ewis
european wind integration study

European Wind Integration Study (EWIS)

Towards A Successful Integration of Large Scale Wind Power into European Electricity Grids

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EWIS

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EWIS Final Report

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EXECUTIVE SUMMARY

Large capacities of wind generators have already been installed and are operating in Germany (26GW) and Spain (16GW). Installations which are as significant in terms of proportion to system size are also established in Denmark (3.3GW), the All Island Power System of Ireland and Northern Ireland (1.5GW), and Portugal (3.4GW). Many other countries expect significant growth in wind generation such that the total currently installed capacity in Europe of 68GW is expected to at least double by 2015. Yet further increases can be expected in order to achieve Europe's 2020 targets for renewable energy.

The scale of this development poses big challenges for wind generation developers in terms of obtaining suitable sites, delivering large construction projects, and financing the associated investments from their operations. Such developments also impact the networks and it was to address the immediate transmission related challenges that the European Wind Integration Study (EWIS) was initiated by Transmission System Operators (TSOs) with the objective of ensuring the most effective integration of large scale wind generation into Europe's transmission networks and electricity system.

The challenges anticipated and addressed include:

- How to efficiently accommodate wind generation when markets and transmission access arrangements have evolved for the needs of traditional controllable generation.
- How to ensure supplies remain secure as wind varies (establishing the required backup/reserves for low wind days and wind forecast errors as well as managing network congestion in windy conditions).
- How to maintain the quality and reliability of supplies given the new generation characteristics.
- How to achieve efficient network costs by suitable design and operation of network connections, the deeper infrastructure including offshore connections, and cross-border interconnections.

Previous work examining wind integration (notably, the TradeWind study [15]) highlighted the benefits of a pan-European transmission network of sufficient capacity such that diversity between wind output in different geographic areas can be exploited and the facilities needed to provide backup and other balancing services can be shared. EWIS has sought to identify what needs to happen in the short-term for such benefits to be achieved in practice. The study took primarily the perspectives of TSOs but sought the help and input of transmission customers and stakeholders to achieve a comprehensive treatment of technical, economical and market aspects.

Approach

EWIS has focused on the immediate network related challenges by analysing detailed representations of the existing electricity markets, network operations, and the physical power flows and other system behaviours that result. The starting point was the actual conditions in 2008 with future challenges assessed against realistic representations of network extensions and reinforcements taken from national development plans. In general, detailed information on user and network developments are only available for a limited number of future years and so 2015 was chosen as a suitable horizon for assessing how current plans will address future challenges. Given the importance of the 2020 targets, however, the study examined the prospects for further developments beyond 2015.

In EWIS, scenarios and sensitivity cases were used to explore the following uncertainties concerning conditions in 2015:

- The nature of future generation developments, especially the total capacity of wind generation installations.
- The impacts of fuel and CO2 prices.
- The effect of different wind patterns across Europe.

Different wind patterns were represented by using actual year-round wind production time series measured across Europe. The effect of fuel and CO2 prices were represented by adjusting the merit-orderings of generation in market areas. In this manner, the plant displaced (or replaced) when wind is assumed available (or unavailable) was identified. The effect of different wind development scenarios was explored by modelling the following cases:
Reference – this represented the expected development of conventional generation up to 2015 but with wind generation fixed at that established in 2008 (circa 70GW across Europe). Comparison of this scenario with others allowed the specific effects of increasing wind to be identified.
Best Estimate – this reflected, on the basis of information available to TSOs, in particular the expected development of all generation up to 2015 (including circa 140GW of wind across Europe). This scenario permitted the performance of planned network developments to be compared against the expected needs arising in 2015.

Optimistic Wind – this described high (very good progress) wind generation in 2015 (circa 185GW of wind across Europe). This scenario examined the performance of the network capacity currently planned for 2015 if additional wind is connected, for example including the further generation developments that may well be needed to approach 2020 targets.

The Best Estimate and Optimistic Wind scenarios are very similar to projections developed by the TradeWind study for the 2015 time horizon. A further EWIS scenario,
Enhanced Network, examined how the generation in the Optimistic Wind case would operate if key network pinch-points were further reinforced (i.e. beyond network transfer capacities that have been calculated for the existing infrastructure with planned reinforcements). This provides an outlook beyond 2015 and the works that might be needed to meet Europe's 2020 targets.

While EWIS has undertaken year round market simulations in order to represent the range of conditions that may arise and assess costs, it is not practical to undertake the detailed network performance calculations on the same basis. Network performance was therefore represented in two ways:

- Physical flows, resulting from simulated year-round market conditions, have been derived for key network pinch points (for example, the cross-border links) by using a linear approximation of the full network physics based on Power Transfer Distribution Factors (PTDFs). This approximation uses parameters which depend on network topology and are largely independent of patterns of network use.
- Full network physics power flow calculations and calculations of dynamic behaviour were focused on a relatively small number of point in time snapshots. These snapshots were selected such that they illustrate challenging but credible conditions.

By combining results from the detailed analysis of the snapshots with the context provided by year-round results, EWIS sought to ensure that the development and operational recommendations are well founded in terms of accurately addressing the technical issues while making appropriate investment/operating cost/risk trade-offs.

The EWIS study is the first time that a year-round market analysis (necessary to represent the effects of wind on a pan-European basis) has been coupled with representations of the networks (necessary to comprehensively address network performance limitations and so ensure reliability and economy). A key recommendation from EWIS to ENTSO-E and TSO colleagues is that pan-European modelling, coordinated and adjusted by more precise regional or national models, should be further developed and used as appropriate to assess future development of the European transmission network, especially as the proportion of wind generation increases. To develop tools suitable for supporting final investment decisions is a challenging task due to the modelling complexities and computational demands and therefore it is likely that a significant development programme will be required which may take some time to complete.

The results from EWIS are relevant to prioritising the reinforcement of network pinch-points and identifying beneficial additional measures to those already identified in National plans. These candidate reinforcements have been provided to ENTSO-E as input for the Ten Year Network Development Plan. The results also provide wider information that is relevant to policy makers concerning, for example, the scale of beneficial network reinforcements, the magnitudes of wind benefits and variability issues, the potential overall efficiency impacts of renewable support mechanisms. The EWIS project suggests that appropriate pan European market/network modelling will be valuable in considering how market arrangements and network access rules are further developed (for example, as part of the on-going regional initiatives).

Year-round simulations

EWIS year round modelling has shown that the annual benefits of wind generation across Europe, which accrue from avoided fossil fuel burn and CO_2 emissions, are much larger than balancing and network reinforcement costs that can be directly attributed to wind.

Representing the diversity in wind variations that can be exploited using the transmission network and the balancing measures that can be shared between countries, EWIS models have shown how the operational costs associated with addressing wind variability are expected to be small relative to the overall delivered benefits (given the representation of balancing requirements within the EWIS models, the costs are €2.1/MWh of wind produced in the best estimate scenario and €2.6/MWh in the optimistic wind scenario, corresponding to no more than 5% of calculated wind benefits).

The cost of currently planned network developments which have been reported as being primarily in response to accommodating the additional wind between 2008 and 2015 (but may address a number of other issues in each TSO network) range between €25/kW for immediate short-term measures to €121/kW for measures that will accommodate the optimistic wind scenario in the short and longer-term. The latter represents around €4/MWh at typical financing costs and for average wind load factors and so is similar in magnitude to the operational costs of addressing variability and a similarly small proportion of the overall benefits of wind generation. Reported network development costs also vary significantly from country to country (with some reported costs representing up to €928/kW of wind), reflecting particular circumstances and interactions with other factors determining network utilisation and expansion requirements.

The EWIS year-round simulations have derived information concerning power flow patterns, cross-border congestion statistics, and estimates of capacity values that might be attributed by market participants. This information has helped TSO network planners identify specific network reinforcement options and development strategies.

In the enhanced network scenario, the benefits of increasing cross-border capacities (where the benefits are likely to justify the capital costs of such reinforcements) were explored. Candidate reinforcements were identified with an indicative total capital cost of €12,3bn. Almost half of these candidate reinforcements relate to the potential development of offshore wind connections into offshore grids. As well as the direct fuel and CO2 benefits of these developments, they would also reduce the operational costs of managing wind variability for a portfolio of 181GW of wind from €2.6/MWh to €1.7/MWh.

<u>Point in Time Analysis</u>

In order to undertake the complex and computationally demanding network analyses needed to confirm acceptable operation and identify realisable reinforcements, a restricted set of point-in-time snapshots had to be selected. These sought to represent realistic but challenging conditions which also reflect the diversity in wind conditions that will occur. EWIS focused on snapshots with high wind in either the north or the south of Europe, reflecting conditions that can be observed in Europe's weather patterns including the diversity in wind production in different regions that often exists. All the point in time snapshots examined relatively low demand (e.g. night time) conditions as these are generally more challenging from various network technical perspectives. The EWIS methodology provides a full time context leading up to the snapshot (for example, showing how the wind conditions develop and other generation responds).

It is inevitable that a restricted set of point in time snapshots will not identify the worst case conditions in every area. For example, the high wind north point in time snapshot, while showing challenging power flow patterns across the northern part of the European transmission network, does not show the maximum wind output conditions that might be experienced at different points in time in, say, Ireland and Northern Ireland, Great Britain, or Denmark. Given the snapshots studied, EWIS has not sought to verify individual national development plans, but instead, it focused on the potential for interactions between countries and the scope for additional measures can be justified on that basis.

In general, the analysis in EWIS has confirmed the continuing urgent need for reinforcements that have been previously identified in earlier studies and incorporated in national plans. A number of these reinforcements are awaiting consents and it is important for connecting and successfully integrating wind that such decisions are progressed as quickly as possible.

In areas where cross-border flows are the subject of controllable links (Ireland and Northern Ireland to Great Britain, Great Britain to continental Europe, Iberian Peninsula to continental Europe and between the Nordic countries and continental Europe) physical flows can follow market transactions and so little need for additional measures to those already identified by those countries were anticipated or found.

However, in the mainland Europe synchronous area under the high wind north snapshot, the difference between actual physical flows and the market exchanges can be very substantial (due to so called “loop flows”). TSOs are already experiencing issues due to these loop flows but analysis of the 2015 snapshots identified:

- High power flows starting in the areas with large wind power installations in Germany and directed to the remote load centres (higher than previous national studies had anticipated and existing planned reinforcements can accommodate).
- Substantial loop flows through Poland and the Czech Republic increasing flows significantly above those that are currently expected to result from market transactions.
- Also high loop flows through Benelux countries, similarly increasing flows.

These large flows, if unmitigated, would risk reducing network reliability by causing overloads and low voltages such that there is a risk of cascade failures and disruption should a fault event occur. On the German-Czech Republic border, flows could exceed line capacities even with all circuits in service, risking network failure without an initiating fault event. On the German-Poland border, flows reach line limits with all circuits in service, risking network disruption in the event of a fault. Unless other risk measures are instigated, the conditions would suggest that the transmission capacity that could be offered to the market would need to be substantially reduced. Some potential overloads on network lines and unacceptable voltage conditions within the German market price area have been identified which cannot be acceptably controlled by reducing transfer capacities offered to the market and network capacity enhancements are therefore essential.

Throughout Europe, improved wind forecasting techniques together with use of within day markets to capture the latest production positions are being developed. Capacity enhancement measures in the Central East and Central West areas already planned include:

- Pilot projects to implement dynamic line ratings (measuring line temperatures that reflect actual ambient conditions including wind cooling and the effects of line loadings).
- Phase shifting transformers (which permit power flow sharing between parallel circuits to be controlled in order to maximise available capacity).
- Special protection schemes that trip certain generation facilities in the event of network faults that would otherwise cause overloads and potential cascade failures.
- Reactive compensation devices to improve network voltage performance.
- New lines (although the speed of establishment of these facilities depends on consenting procedures).

In the South west area, the undertaken measures are:

- Large development of national transmission infrastructure and interconnections with Central Europe.
- Requirements to ensure the technical compatibility of wind farms with networks specifically in order to prevent tripping of generation or voltage degradation in demanding conditions.
- Reactive compensation devices to improve network voltage performance.
- The monitoring and control in real time of wind power by the TSO.

The short-term measures and candidate additional reinforcements identified by EWIS have been notified to the respective TSOs for further development and provided to ENTSO-E for inclusion in the ENTSO-E ten year development plan.

<u>System stability</u>

As well as analysis of network capacity and voltage performance, EWIS analyses also examined system dynamic behaviour for the time horizon until 2015. These analyses identify whether:

- Any electromechanical oscillations that may result between generation in different areas will be satisfactorily damped.
- Transient responses to network fault and switching events will settle to stable conditions and so avoid cascade failures and widespread disruption. (This includes examining conditions where certain legacy wind generation units would be expected to disconnect in the event of voltage dips.)
- Frequency response in the event of sudden generation loss is adequate (particularly important in island systems like Ireland and Northern Ireland and Great Britain).

EWIS has shown that derived models of the dynamic behaviour of generation (including wind generators) give good agreement with actual measurements in actual past disturbances. Existing measures to ensure adequate damping (including the fitting of power system stabilisers to generator excitation controls) appear to remain adequate as wind generation expands.

To exploit improved dynamic line ratings, EWIS has found that improvements in stability performance may be required (for example, by improving the speed of protection operation and by enhancing system voltage profiles). Even with such improvements, stability may remain a limit to power transfer capability such that it will need ongoing assessment, especially as power transfers are increased on existing lines. . The investigations indicated that dynamic line rating is capable to complement new overhead lines under specific conditions (e.g. on defined corridors).

EWIS assessments have shown the benefits of improved 'fault ride through' characteristics and voltage control capabilities on modern wind turbine generators. Such characteristics reduce the risk of widespread simultaneous tripping of wind generation in the event of a fault event on the high voltage network and thereby reduce the barrier that is related to frequency stability and that might limit the amount of wind generation that could otherwise be integrated.

During the course of the EWIS project, stakeholders highlighted the importance of standardising the technical compatibility requirements for wind generators (currently detailed in national grid codes). Given the analysis undertaken by EWIS, and the discussions held with stakeholders on this topic, EWIS proposed and ENTSO-E agreed to the establishment of a working group to develop European Grid Code requirements for wind generators on a pilot basis (i.e. in advance of formal guidance on code development by the soon to be established Agency for the Cooperation of Energy Regulators, ACER).

Operational Measures

While measures to strengthen transmission networks are being progressed in national development plans (and EWIS has identified further candidate reinforcements to improve security and economy), EWIS assessments have also identified significant reliability and efficiency benefits that need to be achieved by enhancing operational arrangements. These measures include:

- Coordinating the operation of increasing number of flow controlling devices (such as phase shifting transformers, series compensation and HVDC links) across Europe.
- Coordinating system to generator and system to demand special protection arrangements to adjust power flows in the event of faults and other events.
- Developing and using dynamic equipment ratings reflecting ambient conditions, loading and conductor temperatures.

To achieve co-ordination of these measures across Europe, TSOs will need to develop the following:

- Shared intelligence on developing generation and load conditions (including wind forecasts).
- Suitable monitoring and control facilities.
- Procedures for using enhanced operational measures so that maximum benefit is achieved across each region.
- An appropriate mechanism for sharing and recovering the costs of such measures.

Market development

The EWIS market model represents the idealised operation of existing day-ahead markets respecting declared cross-border transfer capabilities and it then approximates the subsequent within day action of TSOs to redispatch generation to meet actual network physical limits and respond to emerging information concerning demand, wind output and other generation changes.

In practice, current day-ahead markets depart from ideal operation due to various issues including:

- Differences between the timing of market gate closures (the time at which prices for the following day are decided) leading to sub-optimal compromise positions.
- Differences between the timing of inter-connector capacity allocations and market gate closures giving the potential for sub-optimal positions.
- The effect of complexities and uncertainties associated with obtaining a consistent position across multiple interconnectors, again leading to the potential for sub-optimal positions.
- The effect of other differences in terms and conditions associated with trading in particular markets.

Harmonisation of market arrangements, such as by means of the currently progressing regional initiatives, will reduce the barriers to the efficient operation of wider markets which, as EWIS results highlight, is particularly important for efficiently integrating large scale wind.

It is for consideration whether improving day-ahead market design so that network limits are more accurately represented should also be a priority. While EWIS has illustrated the benefits of efficient European markets for achieving wind integration, it has not been able to explore the relative benefits of improving day ahead network representation compared to other policy developments. This topic merits further work using market/network modelling tools.

In terms of within day markets, EWIS results show how important it is that there is sufficient availability of flexible resources so that the improved information about future wind output available in shorter timescales can be acted upon by TSOs or others. Standardized market arrangements for within day trading, balancing and ancillary services are important to this end. EWIS results show that, if redispatch by market players rather than by TSOs is to be accommodated (such that traders of wind power can benefit by trading closer to real-time) it is important that within day markets more accurately represent network limits than by using the available transfer capacity methodology and instead must use flow based methods to represent network limits.

There is evidence, for example from Spain, that shows the advantage of combining the actions of market participants, who have a responsibility to address wind variability in daily and intra-daily markets, with the actions of the TSO who can perform centralised analysis concerning the best way to balance the system. The TSO can combine information from the monitoring of wind generation with forecasts and other system operation information to perform a strategic management of the network, including the direct control wind output in conditions of severe risk.

Other Policy Areas

EWIS has collated the large volume of network development currently being progressed by TSOs and has highlighted the need for further work both to address the interactions that will occur across the European transmission system and that will be needed to accommodate further wind developments beyond 2015 in order to contribute to the 2020 targets and a low carbon economy in the longer-term. TSOs recognise the importance of ensuring the networks are developed to effectively meet the future challenges but require support from stakeholders to facilitate the necessary changes. In particular, given that transmission extensions are almost always contentious due to their visual impact, TSOs are keen to ensure that these developments are considered within the European and national planning frameworks alongside the generation developments that drive these works. In particular, if there are planning presumptions for the development of renewables in particular areas then the associated network developments must form part of the plan.

Although EWIS has demonstrated how network development costs are likely to be modest compared to the benefits brought by wind generation (and the capital cost of establishing such generation), nevertheless the network capital costs are substantial in absolute terms. Network developers need confidence that they will be allowed to recover the costs of required developments under national regulatory frameworks and, for cross-border works, under international cost sharing mechanisms. TSOs therefore ask that there is good alignment between national regulatory objectives and policies seeking to deliver renewable targets. Also, that cost sharing and cost recovery mechanisms for works with a pan-European benefit are given suitable priority by the new European regulatory authority ACER.

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1 Introduction

1.1 Background

Wind generation is an important front runner renewable technology and large installations can already be observed in some European countries. Further large scale development of wind generation is expected in order to meet European renewable energy targets.

Wind generation brings benefits chiefly from reducing the need to burn fossil fuels and thereby the carbon emissions associated with using these fuels. Reduced reliance on fossil fuels will reduce Europe's need for fuel imports and so improve fuel security while the development of a renewable energy industry will create jobs and wealth in Europe.

However, wind generation has characteristics that differ from existing main generation. In particular, it features:

- A variable output which depends on wind conditions.
- Electrical technology that differs from that generally used in existing main generation (for example, departing from traditional synchronous alternating current alternators).
- A geographically distributed nature (to harness the best wind resources).
- Locations often remote from load centres (perhaps offshore).

These differences give rise to challenges concerning the integration of wind generation in the electricity system (in terms of operating commercially in the electricity markets and technical functioning in the transmission network). In particular, the challenges include:

- How to encourage this technology when markets and network access arrangements have evolved for the needs of traditional controllable generation.
- How to ensure supplies remain secure as wind varies (establishing the required backup/reserves for low wind days and managing network congestion in windy conditions).
- How to maintain the quality and reliability of supplies given the new generation characteristics.
- How to achieve efficient costs by suitable design and operation of network connections and deeper infrastructure including offshore connections and cross-border interconnections.

Many countries have worked on addressing these challenges (and part of the EWIS project has been to collate and share best practice from experience already gained). However, as illustrated by the TradeWind[i] study, there are important physical benefits that can be achieved by taking a European network perspective. The EWIS project was therefore initiated by European TSOs as an integrated pan-Europe network study of how best to accommodate wind.

1.2 Objectives of the EWIS Study

The aim of the EWIS project is to examine how best to accommodate wind generation on a large scale and so meet European targets. It examines, from a pan-European perspective, the immediate challenges that were observable when the project commenced in 2007 and that will emerge as current national development plans are progressed to 2015. It uses these findings to identify how plans will need to be extended to reach targets beyond the 2015 time horizon and hence towards Europe's 2020 targets.

The study therefore seeks to address the immediate network issues arising from wind power, particularly those relevant to TSOs' network development and operational perspectives, but ensuring involvement of relevant stakeholders in order to achieve a comprehensive treatment of the issues. In summary, the objectives of EWIS are:

- To address the network issues arising from wind power.
- To seek proposals for a generic and harmonized European-wide approach towards wind energy issues addressing:
    - operational/technical aspects;
    - market organizational arrangements arising in Europe;
    - regulatory requirements;
    - Common public interest issues that impact the integration of wind energy.

1.3 Principles and Boundary Conditions

The EWIS project examined wind issues by:

- Describing the existing interactions between technological constraints, market designs and energy policies
- Identifying and analysing the consequences in the short and longer-term of integrating large scale wind power

Different scenarios are used to identify the consequences of increasing wind generation capacities in national and regional systems. Where risks are identified, for example in terms of threats to supply reliability or efficient operation, measures are identified to extend any limitations and the costs of such measures are assessed.

Network investigations start by examining the performance of the 4 synchronous areas (GB, Irish, Nordic, and continental Europe) based on network resulting from existing national plans. Pan-European aspects are then investigated on the basis of the understanding gained from the issues relevant to each synchronous area.

1.4 EWIS Stakeholders

To ensure a comprehensive assessment of the issues, EWIS has benefited from the engagement and participation of its various stakeholders. This participation has included the following:

- The discussions and feedback received from members of the EWIS Project Consultation Board (participating organisations listed in Appendix).
- The meetings with members of the wind energy industry on various topic areas, EWIS is especially grateful to the staff and members of EWEA and the TradeWind study for their input and expertise.
- The opportunities provided at various conferences, seminars and open meetings to discuss the EWIS project and wider wind issues.
- The academic staff of the SUPWISci consortium who have contributed the market model and significant associated expertise.
- Staff from transmission system operators contributing to the project, both as study consortium members or respondents the various data requests and technical discussions.

1.5 Structure of report

The next section sets the context for the study in terms of current conditions, expected developments and issues. Section 3 introduces the scenarios that were derived for EWIS analyses, describing the year-round models and selection of point of time snapshots for the detailed network technical analysis. Section 4 presents the results of the technical analysis undertaken. Section 5 presents the results of the cost analyses and economic assessments. Section 6 presents the findings of EWIS for beyond 2015 and section 7 summarises policy implications. The report concludes with a summary of immediate priorities and areas that would benefit from further work.

2 Present Situation & Immediate Challenges

2.1 Wind generation volumes

By the end of 2008, more than 68 GW of wind generation capacity had been installed across Europe, representing about the 13% of the considered countries peak demand and 34% of their minimum demand (see table below). The current situation is characterised by:

- Strong growth in wind generation in many countries, with
- More significant installations in capacity terms in Germany and Spain, and
- High penetrations relative to market size in many other regions (for example, Denmark, Ireland and Northern Ireland or Portugal).
- Most of the wind farms are onshore but there are offshore parks operating as e.g. Belgium (30 MW), United Kingdom (455 MW), Denmark (623 MW) and The Netherlands (220 MW)

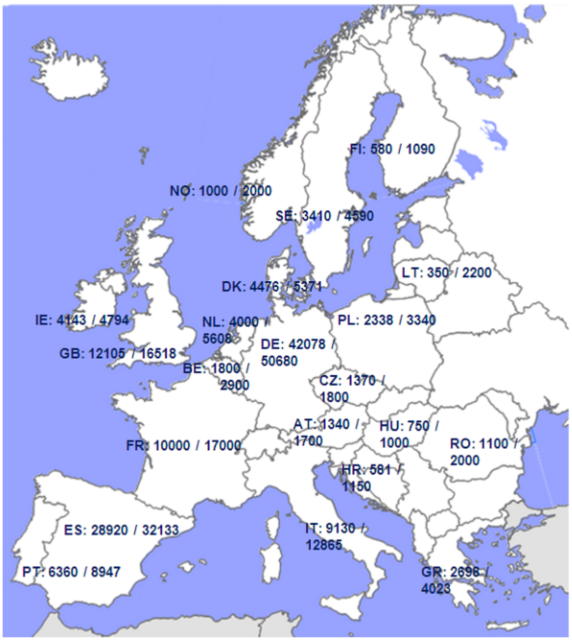
	(MW) at 31/12/2008	Peak demand (2008) [MW]	Minimum demand (2008) [MW]	Min Penetration (installed Wind power Capacity / peak demand) (2008) [%]	Max Penetration (installed Wind power Capacity / min demand) (2008) [%]
Austria	950	9750	3790	9,7	25,1
Belgium	580	14 234	6614	4,1	8,8
Czech Republic	192	10 880	4716	1,8	4,1
Denmark	3326	7050	3900	47,2	85,3
Finland	200	14 700	4400	1,4	4,5
France	3000	83 000	30 000	3,6	10
Germany	25 745	76 750	25 500	33,5	101
Great Britain	5000	63 500	23 700	7,9	21,1
Greece	950	10 880	3600	8,7	26,4
Hungary	300	7000	3200	4,3	9,4
Ireland & Northern Ireland	1300	6750	2270	20.7	61.7
Italy	2600	60 000	25 000	4,3	10,4
Netherlands	2000	18 960	8000	10,5	25
Norway	700	22 800	9000	3,1	7,8
Poland	600	25 630	11 140	2,3	5,4
Portugal	3350	9000	3800	37,2	88,2
Slovakia	5	4568	2729	0,1	0,2
Spain	15 576	46 200	18 500	33,7	84,2
Sweden	1100	27 600	9300	4	11,8
Switzerland	30	11 500	5000	0,3	0,6
TOTAL	68 204	528 908	203 521	12,9	33,5

Table 2.1: Installed wind power (end 2008) and minimum and maximum peak demand in electrical systems covered by EWIS study (* estimated)

As estimated and shown in Figure 2-1, installed wind power generation in Europe is expected to at least double in the next decade. A similar overall distribution of installations is expected in 2015 but with more countries making significant developments.

Wind power generation in 2015 would represent around 15-20% of the installed power, and around 27% and 34% of the studied off-peak load condition. Germany and Spain would together represent 60% of the overall installed wind power. Great Britain and France expect a very high further development of wind power, each installing around 10.000 MW, such that together they would represent 20% of the total installed wind power in Europe. Thousands of MW of wind power is also expected to be installed across Portugal, Netherlands, Sweden, Ireland, Poland, Belgium, Lithuania, Norway, Austria and Greece such that these countries together represent the majority of the remaining 20% of the total installed wind power in Europe.

This simple overview illustrates that while wind penetration is taking a significant market share in some countries, and its variability could require the utilisation of much of the flexibility available from other generation locally, in a pan-European context wind market penetration is modest and there is significant scope for finding flexibility to address wind variability, albeit in locations other than immediately local to wind concentrations.



(MW)	best estimation	optimal wind
Austria	1340	1700
Belgium	1800	2900
B&H	40	80
Bulgaria	540	650
Croatia	581	1150
Czech Republic	1370	1800
Denmark	4476	5371
Finland	580	1090
France	10000	17000
Germany	42078	50680
Great Britain	12105	16518
Greece	2698	4023
Hungary	750	1000
Ireland	4143	4794
Italy	9130	12865
Lithuania	350	2200
Luxembourg	96	98
Netherlands	4000	5608
Norway	1000	2000
Poland	2338	3340
Portugal	6360	8947
Romania	1100	2000
Serbia & Montenegro	40	80
Slovakia	245	545
Slovenia	129	229
Spain	28920	32133
Sweden	3410	4590
Switzerland	150	300
Estimated total	*139769*	*183691*

Figure 2-1: Installed wind power estimations 2015

The market conditions for wind generation vary by country due to the particular support schemes implemented by member states. A majority of countries provide a feed-in tariff while many others provide a premium to the normal market price by a green certificate or by a defined feed-in premium.

While support mechanisms continue to evolve (for example, the GB has introduced a system which provides different numbers of support certificates for different types of renewable generation) a general aim is to provide stability and certainty to renewable generation developers and so EWIS has assumed that there will be no radical change in the form of support mechanisms in the period up to 2015 (for example, support for wind generation is not expected to be harmonised by 2015).

Other market factors which are relevant to wind development in Europe relate to grid access rules, exposure to market signals (for example, for balancing and congestion management) and technical compatibility requirements (in some instances also linked to market access rules). These are summarised in the following sections.

2.2 Grid connection and access rules

The majority of Europe's existing wind generation has been connected to distribution networks (although there are some notable exceptions such as Spain). This is expected to change significantly in the period to 2015. Countries where wind farms have been mainly connected to distribution networks are expecting future installations to be generally larger and often connected directly to the transmission network or the highest distribution voltage levels. This trend is in part due to regulatory changes in certain member states where support and favourable access rules had been limited to smaller distribution connected wind farms. In general, however, it reflects the development of larger wind farms, especially off-shore, which benefit from the economies of higher voltage connection. For example, in Denmark, which until now has seen wind farms connected mainly to distribution systems (with only 10-15% at 150kV), the majority of future connections are expected at 150 kV or even 380 kV such that about 60% of wind farms would be connected to 150 kV or higher.

In terms of network access arrangements, only a few countries allocate firm access rights (reserving grid capacity) for wind generation ahead of operation. In Great Britain, all generation is, by default, allocated firm access rights and may need to wait until the required network capacity is established to support such rights. However, recent regulatory dispensations in Great Britain have permitted significant volumes of new wind generation to connect before all the required deeper network reinforcements are completed. In Portugal, the TSO and central administration determine the location of wind farms and propose the future wind farm emplacements and sizes. Network capacity is reserved as part of this process.

Due to either explicit arrangements to purchase wind energy production or the financial support arrangements which give wind generation an ability to enter markets as required, wind energy has effective priority dispatch in all European countries. In most countries, TSOs have an ability to curtail wind energy in order to preserve system security. In some countries, this ability to curtail is extended to other specific situations (for example, if significant congestion occurs or if wind production exceeds consumption levels). Financial compensation for wind power curtailments is provided in some countries and not in others.

2.3 Wind energy integration in system operation

The main challenges currently reported by TSOs concerning system operation with a significant contribution from wind generation relate to:

- Balancing production and consumption in the presence of wind variability (establishing and despatching the required larger reserves);
- Managing the potential for large simultaneous tripping of wind power that may result from network voltage dips associated with correctly cleared network faults. (This issue concerns legacy wind generation plant. New wind generators offer improved fault ride through).
- Other difficulties related to obtaining accurate telemetering and control at control centres (due to the distributed nature of wind generation).

In the future, as the amount of wind generation increases, the challenges related to the variability and uncertainty of wind are expected to become more important. Improvements in forecasting and the use of flexible generation units are the principal mitigations at the national level that are currently perceived to address these challenges. As the parties responsible for ensuring the real-time matching of production and consumption in their control areas, TSOs are already active in developing and innovating this aspect of electricity system operation. For example, in Spain monitoring and control of renewable energies is managed by dedicated control centres which collate real time measurements of their production and perform real time security analysis to enable the co-ordination of associated balancing actions.

Throughout Europe there is a focus on improving intra-day and closer to real-time trading facilities which will provide market participants with opportunities to manage and evolve their positions. As participants in these markets, or as counter-parties in specialist mechanisms, TSOs are increasingly using these arrangements to procure the services they require and thereby encourage flexibility from both generation and demand in order to address residual imbalances at least cost. In the GB, where market participants can trade and refine energy contracts up to 1 hour before real-time, developed ancillary service arrangements also provide the TSO with fast reserves, such as pump storage, to respond to output changes from wind generation.

2.4 Network capacity implications

TSOs are already strengthening their networks by constructing new circuits, upgrading conductors on existing lines, installing reactive compensation devices to improve voltage performance, and installing devices such as phase-shifting transformers to control the sharing of power between circuits thereby making best use of existing circuits and reducing unwanted loop flows. TSOs are also implementing operational procedures and control systems that seek to maximise the usable capacity of existing assets. Nevertheless, further capacity and strengthening of the European network is anticipated to be needed in order to integrate larger amounts of wind power.

In each of Europe's 4 synchronous areas, TSOs have planned additional network capacity, in some cases directly in response to wind power development:

In Ireland, connected indirectly to Great Britain via a single DC circuit from Northern Ireland, load flow analyses have been performed based on expected wind levels of approximately 1000 MW in 2008. To accommodate the future expansion of wind in Ireland, a new interconnection to Wales is being planned and the transmission network strengthened.

The transmission network in Great Britain is connected to the Continental European electricity system by a 2000MW HVDC link to France. An additional 1320MW HVDC interconnector with the Netherlands is under construction and contracted to begin operation in 2010. To accommodate a large expansion of wind in Scotland (primarily onshore) and in England and Wales (primarily offshore), an extensive set of transmission network upgrades have been identified. The GB government and the regulatory authority have decided that offshore network connections of 132kV and greater will be built by transmission companies selected by a competitive process. These networks together with the existing onshore transmission assets will be operated by the GB system operator, National Grid Electricity Transmission (NGET). Given the unprecedented demand for new generation connections, and the need to connect renewable generators in particular, the GB government and the regulatory authority have initiated a review of the GB network access arrangements, the associated access charges and security standards.

In Nordic countries no major risks at system level are foreseen at this time. (NB Denmark West, where the majority of wind is connected in Denmark, is not directly connected to the Nordel system but forms part of the former UCTE continental system). The close market integration implies that wind power will replace thermal and hydro production and therefore affect power flows but in 2008 the impacts are within the thermal and voltage capability of the network. Looking forward, a development plan identifies potential power infrastructure reinforcements covering both Nordel internal pinch-points and interconnections to the Continent.

In the Continental Europe (formerly UCTE) system, there are both short-term mitigation actions and longer-term developments in progress. In the short-term, TSOs are seeking to manage power flows within the capability of existing networks by using available operational measures (such as network reconfiguration by switching and using flow control devices) and then notifying the resulting available transfer capacity to market participants. In the longer-term, the need for additional network capacity is being addressed by reinforcement actions which, amongst other things, will permit the integration of additional wind generation without reducing the scope for cross-border trade. In some countries, the internal network development has been doubled the investment effort in last 3 years.

At a regional level, a special task force within ENTSO-E has begun harmonising the network models from national plans to produce a “10-year network development plan” (to which EWIS has proposed further candidate measures that will improve wind integration).

In scenarios with high wind installations, especially in North Europe, overloading of transmission lines in normal operation as well as in fault outage conditions is expected (even with best use of available operational measures) so additional network reinforcement is desirable in order to maintain security and reliability of supply. In practice it will take time to deliver certain network expansion measures, particularly those which require new lines, due to the complex and lengthy authorisation procedures for new transmission routes and so additional operational mitigations are expected to be needed for some time. The following sections sets out how EWIS has identified these measures.

3 Scenarios and exchange schedules

3.1 Introduction

For the EWIS 2015 analysis, the goal was to bring common pan-European recommendations on how to best integrate wind power in to the European grid. To facilitate this, European-wide scenarios were derived to analyse the impact of wind generation on the future grid. These scenarios and associated market simulations enabled the assessment of wind power production, production from conventional power plants and market exchange schedules.

Because of the potential for large differences between market scheduled exchanges and the actual physical network power flows, it is vital to transfer the economic view of required operations from the market model into a representation of actual network conditions that can support more detailed network analyses.

The expression '*exchange schedules'* or *'commercial exchange'* is used to describe programs of exchange scheduled from one market to another as a consequence of market activity or cross-border bilateral trading. Conversely, the word *'flow'* or *'loadflow'* is used only for the physical power flows that can be measured on a set of electrical transmission lines. Power flows are currently managed by each Transmission System Operator, acting in his own 'control area'.

3.2 Methodology

EWIS uses two models for its simulations: The EWIS market model and the EWIS network model.

The **EWIS market model** deals simultaneously with a large number of economic and market parameters. It produces an idealised representation of market operation throughout a year, approximating certain physical and legal restrictions on generation operation. Reflecting current market arrangements, schedules are derived ignoring all network limitations except cross-border limits which are implemented as Net Transfer Capacities (NTC). Some basic principles and approximations in the market model and the resulting exchange schedules are described in the Appendix 3-1. Specific hydro modelling approximations were also made (eg for the Nordic countries). To derive actual network flows for the derived year-round market exchanges, an approximation of the full load flow calculation based on Power Transfer Distribution Factors (PTDF) was used. In Appendix 3-2, some information on the used concepts is given. Results of flow-based year-round-runs (PTDF approach) are provided, i.e. statistics on cross-border flows throughout the year. These are compared with the exchange schedules of point-in-time snapshots (NTC approach).

The year-round runs of the market model with PTDF-approximated cross-border flows have permitted a statistical analysis of congestion on borders and offers economic information concerning the potential benefits of reinforcements. The results of the network model allow a few snapshots to identify in detail which connections inside countries and across borders are overloaded, and how these could be reinforced.

The **EWIS network model** permits the calculation of realistic and detailed loadflows for steady state conditions (i.e. conditions before or after transients caused by faults or network switching). To this end, the network model of the former UCTE area alone contains approximately 10,000 nodes, 13,500 lines, 1,800 transformers and 3,000 generators. The national grid development plans for 2015 were included in the system models, consistent with assuming that all currently planned grid reinforcement measures will be realised by 2015 on time.

The flow on each individual element of the power system –and in particular across borders- is the result of the interactions between the location of all generators and consumers on the one hand and the physical characteristics of the transmission lines and transformers on the other. Scheduled cross-border exchanges, as established by the market model for a number of points-in-time, may still be below the available cross-border transmission capacity while the real flows calculated with the network model may exceed available capacity. The difference between scheduled exchanges and real physical flows is often called the “loop-flow”. Only the real physical flow determines whether or not grid congestions occur in practice.

Point in time snapshots from the market model were implemented in the network model for detailed load flow calculations and other analysis by adapting the individual loads and generations in each control area to the values determined by the market model. The coordination between the countries that will be needed to integrate wind power efficiently without violating technical limitations (e.g. considering line limits or limits of must-run-units due to grid stability reasons) could then be investigated.

Scenario Selection

– Approach

For the EWIS Phase I work, wind development scenarios and exchange schedules between market areas were set up for the year 2008. An extension of this approach was applied for the year 2015. These scenarios are the basis for the power system and economic analyses in this report, which are summarised below. The methodology used in setting the scenarios has two modules:

- Selection of wind situation
- Adjustment of conventional power plants and exchange schedules

As a boundary condition for adjusting the conventional power plants and exchange schedules, the available network exchange capacities were determined. Other boundary conditions (or framework assumptions) included two sets of fuel and CO2 prices. A detailed description and analysis of the considered framework assumptions is listed in Appendix 3-3.

3.2.1 EWIS-Scenarios

Four scenarios were provided as shown in Figure 3-1.

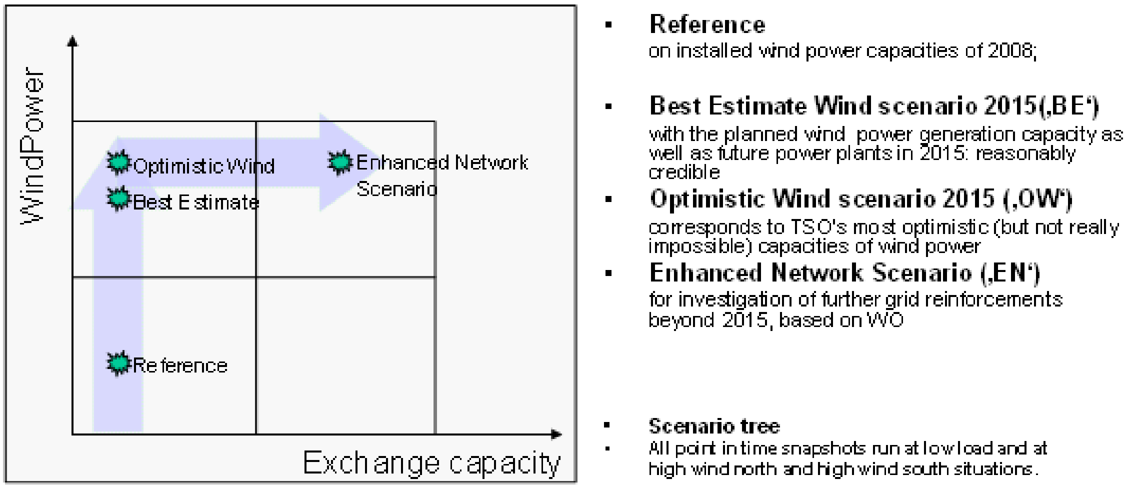


Figure 3-1: EWIS point-in-time scenarios

<u>‘Reference’ (Base case)</u>

Wind power has manifold impacts on strategic and operational decisions undertaken by market participants within the electricity system. The installed wind power capacity in 2008, referred to as the ‘Reference’ scenario, is used as the basis for extracting the wind impact on production dispatch and cross-border exchange in the point-in-time (snapshot) situations and the year-round runs.

<u>'Best Estimate Wind' 2015</u>

The year 2015 situation with the most likely development is referred to as the 'Best Estimate' scenario. This scenario takes into account the generation capacity evolution described in the 'Reference' case as well as future power plants –wind and conventional - whose commissioning by 2015 can be considered as reasonably credible according to the information available to the TSOs: Commissioning (together with decommissioning) resulting from governmental plans or objectives (regarding the development of renewable sources in accordance with the European legislation for instance), from the requests for connection to the grid or from the public information or from information provided to the TSOs by producers or would be producers. This scenario gives an estimation of potential future developments, provided that market signals give adequate incentives for investments.

<u>'Optimistic Wind' 2015</u>

The 'Optimistic Wind' scenario describes high wind power in 2015. This scenario takes into account the generation capacity evolution described in 'Best Estimate' as well as the installed capacity in 2015 which corresponds to TSOs' most optimistic (but credible) views concerning generator parks with high capacities of wind.

<u>'Enhanced Network' scenario 2015 and beyond</u>

This scenario is for the investigation of further grid reinforcements beyond 2015. It is based on the 'Optimistic Wind' results and corresponding year round model runs which gave cross-border marginal values of increased interconnectors and congestion statistics.

3.2.2 Wind power penetration

The wind power penetration at a particular time is defined as the share of wind power production related to the national load. The results are explained representatively on two counties of the North and South of the EU High with wind power capacities installed listed in Table 3.1 At first view ES and DE nearly have the same penetration factors at a high wind situation: DE 80% and ES 78% excl. special measures.

wind power penetration

	high wind north		high wind south	
	ES	**DE**	**ES**	**DE**
national load [GW]	29,9	50,7	28,7	56,5
Reference wind power [GW]	3,5	17	13,1	4,8
	12%	**34%**	**46%**	**8%**
Best Estimate Wind power [GW]	6,3	33,5	24,9	8,2
	21%	**66%**	**87%**	**15%**
Optimistic Wind power [GW]	7,1	40,7	22,4	9,7
	24%	**80%**	**78%**	**17%**
Enhanced Network wind power [GW]	7,1	40,7	22,4	9,5
	24%	**80%**	**78%**	**17%**

Table 3.1: Wind power penetration

ES snapshot results above include curtailment of 2,5 GW wind power that could be avoided by additional interconnection capacity. This highlights the fact that cross-border exchange can support optimal economic dispatch of generation at high wind situations and can be used to avoid wind power curtailment.

When net exports are added to the national load than the 'effective' wind power penetration substantially is reduced as Optimistic Wind results show below.

DE

Wind Power Penetration 80%

Effective Wind Power Penetration 63 % (incl. net export)

ES

Wind Power Penetration 78%

Effective Wind Power Penetration 75% (incl. net export)

Effective Wind Power Penetration 66% (incl. net export and curtailment)

3.3 Year round statistics

3.3.1 Time field of observation

The year-round runs highlight the overall stress on the borders between countries throughout the year. The principle how to quantify the congestion situation is described in Figure 3-2. The results show which borders candidate for reinforcements.

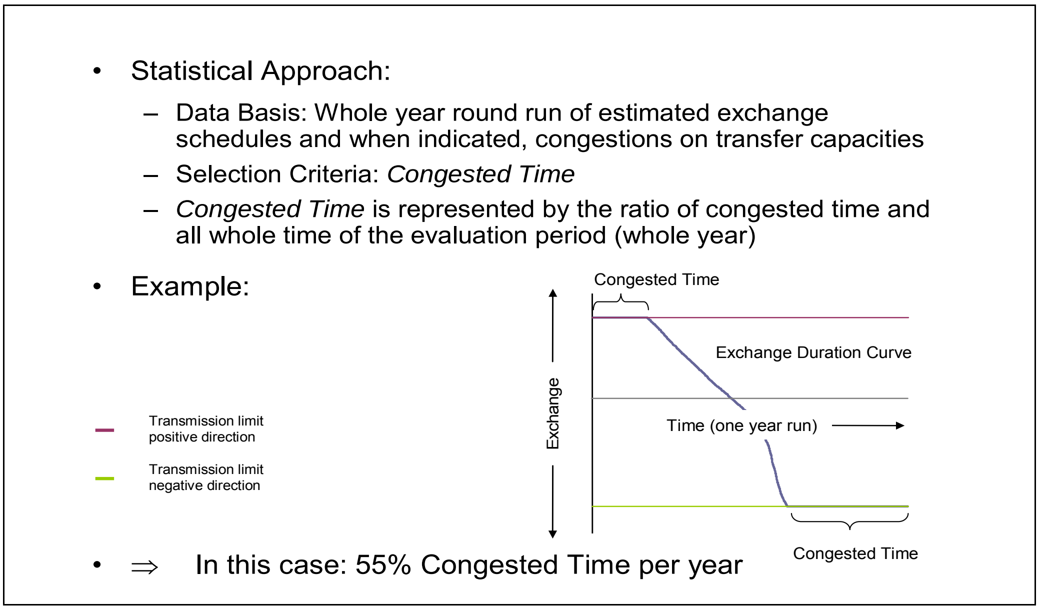


Figure 3-2: Determination of congestions statistics of interconnectors

In the context of the year-round runs EWIS has defined point-in-time snapshots which provide more details - economically and physically.

3.3.2 Congestion Situation Analysis

3.3.2.1 Regional Analysis 2015 – Best Estimate / Optimistic Wind

The EWIS market model with its scenarios represents all EU synchronous systems as different regions: Scandinavia, GB, Ireland and Northern Ireland and the continental. Above the provision of necessary data regional experts have analysed the results with their expertise.
Robust Pan EU scenarios covering the relevant regions of wind power are analysed country-wise focusing on the exchange schedules to reflect the impact of the new generation portfolio and increased wind generation.

