

Transmission Grid Extensions for the Integration of Variable Renewable Energies in Europe: Who Benefits Where ?

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Abstract

Variable renewable energy (VRE) generation from wind and sun is growing quickly in Europe. Already today, VRE's power contribution is at times close to the total demand in some regions with severe consequences for the remainder of the power system. Grid extensions are necessary for the physical integration of VRE, i.e., for power transports, but they also have important economic consequences for all power system participants.

We employ a regional, power system model to examine the role of grid extensions for the market effects of VRE in Europe. We derive cost-optimal macroscopic transmission grid extensions for the projected wind and solar capacities in Europe in 2020 and characterize their effects on the power system with high regional and technological resolution.

Without grid extensions, lower electricity prices, new price dynamics and reduced full load hours for conventional generation technologies result in

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proximity to high VRE capacities. This leads to substantial changes in the projected achievable revenues of utilities. Grid extensions partially alleviate and redistribute these effects, mainly for the benefit of baseload and the VRE technologies themselves.

Keywords: Renewable energy, grid integration, merit order effect

1. Introduction

Political targets of the European Union suggest that 34% of the electricity shall be provided by renewable energies in 2020 (EU Commission, 2006). Major contributions will come from wind and solar energy due to their large potential, attractive feed-in tariffs in many countries and expected cost reductions (Edenhofer et al., 2010; IEA, 2011). Wind energy installations in Europe grew by 10 GW in 2009 and 2010 respectively, with additional 13 to 19 GW expected to come online each year until 2020 (GWEC, 2011; EWEA, 2009a). Photovoltaic installations reached 29 GW in Europe, and 17 GW in Germany alone in 2010 (BMU, 2011; EPIA, 2011). For 2020, EPIA sees a 12% share of photovoltaics in European power demand as both necessary and feasible for Europe to achieve its CO₂ reduction goals (EPIA, 2009).

Wind and solar energy, however, are not just another type of power plant that is set to replace other means of generation. They are different from conventional, i.e., thermal dispatchable, generation in at least three respects: First, generation from wind and sun fluctuates – we term them variable renewable energies (VREs) in this paper. The availability of these renewable resources is only partly predictable, important shares of their supply remains stochastic. At times of low wind and sun an almost complete backup power

20 plant park is needed, see e.g. TradeWind (2009), where the capacity credit
21 of wind is only rated at 10-16% on a European level. The capacity credit of
22 wind and solar energy is the dependable share of the VRE capacity, i.e., the
23 amount of other generating capacity that can be removed from the system
24 without reduction of the security of supply. Thus, most of today's power
25 plant park will have to stay online for a significant period of time, but with
26 strongly reduced full load hours (FLH).

27 The second difference is that generation from VREs is subsidized through
28 feed-in tariffs in many countries. Together with extremely low variable gen-
29 eration cost, this significantly changes electricity markets and their price dy-
30 namics. Third, VRE generation is not spread uniformly over Europe; instead
31 it is centered in regions with high meteorological potential and a supportive
32 political environment, while the current power generation infrastructure is
33 aligned with load centers. This generally calls for more transport capacities,
34 whose realization faces several barriers, such as public acceptance and very
35 long planning periods. In the mean time, above mentioned effects of VREs
36 on electricity markets and conventional power plants will be experienced very
37 differently in different regions of Europe.

38 These qualitative arguments motivate our study. We employ a bench-
39 marked, Europe-wide, power system model based on Heitmann (2005) and
40 Haase (2006) to analyze the role of grid extensions for the market effects of
41 the projected wind and solar capacities for 2020 in Europe. We quantify the
42 regional economic effects of VREs on electricity markets and their partic-
43 ipants in dependence of different grid extension levels. We investigate the
44 potential of grid extension to reduce the effects of VREs to the electricity

45 market. Economic benefits for utility owners, but also potential additional
46 barriers to grid extensions are identified.

47 The model is based on minimization of overall system costs. We determine
48 cost-optimal transmission grid extensions. Also, schedules for conventional
49 power plants, storage facilities and grid operation is determined by the model.
50 Nodal marginal pricing allows us to predict electricity prices.

51 Our paper proceeds as follows: In Section 2 we review related work. The
52 model is described in detail in Section 3. We derive our results in Section 4,
53 where we first focus on cost-optimal grid extensions and second, analyze the
54 effects of VRE to the existing power system. In Section 5 we discuss our
55 results before concluding in Section 6.

56 **2. Related Work**

57 The challenging properties of VREs, namely variability, uneven geograph-
58 ical distribution and vanishing variable cost, spurred numerous research ef-
59 forts.

60 Concerning the first two issues, technical analyses have been conducted to
61 identify measures how VREs can be integrated in power systems, such as
62 storage, demand side management, grid extensions and more flexible power
63 plants. Grid extension are thus one possible way to smoothen fluctua-
64 tions and gain access to areas of high VRE potential. Giebel (2000) and
65 Heide et al. (2010) quantify the statistical advantages of interlinked VRE
66 generation, such as reduced need for backup and storage capacities. Tech-
67 nical and geographical feasibility studies show, that a European supergrid,
68 i.e., a powerful high voltage grid, facilitates visionary renewable scenarios

69 for Europe (Biberacher, 2004; Czisch, 2005; DLR, 2006). Also, a recently
70 published Roadmap (McKinsey et al., 2010) and wind integration studies
71 (Greenpeace and 3E, 2008; EWEA, 2009b) judge grid extensions as necessary
72 on the medium and long term to overcome excess electricity production and
73 high backup capacity needs. Which lines to extend precisely has mainly been
74 identified on a national level, in response to recent wind and solar capacity
75 developments (for Germany: Dena (2005, 2010); Heitmann and Hamacher
76 (2009); Weigt et al. (2010)).

77 In addition to the temporal and geographical variability of wind and so-
78 lar energy, their low level of variable costs has severe consequences on the
79 electricity market: VREs and many other renewable energies have negligible
80 variable costs and, therefore, rank first in the merit order: they are the cheap-
81 est power supply source in terms of variable costs. Due to this cost structure
82 and additionally fixed by the regulator through priority feed-in laws, the sup-
83 ply curve, i.e., the sorted variable costs of all available power plants, is shifted
84 whenever renewable energies contribute to the satisfaction of demand. As a
85 consequence the demand curve intersects the supply curve at lower prices and
86 the price level declines due to renewable supply. This is called the merit order
87 effect. Sensfuss et al. (2008) show in an econometric analysis, that in 2006
88 the German mean wholesale electricity price was lowered by 7.8 €/MWh by
89 this effect due to the integration of renewable energies. This results in a
90 redistribution of economic welfare: consumer surplus increases and producer
91 surplus is reduced (see also de Miera et al. (2008)). Based on the example
92 of Texas, Woo et al. (2011) show that higher wind energy supply leads not
93 only to lower average electricity prices, but also to higher price volatility.

94 This volatility is sensitive to the level of wind speed, the behavior of differ-
95 ent market participants (Green and Vasilakos, 2010) and the distribution of
96 market power, as proven in a theoretical framework by Twomey and Neuhoff
97 (2010). Based on a probabilistic power generation model MacCormack et al.
98 (2010) point out, that opposite to the sinking electricity price, the total
99 costs of the power supply rises with increasing wind contribution. Measures
100 to alleviate the effects of VREs to the electricity price are investigated by
101 Jacobsen and Zvingilaite (2010) for Denmark focusing on storage, demand
102 side management and real time pricing. Leuthold et al. (2009) demonstrate,
103 that the reduction of electricity prices due to wind integration can be di-
104 minished with grid extensions in Europe. They find, that European grid
105 extensions lead to an overall welfare gain.

106 In this study we determine cost-optimal grid extensions for Europe in
107 2020 to integrate VREs and investigate the role of the grid for electricity
108 markets and their participants. The studies mentioned above showed the
109 necessity of grid extensions and the effects of VREs to the electricity prices in
110 general. We apply a regionally resolved power system model based on linear
111 optimization which includes electricity transport between regions and allows
112 to determine necessary grid extensions. Our methodology allows to draw
113 conclusions for each region and generation technology in detail. We quantify
114 changes in power producer revenue due to VREs as well as the effect of grid
115 extensions for each generation technology type in order to identify possible
116 proponents and opponents to grid extensions for VREs in Europe.

