Impacts of large amounts of wind power on design and operation of power systems, results of IEA collaboration

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Abstract — There are a multitude of studies made and ongoing related to cost of wind integration. However, the results are not easy to compare. An international forum for exchange of knowledge of power system impacts of wind power has been formed under the IEA Implementing Agreement on Wind Energy. IEA WIND R&D Task 25 on "Design and Operation of Power Systems with Large Amounts of Wind Power" has produced a state-of-the-art report in October 2007, where the most relevant wind power grid integration studies are analysed especially regarding methodologies and input data. This paper summarises the results from 18 case studies with discussion on the differences in the methodology as well as issues that have been identified to impact the cost of wind integration.

Index Terms — grid integration, wind power, power system operation, reserve requirements.

1. Introduction

The existing targets for wind power anticipate a quite high penetration of wind power in many countries. It is technically possible to integrate very large amounts of wind capacity in power systems, the limits arising from how much can be integrated at socially and economically acceptable costs.

Wind power production introduces more uncertainty in operating a power system: it is continuously variable and difficult to predict. To enable a proper management of the uncertainty, there will be need for more flexibility in the power system: either in generation, demand or transmission between areas. How much extra flexibility is needed depends on the one hand on how much wind power capacity already has been installed in the respective region and on the other hand on how much flexibility already exists in the power system considered.

In recent years, several reports have been published in many countries investigating the power system impacts of wind generation. However, the results on the costs of integration differ and comparisons are difficult to make due to different methodology, data and tools used, as well as terminology and metrics in representing the results. An R&D Task titled "Design and Operation of Power Systems with Large Amounts of Wind Power Production" has been formed within the "IEA Implementing Agreement on the Co-operation in the Research, Development and Deployment of Wind Turbine Systems" [i] in 2006 to collect and share information on the experience gained and the studies made, with analyses and guidelines on methodologies. The Task has started by producing a state-of-the-art report on the knowledge and results obtained so far and will end with developing guidelines on the recommended methodologies when estimating the system impacts and the costs of wind power integration. When possible, best practice recommendations will be formulated on system operation practices and planning methodologies for high wind penetration.

2. Power System Impacts of Wind Power

Wind power has impacts on power system operational security, reliability and efficiency. The studies address different impacts and the different time scales involved usually mean different models (and data) used in impact studies. The case studies for the system wide impacts have been divided to three focus areas: Balancing, Adequacy of power and Grid (Fig 1). In this international collaboration (IEA WIND Task 25), more system related issues are addressed, as opposed to local issues of grid connection like power quality. Primary reserve is here denoted for reserves activated in seconds (frequency activated reserve; regulation) and secondary reserve for reserves activated in 10...15 minutes (minute reserve; load following reserve).

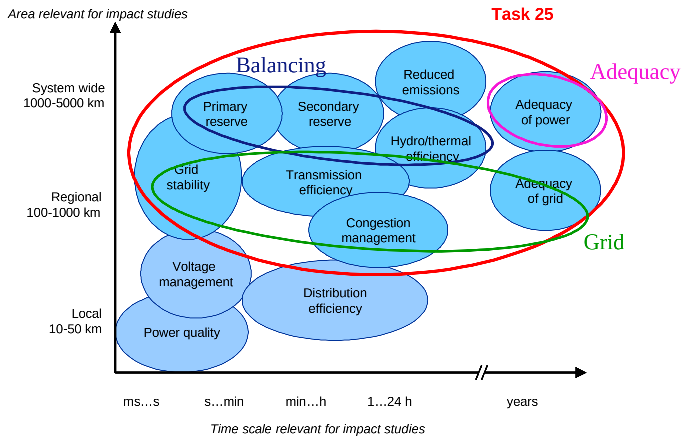

Figure 1 Impacts of wind power on power systems, divided in different time scales and width of area relevant for the studies.

Balancing: increases needed in allocation and use of short term reserves (time-scale minute…half an hour) and the impact of wind variability and prediction errors on efficiency and unit commitment of existing power capacity (time scale: hours…days). Unpredicted part of the variations of large area wind power should be combined with any other unpredicted variations the power system sees, like unpredicted variations in load. Variability of wind power impacts also on how the conventional capacity is run and how the variations and prediction errors of wind power change the unit commitment. Analysing and developing methods of incorporating wind power into existing planning tools is important in order to take into account wind power uncertainties and existing flexibilities in the system adequately. The simulation results give insight into the technical impacts of wind power, and also the (technical) costs involved.