3.3.2.2 Central West

Denmark (DK): Year Round Simulations analysis of exchange schedules

Interconnector DK-W/DE: The wind driven export for 38 % of the time of the year is NTC limited whilst non wind driven import from DE is NTC limited 17 %, which is a congestion total of 55 % in the BE scenario. The congestion situation is at medium range (BE and OW). Southbound exports are limited to 2000 MW one third of a year. No wind situations are relevant with northbound imports limited to 1500 MW for a sixth part of the year. The modelled exchange at a high wind situation may be considered conservative.

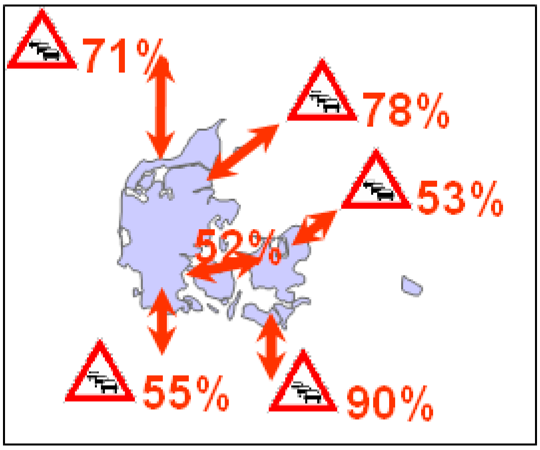


Figure 3-3: DK Interconnectors congestion statistics
2015 Scenario Best Estimate Wind

Interconnector DK-E/SE is congested for 53 % of the time of the year. Transit from DK W and DE through DK E to Sweden is NTC limited 34 % of the time and the reverse limited for 18 % of the year.

Interconnector DK-W/SE is 78 % of the time congested by NTC limits in both directions equally.

Interconnector DK-E/DE 2008 has been a well loaded interconnector driven by market coupling. The congestion situation is expected to increase significantly from 27% of a year (measured data 2008) to 90% (year-round model statistics ‘Best Estimate 2015’ on PTDF approach).

Germany (DE): Year Round Simulations analysis of exchange schedules

In the following, the congestion situation of the interconnectors between DE and its neighbouring countries related to the time horizon of the year 2015 is analysed. The results are shown in Figure 3-4, evaluated for the scenario “Best Estimate Wind”. Within the direction of the arrows the main congested time of the interconnectors is depicted.

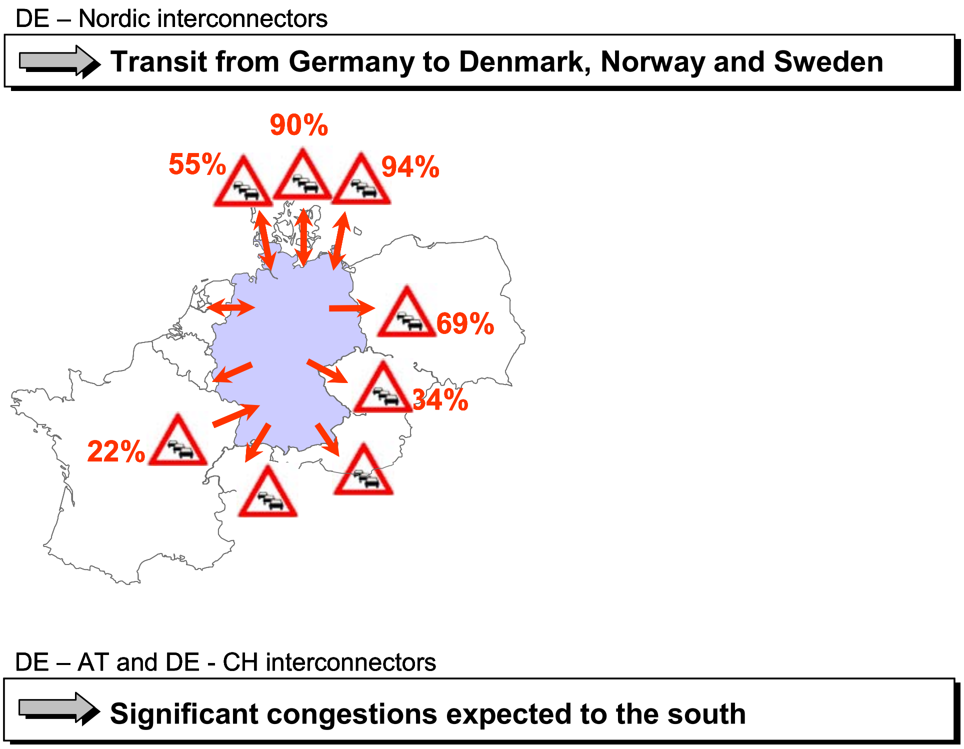


Figure 3-4: DE Interconnectors congestion statistics
2015 Scenario Best Estimate Wind

Interconnector DE/DK-W: For details s. ‘DK’ above.

Interconnector DE/SE DK-E:: These DC-interconnectors have a high congestion situation (average 92%). The exchanges during one year a driven by the price differences between the countries.

Interconnector DE/NL: The low congestion situation is expected due to low price differences between the countries and appears in both directions.

Interconnector DE/PL CZ: The congested time is mainly caused by DE to the counties mentioned above due to higher prices (average of congested time 52 %). In this case, the tendency to an increasing congestion situation related to installed wind power (scenarios) can be observed.

Interconnector DE/FR LU: In this case, a low congestion situation occurs which is caused by small prices differences between DE between its neighbours.

Interconnector DE/CH-AT:

The optional increase of pump storage power plants from today ca. 1,6 GW up to 4 - 5 GW in 2015 and beyond 2015 in Switzerland is not considered in the market model. The present situation on the physical transmission lines showed that already today congestions occurred. Under consideration of the upcoming increase of pump storages, the congestion between Germany and Switzerland, and also between Germany and Austria, will be significant higher in 2015. The pump storage power plant will be pumping (this means higher import of Switzerland) especially in high-wind situation.

Due to the modelling of the electrical coupling between the participating countries in the market model – all physical existing transmission lines between each countries are reduced to one single exchange capacity – the congestion situation on the physical existing transmission lines can differ from the market model results of one exchange capacity. Therefore a detailed modelling of the transmission network and calculation of power flows for the given EWIS-scenarios is performed within the framework of Chapter 4 to find sustainable solutions considering market and regional expert knowledge aspects.

<u>Belgium (BE):</u> Year Round Simulations analysis of exchange schedules

The results show few congestion hours on interconnectors to NL and LU. The year-round statistics show on average a reduction of import with 60 to 120 MW in the Optimistic Wind scenario, compared to the Best Estimate, due to an increased amount of installed wind power capacity.

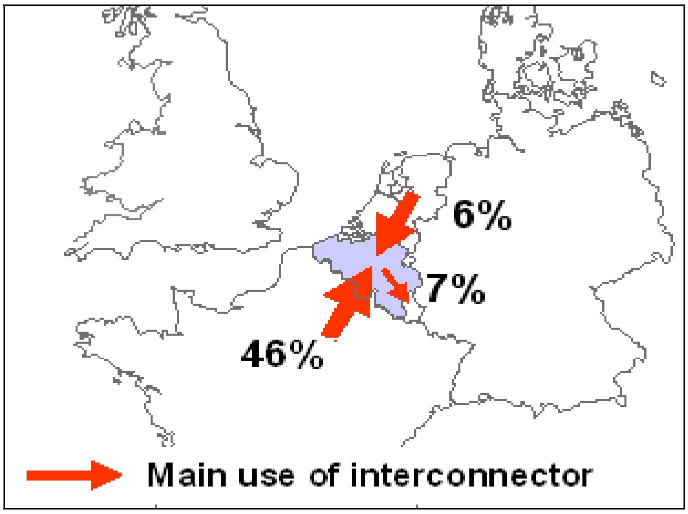


Figure 3-5: BE Interconnectors congestion statistics, 2015 Scenario Best Estimate Wind

Interconnector Belgium /FR: The interconnector is congested almost half the year (46%) in the direction FR to Belgium (3500/4000h at 'BE'/'OW'), in spring, summer and autumn. 6% of the time, concentrated in the winter months, there is congestion from Belgium to FR.

Interconnector Belgium /NL: With 525 hours of congestion from NL to Belgium at 'BE' the results show rather little congestion. There is a tendency for further reduction with more wind power capacities installed in 'OW' (435h), probably mainly due to increased import from France. The congestion is concentrated in the winter months. There is virtually no congestion in the direction Belgium to NL.

Interconnector Belgium /LU: The use of the interconnector does not show a relation with the wind situation. There is congestion during some 7% of the year in the direction to LU. This is evenly distributed over the year. There is virtually no congestion from LU to Belgium.

Congestion from NL across Belgium and to FR occurs some 6% of the time, in winter. More importantly, there is congestion from FR to Belgium during 3500-4000 hours, i.e. during most of the rest of the year.

3.3.2.3 South West

<u>Spain (ES):</u> Year Round Simulations analysis of exchange schedules

The exchange in 2008 is based on daily-hourly commercial capacity and real measurements. The interconnector has been congested 42% of the time. In the horizon of the study, in all scenarios it is expected this level will increase in perfect markets (even if interconnection has been reinforced and its capacity has doubled as implemented in the 2015 scenarios).

The interconnection capacity ES-FR considered in this analysis (1.900 MW) for 2015 corresponds to an interchange value from Spain to France used in planning studies available at the moment of gathering data and performing simulations. Refined local studies from both involved TSOs on the upgraded NTC capacity after reinforcement result in higher NTC capacities than the ones considered in EWIS (about 2500-3000 MW in the direction FR to ES and about 1700 -2800 MW in the direction ES to FR, depending on the season of the year and the load period of the day).

The congestion situation on ES-FR interconnector is shown in Figure 3-6.

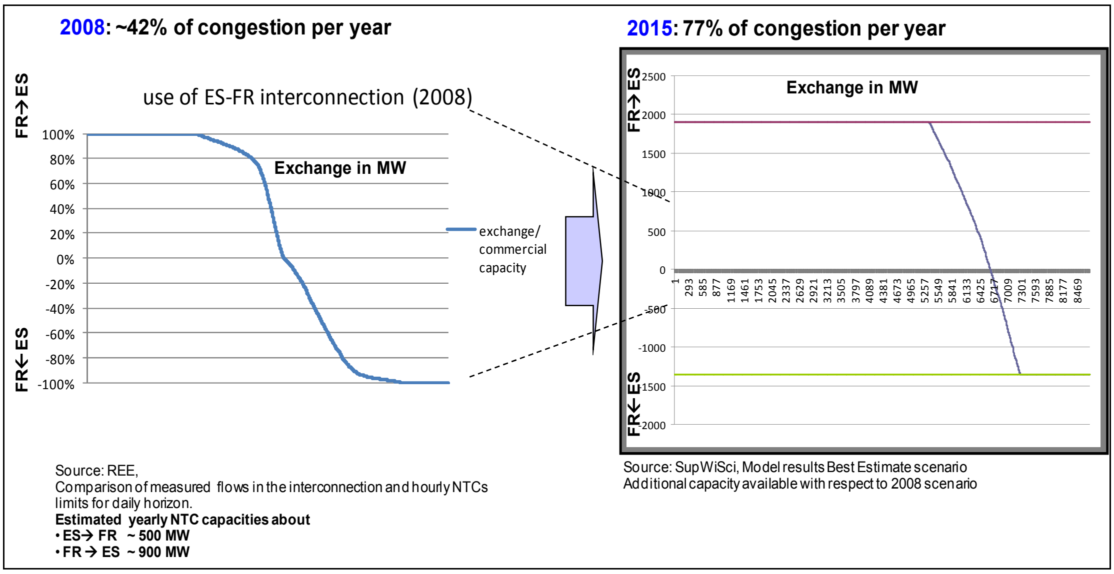


Figure 3-6: Congestion Spain-France interconnector
2008 (REE, measured) vs.
2015 Scenario Best Estimate Wind, PTDF approach

The market model results show a tendency of increasing volumes of exchanges in FR-ES interconnection, even if the number of hours with expected congestion for 2015 horizon, taking into account the actual values in NTCs, would be lower than calculated.

3.3.2.4 Central East

Czech (CZ): Year Round Simulations analysis of exchange schedules

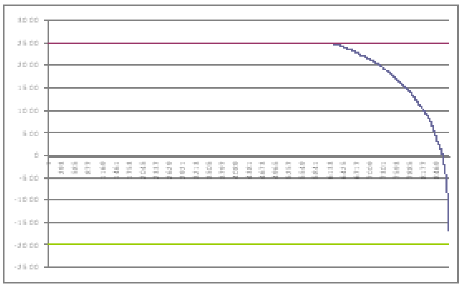
The results show congested Interconnectors DE/CZ and CZ/AT (with congested time more then 30 %). due to high export from Germany to Austria (taking PDTF approach into account).

Poland (PL): Year Round Simulations analysis of exchange schedules

Figure 3-7 presents congestion statistics on PL interconnectors. PL-DE interconnector in 2015 is congested 69% per year.

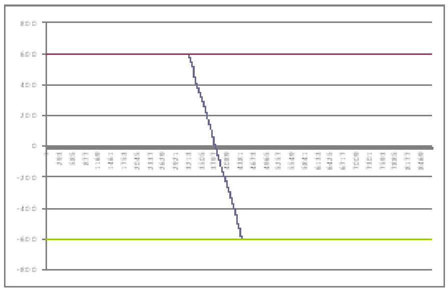
Border-Selection R_DE_R_PL

Limit	2500
reverse limit	-2000
Congestion hours	6007
reverse Congestion hours	2
total congestion hours	6009
% of congestion per year	68,69%



Border-Selection *from to* R_PL_R_SE

Limit	600
reverse limit	-600
Congestion hours	3150
reverse Congestion hours	4304
total congestion hours	7454
% of congestion per year	85,21%



Source: YRR Best Estimate Wind scenario – PTDF approach

Figure 3-7: PL Congestion statistics on interconnectors
2015 Scenario Best Estimate Wind, PTDF approach

Year Round Simulations show tendency to loop flow from DE through PL to CZ and SK which is even better observed in physical power flows.

Austria (AT): Year Round Simulations analysis of exchange schedules

Using the NTC-approach for the point-in-time snapshots the analysis show congestions on the borders DE-AT, CZ-AT, AT-CH, AT- IT, AT- SLO almost all the time.

For the year-round run the PTDF-approach was used and congestions on one border influence all other borders. With that approach congestions can be seen on borders CZ-AT (30% of the time) and AT-IT (70% of the time).

3.3.2.5 South

Greece (GR): Analysis of the results from the market model shows a small impact of wind power on the congestion situation of the interconnectors between Greece and it's neighbouring countries.

3.3.2.6 Nordic

Year Round Simulations analysis of exchange schedules

Most of the interconnectors show rather high congestion values well above 70% (NTC limits in both directions equally) as shown in Figure 3-8

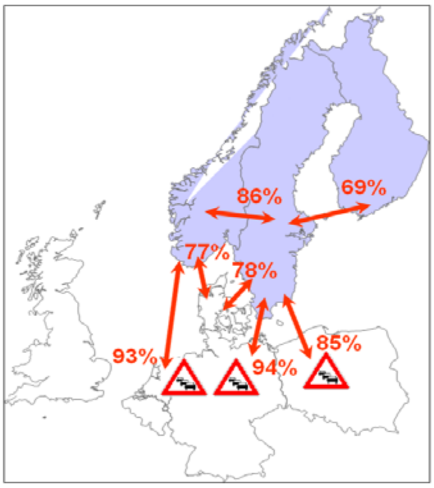


Figure 3-8: Nordic interconnectors - congestion statistics
2015 Scenario Best Estimate Wind, PTDF approach

Interconnector NO/DK-W: Incl. the planned fourth interconnector (SK4=600 MW) 71 % of the time congested by NTC limits in both directions equally.

3.3.2.7 GB , Ireland and Northern Ireland

<u>GB, Ireland and Northern Ireland</u> Year Round Simulations analysis of exchange schedules

Congestion on the GB interconnectors varies considerably with different cost cases, and to a lesser extent with the different wind capacity scenarios. Results for the Best Estimate low cost case are shown in Figure 3-9.

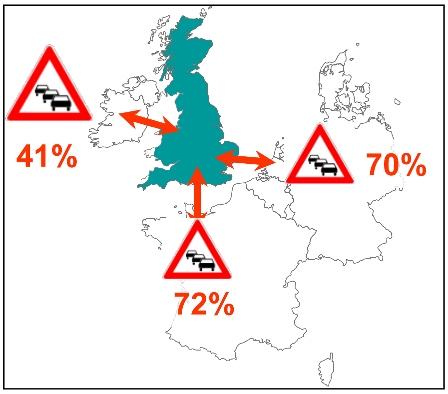


Figure 3-9: Congestion of GB interconnectors
2015 Scenario Best Estimate Wind, Low cost

Interconnector GB – FR: In all the studied point in time snapshots the exchange has been assumed in the direction FR – GB at the NTC limit. For the year as a whole, the exchange is NTC limited in the direction FR – GB for between 60% and 86% of the time, with GB exports to FR NTC limited for between 3% and 12% of the time. Congestion over the year is not affected by the amount of wind capacity; there is hardly any difference in congestion between the reference scenario and the optimistic wind scenario. There is a much greater difference between the Low cost and High cost cases than between the different wind capacity scenarios. In the high cost case the price differential between GB and FR is increased, leading to increased flow in the direction FR – GB.

Interconnector GB – NL: As is the case for the GB-FR interconnector, in the PIT scenarios flows are all in the direction NL – GB at the NTC limit. For the year as a whole the flow into GB is at the NTC limit for between 46% and 70% with congestions in the direction GB – NL for between 8% and 24%. There is no correlation between congestion and wind capacity but quite strong correlation with cost, with greater NL – GB flows in the high cost case.

Interconnector GB – IE: Modelling of the whole year shows that all wind scenarios demonstrate alleviation of congestions at GB-IE borders. Exports from GB to IE in reference low cost (LC) and high cost (HC) scenarios will be at the NTC limit for 75% and 48% of the time accordingly, but there is hardly any congestion in the opposite direction. In BE LC and HC scenarios congestion will be 41% and 24% accordingly. The congestion improvement between the reference HC and BE HC scenarios is clearly seen from Figure 3-10 below. This is because wind is significantly reducing the price differences between two countries, which lead to fewer incentives for exchanges. This is the reason why congestion is heavily reduced with increased wind power. High costs also relieve congestions on the interconnectors. Note that this is the opposite effect to that modelled on the GB – NL and GB – FR interconnectors.

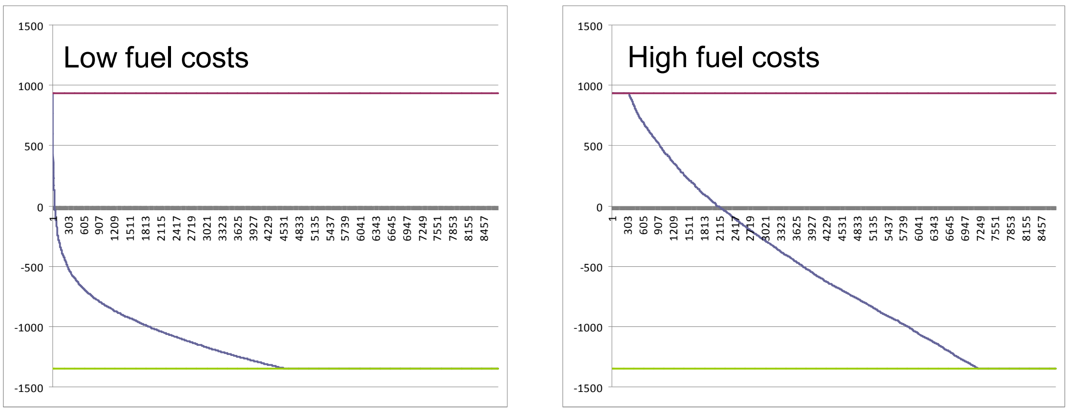


Figure 3-10: Congestions GB-IE at different boundary conditions
(low vs. high fuel cost) 2015 Scenario Best Estimate Wind

IE imports energy from the GB 70-100% of the time depending on scenario with net average imports from 410 MW in optimistic wind (OW) HC scenario to 1300 MW in reference LC scenario totalling from 10 to 25% of total Irish demand. Figures for each scenario are presented in Table3.1 below.

	Scenarios					
	REF HC	REF LC	BE HC	BE LC	WO HC	WO LC
IE-GB congestion [% of the time]	0	0	4	1	7	3
GB-IE congestion [% of the time]	48	75	18	40	15	32
Total congestion [% of the time]	48	75	21	41	21	35
Net Import to IE [MW]	1170	1300	540	900	410	730

Table 3.2: Congestions on the GB/IE interconnector

Scenario Best Estimate Wind/Optimistic Wind at High Wind North

GB, Ireland and Northern Ireland: Summary

Congestion between GB and FR and GB and NL is unaffected by wind, but increasing wind generation reduces congestion between GB and IE.

3.3.3 Interconnectors congestion situation

The statistic results are calculated from the market model's year-round runs on PTDF approach at low costs for CO2 and fuels (Appendix 3-3). High wind situation north and south are included both because of the year-round time field view.

Figure 3.11 compares the congestion statistics of the flows of the different scenarios. It should be noted that the results shown are the outcome of one set of boundary conditions. Further sensitivity analyses have shown that the results can drastically change with different boundary conditions. Small deltas to the values shown in the figures above because of the quality increased calculation algorithms used (incl. stochastics).

Scenario Reference, Best Estimate, Optimistic Wind - year-round statistics on PTDF approach

Congestion level: Implementation of a perfect market premise into the 2015 market model increases congestions on interconnectors due to most cost efficient power mix in the countries, independent of any wind power. This is due to the fact that even rather small price differences result in fully utilized interconnectors.

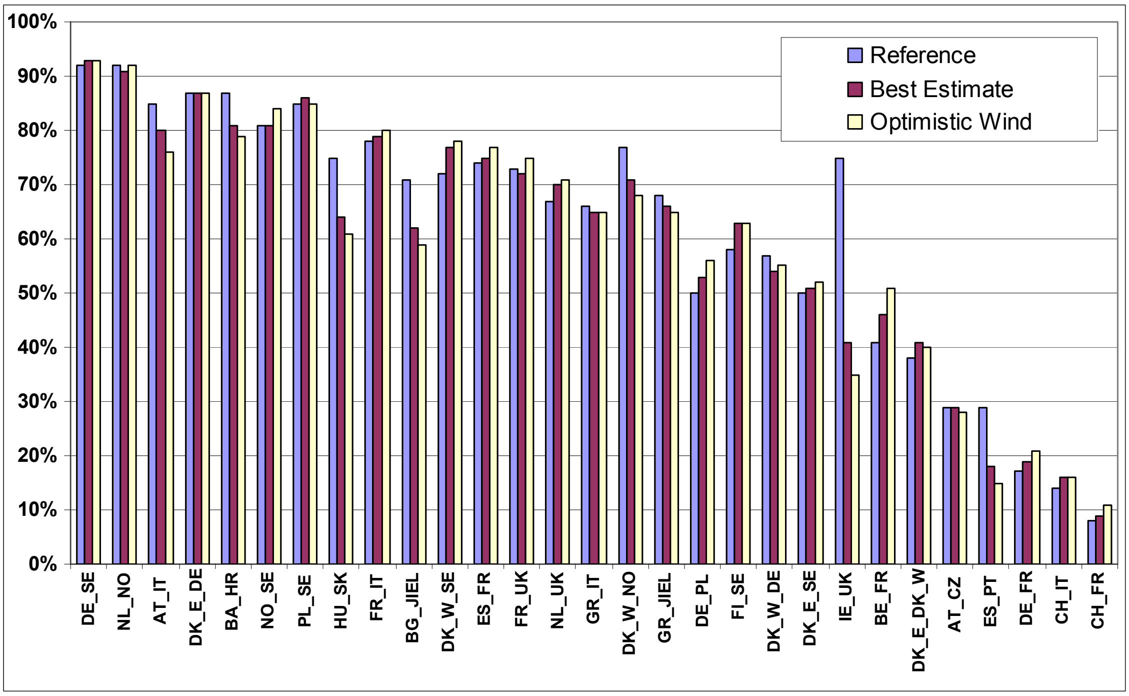


Figure 3-11: High congestion level due to price differences, small impact of wind power on European Interconnectors; impact of boundary conditions
EWIS Scenarios Reference/Best Estimate and Optimistic Wind
(ISO code for the country names, i.e. SI for Slovenia; JIEL is network of Serbia, Montenegro and Macedonia. I.e. DE_SE is the German/Sweden interconnector)

In principle the effect is shown by Figure 3-12. 'DE/DK-E Kontek interconnector 2008 measured 27% increases to around 90% in 2015 modelled (all scenarios). The impact of wind power on the congestions is rather moderate. Within an analysis of the statistic impact of the wind power on the congestion situation the model results show that wind power can also have a positive effect on congestion situations. So the congestions are reduced if ceteris paribus wind power production is high in the country with relative high market price.

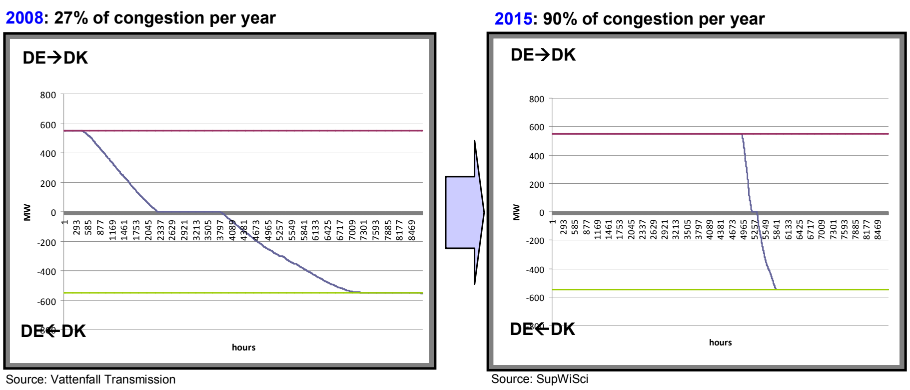


Figure 3-12: Congestions 2008 measured vs. 2015 modelled (example)

On the other hand there is a tendency for an increase of congestions if wind is blowing in a country with low market prices – making the price level even lower. This gives incentives for more exports to neighbouring regions, because price differences might be increased. A further impact on the exchanges can be given by a wind impacted redispatch if conventional capacities have different flexibilities when adjusted to a new power mix.

Explaining the reduction in congestion i.e. on the PT-ES and the IE-GB interconnectors: Wind power significantly reduces the price differences between these countries, if the average absolute hourly price difference on these borders is compared

This leads to less incentive for exchanges and this is the reason why congestion is heavily reduced with increased wind power. Figure 3-13 highlights the findings.

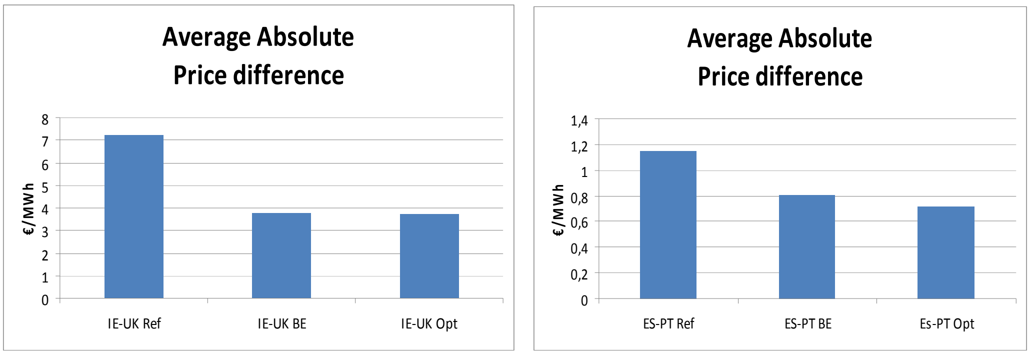


Figure 3-13: Congestion statistics – Price difference IE/GB and ES/PT
2015 Scenario Reference, Best Estimate, Optimistic Wind, PTDF approach

Nevertheless, for the Iberian Peninsula, above explanations do not imply a dramatic reduction in physical exchanges, since network and system topology and relative sizes are not considered.

3.4 Point in time

– Selection of Wind Situation

The expansion of wind power generation in some EU Member States has significant implications for the European electricity system as a whole.

The concentration of wind power in northern Germany is already producing load flows through the neighbouring transmission networks. In order to analyse the impact of wind power generation in northern Europe on the electric infrastructure and the future infrastructure developments, a scenario with a high wind output in northern Europe is selected.

It is expected in 2015, as already evident in 2008, that after Germany, two countries: Spain and Portugal will have the highest installed wind power capacity in continental Europe (together the 3 countries in 2008 represented 65% of the total installed wind capacity within Europe). Furthermore, Italy, France, United Kingdom and Greece are expected to see strong increases in installed wind power capacity. As a result, situations with high wind power generation in southern Europe may have significant effects on the existing power plants in this region and may lead to strong power exchanges with neighbouring countries, too.

For the point-in-time selection EWIS has defined 'wind power penetration' as the share of wind power production related to the system load. EWIS uses this ratio to extract a snap shot showing the wind impact on the transmission grid at a challenging and realistic point-in-time.

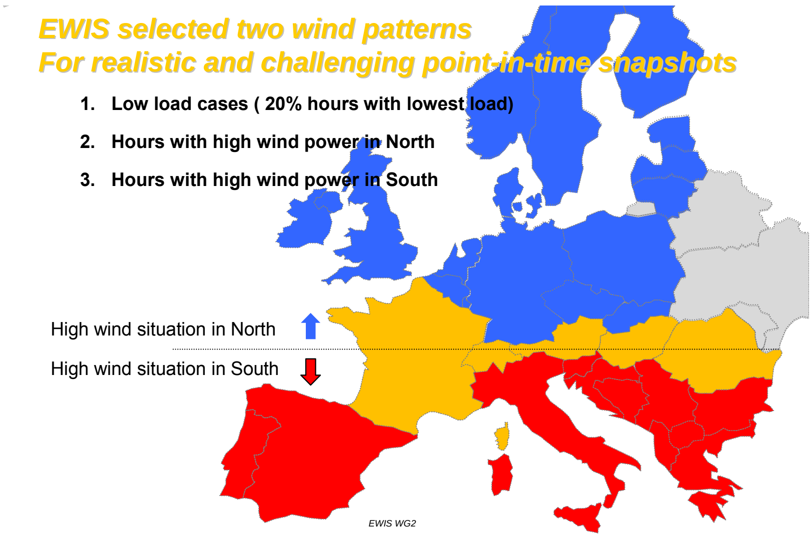


Figure 3-14: EWIS methodology for finding the realistic point-in-time snapshot

At low load cases (20% of hours with lowest load and which give some of the most demanding conditions in terms of network stability and control issues) the hours with the highest aggregated wind generation in North and South of Europe (see. Figure 3-14 above) have been identified. The corresponding hours with the highest 'wind power penetration' were retained as point in time snapshots.

The 'High Wind North' snapshot simulates a strong wind situation in northern Europe when there is low wind in southern Europe whilst the 'High Wind South' snapshot has strong wind in southern Europe when there is low wind in northern Europe.

The time series for the ‘Reference’ were derived from time series for the year 2006 adjusted to 2008 capacities. A similar procedure was followed for the 2015 scenarios (The scenarios used in the study are described in Chapter 3.4.2 *EWIS-Scenarios*).

-Adjustment of conventional power plants and exchange schedules

The output of the conventional power plants and the exchange schedules are adapted to achieve system balance with the additional wind power determined from the selected wind situation described above. Adjustments are carried out according to a generalised generation priority (merit order). This generation priority serves as a ranking to reduce or increase the power generation from the power stations in response to the additional wind generation in the scenario. The exchange schedules are also adapted to reflect the impact of the new generation portfolio and increased wind generation in each country. Thereby, the costs of electricity generation and balancing are minimized, subject to given import/export constraints. If the available import/export capacities for the market area are sufficient, the surplus/deficit power is distributed among other countries according to the generation priorities. If the export/import capacity is insufficient, the surplus power is then balanced within the market area itself. The Joint Market Model (JMM) developed within the WILMAR project (Wind Power Integration in Liberalised Electricity Markets) is used to determine despatch, prices, cost and most importantly the electricity exchange between market areas within the European system.

3.4.1 Time field of observation

The economical and physical analysis of a number of well chosen situations gives the best way to examine future network capacity requirements and network technical performance. EWIS identified these scenarios including their context in terms of conditions one week before the point-in-time using an hourly resolution as shown i.e. for the production mix in Figure 3-15.

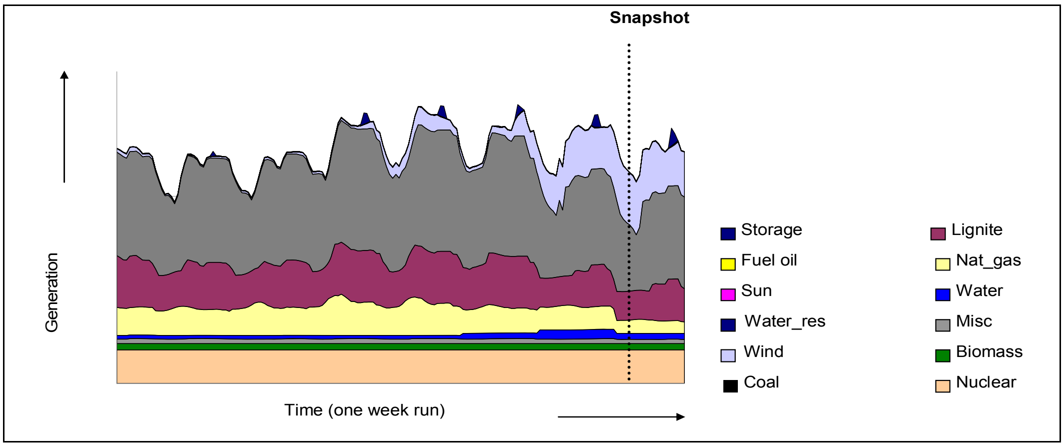


Figure 3-15: Example of a point-in-time scenario

The point-in-time investigations focused in EWIS have an exemplary character giving indications for realistic and challenging situations, within countries and across borders, and allowing a detailed analysis of these particular situations. The points-in-time are chosen from a European perspective; other points-in-time may impose further challenges on smaller regions or nations. These further challenges are not in the scope of this study, but are referred to in the list of references.

3.4.2 Point in time Regional Analysis 2015 – Best Estimate / Optimistic Wind

In order to address the uncertainty of future wind deployment, EWIS selected two wind patterns for realistic and challenging point-in-time snapshots based on TSOs' expectations which were investigated. Within these scenarios the dispatch of the power production and the exchanges were analyzed in detail in order to highlight the effect of wind power on the power system. To manage congestions on cross border pinch-points in an optimal way the analysis of the point-in-time scenarios is focused. This gives insights into the system behaviour in situations where wind induces a lot of system stress. In the context of the year-round analysis the point in time snapshots were analysed in much more detail in order to check system robustness.

The detailed results for each country are shown here, and additionally a summary table showing categories for each exchange is given in Appendix 3-4.

3.4.3 Central West

Denmark (DK): Point-in-time scenarios analysis of exchange schedules

The installed capacity of wind in DK in 2015 will be 4500 MW for the scenarios Best Estimate (BE) and 5400 MW Optimistic Wind (OW) which means a high installed capacity penetration of max. 88% wind power compared to conventional generation capacities. In Figure 3-16 the exchange schedules on DK Interconnectors for BE and OW are listed.

Interconnector DK-W/DE is a back-bone for wind integration because in the case of increasing wind power the need for export can utilize up to 3500 MW when it turns the direction of exchange even if the export capacity is 2000 MW. The PIT-export is wind driven which increases at High Wind North situation about 50% (BE/OW 383/571 MW) in line with more installed wind power capacity. The PIT-import is 1500 MW at no/low wind situation (BE/OW at High Wind South).

As DK exports are wind driven they can be expected to be much higher when the wind power share in DK-West is higher than the modelled (in PIT ~50% of installed capacity), i.e. if the share rises to 80% the plus of wind power on the DK-West grid will be 1600 MW (OW).

The turn can have a maximum of 3.5 GW (NTC 2.0/1.5 ex-/import).

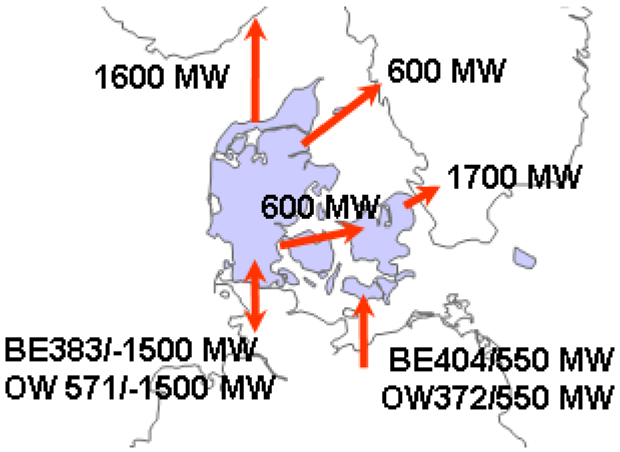


Figure 3-16: Exchange schedules on DK Interconnectors:
2015 Scenarios Best Estimate Wind/Optimistic Wind,
HighWind North/South

Interconnector DK-W/NO: For modelling the NO market an average water year was used. If there is a relatively wet year it can have a price reducing effect for the NO pricing area. And this can reduce northbound exchanges with a plus of wind power on the DK-West grid with a maximal value of 1600 MW (BE/OW). A more detailed analyzes is described in 'Chap. 4.4.1.5 Nordic' (Scandinavian).

Denmark: Summary

National consumption in 2015 will be Min/Max 3000 MW/7000 MW and total capacity for export is 6600 MW. At low wind situation DK serves for non wind driven transit from DE to NO or SE. At high wind situation the export capacities to Scandinavia are fully loaded while export to DE is low (OW 29% of capacity) due to small price delta. The export is strongly correlated to wind power. The interconnectors will be highly congested.

Installed wind power capacity penetration increases from BE 73% up to OW 88% related to 6.1 GW of conventional capacities. Relatively high overall production compared to load in PIT which drives the export - clearly correlated to wind power.

<u>Germany (DE)</u>: Point-in-time scenarios analysis of exchange schedules

The installed capacity of wind in DE in 2015 will be 42.1 GW for the scenarios Best Estimate Wind (BE) and 50.7 GW Optimistic Wind (OW) which means a moderate installed capacity penetration of max. 49 % (WO) wind power compared to conventional generation capacities.

The wind generation infeed of 40.7 GW in 2015 in the scenario "Optimistic Wind", with a national load 50.7 GW, leads to a high wind power penetration rate of 80 %.

Considering the results of the market model, a high substitution of gas, coal and lignite in the scenario Optimistic Wind is calculated. The results show, that the integration of rising wind power is achieved through an adjusted dispatch of conventional generation in connection with the exchanges to the neighbouring countries.

Further investigations, based on the scenario Best Estimate Wind, figure out that the exchanges of Germany are only marginally affected by rising wind generation capacity. According to chapter 3.3.2.1.1 it will be expected, exchanges of Germany to countries with a big amount of pump storage power plants (e. g. Switzerland) are linked to rising wind generation capacity in Germany. The scheduled exchanges are driven by the price differences of the countries merit order. This result can be validated by the estimated small impact of rising wind generation on the market clearing prices in neighbouring countries.

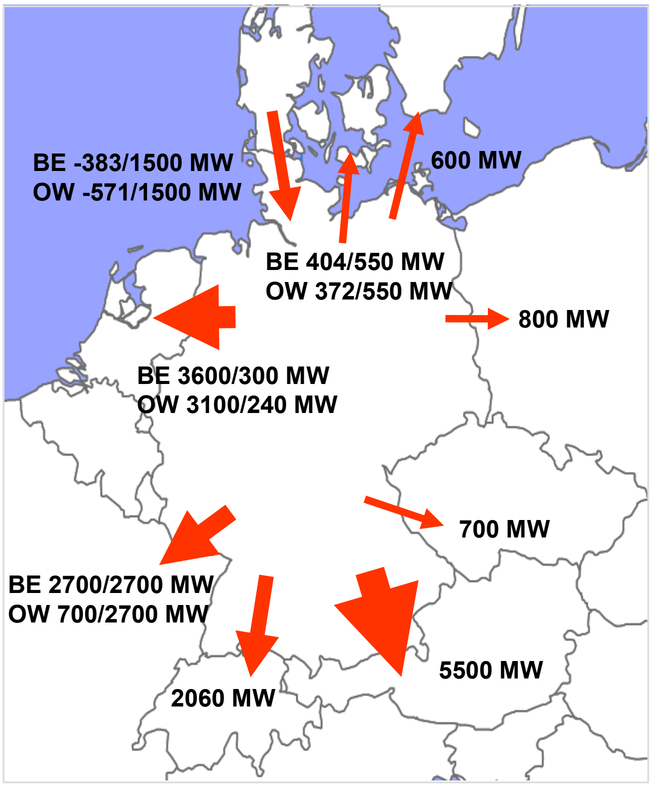


Figure 3-17: Exchange schedules on DE Interconnectors
2015 Scenarios Best Estimate Wind/ Optimistic Wind HighWindNorth/South

Interconnector DE/DK-W: For details s. 'DK' above.

Interconnectors DE/SE, DK-E: Export with volatile or constant value up to NTC limit due to higher prices in these countries which is not correlated to wind.

The results show high exchange schedules at low NTC limits of DC connections, which are represented. Further investigations show high day/night volatilities. This offers a high potential for wind power trading.

Interconnector DE/NL: When there is no/low wind situation there will be a small price difference to DE and the exchange is not hindered by NTC limits but high wind power in DE can increase the export up to NTC limits.

At high Wind situation DE has relevant exports (3,6 GW/3,1 GW for the BE/OW scenario) which decrease at low/no wind situation (~0,3 GW for the BE/OW scenario) because without wind impact there is a small price delta of the markets.

Interconnectors DE/PL, CZ, AT: Export with volatile or constant value up to NTC limit due to higher prices in these countries and not correlated to wind. The scheduled exchange on the interconnectors DE/PL and DE/CZ are mainly caused by the market driven southbound transit. Mitigation methods on PL and CZ borders would lead to an increased inner German transit and load of the interconnector DE/AT.

Interconnectors DE/CH, LU, FR: Export with volatile or constant value up to NTC limit due to higher prices in these countries and not correlated to wind. Under consideration of the foreseeable increasing of pump storage power plants in Switzerland a correlation to the wind energy production will be expected.

Germany (DE): Summary

Correlation of economical driven cross-border exchange schedules and wind power is not significant. Around the PIT Germany has a constant export volume to neighbours AT, CH, LU, PL,CZ, SE, DK-E, NL with no correlation to wind power infeed.

Increasing wind power causes decreasing export on interconnectors to FR and a change on interconnector to DK-W from export to import. Several interconnectors have high congestions. The Interconnector DE/DK-W highly supports wind integration.

<u>The Netherlands (NL)</u> Point-in-time scenarios analysis of exchange schedules

The installed capacity of wind in NL in 2015 will be 4000 MW for the scenarios Best Estimate (BE) and 5600 MW Optimistic Wind (OW) which means a moderate installed capacity penetration of max. 16 % wind power compared to conventional generation capacities. In OW the wind power penetration will have 38% (contribution of wind power to national load).

In Figure 3-18 the exchange schedules on NL Interconnectors for the different scenarios are listed.

Interconnector NL/DE: When there is no wind generation there will be a small price difference to DE and the exchange is not limited by NTC. High wind power infeed in DE increases the exchange limited by NTC.

Interconnector NL/GB and NL/NO: NL will be used as transit node for DE imports to GB and NO markets with higher price delta - regardless of wind. Whist the GB interconnection will be congested up to 80% the NO interconnection is expected to be congested for 90% of the year (DC links operated at maximum capacity).

Interconnector NL/BE: For details s please refer. 'BE'

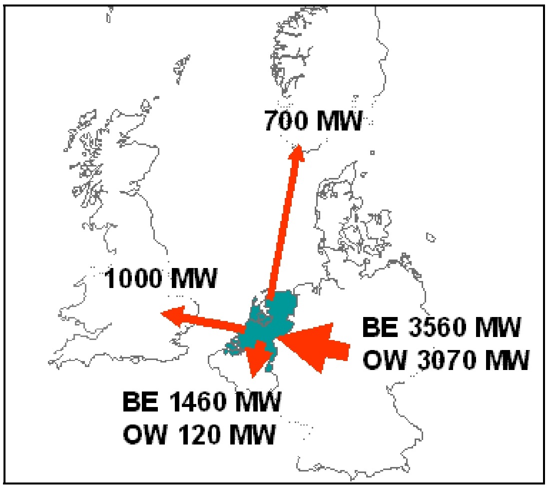


Figure 3-18: Exchange schedules on NL Interconnectors

2015 Scenarios Best Estimate Wind/Wind Optimistic, HighWindNorth

The Netherlands: Summary

The net imports increase if more wind power capacity is installed because exports to Belgium drop significant (Belgium substitute by importing from FR).

<u>Belgium (BE):</u> Point-in-time scenarios analysis of exchange schedules

The installed capacity of wind in BE in 2015 will be 1800 MW for the scenarios Best Estimate ('BE') and 2900 MW Optimistic Wind ('OW') with much of this off shore which means a moderate installed capacity penetration of max. 16 % wind power compared to conventional generation capacities. In 'OW' the wind power penetration will be 17% (contribution of wind power to national load) at the PIT. In Figure 3-19 the exchange schedules on BE Interconnectors for the different scenarios are listed.

The net import of Belgium at 'BE' equals ~3600 MW; at 'OW' this has dropped to ~2400 MW. The PIT are moments of very high import, especially for the BE scenario.

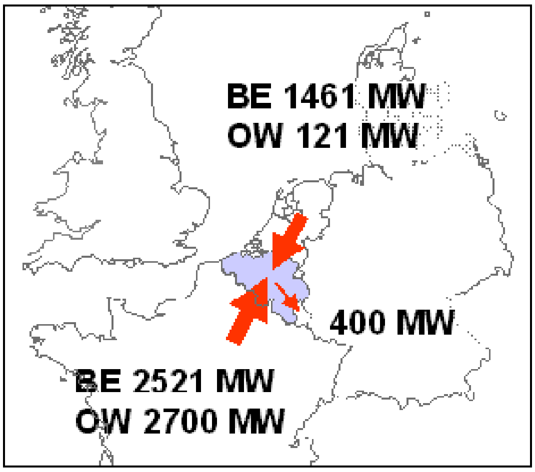


Figure 3-19: Exchange schedules on Belgium Interconnectors
2015 Scenarios Best Estimate Wind/Wind Optimistic, HighWindNorth

Interconnector Belgium/FR: The scheduled exchange from France to Belgium equals 2521 MW in the 'BE' scenario, and reaches the limit of 2700 MW in the 'OW' scenario.