117 **3. The Model**

118 *3.1. Model Formulation*

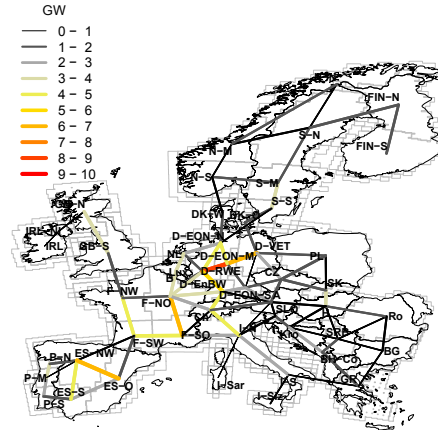


Figure 1: European model regions with aggregated ENTSO-E transmission grid

119 The applied methodology in this study is a power system model based on
 120 linear optimization of overall costs from a social planner perspective. The
 121 model, called URBS-EU, is an extension of the German energy system model
 122 URBS-D (Heitmann, 2005; Haase, 2006). It divides Europe into 83 regions,
 123 50 of which correspond to the major Transmission System Operator (TSO)
 124 regions in the European Network of Transmission System Operators for Elec-
 125 tricity (ENTSO-E) grid and 33 to specific offshore regions (see Figure 1). The
 126 temporal resolution is hourly. Thanks to this high level of detail, the model
 127 is appropriate to analyze variable resources, such as wind and solar energy.

128 The structure of the overall system costs subject to minimization is

$$COST = \sum_{x,i} \left\{ \kappa_i^I CN_i(x) + \kappa_i^F C_i(x) + \sum_t \kappa_i^{Var} E_i^{out}(x, t) \right\}. \quad (1)$$

129 They include the annuity of investment costs κ_i^I , fix, capacity-dependent Op-
130 eration and Maintenance costs κ_i^F as well as the variable costs κ_i^{Var} for power
131 plant, storage and transmission technologies. The costs per technology i are
132 given in Table 1. $C_i(x)$ is the total capacity, $CN_i(x)$ the capacity additions
133 per technology i and region x and $E_i^{out}(x, t)$ is the power production per re-
134 gion, technology and time-step t . Through optimization of the total system
135 costs, power plant dispatch, $E_i^{out}(x, t)$, per region and technology, is deter-
136 mined. On demand, the model also computes cost-optimal extensions of the
137 power plant, storage and transmission infrastructure, based on the annuity
138 of investment costs. This is achieved by using $CN_i(x)$ as free variable, in
139 addition to $E_i^{out}(x, t)$.

140 The linear optimization is subject to restrictions which describe the proper-
141 ties of the power supply system. A complete list of the equations defining
142 the model URBS-EU is given in Appendix A.1. The most important con-
143 straint, is that electricity demand $d(x, t)$ has to be satisfied in each region
144 and time-step:

$$\sum_i E_i^{out}(x, t) - E_{Transmission}^{in}(x, t) - E_{Storage}^{in}(x, t) \geq d(x, t). \quad (2)$$

145 In the energy balance (equation 2), the electricity export ($E_{Transmission}^{in}(x, t)$)
146 and feed-in to storage ($E_{Storage}^{in}(x, t)$) have to be taken into account. The
147 dual solution to this equation gives the marginal costs of electricity genera-
148 tion. Assuming a well functioning electricity market, the marginal costs are a
149 good indicator of the wholesale electricity prices (Borchert et al., 2006). The
150 marginal costs are determined by the variable costs of generation, storage

151 and transmission. Transmission and storage losses indirectly translate into
 152 increased marginal and total costs, as they lead to higher demand for power
 153 generation (see equation 2). In our model, excess production is possible. To
 154 ensure stable operation of the power system, generation that exceeds demand
 155 has to be discarded. If no excess production was allowed for, negative price
 156 would occur. So in our model, negative prices are not taken into account.
 157 This approximation is justifiable, as in reality negative prices occurred only
 158 in very few hours in the past (EEX, 2009). Moreover, negative prices will
 159 most likely be compensated by market participants, who create additional
 160 demand such as thermal storage for example and take advantage of the neg-
 161 ative price events.
 162 Further restrictions to the cost-optimization are maximum generation con-
 163 straints for each generation and storage technology and region:

$$E_i^{out}(x, t) \leq af_i \cdot C_i(x). \quad (3)$$

164 Reduced average availability of power plants due to planned and unplanned
 165 outages are included with an availability factor af_i . Similar upper bounds for
 166 storage and transmission capacity are included in the model and storage and
 167 transmission losses as listed in Table 1 are taken into account. Hourly values
 168 of the capacity factor $cf_i(x, t)$ for VREs serve as constraints to the operation
 169 level of variable renewable technologies. The time dependent capacity factor
 170 is deduced from meteorological data (see Subsection 3.2 and Heide et al.
 171 (2010))

$$E_i^{out}(x, t) = cf_i(x, t) \cdot af_i \cdot C_i(x) \quad , \forall i \in VRE \quad cf_i(x, t) \in [0, 1] \quad (4)$$

172 where *VRE* includes wind on- and offshore, solar PV and also run-off river
173 hydro power plants.

174 Technology specific ramping constraints, i.e., a speed-restriction for changes
175 in electricity generation, are included in the model.

$$|E_i^{out}(x, t) - E_i^{out}(x, t - 1)| \leq pc_i \cdot C_i(x) \quad (5)$$

176 The maximal power change pc_i per technology is listed in Table 1. Ramping
177 constraints are crucial to model power plant dispatch with a linear opti-
178 mization model. Commonly more realistic results can be achieved with unit
179 commitment models, who require Mixed Integer Programming and are com-
180 putationally expensive. Aboumahboub (2011, Ch. 2.4) shows that through
181 the inclusion of ramping constraints in linear models, the results from linear
182 optimization and a unit commitment model converge. Ramp-up costs are
183 not included, but the above restriction leads to an increase in total costs,
184 as it constrains the cost-optimal dispatch of power plants and can lead to
185 higher power generation.

186 We perform a simplified simulation of electricity transmission between
187 regions. Kirchhoff's first law, the conservation of currents in each node of an
188 electricity network, is respected in our model, while the second, the voltage
189 law, is not included. Electricity transmission is thus modeled as a transport
190 problem, neglecting effects of load flows (see Appendix A.1). The approxi-
191 mation of electricity transmission with a transport model allows to keep the
192 optimization problem linear and to optimize grid extensions and power plant
193 additions and operation simultaneously.

194 The model is formulated and optimized using the General Algebraic Mod-

195 eling System (GAMS) software package. The optimization is performed for
196 six representative weeks of each year of available meteorological data (2000-
197 2007). The selected weeks include the minimal and maximal residual elec-
198 tricity demand, are distributed uniformly across seasons and have minimal
199 deviation from the respective annual full load hours (FLH) of wind and solar
200 (less than 3%). Model results are presented as aggregation over the eight
201 years of available data, where energy-related parameters are averaged over
202 the eight years and for capacities, the maximal values are presented.

203 *3.2. Model Data*

204 The cost assumptions and the technical parameters, shown in Table 1, are
205 based on scientific studies (IEA, 2010b; McKinsey et al., 2010; PWC et al.,
206 2010) and industry expert evaluations. Technical parameters, such as con-
207 version and transmission and storage losses η_i , ramping constraints and re-
208 stricted availability, are included also listed in Table 1. The ramping con-
209 straints includes the technical ramping restrictions for each individual power
210 plant, but also the inertia of the aggregated generation capacity per genera-
211 tion technology in each model region. Here some power plants might be shut
212 of and have to respect minimal time of non-use or cold start restrictions. As
213 a results, aggregated ramps are slower than individual ones.

214 To model wind and solar energy supply, we use an eight years dataset
215 of highly resolved weather data based on the Heide et al. (2010). Hourly
216 capacity factors for wind and solar energy have been determined based on an
217 eight years dataset (2000-2007) of highly resolved (50 km) reanalysis data.
218 The aggregation of capacity factors from the 50 km cells to the 83 European
219 model regions is based on a wind and solar capacity distribution across the

Technology	Inv. Costs €/kW _{el}	Fix O&M Costs €/kW _{el}	Var. Cost €/MWh _{el}	η %	af_i %	pc_i %/h
Bioenergy	2500	50	18	38%	40%	25%
Coal	1400	35	21	46%	80%	22%
Gas GT	400	18	68	38%	100%	100%
Gas CCGT	650	18	44	60%	90%	22%
Geothermal	2800	80	4	45%	100%	25%
Lignite	2300	40	13	43%	80%	14%
Oil GT	800	18	126	35%	100%	100%
Oil CCGT	900	18	89	50%	90%	22%
Nuclear	3000	65	12	33%	80%	8%
Hydro run of river	1400	20	5	75%	100%	100%
Hydro storage	1539	20	-	85%	100%	100%
HV lines ,€/MWkm	400	0.7	-	96%/1000km	100%	100%
HV cable ,€/MWkm	2500	0.7	-	96%/1000km	100%	100%

Table 1: Investment, fixed operation & maintenance and total variable costs. The variable costs include fuel costs and variable operation & maintenance costs, but not the carbon costs. For the computation of the annuity of investment, a weighted average cost of capital (WACC) of 7% is assumed. CCGT stands for Combined Cycle Gas Turbine and GT for Gas Turbine.

