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Comparison of integration studies of 30-40 percent energy share from variable renewable sources

Lennart Söder
KTH – Royal Institute of Technology, Stockholm, Sweden,
lsod@kth.se

Christoph Pellinger
Forschungsstelle für Energiewirtschaft e.V., Germany
CPellinger@FFE.DE

Miguel Lopez-Botet Zulueta
EDF, France,
miguel.lopez-botet-zulueta@edf.fr

Michael Milligan
NREL, US,
Michael.Milligan@nrel.gov

Juha Kiviluoma
VTT, Technical Research Centre of Finland – Finland
Juha.Kiviluoma@vtt.fi

Damian Flynn
University College Dublin, Ireland,
damian.flynn@ucd.ie

Antje Orths
Energinet.dk, Denmark,
ANO@energinet.dk.

Vera Silva
EDF, France,
vera.silva@edf.fr

Barbara O'Neill
NREL, US,
Barbara.ONeill@nrel.gov

***Abstract*—The amount of wind and solar power in the world is quickly increasing. The background for this development is improved technology, decreased costs for the units, and increased concern regarding environmental problems of competing technologies such as fossil fuels. For the future there are large possibilities for increasing shares. However there have been questions raised concerning the challenges of integrating larger shares of variable renewable power such as wind and solar power. Because of this many studies have been performed concerning larger amounts of variable generation for different regions in the world. The aim of this paper is to compare seven of these ones in order to identify general challenges and results as well as the connection between used method and results.**

***Index Terms*— Wind power, solar power, integration, power system, power transmission, frequency control, balancing of wind power.**

I Introduction

The world's total electric consumption is currently, 2014, around 23500 TWh per year [1] of which around 4 % [1] is provided by wind and solar power, assuming 2000h utilization time for wind power and 1200h for solar power. The increase in the 5 year period 2009-2014 is for solar power +49% per year and for wind power +18% per year [1]. In 2014 Spain covered 24% [2] of their electric energy demand with wind plus solar power. The corresponding figures were 21% for Ireland 25% for Portugal, and 45% Denmark [2]. The impacts and integration efforts are, however, quite different for Ireland, an isolated system, and Portugal, Spain and Denmark which are part of larger electricity systems. For example Portugal, Spain and Denmark west are a part of the European continental synchronous region that has 10% wind and PV while Ireland is only asynchronous connected to UK.

For the future there is a high expectation for a continuous increase. One example is the European decisions for 2020 and 2030, which means an increased target from 20% renewable energy sources, RES, for 2020 up to 27% for 2030 [3] with 29% RES in the electricity generation. These forecasts have increased the interest to study the consequences of much larger shares than today of the annual energy provided by variable renewable sources. The aim of these reports is to identify challenges and find solutions for these systems. The studies sometimes only consider a single country, but there are also studies for larger areas including several countries. The different results depend on a combination of assumptions, available data and used method [4].

In this article several of these studies are compared concerning assumptions, data, calculation method and results. The aims are to identify the type of results that are possible to get from different studies, to identify possible similar results and to explain the reasons for differences. All studies have in common that they treat power systems in the future where around 30-40% of the yearly energy supply comes from variable renewable sources as wind- or solar power.

In Section II the different studies are presented. Section III summarizes the different results and Section IV provides an analysis and comparison of different results. A summary and conclusions are presented in Section V.

II Performed studied for large amounts of variable generation.

In Sweden, Germany, Iberia, Ireland, Europe, and United States there have been, by different reasons, interests to study future systems with larger share of variable renewables, vRES, in the production mix. Below these studies will be shortly explained. All studies use the same set-up with:

- **B:** Background for each report,
- **D:** Used data for wind, solar and other power plants as well as other date, e.g. transmission.
- **M:** Used method to obtain results
- **R:** Results from the study

It can be noted that different studies have different set-ups, so what is input data (**D**) in one study can instead be a result (**R**) in another study

A. Sweden

B: The background is that within around 10-20 years all current Swedish nuclear plants, which started their production in the period 1972-1986, probably will be closed.

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During 2015 decisions were taken to close the 4 oldes stations constructed in the 70th. During 2015 they delivered 40 percent of Swedish consumption and one possibility is to replace these units with bio-fueled combined heat and power, CHP, wind and solar power. There is then a need to study the possibilities of having a large share of variable renewable power in the future in order to estimate the consequences and requirements for the system. This has been studied in [4] , [5] where an electrically isolated Sweden with 40% of yearly energy from solar and wind power has been studied.

