Article

Comparing Power-System- and User-Oriented Battery Electric Vehicle Charging Representation and its Implications on Energy System Modeling

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Appendix A – Assumptions, scenario study & results

Model description and parametrization

Regarding the model set-up and scope, the main characteristics are summarized in **Table A1** Error! Reference source not found. below.

Table A1. Model characteristics of REMix as used in this case study.

Optimization type	Target year optimization
Optimization method	Linear programming
Objective function	Total cost including CAPEX of all endogenously added capacities, OPEX of all capacities, and penalty costs for unsupplied load
Temporal resolution	Hourly (8760 timesteps)
Geographical horizon and resolution	13 nodes: Germany in two nodes plus neighbors
Optimization variables	Investment in power plant capacities and flexibilities as well as technology dispatch
Energy demand sectors	Power, transport
Transport mode	Private passenger road transport
Transport technology resolution	3 battery electric vehicle (BEV) fleets (S, M, L)
Variation of wind and PV power feed-in patterns	2006-2012 yearly
Variation of load patterns	2006-2012 yearly

Scenario study assumptions

Overarching assumptions regard the following points

- Power demand stays the same in quantity and in its hourly variability as in the underlying data years (2011 for baseline runs and 2006-2012 for sensitivity scenarios e-j)
- Weather patterns stay the same as in the historic years considered
- Socio-economic development: The populations in Germany and its neighboring countries develop according to assumptions in the ENTSO-E TYNDP [2]
- For REMix: The flexibility options are chosen solely based on a (total) cost basis, disregarding power grid phenomena occurring at sub-minute time-scale, import dependency, acceptance of grid- or power plant expansion etc.

Assumptions regarding technical transfer capacities between all model nodes considered in the case study are based on the German "Netzentwicklungsplan" (NEP) [1] (p. 110), the ENTSO-E TYNDP [2] (p. 30), and older data. The capacities are assumed to be equal to the given capacities as "before 2035". Except for the connection from Germany to Sweden these are equivalent to the capacities given in the NEP.

The largest differences in export and import capacities are for the links between Belgium and France, Belgium & Luxembourg, Denmark & Sweden, France & Switzerland, Germany and Poland as well as Germany & Switzerland.

Assumptions had to be made on the model link length between Germany North and Germany South which is assumed to be 150 km and the link length between Belgium and Luxembourg which is assumed to be 100 km. Other link lengths are averaged over given data in the TYNDP.

Power demand

Power demand for Germany and its neighboring countries are based on the "Sustainable Transition" scenario of the TYNDP 2018. It includes power demand from heat and transport sector. Power demand of a 2030 EV fleet was approximated based on data given in [2] and subtracted for Germany in order to avoid double counting. The German power demand is disaggregated based on population census data from 2011 [3] yielding disaggregation factors of 53% for Germany North and 47% for Germany South. Historic development of power demand as well as projections are shown below in Figure A1.

