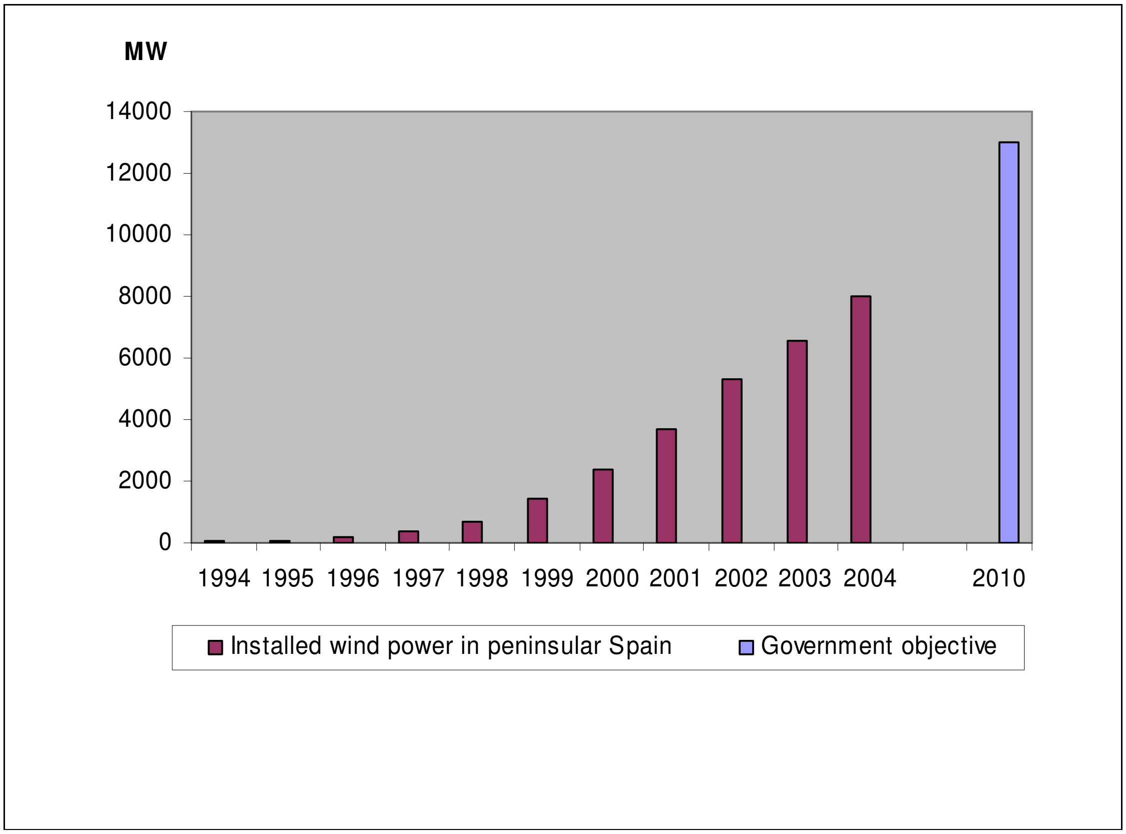


Peninsular Spain

Annual demand: 233.551 GWh
Maximum load (instantaneous): 38.210 MW
Minimum load (hourly average): 15.311 MW
Maximum one day wind production: 86.775 MWh