D+R: Used data is found in Table 1. Mean distance means the mean distance between the units which is a measure of the size of the area. The larger the area, the higher this value and the lower the variation of total power output and the better the forecast accuracy [6]. The same method as in [7] is used to calculate the mean distance, i.e., to draw a rectangle over the studied area and calculate the mean distance within this rectangle [8], [9].

Transmission: Sweden is divided into 4 areas with limited capacity between the areas. New already planned lines are considered. No lines to neighboring countries are considered.

Source	Share of production	Cap. factor	Mean distance	Data from
Wind (D)	32%	32%	350 km	2009
Solar (D)	8%	14%	350 km	2005
	Max ramp (decrease in one hour)	Max ramp as share of installed capacity	Max share of installed capacity	Installed capacity [MW]
Wind (D)	1409 MWh/h	8 % / hour	97 %	16658
PV (D)	1912 MWh/h	20 % / hour	93%	9797
Source	Energy curtailment: % of production		Max curtailment: % of max prod.	
Wind (R)	2,04 %		30%	
Solar (R)	2,98 %		38%	
RES (R) energy	99 % of all production. 45% from hydro, 14% from bio-fuelled CHP.			
Extra capacity (R)	5200 MW of OCGT, 1% of energy			
Transmission (D)	All planned upgrades are included			
Extra costs (R)	The costs of OCGT is 0,2 Eurocent/kWh split to all load energy.			

Table 1 Data and result for the Swedish study.

Other Power plants: Today hydro power plants are considered. Historically highest hydro power production is considered (13 GW) which is lower than installed hydro capacity (16 GW), i.e. some reserve margins are considered. Bio fueled CHP is expected to increase with 50% compared to today, to 4.4 GW.

Load: Load data from 2011 per area and per hour. The load varies between 8884-26174 MW

M: Yearly hourly simulations are performed [4]. Hourly time series for one year of wind and solar power as well as for load and CHP are used. There is a minimum level of synchronous production requirement (17% CHP + Hydro + OCGT because of inertia requirement) and minimum CHP (max 75% decrease) and hydro (minimum 1,9 GW), so at higher production wind and/or solar power is curtailed. Required hydro balancing is then calculated, and for some cases and assumptions it has been checked that the required hydro balancing was also physically possible. Output from the model is required extra capacity (e.g. OCGT) to fulfill load in low wind/solar periods and high demand. Output also includes hourly values of transmission between areas, and resulting curtailment per hour from solar and wind power.

B. Germany

B: The quickened nuclear phase out and accelerated expansion of RES after the disaster of Fukushima accelerate the energy transition in Germany. Political aims strive a RES share of 40-45% by 2025 and 55-60% by 2035 with respect to demand. As Germany only has little hydropower and biomass, the major part of RES will have to be provided by vRES sources. This raises the question whether there will be demand for extra storage. In [10], storage demand is investigated from a system and business based perspective in order to deduce policy recommendations from likely existing differences in the results of the two perspectives. Though the main focus of the study is the year 2030, 2020 and 2025 are also analyzed from the system perspective. Furthermore, there exist multiple scenarios which differ in demand and grid expansion. Installed RES capacities are equal to the ones in the official German grid development plan [11].

Source	Share of net consump-tion	Cap. factor	Mean distance	Data from
Wind (D)	35 %	33 %	270 km	2012
PV (D)	9 %	9.8 %	270 km	2012
	Max ramp (decrease in one hour)	Max ramp as share of installed cap.	Max share of installed capacity	Installed capacity [MW]
Wind (D)	7520 MW/h	12 % / hour	88 %	72200
PV (D)	8116 MW/h	15 % / hour	70 %	53300
Source	Energy curtailment: % of production		Max curtailment: % of max prod.	
Wind (D)	1,1		19	
Solar (D)	< 0,01		< 0,01	
RES (D) energy	56 % (12% from hydro and biomass)			
Extra capacity (D)	Fixed by the scenario framework: decrease of conventional generation capacity from 2015 to 2025 of 24.4 GW; storage capacities: see below			
New / refurbished transmission (D)	No additional transmission lines compared to the national grid development plan			
Transmission (D)	All planned upgrades are included with a 5 year delay in Germany and cross-border capacities in Europe			
CO2 reductions (R)	Up to 61 % savings compared to 1990 level			
Extra costs (R)	Savings due to optimized storage expansion: 101 Mio.€/year			

Table 2 Data and result for the German study

However, in contrast to [11], in [10] weak wind power turbines with hub heights of around 120 m are taken into account. For newly installed onshore wind power, this leads to full load hours of 3000 instead of 2000. In total, this results in a RES-share of at least 68 % by 2030 which is still consistent with the renewable energy act of 2014.