220 50 km cells determined in accordance to planned projects, national policies
221 and actual potential. Most recent wind turbine generators and solar pho-
222 tovoltaic cells (PV) are assumed. The hourly load curve for the years 2000
223 - 2007 stems from the European Transmission System Operator ENTSO-E
224 (ENTSO-E, 2010). We select six representative weeks for each of the eight
225 years database and model 48 (six times eight) weeks in total.

226 The existing grid infrastructure is obtained from freely available data on
227 the European high voltage (HV, 220kV and 380kV) electricity grid (ENTSO-E,
228 2010). A Geographic Information System is applied to digitalize the map of
229 the transmission grid and intersect it with the model regions. HV transmis-

230 sion lines are commonly operated at their natural load level, where no voltage
231 drop occurs. Therefore we compute the total transmission capacity between
232 model regions based on the natural load of all HV lines linking two model
233 regions. In dependence on the voltage level, the natural load for each HV
234 line is calculated. The aggregation of all HV lines between two model regions
235 results in the total transmission capacity. Results are shown in Figure 1.

236 We built a geo-referenced power plant database to determine the ac-
237 tual generation capacities per model region. The database combines the
238 UDI power plant database (Platts, 2009) and a second data base including
239 energy production, emission and geographic location of each power plant
240 (Wheeler and Ummel, 2008). Coupling these two datasets on power plant
241 level provides a powerful and exhaustive geo-referenced database for Europe.
242 The future power plant fleet is extrapolated with technology specific lifetimes
243 (IEA, 2010b; Öko-Institut, 2008).

244 In all scenarios in this paper, we assume that the demand remains the
245 same as in 2007. Studies and a constant trend in the last years support this
246 assumption (McKinsey et al., 2010; ENTSO-E, 2009).

247 We benchmark our model against historical data. The validation shows,
248 that the model reproduces the current European electricity system in ade-
249 quate accuracy. This is presented in detail in Appendix A.2.

250 *3.3. Scenario Setup*

251 We apply the model to study the effects of increasing shares of wind and
252 solar energy in Europe in 2020 and the role of transmission grid extensions.

253 As mentioned above, power plant dispatch, but also infrastructure ex-
254 tension can be determined by the optimization. In this study, VRE ca-

255 capacity additions for 2020 are exogenous to the model and drawn from the
256 National Renewable Energy Action Plans of the European Member States
257 (Beurskens and Hekkenberg, 2011). Regional distributions within countries
258 are based on previous studies, political commitments and planned projects
259 (Bofinger et al., 2008; TradeWind, 2009; EWEA, 2008) and shown in Fig-
260 ure 2. The total planned wind capacity of 218 GW is similar to previous
261 studies assumptions: for wind on- and offshore power a total European ca-
262 pacity of 180 GW in 2020 was assumed by EWEA (2008), 150 GW by the
263 IEA, 128-238 GW by OffshoreGrid (2010) and 280 GW by GWEC (2011).
264 For solar PV, 92 GW are projected for 2020. The National Renewable Ac-
265 tion Plans exceed the projection of 45 GW Solar PV capacity in 2020 by IEA
266 (2010c), but are roughly in line with the projection of EPIA (2011) of more
267 than 60 GW in 2015.

268 By 2020, some of the existing conventional power plants will be retired and
269 the technology mix of the necessary power plant additions ($CN_i(x) \quad \forall i \notin$
270 $\{VRE, Storage\}$) are determined by the cost-optimization for each scenario
271 for the scenario year 2020. For some technologies, such as nuclear power
272 and other renewable power (hydro, bio- and geoenergy), political and geo-
273 graphical limits are taken into account (see Table 2). The model allows to
274 compute cost-optimal transmission grid extensions between model regions.
275 In the scenarios we study different levels of grid extensions. Addition of stor-
276 age capacity, is not allowed in this study focusing on grid extensions only.
277 We assume, that current storage capacities are installed in 2020, reflecting
278 the limited geographic potential for additional pumped hydro storage capac-
279 ity. Finally, the power plant dispatch and usage of the transmission grid and

280 existing storage capacities ($E_i^{out}(x, t)$) results from the optimization and its
 281 boundary conditions, in particular equation 2, 3 and 4.

Input parameter	<i>Base</i>	<i>No Grid</i>	<i>New Lines</i>	<i>New Cables</i>
VRE capacities	current capacities	projected capacities for 2020 (Beurskens and Hekkenberg, 2011)		
Installed non VRE capacities	projected capacities for 2020 (retirements are taken into account), current hydro storage and run-of-river capacities (Platts, 2009)			
Limits for capacity additions	capacity addition for nuclear, geothermal and bioenergy are limited to maximum between 2020 extrapolations and current capacities, no VRE additions allowed, infinite for all other generation technology			
HV transmission grid	current ENTSO-E grid	current ENTSO-E grid and direct connections of offshore wind to shore	overhead line extensions between neighbors possible. Sea-cables allowed on selected connections	cable extensions between neighbors possible. Sea-cables allowed on selected connections
Carbon price	30 €/t	30 €/t	30 €/t	30 €/t

Table 2: Definition of scenarios

282 Table 2 lists the characteristics of the four scenarios. The *Base* scenario
 283 serves as comparison for the VRE scenarios. It mimics the power supply
 284 system by 2020 without the projected VRE capacity additions. For the VRE
 285 scenarios we investigate three levels of grid extensions: today’s network (*No*
 286 *Grid*) and two cases of cost-optimal grid extensions: in the *New Lines* sce-
 287 nario new overhead lines and offshore cables are allowed, in the *New Cables*
 288 scenarios only cable extensions on- and offshore are possible. Cables are
 289 about six times more expensive than overhead lines (see Table 1). The sec-

290 ond case therefore results in less grid extensions. The *New Cables* scenario
 291 thus allows to identify the most important grid extension and furthermore
 292 represents one possible technical response to public resistance towards new
 293 overhead transmission lines.

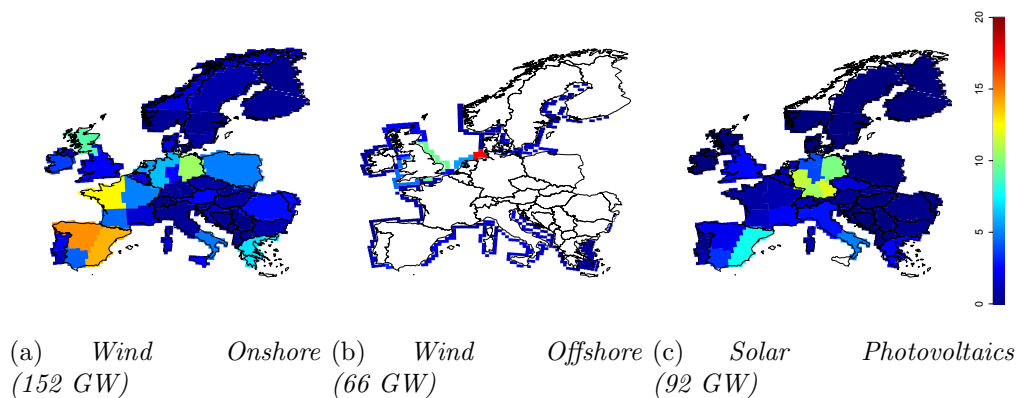


Figure 2: Capacities of Variable Renewable Energies for 2020 in GW (see Beurskens and Hekkenberg (2011)). Total European capacity per VRE technology is indicated in brackets.

294 4. Results: European electricity supply in 2020

295 We apply the model URBS-EU to analyze grid extensions as a measure
 296 to address economic effects of high VRE penetration in Europe. In a first
 297 step we present cost-optimal high voltage transmission grid extensions for
 298 Europe in 2020, then turn to the impacts of the planned VRE capacities to
 299 the existing power plants and finally study prices and revenues per generation
 300 technology and region.