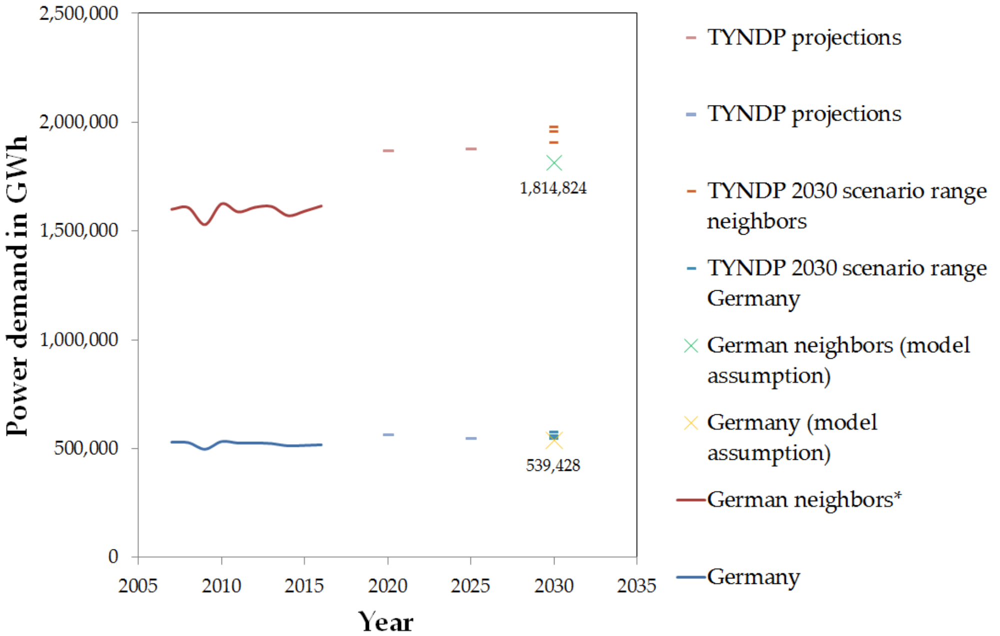

Figure A1. Historic power demand, TYNDP best estimates for 2020 and 2025 as well as scenario values for the scenario "Sustainable Transition" for 2030. The three markers in 2030 present the variety of two TYNDP scenarios, "Sustainable Transition" and "Distributed Generation" as well as an EUCO scenario. Green and orange crosses show the here assumed values from the scenario "Sustainable Transition" corrected by an approximated power demand of the 2030 PEV fleet.

Power plant park

The existing power plant park is used based on REMix-parametrization from the INTEEVER project [4]. There, a base run for 2030 was carried out to quantify a base power plant, grid and storage park in a first step as a quantitative basis for the next step of optimizing the expansion of different flexibility options. Assumptions from the TYNDP 2030ST scenario as well as own assumptions for the scenario study are shown in Table A2.

Table A2. Quantitative assumptions for the existing power supply capacities as an input for the scenario study runs, aggregated for Germany and its neighboring countries. Pumped hydro power is not shown. All values in GW.

	Parameter	TYNDP 2030ST [4]		Own assumptions	
		Germany	German neighbors	Germany	German neighbors
	Conventional thermal power plants*	66	141	61	134
Fluctuating renewable energies	PV	66	69	47	26
	Wind onshore	59	82	50	36
	Wind offshore	15	26	6	12
Controllable renewable energies	Hydro run-of-river	4	24	4	27
	Biomass power**	0	2	0	0
	Hydro reservoir	11	95	1	70

*Including oil and other conventional power plants in [2].

**"Biofuels" in [2].

Flexibility options

One strength of REMix is the modeling of different competing flexibility options to balance fluctuating renewable energy power generation. REMix optimizes the investment in and the operation of different flexibility options, e.g. power plants or energy storage. We consider the following flexibility options:

- Gas power plants (CCGT and OCGT)
- Curtailment of wind and PV power generation
- Controllable renewable energies
- Import and exports
- Battery storage and hydrogen caverns
- BEV fleet controlled charging

The need for balancing renewable energy feed-in is mainly determined by the power balance constrained in a few hours of the lowest fluctuating renewable energy power feed-in. These hours differ from model node to model node and depend on the respective residual load curve.

Similar to power plant capacities, we apply a brownfield approach implying that certain flexibility capacities are already installed in the power system before optimization. Flexibility options' expansion restrictions are shown in **Error! Reference source not found.** and are only set for PV, wind and hydro power plant capacities as well as for hydro power technologies and hydrogen caverns. The expansion of BEVs is not modelled REMix-endogenously but fleet values are taken from the more specialized stock and flow model VECTOR21. Thus, investments in the fleet are not possible but only the utilization of the vehicle fleet battery is optimized subject to annual constraints such as state-of-charge (SOC) limitations, charging infrastructure availability and electric power outflow from the battery due to driving (see main document for more details).

Flexibility option	Technology	Unit	Expansion constraint	Operational constraint	Source

			Germany North	Germany South	Germany North	Germany South	
Thermal power plants	CCGT, GT	GW	-	-	-	-	
Surplus VRE and curtailment	PV	GW	1316	505	Hourly feed-in timeseries		
	Wind power onshore	GW	1172	452	Hourly feed-in timeseries		
	Wind power offshore	GW	210	0	Hourly feed-in timeseries		
Controllable RE	Hydro run-of-river	MW	1044	388	Daily feed-in timeseries		
	Biomass	MW	-	-	-	-	
	Hydro reservoir	TWh	0.043	0.488	-	-	
Power storage	Pumped hydro	GWh	24	14	-	-	
	Lithium ion batteries		-	-	-	-	
	Hydrogen caverns	GWh	113639	1395	-	-	
EV fleet controlled charging	BEV (S, M, L)		-	-	Hourly flexibility profiles (see below)		[6]

Table A3. Quantitative and qualitative flexibility options' restrictions. Sources given in last column.

