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Summary of experiences and studies for Wind Integration – IEA Wind Task 25

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Abstract— **IEA WIND R&D Task 25 on "Design and Operation of Power Systems with Large Amounts of Wind Power" collects and shares information on wind generation impacts on power systems, with analyses and guidelines on methodologies. This paper summarizes the main results from the report published on January 2013 describing experience of wind integration as well as the most relevant wind power grid integration studies in the 15 participating countries. The studies build on the already significant experience in integrating wind power in power systems addressing concerns about the impact of wind power's variability and uncertainty on power system security of supply and costs as well as grid reinforcement needs. The mitigation of wind power impacts includes more flexible operational methods, incentivising flexibility in other generating plants, increasing interconnection to neighbouring regions, and application of demand-side flexibility. Electricity storage is still not as cost effective in larger power systems as other means of flexibility, but is already seeing initial applications in places with limited transmission.**

Keywords-wind; wind integration, reserve requirements, balancing costs, capacity credit

I. INTRODUCTION

In recent years, numerous reports have been published in many countries investigating the power system impacts of wind generation. The results on the technical constraints and costs of wind integration differ, and comparisons are difficult to make due to different methodologies, data and tools used, as well as terminology and metrics in representing the results. Estimating the cost of impacts can also be conservative due to lack of representative data. Some recent efforts on compiling the results have been made in [1] and [2]. Due to a lack of detailed information on the methodologies used, a direct comparison can only be made with few results.

IEA WIND R&D Task 25 on "Design and Operation of Power Systems with Large Amounts of Wind Power" collects and shares information on wind generation impacts on power systems, (http://www.ieawind.org/task_25.html). An effort for more in-depth review of the studies was made under this international collaboration in the state-of-the-art report [3] and final report 2006–2008 [4]. Many wind integration studies already incorporate solar energy, and most of the results and methodologies discussed are also valid for other variable renewables besides wind power. Task 25 has also been working on Recommended Practices for Wind Integration studies [5]. This paper presents the main results of the latest summary report [6] where the most relevant wind power grid integration studies and experience in participating countries have been collected.

The national case study results are grouped according to impacts: balancing the power system on different short-term time scales; grid related impacts and power (resource) adequacy (i.e., capacity value of wind). The report also presents characteristics of variability and uncertainty in wind power from experience of measured data from large-scale wind power production and forecasting.

II. Reserve requirements due to wind power

The operating reserve requirement addresses short-term flexibility for power plants that can respond to load and generation unbalances. These are caused mainly by a combination of prediction errors and variability inside the dispatch interval (in the range of 5–60 minutes). The reserves are operated according to total system net imbalances, for generation and demand, not for each individual source of imbalance.

A. Experience

The experience so far is that wind power has not caused investments for new reserve capacity. High levels of wind power output generally cause conventional generation to back down, making them available to provide up-reserve [8]. However, some new pumped hydro schemes are planned in the Iberian Peninsula to manage more than 20% wind penetration levels in the future. The following experience has been reported:

- Ireland: Due to the nature of the Irish system (a small island system with little interconnection), reserve levels are determined with system flexibility in mind. No additional reserve was required during periods of high wind variability. However, frequency and voltage stability concerns have necessitated rules for the number of conventional units that remain online (three units in Northern Ireland and five in the Republic of Ireland).

- Spain: The impact of wind power on automatic fast reserve has been very small, but the impact on manual reserves has already been significant. Using probabilistic methods to determine the reserve requirement has shown good results but still needs testing to gain confidence in the method [7]. One incident of low load and high wind has resulted in down regulation reserve being exhausted (Nov 9, 2010, from 2 to 5 a.m. when 54% of the consumption was provided by wind resources). This was resolved by the TSO ordering some thermal power plants to shut down, followed by some wind curtailment [9].

- Portugal: The reserve requirement/allocation has been increased by 10% of predicted wind power. That is managed by existing hydro and thermal power plants, and occasionally by reducing import from Spain [10].

B. Estimates from the studies

There are several methods that can be used to calculate the impact of wind generation on operating reserves. The computation of reserve requirements requires estimates of the uncertainty and variability of demand, wind generation, and other generation as inputs. For wind power, the forecast horizon time scale is a crucial assumption because the uncertainty will decrease more significantly than for demand at shorter time scales. A common approach is to compare the uncertainty and variability before and after the addition of wind generation. Adding wind generation means allocating additional reserves to maintain a desired reliability level [11]. These can usually be supplied by unloaded generation at least at lower penetration levels.

The results presented in Figure 1 for increase in reserve requirements have been updated by studies from Canada/Hydro Quebec [12]; Germany [13] and [14]; Ireland [15] Workstream 2B); NL [11]; US/New England ISO [16]. Previous work from 2005-07 are presented for Sweden [17]; UK [18] and US/Minnesota 2006 [19].