Adequacy of power: total supply available during peak load situations (time scale: several years, associated with static conditions of the system). The estimation of the required generation capacity needs includes the system load demand and the maintenance needs of production units (reliability data). The criteria that are used for the adequacy evaluation include the loss of load expectation (LOLE), the loss of load probability (LOLP) and the loss of energy expectation (LOEE), for instance. The issue is the proper assessment of wind power's aggregate capacity credit in the relevant peak load situations – taking into account the effect of geographical dispersion and interconnection.

Grid: The impacts of wind power on transmission depend on the location of wind power plants relative to the load, and the correlation between wind power production and electricity consumption. Wind power affects the power flow in the network. It may change the power flow direction, reduce or increase power losses and bottleneck situations. There are a variety of means to maximise the use of existing transmission lines like use of online information (temperature, loads), FACTS and wind power plant output control. However, grid reinforcement may be necessary to maintain transmission adequacy and security. When determining adequacy of the grid, both steady-state load flow and dynamic system stability analysis are needed. Different wind turbine types have different control characteristics and consequently also different possibilities to support the system in normal and system fault situations. For system stability reasons operation and control properties will be required from wind power plants at some stage depending on wind power penetration and power system robustness.

3. Summary of case studies reviewed

For the case studies reviewed in this paper, the emphasis is on more recent studies and especially on those that have tried to quantify the power system impacts of wind power. A short description of the studies is given here, a more detailed description is provided in [ii] also listing on-going research. A summary table for the power systems and largest wind penetration studied is presented in Table 1.

Greennet-EU27 [iii] estimated increases in system operation costs as a result of increased shares of wind power for a 2010 power system case covering Denmark, Finland, Germany, Norway and Sweden combined with three wind cases. The integration costs of wind is calculated as the difference between the system operation costs in a model run (WILMAR) with stochastic wind power forecasts and the system operation costs in a model run where the wind power production is converted into an equivalent predictable, constant wind power production during the week.

Operating reserve requirement due to wind power in the Nordic countries has been estimated in 2004 [iv], up to 4 GW of wind in the 14 GW peak system of Finland and up to 18 GW wind in the 67 GW peak system of Nordic countries (10-20 % penetration). Methodology is the statistical method

Table 1. Data for power systems and wind power in case studies. The year for power system load scenario is marked after the region name (expect for Minnesota where the year refers to the study). The use of interconnection capacity is not taken into account in studies marked with *. In Nordic 2004 study the interconnection capacity between the Nordic countries is taken into account, not the interconnection to outside Nordic area.

	Load			Inter-connect. capacity	Wind power					
					2007	Highest studied		Highest penetration level		
Region / case study	Peak MW	Min MW	TWh/a	MW	MW	MW	TWh/a	% of peak load	% of gross demand	% of (min load + interconn)
Denmark 2025	7200	2600	38	5190	3125	6500	20.2	90 %	53 %	83 %
Nordic 2004/VTT	67000	24000	385	3000*	4356	18000	46	27 %	12 %	67 %
Nordic+Germany/Greennet	155500	65600	977	6600	26603	57500	115	37 %	12 %	80 %
Finland	14000	5900	90	2280*	110	7300	16	52 %	18 %	89 %
Germany 2015 / dena	77955	41000	552.3	10000*	20622	36000	77.2	46 %	14 %	71 %
Ireland / ESBNG	6500	2500	38.5	0	805	3500	10.5	54 %	27 %	140 %
Ireland / SEI	6900	2455	39.7	900	805	1950	5.1	28 %	13 %	58 %
Ireland 2020/All island	9600	3500	54	1000	900	6000	19	63 %	35 %	178 %
Netherlands	25200	9000	127	7350*	1746	10000	35	40 %	28 %	61 %
Mid Norway /Sintef	3780		21			1062	3.2	28 %	15 %	
Portugal	8800	4560	49.2	1000*	2150	5100	12.8	58 %	26 %	92 %
Spain 2011	53400	21500	246.2	2400*	15145	17500	46	33 %	19 %	73 %
Sweden	26000	13000	140	9730*	788	8000	20	31 %	14 %	35 %
UK	76000	24000	427	2000*	2389	38000	115	50 %	27 %	146 %
US Minnesota 2004	9933	3400	48.1	1500*	1300	1500	5.8	15 %	12 %	31 %
US Minnesota 2006	20000	8800	85		1300	6000	21	30 %	25 %	68 %
US New York	33000	12000	170	7000	430	3300	9.9	10 %	6 %	17 %
US Colorado	7000		36.3			1400	3.6	20 %	10 %	
US California	64300	25000	304		2439	12500	34	19 %	11 %	
US Texas	65200	16000	317		4356	15000	54	23 %	17 %	

combining the standard deviations of wind and load variations time series, 4 times standard deviation of the variations time series is used as confidence level (4s). Three years of synchronous hourly time series for load and (up-scaled) wind power was used. The better predictability of load was taken into account applying load forecast errors instead of load time series. The cost estimates take into account of both new reserve capacity and the increased use of reserves. In 2008, the grid reinforcement needs and costs were evaluated in M.Sc thesis [v] for 2-7.3 GW wind in Finland. The overall grid investments were estimated to 149 Million € for 2GW wind (5 % penetration) and 394 Million € for 7.3 GW wind. This reduced to wind related costs of 8 and 253 Million € when planned grid reinforcements were taken into account.