Table A4. Net transfer capacities from and to Germany

Node	Technology	Value	Source
Germany North to neighbours	HVAC 380 kV	23.3 GW	[2]
	DC	4.7 GW	[2]
Germany South to neighbours	HVAC 380 kV	15.23 GW	[2]
	DC	0 GW	[2]
Germany North to Germany South	HVAC 380 kV	14.3 GW	[1]
	DC	10 GW	[1]

Techno-economic assumptions on BEVs

Historic battery electric vehicle battery capacities as well as literature projection and our own scenario assumptions are shown below in Figure A2.

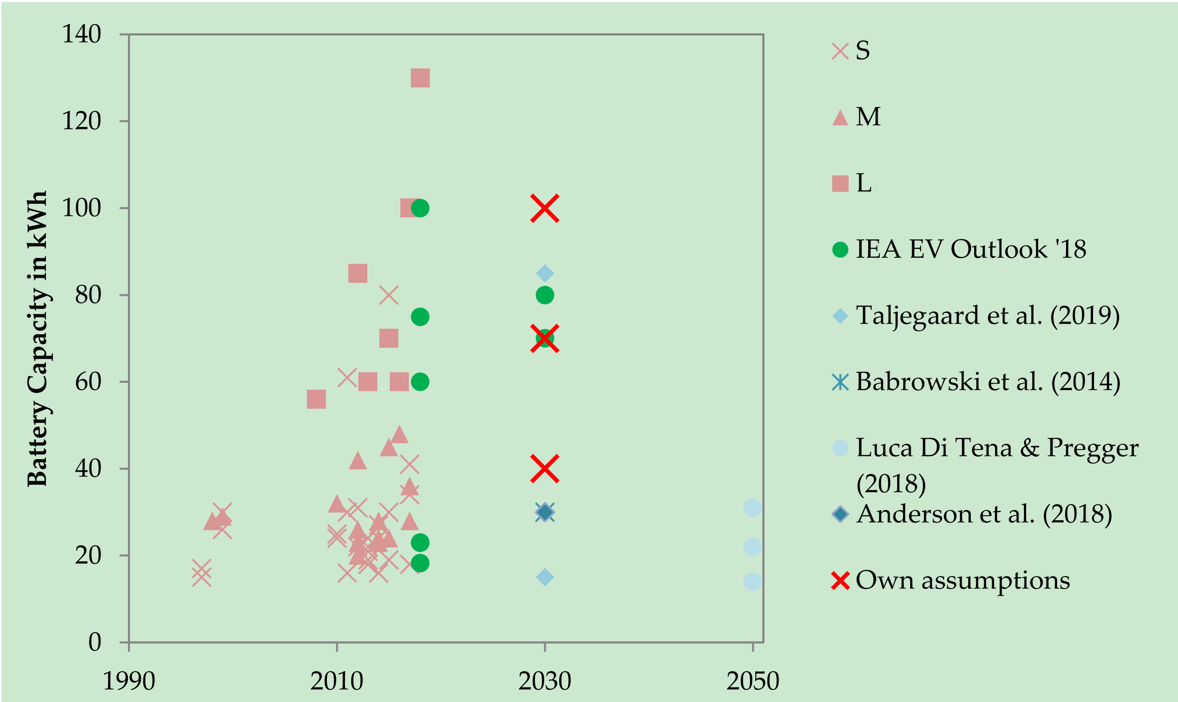

Figure A2. Historic development, prospective values from literature and own assumptions of BEV battery capacity values in kWh. Historic values are given in light red and differentiated between small (S), medium (M) and large (L) BEV models. Historic values are not weighted by sales or stocks. Ranges given in the IEA EV Outlook for 2018 as well as average fleet ranges for 2030 are given in green. Literature projections for 2030 and 2050 are given in light blue as indications. Own assumptions for the REMix model runs 0 and 1 are given as dark red crosses. Sources: Own composition based on [5-9].