Interconnector Belgium /NL: Increasing wind power drives down the scheduled flow from NL to Belgium. It drops from 1460 MW in the scenario 'BE' to 120 MW in 'OW', and shows increasing volatilities around the PIT. The reduction is due to both the lower net import level, and the higher import from France.

Interconnector Belgium /LU: The scheduled flow from Belgium to Luxemburg equals 400 MW in both the 'BE' and 'OW' scenarios.

Belgium: Summary

Belgium in general imports from NL and FR, and exports to LU. Increased wind power capacities will have a slight reducing effect on net import.

3.4.4 South West

Spain (ES): Point-in-time scenarios analysis of exchange schedules

Scenarios delivered are shown in Figure 3-20. In both cases (Best Estimate and Wind Optimistic) a strong displacement of conventional production (including nuclear power) in the hypothesis of High Wind South. At these moments, prices near zero are attained in the Iberian Peninsula, and a difference of price with the French system exists, but there is no possibility to trade energy and dispatching constraints show the need to curtail 2,4 GW of wind power production.

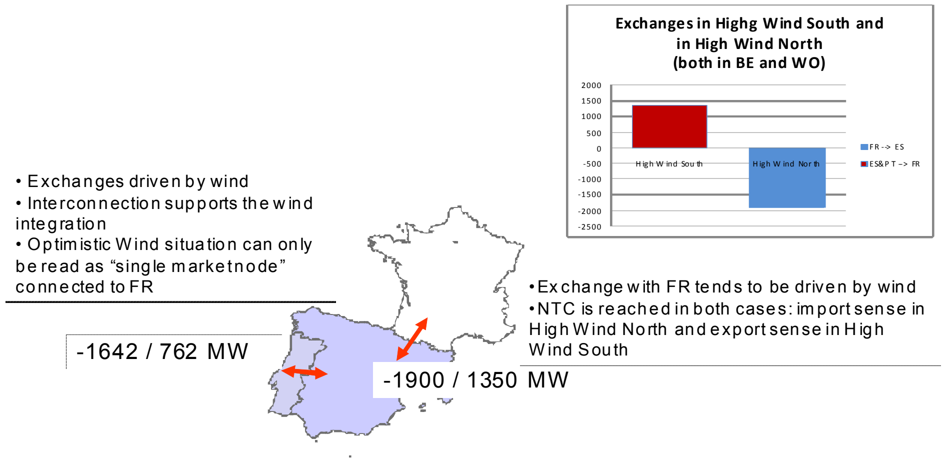


Figure 3-20: Exchange schedules on Spanish interconnectors
2015 Scenarios Best Estimate Wind/Wind Optimistic, HighWindNorth/South

The interconnector capacity with the Northern part of Europe on the border FR/ES represents less than the 7% of the installed wind capacity for the studied horizon, while in other major countries in wind promotion this percentage rises around the 40% of the installed wind capacity (Germany) till more than 80% (Denmark), even regions like Ireland or Great Britain count with a higher correspondent ratio (around 20%).

The interconnection capacity ES-FR considered in this analysis (1.900 MW) for 2015 corresponds to the reference interchange value between Spain-France used in planning studies. This figure takes into account that, according to studies performed by Spain and France TSOs, the NTC between the two countries, once the East Pyrenees new HVDC interconnection is working, ranges between 1.700 MW and 3.000 MW depending on the exchange sense, the season of the year and the load period of the day.

This weak interconnection strongly constrains the dispatching, especially in low load hours, where wind power can not substitute conventional generation that would be required only some hours after. This renewable generation can not be exported, neither peak hours imports can be programmed. Therefore, the need of a certain amount of conventional generation in low load moments makes wind curtailment unavoidable.This explained, it is to be noticed that Spain is the only member state in which the applied market model has shown the need of wind reduction in the selected Point in Time (snapshot) without possibility to be integrated in the European system because of physical constraints (interconnection scarcity). RED ELECTRICA de ESPAÑA (the Spanish TSO) has estimated it is a situation that would be quite often presented in the near future in business as usual scenarios. Own dispatching simulations show some differences in the generation profile, especially in hydro dispatch, other renewable sources and CHP participation, which aggravate the lack of leeway problem for wind power.

Regarding the economic exchanges analysis in the Point in Time scenarios, it is to be noticed that the interconnection between FR and ES is highly impacted by wind production and NTC limits are reached in both directions. This is a sign that shows the important support of this interconnection for the wind integration in a Pan-European level. Exchanges turn from an import at maximum NTC capacity (1.9 GW) during High Wind North to an export from Iberian Peninsula at maximum NTC capacity (1.35 GW) during High Wind South, so the maximum swing amounts to 3,25 GW. Exchange is quickly limited by NTC in both directions.

Spain: Summary
ES imports on the FR/ES interconnector during no wind situation and exports when there is a high wind situation. Interconnector FR/ES supports wind integration.

<u>France (FR)</u>: point-in-time scenarios analysis of exchange schedules
The installed capacity of wind in FR in 2015 will be 10000 MW for the scenarios Best Estimate (BE) and 17000 MW Optimistic Wind (OW) which means a moderate installed capacity penetration of max. 17 % (OW) wind power compared to conventional generation capacities. In OW the wind power penetration will have 17% (contribution of wind power to national load) at the PIT.
Interconnector FR/BE: Constant and NTC limited import from Belgium during no/low wind situations is turned at PIT to export to Belgium by the increasing wind power in FR up to the NTC limit in scenario ‘OW’ (2700 MW).
Interconnector FR/DE: 2700 MW of imports from DE decreases to 700 MW due to higher wind power in OW.
Interconnector FR/CH and IT: Massive exports impacted by wind power to CH (3000 MW) and IT (2400 MW) limited by the NTCs in BE.
Interconnector FR/ES: s. ES analysis above
Interconnector FR/GB: s. GB analysis below

France: Summary
BE and NL serve as transit node for power from DE which is stopped by increasing wind power. FR with exports to ES at high wind north situations, NTC limited, turns to imports from ES at high wind south situation which are NTC limited, too.

3.4.5 Central East

Czech Republic (CZ): point-in-time scenarios analysis of exchange schedules

The installed capacity of wind in CZ in 2015 will be 1370 MW for the scenarios Best Estimate (BE) and 1800 MW Optimistic Wind (OW) which means a moderate installed capacity penetration of max. 9 % (WO) wind power compared to conventional generation capacities.

Interconnectors: Details s. DE and AT section

Poland (PL): point-in-time scenarios analysis of exchange schedules

The installed capacity of wind in PL in 2015 will be 2338 MW for the scenarios Best Estimate (BE) and 3340 MW Optimistic Wind (OW) which means a moderate installed capacity penetration of max. 11 % (WO) wind power compared to conventional generation capacities.

Interconnector PL/DE: DE exports power to all its neighbours. The power coming from DE to PL is partly consumed and transited to neighbours north and south. DE prices are low even at low wind situations. The price is impacted by large amount of installed wind generation in DE (because of CO2 cost of conventional generation).

Interconnector PL/CZ and SK: The direction of exchange is from PL to CZ and SK. PL is used as a transit node for power from DE. The NTC limit may not be met on these two borders but it happens because the import from DE to PL is limited.

Interconnector PL/SE: SE imports power from Continental EU using all its connections including SE-PL link. The reason is price difference. The price difference PL/SE is caused by small amount of installed wind generation in Scandinavia compared to Continental EU and hydro situation in Scandinavia.

Figure 3-21 presents PL balance in the scenario 'Best Estimate Wind', High Wind North and Figure 3-22 presents PL exchange schedules in the corresponding week.

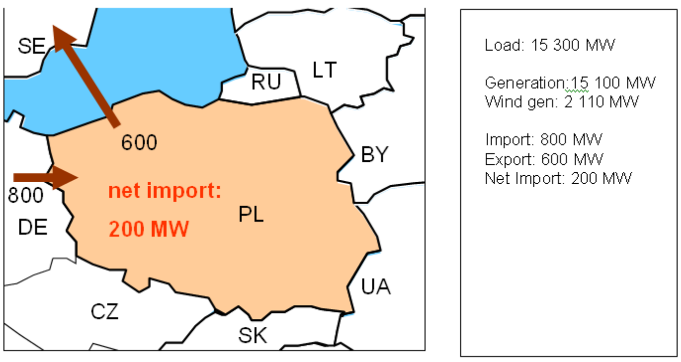


Figure 3-21: Exchange schedules on PL Interconnectors
2015 Scenario Best Estimate Wind, HighWindNorth

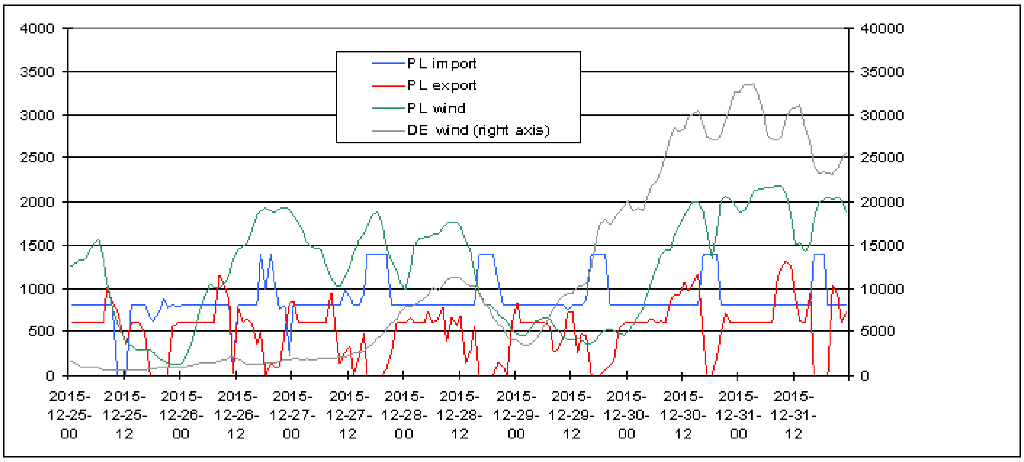


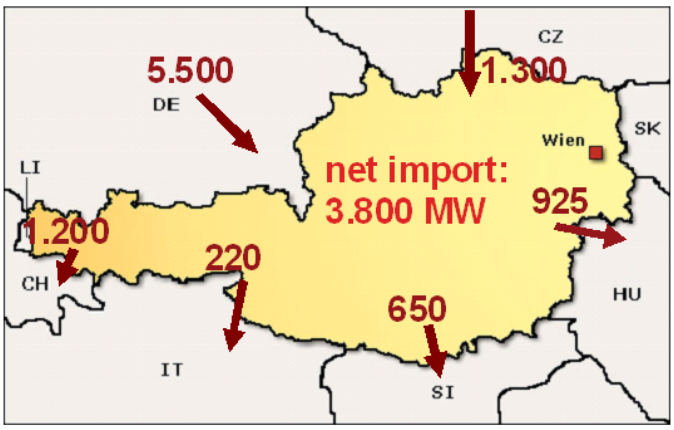
Figure 3-22: PL Exchange schedules vs. Wind power
2015 Scenario Best Estimate Wind, HighWindNorth

Poland: Summary

PL exchange is impacted by wind power and is increased up to NTC limit on Continental EU and SE border. PL exchange with CZ and SK is impacted by exchange with DE which fully uses PL-Continental EU multi-border NTC limit.

Austria (AT): point-in-time scenarios analysis of exchange schedules

The installed capacity of wind in AT in 2015 will be 1340 MW for the scenarios Best Estimate (BE) and 1700 MW Optimistic Wind (OW) which means a moderate installed capacity penetration of max. 7 % (OW) wind power compared to conventional generation capacities. The results are shown in Figure 3-23.



Load: 6.900 MW,
Gross Pumping: 670 MW

Generation:3.840 MW
Wind gen: 290 MW

Import: 6.800 MW
Export: 3.000 MW
Net Import: 3.800 MW

Figure 3-23: Exchange schedules on AT Interconnectors
2015 Scenario Best Estimate Wind at HighWindNorth

Interconnector AT/DE: For modelling the interconnector's limit of 5.500 MW was introduced. Due to price differences in the area (AT and neighbouring countries – see also graph) all NTC-Limits are utilized. Therefore a high net import of 3.800 MW is reached.

As the import capacity is already used completely with low wind production (due to price differences), the import cannot increase anymore even when there is high wind in DE (limited-no import capacity left) shown in Figure 3-24. Therefore also the utilization of the water pumps is low.

The high scheduled import will most probably lead to *physical problems* at borders DE-AT and CZ-AT and within Austria (Salzach – Tauern, Dürnrohr – Wien Südost).

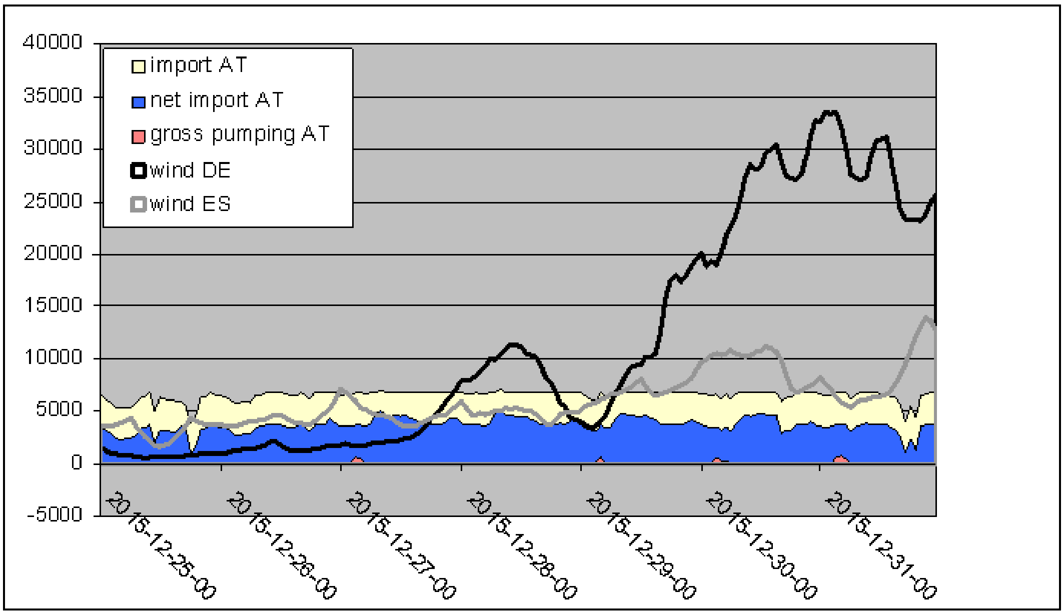


Figure 3-24: AT Imports (Exchange schedules)
2015 Scenario Best Estimate Wind at HighWindNorth/South

Interconnector AT/CZ: Import with constant values from CZ 1,3GW more or less all week due to lower prices CZ, NTC limited.

Interconnector AT/ CH, IT, SI, HU: Export with constant value to CH 1,2GW, NTC limited due to higher price in CH. Further export with constant value to IT and Slovenia.

Export to HU varies due to small price delta.

Austria (AT): Summary

As the import capacity on the north border (especially DE-AT) is already fully used even at low wind situations, no further commercial import is possible with high wind. Therefore no impact of wind power on cross-border exchange AT to neighbours can be seen. Due to price differences the import and export volume is at NTC limit all week long (or mostly) regardless of the wind situation. This results in low usage of pumps (water res).

3.4.6 North

Nordic: point-in-time scenarios analysis of exchange schedules

The installed capacity of wind in Norway, Sweden and Finland (Nordic) in 2015 will be about 4500 MW (1000 MW No, 3000 MW SE, 500 MW Fi) for the scenarios Best Estimate (BE) and 6700 MW for the scenario Wind Optimistic (WO). This means a penetration factor of max. 10 % wind power compared to conventional generation capacities for the Nordic countries (excl. Denmark). Denmark is grouped in Central West and therefore mentioned in chapter 3.1.2.1.

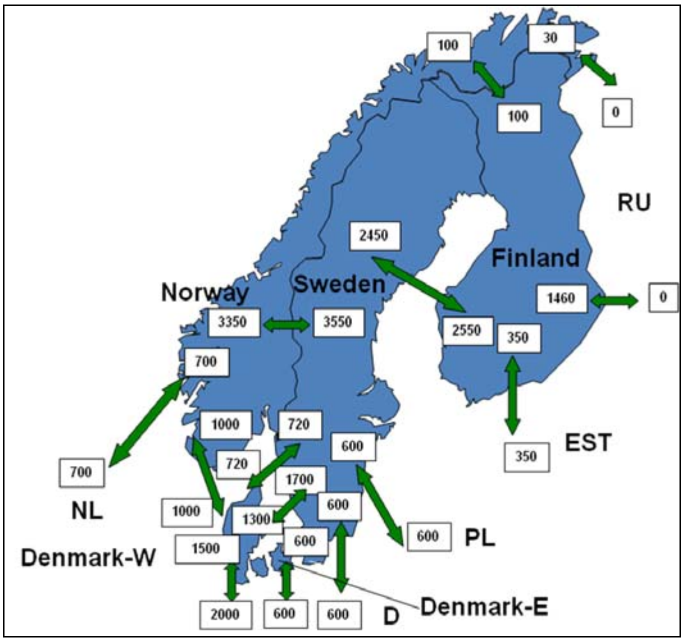


Figure 3-25: Nordic exchange capacities (MW)

Figure 3-25 shows available exchange capacities between internal Nordic price areas and between Nordic price areas and continental price areas. Regarding interconnectors out of the Nordic countries much of the capacity are fully used for export on peak periods and import on off-peak periods. This is because the Nordic market is hydro dominated which gives very good regulating (both technical and economical) compared to thermal generation and to wind generation.

On the same basis Norway and partly Sweden will be a high potential regulator for parts of Europe by transforming energy-production from wind power by using water-reservoirs and by exporting on low wind periods and importing on high wind periods.

Summary

- Nordic countries (excl. Denmark): Internal Nordic interconnectors (NO-SW-FI) with high exchange schedules at NTC limit; the exchange is not wind driven

- Interconnectors to Denmark show high exchange schedules at NTC limit; the exchange is partly wind driven with day/night volatilities. High potential for wind power regulating

-Interconnectors to Continental Europe (NO-DE-PO) show very high exchange schedules at NTC limit; the exchange is partly wind driven with day/night volatilities. High potential for wind power regulating

3.4.7 GB and the All Island Power System of Ireland and Northern Ireland

Point-in-time scenarios analysis of exchange schedules:

Note that throughout this discussion Northern Ireland is included with the republic of Ireland. GB refers to England Scotland and Wales. The installed wind capacity in GB will be 12105 MW in the Best Estimate (BE) scenarios, and 16518 MW in the Optimistic Wind (OW) scenarios, leading to a wind power penetration of 35% in the High wind North Optimistic Wind scenario.

On the all Island Power System of Ireland and Northern Ireland (IE) the installed wind capacity will be 4143 MW in the Best Estimate (BE) scenarios (29% wind power penetration), and 5100 MW in the Optimistic Wind (OW) scenarios (35% wind power penetration. Figure 3-26 shows the exchange schedules for all the GB interconnectors. Single values are shown for exchanges with NL and FR as the exchange is the same in the two scenarios at both wind situations. Exchanges between GB and IE differ between the Best Estimate and Optimistic wind scenarios.

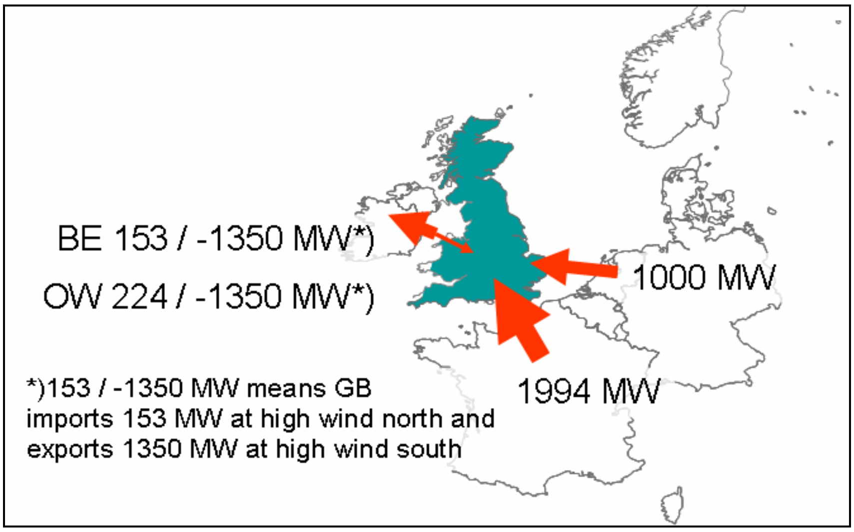


Figure 3-26: Exchange schedules on GB Interconnectors
2015 Scenario Best Estimate / Optimistic Wind, High Wind North/South

Interconnector GB – FR is sensitive to the amount of wind generation, though the direction of flow is correlated more strongly with wind generation in FR than in GB. With little wind generation on either side of the Channel the modelled flow is mostly in the direction GB – FR at the NTC limit. As the wind in FR increases through the week towards the PIT in the High wind North scenario the comparatively small amount of conventional thermal generation is all displaced. In GB however the proportion of thermal generation is much higher than in FR, and even in the Optimistic Wind scenario the thermal generation cannot all be displaced by wind. This means that the marginal cost of generation in FR is lower than in GB, so the direction of exchange reverses and by the PIT is NTC limited in the direction FR – GB giving a net change of nearly 4 GW.

In the High Wind South scenarios the exchanges show no correlation with wind. Electricity flows in both directions during the week, driven by prices in both countries and the complex exchanges between FR and neighbouring countries. The wind in FR is never enough to displace all the thermal generation so the prices in FR do not fall below GB prices in the same way as in the High Wind North scenarios. Prices in GB and FR are frequently very close, so it is possible that a small change in conditions could result in a different pattern of exchanges.

Interconnector GB – NL shows no correlation with wind power. In both the High Wind North and High Wind South scenarios the exchange is almost entirely in the direction NL – GB at the NTC limit.

Interconnector GB – IE is sensitive to wind generation, but, as with FR, the exchange is correlated more strongly with wind generation in IE than in GB (coefficient of correlation 0.5). When wind generation in IE is between 500 MW and 2500 MW, GB exports to IE at the NTC limit. As the wind in IE increases the exports from GB are curtailed and eventually, at the High Wind North PIT when there is high wind and very low load (so called “night valleys”), there is some flow from IE to GB, though not at the NTC limit. In the High Wind South scenarios there is hardly ever enough wind in IE to turn the exchange from GB export to GB import, though the GB export flow is not always at the NTC limit. Prices in IE and GB are similar for much of the time so it is possible that a small change in conditions could change the pattern of exchanges.

Summary: GB exchange with IE is sensitive to wind; increasing wind generation decreases congestion. The direction of GB exchange with FR can be reversed by wind generation in FR.

3.4.8 Impact of wind power

The EWIS Market model minimizes costs for electricity generation and balancing. The generation priority serves as a ranking to reduce or increase the power generation from the power stations in response to the additional wind generation in the scenario. For wind integration the focus is on minimized costs as well as on the avoided emissions.

3.4.8.1 Impact of wind on emissions

Wind integration is mostly achieved through adjusted dispatch of generation effectively supported by export to the neighbouring countries. Figure 3-27 and Figure 3-28 show the displacement of conventional power production for the Optimistic Wind scenario (exc. water storage). The generation mix is adjusted in response to the additional wind power. CO2 intensive production based on lignite, coal and gas are substituted partly.

'High Wind North'

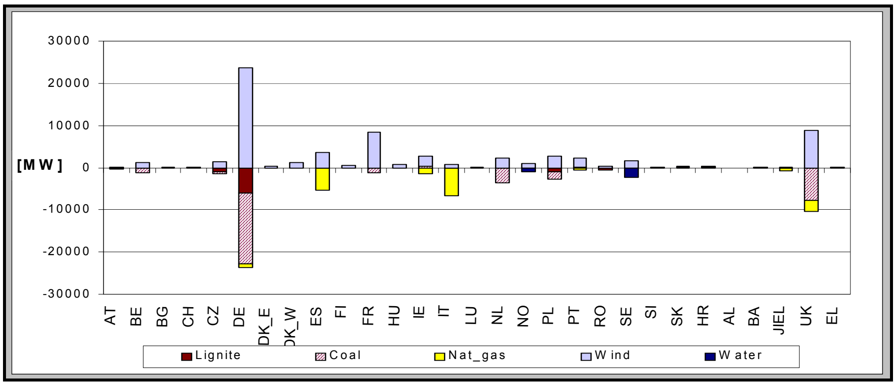


Figure 3-27: Production Displacement

2015 Scenario Optimistic Wind at PIT High Wind North

'High Wind South'

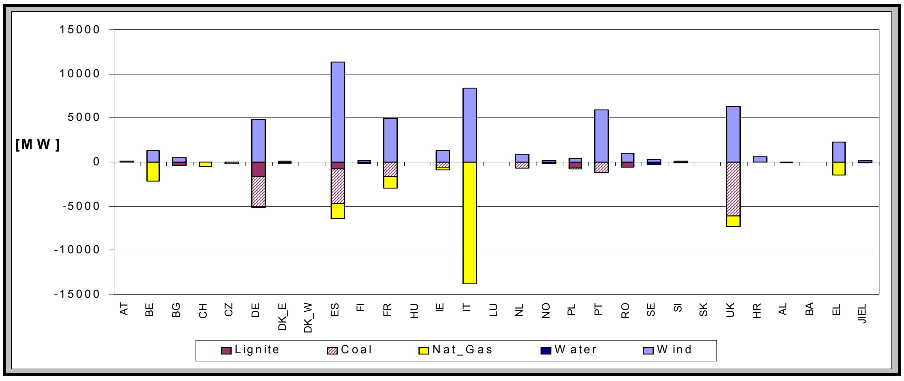


Figure 3-28: Production Displacement

2015 Scenario Optimistic Wind at PIT High Wind South

3.4.8.2 Impact of wind on cross-border exchange schedules

The exchange schedules are adapted to reflect the impact of the new generation portfolio and increased wind generation in each country. The net exchange (exports minus imports) of the Point-in-Time results of all scenarios is shown for the high wind north situation and for the high wind south situation in Appendix 3-5.

3.5 Summary

EWIS has developed a Pan EU market model on 2015 data. Market areas are modelled as "copper-plates" and linked via exchange capacities depicted by NTC and PTDF methodology.

The EWIS investigations from the market perspective underline that the increase of wind power expected in 2015 will be balanced widely within the market areas described in 2015 scenarios. The integration of wind power is achieved through a massive adjusted dispatch of generation. Parts of the CO2 emitting coal and gas production will be displaced.

The market analysis shows that well interconnected markets support the wind power integration. The optimal use of the available exchange capacities will lead to a considerable increase of congestions. Few areas with insufficient import/export capacities balancing of generation within the market area require wind curtailment.

Consequences of increased and decreased congestion are discussed. Using the data from the 2008 reference case, the impact of wind can be isolated. Beyond this approach, the analysis of the benefits of a potential network enhancement –details in Chapter 6 'Enhanced Network Scenario Beyond 2015'- is also seen as useful for the EWIS study in order to derive better recommendations for the dealing with increased wind power.

EWIS economic analysis identified candidate measures.

Further work focusing regional demands is required by affected TSO.

It is vital to transfer the economical view of the market model findings into the physical reality of the net model with more detailed analyses which is described in the following.

4 Technical Analysis

4.1 Introduction

The technical analysis identified the needed operational and structural changes to most efficiently integrate wind power and consists of three main parts. Firstly, based on the selected point in time scenarios, steady state loadflow analyses were undertaken for the situation with all (N) circuits in service and also the situation following the tripping of any single circuit or plant item (the N-1 condition). As well as power flows, such analyses also determined the voltage profiles throughout the network. Risks are identified and both short and long term risk mitigation measures are proposed. These consist mainly of power flow control, to optimise the use of the existing grid, and grid reinforcements. Secondly, the dynamic security of the transmission system was evaluated. Finally, remaining operational risks are discussed and mitigation measures recommended. Where appropriate, the analysis is done by region, i.e. by set of countries that are closely linked and show a high interaction.

4.2 Steady state risk analysis

4.2.1 Methodology

The detailed analysis consists of following steps:

- Detect bottlenecks for the exchange of electrical power within Europe, by analysing the flows in N- (all network elements in operation) and N-1-situations (outage of any given network element) against allowed transmission capacity of each element;
- Find the best location and best option for new devices for steady state voltage control and reactive power compensation, and optimise the overall voltage profiles throughout the network;
- Find the best strategy and location for power flow control devices, allowing the optimal use of the existing network;
- Find the best location and best option for new grid infrastructure, in terms of dimension, cost, capacity, and technology.

The European grid is categorised in 7 different regions, which have common interests or links with each other e.g. Central West region with Benelux countries including parts of Germany Denmark and France or Central East countries such as Poland, Czechia, Austria and parts of Germany. As the wind turbine installations are concentrated in the North part of the Central East Area and Central West areas these regions could not be separated and should be considered together. Due to their geographical structure GB, Northern Ireland and Ireland as well as Scandinavia will be considered as separate regions. Spain with Portugal and parts of

France forms the South West region. Italy, Switzerland, Austria and Greece will form the South region.

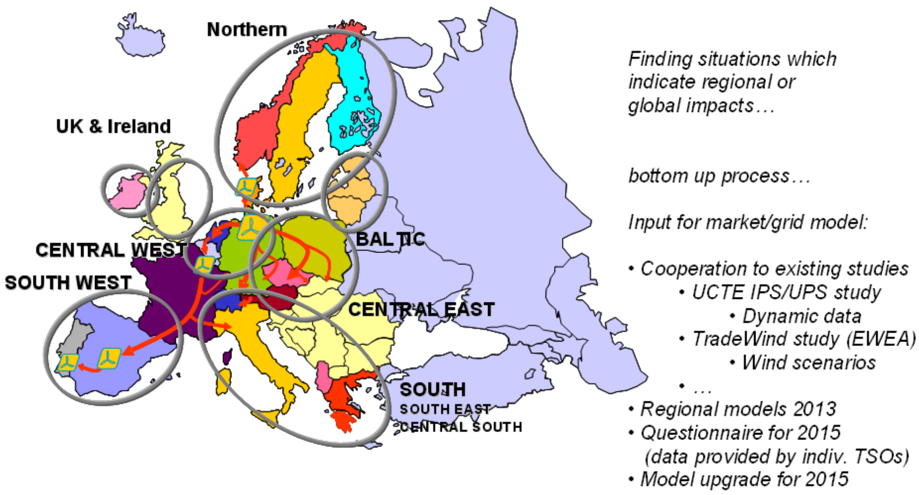


Figure 4-1: Power system analysis regional approach

4.2.2 Risk analysis

In order to better analyse the future development of wind power generation in Europe, a thorough examination is carried out on a European level. This comprehensive analysis is carried out for each region including details like locally installed wind power generation and the provision of necessary information by the regional experts.

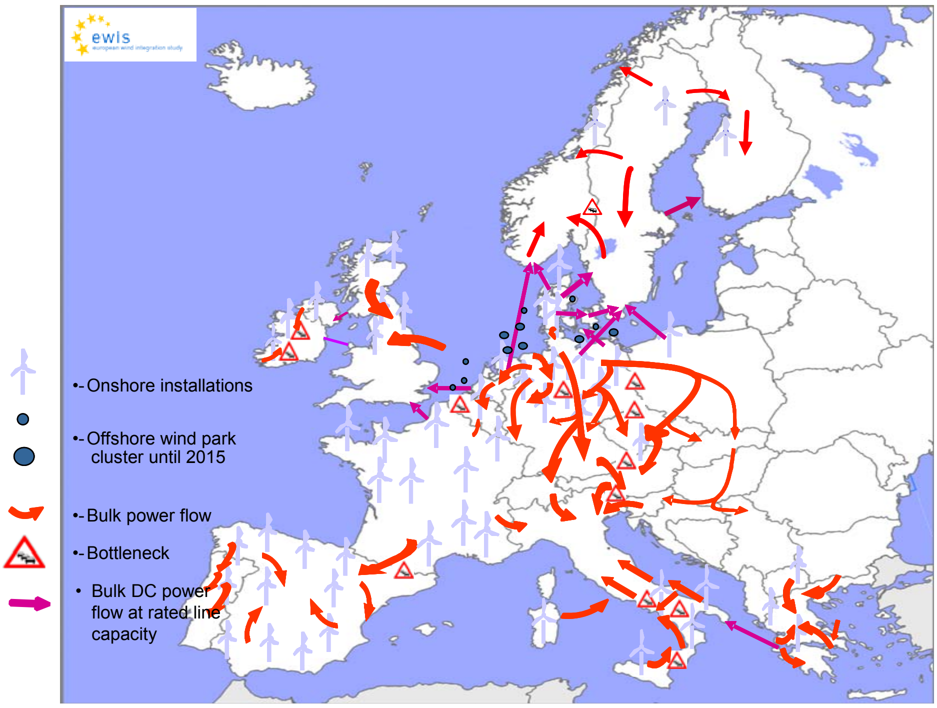


Figure 4-2 Illustration of 2015 physical power flow patterns (High Wind North)

The risk analysis for 2015 shows

- higher power flows than expected in high wind installation areas compared with previous studies (e.g. Dena I in Germany);
- Large difference between scheduled power flow and physical power flows in the Central-East-West region
- Loop flows mainly to Poland, Czech Republic towards Italy, but also to Benelux countries, resulting in overloading of lines not only in regions with high wind power production, but also in regions affected by these loop flows.
- Higher utilization of HVDC links

These spontaneous flows could overload internal networks and increasingly affect trading capacities, thereby reducing the overall benefit of wind energy. Moreover, those flows imply the need for new grid infrastructure reinforcement which may not be necessarily included and planned in the Transmission Development plans of respective affected TSOs/countries.

4.3 Risk Mitigation measures

The EWIS-study found European wide solutions to integrate wind power efficiently. On the operational side, adequate measures were identified to enhance flexibility and capability of the existing grid infrastructure (e.g. dynamic rating and flow control with phase shift transformers). On the planning side, the necessary European wide coordinated grid infrastructure reinforcements were analyzed.

The risks identified in the previous section include a number of issues that are either already being experienced by TSOs or have been identified in national studies such that they are already the subject of network development actions under existing TSO plans. However, some of those mentioned issues are new for some TSOs and bring additional grid reinforcements. Analysis of the EWIS Europe wide scenarios identified the need for further action due to the interactions between countries. Practically it is impossible to perform detailed investigations of the all 8760 hours of scenario snapshots of the year for the European Grid. Therefore based on the experience of the TSO experts and market model experts robust Point-In-Time (PIT) situations were considered in particular to analyze European wide coordinated measures in detail.

To reduce the bottlenecks and to enhance existing grid capability dynamic line rating depending on ambient conditions like temperature and wind velocity was considered. This was applied on the transmission corridors within the transpower area in Germany from North to South, and in a project in Belgium. At high wind speeds, the improved cooling of overhead lines allows in principle a higher loading. EWIS studies show a significant potential for reducing congestion and maximising the use of existing transmission capacity. However, additional reinforcement measures for the substations may be necessary. In general, the use of dynamic line rating is limited due to system security reasons. Therefore further dynamic investigations were carried out to find potential capacities for a secure operation of the transmission system (chapter 4.4).

The following sections summarises the sustainable risk mitigation measures all over Europe for the time horizon 2015.

4.3.1 Central East & Central West Regions

The analysis of this region shows that already installed phase shifting transformers in Central West region control the power flow across Benelux countries with optimal use of the transmission network in the Central West region. However, as a result some power flow is shifted back towards the Central East region, increasing the flow in the already highly loaded or even overloaded German grid and on the borders of Germany-Czech Republic and Germany-Poland. As a first step for a coordinated approach, to prevent large transit and loop flows arising due to high wind power production in the central East West region new phase shift transformer were proposed to many cross border lines, as illustrated in **Figure 4-3**.

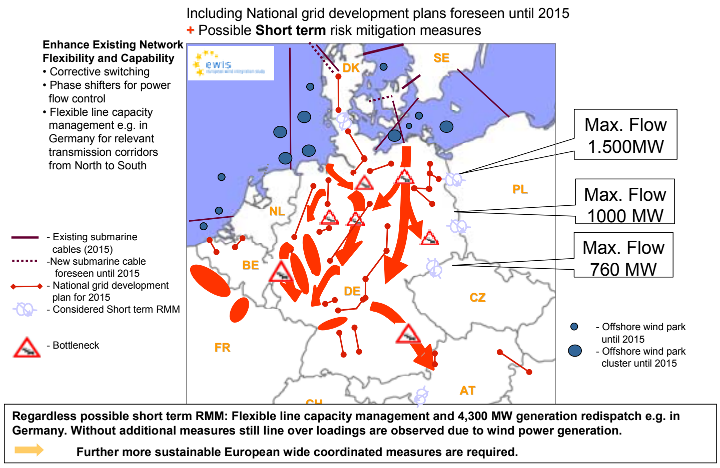
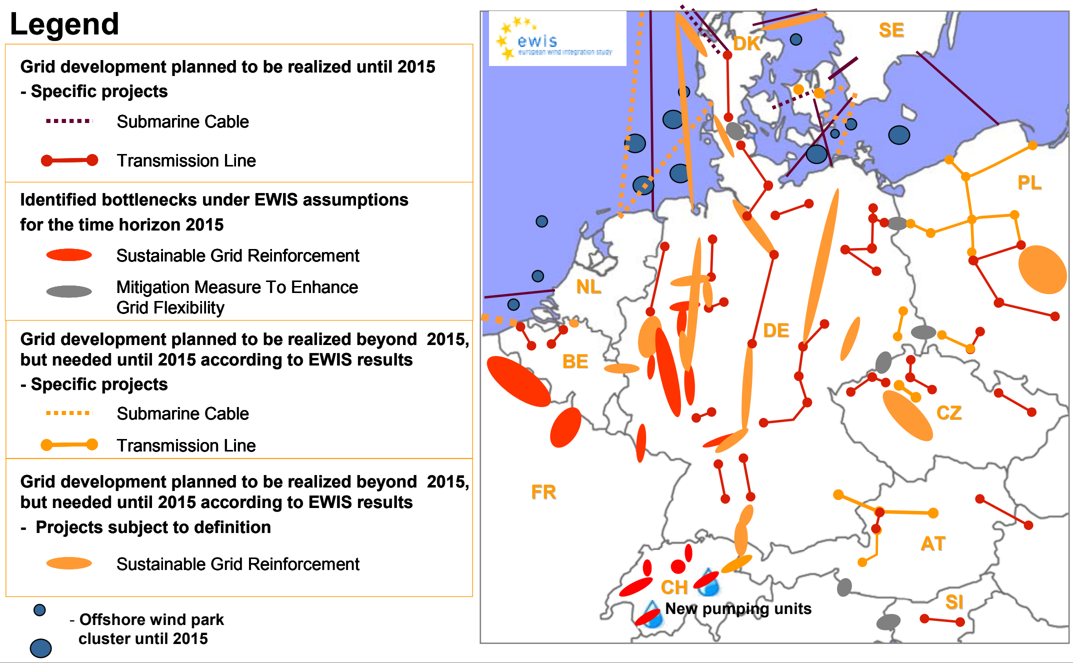


Figure 4-3: Phase shifting transformers on many cross borders creating further unsolvable bottlenecks in Germany and on its south borders thus a non sustainable approach for Central East-West region

The installation of new phase shifting transformers in the Central-East regions like on the Germany-Poland and Germany-Czech Republic borders secures these borders but in turn causes increased overloading in Germany and on the German-Austrian border. As a consequence, massive re-dispatch/countertrading measures and in addition wind power generation curtailment would be necessary within Germany for a secure operation of the European transmission system. In some of the regions the bottlenecks are not solvable by these measures. Therefore this approach is not the sustainable solution. The cost of this approach is very high, both in direct economic terms, and in ecological terms.

The analysis demonstrated that the use of short term measures (e.g. phase shifters) without strengthening the existing grid with new grid infrastructure is not a complete and not a sustainable solution and shifts the bottlenecks to other regions (**Figure 4-3**).. Therefore EWIS further proposes the sustainable risk mitigation measures in the Central East West region to accommodate wind power in an effective way.



Considered sustainable European wide coordinated measures enhances network capability for the further integration of wind power. Until the new lines proposed for 2015 are in operation, minimum 6,900 MW generation redispatch e.g. in Germany is required

Figure 4-4: Sustainable grid reinforcement in Central East West region

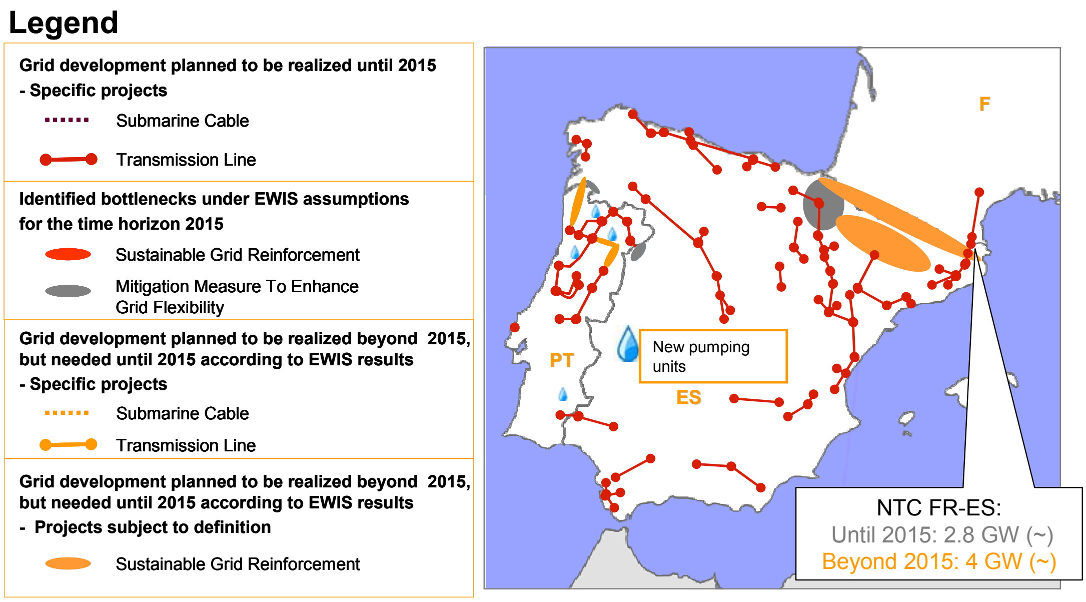
Figure 4-4 shows the main outlines of this sustainable longer-term grid reinforcement. In most of the countries in the Central-East-West region grid reinforcements are planned for and beyond 2015. however some of them are new requirements resulting from this Study The main structural reinforcements are significant number of new connections or reinforcements in Germany, Belgium, France, Poland, Denmark, Czech Republic and Austria.

4.3.2 South West Region

Spanish electricity network planning 2008-2016 [x](1) reveal great orientation to renewable energy integration. In this sense, the figures of the planned reinforcements related to integration of renewable energy (mainly wind energy) are the following:

Element	Voltage level (kV)	Kilometres
New lines	400	> 3500
	220	> 1000
Repowering	400	> 1000
	220	> 1000

Table 4.1: Grid reinforcements related to renewable power integration in Spain. 2008-2016 planning



Long term new interconnections between Spain and France would be studied and agreed jointly between the two countries

Figure 4-5: Sustainable grid reinforcement in Spain and Portugal

1 “Planificación de los Sectores de Electricidad y Gas 2008-2016. Desarrollo de las Redes de Transporte” approved by the Ministry of Industry, Tourism and Commerce of Spain, in May 2008

Currently, the installed capacity of wind power in Spain and Portugal is about 20.000 MW. Future plans show 29.000 MW and 6.360 MW of wind power capacity in 2015 in Spain and Portugal respectively. Achieving a better interconnection between the Iberian system and the rest of the UCTE system is crucial for a better integration of that wind power accomplishing the security standards. This is why, the increase of the network transfer capacity between Spain and France (plus the associated grid reinforcements), as far as the use and building of new pumping units in the Iberian Peninsula appears as a short and long term risk mitigation measure. (see Figure 4-5)

4.3.3 South

<u>Greece:</u>

The major transmission projects foreseen for the reinforcement of the Hellenic Transmission System related to integration of renewable energy according to The Hellenic Transmission System Expansion Planning for time horizon 2008-2012 include the following:

- Peloponnesus
- North Greece
- Evia Island (already interconnected to mainland Grid at 150 kV)
- Interconnection of Cyclades islands to mainland Grid
- Ionian Islands (already interconnected to mainland Grid at 150 kV)

The map below shows briefly the locations where the major transmission projects related to wind power integration are going to be constructed.