301 4.1. The Cost-Optimal Grid

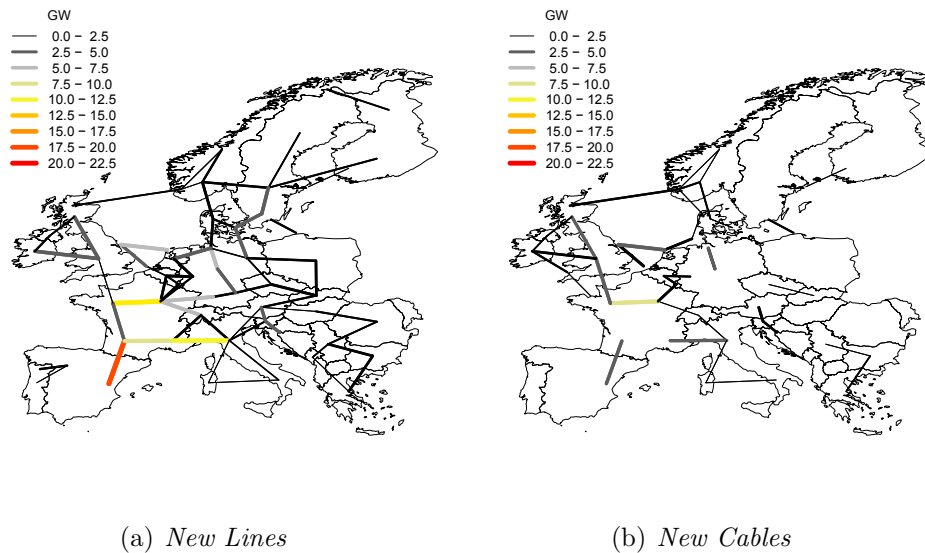
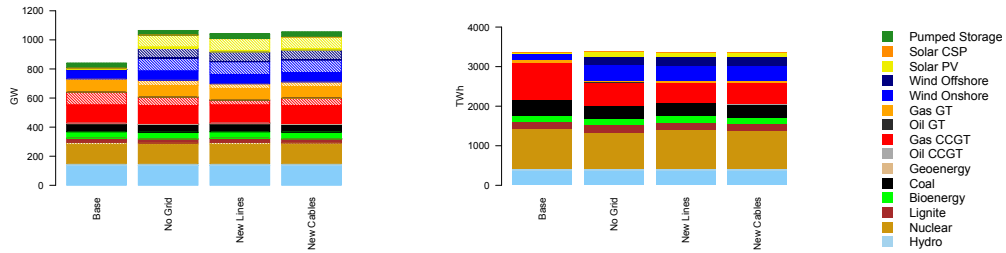


Figure 3: Cost optimal grid extensions

302 The cost-optimal grid extensions in the *New Lines* and *New Cables* sce-
 303 nario are depicted in Figure 3. Large transmission capacities result from
 304 the optimization model. The total the grid capacity increases by almost
 305 60% in the *New Lines* scenario and by more than 20% in the *New Cables*
 306 scenario compared to the current ENTSO-E grid capacity and length (in
 307 MWkm). This is plausible from an economic point of view, since new lines
 308 are relatively cheap compared to the additional use of fossil fuel (see Table 1).
 309 Overhead lines are less expensive than cables (see Table 1) and therefore, less
 310 grid extensions result in the *New Cables* scenario. The grid extensions are
 311 driven by the VRE capacity addition, but also bear benefits for conventional
 312 power plants.

313 Germany, France and BeNeLux¹ act as transit countries. In north-western
314 France, northern Germany and Great-Britain substantial grid extensions are
315 cost-effective in both scenarios to integrate the large wind capacities in these
316 areas. Large new grid capacities result for the Spanish-French connection,
317 but only little additions on the Iberian peninsula occur. Italy, having a
318 rather weak electricity grid today, profits from a cost-effective enforcement
319 of its connection to France. Offshore grid extensions are mainly located in
320 the Northern and Baltic Sea, in proximity to important on- and offshore
321 wind capacities. In the *New Lines* scenario the majority of grid extensions
322 are onshore as lines are cheaper than cables, while in the *New Cables* sce-
323 nario larger shares of the grid extensions are offshore cables. We assumed
324 identical costs for on- and offshore cables. In BeNeLux and Italy for instance,
325 offshore grid extensions are more cost-effective than onshore cable extensions
326 in the *New Cables* scenario. If overhead lines can be built, the bulk power
327 transmission takes place onshore (*New Lines*).

328 We find that an offshore grid in the Northern sea is cost-effective, in
329 consistency with other studies. On- and offshore grid extensions for wind
330 integration proposed in TradeWind (2009) and Kerner (2007) show the same
331 corridors as the ones identified in this study. EWEA (2009b) focuses on Eu-
332 ropean offshore wind parks and proposes a powerful interconnected offshore
333 network in the Northern and Baltic Sea. The proposed capacities for 2020
334 and 2030 by the EWEA are in line with our results.



(a) Capacities

(b) Total Energy Production

Figure 4: Power plant capacities and energy production in 2020 for all scenarios. Shaded areas represent capacity additions.

335 4.2. Power Plants

336 Figure 4 presents the model results for power plant capacities and energy
 337 generation in Europe.

338 To the 690 GW of the power plants that will still be on line in 2020, the
 339 optimization model adds about 115 GW new capacity in the *Base* scenario
 340 to replace retired power plants and those shut down for political reasons,
 341 such as the phase-out of nuclear power in Germany. Capacity additions are
 342 represented by shaded areas in Figure 4(a). The additional 234 GW new
 343 VRE capacity lead to a slight reduction of conventional capacity additions
 344 in the *No Grid* scenario, where 100 GW non-VRE capacity is added. This
 345 corresponds to a capacity credit of the VRE technologies of 4%. With grid
 346 extension less new thermal capacity is needed: about 80 GW is added in the
 347 *New Lines* and about 90 GW in the *New Cables* scenario. The capacity credit

¹including Belgium, the Netherlands and Luxembourg

348 increases to 14% and 9% respectively. In all scenarios, nuclear and gas power
349 plants are the only technologies, where new capacities are added. Compared
350 with the European peak load of 619 GW, the conventional installations are,
351 however, still able to provide full backup for the VREs in all scenarios.

352 Figure 4(b) shows the model's outputs regarding the energy mix. Since
353 the VREs' share in total electricity production increases from 5% to 21%
354 through the VRE capacity additions, the conventional power plants' output
355 is significantly reduced, while conventional capacity remains close to current
356 capacity. The averaged full load hours (FLHs) over all thermal generation
357 types (Coal, Lignite, Gas, Oil, Nuclear and Bio- and Geoenergy) decrease
358 by 9% in *No Grid* case. With grid extensions (*New Lines*) the total average
359 reduction in FLH for thermal generation types amounts 5% and baseload
360 power, mainly nuclear, replaces peaking technologies such as gas, as can be
361 seen in Figure 4(b).

362 The reduction in power plant usage is most severe in regions with high VRE
363 deployment and will create severe pressure for the conventional power plant
364 operators. In regions with high VRE capacity, the FLHs of base load power
365 plants such as nuclear and coal generation units decline sharply, if no grid
366 extensions are realized, because they have to adapt to VRE supply (see
367 Figure 5). With an extended, cost optimal grid, more traditional usage of
368 the power plants is possible: baseload power is used more continuously, while
369 the mid and peak load power plants also in the neighboring regions help to
370 balance the VRE fluctuations. These technologies in turn supply less energy
371 in total.

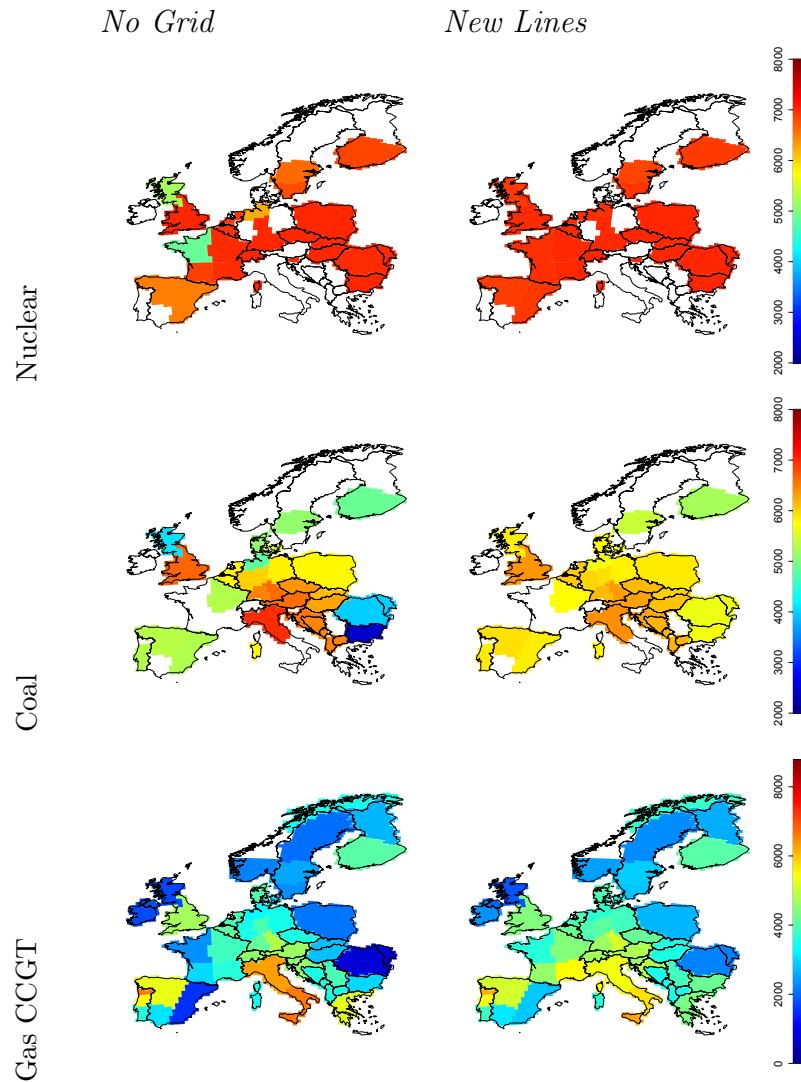


Figure 5: Full Load Hours of nuclear, coal and gas power plants for the *No Grid* and *New Lines* scenario