The Swedish additional reserve requirements for 4-8 GW wind (7-13 % penetration) for the 26 GW peak system were estimated based on similar approach than the Nordic 2004 study, combining the standard deviation of load and wind variation time series. Time scales used were for one and four hour forecast errors separately [vi]. Several years of wind data was acquired based on meteorological data and synchronous load forecast error data was available. No cost estimates were made.

The Danish transmission system operator Energinet.dk has analysed recently implications of the government's energy policy for 2025 of a doubling of wind power to about 6,500 MW until 2025. The change corresponds to a future increase from 20% to about 50% of wind energy coverage in Denmark [vii]. 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. Another study [viii] focusing at the year 2030 with a slightly different grid structure compared to [vii] concentrated on different options of grid expansion. The respective grid reinforcement costs with different options (cabling, overhead lines) results in 335-4906 Million Euros cost for 400 kV transmission grid and 27-1542 Million Euros cost for the 130-150 kV transmission grid, total between 363 and 6448 Million Euro. The reason for grid expansion is the implementation of wind energy on the one hand and market requirements on the other hand.

The impact of wind power on system adequacy for one region in Norway [ix] is assessed using data from a real life regional hydro-based power system with a predicted need for new generation and/or reinforcement of interconnections to meet future demand. Wind power will have a positive effect on system adequacy. Wind power contributes to reducing the LOLP and to improving the energy balance. Adding 3 TWh of wind or 3 TWh of gas generation are found to contribute equally to the energy balance, both on a weekly and annual basis. Both wind and gas improve the power balance. The capacity value of gas is found to be about 95 % of rated, and the capacity value of wind about 30 % at low wind energy penetration and about 14 % at 15 % penetration. The smoothing effect due to geographical distribution of wind power has a significant impact on the wind capacity value at high penetration.

In German Energy Agency’s (dena) study [x] the integration of a total of 36 GW of wind power capacity into the German transmission system in 2015 was studied. According to this study, approximately 850 km of 380-kV-transmission routes as well as reinforcement of 390 km of existing power lines will be needed. In addition, numerous 380-kV-installations will need to be fitted with new components for active power flow control and reactive power compensation (approximately 7,350 Mvar till 2015). A modification of the existing German Grid Code, for instance in view of fault-ride-through and grid voltage control was necessary. Capacity credit of wind power was estimated as well as the additional requirement for reserves. The regulating and reserve power capacity required for the following day was determined in relation to the forecasted wind infeed level. The additionally required regulating energy could be provided by the existing conventional power stations so no cost estimate for reserves was made.

The All Island Grid Study [xi], commissioned by the government of the Republic of Ireland and Northern Ireland included a network study to quantify necessary transmission system upgrades and a unit commitment and dispatch study. Within the modeling limitations of the study methodologies, the study found that up to 42 % of energy from renewable sources (mainly wind) was feasible and that there would be additional costs of the order of 7 % over a business as usual case. There were also significant CO_2 reduction benefits (25 %) and security of supply benefits seen as a reduction in the import of fuels. The study highlighted the need for appropriate plant mix with such high levels of renewables and it also illustrated the significant impact of the operation of thermal plant and the need for substantial network reinforcement. Base portfolio was 2GW wind (Ireland currently has 1GW) and is taken as a business as usual case. Going to 6GW wind the operational costs fall by €13/MWh when compared to the base case. Transmission costs (not annualised) are 915 Million € to go from base case to 6GW. Additional storage did not appear to bring additional benefits, although this needs further study. Improved forecasting did bring some modest benefits. The study also documented the need for further work and concluded that some additional costs were not captured. In previous work, the TSO ESBNG [xii] made system simulations using a unit commitment and dispatch simulator. The study found that a high wind energy penetration greatly increased the number of start ups and ramping for gas turbine generation in the system and that the cost of using wind power for CO_2 abatement in the Irish electricity system is €120/Tonne. Capacity credit of wind power was estimated by assessing the amount of conventional plant that is displaced, while keeping generation adequacy at the desired level. In Irish SEI report [xiii] system simulations were made using a proprietary system dynamic model. Fuel cost and CO_2 savings up to a 1500MW wind power penetration in the Republic of Ireland (ROI) system were directly proportional to the wind energy penetration. It found that while wind did reduce overall system operation costs it could lead to a small increase in operating reserve costs: 0.2 €/MWh for 1300 MW wind and 0.5 €/MWh for 1950 MW of wind.