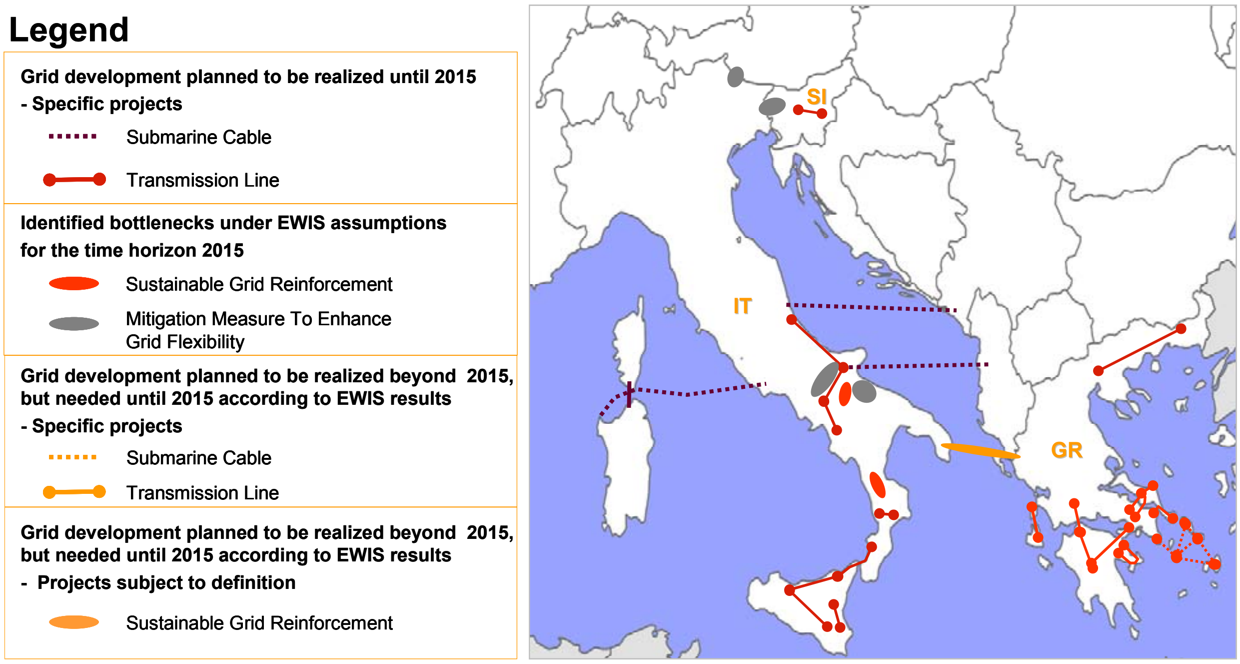


Figure 4-6: Sustainable grid reinforcement in South region

Italy:

The analysis undertaken through the EWIS study has confirmed the reinforcement requirements. The major Italian transmission projects (2015) are:

New 380 kV line “Chiaramonte G. - Ciminna”

New 380 kV line “Sorgente - Ciminna”

New 380 kV line “Paternò - Priolo”

New double circuit 380 kV line “Sorgente - Rizziconi”

New 380 kV line across Calabria

Rearrangement North Calabria grid

New 380 kV line “Montecorvino - Benevento”

Reinforcement 380 kV line “Foggia - Benevento”

New 380 kV line “Deliceto - Bisaccia”

New double circuit 380 kV line “Foggia - Villanova”

New HVDC line from Sardinia to mainland (SA.PE.I.)

Slovenia:

Based on the undertaken analysis through EWIS study the major transmission projects in Slovenian Transmission grid (until 2015) which need to be into operation for the safe operation of grid and reliable power flow transfer through European transmission grid are:

PST 400/400 kV in Divača

Double 400 kV line Beričevo-Krško

4.3.4 North

Risk analysis showed high degree of congestions between Norway - Sweden and Sweden – Finland. Although system security is not endangered frequent congestions are clear hindrance to the functioning of market. The Nordic countries have prepared a common long term projection of prospective future projects and more detailed mid-term grid development plan with socio-economic cost-benefit analysis. Also the most important national reinforcements supporting Nordic projects are included in the plan.

EWIS confirmed three extra Nordic grid reinforcements to be socio-economically viable: Extension of South Link into South-West Link, 420 kV AC line Ørskog - Fardal and 420 kV AC line Ofoten - Balsfjord - Hammerfest. All these reinforcements are planned to be in operation around year 2015. In addition the feasibility of 3rd 400 kV AC connector between Sweden and Finland is being studied by Svenska Kraftnät and Fingrid.

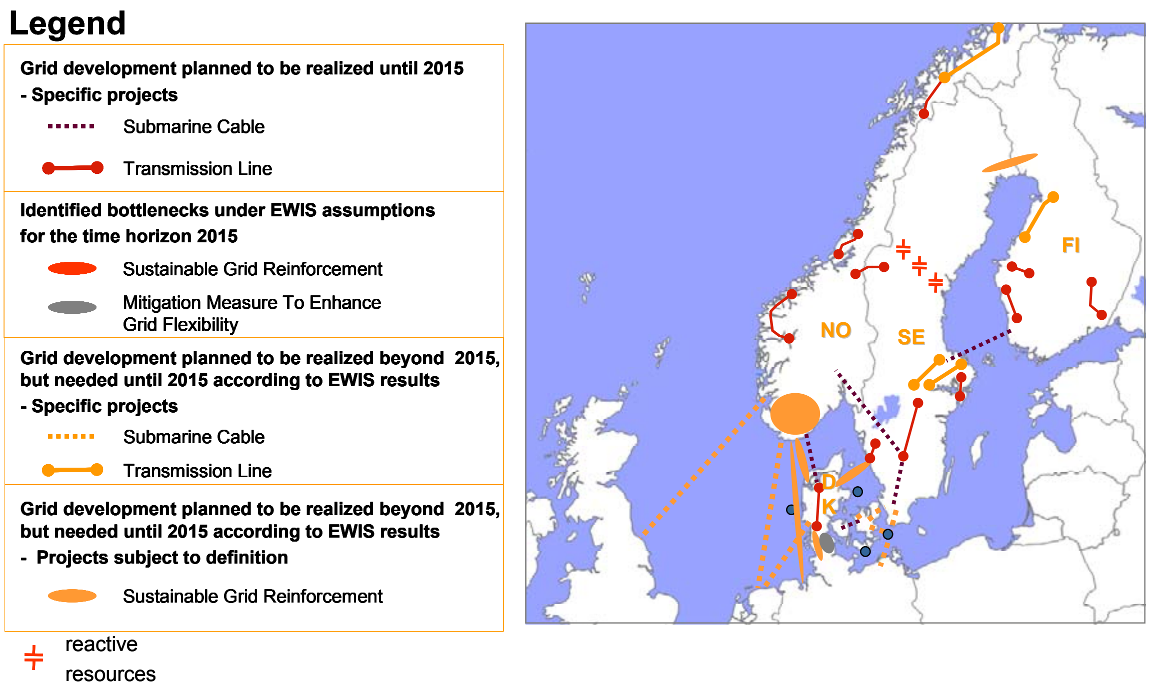


Figure 4-7 **Nordic grid development until 2015**

The Northern area includes a border between the hydropower-dominated area in Norway/Sweden and the thermal-power dominated area in the south with connections to the Continent. This leads to significant benefits from external Nordic interconnectors interfacing with the Continental thermal market as the analysis showed.

4.3.5 GB, Ireland and Northern Ireland

Reinforcements planned within Great Britain (GB) up to 2015 as a result of increased wind generation are predominately in the Northern and Eastern areas. For the most part, the reinforcements within the GB network that can be delivered before 2015 involve the uprating of existing circuits through, where possible, operating conductors at a higher temperature, increasing the operating voltage from 275kV to 400kV and replacing conductors on existing towers with those of a higher rating. These reinforcements, together with installation of both series and shunt connected reactive compensation as well as a limited number of phase shifters, are all that can reasonably be expected to be delivered prior to 2015 given the difficulty in obtaining the necessary planning and consents within GB. It is for this reason that a new 1.8GW, offshore HVDC connection bypassing the heavily congested area of the onshore network across the Anglo-Scottish border and further South into the North of England, is proposed on the West coast. This reinforcement, currently planned to be in place for 2015. An additional 1.8GW, offshore HVDC connection is proposed off of the East coast of GB for the increase in power flows resulting from wind beyond 2015.

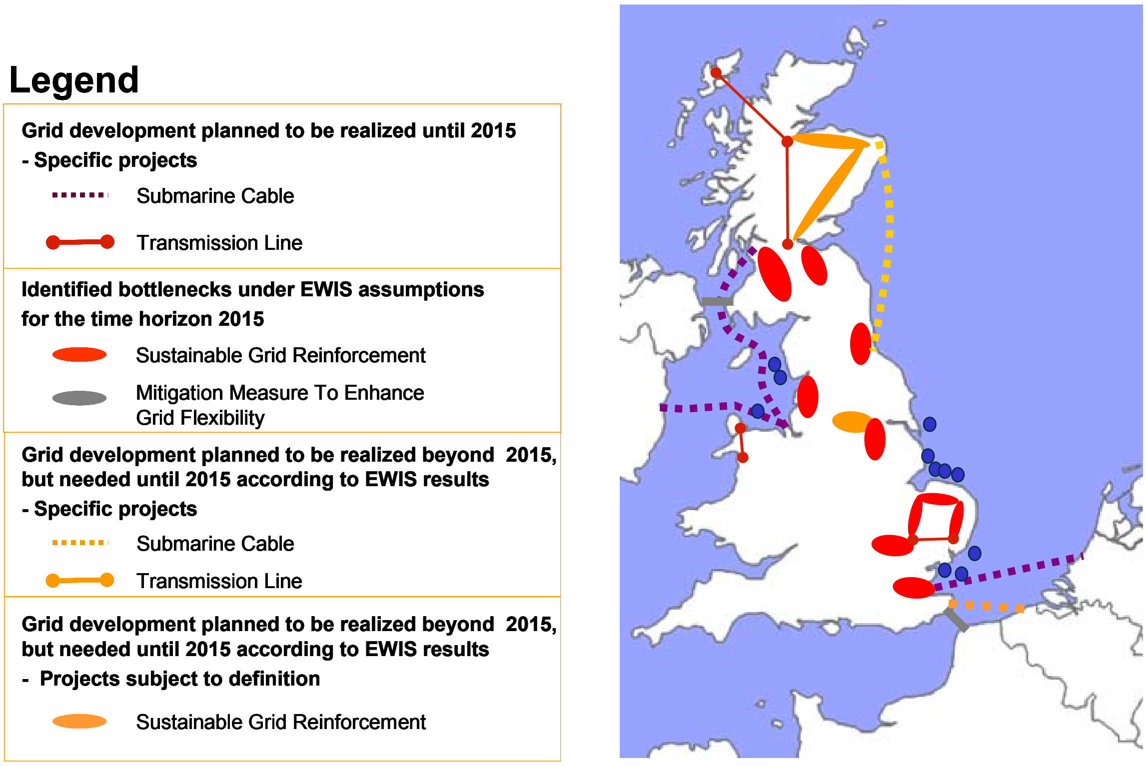


Figure 4-8: GB's areas of reinforcement

The EWIS study has confirmed the need for a number of planned 220/110 kV stations in the South West and reinforcement in the North West, in order to facilitate wind generated power flows. The shift of generation in the Dublin region (on the East coast) will trigger the need for new reactive compensation schemes. Further possible bottlenecks were not highlighted in the High Wind snapshots due to the low interconnection flows with the GB and the assumed high seasonal circuit ratings.

EirGrid's Grid Development Strategy for Ireland (Republic of), Grid25 [9], is the strategy for the development of Ireland's Electricity Grid between now and 2025. The strategy provides a more detailed outlook of the infrastructural development needed for the 2015 time horizon and beyond. The Grid Development Strategy study has highlighted a number of higher regional power flows. As a result, the proposed Grid25 reinforcements greatly outnumber the network pinch-points which were highlighted by the EWIS analysis. The additional reinforcement includes the strengthening of the links between Cork (south of Ireland) and Dublin (east of Ireland), and the substantial uprating of the existing bulk transmission system, in order to facilitate higher capacity power-flows.

The Grid Development Strategy includes the uprating of 2,300 km of existing transmission network and about 1,150 km of new circuits and represents an increase of about 20% on the total length of the existing network and the uprating of approximately 70% of the existing 220 kV network. This level of new infrastructure represents a total investment in the range of €4billion.

The EWIS short term mitigation measures in Ireland might include the introduction of dynamic rated overhead lines before the introduction of major reinforcements. Special Protection Schemes (SPS) and real-time control and monitoring may also be introduced in order to avoid n-1 (the loss of a single item of plant or equipment) equipment overloading after contingency events

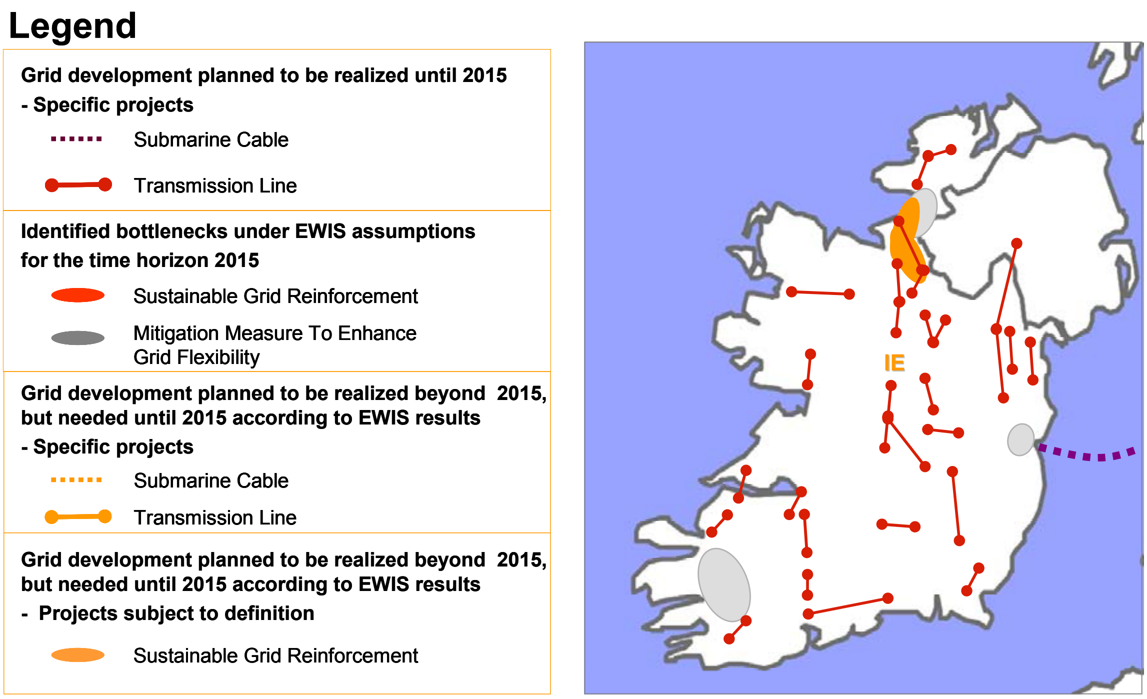


Figure 4-9: – Ireland's areas of reinforcement

4.3.6 Reactive power management

Reactive power and its compensation is always a local problem. Reactive power can not be transported for long distance but it should be locally managed by means of capacitors or reactors. GB identified the need for a significant amount of shunt connected reactive compensation. .The analysis shows a total of 1350 MVar is required, given the assumed location of future generation projects. In addition to shunt connected reactive compensation, 1250 MVar of series connected reactive compensation has also been identified to decrease the impedance across the congested circuits connecting England to Scotland. In Ireland, the high concentration of wind generation in the west of the country leaves the load centres on the east coast susceptible to low voltage problems. In the 2015 time horizon, reactive compensation in the region of 200-300 Mvar will be required in the Dublin region, beyond 2015, the addition of a total of 1400 Mvar may be required across the entire transmission network.

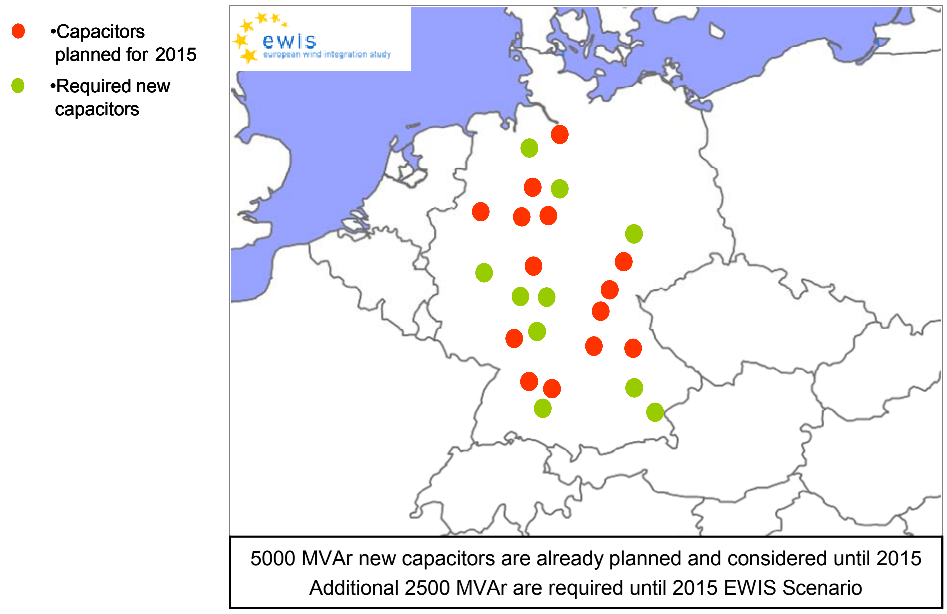


Figure 4-10: **New Capacitors planned until 2015 in Central –East-West region**

In Germany, the expected development of large transits until 2015, leads to an increasing reactive power losses in the transmission grid. Therefore, about 5000 Mvar of new capacitors are planned and already considered for 2015. Increased load flow due to high market-driven cross border exchange lead to further reactive power compensation. This demand is mainly located at the large transit corridors in south of Germany. Also in the north of Germany, further reactive power compensation is needed. The total capacity of the identified further demand of reactive power in the German transmission grid is in the range of 2.500 MVAr. In some areas of Czech Republic which are affected by transit power flows from Germany to Austria, it is necessary to install about 300 MVAr capacitors.

In the Spanish peninsular system, about 3550 MVA of reactive compensators are planned for 2016. These compensators will allow a better performance of voltage control in the power system. Even though, the solutions of voltage (or reactive power) control for wind power will be mandatory implemented at wind farm level.

4.3.7 Conclusion

The EWIS investigations confirm the need to reinforce the grid to accommodate the increasing share of wind power in the European grid.

Based on the risk analysis and risk mitigation for the 2015 time horizon, different operational measures such as phase shifters and flexible line capacity management are defined to mitigate the risks posed in affected areas, in the short term. These measures, if operated in a coordinated way, can enhance flexibility of the network and hence the optimal use of existing capacity. But if they are operated without realisation of the proposed sustainable grid reinforcement all over Europe, the massive re-dispatch/countertrading and/or wind power generation curtailment remains necessary as a congestion management measure, especially during high wind power production in the northern part of continental Europe, at a high economic and ecological cost.

Therefore, only the short-term mitigation measures are not sufficient to mitigate in the long run all congestions due to high wind infeed. While depending upon the situation, case by case, these measures can be used to ensure the operational security; the EWIS study aims at risk mitigation measures all over Europe, looking at long term and sustainable solutions.

- EWIS identified measures to enhance capability and flexibility of the existing transmission grid
- EWIS showed a significant potential for reducing congestion and maximising the use of existing transmission capacity but also the need to strengthen the existing grid with new grid infrastructure to maintain the existing level of system security
- EWIS identified national (grid development within countries) as well as international (interconnectors between countries) grid development
- EWIS confirmed the wind related TSO grid development foreseen by 2015 (red elements in Fig. 4.4 to Fig. 4.9). EWIS strongly proposes to urgently realise all these grid developments.
- The identified additional reinforcements (orange elements in Fig. 4.4 to Fig. 4.9) should be considered and refined by the relevant TSOs as candidate measures for inclusion in the 10 Years Network Development Plan of ENTSO-E
- Results of EWIS technical & economic analysis identified candidate measures, but further work required by relevant TSOs to develop into investment schemes
- EWIS results for grid optimization on a pilot for dynamic rating as a starting point for further investigations of sustainable optimization measures and limitations.

4.4 System security evaluation

The European electricity network is the route for the efficient transport of wind power from turbines to consumers. The technical investigations start from the basis of maintaining the reliability of the European electric power system and the secure and reliable interconnected operations among European partners. The objective of the transient stability analysis is to identify and propose solutions for the existing, medium term and steady state stability problems related to the integration of wind.

EWIS has performed detailed dynamic investigation of the European transmission system including

- Adherence to reliable limit values in the case of individual system faults.
- Developing and using dynamic models for generation (all types) with standard regulation detailed enough for transient stability analysis
- Modelling 3 types of wind turbine technology (incorporating EWEA feedback)

4.4.1 Model Validation

4.4.1.1 Wind turbine Generator Types

For the dynamic behavior of wind turbines in the European context, wind farm equivalents on EHV nodes are necessary. The regional dynamic wind generation model contains three types of wind turbines (squirrel cage induction generator, doubly fed induction generator and synchronous or induction generators with full converter interface) connected to the HV-system and/or distribution system (different electrical distance and voltage level).

For the purpose of this study wind turbine equivalent models are used, based on public available data, endorsed by wind turbine manufacturers, validation and information within simulation tool packages. The results of the different wind turbine models have been compared and evaluated [Wind turbine validation report].

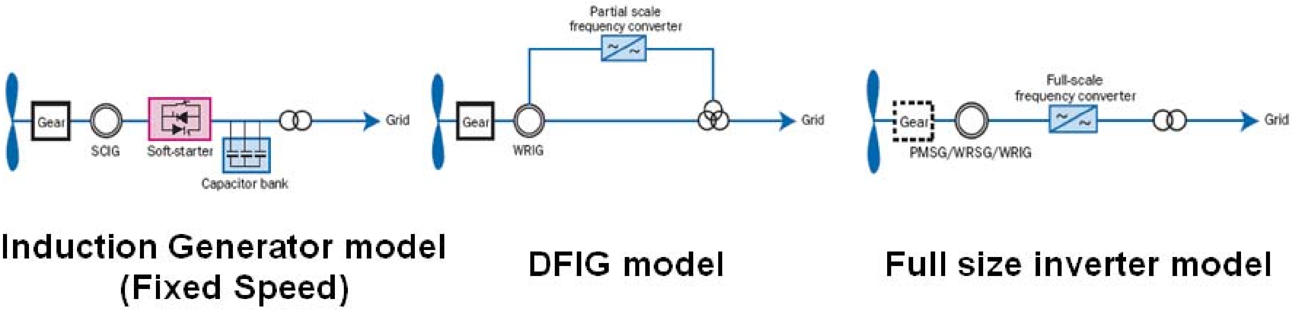


Figure 4-11: Different Wind Turbine Types

EWEA real measurements helped to improve the standard wind turbine model validation process (See Figure 4-12).

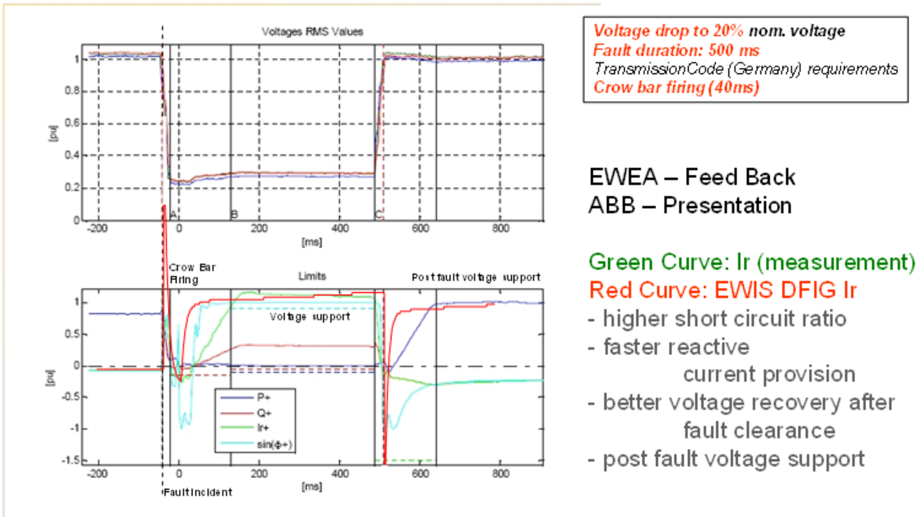


Figure 4-12: EWIS Results compared with the Real measurement provided by EWEA

- EWIS WT standard models are updated to fulfill additional requirements asked by relevant stakeholders

- EWIS WT models are simplified for the Extra High Voltage level but detailed enough to show the desired WT behaviour on the Extra High Voltage level for the EWIS study. EWIS encourages WTG manufacturers to develop simplified models ad hoc for the transient stability analyses that TSOs use to carry out. Also, representing WTG through standard models would be the most desirable option in order to avoid confidentiality issues.

- The simulation results shown in the presentation confirms that EWIS WT models fully satisfy the criteria '**simplification and accuracy**' required for the Global level investigation such as EWIS.

4.4.1.2 Dynamic reference model

The set up and the validation of the dynamic Model in Netomac followed the predefined procedure described in UCTE-IPS/UPS study. In general the entire model validation comprises

- the model verification including the check of collected data, the check of individual units in specific test scenarios, the check of the system behavior in terms of physical plausibility and the determination of tuning parameters
- the model validation itself including the recalculation of selected measurements

For the validation a set of representative WAMS-recording was chosen. The selected recordings give a good overview about the dynamic behaviour of the Continental Power System.

As illustrated in the subsequent paragraph the DRM Winter Peak Load model (2008) in Netomac is representing the dynamic behaviour of the ENTSO-E-System adequately.

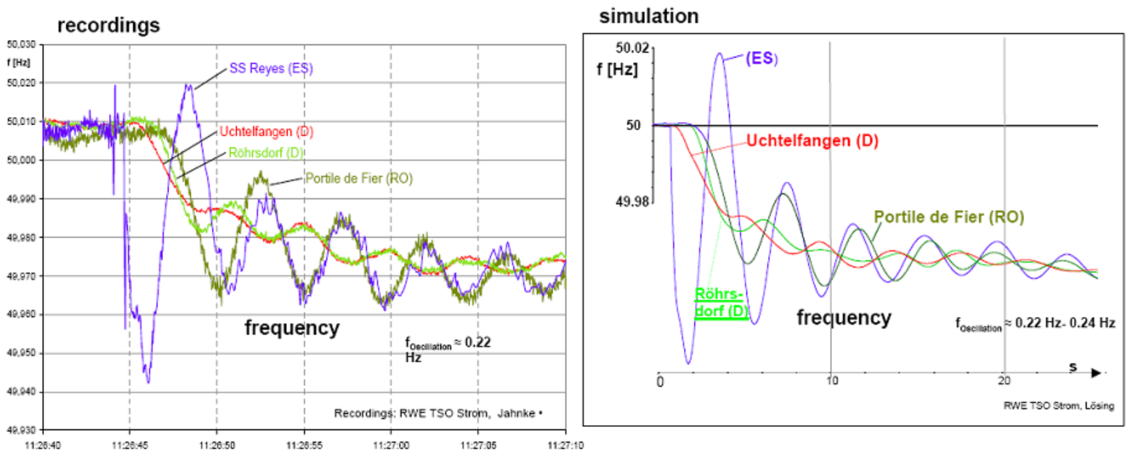


Figure 4-13: Event 1-Outage of a power plant in Spain 1200 MW (Feb. 09th 2006)

Several Power System Stabilisers (PSS) have been installed in the Spanish electrical system, and a plan to face the detected 0.2 Hz oscillatory mode has been established.

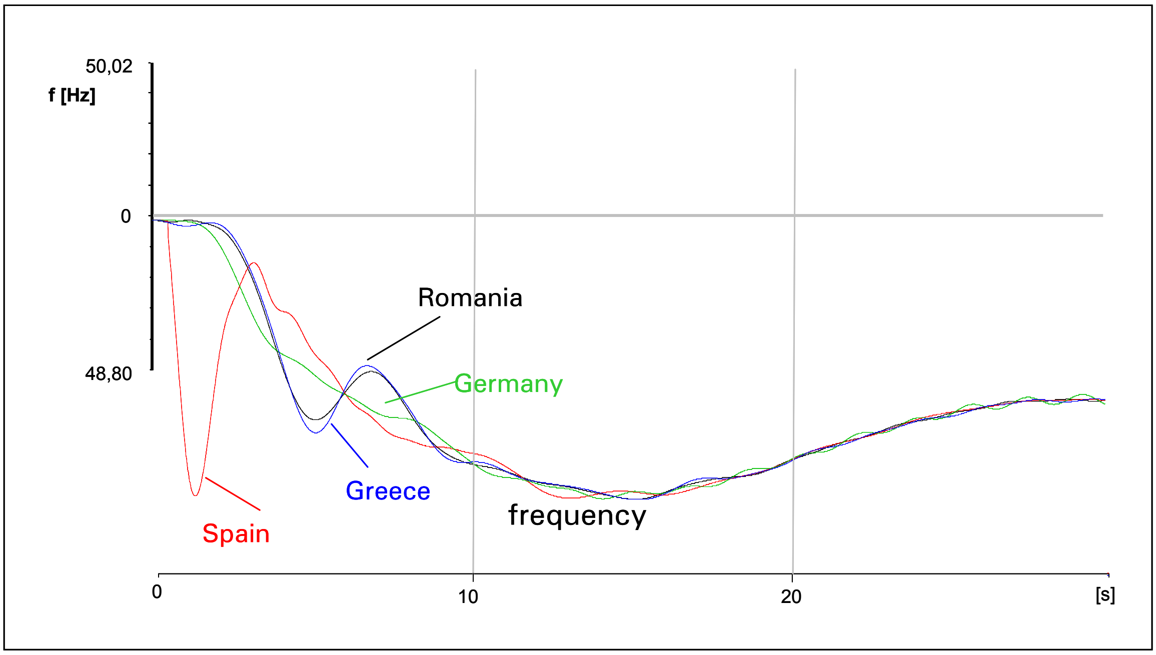


Figure 4-14: Event 1-Outage of a power plant in Spain 1200 MW (Feb. 09th 2006) compared to the 2015 model behavior

Due to these adequate measures foreseen in the Spanish electrical system facing the detected 0.2 Hz oscillatory mode the results of the 2015 model would show a much better damping behaviour than the fault recordings of the event in 2006. The upgraded Netomac model 2015 based 2008 model, which was validated in compliance to the existing recordings, shows the expected well damped swinging.

4.4.2 Impacts on system stability

4.4.2.1 Wind power outages

Disconnection of wind turbines due to voltage drop caused by short circuit reaches different levels in Europe. Simulations in the Polish grid revealed, that the outage of wind power is in the range of 1000 MW. In other countries the loss of wind power is expected be much higher e.g. in the German Grid the loss of wind power may reach up to 3000 MW and might be impacting frequency stability.

Fig. 4-18 shows a normative 3-p-fault near Krümmel in northern Germany and the outage of wind power is 2.600 MW. A new interconnector from Krümmel (TPS) to Güstrow (VE-T) is considered in the 2015 grid model. Enhancing stability on the one side, on the other side this line will increase wind outage in VE-T area when a failure occurs in TPS area.

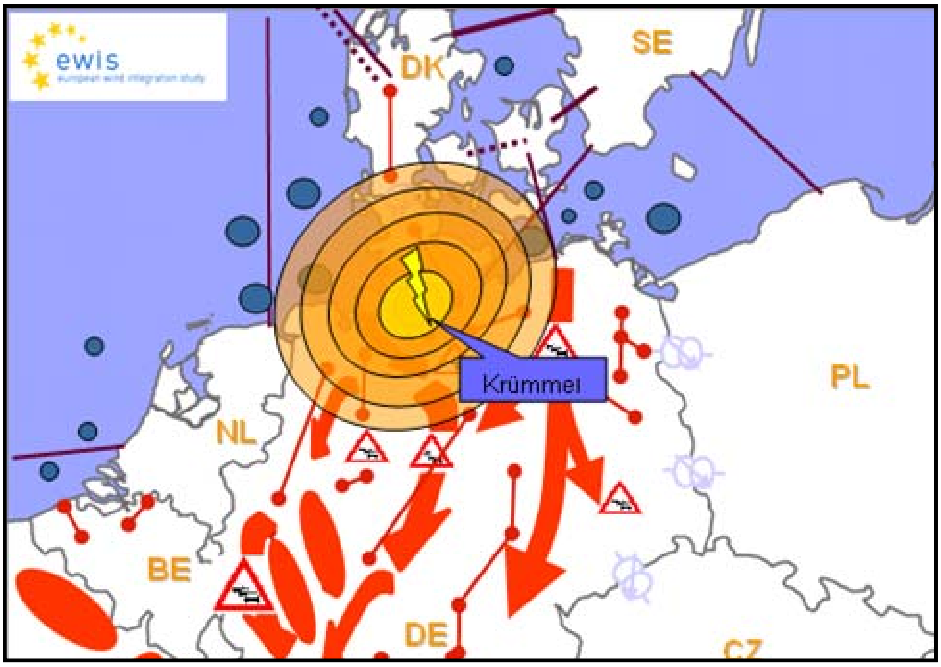
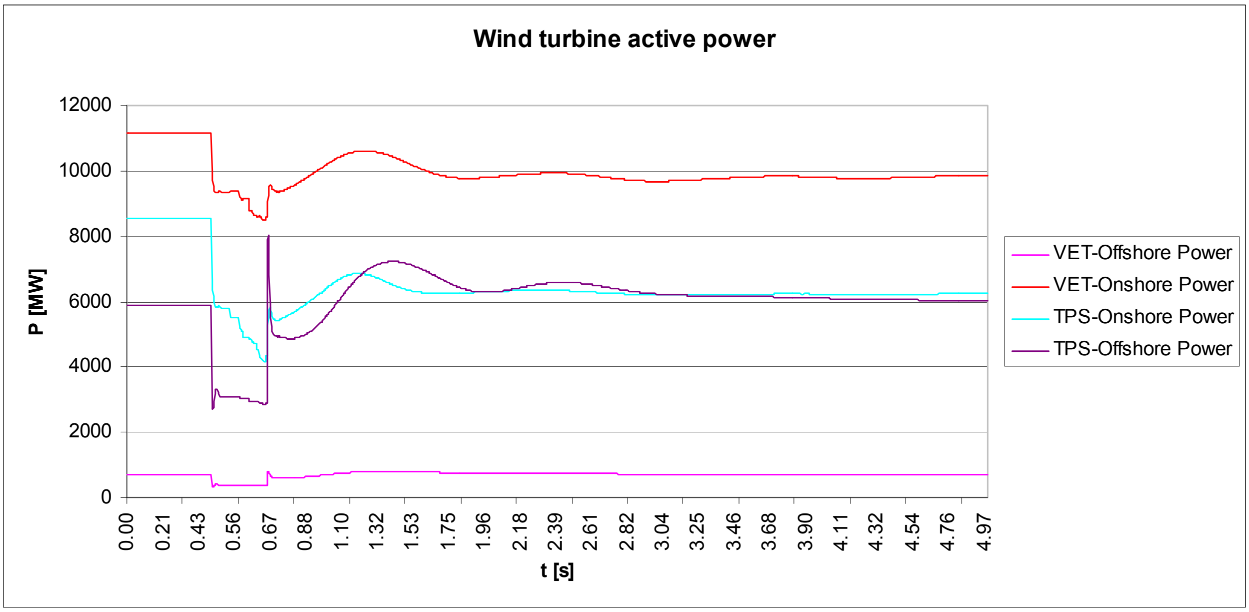


Figure 4-15:.Voltage dip during a three phase short circuit in the German grid

Due to better voltage support and new power plants the outage of wind power is reduced compared to calculations for 2008 time horizon, where an outage of 3.250 MW was identified.

<u>In order to improve frequency stability for non controllable WT-installations it is recommended:</u>
In case of the most likely single line to ground faults, system security may be guaranteed by alignment of voltage protection relays evaluating the maximum line to line voltage for developing corresponding decisions. Furthermore, a time delay of approximately 250 ms would protect tripping also for three phase short circuits.



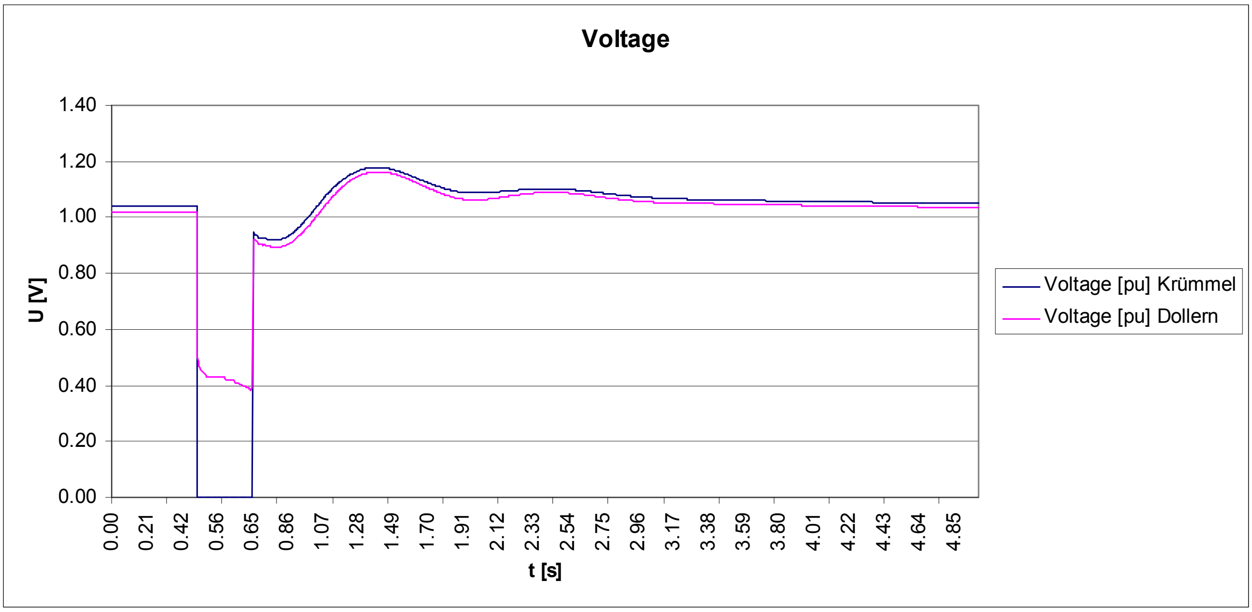


Figure 4-16: 150ms 3-p-fault on transit line near Krümmel

In highly meshed grids it has to be considered that a voltage dip provoked by three phase solid faults in some 400 kV nodes affects the main part of the power system (see left figure 4-15). The amount of WTG which are not fulfilling the grid code in terms of LVRT capability and voltage support, leads to a worsen voltage recovery.

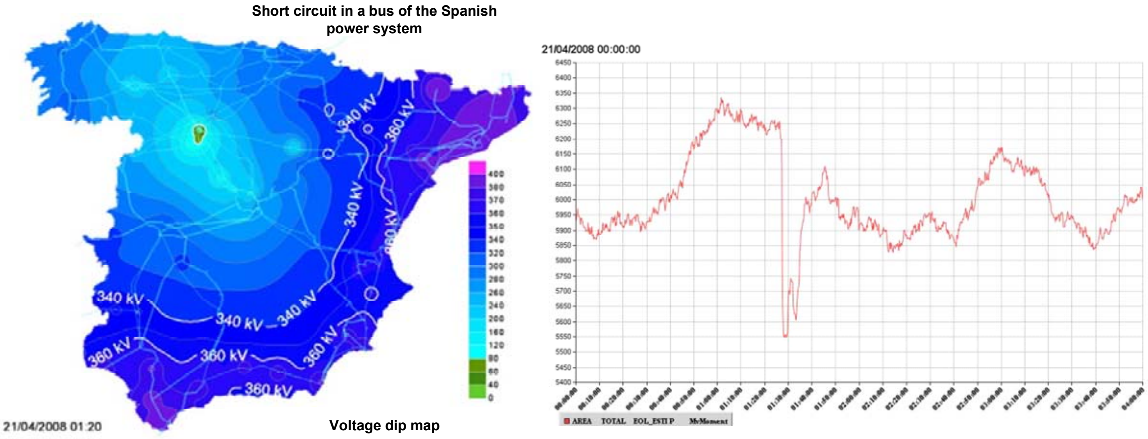


Figure 4-17: Wind power outage in Spain in 2008 due to voltage dip

In the past, as shown in the 2008 disturbance represented in figure above, when less than 10% of the wind power capacity fulfilled the Spanish grid code, certain short circuits caused, in the worst cases, power losses around 1000 MW along the country.

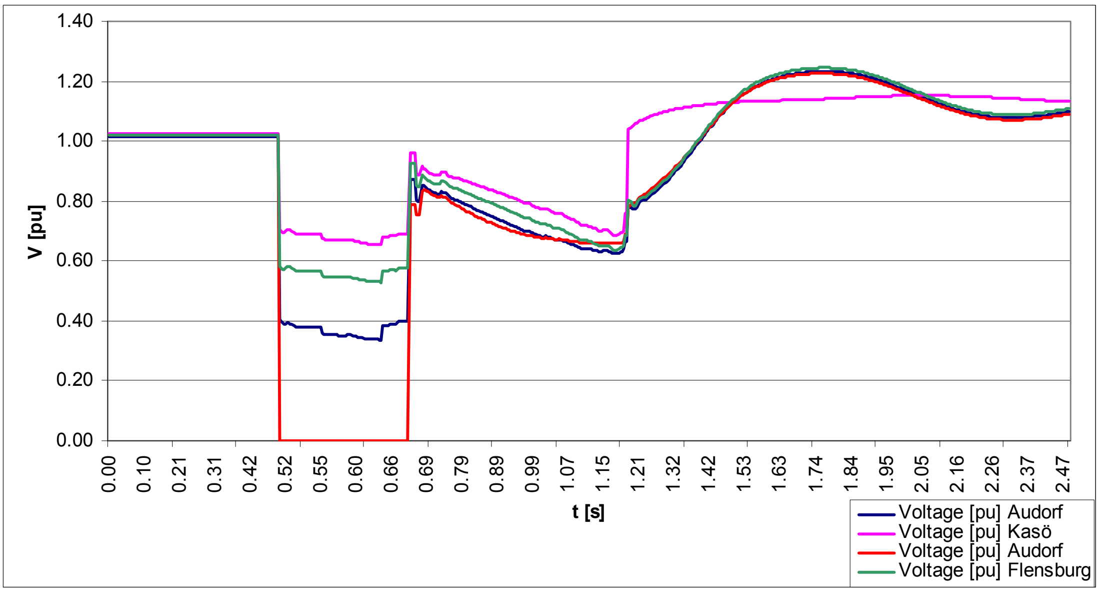
Since 1st of January of 2008 it is mandatory for all the WTGs in Spain to comply with the current grid code. According to Spanish Wind Association (AEE), around 65% of existing wind farms in Spain in mid 2009, fulfil the grid code. AEE points out that by 2012 all the wind farms in Spain will fulfil the current grid code, excepting less than 1000 MW that will not.

According to the investigations, considering the increase of wind power and the reduced share of conventional generators, just simple line faults may endanger the security of the whole European power system in 2015. Three phase short circuits will results in voltage dips in wide areas of the network as shown in Figure 4-15 for a section of the German grid. In this areas, large amount of old installation, not performing reactive power support during a voltage drop are connected to the grid. Subsequently, old wind power plants without any FRT capabilities will be tripped and thus the system will experience loss of a large amount of generation capabilities. Due to better voltage support and new power plants the outage of wind power is reduced compared to calculations for 2008 time horizon, where an outage of 3.250 MW was identified.

4.4.2.2 Transient stability

For regional analysis in the northern region of UCTE grid, the focus of the risk analysis is on Germany and Denmark West. For the specific scenario the networks have been reinforced in order to mitigate the violations of thermal and voltage limits identified during the contingency analysis.

The connection from Denmark to Germany consists of two 220 kV and two 380 kV circuits. Two phase shifters in Denmark enhance transport capability. Thus the export from Denmark to Germany is 1.680 MW concerning the investigated best estimate scenario. Combined with the large wind power infeed in Schleswig Holstein this leads to difference in power angles of more than 100 degrees between Denmark and South Germany at the transmission level.



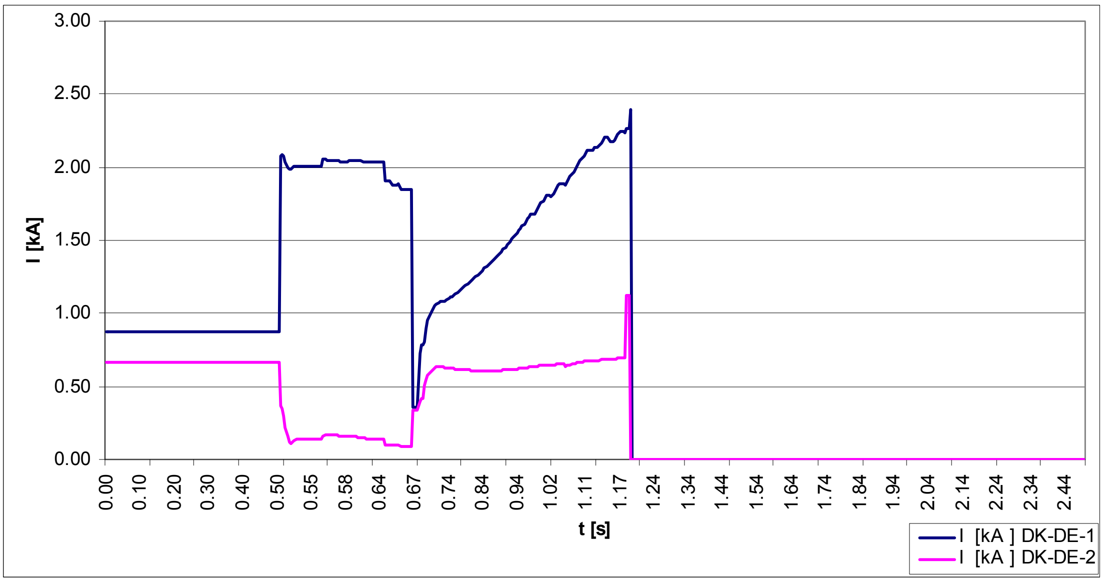
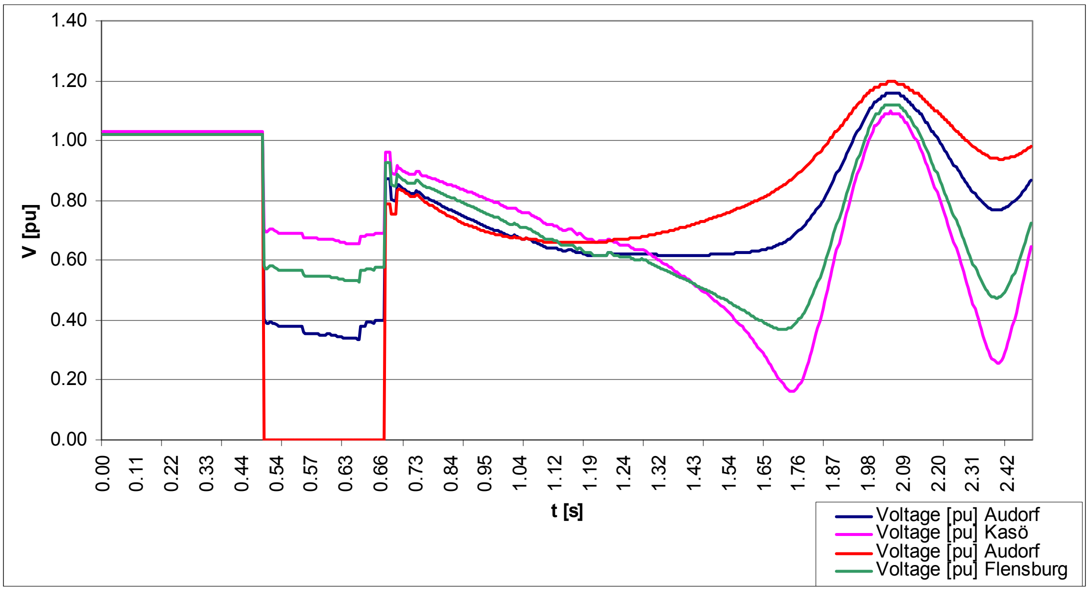


Figure 4-18 : Transients at German-Danish border after 150 busbar failure in Dollern with disconnection by system automatic

This high transit may lead to a loss of angle stability after severe short circuits. Fig. 4-16 shows line current and node voltage in the German-Danish border region. First diagram shows, that there is a loss of synchronism of the Danish peninsula. Electrical centre in the pole slip is very near to the border. In this case, the system automatic and distance protection device have not been modelled. The second part of the figure shows the system performance concerning disconnection by distance protection relays due to very low impedance near the electrical centre. That case is close to reality, because system protection schemes as there are power swing blocking (PSB) combined with out of step functions (OOS) in the distance relays or even the untuned distance protection relays will disconnect the tie lines between Germany and Denmark quickly after first slip or even before.