There is a large range of results for estimates of increases in reserve requirements. This is mainly due to different time scales of uncertainty taken into account in different studies. It is noteworthy that the results for hourly variability of wind are very close to each other from the different studies: in the range of 3% of installed wind capacity or less, with penetrations below 20% of gross demand. When taking into account longer term uncertainty the results start scattering. When 4-hour forecast errors of wind power are taken into account, an increase in the short-term reserve requirement of up to 9–10% of installed wind capacity has been reported for penetration levels of 7–20% of gross demand. The highest results in Figure 1 are from a study in which 4-hour variability of wind (not forecast error), combined with load forecast error, results in a 15% reserve requirement at 10% penetration and an 18% reserve requirement at 20% penetration of gross demand [18].

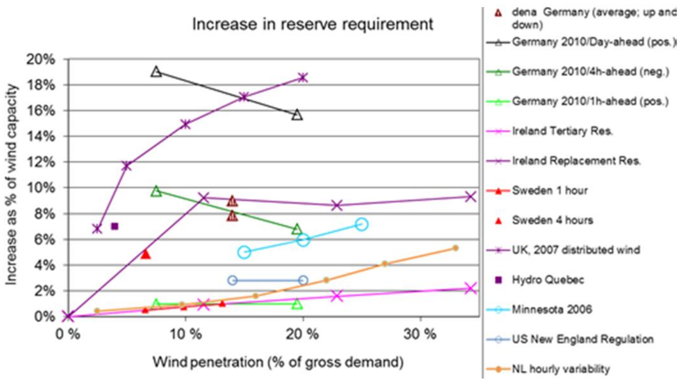

Figure 1. Results for the increase in reserve requirement due to wind power, as relative to wind penetration level.

Some results of special note are German calculations that show how longer forecast time impacts the uncertainty of wind and through that the reserve requirements – if only hour ahead errors are covered by reserves, the required reserves are much smaller than if day-ahead forecast errors are balanced with the short-term reserves. In an earlier German study [20], the reserve requirement was taken as the average impact of day-ahead forecast errors of wind power, showing values of nearly 10%. Using the maximum values would result in an increase that is 15–20% of installed wind capacity [20]. It can be assumed that the wind power forecast will also improve in the future. The German dena grid study II [14] estimates the positive and negative automatic (secondary) and manually activated (minute) reserve for the year 2020 and assumes that the forecast error will decrease by 45% compared to 2008 and this will actually result in lower reserve requirements for 27% penetration level of wind than the 6 % penetration in 2010.

For Ireland, the results for reserve requirements show that the requirement for primary operating reserve (time scale seconds) does not increase significantly with increased wind capacity. There is, however, a significant increase in the tertiary reserve requirements, (Fig. 1, assuming a 1-hour forecast horizon (scheduling in Ireland is based, at best, on a 4-hour forecast).

For Hydro Quebec, the hourly reserve (Automatic Generation Control AGC and load-following reserve) is evaluated based on a method that allocates these reserves differently than most other studies. When adding wind to the system, usually the incremental increase in reserve needs that are caused by wind energy is calculated. The method employed by Hydro Quebec allocates reserves to load and wind based on a variability allocation. This different approach results in the load share of reserves declining after wind is added to the system, which allocates more reserve to wind than an incremental method would. However, because of the capabilities of the hydropower system in Quebec, additional reserve for wind is not needed [12].

For Independent System Operator New England (ISO-NE) in the United States reserves were estimated dynamically in [16]. Additional 10 minute spinning and non-spinning reserve to help manage wind ranged between 193 MW and 261 MW depending on the scenario, at a 20% average penetration, for a wind capacity of approximately 8.1 GW (the installed capacity varies by the sites selected to meet the energy target). The lower penetration level with approximately 6.5 GW gives similar results. ISO-NE results in Figure 1 are based on the average regulating reserve across multiple scenarios at the given penetration rate.

Because wind power output and its uncertainty varies, it is now recognized that reserves should be calculated dynamically for power systems with large amounts of wind power: if allocation is estimated once per day for the next day instead of using the same reserve requirement for all days, the low-wind days will make less requirements on the system, which is cost effective for the system. As the use of dynamic reserve calculations increases, a more standard approach to reporting the results is clearly needed. For example, the California Independent System Operator (ISO) [22] produced estimates for regulation (primary/secondary reserve) that are approximately 100–500 MW or 1–5% of installed wind capacity; however, these are maximum values taken from a dynamic calculation where reserve is a function of the current wind output level. Other results for wind power impacts on this fast response automatic reserve type are very low (e.g., 10 times lower see [23]). Statistical characterizations that include multiple parameters, such as the mean, maximum, minimum, and standard deviation, or the use of annual duration curves can help accurately communicate the reserve characteristics from the analyses [24].