Fluctuating RE and electricity demand profiles

Dispatch optimization in REMix is carried out taking into account hourly profiles for the target year for each node for power demand and VRE feed-in (four separate profiles). In Figure A3, we show the load duration curves of the here utilized 2011 load series as well as simulated feed-in of the four fluctuating RE technologies for Germany North, Germany South and the German neighbors.

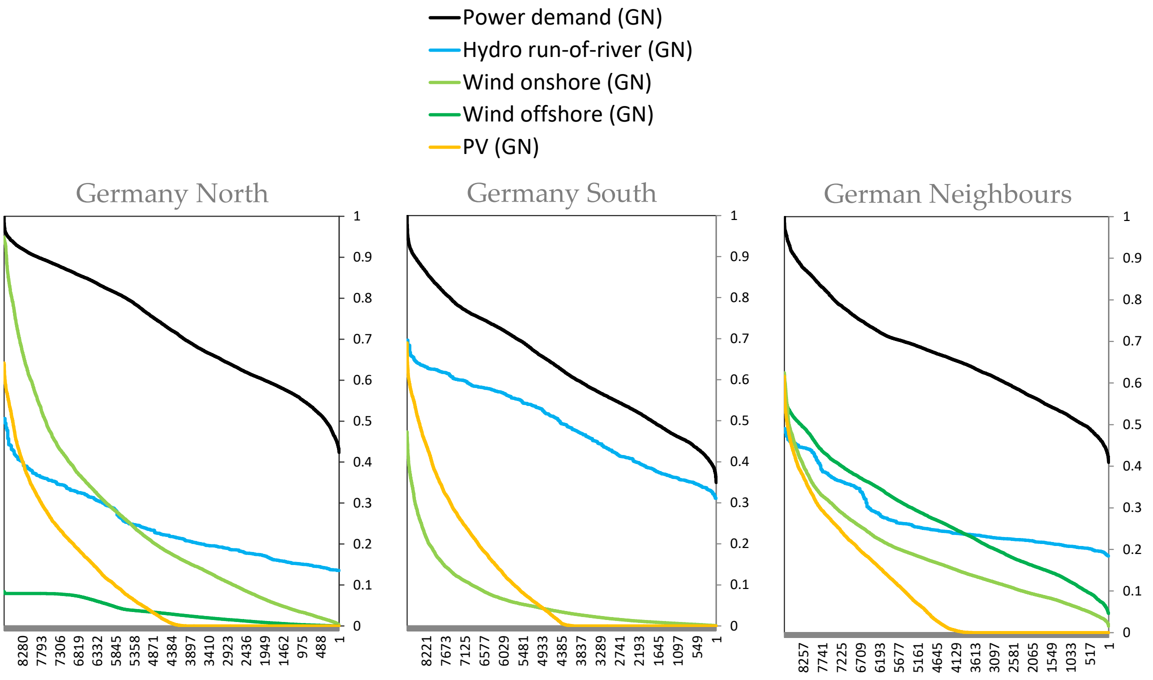

Figure A3. Duration curves of power demand and feed-in series of the four fluctuating RE power plant technologies. Hydro run-of-river profiles are given in 24-hour resolution. Fluctuating RE profiles are given based on the respective rated capacity. Power demand was normalized with the respective peak load in the model node. Source: Own composition based on [10-12].

Emission targets

Emission targets used are based on a 80% GHG reduction target for Germany up to 2050 compared with 1990. In the three sensitivity scenarios b-d, these will be varied between this moderate political target and a 0 t CO_2 emission power system (d). CO_2 costs of 60 €/t CO_2 are assumed. All assumptions are shown below in Table A5.

Table A5. Emission targets for Germany and its neighboring countries as well as CO_2 costs

	Node	**Unit**	**Value**	**Source**
Emission reduction targets	Germany	MT CO_2	123 + sensitivity scenarios (b-d)	
	Cumulated emission target of neighboring countries	Mt CO_2	193	
CO_2 costs	all	€/t CO_2 emitted	60	

Overview table of all model runs carried out in the scenario study

Table A6. Overview on model runs and respective scenario acronyms.

