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Renewable build-up pathways for the US: Generation costs are not system costs

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The transition to a future electricity system based primarily on wind and solar PV is examined for all regions in the contiguous US. We present optimized pathways for the build-up of wind and solar power for least backup energy needs as well as for least cost obtained with a simplified, lightweight model based on long-term high resolution weather-determined generation data. In the absence of storage, the pathway which achieves the best match of generation and load, thus resulting in the least backup energy requirements, generally favors a combination of both technologies, with a wind/solar PV (photovoltaics) energy mix of about 80/20 in a fully renewable scenario. The least cost development is seen to start with 100% of the technology with the lowest average generation costs first, but with increasing renewable installations, economically unfavorable excess generation pushes it toward the minimal backup pathway. Surplus generation and the entailed costs can be reduced significantly by combining wind and solar power, and/or absorbing excess generation, for example with storage or transmission, or by coupling the electricity system to other energy sectors.

1. Introduction

We investigate highly renewable electricity scenarios for the contiguous US. In this paper, the main focus is placed on the optimization of the mix of wind and solar PV power during the renewable build-up. While numerous studies investigate regional or nationwide fully renewable power systems [1–7], they usually focus on detailed single scenarios or pathways and/or only cost-optimal installations. Here, a simplified and computationally lightweight description based on high-resolution wind, solar PV, and load data is used to survey a large number of possible renewable scenarios and derive systematic insights from the spatio-temporal characteristics of the generation-load mismatch.

In our model of the electricity system, the supply is largely reliant on the variable renewable energy sources wind and solar PV power, which we abbreviate as VRES (variable renewable energy sources). CSP (concentrated solar power) is not implemented yet. The rest of the electricity generation is assumed to be dispatchable, and it is implied that it is used to cover the residual demand that remains after VRES generation has been subtracted from the load. From this point of view, the dispatchable part of the power system will be referred to as the backup system, and correspondingly, the energy from this system will be termed backup energy. Examples for backup power plants in a fully renewable setting are hydroelectric power, geothermal power, and to some extent CSP with thermal storage. In general, any other form of dispatchable generation can be used. The share of VRES in the system is measured as gross share, i.e. the total VRES generation divided by the total load. Due to temporal mismatches in generation and load, the VRES net share, i.e. the amount of VRE (variable renewable energy) actually consumed in the electricity system at the time of their generation is generally lower. Even in a system with a VRES gross share of 100%, the load will partly be covered from backup. This renders contributions from dispatchable renewable sources crucial to a fully renewable system.

To get an impression of the dimensions of the installations, current and extrapolated renewable installations are shown in

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Tables 1 and 2. Currently, most of the renewable power capacity is hydro power with a total of almost 80 GW in 2012, closely followed by wind with a total of close to 60 GW. Other technologies are dwarfed in comparison, but solar PV power has seen high growth rates over the past years [8]. The largest future renewable potentials are projected to lie in wind and solar power and are claimed to be sufficient to cover the world energy demand [9,10], so we concentrate on these. When extrapolating wind and solar capacities to the point where they reach a gross share of 100%, maximal total capacities as given in the first two columns of Table 2 result. These capacities are theoretical estimates for the total installed capacity in each FERC (Federal Electricity Regulatory Council) region in a hypothetical setting where wind power (first column) resp. solar PV power (second column) alone produces on average what is consumed. It is seen that even in this upper bound case, average installation densities in each FERC region (third and fifth column of Table 2) remain feasible in all regions. Only the most concentrated wind sites in ERCOT and SE, at which maximal wind installation densities of 23.2 MW/km^2 resp. 39.6 MW/km^2 occur (cf. fourth column of Table 2), will need to be redistributed to neighboring grid cells, which should not be a problem viewed in the light of the low average wind installation densities. Solar installation densities remain moderate even at the most concentrated sites, cf. the sixth column of Table 2.

We make a couple of simplifying assumptions: No ramping limits are imposed on the backup system, entailing no surplus generation from backup plants. The slopes in both the load time series and the residual load are given in Table 3. Column 1 gives the average slope in the load (taking no renewable production into account), column 2 is the maximal slope of the load, and column 3 and 4 are the average and maximal slopes of the residual load for the case of 100% wind and solar gross share with a backup energy minimizing wind/solar mix, see Sec. 2.2 for details. All slopes are normalized by the average load. It is seen that while the average slope does not increase much, extreme slopes rise from around 15% of the average load to 70–100% of the average load within 1 h, indicating the need for a more flexible backup system.