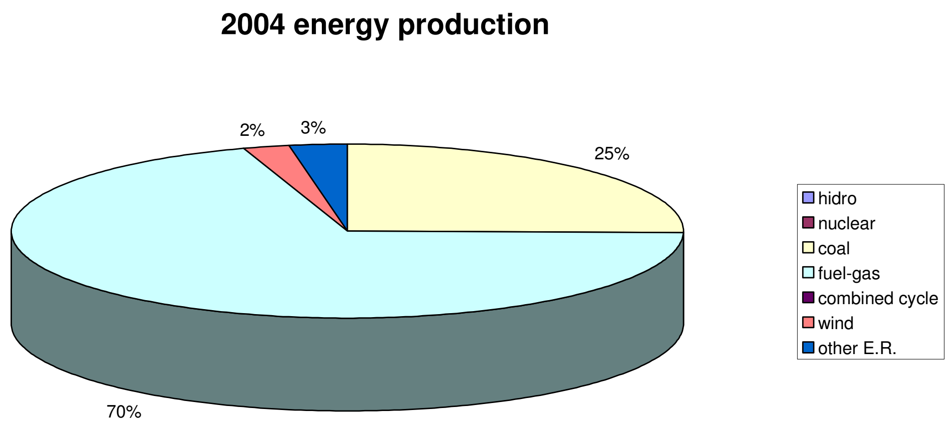

2004 energy production
12%
12%
6%
12%
25%
3%
30%
hidro
nuclear
coal
fuel-gas
combined cycle
wind
other E.R.

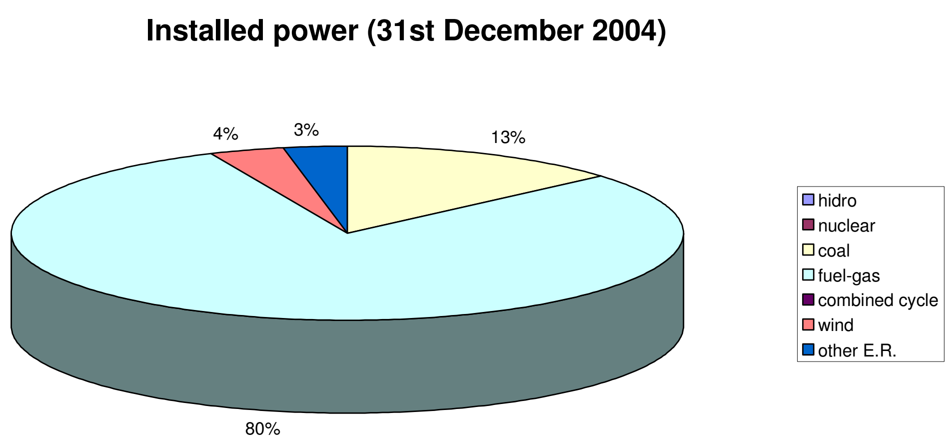

Installed power (31st December 2004)
11%
25%
12%
12%
12%
10%
17%
hidro
nuclear
coal
fuel-gas
combined cycle
wind
other E.R.


MW
14000
12000
10000
8000
6000
4000
2000
0
1994 1995 1996 1997 1998 1999 2000 2001 2002 2003 2004 2010
Installed wind power in peninsular Spain
Government objective

Extra-peninsular Spain (Baleares, Canarias, Ceuta and Melilla)

Annual demand: 13.858 MWh





C1.3 (Planning with generation uncertainty) [This has been maintained in raw data form to show the questionnaire circulated by the Working Group]

Country/Territory ___Scotland - South (ScottishPower Area)____________

C1.3 Member ______________________ E-Mail ______________________

Best contact for further info __________ E-Mail _______________________

Presenter ________________________ E-Mail _______________________
(the person who will speak at the workshop)

Approximate Information

System Details			6790 MW ?	
System Max Demand			4200 MW	
System Average Demand			2800 MW	
System Minimum Demand			1700 MW	
Interconnection No.	3	Total	3550 MW	
Details (1)	North of Scotland		AC	900 MW
(2)	England		AC	2200 MW
(3)	Ireland		DC	450 MW
(4)				

Balancing Sources or Special Arrangements e.g. Hydro or pump-storage, rapid response plant, rapid or other interruptible loads etc.

State source, capacity and limitations eg not available in summer

Pumped Storage (400 MW) (primary - 10 sec response + secondary 30 sec esponse available)
Flexible Thermal Plant (primary response only)
Despatchable Conventional Hydro (106MW) (Secondary response)

Present wind penetration level _____143___ MW _____1.8___%

Scottish Target 780_ (UK government share) MW after 2010___ Date

Corporate target 4,000MW (Wires business)

Relevant Geographical Information

Throughout Scottish Power area, but concentrated in south west Scotland and Borders area.