The time steps chosen for dispatch and market operation can strongly influence the quantity and type of reserve required for balancing. For example, markets that operate at 5 minute time steps, can automatically extract balancing capability from the generators that will ramp to fulfil their schedule for the next 5-minute period [25].

The increasing reserve requirement is usually calculated for the worst case. However, this does not necessarily mean new investments for reserve capacity – rather, generators that were formerly used to provide energy could now be used to provide reserves.

III. IMPACTS ON BALANCING

The variability and uncertainty of wind power will impact how the balance of the conventional power plant in a system is run. Changing the output level from the plants will incur costs due to additional ramping and starts/stops. To study the impact of wind on operation of power systems, simulation model runs that optimise the dispatch of all power plants to meet varying load are made. Most results on balancing costs are based on comparing costs of system operation without wind and adding different amounts of wind.

It is challenging to extract system balancing costs from the total operational costs. Comparing to any alternative to wind is difficult as an alternative would also influence fuel costs. The increase in balancing cost depends heavily on fuel cost assumptions for conventional plant.

The results presented in Figure 2 for an increase in balancing costs due to wind power have been updated for Ireland [26] and US Eastern Wind Integration Study [27], which has three scenarios for the 20% penetration level; in Figure 2, the lowest result was used. The previous results from 2002-2009 for Nordic countries and Germany [28]; UK [29] and [18]; US Minnesota [30] and [19]; US California [31] and US Colorado [32] are shown.

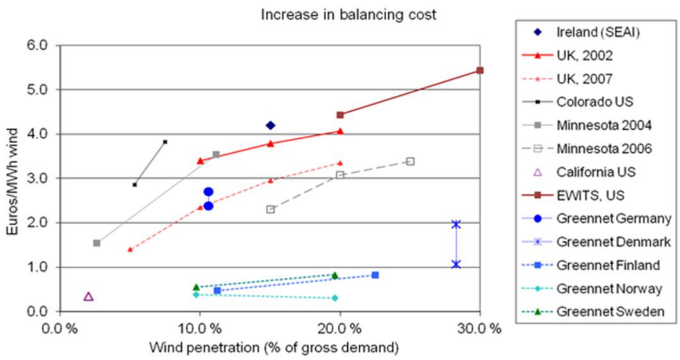

Figure 2. Results from estimates for the increase in balancing and operating costs due to wind power. The currency conversion used here is 1 € = 0.7 £ and 1 € = 1.3 US$.

System operating cost increase due to wind variability and uncertainty amounts to approximately 1–4.5 €/MWh for wind penetrations of up to 20% of gross demand (energy). This is 10% or less of the wholesale value of the wind energy. In [20] more results from US are compared, where the wind penetration level is presented as capacity % of peak load, showing a clear correlation of larger balancing areas and lower integration costs. Most of these cost estimates consider only the cost of variability and uncertainty, and not the full cost-benefit impact of wind energy.

In addition to estimates, there is some experience with actual balancing costs for the existing wind power from electricity markets: 1.3–1.5 €/MWh for 16% wind penetration (Spain), and 1.4–2.6 €/MWh for 24% wind penetration (West Denmark).

When estimating balancing costs, a general conclusion is that if interconnection capacity is allowed to be used for balancing purposes, then the balancing costs are lower compared to the case where they are not allowed to be used. Other important factors that were identified as reducing integration costs were: aggregating wind plant output over large geographical regions, and scheduling the power system operation closer to the delivery hour.

Not all case studies presented results quantified as monetary values for increase in balancing costs. Below are some short summaries of results related to electricity markets, hydropower and wind, and general system studies.

A. Balancing costs from electricity markets

Balancing market integration for the Nordic region, Germany, and the Netherlands in cases of future high penetration of wind power was estimated to reduce activated reserve by 24% due to imbalance netting. The annual expected operational cost saving would be approximately 512 million €, which is 30% of the system balancing cost. In order to draw the imbalances in the system, the wind forecast errors for 3 hours ahead are selected. Dynamic allocation of balancing exchange (on a daily basis) for the high-voltage direct current (HVDC) link between Norway and Denmark would reduce annual procurement cost by 5.93 million € compared to fixed allocation on an annual basis [33].

In Sweden and Finland, the balancing costs as payments for wind power producers have been estimated to be 0.3–3 €/MWh from the balancing market (Nordic Regulating Power market) prices, depending on how distributed the wind power is and on the market price level for balancing ([34]-[36]). These balancing costs only include the costs related to unpredictability because wind power variability is handled in the Nordic day-ahead market.