Table 1
Currently (2012) installed renewable capacities in the US, as reported by the US Department of Energy [8]. The reference gives the installations on a state basis, and they have been aggregated into FERC regions using the following approximations (FERC borders and state borders often, but not always, coincide, cf. Fig. 1): AllCA (All California) – California; ERCOT (Electricity Regulatory Council of Texas) – Texas; ISONE (Independent System Operator New England) – Maine, New Hampshire, Vermont, Massachusetts, Connecticut, Rhode Island; MISO (Midcontinent Independent System Operator) – North Dakota, South Dakota, Minnesota, Iowa, Missouri, Michigan, Wisconsin, Illinois, Indiana; NW (Northwest) – Washington, Oregon, Idaho, Montana, Wyoming, Nevada, Utah; NYISO (New York Independent System Operator) – New York; PJM (Pennsylvania, New Jersey, Maryland) – Ohio, West Virginia, Virginia, Maryland, Delaware, Pennsylvania, New Jersey; SE (Southeast) – Arkansas, Kentucky, Tennessee, Mississippi, Alabama, Georgia, North Carolina, South Carolina, Florida; SPP (Southwest Power Pool) – Nebraska, Kansas, Oklahoma, Louisiana; SW (Southwest) – Arizona, New Mexico, Colorado. Abbreviations are Geo. – Geothermal, Bm. Biomass. All installed capacities are given in GW.

FERC	Wind	PV	CSP	Geo.	Bm.	Hydro
AllCA	5.54	2.56	0.36	2.7	1.3	10.1
ERCOT	12.21	0.14	0.00	0.0	0.5	0.7
ISONE	0.83	0.29	0.00	0.0	1.7	1.9
MISO	17.79	0.12	0.00	0.0	1.6	4.1
NW	9.47	0.44	0.06	0.6	0.9	36.2
NYISO	1.64	0.18	0.00	0.0	0.5	4.7
PJM	2.48	1.38	0.00	0.0	1.9	2.6
SE	0.03	0.40	0.08	0.0	4.6	13.2
SPP	6.31	0.02	0.00	0.0	0.5	1.3
SW	3.32	1.61	0.04	0.0	0.1	3.4
Total	59.62	7.13	0.55	3.3	13.4	78.16

Additional measures of matching VRES generation and demand, such as storage or demand-side management, are not treated explicitly. Likewise, potential future changes in load characteristics or load flexibility, which may arise e.g. due to electric cars, are not directly taken into account. Whenever VRES generation exceeds the demand, surplus energy production occurs. This surplus is initially assumed to be of no value in our model. The effect of surplus energy being sold, possibly at a lower price, to storage, transmission, or to cover other (partly) flexible demand like electric vehicle charging or synthetic fuel production, is investigated later in this paper. Additionally, sensitivities to different price assumptions are examined.

The core model has been developed and applied to obtain optimal mixes in fully renewable energy systems as well as potential transmission grid extensions by Becker et al. [11]. Here, it is applied to different build-up pathways toward a fully renewable electricity supply.

This paper is starts with a short description of the underlying data and methodology in Sec. 2. Subsequently, the resulting US build-up pathways and their sensitivities to cost assumptions and surplus usage are presented in Sec. 3. Sec. 4 summarizes the main findings and concludes the paper.

2. Data and methodology

2.1. Load and generation data

The analysis is based on weather data for 32 years with one hour time steps and 30 × 30 km^2 grid cells, covering the time span 1979–2010, from the NCEP (National Centers for Environmental Prediction) Climate Forecast System Reanalysis [13]. They were converted to wind and solar PV generation data as described in by Refs. [11,14,15]. Wind capacity layouts were chosen similarly to those used to produce the NREL (National Renewable Energy Laboratory) wind datasets [16,17], while solar PV capacity was distributed according to the potential generation in each grid cell. Solar panels with a nameplate capacity of 156 kW fixed in southward direction at a tilt equal to the latitude were assumed. This tilt implies that the panel orientation is optimal for the average solar noon position. In our data, solar capacity factors between 15% (in ISONE and NYISO) and 20% (in California and SW) are observed. 3 MW wind turbines with a hub height of 80 m onshore and 7 MW at 100 m hub height offshore were assumed, yielding average capacity factors between 23% in SE and 42% in ISONE, see Table 4. Power generation from each grid cell was aggregated to FERC (Federal Electricity Regulatory Council) region level. See Fig. 1 for a map of the contiguous US FERC regions. Details of the data processing can be found in Ref. [11].

Historical load data for the years 2006–2007 were compiled for each FERC region in Ref. [12]. Where necessary, load data were extended by repetition to cover the 32-year simulation period.

The aggregation of wind and solar PV generation as well as load implies that no FERC-region-internal bottlenecks are present in the transmission grid. It is indeed likely that in a highly renewable electricity system, the regional transmission grids will be reinforced, because of the beneficial effects of aggregation on smoothing wind and solar PV output, well documented in the scientific literature, e.g. Refs. [18–24]. Inter-FERC-region transmission has the potential to smooth VRES generation even further [10,11], but is initially not incorporated into the model.

Central to our research is the mismatch Δ_n between load L_n and generation G_n^S, G_n^W from solar PV and wind, respectively, in FERC region n.