In UK amounts for increase in reserve requirements are estimated to be modest – around 5% of the wind plant capacity, at the 20% penetration level (% of gross demand). Estimates of extra reserve costs from [xiv] used market costs, which may be expected implicitly to include a capital recovery element. A value of £2.38 per MWh of wind produced for 10% wind penetration is used, rising to £2.65/MWh at 15% and £2.85/MWh at 20% penetration. Transmission costs will depend on how the wind power plants are distributed in UK: if onshore wind generation were developed across Great Britain and included the offshore wind resources around the England and Wales coast, then transmission reinforcement costs could be significantly smaller than if wind power plants were developed mostly in Scotland and off the North West and North East of England and North Wales coasts. In [xiv] costs of between £275m and £615m to accommodate 8 GW of wind, i.e. between £35/kW and £77/kW, were found. In [xv] the effects of connecting wind power plants at various locations across the country considering also the impact of the locations of existing, new and decommissioning conventional plants. The range of cost was found to be between £1.7b and £3.3b for 26 GW wind. Lower values correspond to scenarios with dispersed wind generation connections, while the higher values correspond to the scenarios with considerable amount of wind being installed in Scotland and North of England. For a small level of wind penetration the capacity value of wind is roughly equal to its load factor, approximately 35%. But as the capacity of wind generation increases, the marginal contribution declines. For the level of wind penetration of 26 GW, about 5GW of conventional capacity could be displaced, giving a capacity credit of about 20% (for a future UK system 70GW peak load and a 400TWh energy demand, and a 35% load factor of wind).

In the Netherlands, the consequences of 6000 MW offshore wind power for the 150/380 kV grid were determined by a load flow study. This showed that additional voltage control equipment is required and that a limited number of lines have to be upgraded. Investment costs to the grid were estimated at 344-660 Million €, depending on location/scenario (about 4% of est. total investment for 6 GW wind) [xvi]. Research into the system integration of wind power has shown that minimum load problems rather than the variability or partial unpredictability of large-scale wind power can be foreseen to be the bottleneck for system integration in the Netherlands [xvii]. Additional flexibility from conventional units or use of interconnection capacity will be required. The system integration of future large-scale wind power in the Netherlands does not necessitate the development of energy storage, especially if international exchange is available [xviii]. Although energy storage provides significant opportunities for the reduction of total system costs, this comes at the expense of additional CO_2-emissions at the system level, due to energy conversion losses inherent to energy storage and the additional operation of base-load coal-fired plants at the expense of peak-load gas-fired plants, the latter of which produce less CO_2 on a MWh-basis [xix].

For Portugal, in the overall period 2005–2010, the investment in transmission grid directly attributable to renewables, mostly for wind parks, will total 200 Million €. These numbers do not consider the investment of the wind park main substation nor the direct line to the transmission network connection point, which are built by the promoter. In studies carried out by Spanish and Portuguese TSOs REE and REN [xx-xxi] the wind power impacts on the grid were studied under different scenarios (demand, wind energy production and different degrees of adaptations of new wind turbine and wind power plant technologies). Two scenarios were studied with 17500 MW of installed wind power. With 75% of wind power technically adapted, transient stability was supported for 14000 MW wind power production in a peak demand scenario and 10000 MW wind power production in a valley one (time of low demand). The importance of future 400 kV D/C interconnection line with France was highlighted.

In the Spanish case, wind power development has imposed new connecting and operating rules for wind power plants. The transmission network updates of 2200 Million €, not only attributable to renewable, has been estimated by REE for the overall period 2006–2010. In terms of investments due to wind energy, it is difficult to obtain the figures since grid reinforcements and new lines are needed also due to electrical demand growth which has been high in the last years.

The first Minnesota Dept. of Commerce/Enernex Study (2004) [xxii], estimated the impact of wind in a 2010 scenario of 1500 MW of wind in a 10 GW peak load system. Three year data sets of 10-minute power profiles from atmospheric modeling were used to capture geographic diversity. Wind plant output forecasting was incorporated into the next day schedule for unit commitment. Extensive time-synchronized historic utility load and generator data was available. A monopoly market structure, with no operating practice modification or change in conventional generation expansion plan, was assumed. Incremental regulation due to wind was found to be 8 MW (at 3s confidence level). Incremental intra-hour load following burden increased 1-2 MW/min. (negligible cost). Hourly to daily wind variation and forecasting error impacts are the largest cost items. A total integration cost of $4.60/MWh was found, with $0.23/MWh representing increased regulation costs, and $4.37 due to increased costs in the unit commitment time frame. A capacity credit of 26%-34% was found with a range of assumptions using the ELCC method.