Scenario acronym	Varied value and unit	Amount of variation
S0	Electricity demand from BEV	To 0

	fleet in TWh	
S1		
S2		
a	Maximum share of controlled charging in %	To 0
b	Max climate targets in Germany in Mt	Changed from 122 Mt to 80 Mt
c		Changed from 122 Mt to 50 Mt
d		Changed from 122 Mt to 0 Mt
e	Varied underlying weather and electricity demand data years	2006
f		2007
g		2008
h		2009
i		2010
j		2012
k	Specific investments of fluctuating RE technologies	See Table B
l		See Table B
S1m	Share of controlled charging of BEV fleet	30%

Appendix B – Results of scenario study modeling runs

Annual distributions of daily charging dynamics

Full year

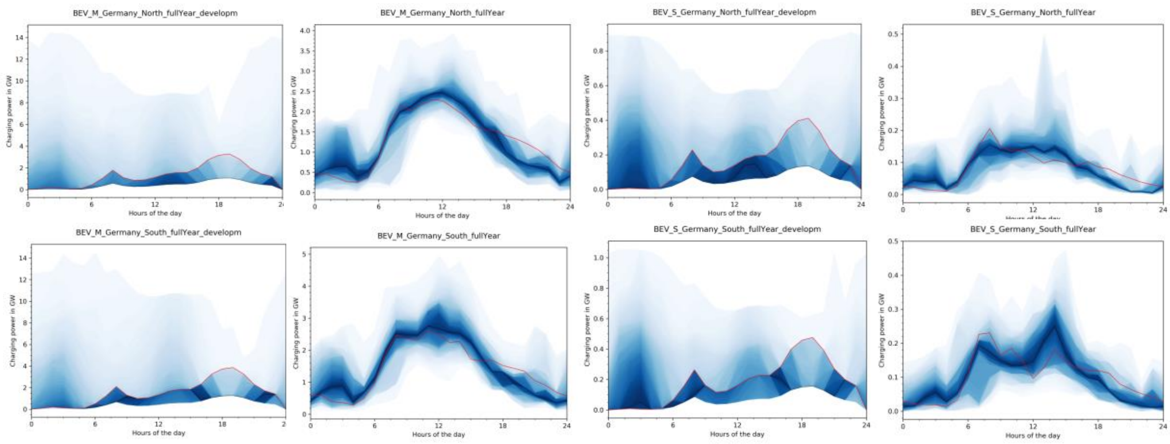

Figure B1. Daily probability distributions for total charging (controlled and uncontrolled) of medium and small sized BEV fleets in northern (top row) and southern (bottom row) Germany. The first and the third column show S1 results and the second and third column show S2 results. A case of completely uncontrolled charging is shown as red line.

Summer hours

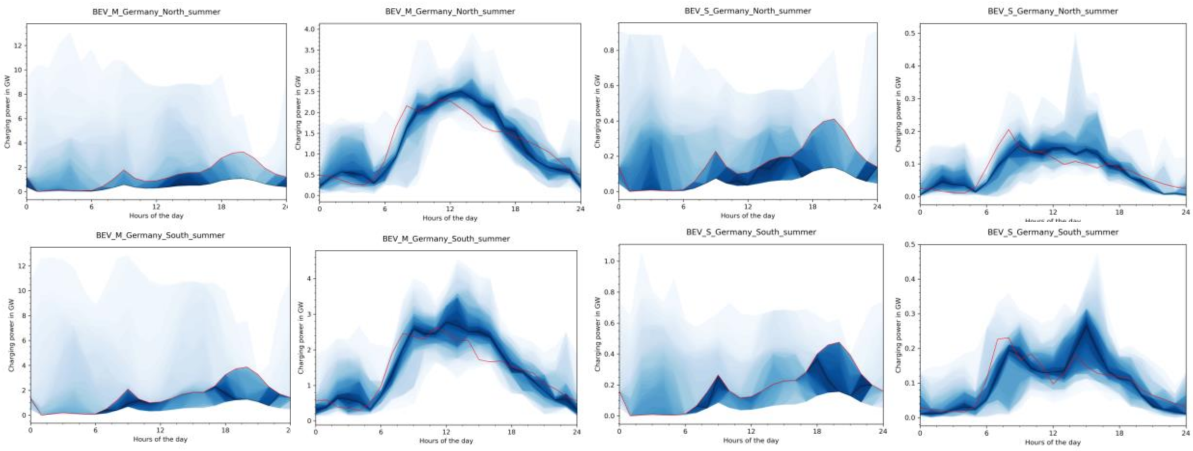

Figure B2. Daily probability distributions for total charging (controlled and uncontrolled) of medium and small sized BEV fleets in northern (top row) and southern (bottom row) Germany in summer hours (3600-5760). The first and the third column show S1 results and the second and third column show S2 results. A case of completely uncontrolled charging is shown as red line.