D+R: Used data and results for the NASA25N scenario can be found in Table 2 for the case with 44% share of wind power and PV.

Transmission:

Within Europe, projects of the TYNDP-2012 [12] are considered. Germany is divided into 20 areas connected via existing and future transmission lines according to the transmission grid dataset from [13]. In both cases, a 5 year delay of the projects is assumed. Imports from and exports to neighboring countries are taken into account with a time-varying trading capacity of 23 GW in average. The links between the German and Austrian regions add up to a transfer capacity of 12 GW. The exchange with neighboring countries amounts to an import of 75 TWh whereas there is an export of 91 TWh.

Other Power plants:

Only existing power plants are considered assuming a fuel dependent life time. Non-gas fired CHPs are replaced by OCGT after they have reached their technical lifetime.

Lignite (12.3 GW), hard coal (20.7 GW), gas (24.4 GW), other conventional (2.18 GW), biomass (8.9 GW), run of the river (3 GW) and seasonal/pumped storage (6.7 GW) are considered. Approximately 34.4 GW of the thermal units are at least partly CHP, which are needed to fulfill the district and industrial heating requirements; extra capacity is mainly added by GTs/CCGTs (4.5 GW).

Load: Total consumption is expected to be 538 TWh with a maximum load of 84 GW and a minimum load of about 35 GW.

Storage: A total of about 6,2 GW (with approximately 40 GWh) installed capacity of pumped hydro storages is used as input data. As a result, industrial demand side management (~3 GW), electrical heaters in public and industrial district heating systems (3,3 GW) as well as heat storages (1 GW/2 GWh) are installed.

M: Hourly resolved simulations of a one year period were performed using a linearized unit commitment and dispatch model for 27 European countries. In a second step, imports and exports resulting from the first run were kept constant and electrical and thermal unit commitment as well as storage expansion were simultaneously calculated for Germany and Austria distinguishing 20 and 8 regions respectively.

Weather data was taken from 2012. To account for start-up costs of thermal power plants costs, the linearization proposed in [14] was used. In the model, no CO_2-Cap is included and industrial power plants in Germany were modeled by taking into account particular incentives. Furthermore, a pre-analysis did show that modeling of frequency reserve is not required, instead simplified estimations are sufficient.

C. *Iberia*

B: The Iberian study reported here sought to isolate how a specific assumption related to frequency reserves impacts the results of integration studies [15]. Frequency reserves have been mainly provided by thermal/hydro generation units. When there is high share of wind power and PV, it becomes increasingly relevant to provide frequency reserves with wind power and PV. Using them can alleviate must-run constraints on thermal units and by doing so save fuel costs. The scenarios started from current situation of 21% variable generation share and moved up to 50% share. A simple sensitivity on the relative share of wind and PV was also performed.

D+R: Used data and results are found in Table 3 for the case with 42% share of wind power and PV.

Source	Share of production	Cap. factor	Mean distance	Data from
Wind (D)	27.3%	24.3%	370 km	2012
PV (D)	13.4%	18.0%	300 km	2012
	Max ramp (decrease in one hour)	Max ramp as share of installed cap.	Max share of installed capacity	Installed capacity [MW]
Wind (D)	2 870	7.1% / h	73.8%	40 211
PV (D)	5 770	22.1% / h	65%	26 119
Source	Energy curtailments: % of production		Max curtailment: % of max prod.	
Wind (R)	2.1 % (0.1%)		40.0 %	
Solar (R)	0.3 % (5.2%)		12.9 %	
RES (R)	50,4 %			
Extra capacity (D)	Just wind power and PV			
Transmission (D)	Only current lines included			

Table 3 Data and result for the Iberian study.

Transmission: Spain is divided into 5 areas and Portugal is presented by 1 area with net transfer capacities between the areas. The capacities are based on current data. No lines to other countries are considered. **Other Power plants**: The power plants were based on historical situation from 2012. 1.6% of total generation came from Run-of-the-river hydro and 6.8% from reservoir hydro. On top of this more wind power and PV were added. **Load**: Load data from 2012 per area.