372 One of the most affected regions by new VRE capacities is north-western
 373 Germany. Here, 18 GW offshore wind capacity is projected for 2020, 4 GW
 374 of solar PV and 6 GW of wind onshore capacity (see Figure 2). Many im-
 375 portant effects of the VRE integration for the power plants can be studied

376 in detail from Figure 6, where the computed energy mix and the resulting
377 energy prices for the North-Western German region *D-EON-N* are shown for
378 one of the eight modeled meteorological years.

379 In the *Base* scenario, the base load is covered by nuclear and coal power
380 plants, gas power plants and also electricity import from neighboring regions
381 provide the mid and peak load. The region exports electricity, as can be read
382 off from the difference between the yellow line, the electricity demand within
383 the region, and the orange total demand line where export and storage charging
384 is included. In the *Base* scenario, the current onshore wind capacity of
385 5.3 GW is installed.

386 In the scenarios *No Grid* and *New Lines*, large amounts of additional wind
387 energy from a dedicated offshore region are imported into the considered
388 region, shown as gray areas in Figure 6 (b) and (c). This results in drastic
389 changes in the power plant dispatch, if no grid extensions are carried out (*No*
390 *Grid*). In windy hours, wind energy replaces power from peak, middle and
391 also base load power plants. Even nuclear power has to shut down several
392 times. With grid extensions (*New Lines*), the base load power plants can
393 be used in a more traditional way. The burden of balancing the fluctuating
394 wind energy is then shared between all peak and mid load power plants in
395 the linked neighboring regions.

396 Also the capacity additions alter slightly across scenarios: in the *Base* case
397 slightly more new Gas CCGT capacity (1.3 GW) is installed.

398

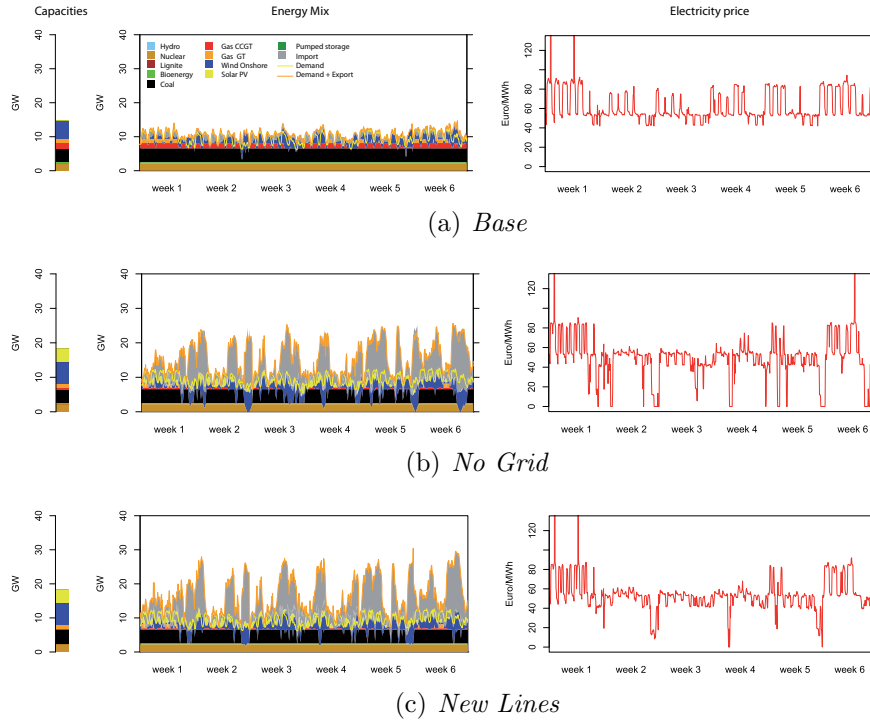


Figure 6: Energy mix in north western Germany (*D-EON-N*) and electricity price for selected weeks in 2020 (meteorological data from 2003).

399 *4.3. Electricity prices and revenues*

400 Not only power plant dispatch changes considerably with VRE capacity,
 401 also the electricity prices are strongly influenced.

402 This can be seen for north western Germany in Figure 6. Power supply from
 403 VRE strongly influences electricity prices. Their variable costs are close to
 404 zero and thus, wind power enters at the first position in the merit order of
 405 power plants. Whenever wind and solar energy supply is sufficient to satisfy
 406 the demand, the price drops to zero and through the merit order effect, the
 407 electricity price in regions with high VRE capacity is lowered. As mentioned
 408 in Section 3, negative prices are not taken into account.

409 Figure 7 shows the average electricity price for the four scenarios. The av-
410 erage electricity price in Europe is 62 €/MWh in the *Base* scenario. In the
411 *No Grid* it drops to 52 €/MWh, 17% lower than the basecase. With grid
412 extensions the average price recovers to 55 €/MWh and 53 €/MWh with
413 new lines or cables respectively. As can be seen from the maps, regions
414 with high VRE capacity are most affected by the reductions in electricity
415 price. In north-western Germany, the average price drops from 65 €/MWh
416 to 50 €/MWh with 2020 VRE capacity additions and no grid extensions (see
417 also Figure 6). Generally speaking, the standard deviation of electricity price
418 across regions increases with increasing VRE capacity. In the *Base* case the
419 standard deviation of electricity prices across the European regions amounts
420 5 €/MWh. It increases to 8 €/MWh and can be lowered with grid extensions
421 to 3 and 6 €/MWh respectively. Grid extensions lead to a homogenization
422 of the electricity prices.

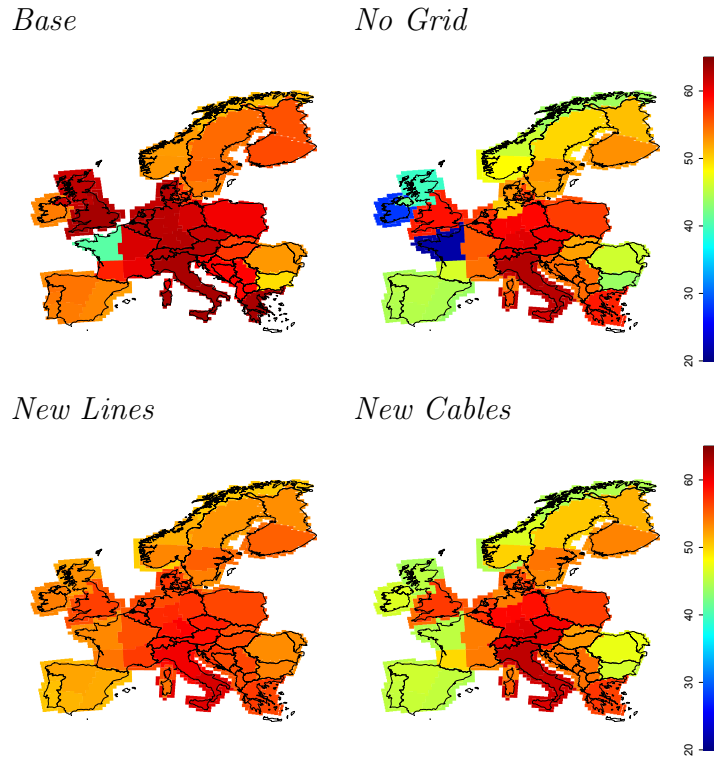


Figure 7: Average electricity price (€/MWh_{el})

423 Furthermore, the dynamics of the prices changes. While in the current
 424 system and in the *Base* case, the electricity price is mainly determined by
 425 the load (see Figure 6), the average correlation between load and prices drops
 426 to around 25% in the 2020 VRE scenarios from 75% today. In turn, gener-
 427 ation from wind turbines plays an increasingly important role for electricity
 428 prices. In regions with high VRE capacity strong anticorrelation between
 429 wind generation and electricity prices can be observed, see Table 3. Solar
 430 power generation is generally smaller and also closer to the load. Therefore,
 431 its effects to the electricity price are not yet as pronounced. Grid extensions
 432 reduce the anticorrelation between wind and price. With grid extensions, the

433 anticorrelation is reduced by about 50% in affected regions (see Table 3).