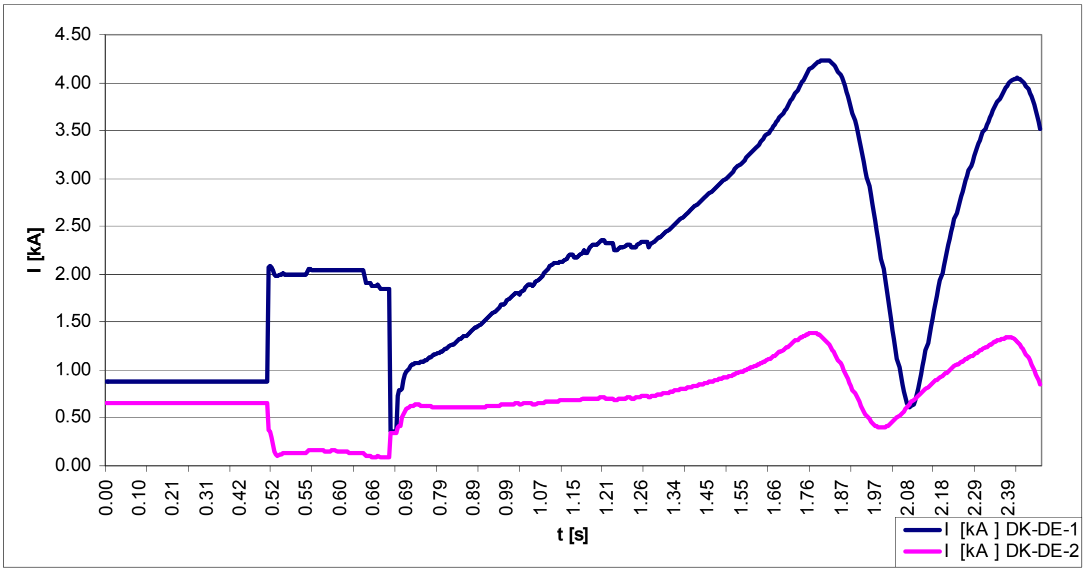


Figure 4-19 : Transients at German-Danish border after 150 busbar failure in Dollern without disconnection

Additional modelling and deeper bilateral investigations is needed to analyse the situation and find solutions to maintain system stability or identify limits of power transport.

The transient stability calculations were carried out for the Central East region as well. No stability problems were detected in this region.

In the South West region, dynamic simulations in the 2008 scenario confirmed power system stability risks due to these massive wind power outages of WTGs that do not comply with the LVRT requirements.

These outages would lead the Spanish and Portuguese power systems to a loss of synchronism with the rest of UCTE, and DRS (loss of synchronism relays) to trip the interconnection lines between Spain and France. These DRS relays detect loss of synchronism when voltage beats occur in the range 0.5 Hz–3.5 Hz.[Reference to be included →"Defence plan against extreme contingencies". CIGRE task force C2.02.24].

The CECRE (Control Centre for Renewable Energies) avoids this risk of losing such amount of WTGs, redispatching, when needed and once analysed the scenario, WTGs that do not have LVRT capability.

For the dynamic analysis of 2015 scenarios, dynamic voltage control in WTGs, during and after voltage dips, is an important topic which is being studied in Spain in order to be addressed in the new grid code. The reason for this is that due to the displacement of conventional power plants in off peak scenarios with a high wind penetration, there is a necessity of analysing the consequences on the stability of a lack of automatic voltage regulators (AVR) in the system. The future HVDC link between Spain and France has been also taken into account in this study, and it has been modelled considering LCC (Line Commutated Converter) technology although other technologies are being considered and are under review in this moment.

The next figure shows the behaviour of the system after 250 ms short circuit in a 400 kV bus of the Iberian Peninsula EHV grid. The plotted variable is the voltage in bus Vic 400 kV, located in the border between Spain and France. The buses allocated in this border are equipped with DRS protections that trip the tie-lines in case of detecting a loss of synchronism between Spain and Portugal respecting the French grid. Regarding the hypotheses of WTGs modelling, it has been considered both in Spain and Portugal that all the WTGs have LVRT, but they do not supply dynamic voltage control during and after the voltage dip.

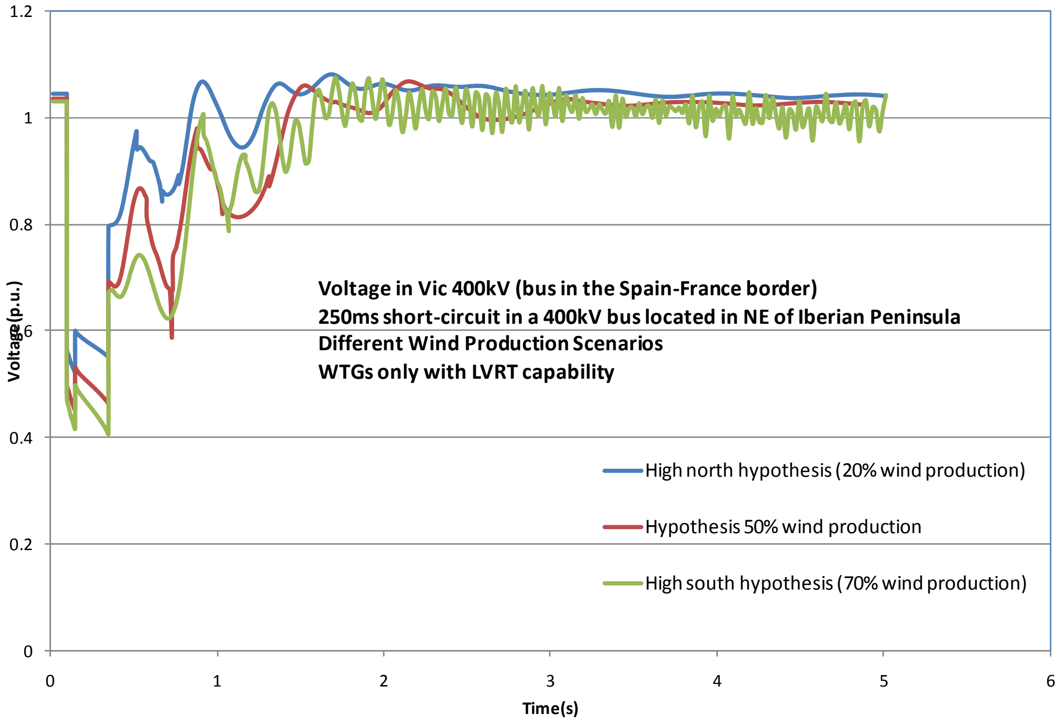


Figure 4-20: Voltage in Vic 400 kV after a 250 ms short circuit in a 400 kV bus located in Central West of the Iberian Peninsula. Different wind penetration hypotheses

The inadmissible voltage oscillations (green line), that according the DRS adjustment would trip the tie-lines (DRS model is disabled in these simulations), appear in the HS hypothesis considering no automatic voltage controls enabled in the WTGs. The other outputs (red and blue) consider also the hypothesis of no automatic voltage controls in the WTGs but lower wind production, which means a higher number of conventional power plants (and of course, AVRs) connected.

4.4.3 Requirements to maintain system security

4.4.3.1 Requirements for wind turbines

Fault Ride-through capability to avoid disconnection of the wind power plants in general in case of system faults (even voltage goes below 80%) is needed to reduce the loss of active power after short circuits. Wind turbines remaining on grid during faults have to return to total active power in-feed with certain range of Pnom/s. Also, WTGs must be able to increase the active power after resynchronization by certain gradients. Details are given on regional level and correspondent grid codes.

Almost all modern wind turbines are able to support the voltage (reactive power infeed) with very fast control, decoupling between reactive and active power control (pre-control, field oriented control, 4-quad control in case of full converter types). In case of severe voltage dips (disturbance is very close to the wind farm) several negative point could emerge such as risk for generator instability, risk to the protection of the power electronic devices – crow bar firing, uncontrolled generator consumes reactive power e.g. after fault clearing.

Wind power can support frequency control – Fast active power reduction in case of high frequency ranges (above 50 Hz) with the help of power controller (short term) and with the help of pitch controller within 1 sec the total power infeed can be reduced to zero, for the longer duration within 10 sec the rated power of the generator can be reached. To avoid such event counteraction following actions could be necessary (especially for isolated systems) including:

- Fast reduction of the rated active power in case of overfrequency starting early
- Return to normal operation after reaching certain value of the frequency
- No disconnection within a certain range
- Detection and prevention of the islanding situation in case of grid separation

4.4.3.2 Requirements grid components

To avoid malfunction of distance relays during power swing, PSB function in combination with OOS function should be activated in the transmission grid. Thus, there will be no disconnection of lines during power swing but the disconnection of lines after losing synchronism will be kept.

Fault clearing time is one of the most important factor for system stability. With high speed fault clearing, the fault clearing time can be decreased to 100ms. This leads to an enhanced stability margin in the system. Also breaker failure protection has to operate as soon as possible to reduce the danger of losing stability. This scheme is already being used in several other countries but nor in all continental Control areas.

4.4.3.3 Reactive power compensation

High transits in the European grid require an improved voltage control. Control of reactive power compensation along the transit corridors is required to ensure an optimized voltage profile along the transit corridor. Besides conventional power plants and wind turbines, also static compensation devices could help to the voltage control and can be implemented in the control scheme.

4.4.3.4 Pilot for capacity line management

Preconditions for the implementation of dynamic rating on the lines of the pilot project identified by detailed studies have been fulfilled. These studies show, that considering the fulfillment of requirements e.g. reactive power compensation or enhancing protection performance, line rating can be increased dynamically to the desired value of 3150 A.
For the pilot corridor in the transpower control area a detailed study revealed the requirements for system performance mainly focused on protection as e.g. PSB/OOS activation, high speed fault clearing and reactive power control.

The stability study also shows that there is a threshold for the dynamic rating due to the stability limit. This threshold may reach 3500A on several transmission lines, but it can also be lower. Depending on boundary conditions as there are protection performance, conventional power plants or reactive power compensation, the maximum value under consideration of dynamic rating has to be calculated individually.

Despite consideration of dynamic rating in the determined transit corridor in transpower control area, the potential for dynamic rating as output of a national grid study is implemented in the model. Hence, depending of the region in Germany, enhanced transit capability is assumed overall in the German transmission grid to reduce congestions. This potential will be investigated.

4.4.3.5 Requirements for conventional generators

The risk of losing angle stability of generators is quite small due to activation of system protection schemes. Many new power plants in the control area of transpower and also in the control area of Vattenfall are equipped with fast closure valves. This fast valving application after severe short circuits is a good method to enhance transient stability. This function should be required, if regional investigations reveal the danger of losing stability of conventional power plants

4.4.3.6 Supervision of wind energy. Control centers

- Target: achieve a greater level of integration for renewable energy sources without compromising system security.
- Main function: Organise special regime electric production according to the needs of the electric system.

Red Eléctrica de España commissioned this type of control center in 2006 and it is being a successful experience.

4.4.4 Steady State Stability

For the time horizon 2015 steady state investigations were performed to in order to achieve reliable system operation in the future environment of the electricity sector given by further system extensions and open market. In future the network operators may be forced to operate the system closer to its stability limits, requiring more detailed investigations of the global system behaviour in order to maintain system security.

In previous studies some global and several regional modes have been identified, which affect the whole system and only subsystems respectively. The damping of east west mode 1 (≈ 0.2 Hz) was relatively poor and decreases significantly by increasing power export from the border areas, that is from Spain/Portugal. East west mode 2 (≈ 0,3 Hz) has sufficient damping within the considered load flow conditions. Therefore east west mode mode 1 is identified to be the main cause for the occasionally observed inter-area oscillations in east west direction of the continental transmission system. In North south direction the so called North-South mode, detected by around 0.4…0.5 Hz may have significant impact on the damping of the continental transmission system when more and more wind power will be installed in Northern Europe (Baltic Sea and North Sea region). The modal analysis for the time horizon 2015 confirmed the existence of the previously detected eigenvalues.

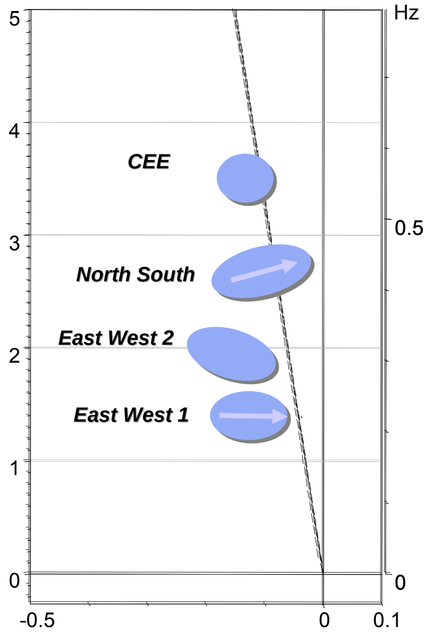


Figure 4-21 : Mode Distribution on the complex s-plane for the continental transmission system (time horizon 2015, different scenarios)

<u>**East West Mode 1**</u>

The effective participation of all PSS in the continental system, mainly those located in the border regions, is crucial for an enhancement in the inter-area oscillations damping. This is the most common way of damping inter-area oscillations, although supplementary controls of HVDC links, SVCs and other FACTS devices could lead to a similar result.

Figure 4-22 : Geographical mode shape east west mode 1 (time horizon 2015, different scenarios)

Figure 4-22 maps the right eigenvectors corresponding to mode 1 (East-West). The bigger the size of the arrow the better mode 1 can be observed in its location. The right eigenvector of a mode indicates a relative mode observability and it is only based on the topology. Power system stabilizers (PSSs) (e.g. In Spain and Portugal) and additional control systems are attached to the voltage regulators of the power plants. These elements allow damping these oscillations in an effective way after some analysis focused on the proper adjustment of the PSS of Spanish Power System combined cycle units. It was concluded that 12.800 MW of these existing units are properly adjusted. For the rest of generation units, new PSS settings have been obtained so that the desired damping is achieved. These new settings are currently being programmed in the concerned units and it is expected that, by the end of 2009, this process will be finished. Moreover, new power plants will install PSS tuned to damp East West inter-area mode 1. With these measures it is expected a correct performance of Spanish power plants in terms of damping inter-area oscillations, so no limits in the power export to Spain-France have to be addressed for this reason.

Figure 4-23 shows a comparison between the 2008 and 2015 situation with and how the new settings for existing Spanish PSSs improves considerably the damping of inter-area oscillations in east west direction.

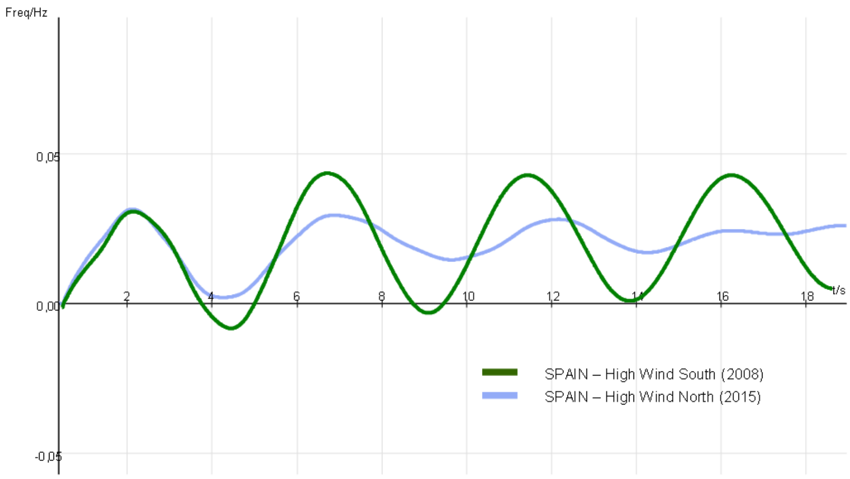


Figure 4-23 : ***Comparison High Wind North 2015 – High Wind South Scenario 2008 (time domain)***

<u>North South Mode</u>

For the North South mode detected in 2000 [Cigre 2000 publication] the North of the continental transmission system with Denmark, Northern Germany and the Netherlands is swinging against the south region (Italy, Switzerland …). During the last years some recordings of real disturbances (double bus bar fault at substation Wilster, Northern Germany in 2007) confirmed the existence of this interarea-oscillation with a rather low damping.

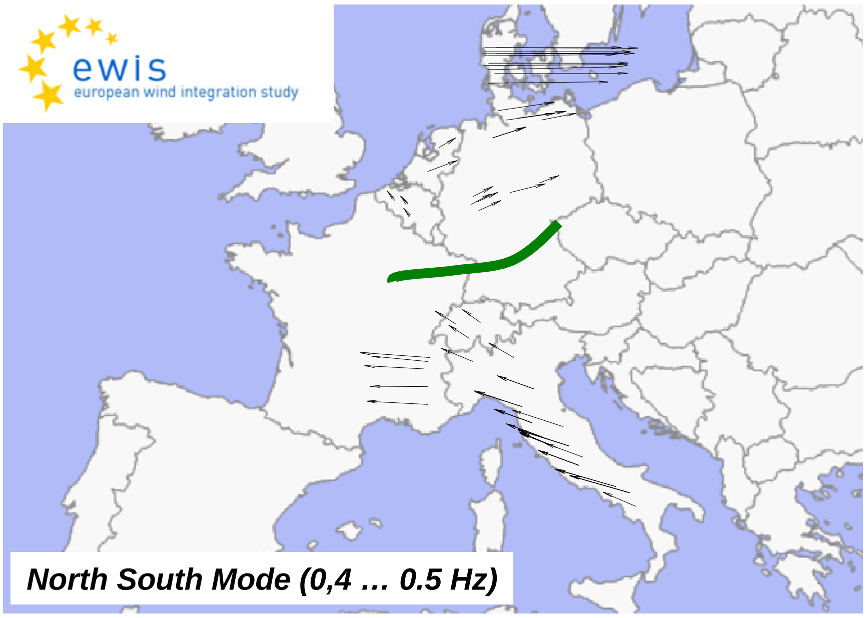


Figure 4-24 : Geographical mode shape north south mode

Time domain simulation results visualized the coherent generator groups in the North and in the South of Europe. Figure 4-25 shows the phase opposition between the generator group in Denmark and Italy.

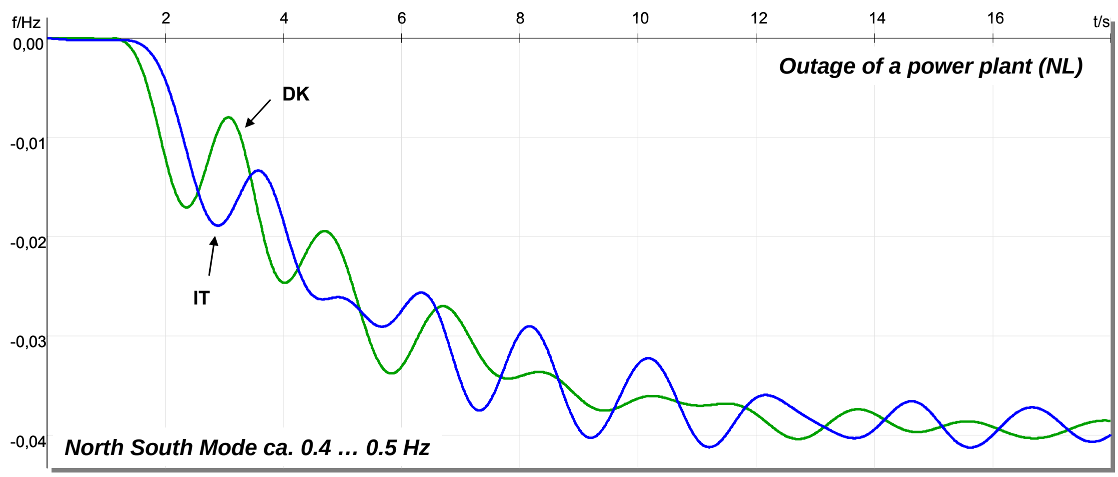


Figure 4-25 : Time domain analysis north south mode

Figure 4-26 gives the participation factors for the North South Mode indicating the location of generator groups in the system, where PSS tuning/installation would be most effective.

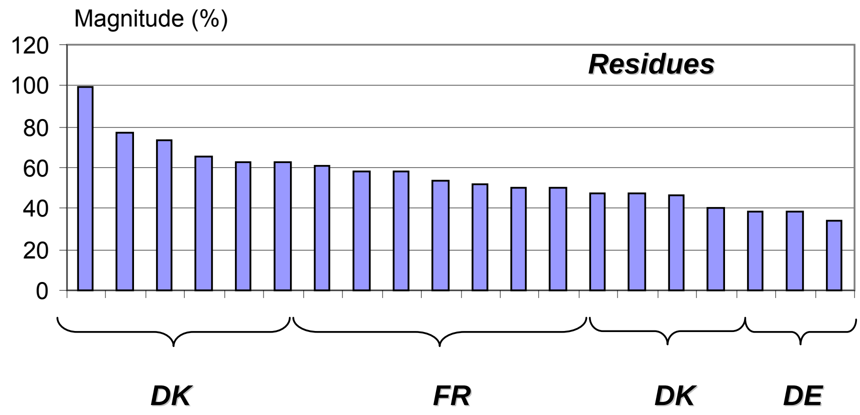


Figure 4-26 : Participation Factors for the north south mode

Conclusion

The damping of the east west mode 1 is currently being adequately addressed, since several Power System Stabilisers (PSS) have been installed in the electrical system since 2006, and a plan to face the detected 0.2 Hz oscillatory mode has been established (collection of data and identification of manufactures for suitable power plants, design of the adequate PSS and presentation and request to power plant owners). The continuous implementation of adjustments is on course and planned to end by 2009. These measures will prevent system for suffering strong oscillatory phenomena, allowing the increased exchange from the South West region to the Northern of Europe. For the North South Mode further analysis will be necessary to find the best location for damping devices. The investigations show, that increasing the transit capability followed by huge transits leads to further efforts to maintain steady state and transient stability.

4.5 System operational risk mitigation

Finally, those risks that persist during the operation of the power system are discussed and operational mitigation measures are recommended in this section. This section also deals with operational risk mitigation measures that can mitigate earlier mentioned risks.

There are two basic features of reliable system operation:

Adequacy - The ability of the power system to supply the aggregate electrical demand of the customers at all times. This takes into account scheduled and reasonably expected unscheduled outages of system elements. TSOs use all reasonable efforts to enable sufficient short-term operational reserve available to be able to deal with both the possibility of faults on the system and the uncertainties in wind generation forecast. The levels of uncertainties to be covered are established in the operational standards. The wind forecast uncertainty affects the TSO even in markets where the wind generation owners are contractually responsible for the imbalances caused by imperfect forecasting.

Security – The ability of the power system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements. Security limits define credible faults on the system (e.g. n-1 rule) and the acceptable operating boundaries (thermal, voltage and stability limits).

Besides the operational risks the above issues may also result in TSOs being faced with additional financial risks. These risks depend upon the model of their financing and the degree to which the additional costs incurred are allowed for or passed on to all system users. These aspects will be analysed in the cost analysis chapter. A wide variety of risks has been experienced, due to the fact that wind power development varies greatly between countries. The perceived risk levels range form very low to very high. Despite all differences there is a common picture of operational risks reflecting the same features of wind power and power systems all over Europe.

4.5.1 Operational risk assessment

The risks have been assessed based on the level of the impact and the probability of occurrence. Subsequently, they are plotted in risk matrices (shown in the Appendix) to give a structured overview of the risks. This procedure has identified the high risks, which combine high probability with high impact, for both present and 2015 situation. Further analysis and mitigation has been focused on these risks. Mainly the risks imply power flows that cause congestion and loss of (n-1)-security as described earlier, with the proposed grid reinforcements and sustainable mitigations these risks can be mitigated. However, the risks can still be mitigated with additional operational mitigation measures proposed later on. Another major risk concerning adequacy has to do with lack of available reserves, resulting in imbalances which cannot be managed without emergency measures.

Wind farm production requires a new approach for balancing electricity production and consumption. Balance management has to compensate mainly the imperfect forecast of production and consumption. The prediction of medium to high winds, and extreme high wind exceeding cut-out wind speed, is difficult. Due to the large share of wind production in some countries, their impact on balance management is already often the dominant error for the TSO to manage. This change of focus in forecasting can occur quickly.

Considering the different synchronous areas, Ireland faces a very high risk of imbalance in high wind/low load periods due to limited interconnection and wind penetration level. The Nordic region with less penetration and access to vast dammed hydro storage capacity assesses this risk only medium. ENTSO-E's regional group central Europe sees a high risk of imbalance in Portugal, resulting of the possible enforced tripping of a large amount of wind turbines.

Germany mitigates the risk of huge imbalances in the highly penetrated control areas of transpower and VE Transmission by an inter-TSO equalisation scheme. Each German TSO has a balance obligation for a fixed part of the German wind power infeed only. This percentage corresponds with the proportion of demand in each (of four) control area. Therefore the balance obligation is not directly proportional to the wind power penetration in the respective control area. Any surplus of wind power production over the balancing obligation is physically exported to the other German control areas in real time. This scheme reduces the probability of event from high to medium in the control areas of transpower and VE Transmission.

Spain does not perceive a major risk at the present moment for the possibility of imbalance, because in the Spanish market wind producers participate in the day-ahead market, as well as in the deviation processes, as any other conventional generator. This fact gives wind farm the incentive to improve the quality of their schedules (forecast, regrouped offers to compensate deviations). In GB large wind farms are required to participate in the market up to one hour ahead (short gate closure) as all conventional generation has to. This gives the wind farm owners an incentive to carry on balancing their deviations from their earlier forecast using their portfolio of generation. The impact of this incentive in GB has not yet fully emerged in operation, although the largest wind farms have gradually become owned (or at least traded) by the large generator & supply portfolio companies, rather than smaller independent developers.

4.5.2 Operation risk mitigation

This section describes operation risk mitigation method which can mitigate previously mentioned operational risk, as well as operational support to risks identified earlier in this study.

4.5.2.1 Coordination by TSOs on a regional and inter-regional level for congestion management and balance management

The power systems of Europe become increasingly interdependent as the amount of wind power increases in each system. To meet the increased operational challenges, a coordinated approach to power system operation over the boundaries of each individual system operator is necessary. By using regional forecasts (international) flows can be predicted more accurately and security issues and congestions will be detected sooner. This information is very useful for congestion management purposes.

Coordination by the TSOs on a regional and intra-regional level makes it possible to re-distribute the reserves, to reduce the risk of congestion and the risk of reserves that cannot reach their destination. When information is shared between TSOs, congestion in the transmission grid and on the border connections between control areas can be reduced. Sharing of real-time pan-European information (e.g. cross-border schedules, real-time cross-border flows, frequency) in case of a critical situation detected by one of the TSOs makes could be helpful (so called Regional Alarm and Awareness System). Sharing of information could help to make a better estimation (by existing or new developed tools) of the critical situation. If such a situation is determined, a suitable measure can be applied to reduce the occurrence of congestion (e.g. by real-time coordinated phase shifter tap settings).

In Germany the Net Transfer Capacity (NTC) at the borders is adjusted to the wind forecast to prevent congestion. In periods with high wind power the export capacity for trading will be reduced due to forecasted congestions and load flow congestions in Germany and neighbouring countries

Several TSOs (VE transmission, transpower, PSE-O and SVK, Amprion, EnBW and Swissgrid) have a cross-border re-dispatch cooperation on congestion management at their borders. In GB the England & Wales SO region was merged with the two SO regions in Scotland a few years ago forming a single GB System Operator. With the large scale expansion of wind in

Scotland, this facilitates a better overview and short term (post gate closure) decision making process.
A negative side effect for market participants of the coordination on a regional and inter-regional level is that at times with high wind power the export capacities for trading have to be reduced. This leads to very volatile prices at the power exchanges due to the wind power (even negative prices have been seen at times of high wind).

As a good example of TSO coordination, a project named TSO Security Cooperation (TSC) can be mentioned. This is a new initiative (starting in 2009) developed by TSOs from Austria, Germany, the Netherlands, Poland, Czech Republic and Switzerland. Coreso is a comparable initiative from the TSOs RTE, Elia and National Grid. The main objective is to improve the system security by more intensive cooperation particularly in the field of common security assessment criteria and open data exchange.

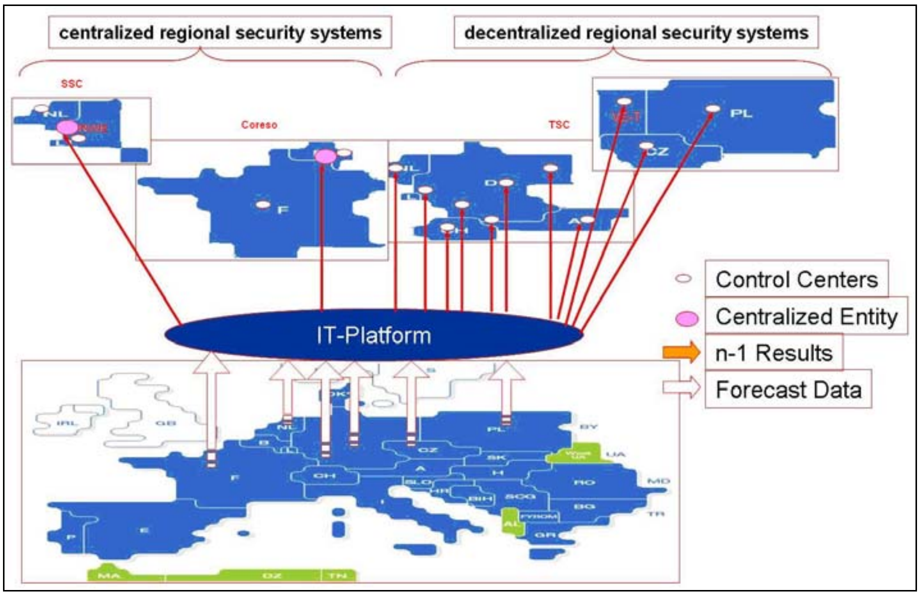


Figure 4-27 : Common IT-platform for day-ahead security analysis

The first phase of the project will focus on developing a single common IT-platform for day-ahead security analysis performed on unique merged grid model, also referred to as Day-Ahead Congestion Forecast (DACF). There is also a plan to extend to other operational planning time horizon in security analysis later on. Then it should be feasible to apply the same solutions to common intraday and real time analysis. When all this information is shared among the TSOs a sort of inter-TSO control centre will appear.

Main concept of the project refers to:

- Common daily (or any other available time horizon) evaluation of security calculation results, identification and coordination of remedial actions.
- Developing coordinated procedures in case of critical grid situations; we can assume it will be also useful for covering operational risk with high influence of wind generation.
- A main challenge of the project is to define a good system for sharing the costs in case of problems and congestions occurring in neighbouring power systems by for example cross-border redispatch.

Another project that is currently under execution is the PEGASE project. In this project a consortium of twenty partners including TSOs, expert companies and research centres define the most appropriate state estimation, optimization and simulation frameworks, their performance and dataflow requirements to achieve an integrated security analysis and control of the European Transmission Networks.

A higher complexity for the operation of large power system, mainly caused by deployment of new Special Protection Schemes (SPS), phase shifters (PST), static VAr compensators (SVC) etc. in combination with vast integration of renewable generation (particularly wind), is expected while traditional grid reinforcement is limited. This creates a need to find advanced solutions to support TSOs.
New methods and algorithms that will be studied in the project to apply efficient solutions to the following applications:
- Pan-European State Estimator and Optimal Power Flow (OPF) tools.
- Time Dynamic simulation for dynamic security assessment in real time.
- Full scale European training simulator.
It shows new directions on how to improve existing approaches for system planning and operation. It also offers new capabilities for evaluation of the current situation in an interconnected power system and introducing coordination of control devices (like PST, SVC, HVDC). However, development and potential implementation of such tools is very challenging and may require huge effort. Finally, it should be feasible to operate with smaller security margins but also with reduced risk and uncertainty. More information about the PEGASE project can be found on their website.[2]

[2]http://cordis.europa.eu/fetch?CALLER=FP7_PROJ_EN&ACTION=D&DOC=1&CAT=PROJ&QUERY=01221b9eae32:dd6d:25440efe&RCN=88387

4.5.2.2 Sharing of operational planning information between TSOs (wind power forecast, grid layout)

Related to the previously mentioned TSO coordination is the sharing of operational planning information. Day-ahead wind forecast information could be shared between TSOs for system security reasons by improving the planning and making better estimations of the flows. Risk of congestion in both transmission grids and on cross-border connections will be limited since better flow predictions can be made. Several countries use online weather forecast and the current weather situation for their predictions. In Germany forecast information and online measurements are shared between the four TSOs to enable its national inter-TSO equalisation scheme.

All German TSOs already share their wind power forecast information with PSE-O and other TSOs in the CEE-region, but this information is by far not enough to make a good estimation of the transit flows. A larger region has to be taken into account and unlike today reliable schedules of conventional power plants and information on network topology (eg. phase shifter settings) have to be provided. Only this altogether will enable calculation and exchange of better load flow prediction.

Since provision of wind power forecast information is a commercial service, sharing of this information would require suitable agreements with the forecast provider. In systems with very short gate closure time, such as GB with only 1 hour, the possibility of sharing of forecasting information between the pre-closure balancing participants (the Generators) and the post closure responsible party, the system operator, becomes a significant issue.

4.5.2.3 Better harmonization of the regional market design

Harmonisation of the regional market design can be implemented by the use of market codes, which have to be developed. When market designs are better harmonised, the risk of low to negative market prices and maximum prices might be reduced. Furthermore, volatile market prices might be prevented and high balancing costs reduced. In the Nordic area all areas have comparable market rules and wind power is being exchanged according to the market price. In hours where there is surplus in an area, caused by wind power, the price will go towards zero, and there will be an export out of the area if there is any capacity.

Not harmonised market rules can result in distortions which can potentially cause undesirable power flows. For example, between Denmark and Germany the market rules are not harmonised, and it is often seen that the power is going in the wrong direction from a high price area to a low price area. This is very disturbing for managing the wind power, meaning that power sometimes goes from areas with little wind to areas with a lot of power. E.g. when the two markets are disconnected and the flow over the boarder is decided by bilateral trades, the traders must guess what the price level is in the two areas. If those guesses are wrong the flow can go from high price area to low price area instead of the right way; from low price area to high price area. Harmonising market rules could also reduce disturbances to consumers in extreme system conditions.

4.5.2.4 Wind power management in case of jeopardized system security

There is a possibility to control wind turbines or entire wind farms by remote control. The wind power plants can be remotely controlled in both active and reactive power output by managing the wind power plant. This includes the reliable legal right or cost reflective contractual option to curtail wind power plants if needed to maintain system security.

With the possibility to control the active power of wind power plants the risk of control area imbalance and congestion can be limited. Furthermore, the possibility of wind farms to be implemented into system secondary frequency control remotely and/or locally, will improve system operational quality. Wind farms' contribution to secondary frequency control will be helpful, especially at low load conditions with high wind penetration, when all available conventional thermal units have reached their technical minimum. On the other hand the possibility, as a last resort measure, of remote control of power production can be helpful for limiting congestion problems. This will reduce the risk of loss of (n-1)-security. Better management of system congestion problems, as well as system imbalance, permits the integration of higher amount of wind farms in system operation by keeping the same level of system operational security.

Remotely and/or locally voltage control of wind power farms, additional to conventional generators voltage control, will help to a better optimization of system reactive power flows and contribute to reduced system reactive losses and improved voltage stability.
Different remote control capabilities have already been installed in several countries (e.g. transpower), but control is not required in every country's grid code. Many countries have control capabilities for wind farms, though regulations are very diverse.

In Spain, a special regime (mainly wind power plants) production facilities with a total installed power greater than 10 MW must be connected to a Renewable Energy Source Control Centre (RESCC), which at the same time is connected to the Control Centre for Renewable Energies (CECRE). This two-way communication gives the system operator insight in real time information of the connected generation (such as: active and reactive power, farm connection status, voltage, wind speed, temperature, etc.) and transmits the necessary instructions to the RESCC to contribute and comply with the system operation and grid security criteria.

The aim of these Control Centres is to enable the integration of a bigger amount of special regime generation into the electricity system so that it is compatible with its grid security. This is because the centre allows performing a real production control, instead of considering hypotheses of simultaneity in a certain zone (necessarily conservative hypotheses of higher production of energy or greater power installed). The centre also allows the coordination of the Transmission Network facilities maintenance plans with the maintenance of connection facilities and generation facilities, minimising the extent to which the generators are affected.

Dedicated Control Centres may act as an important mitigation measure for the main operational risks associated to wind generation:

- The lack of Power Guarantee is addressed in such a way that these centres are used to monitor the availability of wind energy in accordance or comparing it to the forecasted values and the respective programming. Then, if applicable, the necessary substitute power, to be generated based on other technologies, can be determined.

- Risks associated to the wind resource contraposition to the system needs (later demand increase that is the cause of the need to integrate the technical minimums of the thermal energy that is going to be required) are minimised. In this sense, the Control Centre can make wind generation compatible with the status of the system and net demand, wherever possible, by issuing the pertinent control instructions with respect to the generation which is necessary in each particular case.

- Risks associated to the disconnection of vast volumes of wind generation in case of voltage dips are minimised, by preventing disconnections, which could cause a serious impact on the security of supply.

- Risks associated to the high number of interlocutors with the System Operator are eliminated, since a specialised Control Centre acts as interlocutor for wind generators, thereby freeing up the National Electrical Control Centre from this task, which is, however, essential. This way, CECRE will also be the only interlocutor of the National Control Centre for the management of wind generation in real time.

Drawbacks of remote control are the additional prime (direct) and indirect costs. Wind farm owners have to pay the extra prime cost for remote control equipment that has to be installed in wind power plants. The remote wind power production control will be charged with an additional prime cost, because TSO/DSO have to acquire additional equipment and software for the remote control of wind farms and to include them in their Energy Management Systems. This can be done in a centralised or decentralised way. It is obvious that (in situations when there is no general power surplus) any limitation of the available wind power production has to be replaced usually by more expensive power production of conventional units.

The increase of system production cost is an additional indirect cost, which can even be higher if additional penalty costs for higher greenhouse emissions are taken into account. For this reason the decision of control of real wind production should be last by merit order. Due to this low priority of wind control, the expected time period for the wind power to be limited will be extremely low in comparison to the total operation time of wind plants.

The additional costs caused by control of wind power, either for removing congestion problems or system imbalance, is the ‘’price” paid for better system security and system operation quality. The costs for this mitigation measure will be calculated in chapter five, but they probably will be low in comparison to the benefit of allowing a higher wind power penetration safely into the system, producing more sustainable energy most of the time.

4.5.2.5 Use of large scale energy storage (better use of existing storage or construction of new storage facilities)

In a system with large amounts of wind power integration, energy storage can be helpful in matching power production and load patterns. Most storage systems have a high flexibility, enabling balancing of wind power.

Large scale storage systems reduce the risk of imbalance and risks of control of wind energy in congested areas. Financially, storage systems can prevent volatile market prices because of their stabilizing influence. And, related to that, reduce the need for balancing in terms of less secondary reserve that is needed, which will stabilise and probably reduce balancing prices. Energy storage can be used to avoid grid reinforcements in minimum load situations. The costs of using large scale energy storage in the European system will be analysed in chapter five.

There are many possible storage systems, for instance pumped hydro power, compressed air energy storage (CAES), chemical storage systems (batteries or hydrogen) and flywheels. Energy storage systems can be divided into short or long term storage, of both types there are distributed and centralised systems. Probably the largest long term "storage" facility is hydro behind dams, with high power installation and changing its output in response to wider balancing requirements (rather than simply generating for its local demand). The largest such facility is in Norway with about 50TWh stored energy. This is critical to balance Denmark with the world highest wind penetration level (excess of 100% for Western Denmark under some conditions). However, this facility relies on sufficient interconnection capacity between the two systems.

A Dutch study showed that storage does not seem to be best option for balancing, but the result is strongly dependent on the region and the surrounding area. The Netherlands however has in 2008 effectively secured access to remote storage facility by its connection to Norway and is now even considering building a further link. In countries like Spain, the interconnection scarcity and the attained level of wind integration make the additional installation of pumping units a highly interesting solution to mitigate operational, balancing, as well as financial risks. In areas with mountains where hydro plants are cheaper and easier to install show a more favourable situations to the installation of additional hydro-storages.
Most pumped hydro facilities can be found in Austria, France, Germany, Norway and the United Kingdom. The only large scale CAES facility in Europe can be found in Germany (290 MW). Other storage systems are mostly still in the development stage.

4.5.2.6 Demand Side Management

Demand Side Management (DSM) is the optimisation of the match between supply and demand of electricity, to match the actual supply. Nowadays, electricity is mostly demand oriented and managed by varying the supply. More and more, there is generation of electricity that can not be managed easily, wind and micro co-generators are examples of such generation. In these situations management of demand can be helpful to provide a way to better match the demand to the momentary wind power production. In terms of demand side management, it is not in the legal scope of many European TSOs.

The environmental and financial case for introducing significant demand management from the heating (heat pumps) and transport sectors depends heavily on decarbonising the electricity production. In GB, for example, this is likely to start to become attractive post 2025, but remains difficult up till this time. In contrast, the cooling demand (fridges and freezers which account for about 20% of electricity demand is ideally suited for short term demand management (up to 20-30 minutes). Extensive work is in progress to make this a reality in the near future (e.g. through requirements for all new cooling equipment to have a frequency control device).

DSM units are able to reduce consumption on the day-ahead market and provide up-regulation through reduced consumption on the intra-day market. The basic hypothesis is that DSM will imply a cost reduction which in EWIS is quantified by comparing two model runs, one with DSM and one without. The results of the analysis have been summarized in the section on cost analysis.

4.5.2.7 Flexible Line Management

Countries such as Germany, Portugal and Denmark (and to a small extent UK) with large amounts of wind power, have found more efficient use of transmission infrastructure is possible by determining the capacity of transmission lines dynamically based on measurements of conductor and ambient temperature and other parameters. This is something which can have a significant potential for reducing congestion and maximising the use of existing transmission capacity.

Regarding NTC enhancement (analysed in chapter 5 of the report), dynamic rating based on atmospheric conditions of line capacity entrains several operational implications to be here shortly described:

In order to establish the possible capacity increase of a certain line is necessary firstly to install meteorological substations (or CAT devices to directly measure the wires tension) in all the line stretches of the considered line. Only this way the critical stretch conditions would be identified and with them the capacity of the line could be calculated under real hypothesis.

This is a practice that could be exploited for a line or corridor whose congestions could be alleviated. Analysis of possible benefits of this practice associated to the estimated increase in NTC capacity has been provided in chapter 6. Nevertheless, several points in relation with the operational feasibility of this hypothetical use of thermal rating for enhance NTC capacities have to be commented.

- To start with, it is important to note that the calculation of a NTC regards generally not only to a line but to an ensemble of lines that could be distributed along a significantly large territory and therefore, submitted to different atmospheric conditions.

- The concept NTC is also related to operational criteria, including the need for reserved capacity for deviations in the exchange programs, etc and besides that to the conditions in the transmission networks near the interconnection (possible outages or dispatching conditions could limit the NTC because of congestion in internal networks).

- It is important to remark that certain protections (over-current protections in particular) installed in some European power systems should be adjusted in coherence with the new capacity values, that meaning an adjustment of the values of the protections nearly in real time. This practice entails significant risks, that can be assumed in the case of long internal power corridors deserving a certain zone, but not in the case of a interconnection that supports the stability of the system (especially for radial countries).

- The calculated enhancement of exchange capacity, if feasible and interesting to be implemented, should be consequently put at the market agents disposal. This present the inconvenient of the non existence of capacity allocation markets close to the real time.

The here above describe implications permit to conclude that the increase of interconnection capacity between countries would be rarely addressed by rating their capacity depending on the atmospheric conditions. Flexible Line Management (FLM) as described in the document could nevertheless be a useful measure for alleviating internal congested corridors.

4.5.2.8 Investigation of an offshore grid, interconnecting several wind farms and countries from the sea

Investigation on the construction of an offshore transmission infrastructure, in order to connect large amounts of offshore wind power capacity, can give information on increase of cross-border capacity and provision of a better integration of the four European synchronous areas. This will help in developing interconnection between markets resulting in a better market process and more stable prices, and therewith allows the impact of increased wind power penetration to be shared amongst as many countries as possible.

Extra interconnections created by the offshore grid can help reduce maximum prices, and this creates a less volatile market price and mitigate the risk of high balancing costs. These advantages only occur if the grid is laid out with enough margin in the transport capacity. When the offshore grid is build to connect the offshore wind farms to a coupling point of the existing transmission network, further transportation of the wind energy has to be feasible as well. TSOs seem to be the most appropriate party to build and operate the offshore grid, based on the experience so far and the overall coordination with onshore grid alignment.

An offshore grid for the large-scale integration of offshore wind is still in the concept phase. Several companies and organisations have made plans and proposals for a large offshore grid interconnecting wind farms. These plans involve large wind farms up to several GW and grids between the Netherlands and Great Britain, between the Netherlands, Denmark and Norway and between Germany, Denmark and Sweden.