The use of an intra-day market to help reduce the imbalance costs of wind power has been examined in Germany [37], and for the Nordic market in Finland [38] and Sweden [35]. For lower penetration levels and the current price assumptions, there is not a straightforward benefit for producers to use an intra-day market to correct all imbalances foreseen. This is because the imbalance payments only apply to the imbalances that affect the total power system net imbalances – and wind power is not causing imbalances 100% of the time (at low penetrations, only 50% of the time as wind imbalances do not correlate with other imbalances in the system). It is clear that at higher penetration levels, correcting at least a larger forecast error closer to delivery would reduce impacts for the system and also be worthwhile from the producer's point of view [39].

In simulated cases in the Netherlands, it is shown that the international trade of electricity and postponing market gate closure are important solutions for integrating more wind power in an efficient way. Wind power worsens the business case for thermal generation, in particular for combined cycle gas turbine CCGT during peak demand and for base-load coal during low demand [40].

EU project TradeWind evaluated the effect of improved power market rules and quantified these in terms of reduction of the operational costs of power generation, for the scenarios reaching 33 % wind penetration in 2030-40. The establishment of intra-day markets for cross-border trade is found to be of key importance for market efficiency in Europe because it will lead to savings in system costs on the order of 1–2 billion € per year as compared to a situation in which cross-border exchange must be scheduled day-ahead [41].

B. Wind impacts on balancing in hydropower dominated systems

Hydropower with large reservoirs has the potential to provide balancing for larger amounts of wind power. The Norwegian reservoir size of approximately 85 TWh is nearly half of the total installed reservoir size in Europe. The hydropower system benefits from higher HVDC capacities because Norway can import more wind energy, especially in periods of low prices in the continent and UK power market. As a result, water can be stored in the reservoirs, so hydropower can be exported in periods of high prices in the continent and the UK [42].

In Sweden, the capability of hydropower to balance various amounts of wind power in Northern Sweden was studied [43]. The existing hydropower in Northern Sweden has sufficient installed capacity and is fast enough to balance at least up to 30 TWh of wind power (i.e. 20% of gross demand). An important aspect is that Sweden has comparatively strong interconnections with its neighbouring countries.

Several countries indicate the increase of the energy storage capacity using pumped hydro stations (PHS) (Portugal, Spain, Norway) and other forms, such as heat storage (Finland and Sweden) as a means to integrate more wind generation when penetration is already high, typically above 15% [44]. However, an optimized articulation of the operation of PHS and wind generation would require the design of new market operation principles.

C. Other balancing results from system studies

In Denmark, the TSO has estimated the impacts of increasing the wind penetration level from 20% to 50% (of gross demand) and concluded that further large-scale integration of wind power calls for exploiting both domestic flexibility and international power markets with measures on the market side, production side, transmission side, and demand side [45] and [46].

The Irish All Island Grid Study shows that going from 2 to 6 GW of wind, the operational costs of the electricity system fall by 13 €/MWh when compared to the base case. Due to the cost benefit approach in the study, the cost component was not published as such [15].

A joint study by SEAI and EirGrid simulated the 2011 All Island System with and without wind [26]. Comparison showed that 2.2 GW of wind power increased constraint costs by 24 million € or 4.2 €/MWh. This increase in constraint costs, along with subsidy costs, was offset almost equally by decreased wholesale market prices resulting in a neutral net cost difference overall.

The Eastern Wind Integration and Transmission Study [27] calculated the impact of 20% and 30% wind energy in the Eastern Interconnection of the United States, with three 20% cases with alternative wind locations. Based on hourly production simulations modelling the study found that the bulk power system could be operated at these wind levels, assuming a high degree of coordination in operations across the eastern power markets.

The Western Wind and Solar Integration Study (WWSIS [47]) for the Western Interconnection of the United States found that:

- up to 27% wind and solar energy penetration was feasible if operational changes including Balancing Area (BA) cooperation and intra-hour scheduling between BAs were made. Additional flexibility reserves were not needed for the wind variability, but they were needed for the wind uncertainty to cover extreme forecast errors. As holding high levels of flexibility reserves 8760 hours of the year for only 89 hours of events per year is costly, an additional 1300 MW of demand response that could respond to contingencies would provide a more cost-effective approach to system balancing.