M: One year of hourly simulations were performed using unit commitment and dispatch model with wind power and demand forecasts. Thermal power plants were modelled individually including mixed integer start-up constraints. Wind power, PV and hydro power had regional aggregation. Reservoir hydro was aggregated into a single reservoir per region, but with 5-7 price steps in each region. The need for primary and secondary frequency reserves was static while tertiary reserve need was affected by wind power, PV and load forecasts.

R: The results are shown in Table 3. The curtailments in parenthesis are from a case where wind and PV were not allowed to participate in frequency reserves. The model did not have any preference whether it curtails wind power or PV and consequently their relative shares varied a lot. Together the curtailment was 1.8 % of annual energy when they were not used for frequency reserves and 1.5 % when they were used. Solar power contributed with a larger share of the curtailment than wind power as shown in Table 3. There was also large change in the amount of nuclear generation. Sometimes the model even down regulated nuclear generation, in order to make room for wind power and PV. The combined 'curtailment' of wind power, PV and nuclear decreased from 6.7 TWh to 4.0 TWh when wind power and PV participated in frequency reserves. The annual electricity demand was 305.7 TWh.

All above results were from the case with 41 % share of wind power and PV. When the share was increased to 50 %, the total wind power plus PV curtailment was 4.5 % without frequency reserve participation and 2.7 % with participation. 'Curtailed' wind power, PV and nuclear was 13.6 TWh and 7.3 TWh respectively.

D. Ireland

B: For the island of Ireland, consisting of the Republic of Ireland (RoI) and N. Ireland (NI) power systems, it was recognised that there was great potential for renewable generation, and in particular wind power. Consequently, the governments of RoI and NI commissioned the all-island grid study (DCENR and DETI) [16], delivered in January 2008, to better understand the technical and economic impacts associated with high penetration from renewable energy sources (up to 59%) for the combined power system for the year 2020. Renewable energy from wind, wave, tidal, hydro, solar and biomass were all considered. The multi-part study consisted of resource assessment, portfolio screening, dispatch study, network study, costs and benefits analysis phases, with 6 different plant portfolios considered.

D: At the time of the study, the installed renewable capacity on the Irish system was ≈ 1 GW (mainly wind and hydro), and consequently the initial phase of the study involved a resource assessment, which then informed the portfolio screening, and latter parts of the study. The location, grid connection point, capacity and levelised cost were identified for all MW-scale potential renewable projects. Wind and demand time series, appropriately scaled for the year 2020, were provided by the TSOs in RoI and NI (EirGrid and SONI). Similar (but reduced) data was obtained for the neighboring GB system from the TSO, National Grid. An existing 500 MW HVDC link to Scotland was considered along with a (future) 500 MW HVDC link to Wales. Conventional generation capacity assumptions and plant data for 2020 were based on TSO inputs, but supported by a range of new build decisions across 6 portfolios, recognizing a range of coal, gas and renewable-weighted futures.

M: Hourly unit commitment stochastic simulations for the combined Ireland and Great Britain system were performed for the defined plant portfolios using supplied demand and renewable generation forecasts. Each thermal power plant was individually modeled, recognizing startup procedures, maintenance schedules and unscheduled outages. Spinning and replacement reserve were modeled, with the former being based on existing tertiary reserve requirement (90 s – 5 min) weighted by wind variability during the activation timeframe, while the latter was determined at each hour with an integral scenario tree tool based on the likelihood of demand and wind forecast errors and forced outages.

R: The main 'public' conclusion from the study was that a portfolio providing a 42% energy contribution from renewable sources (predominantly wind) was technically achievable. Summary results for this portfolio are included in Table 4 below. Subsequently, the 40% renewables targets for the Ireland and N Ireland systems by 2020 were introduced by the respective governments. For the 59% renewables scenario it was viewed that the methodology and the tools employed were being pushed to their limits, and, indeed a system re-design was required, including significant network reinforcement. One major caveat from the study conclusions was that the dynamic behavior of the power system may be significantly affected at higher renewable penetration levels and that this had not been addressed in detail.