Main barriers are backing and support from the EU and national governments, the financing and the lack of experience with the proposed technologies. Appropriate market arrangements have to be developed and the full impact on onshore transmission systems has to be studied further.

4.6 Technical Conclusions

The EWIS investigations confirm the need to reinforce the grid to accommodate the increasing share of wind power in the European grid. Based on the risk analysis and risk mitigation for the 2015 time horizon, different types of measures were defined:

- EWIS identified national (grid development within countries) as well as international (interconnectors between countries) grid development
- EWIS confirmed the wind related TSO grid development foreseen by 2015 (red elements in Fig. 4.4 to Fig. 4.9). EWIS strongly proposes to urgently realise all these grid developments.
- The identified additional reinforcements (orange elements in Fig. 4.4 to Fig. 4.9) should be considered and refined by the relevant TSOs as candidate measures for inclusion in the ENTSO-E TYNDP
- Results of EWIS technical & economic analysis identified candidate measures, but further work required by relevant TSOs to develop into investment schemes

- EWIS showed a significant potential for reducing congestion and maximising the use of existing transmission capacity but also the need to strengthen the existing grid with new grid infrastructure to maintain the existing level of system security

EWIS analysis concludes that to effectively integrate wind power in the European Electricity network, strengthening of the European Grid with planned Grid reinforcements is urgently required. EWIS proposes for further coordination of the European TSOs for European wide grid reinforcements to meet the European 2020 targets.

- Urgent and sustainable system development to enable RES integration in the European grid which is necessary to reach the EU targets for climate protection, building new grid infrastructure for bulk power transmission e.g. over long distances (onshore and offshore).
  - Immediate realization of urgently needed grid infrastructure projects (existing national grid development plans, not realized yet)
  - Full and timely completion of all Regional Mitigation Measures, for achieving secure integration of wind sources into the electricity system
  - EWIS findings and recommendations as an input to ENTSO-E 10Y network development plan.
  - EWIS findings and recommendations as an input to ongoing or future regional/national studies.

- Use of robust measures to optimize grid usage
  - Flow control optimization by operational switching and phase shifters.
  - Further analysis to enhance network capability and flexibility by using available line capacity management.

- Onshore Offshore grid perspectives: Strengthen the Pan European electricity system for better exchange of regional energy increase and better utilization of dispatchable and variable renewable energy sources (e.g. large hydro-energy capacity and offshore wind)
  - EWIS beyond 2015 results as a starting point for detailed investigations of sustainable offshore grid infrastructure and offshore windpark cluster concepts e.g. for the time horizon 2020/2025.

- Need for a common basis on offshore infrastructure development (e.g. regulatory framework, market coupling and security of supply).
- In order to prevent system stability risks (large generation outages, risks for voltage collapse and rotor angle stability), wind turbines have to fulfill minimum requirements all over Europe to support system stability (EWIS proposal on harmonized grid code requirements).

4.7 Wind-network technical compatibility

The EWIS proposal for the harmonization of the grid code for wind power is taken a significant step towards the European wide grid code for the generation. EWIS has concluded it is appropriate to propose harmonizing grid code requirements to be fulfilled by wind power plants all over Europe. The main purpose of the code is to minimize risks to system stability.

Based on the European wide investigations for the time horizon 2015 carried out by the power system analysis group, wind power installation in the European grid will be significant and could not be ignored from the operational point of view. Due to variable nature of power generation and the uncertainty caused by inability to perfectly forecast the weather, wind power integration becomes a challenging task on the day by day basis for the transmission system operators. Certain requirements could be listed out as absolutely necessary to be fulfilled by the wind power generators to better integrate wind power. In several countries grid codes for the wind generators do exist and found to contribute to keep the grid operation stable in normal operation as well as in case of disturbances. The overview of the existing grid codes demonstrated the need to list some key technical requirements which needs to be fulfilled by the wind power generators all over Europe. This will ensure appropriate sharing of the responsibility for the reliable integration of wind in the developing European grid.

These minimum grid code requirements for wind power generation emerged from the EWIS investigations by the technical experts, have provided a solid basis to ENTSO-E to further develop harmonized requirements for grid codes all over Europe to ensure the best integration of wind power.

As a prerequisite for the sustainable integration of wind power, minimum requirements on European level should be established based on regional requirements. These include:

- Fault ride through (FRT)
- Voltage control
- Frequency control
- Control and monitoring
- Repowering capabilities

These requirements should be demonstrated against defined compliance processes. Compliance of wind farms should be measured at the Point of Common Coupling (PCC) where the functional performance requirements apply, supplemented by information gained in certification process for single wind turbines.

To cover legacy situations where wind farms are not fully compliant with these requirements, there may be regional needs for measures such as emergency control actions and disconnection of non-compliant wind generation. This includes in particular lack of FRT performance for system faults. Other considerations such as treatment of non controllable wind power generation should also be considered.

The following objectives summarize the need for grid codes

- Definition of technical standards for grid connectivity for the prevention of large outages of wind power generation and voltage collapse caused by wind turbines.
- Adequate FRT requirements, which could also include support to the voltage restoration, and reconnection conditions when tripping
- Provision of voltage and frequency control
- Establishment of mechanisms for monitoring of the fulfillment of grid code requirements
- Repowering capabilities and treatment of the non-compliant wind generation in case of system faults and security management measures in emergency cases

4.7.1 European-wide minimum harmonized requirement for wind power plants

4.7.1.1 Fault ride through capability

Large scale integration of wind power into power system operation gives rise to new challenges for each of the interconnected systems and for their transmission system operators in particular. As wind penetration increases the risk that regular faults (which lead to low voltages spread to a wide area around the fault point for the transient period) may lead to the disconnection of large amounts of wind power. Massive loss of wind turbines after a regular fault lead to more severe disturbances i.e. drop in frequency and unexpected and uncontrolled power flows that may overload both internal transmission lines and tie lines with neighbour systems possibly leading to cascading trips causing system splitting, load shedding, major faults, brown outs and even black outs. It should also be noted that power systems have been designed to withstand the loss of a specific upper limit of power production (usually the largest unit, crucial interconnectors etc). The size of the largest loss and its percentage of the total capacity on that interconnected system varies greatly. Generally the smaller the system (e.g. islands) the greater is this challenge. In cases of high wind penetration, a regular fault at transmission network may lead to the simultaneous loss of generation much more than the said limit when wind turbines are operating without FRT capability.

The TSOs all around Europe recognize the need that wind farms should remain stable and connected to the network when faults occur on the transmission network. This is known as fault ride-through capability (FRT) or low-voltage-ride-through capability (LVRT), and it is has been a requirement for some years in particular for TSOs with existing or expected high wind power penetration (such as Denmark, Germany, GB, Portugal and Spain).

A number of reasons make the requirement of fault ride through capability necessary:

- Security of supply must be ensured. Massive loss of wind turbines without FRT capability after a regular fault lead to severe disturbances i.e.
    - unexpected and not controllable power flows that may overload both internal transmission lines and tie lines with neighboring systems possibly leading to cascading trips causing system splitting
    - load shedding
    - major faults
    - severe network situations and even black outs

  It should be also underlined that power systems have been designed to withstand the loss of a specific upper limit of power production (usually the largest unit, crucial interconnectors etc). In cases of high wind penetration, a regular fault at transmission network may lead to the simultaneous loss of generation much more than the concerned limit when wind turbines are operating without FRT capability.
- If FRT capability is not applied then the capacity of the wind power that can be securely connected to the system is considerably lower.

If the wind turbines installed are not capable to ride through faults in the areas where high wind penetration has been achieved or is expected, large amounts of wind power may be switched off in view of a system fault leading to massive loss of wind generation and as consequence system splitting etc. The wind power curtailments are decided after exhaustive system fault simulations. Given future high level penetration of wind power, FRT capability has to be provided for every new wind farm. This needs to be supplemented by national (or regional) reviews regarding need for retrofitting this capability.

Requirements

FRT requirements are based on a time-voltage diagram, which shows the permitted area of voltage variation. Wind turbines have to stay connected to the grid for voltages greater than those on the borderline. This diagram is applied to the point of common coupling (PCC) of the Wind farm. The parameters determining the exact application of the FRT capability depend on each particular TSO depending on the current generation mix, wind power penetration, local conditions in each control area, transmission system topology, etc.

The FRT capability is already required by the Grid Codes in numerous European countries (Germany, Denmark, Spain, Greece, Sweden, Norway, Finland, Italy, Ireland, GB, Portugal, Belgium etc).

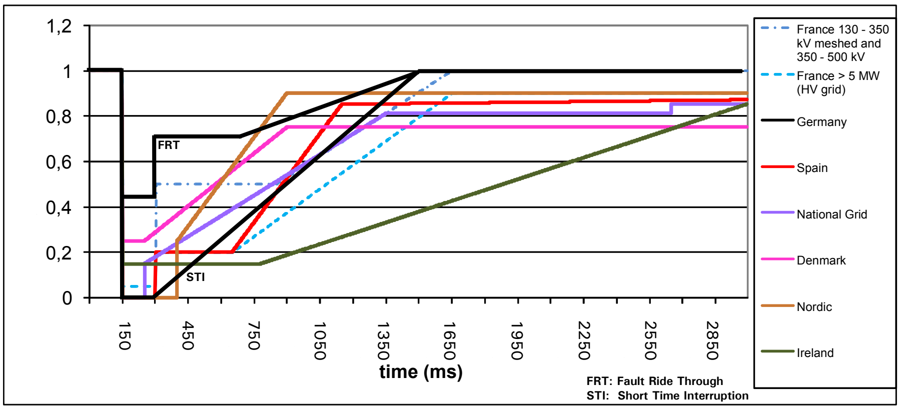


Figure 4-28: FRT requirements based on local conditions in different control areas

4.7.1.2 Voltage control in steady state and dynamic support

4.7.1.2.1 Steady state

Voltage support/control is an essential functionality for the operation of a power system in order to keep voltage variations within limits that are tolerable by the devices connected to the network, minimize the risk of instabilities and also reactive and active grid losses.

Increased wind penetration may affect reactive power balance and voltage control due to the following reasons:

- Older type wind turbines (initially allowed in some countries without added reactive compensation, e.g. at farm level) are absorbing reactive power, providing in this way a negative contribution in the reactive power balance of a power system

- Fluctuations in the active power produced by the wind farms leads to variations in the reactive power consumed by the transmission network, necessitating in this way additional reactive power reserves.
- In case of high wind penetration the portion of conventional power will be decreased in order to accommodate wind production; thus, the reactive power reserves of the power system will be also reduced.
- Usually wind farms are installed in remote areas thus leading to bulk transmission over long distances. This fact increases reactive power requirements of the power system both steady state and dynamic.

Requirements

Due to the above mentioned reasons TSOs agree that wind farms should contribute to voltage control. This is feasible with modern wind turbines, although some manufacturers still chooses to use farm level reactive compensation, reserving more converter capability for real power production. In particular, wind turbines equipped with a power electronics grid interface (i.e. utilizing a double-fed generator or a generator connected via a full power converter) or reactive compensation at farm level (switched shunt capacitor or SVC) are capable of varying their reactive power in a controllable way.

Contribution of wind farms to voltage control can be achieved by applying either voltage control, MVAR-control or power factor control in combination with current boost in case of disturbances. In all cases it is recommended that regulation refers to the point of common coupling (PCC) and a dedicated wind farm controller is used for this task. More specifically, in the power factor control mode the objective is to regulate power factor in order to follow a predefined set-point, mainly in order to minimize reactive power burden of the transmission and distribution networks. In the voltage control mode, the control task is to regulate voltage at the PCC within a predefined range, in order to minimize risks associated to disconnection of wind farms in particular nodes with high penetration or to voltage collapse in certain nodes where wind farms are the only ones that can regulate and ensure the respect of voltage nominal ranges. The ultimate use of voltage control for wind farms is to fully replace the performance (both steady state and dynamic) from displaced conventional power stations. This has been fully demonstrated as practical across the range of technologies and configurations. In the MVAR-control mode, a MVAR output is controlled according to a given MVAR set point.

The operation mode is a responsibility of each particular TSO (or DSO). Constant power factor operation is for instance preferred for wind turbines connected at the distribution and 110-kV-level when voltage control at this level is difficult to be implemented due to a number of reasons including the possible negative interaction with other voltage control devices (notably transformers) that may lead to hunting situations. The MVAR-control mode mitigates the risk of hunting situations in case of voltage control, but requires a central management of voltage level control.

However, in specific cases (e.g. the connection of wind farms in points with low short circuit capacity) the implementation of voltage control may be also opted.
For larger wind farms connected at the transmission level, voltage control seems to be preferable in order to cope with reactive power imbalances caused by increased wind penetration.

Depending on the local network conditions, TSOs should set the requirements concerning the operational mode (voltage, MVAR-control or power factor control) and the respective regulation settings. These settings concern the required range of power factor variation as a function of wind farm operating point and grid voltage levels.

Dynamic voltage support

In cases in which a risk associated to instability (and possible cascade effect) in faulted situation is present, additional requirements related to the participation of the wind generators in voltage support during the fault and during the voltage recovery, or at least requirements on the limitation of reactive consumption and support, could be needed. That implies the need to manage reactive current in case of voltage dips and during transient over-voltages during the restoration period. Injection of reactive power/current in opposition to the voltage deviation with a certain required speed could be essential in some cases. . Some countries already use full voltage control more widely. This has been successfully achieved with performance equivalent to that of the synchronous plant which the wind farms displace in high wind conditions. Change in wind farm reactive output covering the full reactive change is delivered dynamically in less than 1 second.

4.7.1.3 Monitoring and controllability

EWIS perceives that for the safe and sustainable integration of the expected large wind power in the European electrical system system operators has to be provided by tools (and legislative support) to monitor and control wind power. These tools may allow the System Operator to observe and command if needed the active power output, voltage or state of wind farms, etc. For the prevention and restriction of the emergency process in case of perturbations (restriction of voltage collapse and large outages of wind power generation) it could be helpful to combine monitoring with special counter emergency control automations to induce direct and selective actions.

For larger wind farms it is recommended to establish a certain control structure allowing the final communication with the system operator (SO), in such a way that real availability of wind energy is followed, and the respective substitutive programming and security analysis could be performed.

It is recommended to foresee the following information exchange:

- Active and reactive power
- Farm connection status
- Voltages (terminal generator voltage, PCC)
- Other (temperature, wind speed…)

4.7.1.4 Repowering capability of non controllable generation

According to the EWIS results and recordings of real disturbances under the hypothesis of non adaptability of old wind generators to FRT and controllability requirements, just simple line faults may endanger the security of the whole European power system in the near future. Three phase short circuits will results in voltage dips in wide areas of the network. Subsequently, non controllable wind power plants without any FRT capabilities will be tripped and thus the system will experience loss of a large amount of generation capabilities.

In case of the most likely single line to ground faults, system security may be guaranteed by alignment of voltage protection relays evaluating the maximum line to line voltage for developing corresponding decisions. Furthermore, a time delay of approximately 250 ms would protect tripping also for three phase short circuits.

4.7.1.5 Provision of frequency control facilities by wind farms

For countries (or Balancing zones) were either wind generation has already reached high level of penetration or there are reasonable expectations (or plans) for high wind penetration within the lifetime of the soon to be connected wind farms, it could be important that wind farms have the capability to reduce active power in order to support frequency control. Wind turbine technology is technically well suited to provide this service. However, only high frequency control can be delivered at a low cost and in an environmentally friendly manner (minimum addition of CO2 due to the action). Low frequency control capability would only be applied if other cheaper (and environmentally friendlier) options are exhausted. This is expected in high wind low demand situations with most of the conventional plant temporarily displaced.

4.7.1.5.1 Settings for active power reduction with over frequency

As other generation units, wind turbines have to reduce active power in case of over frequency. E.g. Italian black out, caused an overfrequency in the remaining system of about maximum 50.2 Hz. All wind farms must, when operated at a frequency higher to a certain figure, reduce the current active power with a gradient of a certain % per Hertz of the presently available power of the generator within the time observed by the TSO. When the frequency returns to a value an acceptable value, the active power infeed may be increased again. This regulation is performed at each individual generator. The specific requirements are to be defined by the individual TSO within the given harmonized frame.

4.7.1.5.2 Security Management

It must be possible to reduce the power output of a wind farm when requested (emergency situation) in any operating condition and from any operating point to a given power value (set-point value).

4.7.1.5.3 Full frequency control capability (pros and cons)

Some countries have very high expectations for wind penetration, e.g. at least 15-20% of annual energy demand overall. Typically this means 50-100% of instantaneous demand in the most extreme wind and demand combinations. West Denmark (UCTE part) with an average penetration level in excess of 20% of annual energy demand has already experienced wind production in excess of 100% of instantaneous demand. In such cases it is essential to also consider the means available for regulating upwards, providing frequency response e.g. in case of large loss of generation or unexpected sudden increase in demand.

The actual use of this service has however a major disadvantage. It can only be provided (at least sustained in significant quantity) by deliberately spilling wind power (during the periods when this service is enabled). There are therefore CO2 environmental and cost implications with its use. Alternative actions e.g. full flexibility of other new generation or trading services should be considered first to provide such services, e.g. on a lowest price basis.

5 Cost Analysis

5.1 Introduction

This chapter analyses the costs associated with the future integration of wind power capacities in the European power system. It also looks at the costs linked to national or internal grid reinforcements induced by additional wind capacity and gives an insight into costs of the cross-border reinforcements as detailed in a so-called Enhanced scenario. Finally, also the costs represented by public support to wind power producers are included. For more studies containing economic valuations of national grid extensions, a summary is available in the IEA Task 25 Report.

The internal and cross-border grid reinforcement costs are derived exogenously to the model as grid-related mitigation measures. Both are added onto the market model outcome.

5.2 Benefits of adding wind power to the system

5.2.1 Introduction

The benefits of the wind capacity added into the European system are assessed by looking at the reduction in total operational costs of power generation. As wind power, characterized by zero marginal cost, is replacing conventional units and reducing the CO2 emission, it decreases the operational costs of power generation.

5.2.2 Benefits of adding wind power

For the 27 countries retained in the analysis, the operational costs with almost 125GW extra wind in the Optimistic-HC case amount to 120,9B€ in 2015 compared to 139,5B€ in 2008. This represents a 13% reduction on annual basis. The annual operational costs and the respective reduction for each scenario costs are presented in Figure 5.1.

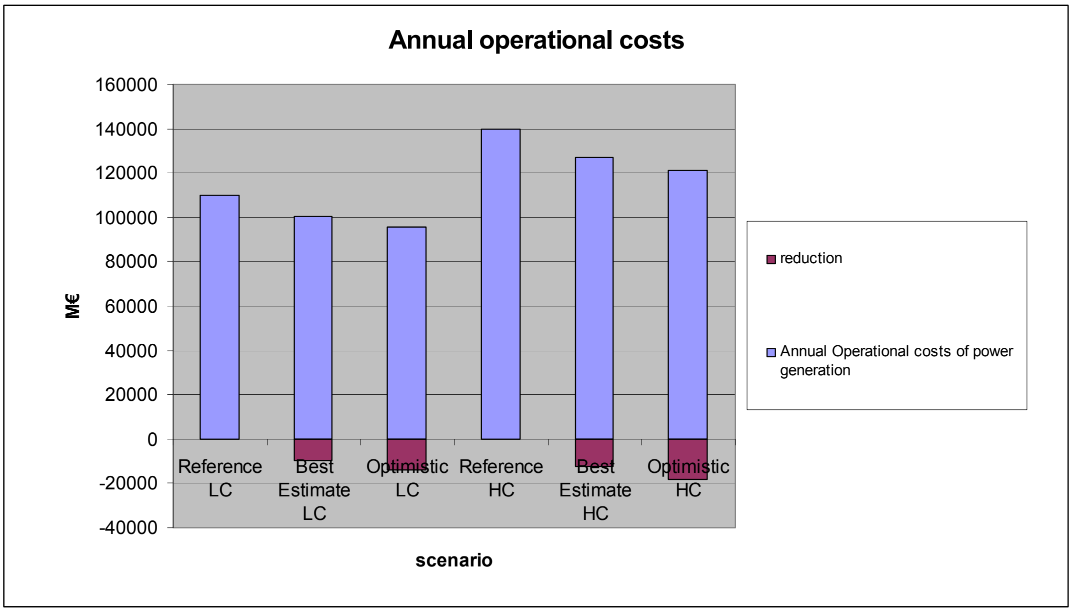


Figure 5.1: Annual Operational Costs in 2015 with gross benefits

It is important to note that the net benefits account for the additional system integration costs. The gross benefits exclude these additional system integration costs. In the Figure 5.2 a decomposition of the net benefits of wind power across Europe in 2015 is presented, split by cost category. As it can be observed, there are significant savings resulting from reduced fuel usage and CO2 emissions. The reductions are significant and increasing with more wind added onto the system and with higher fuel and CO2 prices.

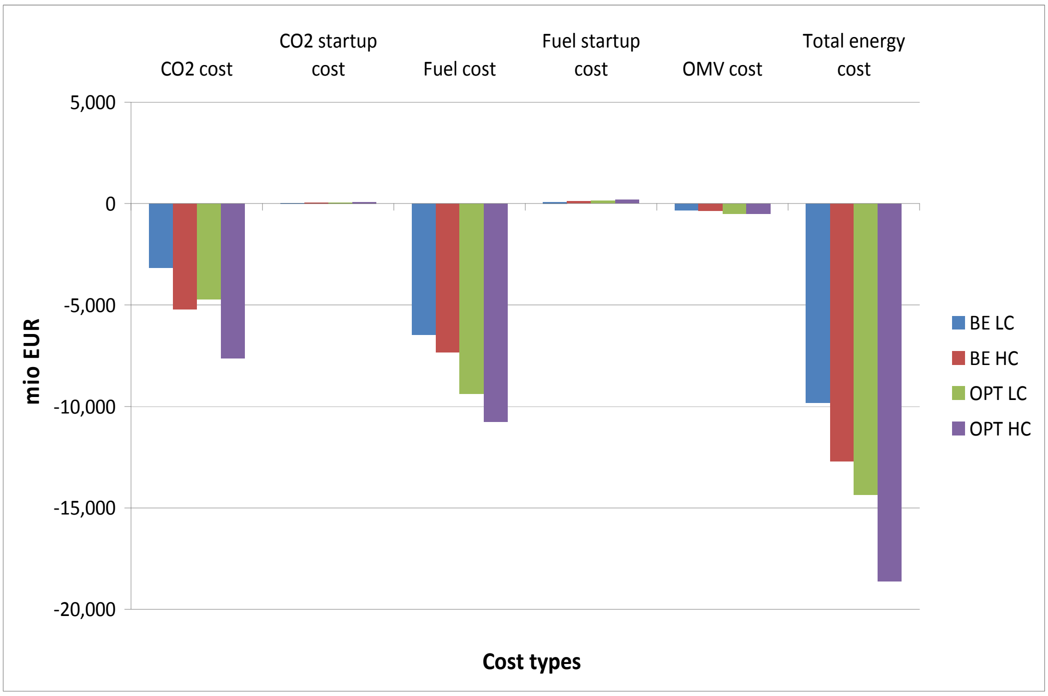


Figure 5.2: Net Benefits of Wind Power

Hence, the economic value of additional wind into the power system (reducing operational costs) can be estimated between 45€/MWh for low up to 60€/MWh for high boundary conditions. Important to note is that this value does not include the additional costs caused by adding wind to the system such as grid reinforcement costs nor surplus costs.

Another consequence of the same displacement effect of wind consist in the shift in the power generation merit order thereby reducing the marginal production cost and hence having a lowering effect market clearing prices. This is the so-called "merit order" effect of wind power. This decrease in wholesale power prices is different country per country but is estimated to range on average between 2,1€/MWh and 3,8€/MWh depending on the boundary conditions (cfr. Figure 5.3).

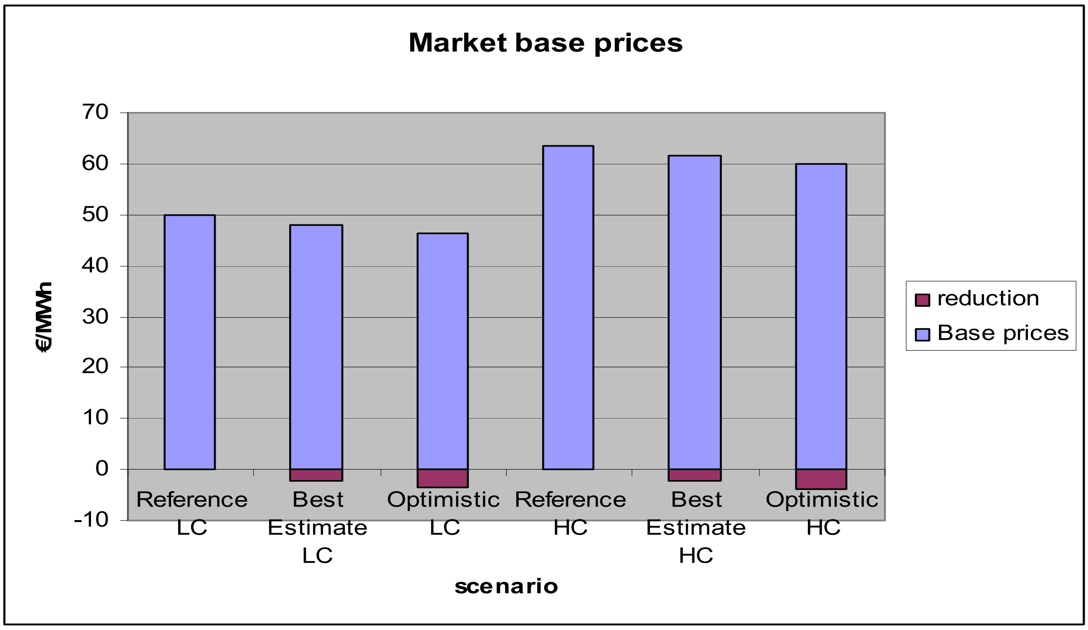


Figure 5.3: Estimated reduction in base prices in European power system

Estimated decreases on wholesale base prices average between 3% and 7%. More wind capacity installed induces a steeper reduction and this effect is higher with higher boundary conditions. On a country level, price decreases vary from 0€/MWh up to 10€/MWh.

5.3 System Integration Costs

5.3.1 Introduction

The main drivers of these system related costs are the uncertainty and unpredictability of wind. These factors drive an increased number of start-ups and shutdowns of conventional power stations and the need for more flexible dispatch, causing an increased fuel consumption, CO2 release and additional operation & maintenance costs. It is the potential uncertainty of wind energy that causes additional cost to be incurred by the running of conventional power stations to 'fill in the gaps'. Uncertainty drives the need for more starts and stops of conventional power stations, and unpredictability drives the need for more flexible dispatch.

5.3.2 Additional System Integration Costs

Figure 5.4 shows the total additional System Integration costs across Europe in 2015, for both the Best Estimate and Wind Optimistic scenarios under low (LC) and high (HC) boundary conditions. Additional (compared to 2008) System Integration cost range under 'Best Estimate' of between 349M€ and 406M€; and under 'Wind Optimistic' between 650M€ and 768M€.

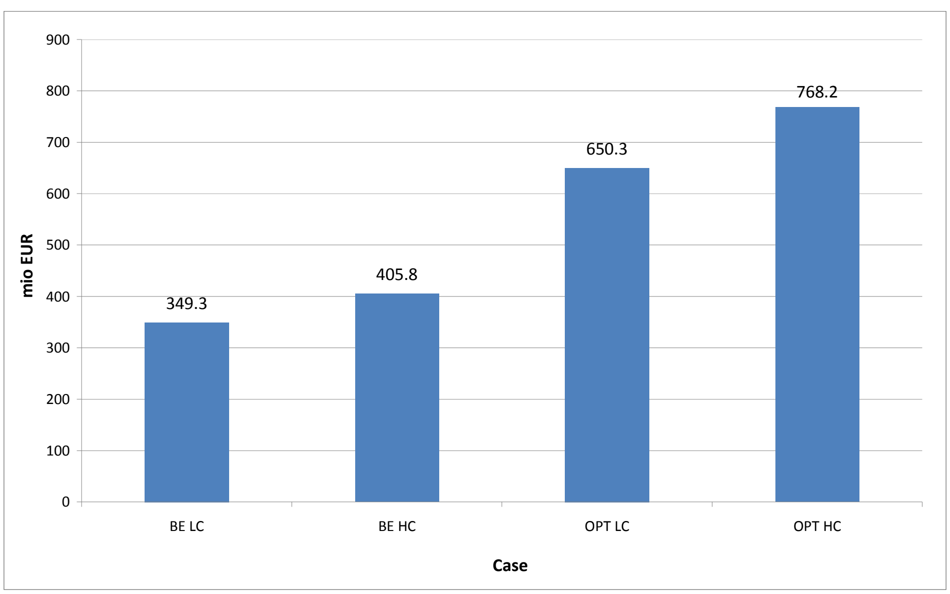


Figure 5.4: Additional System Integration Cost for Europe

It is important to note that these calculated costs are an optimistic estimation, since due to the magnitude of the analysis, it was necessary to simplify some elements of the problem. For example, the model focuses on transmission infrastructure between countries, with internal networks considered as unconstrained. Hence the additional System Integration costs results exclude any additional costs associated with management of transmission congestion within individual countries.

Comparing the annual operational costs of power generation to the additional system integration costs reveals that the latter form an extremely low part (less than 1%) of total operational costs of power generation in 2015. Hence the gross benefits largely outweigh the associated increase in system integration costs. The difference between both, the aforementioned net benefits, have however to be compared to the increased grid investments to obtain a complete cost-benefit assessment from a societal perspective. Wind energy related additional system integration costs, on a €/MWh basis, are as follows:

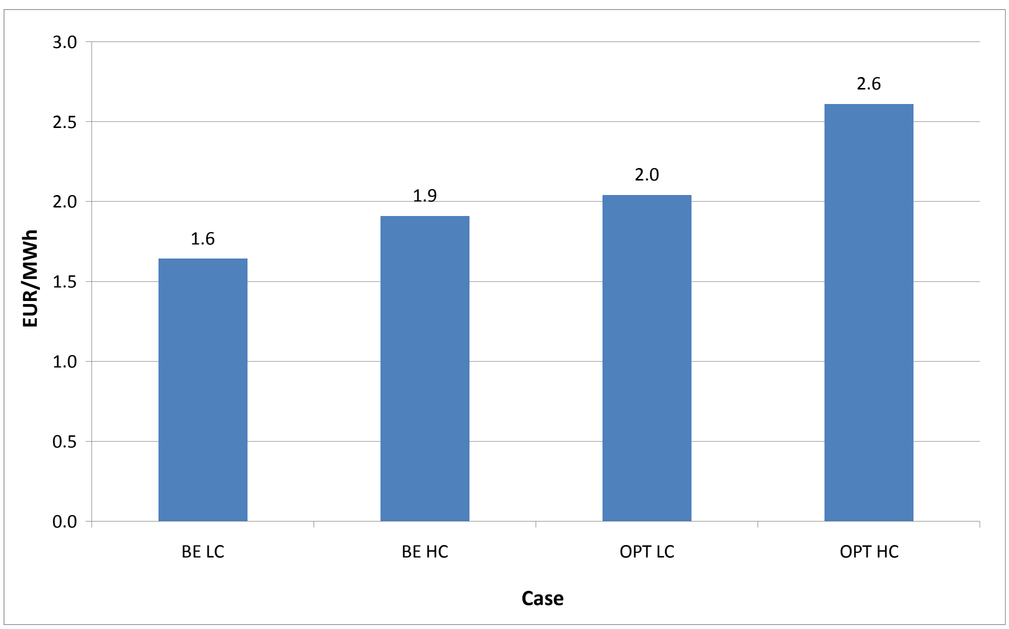


Figure 5.5: Wind Energy Related System Integration Costs

Under 'Best Estimate', the System Integration Costs equate to an additional cost of between €1,60 to €1,90 per MWh of wind energy generated and under 'Wind Optimistic', the System Integration Costs correspond to an additional cost of between €2,00 to €2,60 per MWh of wind energy generated.

The System Integration Costs break down into its component parts as follows:

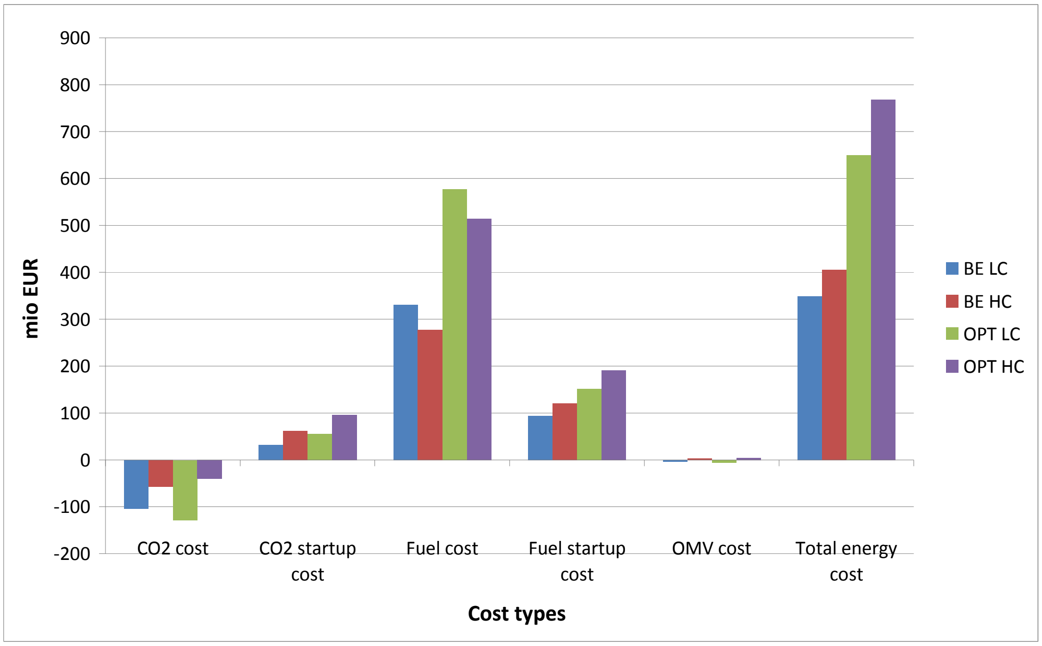


Figure 5.6: Breakdown of System Integration Costs

As can be seen from Figure 5.6, by far the most significant component of the System Integration Costs is associated with additional fuel required to increased part-load operation of non-wind power stations due to the fluctuations of wind. Compared to the additional CO2 and fuel costs, variable operation and maintenance costs (OMV costs) are negligible.

There are some aspects of Figure 5.6 that initially seem counter-intuitive. These are driven to an extent by the boundary conditions that feed into the model:

- CO2 integration costs are shown as negative

It could be expected that the intermittency of wind, which requires conventional power stations to cope with it, would result in a positive CO2 integration cost. However, Figure 5.6

shows this not to be the case. Negative CO_2 integration costs arise from the fact that the model is set to optimise total costs and, if it is cheaper to use a generation technology with a high CO_2 cost and lower fuel cost, the model will do so. Hence, more lignite and coal is used in the case with excluded wind uncertainty than in the best estimate and wind optimistic scenario cases and consequently CO_2 costs are reduced when flexible gas plants step in in these scenarios to cope with the fluctuating wind energy.

- Integration costs related to CO_2 start up costs increase whereas those related to fuel costs decrease with higher fuel/CO_2 prices

As fuel and CO_2 prices increase, the merit orders of some countries are significantly affected. Within the scenarios the gas price increases more than coal which, taking emissions and efficiencies of old and new plants into account, causes coal units to become cheaper relatively to gas units. A higher clean dark spread than a clean spark spread is inducing this switch. The fuel price increase has a more significant cost impact than the increasing costs of higher CO_2 emissions in coal plants, causing these to be used more frequently for balancing wind energy, e.g. through part load operation.

To make analysis at a country level is more difficult as the conversion of wind energy from an intermittent to a constant source of power affects the interconnected merit orders of individual countries, and hence the scheduling of power stations, in a complex and non-linear way. This then affects exports and imports between countries; the overall effect being that, whilst aggregate costs are correct, the distribution of the costs at a country level becomes difficult to interpret.

5.3.3 Conclusions

The results of the model runs show that the additional System Integration Costs form a very small percentage of the overall absolute cost of energy across Europe in 2015. System Integration Costs are also small compared to the net benefits seen at region level. As highlighted in the Denmark case, the importance of interconnection cannot be under-estimated – it is vital to allow power generated in windy regions to get to those regions that contain large concentrations of coal & gas plant so that the maximum fuel savings and CO_2 reductions are realized.

5.4 Grid reinforcements till 2015

5.4.1 Introduction

When departing from the 2015 grid typology and assessing the impact of the added wind, TSOs identified some grid reinforcements that are necessary to handle the additional power flows on the system. This category of grid reinforcements, are labelled as Risk Mitigation Measures (RMM). For the concerning timeframe (2008 – 2015), Risk Mitigation Measures were divided into short term investments and longer term investments. The short term Risk Mitigation Measures are associated to the Best Estimate scenario, and the longer term Risk Mitigation Measures to the Wind Optimistic scenario.

Information on Risk Mitigation Measures was collected from TSOs for the following countries: Austria, Belgium, Czech Republic, France, Germany, Great Britain, Ireland, Poland, Portugal, Spain and the Netherlands.

Generally, Risk Mitigation Measures mainly represent internal grid reinforcements and almost no cross-border reinforcements, which results from the relatively short time horizon considered. Mitigation measures include mainly reactive compensation, new circuits, new substations, new transformers or phase shifter, grid reconfiguration and automatics.

5.4.2 Cost of Risk Mitigation Measures

The costs associated with the Risk Mitigation Measures were calculated separately for each scenario. The total Risk Mitigation Measures cost for a particular scenario is aggregated for the relevant countries.

The short term mitigation measures for the aforementioned countries amount to 1,4B€ and are considered as potential reinforcements realizable till 2015 for a total of 139GW wind capacity installed. The longer term upgrades are de facto beyond 2015. In the wind optimistic scenario with 181GW total installed wind capacity, both long and short term upgrades are needed and hence amount to 10,5B€ of (mostly internal) grid investments.

The investment cost of the proposed grid reinforcements, annualized using a 7% pre-tax WACC and depreciation period of 50 years, amounts to 48M€/year for the short term mitigation measures and up to 362M€/year for the long term mitigation measures .

5.4.3 Conclusions

When assessing these Risk Mitigation Measures, additional to those already planned, it must be noted that these are related to the additional wind in 2015 compared to 2008. However, on a country level, the costs of these Risk Mitigation Measures are very dependent on where the wind is situated relative to the existing grid infrastructure and load centres. Therefore, it is difficult to give an exact cost figure. Relative to additional wind capacity installed, these Risk Mitigation Measures on a country basis vary from 0€/kW to 928€/kW.

5.5 Support Costs and cost benefit analysis up to 2015

5.5.1 Introduction

In Europe wind power is seen as the most promising renewable technology for electricity production (RES-E) to reach ambitious renewable targets set by the European Commission in the short to medium term. Even if power prices have increased in the last years still support is needed to facilitate investments. In European countries a variety of support mechanism is currently in place. From a societal viewpoint through these support mechanisms money is transferred from consumers to wind power producers in order to close the gap between the wholesale power price and the so called "long run marginal cost" of wind power.

5.5.2 Definition of support cost

Support cost - i.e. the net transfer costs for consumers (society) – due to RES-E support are defined as the financial transfer payments from the consumer to the RES-E producer compared to the reference case of consumers purchasing conventional electricity on the power market. This means that these costs do not consider any indirect costs or externalities (environmental benefits, change of employment, etc.).

There are two basic approaches in place for supporting RES-E:

- Price driven support instruments
- Quantity driven support instruments

Under price driven instruments RES-E is sold at defined tariffs (prices) – so called feed-in tariffs (FIT) – which are guaranteed for a defined period of 10 to 20 years. A more market oriented approach is the feed-in premium (FIP) system that provides a bonus (premium) additional to the market price for any produced MWh RES-E.
Quantity based support schemes instead define the share (quantity) of RES-E that has to be purchased by end users in a defined period of usually one year. In practise retailers ensure that their consumers have fulfilled the quota by presenting a corresponding amount of certificates for purchased RES-E.

In order to introduce more flexibility in such a system these certificates may be traded among power market actors. In this case the price of the so called Tradable Green Certificates (TGC) reflects the difference between long-run marginal cost3 of the marginal RES-E technology and the corresponding market value.

In general specific support cost (e.g. per MWh wind) result from the difference between the resulting specific remunerations (per MWh wind) and the market price for electricity4. More specifically, in a FIT scheme specific support cost result from the difference between FIT and the market price for conventional electricity, while for FIP and TGC schemes the Premium and the price for the TGC itself reflect support cost respectively. This relation is illustrated in Figure 5.7 for the exemplary case of a Quota System based on Tradable Green Certificates (TGCs).

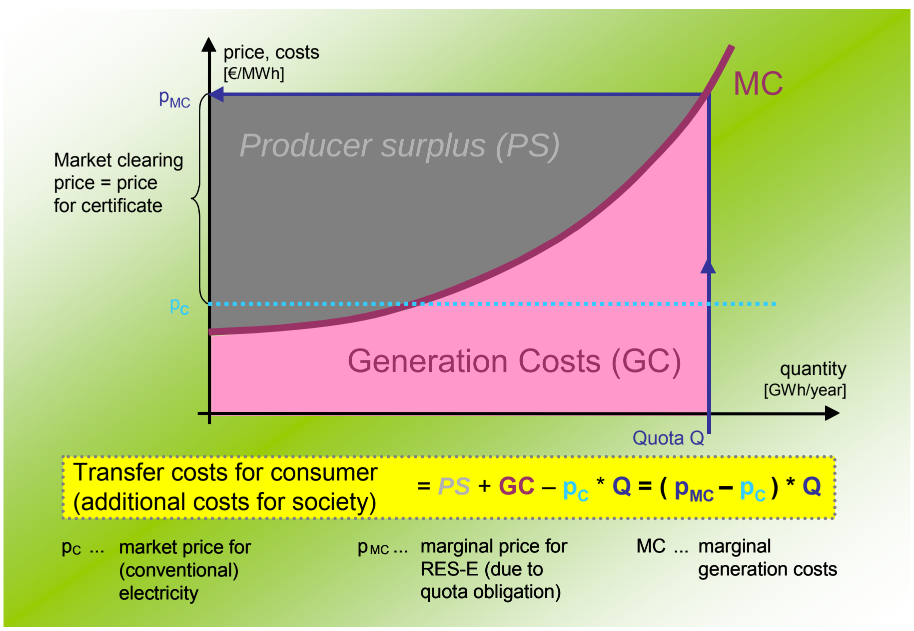


Figure 5.7: Calculation of transfer cost for consumers for a TGC system

The resulting revenues the generator receives have to cover the LRMC i.e. both CAPEX and OPEX and are partly covered by support cost. Depending on the cost allocation policy

[3] The Long Run Marginal Cost (LRMC) are the electricity generation cost taking into account both fixed and variable cost. LRMC are expressed in specific terms (€/MWh).

[4] More precisely the average market value of RES-E has to be taken into account that may also deviate from the average wholesale power price. In the case of wind power usually the baseload price, i.e. the price a generator with constant power output sees on the market, is used as a reference.

CAPEX and OPEX may include cost components related to grid and system integration. This has to be considered when deriving total wind integration cost.

5.5.3 Actual support cost

Support costs in absolute terms vary significantly between the investigated countries due to the fact that newly installed capacities vary to a large extent. The total support costs for existing installations (end of 2007) in investigated countries amount to 6,1B€ per year under the assumption of 2009 support levels and low boundary conditions. Total costs for supporting new installations (2008-2015) are about twice as high (12,7B€ per year) for the "Best estimate" case and triple as high (18,7B€ per year) for the "Wind optimistic" case.

For existing installations 97% of support cost (5,9B€ per year) refer to onshore wind. Due to an increasing utilisation of offshore wind this share is considerably lower for future installations up to 2015 with 62 % (best estimate) and 59 % (wind optimistic) respectively.

Actual support costs vary considerably between countries. Specific support cost range from 0 to 115 €/MWh for wind onshore and from 0 to 145 €/MWh for wind offshore. Specific support costs are comparable for both deployment scenarios. In countries with ambitious offshore targets actual support for wind offshore is significantly higher than for wind onshore. This fact reflects the still less favourable economics of offshore wind.

5.5.4 Actual vs. optimal support levels

A comparison of actual support with an optimized support cost would allow a cost optimal achievement of the pre-specified wind capacity targets. In many countries actual support levels are far below optimal ones. In these countries there is still improvement for the actual support level necessary in order to reach capacities as specified in the "Best Estimate" or "Wind optimistic" scenario. In other countries, actual specific support costs are estimated to be significantly higher than in an optimal design. In these countries there is still room for supporting wind power more efficiently. Thereby, the elimination of unnecessary risk that has to be born by the investor is a key for future policy improvements[5].

For countries with offshore deployment, optimal support levels are usually higher than for wind onshore due to less favourable economics like mentioned before.

5.5.5 Support cost on European level

Figure 5.8 shows that overall support cost range from 11,1B€ to 12,7B€ per year for the “Best estimate” scenario and 16,5B€ to 18,7B€ per year for a deployment up to 2015 according to the “Wind optimistic” scenario.

For the two wind deployment scenarios support cost for wind offshore become significant on European level. Their share in overall support cost ranges from 35 to 42%. A comparison of results for low and high boundary conditions illustrates, that support cost are sensitive to the level of wholesale power prices. Increasing fuel and CO2 prices as foreseen in the high boundary scenario reduce support needs by 12% in the case of actual support and 28 to 33% for optimal support. Optimal technology specific support levels allow to lower support cost by 22 to 30% in the low boundary scenario and by 36 to 46% under high boundary conditions.

[5] Risk is related to an investor’s uncertainty on future earnings. For FIP and TGC schemes one source of uncertainty is the power price development over the life time of the wind farm. For TGC schemes additionally the support scheme itself introduces uncertainty due to the uncertain development of certificate prices. A rational investor reacts on a higher risk with a higher expectation on the rate of return that means higher support cost for society. Therefore one measure to lower support cost is the minimisation of risk for the investor through a proper design of the support mechanism (cf. Resch et al. (2009)).