- as wind and solar are initially added to the grid (0–15% energy), there were fewer cold starts of fossil plants. As wind and solar penetrations increase (above 15%), the number of fossil plant start-ups increases significantly, especially cold starts. Phase 2 of WWSIS determined wear-and-tear costs and impacts for cycling and ramping of fossil plants [48]. A new cost data set was utilized with a production simulation model to determine the maximum level for these wear-and-tear costs. The electricity production simulation model ran a day-ahead unit commitment and 5-minute economic dispatch. At 33% wind and solar energy penetration (16.5 % each, respectively), the ceiling wear-and-tear cost was $35-157 million, or $0.14–0.38/MWh of wind and solar energy produced. This is 0.7–1.7% of the value of wind and solar energy **Error! Reference source not found.**, as measured by the reduction in fuel costs.

In [9] it was shown that the intra-hour variations of total wind power from larger areas varies from 3% (percent of installed capacity, standard deviation) when mean distance between wind power plants are 10 km for 30-min changes down to less than 0.5% for mean distance of 350 km and time horizon 10 min.

IV. Grid Impacts

Grid reinforcement may be needed for handling larger power flows and maintaining stable voltage, and is commonly needed if new generation is installed in weak grids far from load centres. The issue is generally the same, be it wind power plants or any other power plants. The grid reinforcement needed for wind power is very dependent on where the wind power plants are located relative to load and grid infrastructure, and hence results vary from country to country.

Grid studies involve a more detailed simulation of power flows in the transmission grid, to confirm the steady-state adequacy and utilization of the transmission system and to assess if the grid is sufficiently strong to cope with added wind power plants also during significant failures. Dynamic system stability analyses are usually not performed at lower penetration levels unless particular stability issues are foreseen in the system. Wind turbine capabilities are still evolving and may mitigate some potential impacts of wind power.

The allocation of grid investments to wind power is challenging, in a similar manner to balancing costs. System operators rarely make allocation of grid infrastructure because new infrastructure usually benefits all users. The investments are made for improving electricity market operation, to increase the security of supply and to bring about strategic transitions in the long-term sustainability of electricity supply. Even in cases where wind power would be the main reason for investing, after the grid is built, it is not possible to allocate the benefits to any single user.

There is a trend towards regional planning efforts around the world, with regions ranging over several countries.

A. *Transmission planning for larger areas*

In the United States the following approaches to transmission expansion for remote wind projects have been undertaken [49]:

- The Electric Reliability Council of Texas (ERCOT) has designated specific remote areas with excellent wind resources as Competitive Renewable Energy Zones (CREZ), and undertaken a transmission expansion plan to link these regions with load centers. Once a transmission line has received the necessary approvals, its cost is rolled into the rate base and all customers pay a pro-rata share of its cost. The approved plan consisted of an integrated 345 kV system expansion with over 2000 miles of new lines to accommodate over 18,400 MW of wind capacity. California, Colorado, and Minnesota have similar processes underway.

- The Eastern Interconnection of the United States was studied in [27]. Without transmission enhancements, substantial curtailment of wind generation would be required for all of the 20% scenarios. Although costs for aggressive expansions of the existing grid are significant, they make up a relatively small piece of the total annualized costs. In comparing the alternative transmission build-out scenarios, a common “core” of transmission corridors can be identified, that represent a robust selection of lines that will be useful regardless of the specific wind scenario that will evolve.

In Europe, cross-border transmission is also an issue at the European level:

- In the TradeWind project power flows in the European transmission network were simulated with the expected wind power capacity deployment scenarios reaching 300–400 GW in 2030, a 33% share of the electricity demand covered by wind power in 2030–2040. Increasing wind power capacity in Europe was found to lead to increased cross-border energy exchanges and more severe cross-border transmission bottlenecks in the future, especially with the amounts of wind power capacity in 2020 and 2030. If the 42 identified onshore and offshore cross-border transmission upgrades were implemented, operational costs of power generation would be reduced by 1.5 billion € per year after 2030 [41].

- A key recommendation from the European Wind Integration Study EWIS is that pan-European modelling, coordinated and adjusted by more precise regional or national models, should be further developed and used to assess future development of the European transmission network, with increasing wind penetration levels [50]. These recommendations have afterwards been implemented by the European Network of Transmission System Operators (ENTSO-E) in their work on the Ten-Year-Network Development Plans (TYNDP). EWIS also examined the benefits of enhancing cross-border interconnection capacity and identified those links that are likely to have congestion-reducing benefits that exceed the likely capital costs. These include some 30 links with a total capital cost of approximately 12 billion € where fuel savings and CO2 emission benefits would probably exceed the reinforcement capital costs. Most of the links identified in the EWIS study are also confirmed by the TYNDP editions of 2010 and 2012 [51].

• The EU-project SUPWIND assessed transmission infrastructure extension as a mitigation measure for the effects of increased wind generation in power systems. Results show that reinforcements of 500 MW each in eight existing interconnectors and five new 1 GW lines, costing 8.1 billion € of investment, would bring benefits of 15.5 billion € in 2020. Also, with additional grid capacity, electricity prices converge to a higher extent compared to a case without investment [52][53].