Correlation price and wind	Spain NW	Scotland	Germany NW
<i>No Grid</i>	-61%	-50%	-32%
<i>New Lines</i>	-28%	-20%	-16%
<i>New Cables</i>	-58%	-36%	-17%
Wind capacity (GW)	18	11	23

Table 3: Correlation between electricity price and generation from wind energy in selected regions. The last row lists the total on- and offshore wind capacity in the regions.

434 The changes in electricity prices and FLHs affect the revenues of the util-
435 ities. Figure 8 shows the average annual revenue per installed MW for each
436 generation technology. All technologies are affected and achieve lower rev-
437 enues. Note, that Figure 8 shows the average revenues per technology. New
438 power plants will be used more frequently, due to higher efficiency and result-
439 ing lower variable costs. They may thus achieve higher revenues. However,
440 for some peaking technologies, the benefit is small and balancing markets
441 have to be used as well. Stagnant investment in new power plants before the
442 economic crisis reflects the difficulties at the market (Dena, 2008). Without
443 grid extensions for the new VRE capacity (*No Grid*), the standard deviation
444 of the revenue across regions increases due to the inhomogeneous distribution
445 of VRE capacities in 2020. The profitability of conventional power plants will
446 be strongly influenced by the amount of VRE capacity close by.
447 Network improvements lead to more uniform prices in time and space. They
448 reduce the standard deviation of the revenues across the regions significantly.
449 VREs are affected very positively by grid extensions since fewer low price sit-
450 uations occur. As large VRE generation mainly causes the low prices, these

451 technologies can hardly earn important revenue in the current market struc-
 452 ture (Neuhoff, 2005). Grid extensions smoothen the electricity price. As
 453 a result, less low price events occur and the revenues for VRE increases.
 454 Baseload power plants such as nuclear, coal and lignite also benefit sub-
 455 stantially from grid extensions. The average revenues reach current levels
 456 if cost-optimal overhead transmission extensions are realized. For mid and
 457 peak-load power plants, the economic situation remains difficult even with
 458 large grid extensions, due to important FLH reductions.

459

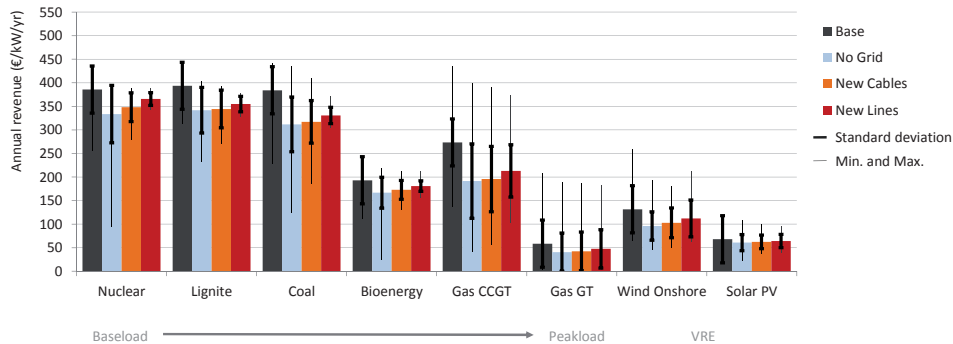


Figure 8: Revenues per generation technology for the four scenarios. Standard deviation and minimal and maximal values across the model regions are indicated with the black lines.

460 Figure 9 shows the change in revenue due to VRE additions by country.
 461 Regions with largest additions are most affected, as for example Germany,
 462 Spain, France and Great Britain, where the revenues for nuclear power are
 463 reduced by up to 25%. Looking in more detail, in north-western France and
 464 in Scotland, revenue for nuclear reach is reduced by more than 50% from the
 465 *Base* to the *No Grid* scenario. As pointed out before, VREs are most af-
 466 fected if they participated in the electricity market directly. For Gas CCGT

467 power plants, a mid and peak load technology, grid extensions show only
 468 little effect and the revenue remains low. In importing regions, such as Italy,
 469 grid extensions can even lead to an additional decrease revenue.

470

471 In general, transmission grid extensions reduce the future revenue reduc-
 472 tion from VRE and distribute the economic surpluses evenly across intercon-
 473 nected regions.

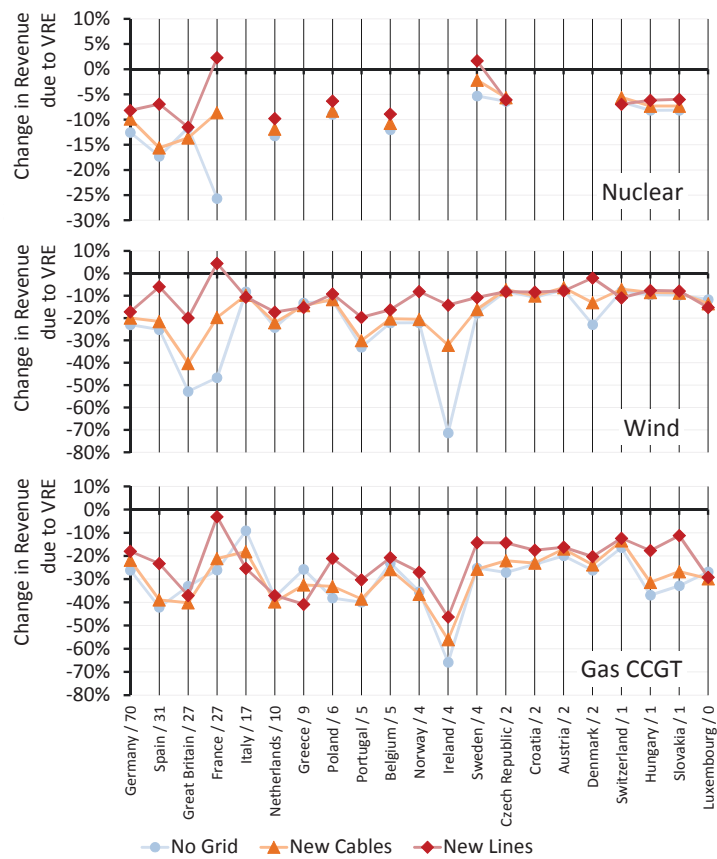


Figure 9: Relative change in revenue with VRE additions compared to *Base*. The countries are plotted in decreasing order of VRE capacity additions. After the country names VRE additions until 2020 are indicated in GW.

474 5. Discussion

475 In this study we apply a regionally-resolved, power system model to an-
476 alyze the role of grid extensions for the interaction of wind and solar energy
477 with electricity markets in Europe. Our results show, that the expected VRE
478 extensions for 2020 have significant impact on electricity markets and their
479 participants. Wholesale electricity prices decrease on average, their variance
480 in time and space increases, and they are dynamically correlated with VRE
481 supply rather than with power demand. Transmission grid extension can
482 help to reduce the market effects of VREs, and moreover creates benefits for
483 other generation technologies.

484

485 We investigate two levels of grid extensions, where in a first stage we
486 allow overhead grid extensions between all neighboring regions. The cost-
487 optimal grid additions amount 60% of current grid capacity and length. In
488 a second scenarios, taking into account public acceptance and political chal-
489 lenges, only cable additions are allowed, and a 20% increase in grid capacity
490 results.

491 Regardless of the level of grid extensions, the VRE additions projected for
492 2020 have severe consequences for all other power plant types. Due to the
493 limited capacity credit of wind and solar power, conventional generation ca-
494 pacity is hardly reduced as compared to current level, while the share of VRE
495 in total electricity generation increases from 5% to 21%. This results in a
496 reduction of FLHs for all conventional generation technologies.

497 Without grid extensions, very high FLH reductions occur in proximity to im-
498 portant VRE capacities. Through the merit order effect, VREs furthermore

499 lower the average simulated electricity prices by more than 15% in 2020.
500 Utility owners will face drastic FLH reduction and higher wearout of their
501 turbines due to increased ramping if wind or solar capacity is built close by.
502 The oversupply of electricity in regions with large VRE capacity and insuffi-
503 cient transmission capacity furthermore lowers the electricity price drastically
504 in these regions. In the current market structure, conventional power plants
505 will therefore face serious economic challenges. In regions with large VRE
506 capacities, the reduction in revenue for conventional base, mid and peak load
507 power plants can reach 60%. The average revenue for baseload technologies
508 is reduced by about 15%, for peakload by 30%. VRE capacities in 2020 thus
509 create major inequalities in Europe, if no grid capacity additions are carried
510 out simultaneously.