Source	Share of consumption	Cap. factor	Mean distance	Data from
Wind (R)	34%	35%	140 km	2005
Solar (R)	0	-	-	-
	Max ramp (decrease in one hour)	Max ramp as share of installed cap.	Max share of installed capacity	Installed capacity [MW]
Wind	~3003	~50,0	~88,3%	6000 MW
Solar	-	-	-	-
Source	Energy Curtailments: % of production		Max curtailments: % of max prod.	
Wind (R)	>0.5 %		3,5%	
Solar (R)	0		0	
RES share of electricity con-sumption (R)	42% (wind, hydro, tidal stream, biomass, biogas)			
Extra production capacity (R)	1800 MW conventional plant retirements; new build 829 MW OCGT, 111 MW ADGT, 1200 MW CCGT, 200 MW tidal stream, ≈300 MW biofuels, ≈ 5000 MW wind			
New / refurbi-shed trans-mission (R)	845 km new lines at 220/275 kV and 110 kV			
Transmission investment cost	1,007 M€ = 63 M€/year = 1,8% of all extra required costs.			
CO2 reductions (R)	24% reduction, relative to low renewables (16%) reference case			
Electricity Production cost savings (R)	30% reduction, relative to low renewables (16%) reference case			

Table 4 Data for the Irish study, mainly from [16], but some data updated from newer studies.

Subsequently, the Facilitation of Renewables (FOR) study [17], [18] was completed in 2010 to examine the spectrum of frequency, voltage, small-signal and transient stability issues. Subsequent initiatives have included the DS3 (Delivering a secure sustainable electricity system) program [19] to fulfill the outcomes of the AIGS and FOR studies, and the GRID25 program [20] to build out the necessary grid expansion.

E. Europe-1: ENTSO-E

B: The European association of the Network transmission system operators ENTSO-E has, based on regulation EC 714/2009 to publish a Ten-Year-Network-Development Plan every other year. The plan is based on 6 Regional Investment plans, which are based on market- and network simulations, analyzing possible future visions concerning the time horizon of 2030. These visions have to consider European Energy targets, recently set to 40 % carbon cut up to 2030, and 27 % energy share of renewables.

The TYNDP published plan in December 2014 [21] comprises four visions; two "bottom-up" visions, i.e., with data provided by the TSOs of each country representing the known national political scenarios; and two "top-down" visions, i.e., focusing more on European ambitions than national policies. The visions are built along two axes: one representing the level of integration of green energy and the other one representing the level of international cooperation. The extreme visions are Vision 1 (national, conventional power) and Vision 4 (international, green power) [22].

Source	Share of consumption	Cap. factor	Mean distance	Time Horizon
Wind (R)	24%	28%	1200	2030
Solar (R)	11%	16%	1000	2030
	Max ramp (decrease in one hour)	Max ramp as share of installed cap.	Total installed capacity (all fuel types	Installed capacity [MW]
Wind	n/a	n/a	1712 (GW) with 1150 GW RES	431250
Solar	n/a	n/a	-	338850
Source	Energy Curtailments: % of total production		Max curtailments: % of max prod.	
Wind + Solar (R)	0.76%		n/a	
RES share of electricity consumption	60%			
Extra production capacity (**D**)	0			
New / refurbished Transmission (**R**)	About 100 investment needs at ~50000km (~25 Tkm DC, ~24 Tkm AC)			
Transmission Investment cost (**R**)	110-150 bn EUR			
CO2 reductions (**R**)	Up to 80% savings compared to 1990 level			
Electricity Production cost savings (**R**)	2…5 EUR / MWh			

Table 5 Market Model Data and results for EuropeanVision 4.

All visions fulfill the European energy targets, with vision 1…4 having a share of 40-60 % renewable energy of the total consumption, leading to saving 40-80 % CO2 compared to the 1990 level.

D+R: Input data for the market models are capacities of installed production units per fuel type and technology and market area, efficiencies per fuel and power plant type, fuel and CO2 prices, climate data for a period of 10 years (=correlated time series of wind, solar, temperatures), time series of electricity consumption. Additionally must-run requirements are fed into the models to avoid security issues.

Input data for network calculations are network data with state of production and consumption level being set according to the hourly market flows. The identified infrastructures projects help avoid 30 to 100 TWh of RES spillage, reducing it to less than 1% of the total supply. Data and results are shown in Table 5.

M: As the target of the study is to identify bottlenecks in the European transmission system and evaluate proposed remedial connections, the market simulations are executed with the production portfolio kept constant according to the assumptions of the respective vision.

Year-Round-Runs of market models using hourly resolutions identify in a first step the market flows (electricity exchanges between countries), the cost for electricity production, data on production per fuel type, resulting CO2 emissions and RES spillage.

The network simulations differ between countries; some execute year-round runs, while most TSOs used a number of representative planning cases of their system. Output data are usual load flow and (n-1) contingency results.