• The European Network of Transmission System Operators for Electricity (ENTSO-E) is composed of 41 European TSOs who are organized in 6 regions. ENTSO-E started publishing Ten-Year-Network-Development-Plans (TYNDP) every second year, composed of 6 regional investment plans and one Pan-European plan extracting the projects of Pan-European interest. While the 2012 edition showed two scenarios, one reflecting the European 2020 energy targets, and the other one with slight variations, the 2014 edition will come up with 4 scenarios on the year 2030 along two axes: The European framework being either loose or strong on one axis and the energy roadmap 2050 being either on track or not on the other axis. Common planning starts with elaborating and consulting these scenarios on Pan-European and regional level, which are then analyzed using market simulation tools. The market flow results and beneficial projects are delivered to the grid experts. The international grid expert groups use this input for detailed network studies to analyze the proposed or additional projects, which then are described by seven indicators in the bi-annual TYNDP report. Among these indicators are e.g. RES integration, social welfare, CO2 emission variation, flexibility and environmental sensibility. The indicators are described in a Cost-Benefit-Analysis guideline developed by ENTSO-E together with the regulators' organization ACER and the European Commission [54]. The results of TYNDP 2012 show that for 125 GW of new connected renewable energy sources (mostly wind and photovoltaic), delivering 38% of the electricity demand in 2020, and facilitating CO2 emissions from the power sector to decrease by 28–57%, grid investments of more than 100 billion € are necessary. These will save 5% of the generating costs by connecting electricity markets. Approximately 51500 km of grid corridors will be built or refurbished through 2020, of which 12300 km are direct current DC connections. This is an increase of 1.3% in grid length development. The costs correspond to 1.5–2 €/MWh over the 10-year period, which is approximately 2% of the bulk power prices or less than 1% of the total end-users' electricity bill [51].

In Europe, another new and international issue is offshore wind power and transmission planning with offshore grids. European 2020 targets concerning offshore wind power sum up to an amount of 42 GW. Assumptions concerning installed offshore wind capacity for 2030 range from 55 MW to 150 MW for the North seas alone. Another European target is to better integrate European power markets by increasing interconnections.

• European project OffshoreGrid research study aimed to find the most beneficial connection concept for offshore wind plants, comparing different variants [55][56] The overall infrastructure costs for connecting 126 GW of offshore wind power plants by 2030 in the North Sea would amount to 84–86 billion €, representing about a fifth of the value of the electricity that is generated offshore by 2030. 114 out of 321 offshore wind power plant projects were recommended to be clustered in hubs, saving up to 14 billion € by 2030 (total investment costs 69 billion € rather than 83 billion €). Two designs enabling increased interconnection between countries (so called split design and direct design) were investigated and both are shown as highly beneficial from a socio-economic perspective because the offshore interconnection capacity in northern Europe is boosted from 8 GW in 2009 to more than 30 GW by 2030. This will also enhance balancing in central Europe by connecting large hydro power capacities in northern Europe. The project found that a meshed offshore grid would make the offshore wind power plant connection more reliable and significantly increases security of supply within Europe. The additional cost for creating a meshed offshore grid, even including wind power plant connections and planned interconnectors, would according to OffshoreGrid amount to only 0.1 €c/kWh consumed in the 27 European Union countries (EU27) over the project life time.

• At the end of 2010 the North Seas Countries Offshore Grid Initiative (NSCOGI) had been formed by the energy related ministries of the ten countries around the North Seas with the objective of coordinating investigations on technical and grid planning questions, as well as identifying market and regulatory barriers. The initiative comprises ministries, national regulators, the TSOs and the European Commission. For a comprehensive grid design study, the governmental assumptions of 55 GW installed offshore wind capacity in the North Seas were analyzed as well as a sensitivity of 117 GW [57][57][59]. Two main structures, radial vs. meshed, have been compared in order to find out if Europe should continue with national solutions, or if international coordination should be increased due to regional socio-economic benefits. While the 55 GW scenario showed only marginal regional differences in on- and offshore infrastructure investment costs of ~30 bn€ as well as in annual production cost savings (including all fuel types around) of ~1,45 M€/a, the sensitivity showed increased advantages for the meshed solution already when comparing necessary offshore investment cost.

To provide technical input assumptions for the NSCOGI grid study, ENTSO-E has published an HVDC technology report, reporting on which technology is assumed to be available in 2030 [60].