Winter hours

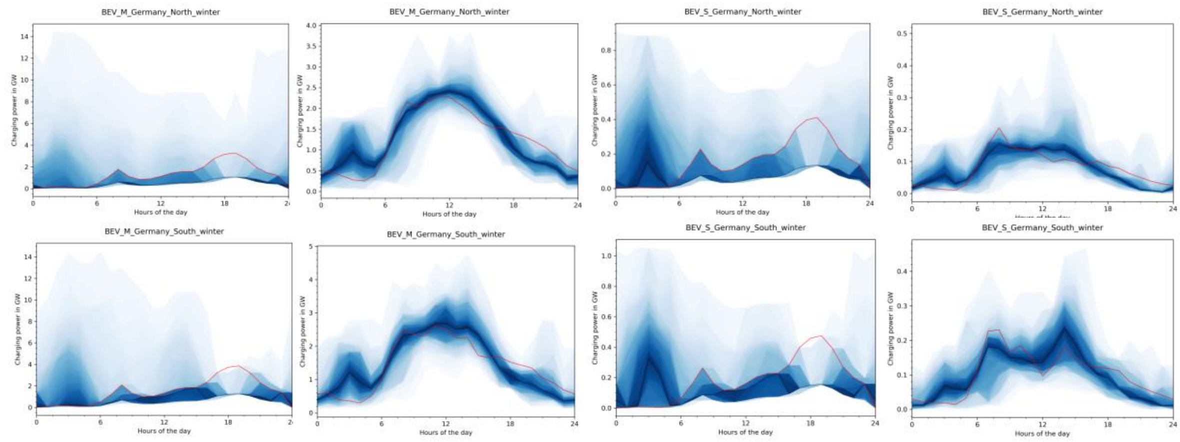

Figure B3. Daily probability distributions for total charging (controlled and uncontrolled) of medium and small sized BEV fleets in northern (top row) and southern (bottom row) Germany in winter hours (1-2160 and 7920-8760). The first and the third column show S1 results and the second and third column show S2 results. A case of completely uncontrolled charging is shown as red line.

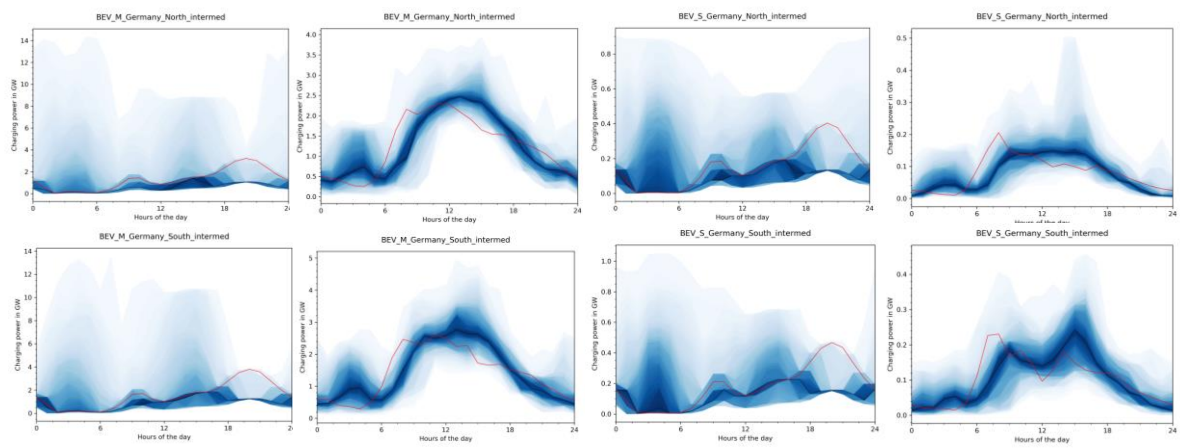

Figure B4. Daily probability distributions for total charging (controlled and uncontrolled) of medium and small sized BEV fleets in northern (top row) and southern (bottom row) Germany in winter hours (1440-3600 and 5760-7920). The first and the third column show S1 results and the second and third column show S2 results. A case of completely uncontrolled charging is shown as red line.