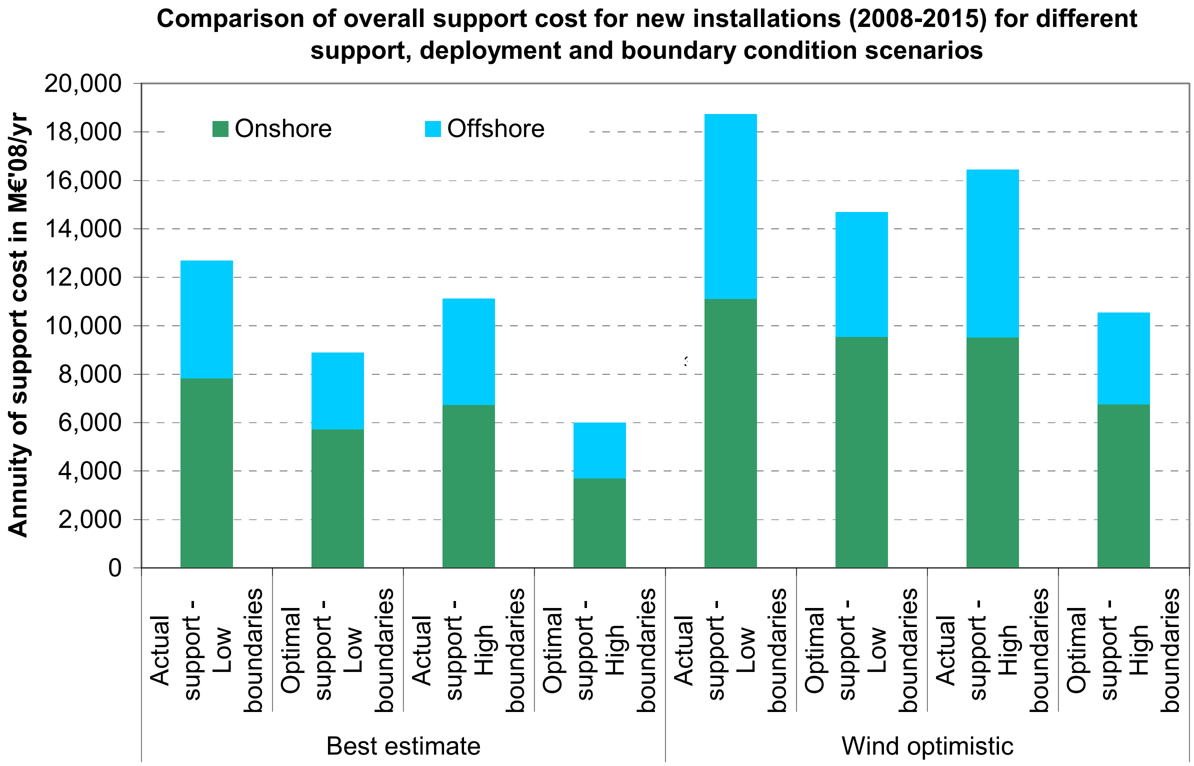


Figure 5.8: Comparison of support cost for new installations in absolute terms on average per year in the period 2008-2015 for different investigated scenarios on European level.
Assumptions: support normalized to 15 years, numbers in €'2008. Sources: Green-X, update of Ragwitz et al. (2007).

Summarizing support cost are determined by a number of parameters including

- the supported amount of wind power,
- the power price level,
- the quality of available wind potentials,
- the amount to which these potentials are exploited,
- the share of wind onshore and offshore,
- and the specific design of the support scheme (support level, support duration, associated investors risk)

5.5.6 Cost benefit assessment up to 2015

Besides assessing several benefit and cost components of increasing wind power penetration in Europe also a synthesis may be derived. Hence the resulting net effect may be derived, however with a clear limitation to the period of investigation which covers the years up to 2015. The benefits are related to the reduction of operational cost as assessed in section 5.2. It should be noted that benefits due to the reduction of green house gas emissions are reflected only partly as the assumed market-based CO2-certificate prices are likely not to reflect the actual externalities to a full extent. [6] On the other hand considering additionally the so-called „merit-order effect“ of wind energy would result in double counting, since the benefits of reduced usage of conventional plants are already included in the reduction of operational costs. In Table 5.1 below, the gross benefits are given, since these correspond to the benefits before taking into account the system integration costs resulting from the fluctuations of wind energy.

These system integration costs are indicated separately in the next row in Table 5.1, referring to the analyses carried out in section 5.3. Further rows include the grid reinforcement cost allocable to wind power (cfr. section 5.4) and the capital and operational cost of wind power. The grid reinforcement costs have been transformed into annual costs assuming a real interest rate of 7 % and a lifetime of 50 years. For the cost benefit analysis, the annualized capital and operational cost of wind power have been considered because a cost benefit analysis has to be carried out at a societal level, not considering transfer payments between societal groups like support costs. Instead for wind energy as like for conventional power production, operational costs and capital costs have to be included.[7] Moreover, the consideration of the net support costs as investigated above would already include a deduction of the market value of the delivered wind energy as benefit to the system. This benefit is however quantified in Table 5.1 through the reduction in operational costs. Hence considering net support costs as discussed above would result in a double counting of benefits. Instead societal costs and benefits include the annualized investment and operational costs for all technologies included in the energy system.

[6] Cfr. e.g. the analyses carried out in the WindFacts project.
[7] Given the intermittency of wind energy, savings in capital costs for conventional technologies will be rather limited and have not been considered here.

Hence Table 5.1 summarises the results for costs and benefits of adding wind power to the system for different wind deployment and framework scenarios up to 2015. Net costs to the system due to additional wind turn out to be positive in all scenarios, meaning that the net benefits of introducing wind into the European power system are negative at the considered time horizon. This does however not allow any firm conclusions on the longer run. Rather in a longer time perspective, investment cost of wind power are expected to decline due to the effect of technological learning and at the same time fuel and carbon prices are likely to increase, so that an integral cost-benefit analysis of wind energy is likely to provide more positive results.

Table 5.1: Summary of costs and benefits

Cost in B€/yr	**Best estimate**		**Wind optimistic**	
	Low boundary	**High boundary**	**Low boundary**	**High boundary**
Gross benefits of wind power integration (i.e.operational cost reduction)	-10.2	-13.1	-15.0	-19.4
Increase in system integration costs	0.4	0.4	0.7	0.8
Grid reinforcement cost	0.1	0.1	0.8	0.8
Capital and operational costs of wind energy	19.1	19.1	28.9	28.9
Net Costs to System	**9.4**	**6.5**	**15.4**	**11.1**

5.5.7 Conclusions

Results indicate that there are substantial integration costs for wind energy in the order of 0,5B€ to 1,6B€ per year, related both to the fluctuations inherent to wind energy and the necessary internal grid reinforcements. However these integration costs are rather small compared to the gross benefits of wind power integration in terms of operational cost reduction which are between 10B€ to 20B€ per year. Yet such an analysis would also be incomplete without considering the capital and operational costs of wind energy.

The level of support required highly depends on the power price level, the quality of wind resources, the degree to which these resources are exploited and the specific design of the support scheme. The comparison of actual and optimal support shows that there is still room for future policy improvement. In some countries the support level has to be increased in order to meet deployment scenarios specified in EWIS, in others the support level significantly exceeds the optimal level determined by model calculations. In the latter case the elimination of unnecessary risk that has to be born by the investor is a key for future policy improvements. In order to reach ambitious wind power targets as specified in the EWIS “Wind optimistic” scenario, aside sufficient economic incentives, also supportive non-economic framework conditions are required. In this respect existing barriers like complex planning procedures (land use permits, environmental impact assessments, etc.) and the lack of grid infrastructure still have to be overcome in most European countries.

For a detailed investigation of several aspects related to renewable support we refer to the Intelligent Energy for Europe projects OPTRES and Futures-e (see www.optres.fhg.de/ and www.futures-e.org/). An overall assessment of the costs and benefits of wind energy in the year 2015 leads to additional costs to the system between 6.5 B€ and 15.4 B€ depending on the level of wind deployment and the development of framework conditions. However this is a medium-term perspective which does not account for longer term decreases in cost and increases in benefits of wind energy.

5.6 Operational Mitigation Measures

In order to improve the integration of wind energy several operational mitigation measures may be envisaged. These are evaluated in the subsequent sections. More far reaching mitigation measures related to an enhancement of the cross-border connections in the European power grid are investigated in chapter 6..

5.6.1 Wind Power Curtailment

The possibility to curtail wind can be a solution for situations with too low load for a given wind generation or for specific congestions in the grid. For the selected scenario of Optimistic Wind in 2015, EWIS studied the impact of the possibility of curtailment. Important to quote is that the internal constraints in Germany are not modelled in the study.

Total wind curtailment is only 0,11 TWh. From total wind power production 435,4 TWh, i.e. only 0,03% is curtailed. As stated earlier, this figure is not taking into account the internal constraints. In the scope of this study and with applied assumptions, the overall impact of wind curtailment on costs and electricity prices is neglect able. Wind curtailment is used extremely little even if wind power can be curtailed without compensation to the wind power producers. However one has to be aware that this analysis has been performed without taking into account internal bottlenecks of the transmission and distribution grids in the EU member states.

Hence allowing the grid operators to curtail wind is not expected to decrease considerably the benefits of wind power production to society nor the revenues for wind power producers. However one has to be aware that this analysis has been performed without taking into account internal bottlenecks of the transmission and distribution grids in the EU member states

5.6.2 Demand Side Management

5.6.2.1 Introduction

Demand side management (DSM) units are able to reduce consumption on the day-ahead market and provide up-regulation through reduced consumption on the intra-day market. The basic hypothesis is that DSM will imply a cost reduction which in EWIS is quantified by comparing two model runs with and without DSM. The amount of statistic data on the fees for delivering DSM is very limited. Therefore, a value of 100 €/MWh has been chosen.

5.6.2.2 Results

Total usage of DSM in the model for all Europe is 2,0 TWh. Mainly the use of natural gas and lignite is reduced. Overall impact of DSM on electricity prices on the intra-day market is small to neglect able. No country has a price impact higher than 0,15 €/MWh.

5.6.2.3 Cost reductions

Table 5.2 shows the cost reductions associated with DSM. Total costs are reduced by 89 M€/year. The only cost component that is increased is OMV costs - due to modelling of DSM units allocating costs as OMV costs.

Table 5.2: Cost savings due to DSM [M€/year]

CO_2	CO_2 startup	Fuel	Fuel startup	DSM activation costs	Other OMV costs	**Total**
100	2	163	23	-205	6	**89**

Based on the hypothetical assumptions made in this analysis, it has been shown that the impact of DSM is very limited.

5.6.3 Flexible Line Management

5.6.3.1 Introduction

Flexible Line Management (FLM) is an approach to compute the thermal rating close to real time, so that in favourable environmental conditions a thermal rating higher than the conventional static rating can be utilized. Whilst the concept per se can be used generically, other restrictions for safe grid operations, e.g. dynamic behaviour of the grid, remain. The FLM example looked at in the Wind Optimistic with high boundary conditions shall only be considered to show the economic effects of one single change in coupled markets rather than saying something about the technical viability of the example chosen.

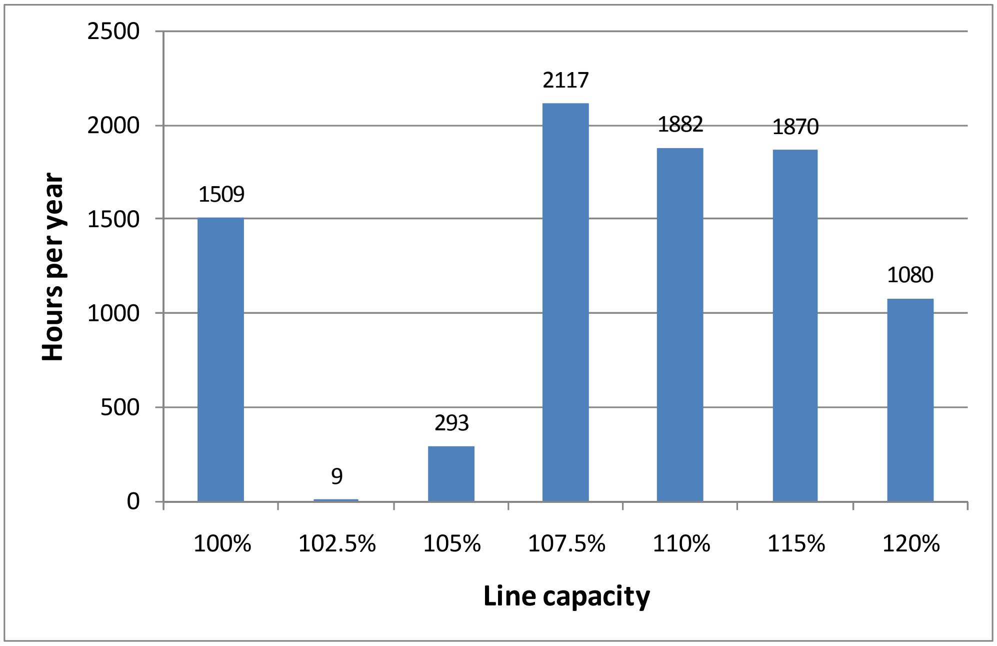


Figure 5.9: Hours of enhanced line capacity in 2015

To show the effects of FLM these capacities are modified using an hourly schedule. The capacity schedule is derived from historical data on wind speed, temperatures and wind direction. In case that temperatures are cooler than in the design case, or when orthogonal and intensive wind is blowing, the thermal rating of the line is increased compared to the standard case. Figure 5.9 shows these enhanced capacities, ranging from the nominal 100% capacity up to 120 % of nominal capacity

5.6.3.2 Results

Introducing FLM at the selected border has a direct effect on the flows between these countries but also an indirect one. This is due to the fact that increasing flows on the selected cross-border impact also other interconnectors via modified power plant operations in the concerned countries and the applied PTDF matrix. But also the indirect effects of interconnected markets are clearly observed, a shifting of energy of 4TWh between affected countries.

In terms of change of fuel source for the electricity production wind power is only one part of the whole picture. In general power plants with lower variable cost profit from the higher exchange and this encompasses – apart from wind – also production from lignite and nuclear. Summing up the direct and indirect effects, the total savings due to FLM at the selected border on a European level reach ~26 M€/year. They are mainly driven by fuel savings (14M€) and CO2 savings (12M€) while savings in start-up cost and OMV play a minor role.

The costs of FLM are difficult to estimate because they are highly dependent on the existing infrastructure. First there is some IT-infrastructure (including stations that monitor weather data) that has to be integrated into the control systems of the respective TSOs. Secondly and more important there is the uncertainty which parts of the grid can be operated at more than a 100% nominal level. It can be assumed that in current grids, single parts of the system are inherently able to be operated at levels above nominal level, while some other crucial parts constitute the boundary conditions that yield in the nominal rating. These have to identified and changed. Published data on costs of FLM are scarce[8]

5.6.3.3 Conclusion

The effects of FLM in the example shown can be parted into two categories. First, the direct effects of this measure include the changes of the production in directly linked countries. Second, the indirect effects caused by the changes in the production costs and balances in a directly linked country, including notably lower exports to other indirectly countries and enabling also more flows on other borders. This also causes changes in the production of these indirectly linked countries.

The results indicate that flexible line management can play a certain role in the European power system. It is a measure which reduces overall generation cost and helps to transport wind power around Europe at rather low investment costs..The results indicate that the FLM seems to be an additional measure which could help to integrate wind power in a more cost efficient way. But it is not seen as realistic to achieve substantial increases on all needed interconnector capacities in Europe. Therefore it must be underlined that it is

[8] (cfr. for example *http://www.eonnetz.com/pages/ehn_de/Presse/Reden_und_Praesentationen/pressekonferenz_freileitungsmonitoring_20_09_2007.pdf,* where 4M€ of costs are given for a some 200 kilometers for high voltage grid.

hardly capable of replacing investments in real line extensions, which have to be considered as lumpy.

5.6.4 Storage

5.6.4.1 Introduction

In the EWIS study, cost and benefits of the application of large scale energy storage have been analysed. The analyses looked both at the added value of large scale energy storage for increasing the technical scope for integration and the value of large scale energy storage for optimizing the integration of wind energy. Analyses with and without extra pumped storage capacity have been made in the reference scenario and compared with the results in the wind optimistic scenario.

The following options have been considered:

- Pumped hydro energy storage in Spain (4.6 GW over the pumping capacity considered in the EWIS reference case), Germany (1 GW with storage content of 5GWh[2].) and the Netherlands (1.5 GW – OPAC 16GWh storage content with 79% cycle efficiency)).
- Compressed air energy storage (diabatic) in Germany (4.2 GW of CAES capacity with 1,6 GW of compressor power and a storage volume of 12,8 GWh)
- Use of Nordic storage by increasing interconnection capacity with 1.5 GW from the CWE region to Norway.

The storages analysed are supposed to be installed after the year 2015 (some additional 2-3 GW are nevertheless expected in Spain by this horizon) and are on top of the facilities coming on line until the year 2015, mainly in Austria with approximately 1.6 GW.

5.6.4.2 Main results

The central conclusion of the analyses is that, on the basis of the assumptions made, large scale energy storage offers little added value in relation to the operation of the European electricity supply system, except for Spain (cfr. 5.6.4.3). Electricity production from wind can, already without extra storage, mostly be integrated in the European system and can help to prevent wind curtailment.

However, storage has an economic benefit, because the variable operation cost of the electricity system are reduced: expensive peak generation can be replaced by generation from storage, which was filled with cheaper off-peak generation. This paragraph shows a rough comparison of these benefits with the cost.

Figure 5.10 gives an overview of the main findings. It shows a global overview of the cost and benefits when introducing additional large scale energy storage into the European system or increasing the interconnection capacity to Nordic storage. Both costs per country and average benefits for the whole European dispatching are normalized to installations of 1GW. The green striped area shows the range of the annual operational cost savings in average for the whole European dispatching (fuel, CO2 and variable O&M cost) that were found when the different storage technologies are added to the system in the reference scenario. The yellow area gives the same information for the scenario Wind optimistic. In the same graph estimates of the annual fixed cost ranges (capital and fixed O&M cost) are shown for the different storage technologies. The right hand side of the same graph shows the comparison of costs and benefits for increasing the interconnection capacity from CWE region to the Nordic area in the scenario Wind Optimistic.

The graph shows that the variable cost reduction by storage decreases at higher levels of installed wind capacity in the Wind Optimistic scenario, compared to the reference scenario. This is caused by the fact that the difference in peak and of peak cost decreases in general if more wind is brought into the system. Nevertheless, the model has not considered the possible optimization of consumption and production of energy in weekly or seasonal cycles. So, the calculated benefit is in those cases underestimated.

The saving after applying storage decreases roughly from a range between 50 to 90 M€ per installed GW of storage in the reference scenario to a range between 40 to 55 M€ per year in the scenario wind optimistic.

The graph clearly shows that introduction of large scale pumped hydro storage appears not to be economic in the Netherlands, because of the very high capital cost. To a lesser extent this is also true for the CAES in Germany.

Because of the relative low capital cost to increase the storage capacity in the Alp region and Spain, installation of extra storage capacity could be beneficial.

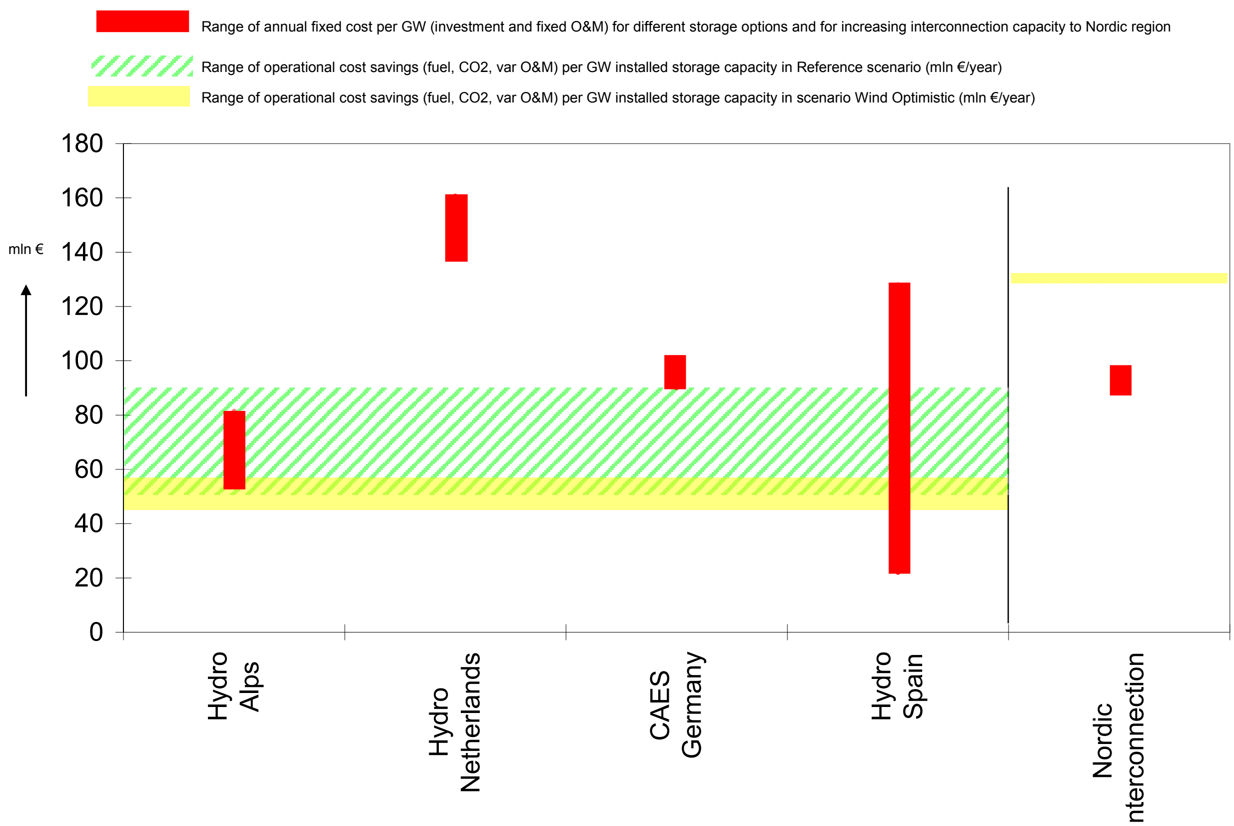


Figure 5.10 : overview of the cost and benefits when introducing large scale energy storage into the European system or increasing the interconnection capacity to Nordic storage

The use of Nordic storage by increasing the interconnection capacity from the CWE region to Norway results in much higher variable cost savings, compared to the variable cost savings that can be achieved by building storage with equal capacity in the CWE Region. The graph shows that from a cost-benefit perspective, increase of interconnection capacity from the CWE region to the Nordic area could be beneficial

5.6.4.3 Storage in Spain

When looking in detail at the Spanish electrical system, it can be observed that the daily load curve is particularly characterised by the strong difference between peak and off-peak consumption, which some days reaches a ratio of 2,5. This is not the case for neighbouring European countries, in which the demand curve shows a more flat shape. Moreover, wind power has historically increased the peak/off-peak net demand ratio in Spain, since statistics show a higher wind production in off-peak hours (typically at night). This behaviour of the Spanish net consumption (demand – wind production) has consequences in the reserves for covering variability and therefore in the need of started generators some hours prior to the peak consumption. As a result, and due to the lack of sufficient interconnection capacity, the leeway for wind power is constrained by the need of having operative thermal generation to cover demand some hours later. In REE analysis, this constrained situation has been stated especially in windy seasons (March, April) in which significant spillages could happen, if no measures (additional interconnection capacity, peak generation, additional pumping) are taken.

5.6.4.4 Conclusion

Storage has an economic benefit, because the variable operation cost of the electricity system are reduced: expensive peak generation can be replaced by generation from storage, which was filled with cheaper off-peak generation. The analyses show that the variable cost reduction by storage decreases at higher levels of installed wind capacity in the wind optimistic scenario, compared to the reference scenario. This is caused by the fact that the difference in peak and of peak cost decreases in general if more wind is brought into the system.

One can conclude that the overall impact of storage extension measures is lower than expected, except for Spain where electricity storage can help to prevent wind curtailment. Because of the relative low average capital cost to increase the storage capacity in Spain (around 950€/kW), installation of extra storage capacity could be beneficial. The conclusion for Spain is most likely also valid for the hydro systems in the Nordic area and in the Alps.

The use of Nordic storage by increasing the interconnection capacity from the CWE region to Norway results in much higher variable cost savings, compared to the variable cost savings that can be achieved by building storage with equal capacity in the CWE region.

Introduction of large scale pumped hydro storage appears not to be economic in the Netherlands, because of the very high capital cost (around 1,700€/kW). Also adding compressed air energy storage (CAES) in Germany seems not to be attractive from an economical point of view.

5.7 General Conclusion

Wind brings significant savings in the annual operational costs for electricity generation in Europe. But when assessing the net cost to the system of wind integration in Europe from a societal perspective, it is necessary to offset these net benefits of wind power (reduction in operational costs with increase in additional system integration costs) versus the needed grid reinforcements, additional mitigation measures and the capital and operational costs of wind energy.

For TSOs, the cost for internal grid reinforcements may be substantial and also the system integration costs, although considerably lower than the gross benefits of wind energy, reach 350M€ to 770 M€ per year and have to be compensated by corresponding additional revenues.

Operational Mitigation measures may substantially alleviate the integration cost for wind energy. Thereby Wind power curtailment will be mostly needed to handle extreme cases and also the use of Demand Side Management is found to be not too important up to the year 2015. Even in the Wind Optimistic scenario with high boundary conditions the corresponding savings are expected to reach only 89 M€ per annum. Flexible Line Management using dynamic thermal rating could be an opportunity for contributing to a certain extent to improving wind integration. But it is not seen as realistic to achieve substantial increases on all needed interconnector capacities in Europe. Also an increased use of storages may provide substantial benefits to the system, yet it will only be cost efficient, if the investment may be realised at low costs.

6 Enhanced network beyond 2015

6.1.1 Introduction

Investments in interconnectors might be valuable, in order to reduce the overall investment and operation cost of a power system. The reason for this is that inefficient operation of power plants due to congestion is avoided and that interconnectors might reduce the necessary amount of backup capacities. In relation to wind, interconnectors also offer the possibility to exchange flexibility between adjacent regions. Unexpected and/or volatile wind in-feed has to be covered by a reduction of conventional generation or it has to be transported towards a neighbouring country. If units in a neighbouring country can offer the required flexibility in production with fewer costs, interconnectors can be used to reduce the integration cost of wind. The benefits of interconnections should not be evaluated only in the view of wind integration, but from the point of view of the power system, also taking into account all cost savings due to increased trading. Within this sensitivity run of the EWIS study, impacts of the enhancement or introduction of 29 European interconnectors are investigated. The run is based on the "standard" run from the core study of EWIS, the "wind optimistic with high boundary conditions" and the reference year of 2015 is chosen. This is done in order to highlight the welfare benefits of increased interconnection and its value for wind integration. It has to be stressed that for real world decisions on additional interconnections, also other years, other scenarios and long run issues as saved investments into power plants should be considered. [Turvey 2008][9] gives an overview on the issue of interconnector economics. In addition, the off-shore wind park "Kriegers Flag" was introduced as a new region whose wind capacities are part of the region Germany in the standard case. The new region has three interconnectors to Denmark East, Sweden and Germany in order to demonstrate possible effects a "Super-grid" in the Baltic Sea could have if realized.

[9] Turvey, R.: *Interconnector economics*, in Energy Policy, Issue 34, no. 13, pp.1457-1472

6.1.2 Detailed Methodology

6.1.2.1 Selection of lines

Due to the fact that interconnector investments are costly, it is not very likely that all lines within Europe are extended in the future. Within the EWIS study some efforts were made to identify those line extensions which are most valuable in welfare terms. For a full economic ranking of alternatives, all different possibilities would have to be investigated by detailed modelling. In this case, a simplified approach is chosen for line selection. The identified lines on which to be focused are selected based on three issues:

- Shadow values of interconnectors or the marginal values of restrictions. These values are extracted from the load flow restrictions of the applied market model. In case of DC lines the shadow value can be understood as the price difference between adjacent regions. In case of AC lines the impact of flows on other lines is implicitly covered by the marginal value.
- Congestion statistics: In view of the TSOs it is regarded as critical whether an interconnector was congested during long periods a year. Therefore also congestion duration curves for all existing borders are investigated.
- Beyond pure market aspects, also technical reasons for stronger interconnection are identified by some involved TSOs.

In total 29 line enhancements or newly built interconnectors are identified for potential beneficial wind integration and market operation (see Figure 6.1 with arrows showing indicative position for interconnectors between countries). Important to quote is that the associated investment costs are not solely linked nor cannot be allocated to wind as consumers and producers benefit from this extra capacity.

The optional increase of pump storage power plants from today ca. 1,6 GW up to 4 - 5 GW in 2015 and beyond 2015 in Switzerland is not considered in the market model. Under consideration of the upcoming increase of pump storages, the congestion between Germany and Switzerland, and also between Germany and Austria, will be significant higher in 2015. EWIS beyond 2015 results serve as a starting point for detailed investigations of sustainable offshore grid infrastructure and offshore windpark cluster concepts e.g. for the time horizon 2020/2025.

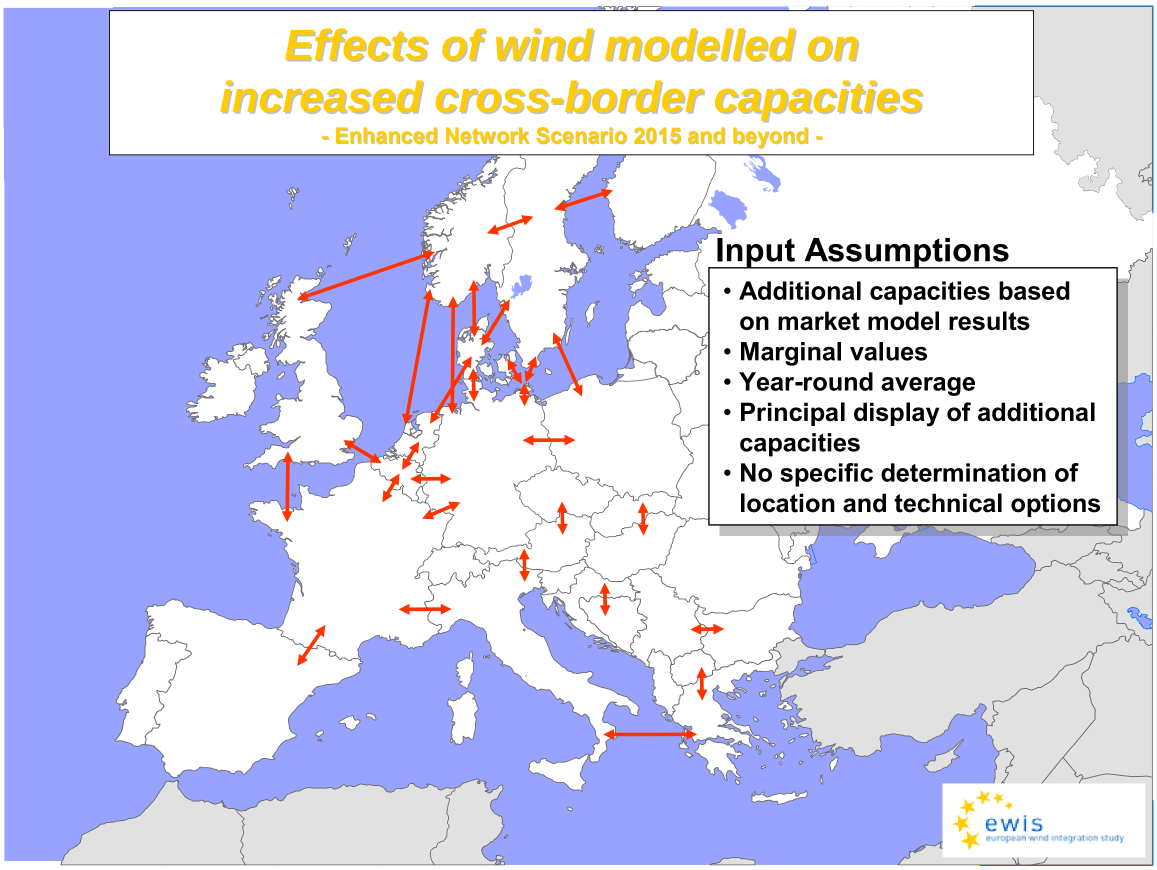


Figure 6.1: Enhanced network scenario

6.1.3 Results

Extending the capacities on a large number of interconnectors and introducing new ones simultaneously makes it very difficult to isolate the effects of single measures. The total exchanged electricity in the European grid raises from 613 TWh to 844 TWh – a raise by 231 TWh or 37,7 %. Due to the additional interconnectors the number of interconnectors in Europe increases from 60 to 68. The enhancement of the European interconnectors has not only effects on the chosen 29 but also on all the others via the applied PTDF matrix.

By directly or indirectly increasing all interconnector capacities, countries with low variable cost production increase their output and sell the additional electricity to countries with higher base prices.

6.1.4 Total enhancements benefits

The total cost savings effect of the investigated enhancement of the 29 interconnectors compared to a situation without the enhancement amounts to 1,925B€. As illustrated in Figure 6.2 the main effect is caused by fuel savings (1B€). Another 0,7B€ are saved by avoided CO2 emissions and the corresponding certificates. This savings are partly caused by the idealised assumption of a constant price for CO2 certificates within the modelling approach. Within a cap-and-trade system such a massive reduction in CO2 emissions would cause a massive drop of the certificate price. This would even increase the cost saving effect. The remaining cost savings amount to 0,2B€. Although only contributing a rather small part to the overall cost reduction this is still a considerable amount..

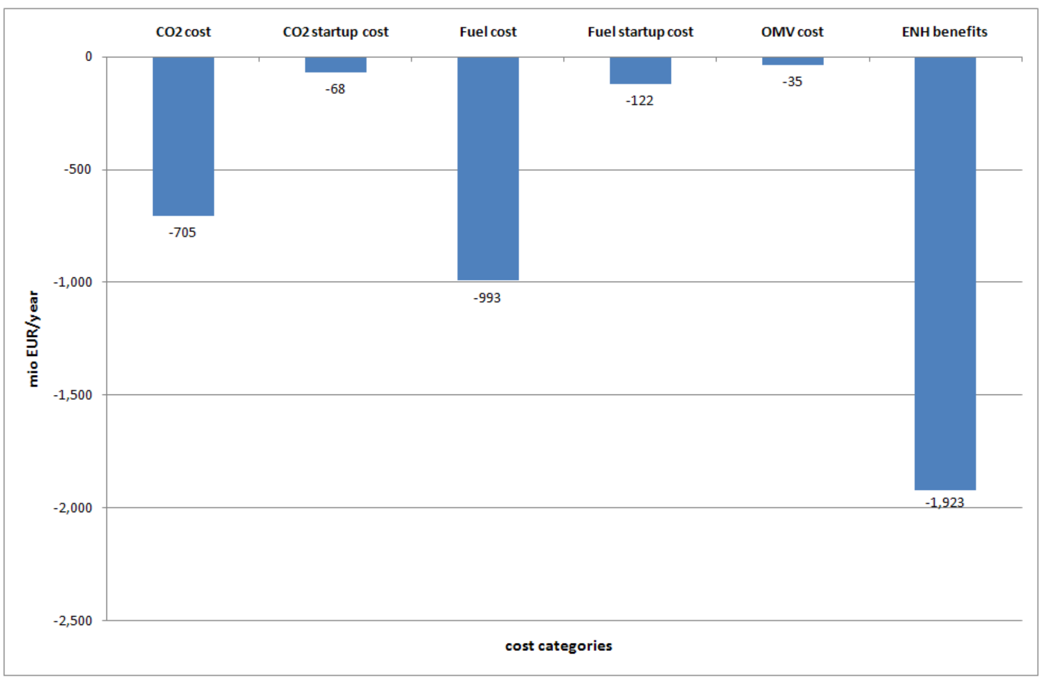


Figure 6.2: Cost savings of the line capacity enhancement per cost category

6.1.4.1 Impact of wind on enhancement benefits

In order to estimate the effects of wind on the enhanced benefits, the benefits of the enhanced scenario within the "wind optimistic" case were compared to the benefits of the enhancement within the "reference" case (see Table 6.1). As one can observe, the line capacity enhancement is already saving about 1,57B€ without any additional wind capacities build between 2008 and 2015. In case of the "wind optimistic" scenario these benefits become even higher indicating that the line capacity enhancement would help introducing higher amount of electricity produced by wind into the European grid.

Table 6.1 : Comparison of enhancements benefits between the reference and the wind optimistic case

Enhanced OPT HC vs OPT HC	Enhanced Ref HC vs Ref HC
-1,925M€	-1,568M€

The additional benefits of wind in the Enhanced scenario versus the Wind Optimistic scenario amount to 357M€. Hence, majority of the net benefits is due to the grid investments, enabling a higher distribution of cheaper produced electricity over Europe.

In Table 6.2 the annual operational cost savings are compared between Enhanced and Optimistic scenario, with resulting additional benefits of wind.

Table 6.2: Comparison of the net benefits

Cases	OPT HC vs Ref HC	OPT HC Enhanced vs Enhanced Ref HC	Net benefits due to Wind
Annual Operational Co Savings	-18.605M€	-18.962M€	-357M€

6.1.5 System integration cost

Following the approach of the EWIS core study, the system integration costs within the enhanced scenario are calculated. It is the deviation of the system operation cost in the wind optimistic case compared with real wind infeed compared to an equivalent infeed without the variability of wind. The negative deviation showed in Table 6.3 indicates that the measure is beneficial for the introduction of additional wind to the system. The savings in additional System Integration Costs due to wind integration amount upto 174M€.

Table 6.3: Comparison of the additional system integration cost versus Reference case

Cases	OPT HC	Enhanced OPT HC	Deviation
Cost	768M€	594M€	-174M€

6.1.6 Cost of cross-border reinforcements

The investment cost of the proposed Enhanced scenario amounts to 12.3B€. The corresponding annualized cost is 896M€ per year using a 7% pre-tax WACC and depreciation period of 50 years. This results in an average investment cost of 426M€ for each of the 29 projects (representing 29,1GW capacity increase) that were proposed. The offshore part within this Enhanced scenario accounts for 8,144M€ (representing 12,1GW capacity) or an average investment cost of 592M€ for each of the 13 offshore projects. Equivalently, the average investment cost of 306M€ for each of the 16 onshore projects identified (representing 17GW capacity).

6.1.7 Conclusions

Comparing the 2015 net benefits of the enhancements in both Reference case (1,57B€) and Wind Optimistic case (1,92B€) to the annualized cost of the cross-border grid reinforcements (0,9B€) reveal the positive economic value of these network investments.

The results of the presented analysis indicate that new lines are rather valuable and that it is interesting to invest in them. However, the EWIS enhanced scenario must be understood as a scenario just giving a feeling on potential cost savings. For a complete analysis the following issues have to be considered too:

- Fuel/ CO_2 cost uncertainty
- Market inefficiencies (no PTDF consideration in markets!)
- Change of merit order curves over time
- Discounting of future benefits
- Allocation of welfare gains on consumers, producers and TSOs
- Demand growth uncertainty
- Savings in conventional power plants
- Uncertainty of Hydro Inflow
- Cost of interconnection

The sensitivity analysis shows that there are significant welfare gains by introducing new grid extensions and reinforcements. It can be shown that new build interconnectors also have a positive impact on wind integration, because flexibility of conventional plants becomes cheaper in a stronger intermeshed power system. The results indicate that there should be further research, especially further sensitivity analysis, in order to identify of most valuable interconnectors.

Enhancements in the European Transmission grid in order to increase the cross-border transmission capacities can yield annual savings in operating costs of more than 1,9 B€. They also contribute substantially to improved integration of wind energy. However, the scenario investigated within EWIS must be understood as one case just providing a first estimate on potential cost savings. For a complete analysis a number of further issues and scenarios have to be considered.

7 Political, Legal and Regulatory Implications

Legal Framework and Context

The legislation relevant to the internal market in electricity and renewable energy sources (RES) can be summarized through the following main documents:

- White paper 1997
- Directive 2001/77 - promotion of electricity from RES
- Directive 2003/54
- Green Paper – share of renewable energy in 2004
- Communication EC (2005)0627 – support to electricity from RES
- Decision 1364/2006/EC guidelines for trans-European energy networks
- Directive 2005/89 – security of electricity supply and infrastructure investment
- Roadmap for RES (COM (2006) 848)
- 2009/28 Directive on the promotion of RES-E
- Third package

In the 1997 White Paper, Europe set out its aspirations to obtain 12 % of electricity from renewable sources (RES-E) by 2010, to reduce its dependence on imported energy sources, reduce CO^2 emissions and create jobs. The white paper contained an action plan focused on creating fair market opportunities for renewables without excessive financial burdens, for example, by giving non-discriminatory access to the electricity market and through appropriate financial supports. The action plan also stressed the need to enhance awareness of authorities, increase cooperation between Member States, and begin to standardize approaches.

In order to enhance the investors' confidence, Directive 2001/77 on the promotion RES-E recognized state aid for renewables. It meant different national support policies could co-exist and, while recognizing that it was too early to create a common framework, it required RES-E guarantees of origin to be mutually recognized. TSOs were required to ensure grid connection fees were cost-reflective and transparent. The Directive also imposed new requirements to provide guaranteed access, priority access and priority of dispatch for RES-E. The 2003/54 Directive further strengthened the market perspective, identified the need to disclose energy sources related environmental impacts, and highlighted important shortcomings, like market dominance and the lack of transparency in the access tariffs, which could constitute obstacles for the integration of RES-E.

The 2004 Green Paper on the share of renewable energy across Europe showed large differences in the progress of Member States towards targets and differences in Member States' abilities to reach their targets. In order to address this issue supplementary action was identified including new financial instruments, enhanced supports for action at local/regional level, measures to strengthen public support and an assessment of the merits of the different technologies. On wind, higher penetration targets were proposed, together with measures to address obstacles and objections to the development of offshore wind. The Green Paper also paid attention to the integration of RES-E from a security of supply perspective.

With the Communication EC (2005)0627 on the support to RES-E, Europe examined further the solutions to optimize the integration of RES-E. It judged competition between different support mechanisms healthy as it was too early to assess and compare pros and cons of these mechanisms. On this basis, coordination was better than harmonization. Stop-and-go measures were identified as being less efficient and more expensive than stable and reliable measures.

The Decision 1364/2006/EC "guidelines for trans-European energy networks" focused on encouraging efficient operation/development of grids and facilitate development and connection of RES-E by creating a more favourable context for technical cooperation between TSO's. It also promoted the integration of islands and remote areas, due to the opportunities for RES-E there. The Decision defined projects of common interest, priority projects and projects of European interest, some of which involve the connection of large wind farms. The 2005/89 Directive on the security of supply and infrastructure investment recognized the link between RES-E and reliability of network through availability of associated back-up capacity.

The Roadmap for RES-E (COM (2006) 848) prepared the ground for the 2009/28 Directive on the promotion of RES-E. Starting from an unequal progress to date by Member States, it defined a long term strategy which would lead to the 20-20-20 target. RES-E targets are now mandatory on Member States with the 20-20-20 Directive objectives supported and integrated in the 3rd package (see recital 6 2009/72 Directive). Establishment of the Agency for the Cooperation of Energy Regulators (ACER) and recognition of the role of the European Network of Transmission System Operators for Electricity (ENTSO-E) to progress market integration measures will address a number of key wind integration issues including, for example, the establishment of a single European Grid Code and collation of a European network development plan.

Legal, Regulatory and Policy implications of EWIS findings

The EWIS findings that are relevant to legal, regulatory and policy areas are as follows:

1) The identification in EWIS analyses of the need for further network strengthening in addition to that already identified in national plans highlights the importance of considering Europe wide market effects in the development of network plans, especially as the proportion of wind generation increases.

The EWIS project has passed candidate reinforcements and operational measures that have been identified in the project to individual TSOs for further refinement and to the team within ENTSO-E developing the Ten Year Network Development Plan (TYNDP). The market modelling capabilities established by EWIS is available for further analysis and future planning. These actions are examples of the co-ordinated action from TSOs to integrate RES-E and wind generation that are sought in policy documents introduced above.

As individual schemes become ready for implementation and will require substantial investments, TSOs will require confidence that associated costs can be recovered. It is likely that many of the additional reinforcement measures will form part of enhanced national plans and so will be considered by National Regulators. However, as these measures will address both national and wider European needs, National Regulators will need to consider the efficiency of such measures with ACER in a Europe-wide context.

To aid this process, TSOs will identify network enhancements in the ENTSO-E TYNDP and may also declare certain projects of common interest to be priority projects or projects of European interest under the 1364/2006 Decision. This may qualify such projects for financial aid provided under the 2236/95 Regulation and may enhance the speed of implementation by having a European coordinator appointed to deal with issues creating significant delay or implementation difficulty. To qualify as a priority project, schemes will need to meet certain criteria concerning their justification and will need to be the subject of specific agreements with policy makers.

2) EWIS has identified the need for the enhancement of network capacity, particularly in the short-term, and this highlights the challenge of obtaining required consents in a timely fashion.

Article 16 of the 2009/28 Directive requires Member States to take appropriate steps to develop transmission and distribution grid infrastructure, intelligent networks, storage facilities and the electricity system, in order to allow the secure operation of the electricity system as it accommodates the further development of electricity production from renewable energy sources, including interconnection between Member States and between Member States and third countries. Member States are required to take appropriate steps to accelerate authorisation procedures for grid infrastructure and to coordinate approval of grid infrastructure with administrative and planning procedures.

The EU has defined the form of environmental impact assessments (EIA) for both planning and project consenting. These EIAs provide a useful opportunity to highlight wider European benefits. Further integration of the requirements for EIAs in planning and consenting could further streamline the process of obtaining necessary consents/permits.

In the case of the additional infrastructure identified by EWIS, these works may not be linked to just achieving the targets in a particular Member State but may also be needed to help other countries meet their targets securely. While the above requirement on Member

States to accelerate network consenting procedures is helpful, there remains a risk that such accelerations may not be effective if works are not directly to the benefit of that Member State because they may not be accepted by the public affected by such works. EWIS therefore highlights the need for support from policy makers for works which have wider European benefits.

3) EWIS analyses have illustrated the significant differences that can arise between market scheduled cross-border exchanges and the resulting physical flows. Results have also shown how wind forecasts at the day ahead stage can vary significantly from conditions that outturn.

Differences between market scheduled exchanges and physical flows highlight the potential for better representation of network physics in markets and thereby make more efficient use of network capability. Flow based market coupling/splitting is currently being considered in Regional Initiatives to develop the electricity market and the EWIS market models offer a tool for assessing the benefits of such developments.