The second Minnesota Dept. of Commerce/EnerNerx study (2006) [xxiii] took as a subject power system a consolidation of four main balancing areas into a single balancing area for control performance purposes. Simulations investigating 15%, 20%, and 25% wind energy penetration of the Minnesota balancing area retail load in 2020 were conducted. The 2020 system peak load is estimated at 20,000 MW, and the installed wind capacity is 5700 MW for the 25% wind energy case. Three years of high resolution wind and load data were used in the study. The cost of wind integration ranged from a low of $2.11/MWh of wind generation for 15% wind penetration in one year to a high of $4.41/MWh of wind generation for 25% wind penetration in another year, compared to the same energy delivered in firm, flat blocks on a daily basis. These are total costs and include both the cost of additional reserves, and cost of variability and day-ahead forecast error associated with the wind generation. The cost of the additional reserves attributable to wind generation is included in the wind integration cost. Special hourly runs were made to isolate this cost, which was found to be about $.11/MWh of wind energy at the 20% penetration level. The remainder of the cost is related to how the variability and uncertainty of the wind generation affects the unit commitment and market operation. In the study, the Minnesota balancing authority was assigned responsibility for all the reserves and intra-hour resources for balancing. At the hourly level, the day-ahead markets and in-the-day re-dispatch at the hourly level were administered by MISO for the entire footprint, with an assumed 2020 peak load in excess of 120 GW. Since the real-time market actually operates on five-minute increments, further efficiencies could be obtained if it were assumed that out-of-state resources were available to balance within the hour. Capacity values were investigated and ranged between 5% and 20% for the scenarios studied.

The NYSERDA/GE Energy Study for the New York ISO [xxiv] estimated the impact of wind in a 2008 scenario of 3300 MW of wind in a 33 GW peak load system. Wind power profiles from atmospheric modeling were used to capture statewide diversity. The study used the competitive market structure of the NYISO for ancillary services, which allows determination of generator and consumer payment impacts. For transmission, only limited delivery issues were found. Post-fault grid stability improved with modern turbines using doubly-fed induction generators with vector controls. Incremental regulation due to wind was found to be 36 MW. No additional spinning reserve was needed. Incremental intra-hour load following burden increased 1-2 MW/ 5 min. Hourly ramp increased from 858 MW to 910 MW. All increased needs can be met by existing NY resources and market processes. Capacity credit was 10% average onshore and 40% offshore. Significant system cost savings of $335- $455 million for assumed 2008 natural gas prices of $6.50-$6.80/MMBTU were found.

The Xcel Colorado/Enernex Study (2006) [xxv] examined 10% and 15% penetration cases (wind nameplate to peak load) in detail for ~7 GW peak load system. Regulation impact was $0.20/MWh and hourly analysis gave a cost range of $2.20-$3.30/MWh. This study also examined the impact of variability and uncertainty on the dispatch of the gas system, which supplies fuel to more than 50% of the system capacity. Additional costs of $1.25-$1.45/MWh were found for the 10% and 15% cases, bring the total integration costs to the $3.70-$5.00/MWh range for the 10% and 15% penetration cases.

The CA RPS Integration Cost Project [xxvi] examined impacts of existing installed renewables (wind 4% on a capacity basis). Regulation cost for wind was $0.46/MWh. Load following had minimal impact. A wind capacity credit of 23%-25% of a benchmark gas unit was found. The Intermittency Analysis Project in [xxvii] studied three different scenarios: 7500 MW and 12500 MW wind power for year 2010 64 GW peak load system (20 and 33 % total renewable capacity penetration) and 12700 MW for year 2020 81 GW peak load system (33 % total renewable capacity penetration). The study recommended significant increases in transmission infrastructure. For scenario 2010accelerated: 72 new or upgraded line segments equalling $1.2 billion. For 2020 scenario (including increased 2020 load): $5.7 billion in transmission upgrades. The California ISO added to this study with their results on integration impacts [xxviii]. The ISO reported an extremely large increase in regulation capacity, which is due to assumptions on forecast errors by persistence. The report showed that existing generation resources would be able to account for the required increases in regulation and load following capacity in normal operation conditions but that it is possible during low hydro periods and because of the reliance on slower moving thermal units that the ISO may need to commit additional capacity for the required regulation.