F. Europe-2: EDF R&D

B: EDF R&D Study – Technical and economic analysis of the European electricity system with 40% variable renewables.

The European Commission (EC) has ambitious targets concerning the development of electricity generation from renewables that should rise to 27% of total electricity demand in 2030. Moreover, in 2011 the EC published its energy roadmap that includes a scenario, high RES, with 60% electricity produces from renewable sources of which 40% are variable renewable generation (VRG) as wind and PV [23]. In order to highlight the impacts of 40% variable renewables on the development and operation of the European interconnected system (EIS), EDF R&D conducted a large technical-economic study that analyses several aspects. These include the need for developing generation and interconnection infrastructure, the operation of the European system including flexibility needs and cost benefit evaluation of flexibility sources, the impact of wind and PV on markets prices and plant revenues and the impacts of lower inertia on the frequency stability of the continental European system.

D+R: A significant body of work was conducted to build a realistic representation of the future EIS with high penetration of VRG. This covers the main synchronous regions which are the Great-Britain, Ireland, Nordic system and European continental synchronous area (ECSA). For each country we represent: hydro-generation (run of the river and lake), pump storage, thermal generation data, demand, wind, PV and other renewables (biomass, geothermal, etc) and interconnection capacity. The installed capacity and geographical distribution of VRG is obtained based on national targets and resource potentials. For each scenario, wind, PV and hydro hourly generation are constructed using projections of the development of the generation technology (type and location) and different historical years of meteorological data. Demand data is

Source	Share of consumption	Cap. factor	Mean distance	Data from
Wind (R)	33%	28%	1200	1973-2003
Solar (R)	7%	13%	1000	1997-2010
	Max ramp (decrease in one hour)	Max ramp as share of installed cap.	Total installed capacity (all fuel types	Installed capacity [GW]
Wind	[-35 GW, 50 GW]	[-7%,10%]	1250 GW	485
Solar	[-36,+40]	[-18%,21%]	-	220
RES share of electricity consumption	60% RES with 40% VRG			
Extra production capacity (**D**)	net decrease : -90 GW (decrease in baseload generation and increase in backup capacity)			
New Interconnection capacity compared to today's (**R**)	+47 GW			
CO2 reductions (**R**)	-70% Compared to 1990 levels			
Frequency stability indicators (**R**)	0,8% of the hours there is a risk of under frequency load shedding following to a 3,5 GW loss (Frequency nadir =< 49Hz During 25% of the time Frequency nadir =< 49,2Hz following to a reference incident of 3;5 GW (violation of ENTSO-E recommended security levels)			

Table 6 Results from the EDF R&D study.

constructed using the same meteorological data, combined with load growth and new loads development assumptions. As a result, we obtain 30 scenarios of time-synchronized chronological data. These are combined with randomly generated unit availability to obtain about 100 scenarios. Each country corresponds to a single node with interconnections between countries represented by net transfer capacity (NTC).

The level of interconnection is optimized using sensitivity studies. The conventional generation mix is defined by the market model and its investment loop using the commodity and CO2 prices obtained from [23]. The results are shown in Table 6.

M: As the target of the study is to simulate the development of the generation mix and interconnections required to accommodate 40% VRG and, study the hourly load-generation balancing and flexibility needs of the system and understand the impacts of the connection of an important share of generation with a power electronics interface on the frequency stability of the ESCA. The study is performed using a chain of tools [24] in order to have a whole system approach that covers both generation and network investment and covers time-scales from long term planning to real time system operation, including dynamic frequency stability. This whole system approach builds on a multi-area market equilibrium model, Continental Model (CM) [25], with all units bidding their marginal costs and assuming perfect market competition. CM simulates the hydro-thermal dispatch, for every hour of the year, given the interconnection constraints between the countries. The optimization of water reservoirs and pump storage is performed using dynamic programming. The thermal unit commitment and dispatch, solved using mixed integer linear programming (MILP), minimizes the thermal and hydro generation costs. The stochastic nature of demand, wind, PV and water inflows is incorporated by solving the problem for a large number of scenarios. Each scenario corresponds to an alternative realization of these variables, created using historic weather data, and is composed by chronological data, with hourly resolution, for each country.

The multi-area investment planning problem is solved using an investment loop, Continental Investment Loop (CIL) [24]. The objective of the CIL is to obtain, using an iterative process with CM, a thermal generation mix that minimizes system cost and ensures that the market revenue of every new unit is equal or higher to its annualized fixed and variable costs. The fixed costs include investment and O&M and the variable costs include start-up and fuel costs. An adequacy criterion, defined as the maximum number of hours per year with a marginal cost equal to the value of lost load (VOLL), needs to be respected.