Policy concerning the resolution of energy imbalances requires the use of market-based approaches as far as possible. For the market to resolve variations in wind output, intraday markets which permit traders to refine their contract position close to real-time are required. (The last opportunity for market participants to notify contracts before real time delivery is often referred to as the ‘gate-closure’ time. For example, participants in the GB electricity market can currently notify contracts up to 1 hour prior to each ½ hour real-time delivery period.) Intra day markets are currently being developed in various Member States and as part of the regional initiatives. The EWIS market models offer tools for quantifying the benefits of such developments.

4) The need for enhanced control facilities (with centralised wind forecasting and co-ordinated network responses) has been identified by EWIS as the best way of addressing both the short-term risks prior to establishment of new reinforcements and also the best approach for obtaining most benefit from new transmission developments.

In parallel with approaches that would facilitate the resolution of imbalances and congestion by market participants, EWIS operational assessments have highlighted the benefits that may be realised by enhancing system operator management actions and control (For example, replicating the best practice observed in Spanish control arrangements in situations where multiple TSOs must co-operate). The advantages in centralising demand and wind generation forecasting in control centres that have extensive network and wind monitoring facilities derive from the ability to take co-ordinated/strategic actions using this information. For example, correlations between wind generation output, demand (e.g. wind chill) and line dynamic ratings can then be exploited. Strategic actions to adjust the readiness of backup reserves and the configuration of networks by adjusting flow control devices and switching can then be co-ordinated and actioned. To facilitate such enhanced control measures, National Regulators, ACER and policy makers should consider the benefits of TSO actions to enhance control facilities and also the benefits of standardising the facilities for monitoring wind farm output.

5) EWIS stakeholders have highlighted the importance of harmonising grid code requirements on wind generators and analysis by EWIS has identified basic common features as well as necessary regional differences that are relevant to establishing the network code requirements for wind generators.

Recital 6 of the 714/2009 Regulation on the conditions for access to the network for cross-border exchanges in electricity considers increased cooperation and coordination among transmission system operators is required to create network codes that are fit for purpose. Those network codes should align with (non-binding) framework guidelines to be developed by the Agency for the Cooperation of Energy Regulators (‘the Agency’ or ACER) established by Regulation (EC) No 713/2009 of the European Parliament and of the Council of 13 July 2009 establishing the Agency. The Agency should have a role in reviewing draft network codes, including their compliance with the framework guidelines, and it should be enabled to recommend them for adoption by the Commission. The Agency should assess proposed amendments to the network codes and it should be enabled to recommend them for adoption by the Commission. TSOs should then operate their networks in accordance with those network codes.

It is to be noted that the network codes prepared by the ENTSO-E are not intended to replace the necessary national network codes for non-cross-border issues (recital 7 714/2009 Regulation).

During the course of the EWIS project, stakeholders have highlighted the importance of standardising the technical compatibility requirements for wind generators (currently detailed in national grid codes). Given the analysis undertaken by EWIS, and the discussions held with stakeholders on this topic, EWIS proposed and ENTSO-E agreed to the establishment of a working group to develop European Network Code requirements for wind generators on a pilot basis (i.e. in advance of formal guidance on code development by ACER). Candidate code features have been provided by EWIS to this pilot group.

6) EWIS has identified significant differences in the cost of integrating wind in different locations and also potentially significant differences between the current level of support for RES-E and the amount that might be needed in theory to promote renewables in different locations.

While it is beyond the scope of the EWIS project to make recommendations concerning RES-E targets and the nature of support mechanisms to achieve such targets, nevertheless policy makers may wish to note the capability of the EWIS market and network modelling tools to provide information that may be relevant to informing policy development in this area.

It is noted that Directive 2009/28/EC has two objectives relevant to this topic: (Recital 25) confirms that it is important to guarantee the proper functioning of national support schemes, as under Directive 2001/77/EC, in order to maintain investor confidence and allow Member States to design effective national measures for target compliance and, on the other hand it aims at facilitating cross-border support of energy from renewable sources without affecting national support schemes. This can be achieved through cooperation mechanisms between Member States which might allow them to agree on the extent to which one Member State supports the energy production in another and on the extent to which the energy production from renewable sources should count towards the national overall target of one or the other. Such types of bilateral cooperation suggest there will eventually be a need for a single European approach to RES-E support. However, apart from recalling (Recital 6) that a well-functioning internal market in electricity should provide producers with the appropriate incentives for investing in new power generation and (Recital 36) showing the awareness that the cost of achieving the targets should be reduced, the new directive does not intervene in the incentive level.

In examining the drivers for wind power and renewables in general, EWIS has noted the different support arrangements and interactions with market signals that currently exist in different Member States. In some countries, the support is paid as an addition/premium to the market price upon delivery at the market hub. In such systems, the developers of wind generators will receive signals from the market and may also receive, depending on network charging arrangements, locational and balancing signals from the network. This approach can impose revenue uncertainties on renewable generators which may make establishing such projects more difficult given any particular level of support. The alternative approach is to offer a long-term price for the renewable energy with minimal exposure to market price, balancing or network locational signals. (In such an approach, network locational costs might be taken into account to some extent in the planning/consenting process).

The results from EWIS confirms that the location of wind developments can have a significant impact on network costs both internally and on cross-border links but these costs, in general, remain small compared to the cost of establishing wind generation. To this end, policy makers may wish to consider the network cost information available from the EWIS market and network models when considering the potential harmonisation of support mechanisms alongside other market and network charging developments.

7) EWIS has identified different interpretations concerning the implementation of guaranteed access or priority access and despatch for RES-E exist across Member States.

Directive 2009/28 states that, subject to requirements relating to the maintenance of the reliability and safety of the grid, and based on transparent and non-discriminatory criteria defined by the competent national authorities:

(a) Member States shall ensure that transmission system operators and distribution system operators in their territory guarantee the transmission and distribution of electricity produced from renewable energy sources;

(b) Member States shall also provide for either priority access or guaranteed access to the grid-system of electricity produced from renewable energy sources;

(c) Member States shall ensure that when dispatching electricity generating installations, transmission system operators shall give priority to generating installations using renewable energy sources in so far as the secure operation of the national electricity system permits and based on transparent and non-discriminatory criteria. Member States shall ensure that appropriate grid and market-related operational measures are taken in order to minimise the curtailment of electricity produced from renewable energy sources. If significant measures are taken to curtail the renewable energy sources in order to guarantee the security of the national electricity system and security of energy supply, Members States shall ensure that the responsible system operators report to the competent regulatory authority on those measures and indicate which corrective measures they intend to take in order to prevent inappropriate curtailments.

The differences in interpretation of priority access and despatch identified by EWIS between Member States can relate to how the need to provide priority for renewables is reconciled with the need to provide cost-reflectivity (to achieve economic development signals) and non-discrimination between all network users (to facilitate competition). In order to assist with providing legal certainty, policy makers and regulators should clarify by means of guidance how priority dispatch and access for renewables should be reconciled with guidance concerning development of access and charging arrangements to promote efficiency and competition.

Legal, Regulatory & Policy Conclusions

In the light of the analysis made within the EWIS project, the conclusions concerning legal, regulatory and policy aspects are summarised as follows:

1. The network developments identified within the EWIS project to integrate large scale wind generation in transmission networks reflect the interactions between wind generation and markets across Europe. In deciding whether to approve TSOs' recovery of the associated costs, National Regulatory Authorities will similarly need to consider the wider European benefits of such developments with ACER.

2. Given the urgency of the need for additional network capacity in key areas, policy maker support for use of accelerated consenting/permitting procedures will be important. Moreover, given that works may have benefits in areas wider than the Member State in which they are located, TSOs will also value support from policy makers that will generally enhance the public acceptability of such works.

3. EWIS results have highlighted the scope for improved representation of network limits in the electricity markets. TSO colleagues, National Regulators and ACER may wish to use EWIS models to assess the benefit of such market design developments, for example in the current Regional Initiatives.

4. National Regulators and ACER may wish to note the benefits of strengthening the monitoring of wind generation and development of control facilities that permit co-ordinated operational actions.

5. National Regulators and ACER may wish to note the establishment of a pilot working group on the network code aspects for wind generation. EWIS findings have sought to identify the areas for harmonized requirements and those areas where regional differences will be justified.

6. Policy makers may wish to consider the network cost results from EWIS market and network models in considering the most appropriate approach to developing renewable support mechanisms and efficient market/network locational signals.

7. EWIS has identified different interpretations concerning the implementation of guaranteed access or priority access and despatch for RES-E exist across Member States. Guidance from policy makers concerning how priority for renewables should be reconciled with non-discriminatory cost-reflective access for all network users would be helpful.

8 Priority areas for immediate action

<u>Recommendation 1 – Approach</u>

To achieve a coordinated economic development of the European transmission system in the presence of wind, European market modeling (such as undertaken in EWIS) should be used. The development of suitable tools for making final investment decisions is a challenging task and a suitable development program will need to be established.

- **Who: ENTSO-E SDC**
- **Why:**
  - EWIS studies show significant market interactions and loop flows
  - EWIS identifies beneficial additional measures addition to those already in existing national plans

[Chapter 3, Scenarios and Exchange Schedules]

<u>Recommendation 2 – Reinforcements</u>

The identified potential additional reinforcements should be considered and refined by the relevant TSOs as candidate measures for inclusion in the ENTSO-E Ten Years Network Development Plan.

- **Who: ENTSO-E (TYNDP) and TSOs**
- **Why:**
  - Results of EWIS technical & economic analysis identify candidate measures
  - But further work required by relevant TSOs to develop into investment schemes

[Chapter 4, Technical Analysis]

<u>Recommendation 3 – Consents</u>

Policy makers and planning authorities should ensure necessary network infrastructure is given equivalent priority as that given to renewable generation developments so that necessary network upgrades are progressed in a timely fashion. Obtaining consents and progressing network strengthening works already identified remains a priority.

- **Who: EC, National Governments and planning authorities**
- **Why:**
  - EWIS confirms the existing network reinforcements and identified the need for additional transmission capacity for a better integration of wind power.
  - Current consent procedures are long and complex and risk network being developed after the wind farms delaying the realisation of the benefits.

[Chapter 4, Technical Analysis]

Recommendation 4 – Network Finance
When setting TSO price controls and investment allowances, policy makers should ensure national regulators recognise the urgent need to develop European network infrastructure to facilitate wind generation and permit TSOs to raise required finance and recover the associated financing costs. TSOs should identify appropriate sources of revenue/funding for these costs.

- **Who: TSOs, ACER, National Regulators**
- **Why:**
  - EWIS identifies additional investments to those in National plans which need financing
  - Additional developments may bring European rather than National benefits, e.g. offshore

[Chapter 5, Cost Analysis]

Recommendation 5 – Grid Security, Capability and Flexibility
Enhance capability and flexibility of the existing transmission grid by using operational switching, capacity line management and phase shift controllers for power flow control.

- **Who: ENTSO-E and TSOs**
- **Why**
  - EWIS investigations show a significant potential for reducing congestion and maximising the use of existing transmission capacity
  - EWIS results for grid optimization on a pilot for dynamic rating may acts as a starting point for further investigations of sustainable optimization measures and limitations.
  - In all cases there is a need to strengthen the existing grid with new grid infrastructure to maintain the existing level of system security

[Chapter 4, Technical Analysis]

Recommendation 6 – Coordinated Operation
TSOs should further develop improved operational tools and procedures that will permit shared wind forecasting, coordinated operation of power flow control devices, coordinated voltage control, and reserve monitoring and management actions across the European network.

- **Who: ENTSO-E and TSOs**
- **Why:**
  - Wind patterns across Europe often affect countries in sequence & groups (from EWIS time series and operations analysis)
  - EWIS analysis identifies beneficial additional short-term risk management measures to current practice
  - Operational measures are most beneficial when actions of adjacent TSOs co-ordinated
  - Good experiences are already gained from inter TSO coordination such as coreso, CECRE, TSC, SEM, NOIS etc

[Chapter 4, Technical Analysis]

Recommendation 7 –Network Code

EWIS has provided basic inputs for the European Network Code development which should be taken as a first priority and further developed by ENTSO-E.

- **Who: ENTSO-E and relevant stakeholder**
- **Why:**
  - Grid Code harmonization identified as a stakeholder priority
  - ENTSO-E is responsible for developing European network codes (see third package)
  - EWIS technical analysis identified the need for Europeanwide and specific recognition of local issues

[Chapter 4, Technical Analysis]

Recommendation 8 – Market Development

The potential market development opportunities and results identified by EWIS (better network representation and consistent timing of markets etc) should be considered by regional initiatives and by ACER in setting market development priorities.

- **Who: ACER, ENTSO-E, TSO Regional Initiatives**
- **Why:**
  - EWIS studies show significant differences between market transactions and physical flows, especially when windy.
  - Market resolution of congestion offers more efficient prices
  - Intra-day markets may help address wind imbalances

- **Future:**
  - Use EWIS market modelling to examine further market design considering congestions in market areas

[Chapter 3, Scenarios and Exchange Schedules]

Recommendation 9 – Control of Wind Generation

Policy makers and regulators should facilitate arrangements that give system operators improved capabilities to manage and control wind power output to ensure system security. Ways of recovering the cost of such control facilities including the techniques promoting flexible production/demand/storage should also be addressed.

- **Who: EC, ACER, National Regulators and TSOs**
- **Why:**
  - EWIS identifies from existing experience that control by TSOs is the most effective option in emergency cases

[Chapter 4, Technical Analysis]

<u>Recommendation 10 – Location</u>

To improve power system economics, Policy makers should consider the results from the pan-European market model developed in EWIS to consider the future development of wind support mechanisms and/or network access rules.

- **Who: EC, National Governments, ACER**
- **Why:**
  - EWIS studies identify wide range of integration costs for different locations
  - EWIS analysis suggests economic efficiency may be improved if:
    - wind development focused away from high cost areas
    - Higher cost of transmission in certain areas is included within the equation cost of promoters of wind generation.

[Chapter 5, Cost Analysis]

<u>Recommendation 11 – Offshore Grids</u>

TSOs, regulators and policy makers should further analyze the longer term (2020-2025) potential of Offshore grids interconnecting wind farms and countries across the sea and including the implications on Onshore grids.

- **Who: ENTSO-E – Regulators – Policy makers**
- **Why:**
  - Strengthen the Pan European electricity system for better exchange of regional energy increase and better utilization of dispatchable and variable renewable energy sources (e.g. large hydro-energy capacity and offshore wind)
  - EWIS beyond 2015 results as a starting point for detailed investigations of sustainable offshore grid infrastructure and offshore windpark cluster concepts e.g. for the time horizon 2020/2025.
  - Need for standards and a secure well coordinated approach considering all offshore onshore perspectives.

[Chapter 6, Enhanced Network beyond 2015]

9 Further work

- Immediate realization of urgently needed grid infrastructure projects (existing national grid development plans, not realized yet)
  - Permitting procedures for grid investments have to be accelerated
- Detailed examination of the results on regional/European level
  - Input to ENTSO-E 10Y network development plan
  - Input to regional/national ongoing studies
  - Input to ENTSO-E pilot code (Requirements for wind turbines on European level)
- Analyze deployment of additional wind turbines in Europe
  - To give hints for socio- and macroeconomic optimal setting of wind parks
  - To optimize the overall social welfare of investments
- Ongoing development of EWIS European wide market model (further development by TSOs/ENTSO-E)
  - Market Model update by each TSO organized by ENTSO-E
  - European wide overall analysis of different flow pattern and different situations
  - Detailed analysis based on a European wide market model in a specific region (need for regional redispatch, market splitting, market coupling, need for storages …) by individual TSOs/regional groups
- Look at 2020 and 2025
  - Start to analyze an offshore grid, interconnecting several wind farms and countries from the sea (onshore/offshore grid perspectives)
  - Balancing arrangements and Demand side management.
  - Examine new technologies and overlay systems
  - Examine more generation profile scenarios and different flow pattern

C Conclusion

Context

Wind generation is the front runner renewable electricity technology and essential to meeting Europe's renewable energy and climate change objectives. Large capacities of wind generators have already been installed and are operating in Germany (26GW) and Spain (16GW). Installations which are as significant in terms of proportion to system size are also established in Denmark (3.3GW), Ireland and Northern Ireland (1.5GW), and Portugal (3.4GW). Many other countries expect significant growth in wind generation such that the total currently installed capacity in Europe of 68GW is expected to at least double by 2015. Yet further increases can be expected in order to achieve Europe's 2020 targets for renewable energy.

Approach

The approach and methodology used by EWIS recognises that wind is most effectively integrated in Europe's electricity system (and thereby will give most benefit in terms of reducing fossil fuel burn and CO2 emissions with least impact on supply reliability) by using the transmission networks to exploit the diversity that exists between the variations in wind power output in different areas and also share the backup facilities that will be required.

To assess the transmission implications of efficiently integrating wind, a Europe wide model of market and network is required. EWIS, with its partner SUPWISci, has developed models which permit wind implications to be assessed in economic terms and also permit detailed network technical issues to be assessed in the context of year-round market and wind behaviours. As well as providing the results of an assessment of current national plans to 2015 to TSO colleagues and the ENTSO-E team developing the Ten Year Network Development Plan, EWIS has also provided a modelling capabilities and economic assessment tools which the project recommends are used in future work addressing development of; the transmission networks, the form and functioning of the electricity market, network codes (especially technical compatibility rules), and wider issues concerning the achievement of energy policy goals.

Immediate network challenges and potential solutions

Analysis of current national plans confirm the urgent need for the reinforcements and network strengthening measures that have already been identified for the period to 2015. Moreover, given the interactions that will occur across Europe, EWIS has identified that additional network reinforcements and strengthening measures will be beneficial both in economic terms and maintaining supply reliability.

In the short-term, prior to the opportunity to construct new lines, measures which make the most of existing network capacity should be enhanced. These include using flow control devices, adapting network switching arrangements, using special protection schemes, and using dynamic line ratings.

The potential for beneficial new transmission facilities has also been identified and these have been notified to the TSOs affected and advised to the ENTSO-E team developing the Ten Year Network Development Plan. These candidate reinforcements will need further analysis and refinement in order to become schemes that can be sanctioned and initiated by TSOs.

EWIS has examined the physical phenomena that could represent systemic risks to the European electricity system including; the potential for poor voltage behaviour, instability following faults or other significant disturbances, and the potential for inadequate damping of oscillations between generators across Europe. These issues will become more important as utilisation of the existing network facilities is increased. Identified mitigations include voltage control reinforcements, ensuring suitable technical compatibility requirements in Grid Codes, enhanced protection arrangements and increased use of power system stabilisers. Wide area monitoring will become more important to ensure these issues are properly taken into account when measures such as dynamic line ratings are utilised.

In terms of network operations and control, enhanced cooperation between TSOs will be increasingly important to coordinate operational actions to manage congestion and balancing. A number of initiatives are already being progressed in this area. EWIS identifies from existing experience how bringing together wind forecasting, system monitoring and control actions will be beneficial and permit a strategic response to emerging issues resulting from the interactions between wind generation and markets.

Wind integration can also be enhanced by encouraging efficient and timely market responses and these issues are already being addressed in regional market initiatives. EWIS highlights the potential for the better representation of actual network capability in electricity markets so that more efficient market schedules are produced and the opportunities for intra day markets to offer responses to emerging information concerning wind output in the short-term. Harmonisation of market designs and ancillary service procurement arrangements will increase the effectiveness of market actions to integrate wind.

In the future, offshore grids, new storage facilities and enhanced demand side responses facilitated by smart metering may also contribute to enhanced network control and effective wind integration.

Costs and Benefits of Wind Integration Approaches

EWIS economic analyses has shown that the costs of integrating wind in terms of operating flexible generation to balance wind variations and already planned measures to strengthen transmission networks are small (circa €6/MWh of wind produced in total) compared to the overall benefits of wind generation in terms of reduced fuel burn and CO_2 emissions of at least €45/MWh of wind produced (and more if higher fuel and CO_2 costs are assumed).

In terms of opportunities for optimising network integration costs, the EWIS results provide information concerning the cost implications of developing large scale wind generation in different areas and policy makers may wish to note these results when considering the future development of renewable support policies.

Economic assessments show that the need to curtail wind output (for example, in circumstances where available wind would exceed local demand and expected network

export capacity in 2015) is very small (circa 0.03% of wind produced). Nevertheless, an operational means to control wind output in extreme conditions will be important.
The development of demand side response has been examined and, with the assumptions chosen, a small potential benefit in terms of balancing and congestion management costs has been found (circa €90m per annum). While development of demand response in the electricity market may give larger opportunities (for example, as a result of Smart metering developments) it is unlikely that enhanced demand side response will provide an immediate large scale alternative to the network reinforcement measures identified in the EWIS network studies.

The economic implications of more extensive use of flexible line management (dynamic ratings) have been investigated. Given the small cost of these measures, such schemes are likely to be attractive but the overall contribution is expected to be modest (circa €30m per annum) and will not offer a large scale alternative to the network reinforcement measures identified in the EWIS network studies.

Dedicated electricity storage facilities that may be realised by modifying hydro generation in Norway, or developing additional pump storage facilities in mountains, or by using compressed air technology has been investigated. These studies show that enhancing interconnections to make more flexible use of existing hydro facilities is the most attractive option and there may be some opportunities for developing economic new pump storage facilities in favourable locations such as in Spain.

Beyond 2015 – The Enhanced Network Scenario

In examining the benefits of increasing cross-border capacities, EWIS has identified 29 links (approximately 50% of all links) in which there is a good prospect that the expected costs of network reinforcements will be exceeded by the additional benefits from reduced fuel costs and CO_2 emissions. The total benefits due to these reinforcements are estimated under central assumptions at €1.9bn per annum justifying an estimated total capital cost of the reinforcements of circa €12bn.

These results are sensitive to a number of assumptions and practical issues associated with the realization of these reinforcements. However, the assessment highlights the opportunities for deriving larger benefits from wind developments by enhancing Europe's transmission network capacity.

Legal, Regulatory & Policy Conclusions

The network developments identified within the EWIS project to integrate large scale wind generation in transmission networks reflect the interactions between wind generation and markets across Europe. In deciding whether to approve TSOs recovery of the associated costs, National Regulatory Authorities will also need to consider the wider European benefits of such developments.

Given the urgency of the need for additional network capacity in key areas, policy maker support for use of accelerated consenting/permitting procedures will be important. Moreover, given that works may have benefits in areas wider than the Member State in which they are located, TSOs will also value support from policy makers that will generally enhance the public acceptability of such works.

EWIS results have highlighted the scope for improved representation of network limits in the electricity markets. TSO colleagues, National Regulators and ACER may wish to use EWIS models to assess the benefit of such market design developments, for example in the current Regional Initiatives.

National Regulators and ACER may wish to note the benefits of strengthening the monitoring of wind generation and development of control facilities that permit co-ordinated operational actions.

National Regulators and ACER may wish to note the establishment of a pilot working group on the network code aspects for wind generation. EWIS findings have sought to identify the areas for harmonized requirements and those areas where regional differences will be justified.

G Glossary

Chapters

A. Glossary of terms

B. List of acronyms

C. List of units

Active Power: ACTIVE POWER is a real component of the apparent power, usually expressed in kilowatts (kW) or megawatts (MW), in contrast to REACTIVE POWER, Including virtual TIE-LINES that may exist for the operation of jointly owned power plants.

Adjacent Control Area (Adjacent System): An ADJACENT CONTROL AREA (or ADJACENT SYSTEM) is any CONTROL AREA (or system) either directly interconnected with or electrically close to (so as to be significantly affected by the existence of) another CONTROL AREA (or system).

Ancillary Services: ANCILLARY SERVICES are Interconnected Operations Services identified as necessary to effect a transfer of electricity between purchasing and selling entities (TRANSMISSION) and which a provider of TRANSMISSION services must include in an open access transmission tariff.

Apparent Power: APPARENT POWER is the product of voltage (in volts) and current (in amperes). It consists of a real component (ACTIVE POWER) and an imaginary component (REACTIVE POWER), usually expressed in kilovolt-amperes (kVA) or megavolt-amperes (MVA).

Automatic Generation Control (AGC): AUTOMATIC GENERATION CONTROL is equipment that automatically adjusts the generation to maintain its generation dispatch, interchange schedule plus its share of frequency regulation. AGC is a combination of SECONDARY CONTROL for a CONTROL AREA / BLOCK and real-time operation of the generation dispatch function (based on generation scheduling). SECONDARY CONTROL is operated by the TSO, generation scheduling is operated by the respective generation companies (GENCOs).

Available Transfer Capacity (ATC): AVAILABLE TRANSFER CAPACITY is a measure of the transfer capability remaining in the physical TRANSMISSION network for further commercial activity over and above already committed uses.

AVAILABLE TRANSMISSION CAPACITY is the part of NTC that remains available after each phase of the allocation procedure for further commercial activity. ATC is defined by the following equation: ATC = NTC- AAC

Balance Responsible Party: A party that has a contract proving financial security and identifying balance responsibility with the imbalance settlement responsible of the market balance area entitling the party to operate in the market. This is the only role allowing a party to buy or sell energy on a wholesale level.

Additional information:

The meaning of the word “balance” in this context signifies that that the quantity contracted to provide or to consume must be equal to the quantity really provided or consumed. Such a party is often owned by a number of market players.

Equivalent to “Program responsible party” in the Netherlands. Equivalent to “Balance responsible group” in Germany. Equivalent to “market agent” in Spain. Equivalent to “Balancing Mechanism Unit” (BMU) in Great Britain. Covers all large Power Stations (>100MW in England & Wales & in Scotland either >10MW (North) or >30MW (South).

Black-start Capability: BLACK-START CAPABILITY is the ability of a generating unit to go from a shutdown condition to an operating condition and start delivering power without assistance from the electric system.

Capacity: CAPACITY is the rated continuous load-carrying ability of generation, transmission, or other electrical equipment, expressed in megawatts (MW) for ACTIVE POWER or megavolt-amperes (MVA) for APPARENT POWER.

Consumption: See: DEMAND

Contingency: CONTINGENCY is the unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch, or other electrical element. A CONTINGENCY also may include multiple components, which are related by situations leading to simultaneous component outages.

Control Area (CA): A CONTROL AREA is a coherent part of the UCTE INTERCONNECTED SYSTEM (usually coincident with the territory of a company, a country or a geographical area, physically demarcated by the position of points for measurement of the interchanged power and energy to the remaining interconnected network), operated by a single TSO, with physical loads and controllable generation units connected within the CONTROL AREA. A CONTROL AREA may be a coherent part of a CONTROL BLOCK that has its own subordinate control in the hierarchy of SECONDARY CONTROL.

Curtailment: CURTAILMENT means a reduction in the scheduled capacity or energy delivery.

Defence Plan: The DEFENCE PLAN summarizes all technical and organizational measures taken to prevent the propagation or deterioration of a power system incident in order to avoid a collapse.

Demand {Consumption}: DEMAND is the rate at which electric power is delivered to or by a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time. DEMAND should not be confused with LOAD (a LOAD is usually a device).

Disturbance: DISTURBANCE is an unplanned event that produces an abnormal system condition.

Droop of a Generator (P1-A, A1-A): The DROOP OF A GENERATOR is one of the parameters set on the primary speed controller of a GENERATING SET (generator and turbine). It is equal to the quotient of the relative quasi-steady-state FREQUENCY OFFSET on the network and the relative variation in power output from the generator associated with the action of the PRIMARY CONTROLLER. This ratio without dimension is generally expressed as a percentage.

Electrical Energy: ELECTRICAL ENERGY is a measure of the generation or use of electric power by a device integrated over a period of time; it is expressed in kilowatt-hours (kWh), megawatt-hours (MWh), or gigawatt-hours (GWh).

Electric System Losses: ELECTRIC SYSTEM LOSSES are total electric energy losses in the electric system. The losses consist of TRANSMISSION, transformation, and distribution losses between supply sources and delivery points.

Electric energy is lost primarily due to heating of transmission and distribution elements.

Exchange Schedule (CAS, CBS): An EXCHANGE SCHEDULE defines an agreed transaction with regard to its size (megawatts), start and end time, RAMP PERIOD and type (e.g. firmness); it is required for delivery and receipt of power and energy between the contracting parties and the CONTROL AREA(S) (CAS) or between control areas and control blocks (CBS) involved in the transaction.

Exchange schedules

The expression 'exchange schedules' or 'commercial exchange' is used to describe programs of exchange scheduled from one market to another one as a consequence of market activity or cross-border bilateral trading.

Flow: Conversely, the word 'flow' is used only for the physical load or power flows that can be measured on a set of electrical transmission lines. Power flows are currently managed by each Transmission System Operator acting in his own 'control area'.

Frequency: see: SYSTEM FREQUENCY

Frequency Bias: see: NETWORK POWER FREQUENCY CHARACTERISTIC

Frequency Control: See: PRIMARY CONTROL.

Frequency Deviation: FREQUENCY DEVIATION means a departure of the actual SYSTEM FREQUENCY from the set value frequency.

Frequency Offset: FREQUENCY OFFSET is the difference between the actual and the nominal value of the SYSTEM FREQUENCY in order to correct the SYNCHRONOUS TIME (TIME CONTROL); it is not identical with FREQUENCY DEVIATION.

Generation: GENERATION is the rate at which a GENERATION SET delivers electric power to a system or part of a system, generally expressed in kilowatts (kW) or megawatts (MW), at a given instant or averaged over any designated interval of time, see also: DEMAND.

3 Including virtual tie-lines that may exist for the operation of jointly owned power plants.

Interconnected System: An INTERCONNECTED SYSTEM is a system consisting of two or more individual electric systems that normally operate in synchronism and are physically connected via TIE-LINES, see also: SYNCHRONOUS AREA.

Interconnection: An INTERCONNECTION is a transmission link (e.g. TIE-LINE or transformer) which connects two CONTROL AREAS.

Island: An ISLAND represents a portion of a power system or of several power systems that is electrically separated from the main INTERCONNECTED SYSTEM (separation resulting e.g. from the disconnection / failure of transmission system elements).

Load: LOAD means an end-use device or customer that receives power from the electric system. LOAD should not be confused with DEMAND, which is the measure of power that a load receives or requires. LOAD is often wrongly used as a synonym for DEMAND.

Load-Frequency Control (LFC): See: SECONDARY CONTROL

Load-Shedding: LOAD-SHEDDING is the disconnection of LOAD from the synchronous electric system, usually performed automatically, to control the SYSTEM FREQUENCY in emergency situations.

Loop Flows: See: PARALLEL PATH FLOWS.

Market Information Aggregator: Market Information Aggregatoris a party that provides market related information that has been compiled from the figures supplied by different actors in the market. This information may also be published for general use.

Market Operator: The unique power exchange of trades for the actual delivery of energy that receives the bids from the Balance Responsible Parties that have a contract to bid. The market operator determines the market energy price for the market balance area after applying technical constraints from the system operator. It may also establish the price for the reconciliation within a metering grid area.

N-1 Criterion: The N-1 CRITERION is a rule according to which elements remaining in operation after failure of a single network element (such as transmission line / transformer or generating unit, or in certain instances a busbar) must be capable of accommodating the change of flows in the network caused by that single failure.

Net Transfer Capacity (NTC): The NET TRANSFER CAPACITY is defined as:

NTC = TTC-TRM

The NET TRANSFER CAPACITY is the maximum total EXCHANGE PROGRAM between two ADJACENT CONTROL AREAS compatible with security standards applicable in all CONTROL AREAS of the SYNCHRONOUS AREA, and taking into account the technical uncertainties on future network conditions.

Network Power Frequency Characteristic: The NETWORK POWER FREQUENCY CHARACTERISTIC defines the sensitivity, given in megawatts per Hertz (MW/Hz), usually associated with a (single) CONTROL AREA / BLOCK or the entire SYNCHRONOUS AREA, that relates the difference between scheduled and actual SYSTEM FREQUENCY to the amount of generation required to correct the power imbalance for that CONTROL AREA / BLOCK (or, vice versa, the stationary change of the SYSTEM FREQUENCY in case of a disturbance of the generation-load equilibrium in the CONTROL AREA without being connected to other CONTROL AREAS); it is not to be confused with the K-FACTOR. The NETWORK POWER FREQUENCY CHARACTERISTIC includes all active PRIMARY CONTROL and SELF-REGULATION OF LOAD and changes due to modifications in the generation pattern and the DEMAND.

Operating Procedures: OPERATING PROCEDURES are a set of policies, practices, or system adjustments that may be automatically or manually implemented by the system operator within a specified time frame to maintain the operational integrity of the INTERCONNECTED SYSTEMS.

Parallel Path Flows {loop flows, circulating power flows, unscheduled power flows}: PARALLEL PATH FLOWS describe the difference between the scheduled and actual power flow, assuming zero inadvertent interchange, on a given transmission path in a meshed grid.

Power Deviation: A POWER DEVIATION is a power deficit (negative value) or a increase (positive value) in a CONTROL AREA / BLOCK of the SYNCHRONOUS AREA4, usually measured at the borders of the area, with respect to the CONTROL PROGRAM.

Power System: The POWER SYSTEM comprises all generation, consumption and network installations interconnected through the network.

Power Transfer Distribution Factor: A load flow alternative based on Power Transfer Distribution Factors (PTDF) is provided, too.

Primary Control {Frequency Control, Primary Frequency Control}: PRIMARY CONTROL maintains the balance between GENERATION and DEMAND in the network using turbine speed governors. PRIMARY CONTROL is an automatic decentralised function of the turbine Power exchanges over DC-connections are not included in the calculation of the power deviation, they are considered to be either an injection or a load in the CONTROL AREA connected.

governor to adjust the generator output of a unit as a consequence of a FREQUENCY DEVIATION / OFFSET in the SYNCHRONOUS AREA:

- PRIMARY CONTROL should be distributed as evenly as possible over units in operation in the SYNCHRONOUS AREA;
- the global PRIMARY CONTROL behaviour of an interconnection partner (CONTROL AREA / BLOCK), may be assessed by the calculation of the equivalent droop of the area (basically resulting from the DROOP OF ALL GENERATORS and the SELF-REGULATION OF THE TOTAL DEMAND).

By the joint action of all interconnected undertakings, PRIMARY CONTROL ensures the operational reliability for the power system of the SYNCHRONOUS AREA.

Primary Control Power: PRIMARY CONTROL POWER is the power output of a GENERATION SET due to PRIMARY CONTROL.

Primary Control Range: The PRIMARY CONTROL RANGE is the range of adjustment of PRIMARY CONTROL POWER, within which PRIMARY CONTROLLERS can provide automatic control, in both directions, in response to a FREQUENCY DEVIATION. The concept of the PRIMARY CONTROL RANGE applies to each generator, each CONTROL AREA / BLOCK, and the entire SYNCHRONOUS AREA.

Primary Control Reserve: The PRIMARY CONTROL RESERVE is the (positive / negative) part of the PRIMARY CONTROL RANGE measured from the working point prior to the disturbance up to the maximum PRIMARY CONTROL POWER (taking account of a limiter). The concept of the PRIMARY CONTROL RESERVE applies to each generator, each CONTROL AREA / BLOCK, and the entire SYNCHRONOUS AREA.

Primary Controller: The PRIMARY CONTROLLER is a decentralised / locally installed control equipment for a GENERATION SET to control the valves of the turbine based on the speed of the generator (for synchronous generators directly coupled to the electric SYSTEM FREQUENCY); see PRIMARY CONTROL.

The insensitivity of the PRIMARY CONTROLLER is defined by the limit frequencies between which the controller does not respond. This concept applies to the complete primary controller-generator unit. A distinction is drawn between unintentional insensitivity associated with structural inaccuracies in the unit and a dead band set intentionally on the controller of a generator.

Primary Frequency Control: See: PRIMARY CONTROL

Production Responsible Party: A party who can be brought to rights, legally and financially, for any imbalance between energy sold and produced for all associated metering points.

Pseudo-Tie-Line: See: VIRTUAL TIE-LINE.

Reactive Power: REACTIVE POWER is an imaginary component of the apparent power. It is usually expressed in kilo-vars (kVAr) or mega-vars (MVAr). REACTIVE POWER is the portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. REACTIVE POWER must be supplied to most types of magnetic equipment, such as motors and transformers and causes reactive losses on transmission facilities. REACTIVE POWER is provided by generators, synchronous condensers, or electrostatic equipment such as capacitors, and directly influences the electric system voltage. The REACTIVE POWER is the imaginary part of the complex product of voltage and current.

Reliability: RELIABILITY describes the degree of performance of the elements of the bulk electric system that results in electricity being delivered to customers within accepted standards and in the amount desired.

RELIABILITY on the transmission level may be measured by the frequency, duration, and magnitude (or the probability) of adverse effects on the electric supply / transport / generation. Electric system RELIABILITY can be addressed by considering two basic and functional aspects of the electric system:

Adequacy: The ability of the electric system to supply the aggregate electrical demand and energy requirements of the customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.

Security: The ability of the electric system to withstand sudden disturbances such as electric short circuits or unanticipated loss of system elements.

Secondary Control {Load-Frequency-Control}: SECONDARY CONTROL is a centralised automatic function to regulate the generation in a CONTROL AREA based on SECONDARY CONTROL RESERVES in order to maintain its interchange power flow at the CONTROL PROGRAM with all other CONTROL AREAS (and to correct the loss of capacity in a CONTROL AREA affected by a loss of production) and, at the same time, (in case of a major FREQUENCY DEVIATION originating from the CONTROL AREA, particularly after the loss of a large generation unit) to restore the frequency in case of a FREQUENCY DEVIATION originating from the CONTROL AREA to its set value in order to free the capacity engaged by the PRIMARY CONTROL (and to restore the PRIMARY CONTROL RESERVES).

In order to fulfil these functions, SECONDARY CONTROL operates by the NETWORK CHARACTERISTIC METHOD. SECONDARY CONTROL is applied to selected generator sets in the power plants comprising this control loop. SECONDARY CONTROL operates for periods of several minutes, and is therefore dissociated from PRIMARY CONTROL. This behaviour over time is associated with the PI (proportional-integral) characteristic of the SECONDARY CONTROLLER.

Secondary Control Range: The SECONDARY CONTROL RANGE is the range of adjustment of the secondary control power, within which the SECONDARY CONTROLLER can operate automatically, in both directions at the time concerned, from the working point of the secondary control power.

Secondary Control Reserve : The positive / negative SECONDARY CONTROL RESERVE is the part of the SECONDARY CONTROL RANGE between the working point and the maximum / minimum value. The portion of the SECONDARY CONTROL RANGE already activated at the working point is the SECONDARY CONTROL POWER.

Secondary Controller : A SECONDARY CONTROLLER is the single centralised TSO-equipment per CONTROL AREA / BLOCK for operation of SECONDARY CONTROL.

To a great extent, the overall RELIABILITY of the electric power supply (for customers being connected to the distribution grid), that is usually measured, is defined by the RELIABILITY of the power distribution instead of the transmission or generation.

Security Limits {Operating Security Limits}: SECURITY LIMITS define the acceptable operating boundaries (thermal, voltage and stability limits). The TSO must have defined SECURITY LIMITS for its own network. The TSO shall ensure adherence to these SECURITY LIMITS. Violation of SECURITY LIMITS for prolonged time could cause damage and/or an outage of another element that can cause further deterioration of system operating conditions.

Self-Regulation of Load: The SELF-REGULATION OF LOAD is defined as the sensitivity of consumers' demand to variations in the SYSTEM FREQUENCY (a decrease of the SYSTEM FREQUENCY results in a decrease of the LOAD), generally
expressed in % / Hz.

Stability: STABILITY is the ability of an electric system to maintain a state of equilibrium during normal and abnormal system conditions or disturbances.

Small-Signal Stability: The ability of the electric system to withstand small changes or disturbances without the loss of synchronism among the synchronous machines in the system while having a sufficient damping of system oscillations (sufficient margin to the border of stability).

Supervisory Control and Data Acquisition (SCADA): UPERVISORY CONTROL AND DATA ACQUISITION is a system of remote control and telemetry used to monitor and control the electric system.

Synchronous Area: SYNCHRONOUS AREA is an area covered by INTERCONNECTED SYSTEMS whose CONTROL AREAS are synchronously interconnected with CONTROL AREAS of members of the association. Within a SYNCHRONOUS AREA the SYSTEM FREQUENCY is common on a steady state. A certain number of SYNCHRONOUS

AREAS may exist in parallel on a temporal or permanent basis. A SYNCHRONOUS AREA is a set of synchronously INTERCONNECTED SYSTEMS that has no synchronous interconnections to any other INTERCONNECTED SYSTEMS, see also: UCTE SYNCHRONOUS AREA.

Synchronous Time: YNCHRONOUS TIME is the fictive time based on the SYSTEM FREQUENCY in the SYNCHRONOUS AREA, once initialised on UTC time and with the clock frequency being 60/50 of the SYSTEM FREQUENCY. If the SYNCHRONOUS TIME is ahead / behind of the UTC time (TIME DEVIATION), the SYSTEM FREQUENCY has on average been higher / lower than the nominal frequency of 50 Hz. TIME CONTROL action will return a TIME DEVIATION to zero again.

System Frequency {Frequency}: YSTEM FREQUENCY is the electric frequency of the system that can be measured in all network areas of the SYNCHRONOUS AREA under the assumption of a coherent value for the system in the time frame of seconds (with minor differences between different measurement locations only).

Tertiary Control: ERTIARY CONTROL is any (automatic or) manual change in the working points of generators (mainly by re-scheduling), in order to restore an adequate SECONDARY CONTROL RESERVE at the right time.

Tertiary Control Reserve {Minute Reserve}: The power which can be connected (automatically or) manually under TERTIARY CONTROL, in order to provide an adequate SECONDARY CONTROL RESERVE, is known as the TERTIARY CONTROL RESERVE or MINUTE RESERVE. This reserve must be used in such a way that it will contribute to the restoration of the SECONDARY CONTROL RANGE when required. The restoration of an adequate SECONDARY CONTROL RANGE may take, for example, up to 15 minutes, whereas TERTIARY CONTROL for the optimisation of the network and generating system will not necessarily be complete after this time.

Tie-Line: A TIE-LINE is a circuit (e.g. a transmission line) connecting two or more CONTROL AREAS or systems of an electric system.

Time Deviation: The TIME DEVIATION normally is the time integral of the FREQUENCY DEVIATION. In practice, an electrical clock that follows the SYSTEM FREQUENCY is compared with the astronomical time (UTC).

Time Control: TIME CONTROL is a control action carried out to return an existing TIME DEVIATION between SYNCHRONOUS TIME and UTC time to zero.

Total Transfer Capacity (TTC): TOTAL TRANSFER CAPACITY is the maximum EXCHANGE PROGRAM between two ADJACENT CONTROL AREAS that is compatible with operational security standards applied in each system (e.g. GridCodes) if future network conditions, generation and load patterns are perfectly known in advance.

Transient Stability: he ability of an electric system to maintain synchronism between its parts when subjected to a disturbance of specified severity and to regain a state of equilibrium following that disturbance.

Transmission: TRANSMISSION is the transport of electricity on the extra-high or high-voltage network (transmission system) for delivery to final customers or distributors. Operation of TRANSMISSION includes as well the tasks of system operation concerning the management of energy flows, reliability of the system and availability of all necessary system services / ANCILLARY SERVICES.

Transmission System Operator (TSO): A TRANSMISSION SYSTEM OPERATOR is an company that is responsible for operating, maintaining and developing the transmission system for a CONTROL AREA and its INTERCONNECTIONS.

Wind power: Wind power infeed as share of installed capacities of wind power. The ratio is often used for operational tasks as to show stress on the grid impacted by wind power.

Wind power penetration: Wind power penetration rate as share of wind power production related to national load [%]. Within EWIS used to define the point-in-time snapshot, representing high and realistic stress on the grid impacted by wind power.

B. List of Acronyms

AAC Already Allocated Capacity

ACE Area Control Error

AGC Automatic Generation Control

ATC Available Transmission Capacity

BRP Balance Responsible Party

CA Control Area

CAES Compressed Air Energy Storage

CAS Control Area Schedule

CAX Control Area Exchange

CB Control Block

CBS Control Block Schedule

CBX Control Block Exchange

CC Control Centre

CCS Co-ordination Centre Schedule

CECRE Control Centre for Renewable Energies

CoC Co-ordination Centre

CP Control Program

DACF Day Ahead Congestion Forecast

DSM Demand Side Management

EH Electronic Highway

EIC ETSO Identification Code

EMR Energy Meter Reading

ERGEG European Regulators' Group for Electricity and Gas

ESS European Scheduling System

ET Tie-line Flows

EVT Virtual Tie-line Flows

FACTS Flexible AC Transmission Systems

GENCO Generation Company

GMT Greenwich Mean Time

GPS Global Positioning System

HV High Voltage

HVDC High Voltage Direct Current

LFC Load-Frequency Control

NTC Net Transfer Capacity

OpHB Operation Handbook

OPF Optimal Power Flow

PCC Point of Common Coupling

PST Phase Shifter

PI Proportional-Integral

RAAS Regional Awareness and Alarm System

RES Renewable Energy Source

RESCC Renewable Energy Source Control Centre

SCADA Supervisory Control and Data Acquisition

SVC Static Var Compensator

TM Tele-measurement

TRM Transmission Reliability Margin

TSC TSO Security Cooperation

TSO Transmission System Operator

TTC Total Transfer Capacity

UCTE Union for the Co-ordination of Transmission of Electricity

UD Unintentional Deviation

UHV Ultra High Voltage

UTC Universal Time Co-ordinated

WAMS Wide Inter-Area Measurement System

C. List of Units

A ampere

d day

GW gigawatt (1.000.000.000W)

GWh gigawatt-hour

h, hrs hour

Hz hertz (1/s)

kV kilovolt (1000V)

kVA kilovoltampere

kVAr kilovars

kW kilowatt (1000W)

kWh kilowatt-hour

mHz milli-hertz (1/1000 Hz)

min minute

ms milli-second (1/1000 s)

MVA megavolt-ampere

MVAr mega-vars

MW megawatt (1.000.000W)

MWh megawatt-hour

s, sec second

TW terawatt (1.000.000.000.000W)

V volt

W watt

List of technical Reports:

1. Appendix 3-1 modeling of markets and flexibility needs-SUPWISCi.doc
2. Appendix 3-2 load flow concepts in market modeling-SUPWISCi.doc
3. Appendix 3-3 Boundary Conditions.doc
4. Appendix 3-4 Categories Interconnectors .doc
5. Appendix 3-5 Net Exchange .doc
6. Appendix 4.1- Risk analysis.doc
7. Appendix 4.2- Risk mitigation.doc

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