B. Transmission planning from national studies

The reported results in the national case studies for grid reinforcements are as follows:

• In Ireland a network investment strategy out to the year 2025 to accommodate up to 40% energy from renewable generation (approximately 6.6 GW of wind generation capacity) and future conventional generation and demand growth estimates total investment of 4 billion € [61]. The All Island Grid Study [15] indicates that for 2.25 GW of renewables, of which 2 GW is wind, modest amounts of additional high-voltage transmission are required. For 6.6 GW of renewables, including 6 GW of wind, total capital investment in transmission in excess of 1,000 million € will be required. This represents a total investment of 154 €/kW of renewable generation installed. When annualised, these costs were modest, adding on the order of 1–2% to the cost of electricity, even in the highest wind portfolios. Significant reactive power issues were identified that were addressed more fully in EirGrid Facilitation of Renewables studies [62], with on-going work [63] including measures to address them.

- In Italy, investments in reinforcement of the transmission grid in the short term have been estimated to about 2.5 billion € for integration of an additional 4 GW of wind power and 5 GW of solar, considering respectively the existing 8.1 GW and 16.6 GW already installed in 2012 [64].

- The Spanish TSO Red Eléctrica de España (REE) plans an investment of 8,000 million € during 2007–2016 to accommodate high renewables targets [65]. To integrate the planned wind power capacity into the Spanish power system also compliance with the actual and proposed technical grid code requirements are required and challenges remain in the areas of dynamic voltage control and management of reserves.

- In Portugal, an effort to allocate the grid reinforcement costs to wind power has been made. The Portuguese TSO has consistently invested in added transmission capacity to integrate the wind production: 145 million € in the period 2004–2009, for increasing wind penetration from 3% to 13%), 159 million € for the 2006–2010 period (16% driven by wind and other smaller independent producers), and 120 million € for the period 2009–2014 (9% of the network investment dedicated to the connection of wind and other comparatively small independent producers) [49]. The grid reinforcement cost for 5,100 MW of wind power was estimated to be 53 €/kW wind installed, when only accounting for the proportion related to wind power of total cost of each grid development or reinforcement [66].

- In Germany, dena II study [14] calculated the annual cost of grid investments for renewables, including annualised capital as well as operational cost, rather than the investment alone. The result is an annual cost of approximately 20 €/kW/year for 51 GW of wind, together with 18 GW of photovoltaics and 6 GW of biomass generation capacity in 2020 when 39% of the gross electricity consumption is assumed to be contributed by renewable energy sources. After the dena studies, the four TSOs in Germany and the national Regulator BNetzA have launched German Network Development Plan (NDP). At the end of a 2-year's process with public consultations at different steps of the process, the common proposal is given to the government who turns it into national law. The development plan is built around four general scenarios with variants in the national fuel mix. Fulfillment of the national 2020 target of 35% electricity consumption being provided by RES is a prerequisite for all scenarios. The market flows and corresponding physical flows are identified, triggering the need for grid expansion. In the three 2023 Scenarios variable renewable resources amount to 46-86 GW for onshore wind, 10.3-18 GW offshore wind and 55-61 GW for solar energy. For the 2033 scenario onshore wind is 66 GW, offshore wind is 25 GW and solar capacity 65 GW. In the TSO's NDP 2013 edition the identified grid expansion amounts to 1,700 km new AC lines plus 3,400 km AC-refurbishment, together estimated at a cost of 21 bn€. Additionally, 2,100 km of HVDC lines divided to four corridors should be built. The grid expansion is not only caused by renewable energies, but by multiple reasons, e.g. the German nuclear phase out, thus the costs are not explicitly allocated to a certain source, because the infrastructure serves and benefits multiple purposes [67]. Currently the NDP2012 is in the process to be turned into national law, while the NDP2013 is at the stage to be checked by the national regulator. While TSOs and the regulator go through the planning steps every year, the government only treats the issue every third year.

The German dena grid study II [14] investigated the cost of a number of different technologies for a major grid extension, since public acceptance of new overhead lines is a major problem. Dynamic line ratings, taking into account the cooling effect of wind together with temperature in determining the transmission constraints, can increase transmission capacity from the North to the middle of Germany by 40% to 90% at times when the German wind power generation is above 75% of the installed capacity. For 99% of the time, the increase is above 15% for all lines, except some very unfavourable cases in which only an increase of 5% is calculated [68]. However, it does not significantly reduce the amount of grid reinforcement needed if all wind-generated power is to be transported at any time [14]. Comparing conventional overhead lines to high-temperature conductors was not cost effective (three conventional 600-km lines at a cost of 0.9 billion €/year compared to only one 700-km new line along with five 700-km line upgrades at a cost of 1.6 billion €/year). The use of an HVDC meshed grid with underground cables would also exceed the conventional line costs (three 400-km new cables with a cost of 2 billion €/year). Gas insulated lines were also investigated, but found to be much more expensive than all other options.