Uncertainties in Power Serving

Studies carried out or being undertaken to determine the effects of unpredictability and intermittency and lessons learnt

Effect on unit commitment and cost.
None – (Operational Issues will be the responsibility of GBSO in April 05)
How accurate do these investigations seem to be in quantifying capacity factors, plant loading factors and cost?
N/A
Mitigation – techniques to maintain security of supply.

Eg
- operate all existing plant at reduced output
- DSM
- hydro schemes
- rapidly available traditional plant

Studies carried out to:-

1) Predict likely generation market in 2010 that will operate in parallel with 4GW of renewable generation.
2) Assess the need for reactive power ancillary services in 2010 to maintain a licence compliant network
3) Assess the rate of change of renewable output from existing installations extrapolated up to 4GW, to assess the future need for Interconnection with E&W.
4) Assess minimum ratio of conventional to renewable generation to maintain a viable network resilient to transient faults.

What risks remain and are there costs not accounted for above?
Can these be modelled?

Energy Source Reliability

What studies have been carried out to determine the confidence in wind prediction? How does this change with weather type and geospread?
Due to existing low penetration, studies are only now commencing to forecast wind farm output.
Have these studies evaluated the probability of sudden loss of wind generation against geographical diversity?
(Not yet). YES the effect of diversity has been taken into account above studies looking at extreme rates of change of wind output.
Have these studies yielded useful results? Are there any general lessons?
Studies are currently being reconciled with work by S&SE and NGT

<u>Uncertainties in Network Performance arising from new generation types - Wind</u>

System Stability Investigations & Lessons

Types of Wind Generator Modelled

Simple induction generator and dual fed induction generator (DFIG)

Study Engine Used

PSS/E

Wind Farm or Turbine Models Used

Standard induction generator model, together with DFIG models for Vestas, Nordex and GE machines

Voltage Stability Studies carried out

Only at a very early stage.

Lesson learnt

Lack of good DFIG models.
Difficulty of present generators to meet new Grid Code requirements.

Dynamic Stability Studies (loss of generation)

Lessons learnt

Studies have not yet been carried out.

Transient Stability Studies (fault ride through)

Lessons learnt

Lack of good DFIG models.
Difficulty of present generators to meet Grid Code requirements- most models trip when subject to grid fault.

Black Start Studies

Lessons learnt eg at what stage/level should wind generation be permitted to contribute.

Studies have not yet been carried out. Do windfarms not need a stable source of voltage and frequency to commence generation ?

Comment on limitations of stability studies regards models etc.

It is only now becoming possible to carry out stability studies as models become available.

Have any model validation studies been carried out?
If so describe the method and result.

Current wind farms have not been modelled. Grid Code Compliance Testing and model validation will be carried out on new wind farms above 30 MW.

[The above questions are to establish a reliability index for the studies.]

Frequency Control and Voltage Control Studies

Types of Wind Generator Modelled

Study Engine Used - PSS/E

Wind Farm or Turbine Models

Frequency Control Studies

What lessons learnt

Are wind farms assumed to contribute to frequency control? sometimes/all the time?

Wind farms will be required to have frequency control capability, but will not normally be required to operate in this mode.

Voltage Control Studies

What lessons learnt as large wind farms and small embedded wind farms.

All wind farms should provide voltage control.

Large wind farms should be capable of running at leading or lagging power factor, however small embedded farms normally have to run at leading power factor to minimise voltage rises on the local network (33kV or 11kV).

What work has been done on wind farm connection?

What standards are adopted and are these different from traditional generation?

Grid Code requirements have to be met. Proposed changes to the Code allow for differences between synchronous generators and generators used on wind farms. Customer choice of security of connection is offered. eg up to 600MW on single connection.

How are transmission backbone issues dealt with – by reinforcement or wind farm constraint? What economic and technical approaches are taken?

Constraints will be used in the short term, however we hope to develop the network to reduce the need for constraints in the future. A cost benefit analysis approach is being developed using EDF software ASSESS. Infrastructure reinforcement will be justified when the annual cost of constraints is greter than the annualised cost of making an investment to remove these constraints

What studies have been carried out into local transmission and distribution issues

Types of Wind Generator Modelled

Study Engine Used - PSS/E

Wind Farm or Turbine Models Used – Dynamic studies not carried out yet.