511 Our results concerning the electricity price reduction are on the conservative
512 side, as we do not take into account negative prices in our model. If nega-
513 tive prices were included, the average prices would be lower. In periods and
514 regions with negative prices it would furthermore become beneficial to shut
515 down power plants, even VRE technologies.

516

517 With grid extensions, the average utilization of baseload technologies is
518 raised again and less ramping of baseload technologies is necessary, as the
519 balancing of VRE supply is shared between more flexible power plants in
520 the interconnected regions. Furthermore, the burden of reduced revenues for
521 conventional power plants due to VRE extensions is distributed more evenly
522 among all regions. Both levels of simulated grid extensions boost the revenue
523 for baseload and VRE technologies. Revenues close to pre-VRE levels can

524 however only be attained with a substantial grid growth of 60%. For mid- and
525 peakload power plants, average revenues remain low. For VRE technologies
526 themselves the anti-correlation between electricity prices and VRE genera-
527 tion creates a large incentive for grid extensions, if market participation of
528 these technologies is desired. Grid extensions reduce the anti-correlation of
529 prices with VRE generation and thus raises the revenue for VRE technolo-
530 gies.

531 As a result, grid extensions are economically very advantageous for baseload
532 *and* VRE utility owners – a rather unlike pair. In the overall picture, a pow-
533 erful international transmission grid thus bears many advantages. It lowers
534 overall system costs (we derive grid extensions it through cost-optimization),
535 it facilitates the technical and economic integration for VRE technologies and
536 furthermore bears benefits for conventional power plants, mainly for baseload
537 power plants in regions with high VRE deployment.

538 However, regions with low VRE capacity experience lower electricity prices
539 and potentially lower revenues through grid extension. Mid and peak load
540 utility owners in those regions might not want to share the burden of VRE
541 integration with neighboring regions as this results in increased ramping,
542 lower FLHs and lower electricity prices. Therefore the political challenge of
543 international electricity market coupling will increase with increasing VRE
544 capacities. While today, existing infrastructure mainly determines interna-
545 tional trade flows, e.g., export of nuclear power from France to Italy, different
546 trade flows, highly determined by VRE capacity, will occur in 2020. The im-
547 porting region will still have to provide sufficient capacity to ensure security
548 of supply, which in turn has lower utilization and revenue, because the neigh-

549 boring country installs large VRE capacity and exports parts of its electricity
550 generation. Increased coordination of the dispatch of interlinked regions and
551 also of the national requirements for security of supply to reduce the disad-
552 vantages for the importing region.

553 As mentioned above, electricity prices show a change in dynamics with in-
554 creasing VRE capacity: they are no longer correlated to electricity demand,
555 but driven by wind generation. With grid extensions, furthermore electricity
556 trades will influence the price level. The more complex dynamics of electric-
557 ity market will be challenging for market participants. When linking a region
558 with large VRE deployment to one without, the exporting region generally
559 profits from a reduction of complexity in price drivers and in the European
560 overall picture, a smoother and geographically more homogeneous electricity
561 price results, but the importing regions can face an increase in market com-
562 plexity. Low nodal electricity prices can create incentives for more flexible
563 demand, which can be realized by demand side management, smart grid ap-
564 plications or storage.

565

566 Grid extensions for the integration of VREs in Europe bears many ben-
567 efits, for VRE technologies themselves, but also for other power plants in
568 proximity to VRE capacities. It is not only necessary for the technical inte-
569 gration of VREs, i.e., the transport of electricity from renewable generation
570 to load centers, but also for the economic integration. Revenues for conven-
571 tional power plant owners are lowered substantially without sufficient grid
572 extensions. However, successful planning of transmission grid extensions for
573 VREs should address potential difficulties for market participants mainly in

574 importing regions in addition to existing political challenges.

575 **6. Conclusion**

576 Based on a power system model we have analyzed the role of grid ex-
577 tensions for the market effects of VRE. Our model of the European power
578 system is a regionally resolved model and based on linear optimization of
579 overall costs. We benchmarked our model with historical data to fortify our
580 analysis.

581

582 Our modeling approach includes several simplifications, of which the as-
583 sumption of a pan-European electricity market with nodal pricing policy is
584 most relevant to our results. In reality national markets form only one price
585 in each country, which however is strongly influenced by the region with the
586 lowest marginal costs (Ockenfels et al., 2008). However, the model bench-
587 mark shows, that our approach reproduces historical electricity prices. We
588 furthermore approximate power plant dispatch with linear functions and ag-
589 gregate capacity in larger regions. However, the most relevant technical con-
590 straints, such as ramping constraints, are included in the model and again,
591 the validation shows adequate consistency of model results with historical
592 data. The model's predictions can thus be taken as a good indicator for
593 future developments of the interlinked European power generation system.

594

595 Our results show that expected VRE capacities for 2020 create important
596 inequalities among power plant owners in Europe. Close to VRE generation,
597 lower utilization and electricity prices lead to reduced revenues. Through

598 grid extensions, the market effects of VREs are reduced and benefits can be
 599 created for other power plants, mainly baseload technologies, through more
 600 homogeneous and stable electricity prices and larger revenues. For importing
 601 regions and mid to peak load technologies disadvantages can occur through
 602 grid extensions.

603 Our analysis does not include the control power market nor the role of storage
 604 in combination with grid extensions. Coming studies may focus on the role
 605 of the control power and other system services and tools for the security
 606 of supply, which will gain increasing importance in a future with highly
 607 renewable electricity supply. Moreover, it would be interesting study the
 608 combined effects of grid and storage for VRE market effects.

609 **Appendix A.**

610 *Appendix A.1. Model formulation*

611 For detailed understanding, we list the fundamental equations defining
 612 the power system model URBS-EU in this section. The list of symbols is
 613 provided in Table A.4.

614

615 The objective function, i.e., the total costs subject to minimization are

$$\begin{aligned}
 K &= K_{IG} + K_{IS} + K_{IT} & (A.1) \\
 K_{IG} &= \sum_{x,i \in IG} \{ \kappa_i^I C N_i(x) + \kappa_i^F C_i(x) + \kappa_i^V \sum_t E_i^{out}(x, t) \} \\
 K_{IT} &= \sum_{x,i \in IT, x' \in N} \{ r(x, x') [\kappa_i^I C N_i^T(x, x') + \kappa_i^F C_i^T(x, x') + \kappa_i^V \sum_t F_i^{imp}(x, x', t)] \} \\
 K_{IS} &= \sum_{x,i \in IS} \{ \kappa_i^I C N_i^S(x) + \kappa_i^F C_i^S(x) + \kappa_i^V \sum_t V_i(x, t) \}
 \end{aligned}$$

616 The most important restriction is the satisfaction of demand. All restric-
617 tions are valid $\forall x$ and $\forall t$, if not indicated differently.

$$d(x, t) \leq \sum_i E_i^{out}(x, t) - \sum_{i \in I_S \cup I_T} E_i^{in}(x, t) \quad (\text{A.2})$$

618 The following equations control the generation processes.

$$E_i^{out}(x, t) \leq af_i \cdot C_i(x) \quad \forall i \in I_G \quad (\text{A.3})$$

$$E_i^{out}(x, t) = cf_i(x, t) \cdot af_i \cdot C_i(x) \quad \forall i \in I_R \quad (\text{A.4})$$

$$pc_i \cdot C_i(x) \geq |E_i^{out}(x, t) - E_i^{out}(x, t - 1)| \quad \forall i \in I_G \quad (\text{A.5})$$

$$C_i(x) = c_i^0(x) + CN_i(x) \quad \forall i \in I_G \quad (\text{A.6})$$

$$c_i^{min}(x) \leq C_i(x) \leq c_i^{max}(x) \quad \forall i \in I_G \quad (\text{A.7})$$

619 Power transmission is modelled as a transport problem. All equation are
620 valid $\forall x, t, \forall x' \in N, \forall i \in I_T$.

$$F_i^{imp}(x, x', t) \leq C_i^T(x, x') \quad (\text{A.8})$$

$$F_i^{imp}(x, x', t) = F_i^{exp}(x', x, t) \cdot \lambda_i(1 - r(x, x')) \quad (\text{A.9})$$

$$E_i^{out, in}(x, t) = \sum_{x' \in N} F_i^{imp, exp}(x, x', t) \quad (\text{A.10})$$

$$C_i^T(x, x') = c_i^{T, 0}(x, x') + CN_i^T(x, x') \quad (\text{A.11})$$

$$c_i^{T, min}(x, x') \leq C_i^T(x, x') \leq c_i^{T, max}(x, x') \quad (\text{A.12})$$