Weekend

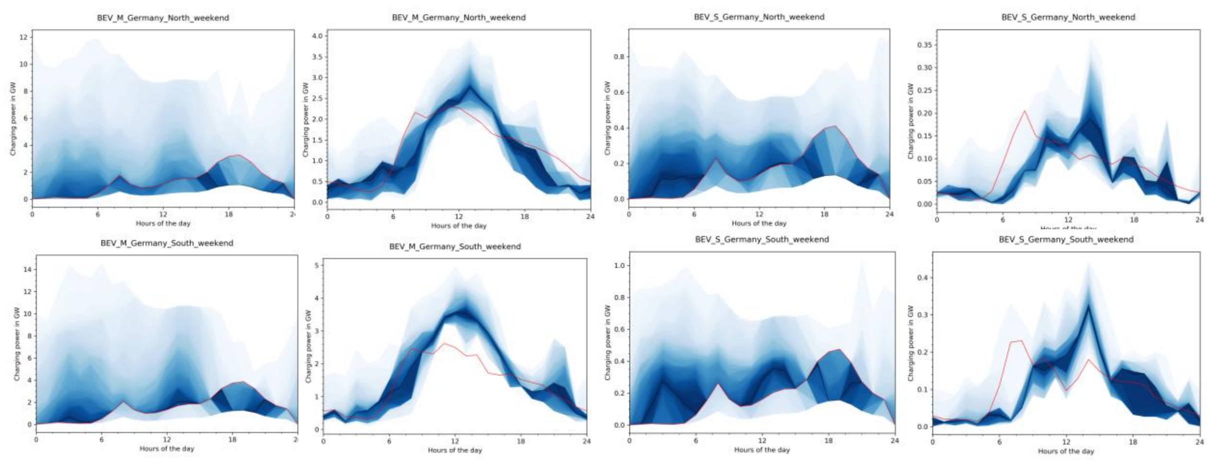

Figure B5. Daily probability distributions for total charging (controlled and uncontrolled) of medium and small sized BEV fleets in northern (top row) and southern (bottom row) Germany on weekends. The first and the third column show S1 results and the second and third column show S2 results. A case of completely uncontrolled charging is shown as red line.

Marginality analysis

For our case of controlled charging without feeding electricity back to the grid, $\Psi_{V2G}=0$ and $\Phi_{V2G}=0$ hold true and bringing all variables to the left-hand and all parameters to the right hand side of the *batLevBal* equation (see Section 2.3 for all equations), yields

$$\Psi_{CC}(t) - \Lambda(t) + \Lambda(t-1) = P_{drive}(t) - C_{unc}(t)$$

The marginal value of this equation corresponds to the increase of the total system costs that originate from an increase of the right-hand side of the battery level balance equation by 1. Since the equation is formulated in units of GW, in this case, we can interpret the marginal value of the equation by either an increase of electricity for driving or a decrease of uncontrolled charging (or a mixture) by 1 GW. The three other relevant equations are the battery level constraints for minimum (*minBatLev*) and maximum (*maxBatLev*) SOC as well as the equation limiting controlled charging by the fleet connection power to the grid (*maxCC*). Additionally, the marginal value of power generation is shown since it presents the cost of an additional unit (GWh) of electric demand for the German power system.

The analysis will be carried out on two different timescales to show effects on a weekly and a monthly timescale. The marginal values of the equations for the full year are given in Figure B6 and Figure B7. Two time intervals were chosen for a more in-depth analysis of the marginal values since they provide an interesting array of load and feed-in situations. Figure B6 shows BEV fleet battery operation and marginal for the first 15 days while Figure B7 shows the same quantities for the last 42 days of the year.

SOC constraints (model input parameters), levels (model solutions), marginal values of equations and variables as well as the power plant dispatch are given in Figure B for the first 15 days of the model year for scenarios S1 (left) and S2 (right).