In Texas the ERCOT/GE study [xxix] looked at penetrations of up to 15,000 MW wind power in a 65 GW peak load system. Using a 98.8th percentile for changes in regulation requirements with wind, the study reported about a 54 MW and 48 MW increase in up regulation and down regulation, respectively. The load following time scale was not studied in detail. Interestingly in this study, the cost of regulation per MWh of wind using a state-of-the-art wind forecast increases as wind capacity reaches 10,000 MW up to $.27/MWh but then decreases to an actual savings of regulation costs of $.18/MWh at the 15,000 MW penetration level. The reason for this is that even with the higher regulation requirements the regulation clearing prices for the ancillary service market decrease as the unit commitment problem is solving to commit cheaper units because of the added wind. Therefore the lost opportunity costs for regulation decrease and also payments for regulation as $/MWh regulation decrease. This conclusion hasn’t been seen in any other integration study. Wind generation also decreases the total production cost on the system to about $55/MWh of wind energy due to a decrease in energy prices.

4. SUMMARY OF RESULTS ON INCREASED BALANCING REQUIREMENTS

Summaries for the results for balancing requirements presented in section 3 are presented in Fig 2 and 3.

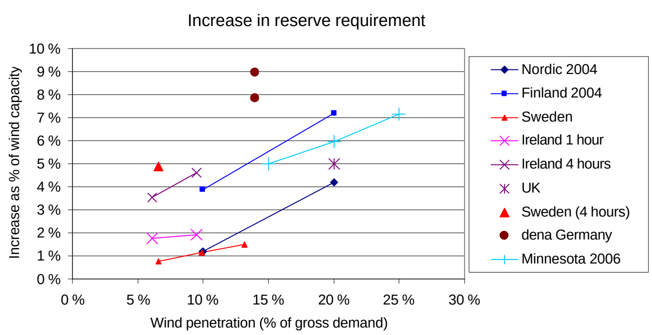

Figure 2. Results for the increase in reserve requirement due to wind power. German dena estimates are taking into account the day-ahead uncertainty (for up and down reserves separately). In Minnesota, day ahead uncertainty has been included in the forecast. For the others the effect of variations during the operating hour is considered. For UK, Ireland and Sweden the 4 hour-ahead uncertainty has been evaluated separately.

The increase in reserve requirement is mostly estimated by statistical methods combining the variability of wind power to that of load. In some studies also the sudden outages of production is combined to reserve requirements (disturbance or contingency reserve). For the impact on operation of power systems, model runs are made and most results are based on comparing costs of system operation without wind and adding different amounts of wind. The costs of variability are also addressed by comparing simulations with flat wind energy to varying wind energy (for example in US Minnesota and Greennet Nordic+Germany). The differences in methods used will also contribute to the differences in reserve requirement results and balancing costs.

The increase in short term reserve requirement has been estimated to less than 4 % of installed wind capacity with low penetration (<10 % of gross demand) and for hourly variability of wind, to about 5 % for forecast errors for 4 hours ahead and to nearly 10 % if day-ahead forecast errors are left to be balanced with the short term reserves.

At wind penetrations of up to 20% of gross demand, system operating cost increases arising from wind variability and uncertainty amounted to about 1-4 €/MWh. This is 10% or less of the wholesale value of the wind energy. It can be seen that there is considerable scatter in results for different countries and regions.

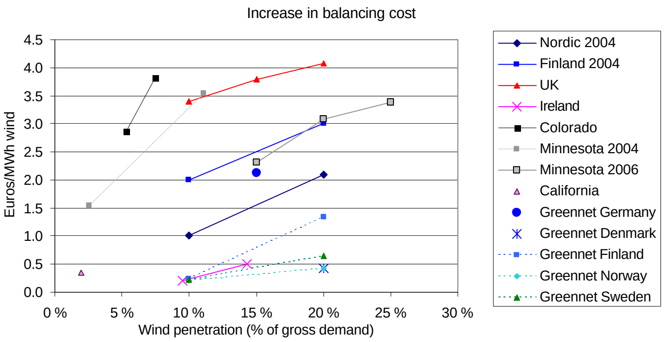

Figure 3. Results from estimates for the increase in balancing and operating costs due to wind power. The currency conversion used here is *1 € = 0.7 £ and 1 € = 1.3 US$.*

The following differences have been remarked:

- Different time scales used for estimating – For UK, the increased variability to 4 hours ahead has been taken into account. For US studies also the unit commitment impact for day-ahead scheduling is incorporated. For the Nordic countries and Ireland only the increased variability during the operating hour has been estimated. For the Greennet study, the unit commitment and reserve allocation are done according to wind forecasts but the system makes use of updated forecasts 3 hours before delivery for adjusting the production levels.
- Costs for new reserve capacity investment – For the Greennet and SEI Ireland studies only incremental increase in operating costs has been estimated whereas also investments for new reserves are included in some results (Nordic 2004)
- Larger balancing areas – The Greennet, Minnesota 2006 and Nordic 2004 studies incorporate the possibilities for reducing operation costs through power exchange to neighbouring countries, whereas Colorado, California, German dena study, Sweden, UK and Ireland studies analyse the country in question without taking transmission possibilities into account. The two studies for Minnesota, US show the benefit of larger markets in providing balancing. The same can be seen from the Nordic 2004 results compared with results calculated for Finland alone. Dealing with large wind output variations and steep ramps over a short period of time could be challenging for smaller balancing areas. Larger power systems make it possible for smoothing of the wind variability.

As shown in table 1 the interconnection capacity to neighbouring system is often significant. For the balancing costs it is then essential in the study setup whether the interconnection capacity can be used for balancing purposes or not. A general conclusion is that if interconnection capacity is allowed to be used also for balancing purposes, then the balancing costs are lower compared to if they are not allowed to be used. From first review of methodology the other important factors identified as reducing integration costs were aggregating wind plant output over large geographical regions, and operating the power system closer to the delivery hour.

The recently published Irish All Island Grid Study Going from 2 to 6 GW wind the operational costs fall by €13/MWh when compared to the base case – due to cost benefit approach in the study, the cost component was not published as such.

5. SUMMARY OF GRID RESULTS

With current technology, wind power plants can be designed to meet industry expectations such as riding through voltage dips, supplying reactive power to the system, controlling terminal voltage, and participating in SCADA system operation with output and ramp rate control. In areas with limited penetration, system stability studies have shown that modern wind plants equipped with power electronic controls and dynamic voltage support capability can improve system performance by damping power swings and supporting post-fault voltage recovery. The results of the studies performed in Spain and Portugal suggest that at higher penetration levels, requiring sufficient fault ride through capability for large wind power plants would be economically efficient.

Grid reinforcements may be needed for handling larger power flows and maintaining a stable voltage, and is commonly needed if new generation is installed in weak grids far from load centers. The issue is generally the same be it modern wind power plants or any other power plants. The cost of grid reinforcements due to wind power is therefore very depending on where the wind power plants are located relatively to load and grid infrastructure, and one must expect numbers to vary from country to country. It is also important to note that grid reinforcements in general should be held up against the option of curtailing wind or altering operation of other generation, and these latter options may in some cases prove to be very cost efficient.

For the grid reinforcement, the reported results in the national case studies are:

- UK: £65-125 / kW (85-162 €/kW) for 26 GW wind (20 % energy penetration) and £35/kW- £77/kW for 8 GW of wind
- Netherlands: 60-110 €/kW for 6 GW offshore wind
- Portugal: from 53 €/kW (only summing the proportion related to the wind program of total cost of each grid development or reinforcement) to around 100 €/kW (adding total costs of all grid development items) for 5.1 GW wind.
- Germany, dena study: 100 €/kW for 36 GW wind.
- Finland, 2008: 54 €/kW for 7.3 GW wind. If grid will be reinforced due to other needs with a scenario assumed extra costs for wind power are 35 €/kW.
- Ireland, 2008: The grid investments are 228 € per kW for the additional 4 GW to reach 6 GW, or 153 €/kW allocated for all of the 6 GW of wind.

- In Denmark there is a large range for future grid investments depending on whether cabling or overhead lines are used: 107-1910 €/ kW for additional 3 GW of wind (or 53-994 €/kW for 6.5 GW wind, assuming the costs for existing 3 GW have been small). This cost is not all attributable to wind power.

The costs of grid reinforcement needs due to wind power cannot be directly compared, they will vary from country to country much depending on location of the wind power plants relative to load centers. The grid reinforcement costs are not continuous; there can be single very high cost reinforcements. Also there can be differences in how the costs are allocated to wind power – for example, in Portugal it has been evaluated how much of the new lines are due to wind power, and only that part of the costs have been allocated to wind.

6. Summary of adequacy/capacity credit results

The capacity credit of wind power answers questions like: Can wind substitute other generation in the system and to which extent? Is the system capable of meeting a higher (peak) demand if wind power is added to the system?

Wind generation will provide some additional load carrying capability to meet expected, projected increases in system demand. This contribution can be up to 40% of installed wind power capacity (in situations with low penetration and high capacity factor at times of peak load), and down to 5 % in higher penetrations or if regional wind power output profiles correlate negatively with the system load profile.