The outputs of the simulation are the generation mix and the hourly generation scheduling and dispatch that respects relevant static constraints. In order to fully access the technical performance of the system, however, further analyses concerning the dynamic robustness of the generation mix is also performed [26].

A. *United States - Minnesota*

B: The state of Minnesota embarked on an engineering study to evaluate increasing levels of renewables from 28.5% (Baseline) to 40% by 2030 (with a second scenario at 50%, but not discussed here) and the impact on reliability and costs. The objective was to calculate the impact on curtailment, unserved energy, thermal unit operation (cycling), reserve violations, ramp rates, ramp ranges and other affected parameters, in the context of increased transmission. Further, a conceptual plan for transmission was intended to be developed to increase access for regional geographic diversity and increased system flexibility.

The study examined an annual 40% wind and solar energy penetration for Minnesota customers. But because of jurisdictional boundaries, the associated Minnesota-centric utilities (Dairyland Power Cooperative, Great River Energy, Minnesota Power and Light Company, Missouri River Energy Services, Northern States Power Company, Otter Tail Power Company, Southern MN Municipal Power Agency, and Minnkota Power Coop) were used as the focus of the study. Thus, the level of renewables for the Minnesota-centric region differs somewhat from that of the state of Minnesota. The data provided is for the Minnesota-centric region.

D: The Minnesota Renewable Integration and Transmission Study (MRITS) study [27] data is provided below. Small hydro and biomass accounts for about 3% renewable energy on top of solar and wind.

Transmission: For non-Minnesota utilities, the Baseline scenario used the 2013 approved MISO Transmission Expansion Plan, which incorporates the CapX2020 plan and the Multi-Value Project (MVP) portfolio. The 40% scenario required 54 transmission mitigations (but no new lines) at a cost of 330 MEuro.

Other Power plants: Coal plant retirements totaled 12.6 GW which is MISO's current expectation, not including the Clean Power Plan 111(d) effects. Other scenarios modified that assumption to avoid Must Run status.

Load: The study year was chosen as 2028 to utilize vetted assumptions and approximate the legislated 2030 target. MN utilities and MISO non-MN demand curves were scaled up from 2013 using load growth rates of 0.5% and 0.75% respectively.

M: MRITS performed power flow, production simulation, and transient analysis. This discussion of results focuses primarily on the hourly production simulations, which used the PLEXOS model. Minnesota was modeled to reach renewable energy targets, and additional resources could be sited in the non-MN states of the Midwest Independent System Operator (MISO). Northern and Central states of MISO retained existing legislated renewable portfolio standards (15%). Central and distributed solar were treated separately in the modeling.

Source	Share of production	Cap. factor	Mean distance	Data From
Wind (R)	24,9%	39,7%	200 km	2006
Solar (R)	1,7%	14,2%	200 km	2006
	Max ramp (decrease in one hour)	Max ramp as share of installed capacity	Max share of installed capacity	Installed capacity [MW]
Wind (R)	2646 MWh/h	36,2 % /hour	19,9%	7319
PV (R)	417 MWh/h	30 % / hour	3,5 %	1375
Source	Energy Spillage: % of production		Max spillage: % of max prod.	
Wind (R)	1,63 %		53,1 %	
Solar (R)	0,04 %		30,1%	
RES share electricity (**D**)	27% from wind and PV, 3% for small hydro and biomass			
Extra capacity (R)	7301 MW of OCGT, 0,06 % of energy			
Transmission (D)	All planned upgrades from CapX2020 and MVP are included, plus 54 mitigation options, total cost of 330 MEuro			
Extra costs (R)	100 Euro/MWh is average cost of OCGTs received when generating			
CO2 reduction (R)	132045 tons/year compared to baseline			
Cost savings (R)	2.2 Euro/MWh production cost savings compared to baseline			

Table 7 Data and result for the MRITS.

Wind and solar plant sites were chosen based on resource maps and NREL hourly resource profiles, distributed among already defined renewable energy zones. [28] The model captured forecast uncertainties between the Day-Ahead Unit Commitment and Real-Time Security-Constrained Economic Dispatch.

Must-run coal plants in the main 40% scenario were allowed to retain their must-run status. This contributed to 0.5% more curtailment for wind plants than the main 40% scenario.