V. CAPACITY VALUE

Wind power has a capacity value in addition to its energy value. The recommended methodology for assessing the capacity value of wind power is Effective Load Carrying Capability (ELCC) based on loss of load expectancy calculations [69]. If using of alternative, simplified methods they should be compared to the more robust approaches based on reliability analysis. Approaches used to calculate capacity credit based on simplified approaches in the United States are summarised in [70].

The results updated in Figure 3 for capacity value of wind power are from the following studies: Ireland [15]; Quebec [71] and US Eastern Interconnect [27]. The previous study results are from Germany [21]; Norway [73]; UK [29]; US Minnesota [19][30]; US New York [72] and US US California [31].

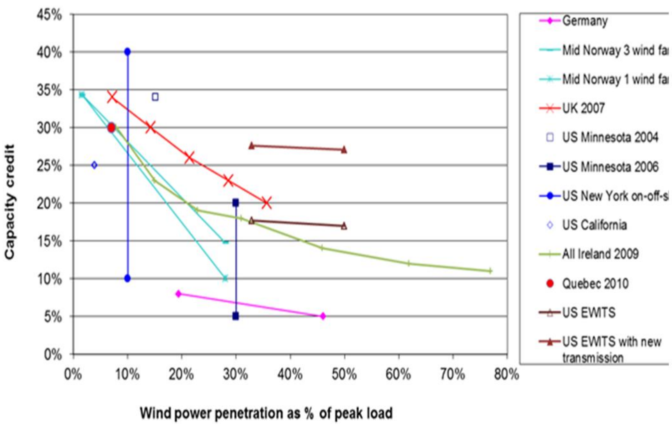

Figure 3. Capacity credit of wind power, results from ten studies, showing reduction of capacity value as penetration level increases.

The results show a range from 5-40% of installed wind power capacity. With correlated wind power and load, the capacity value of wind can be significant, as can be seen in the case of US New York, where onshore wind is generally not high during peak load situations giving capacity value of 10 %, whereas offshore winds tend to blow also at peak load situations giving capacity credit of 40 %. One reason for different resulting levels arises from the wind regime at the wind power plant sites and the dimensioning of wind turbines. This is one explanation for the low German capacity credit results shown in Figure 3. For near zero penetration level, most capacity credit values are in the range of the capacity factor of the evaluated wind power plant installations. The capacity value of wind will decrease as wind penetration increases.

Aggregation benefits apply to capacity credit calculations – for larger geographical areas, the capacity credit will be higher. The US Eastern Wind Integration Study [27] showed the impact of adding more transmission to enlarge the area: Without transmission overlay the results were between 16–23% (for scenarios of 20% and 30% penetration) and with new transmission 24%–33% of wind rated capacity.

VI. Discussion and Conclusions

The national case studies address different impacts: balancing the power system on different short-term time scales; grid congestion, reinforcement, and stability; and power adequacy. Reasons underlying the wide range for wind integration impacts include definitions for wind penetration, reserves types, and costs; different power system and load characteristics and operational rules; assumptions on the variability of wind, generation mix, fuel costs, and the size of balancing area; and assumptions on the available interconnection capacity.

There is already significant experience in integrating wind power in power systems. The mitigation of wind power impacts include more flexible operational methods, incentivising flexibility in other generating plants, increasing interconnection to neighbouring regions, and application of demand-side flexibility. Electricity storage is still not as cost effective in larger power systems as other means of flexibility, but is already seeing initial applications in places with limited transmission. Electricity markets, with cross-border trade of intra-day; balancing resources; and emerging ancillary services markets are seen as a positive development for future large penetration levels of wind power.

In many studies, estimates for integration costs are presented. Integration cost can be divided into different components arising from the increase in the operational balancing cost and grid expansion cost. The value of the capacity credit of wind power can also be stated. In most case studies, a comparison with other alternatives to wind has not been studied. Estimating the integration costs of wind power is challenging because capturing and allocating costs are not straightforward. It is difficult to allocate infrastructure or system costs to a single technology because the infrastructure and system services benefit all grid users, both consumers and producers, and integration cost is not deterministically observable. This inability to assess integration cost has resulted in multiple indirect methods for estimating it. While it is very difficult to calculate the costs of integrating wind, estimates indicate that these costs are manageable. When considering the question of integration costs, it is also important to keep in mind that all generation sources, including nuclear and fossil plants, have costs associated with integrating them into the grid and managing their individual characteristic operational capabilities to provide a stable and reliable electricity supply to meet varying load.

The Task 25 has proved to be valuable forum for exchange of information on wind integration internationally and work will continue to assess different methods for capturing integration impacts as well as highlight emerging experience and solutions in integration.

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