What studies have been done and lessons learnt?

(Are these concerns eg absolute or step voltages?

Switchgear fault rating, absolute voltage, voltage step and thermal limits have all been encountered.

What mitigation is being undertaken or suggested?

Non-firm connection offers are being made.
Power factor correction measures required at some locations.
Bus section reactors are being considered for some 33kV busbars.

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Market Impacts Studies

How strongly and in what way is renewable technology incentivised?

By the use of UK market Renewable Obligation Certificates (ROCs)

To what degree is the market distorted?

The guaranteed premium for renewable energy is 3 p/kwh, however the shortage of renewable energy gives rise to an auction resulting in the price sometimes reaching a 6 or 7 pence premium. Suppliers who cannot resource their obligation percentage of renewables have to purchase their ROC's and these payments are passed back to the suppliers who have satisfied their obligations. A pretty distorted market !

Have mechanisms been developed to dispatch wind and if so how is equity ensured?

At present we do not intend to dispatch wind, but allow them to run when wind speed is high enough. Some dispatch may be required for network conditions (outages, requirement for frequency responsive plant, etc.)

Externalities

Describe the Utility/TSO culture to intermittent generation

Currently not an issue due to low penetration, however connection applications indicate it will become a major issue. Ofgem have issued an instruction to SP to ensure that future applicants are aware that new connections in Scotland will have no automatic access rights to the GB market under BETTA. This is causing much unrest I the renewables community.

Does the Utility/TSO own intermittent generation?

Yes, two wind farms at present (30 MW) with more under development. (600MW +)

To what degree has model deficiency hindered acceptancy of stretching intermittent generation targets?

Lack of models is a major concern in view of the large number of applications.

APPENDIX 6

Commonly Used Terms for Balancing and Regulation

AGC /Regulation –Generator's equipment that provides regulation service under direct control by system operator to increase or reduce power (WSCC)

Contingency Reserve - available up to 24 hours ahead. Need not be synchronized, but must be available for synchronization in a limited time scale. (Eirgrid)

Non-spinning Reserve – A quantity of capacity that is not synchronized to the grid but which can ramp up in 10 minutes (may include generation and load resources) (WSCC)

Primary Frequency Control - 0-30 seconds, governor or automatic frequency-switched peaking unit start-up (Eirgrid)

Primary Operating Reserve (POR) – 5-15 seconds (MW) (Eirgrid)

Primary Response

Automatic increase in generator output (or automatic decrease in consumer load) in response to a fall in system frequency. This is expected over a period of 0-30seconds from the frequency deviation, with full effect available within 10 seconds, continuing for at least a further 20 seconds. Response if dominated by the automatic governor action and machine inertia. (NGT)

Generating capacity under automatic control cable of maintaining system frequency and tie line loads within acceptable deviations from schedules (se control area). [CIGRE Glossary July 2001]

Replacement Reserve – A quantity of capacity that will ramp up within 60 minutes (WSCC)

Replacement Reserve (RR) - 20 minutes – 4 hours (MWhr) (Eirgrid)

Secondary Frequency Control 5 seconds – 10 minutes, AGC action (Eirgrid)

Secondary Response

Similar in principle to Primary Response, but with differing time of delivery. Automatic increase in generator output (or automatic decrease in consumer load) in response to a fall in system frequency. This is expected over a period of 30 seconds to 30 minutes from the frequency deviation, with full effect available within 30 seconds, continuing until at least 30 minutes from the frequency deviation. (NGT)

Secondary Operating Reserve (SOR) - 15-90 seconds (MWhr) (Eirgrid)

Generating capacity under secondary control which reacts within minutes to restore exchanges between control areas to schedules and to restore system frequency to normal. [CIGRE Glossary July 2001]

Spinning Reserve – A quantity of unloaded capacity (may be a partially loaded machine) synchronized to the grid that will ramp up in 10 minutes (WSCC)

Tertiary Operating Reserve 1 (TOR1) - 90 seconds – 5 minutes (MWhr) (Eirgrid)

Tertiary Operating Reserve 2 (TOR2) - 5 minutes – 20 minutes (MWhr) (Eirgrid)