MISO's Dispatchable Intermittent Resources (DIR) process is already in operation for wind and is assumed to be available for solar during the study period.

R: Most of the increased solar and wind in Minnesota was balanced by a decrease in imports. Solar and wind were allowed to be sited in neighboring states. About 53% of incremental wind was sited in Minnesota itself.

The models found that 40% renewables would not impact reliability if transmission upgrades were incorporated, but no new lines were added in the 40% scenario. No impact on reliability was observed, as measured by no unserved energy, no reserve violations, and minimal curtailment.

It was observed that a longer-term forward market (e.g., 3 to 5 days) would reduce coal plant cycling by allowing coal plant owners to modify their operational strategy. In the case of CCGT, utilization was decreased in the 40% scenario.

V Summary and Conclusions

We will now summarize the results from the different studies in order to identify possible general conclusions, at least from these studies. The results from the diffetent studies are summarized in Table 8.

All studies consider systems where 30-40% of the yearly energy comes from of variable renewables. The result includes:

- Additional storage for system level demand-generation balancing has not been found necessary in any of the studies.
- System operability, in particular, the provision of ancillary services and frequency stability will be important issues even in large interconnected systems (EDF R&D study) and wind and PV should contribute to system operability (shown in Ibera study) in future when large penetrations are to be achieved.
- Curtailments are in the range of single-digit percentages.
- The maximum 1h-ramp rate for total wind power is in the range of 8-10% in the studies where this data has been reported, with the exceptions of Ireland and the US, which are smaller systems. The data are plotted in Figure 1.

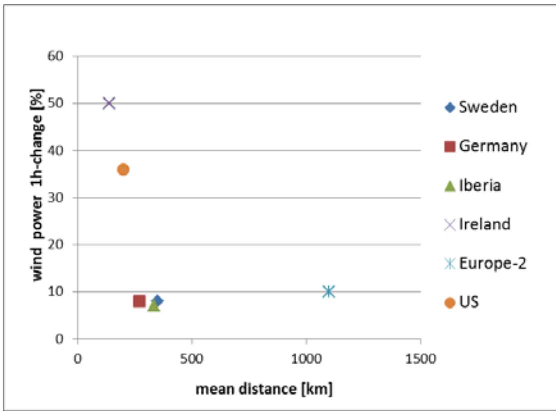

Figure 1 Wind power 1-h changes in the different studies

It can be noted that the Europe-2 study has comparatively high data for such a large system. But this then depends on that 31 climate years were studied, so also rarely were included.

- There can be extra costs for extra capacity and/or for needs of new transmission lines, although the studies do not address avoided costs or capacity if the wind and solar is not built. The reported costs are in the range of single Euros per MWh.

- Different studies have different aims, and it is important to study these when they are compared. If one, e.g., adds more wind and PV to an existing system (e.g. the Iberian study) then one will not need more capacity, to be compared with (e.g. the Swedish study) a study where a future system is studied where thermal generation is replaced with solar/wind. In Europe-1 the target is to identify bottlenecks in the European transmission system and evaluate proposed remedial connections, the market simulations are executed with the production portfolio kept constant according to the assumptions of the respective vision. This is a significant difference to the Europe-2 study which assumes a certain transmission grid instead.
- The possibility to balance wind and solar in a larger area decreased the challenges as shown in the German and US-Minnesota study.
- More transmission limits the challenges of curtailments as shown in the Europe-1 study.

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Area	Sweden	Germany	Iberia	Ireland	Europe-1	Europe-2	US-Minnesota
Solar + wind [Energy-% of total consumption]	40%	41%	41%	34%	35%	40%	27%
Mean distance [km]	350	270	300-370	140	1000-1200	1000-1200	200
Wind – [Energy-% of total consumption]	32%	31%	27%	34%	25%	33%	25%
Wind – max down ramp %/hour	8%	8%	7%	50%	n/a	[-7%,10%]	36%
Solar – [Energy-% of total consumption]	8%	10%	14%	-	11%	7%	1,7%
Solar – max down ramp %/hour	20%	21%	22%	-	n/a	[-18%,21%]	30%
Curtailment– solar+wind [%]	2,2%	0,9%	1.5%	>0,5%	0.76%	n/a	1,53%
Capacity to neighbors: [% of wind+solar capacity]	0%	18%	0%	17%	differs per country	differs per country	n/a

Table 8 Comparison on results from the six different studies

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