Results for the capacity credit of wind power are summarised in Fig 4. Results of capacity credit calculations show a considerable spread. One reason for different resulting levels arises from the wind regime at the wind power plant sites. For zero penetration level, all capacity credit values are in the range of the capacity *factor* of the evaluated wind power plant installations. This is one explanation for low German capacity credit results shown in Fig. 4. The correlation of wind and load is very beneficial, as can be seen in Fig. 4 in the case of US New York offshore capacity credit being 40 %.

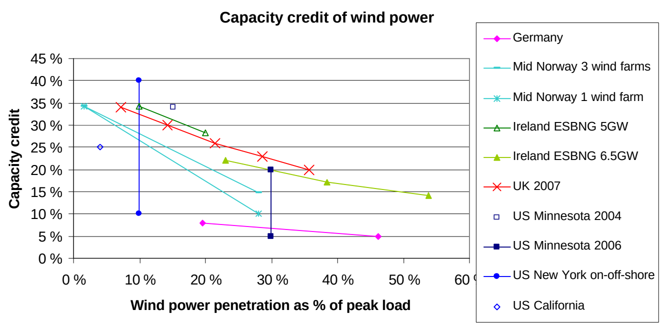

Figure 4. Capacity credit of wind power, results from national studies.

The wind capacity credit in percent of installed wind capacity is reduced at higher wind penetration, but depends also much on the geographical smoothing. This is demonstrated comparing the cases of Mid Norway with 1 and 3 wind power plants. In essence, it means that the wind capacity credit of all installed wind in Europe or the US is likely to be higher than those of the individual countries or regions, even if the total penetration level is as in the individual countries or regions. Indeed, this is true only when assuming that the grid is not limiting the use of the wind capacity, i.e. just as available grid capacity is a precondition for allocating capacity credit to other generation

7. Conclusions and discussion

High penetration of wind power has impacts that have to be managed through proper plant interconnection, integration, transmission planning, and system and market operations. 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. The case studies summarized in this paper are not easy to compare due to different methodology and data used, as well as different assumptions on the availability of interconnection capacity.

From the investigated studies, system operating cost increases amounted to about 1-4 €/MWh. This is 10% or less of the wholesale value of the wind energy. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels. The increase in short term reserve requirement has been estimated to less than 4 % of installed wind capacity with low penetration (<10 % of gross demand) and for hourly variability of wind, to about 5 % for forecast errors for 4 hours ahead and to nearly 10 % if day-ahead forecast errors are left to be balanced with the short term reserves.

The cost of grid reinforcements due to wind power is dependent on where the wind power plants are located relative to load and grid infrastructure. The grid reinforcement costs from investigated studies vary from 35 €/kW to 160 €/kW. The grid reinforcement costs are not continuous; there can be single very high cost reinforcements. Also there can be differences in how the costs are allocated to wind power. It is also important to note that grid reinforcements in general should be held up against the option of curtailing wind or altering operation of other generation, and optimised use of transmission network can also postpone grid investments. However, when planning for large wind power additions to the system, grid reinforcements and extensions are usually required, and making the grid reinforcement directly to the foreseen wind amounts in future will in most cases be more cost effective than building the grid in phases. With current technology, wind power plants can be designed to ride through voltage dips and participate in voltage and frequency control.

The capacity value of wind power can be up to 40 % of installed capacity if wind power production at times of high load is high, and down to 5 % in higher penetrations and if local wind characteristics correlate negatively with the system load profile. Aggregating larger areas benefits the capacity value of wind power.

Several issues that impact on the amount of wind power that can be integrated have been identified. Large balancing areas and aggregation benefits of large areas help in reducing the variability and forecast errors of wind power as well as help in pooling more cost effective balancing resources. System operation and working electricity markets at less than day-ahead time scales help reduce forecast errors of wind power. Transmission is the key to aggregation benefits, electricity markets and larger balancing areas.

Integration costs of wind power need to be compared to something, like the production costs or market value of wind power, or integration cost of other production forms. There is also benefit when adding wind power to power systems: it reduces the total operating costs and emissions as wind replaces fossil fuels. Indeed, the benefits are expected to be significantly higher than the costs. Taking fuel savings only, these will be roughly proportional with the wind generation, and a magnitude higher than the foreseen cost of balancing. In this summary only the cost component has been analysed.

For high penetration levels of wind power, the optimisation of the integrated system should be explored. Modifications to system configuration and operation practices to accommodate high wind penetration may be required. For high penetrations there will be need for increased generation flexibility, transmission to neighbouring areas, demand side management or storage (e.g. pumping hydro or thermal or batteries of electric cars). Wind power integration should be assessed at the international level, to identify the needs and benefits of interconnection of national power systems.

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