621 Storage is described by the following equations, valid $\forall x, t, \forall i \in I_S$.

$$V_i(x, t) \leq C_i^S(x) \quad (\text{A.13})$$

$$E_i^{in}(x, t) \leq af_i \cdot C_i(x) \quad (\text{A.14})$$

$$c_i^{S,min}(x) \leq C_i^S(x) \leq c_i^{S,max}(x) \quad (\text{A.15})$$

$$C_i^S(x) = c_i^{S,0}(x) + CN_i^S(x) \quad (\text{A.16})$$

$$E_i^{out}(x, t) \leq V_i(x, t) \cdot \eta_i^{out} \quad (\text{A.17})$$

$$V_i(x, t) = V_i(x, t - 1) + E_i^{in}(x, t) \cdot \eta_i^{in} - E_i^{out}(x, t) / \eta_i^{out} \quad \forall t > 0 \quad (\text{A.18})$$

Symbol		Explanation
Sets		
$i \in I = I_G \cup I_T$		Process type (generation and transmission)
$I_G = I_R \cup I_D \cup I_S$		Generation processes (renewables (VREs), dispatchable and storage)
$x \in X$		Model regions
$N = \{x' \exists x \in X : z(x, x') = 1\}$		Set of neighbors
$t \in T$		Time steps
Variables	Domain	Note: all variables are positive
$C_i(x)$	$X \times I_G$	Power plant and storage in- and output capacity
$C_i^S(x)$	$X \times I_S$	Storage reservoir capacity
$C_i^T(x, x')$	$X \times I_T$	Grid capacity between region x and x'
$CN_i^{(T,S)}(x)$	$X \times I_G, I_S, I_T$	Capacity additions
$E_i^{out}(x, t)$	$X \times T \times I$	Electricity production
$E_i^{in}(x, t)$	$X \times T \times (I_S \cup I_T)$	Input into storage, sum of exports
$F_i^{imp,exp}(x, x', t)$	$X \times N \times T \times I_T$	Power import/export from region x to x'
$V_i(x, t)$	$X \times T \times I_S$	Stored energy
$K, K_{I_G}, K_{I_S}, K_{I_T}$		Costs
Parameters	Domain	
$d(x, t)$	$X \times T$	Electricity demand
$cf_i(x, t)$	$X \times T \times I_G$	Capacity factor
$c_i^{0,min,max}(x)$	$X \times I_G$	Installed, minimal and maximal capacity for power plants and storage in- and output
$c_i^{S,0,min,max}(x)$	$X \times I_S$	Installed, minimal and maximal capacity for storage reservoir
$c_i^{T,0,min,max}(x, x')$	$X \times I_T$	Installed, minimal and maximal capacity for grid
$z(x, x')$	$X \times N$	Adjacency matrix
$r(x, x')$	$X \times N$	Distance between two model regions
af_i, pc_i, η_i	I_G	availability, maximal power change, efficiency
$\lambda_i, \eta_i^{in,out}$	I_T, I_S	transmission losses, storage in- and output efficiency
$\kappa_i^I, \kappa_i^F, \kappa_i^V$	I	Annuity of investment, fix and variable costs

Table A.4: List of symbols

622 *Appendix A.2. Model validation*

623 To validate the model's ability to reproduce the real power system, we
 624 perform a simulation of the European electricity system of 2008, the most
 625 recent year of complete available data before economic crisis. In this so-called
 626 *Base 2008* scenario no capacity extensions for grid, power plants or storage
 627 are allowed and current costs are assumed as shown in Table 1 with a carbon
 628 price of 15€/t. We simulate 48 weeks in total: six representative weeks of
 629 each of the eight year of available meteorological data.

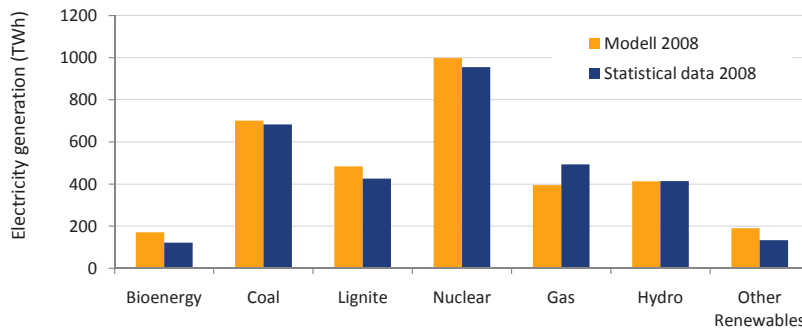


Figure A.10: Comparison of modeled electricity production in Europe to measured data (IEA, 2010a).

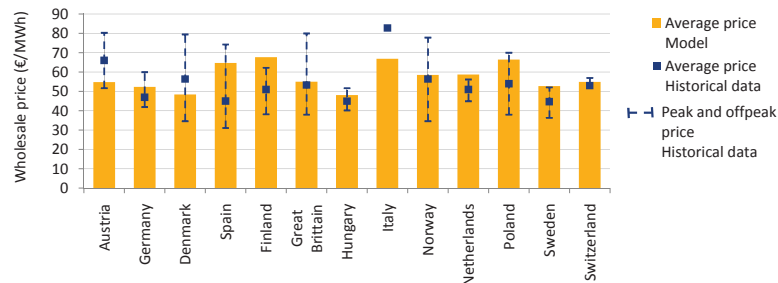


Figure A.11: Comparison of the average electricity prices in Europe (Bower, 2003; OMEL, 2010; EXAA, 2010; EEX, 2009; NordPool, 2010) with the modelled average marginal costs of electricity generation

630 Figure A.10 compares the total European electricity generation by fuel
631 resulting from the model to historical data (IEA, 2010a). We observe a good
632 fit of the produced power for the base load plants (coal, lignite, nuclear and
633 hydro). The model slightly underestimates the power production of peak
634 load power plants (gas). This is due to the deterministic nature of the op-
635 timization model. Unforeseen outages of power plants and forecast errors
636 are not included in the model, while peak load power plants are often used
637 exactly to counter balance these events.

638 Wholesale electricity prices are deduced from the marginal costs of electric-
639 ity generation and are consistent with historical average wholesale prices (see
640 Figure A.11). The model furthermore reproduces extreme values of the elec-
641 tricity price and the computed price shows 70% correlation with the historical
642 day ahead market prices for Germany (EEX, 2009).

643 Modeled cross-boarder electricity exchange is similar to historical data as
644 shown Figure A.12. One reason for remaining deviations might be a non cost-
645 optimal cross-border scheduling in reality, as well as our simplified method-
646 ology to model power transport.

647 The reproduction of historical data with the model is robust against changes
648 in fuel prices. A considerable increase of fuel prices (20% for gas, 40% for
649 coal, 120% for nuclear variable costs) has no major impacts on the model
650 benchmark.

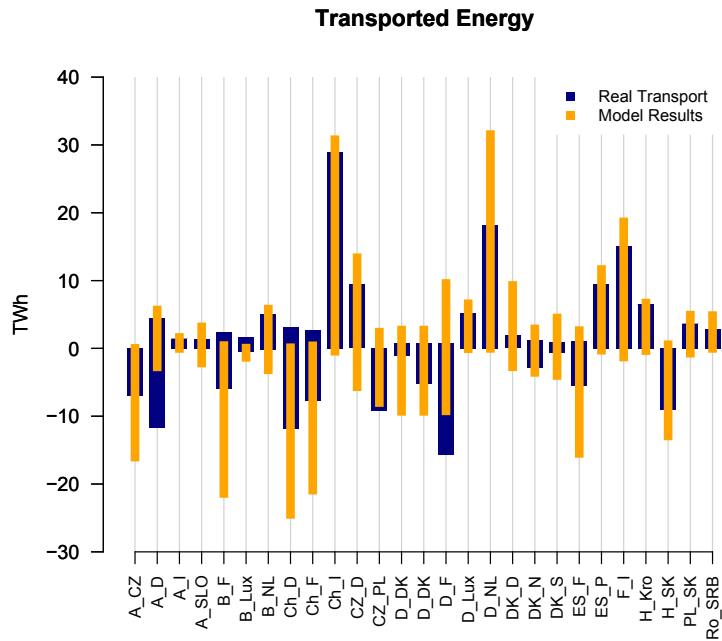


Figure A.12: Cross-boarder electricity exchange: model results (*Base 2008*) and historical data (ENTSO-E, 2010)

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