Figure B6. Marginality analysis of first 15 days (360 hours) in the scenario for 2030 comparing scenario S1 (VencoPy input) (left) and scenario S2 (CURRENT input) (right) for Germany North. In the first row, EV fleet SOC constraints (turquoise) and levels (black) are depicted. The second row plots show the marginal values of the equations of the REMix module and the power generation marginal for northern Germany. The third row shows the marginal value of the controlled charging variable. The fourth row shows the power plant dispatch in Germany with fossil power plant dispatch in grey, renewables in shaded green, and curtailment in shaded red, imports in yellow. Uncontrolled charging is in dark turquoise while controlled charging is in light turquoise. The demand line comprises both electricity demand by households, industry, and service sector as well as EV charging demand. Duration curves of all marginal are shown in Figure B9-Figure **B11**.

The SOC plots on the top of Figure B6 show the implications of the reduced BEV fleet battery potential. In S1, the fleet battery is always discharged during daytime and charged every 3-7 days at

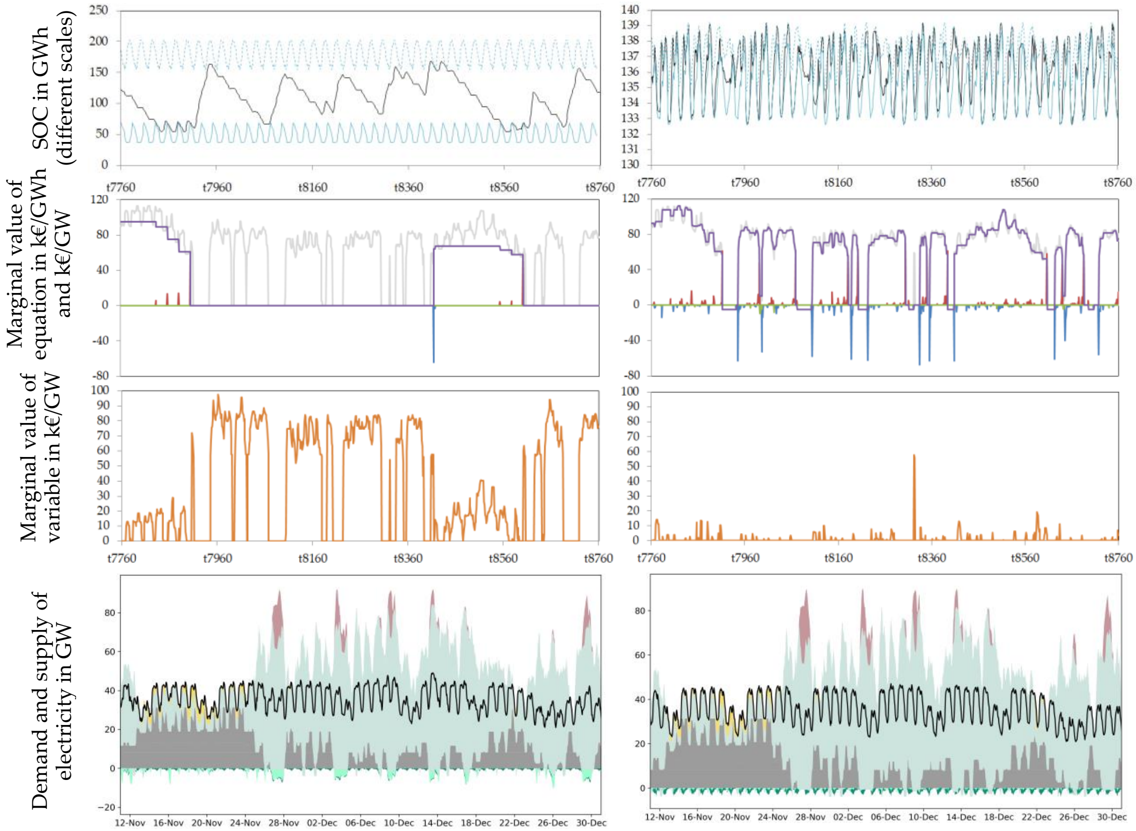

Figure B7. Marginality analysis for the last 42 days of the year.

times of low residual load. This can be observed on the dispatch plot on the bottom left. This concentrating effect of charging has been shown for the concentration from a relatively continuous charging power to hours of night and partly of daytime [13]. In scenario S2, the difference between the SOC min and SOC max constraints is significantly decreased to 5-10 GWh. Since the axes of the SOC plots have a different scaling, the effect is even larger than visualized (compare **Error! Reference source not found.**). Especially on weekday evening hours, the load shifting potential is almost completely diminished. In the dispatch plot for S2, both increased uncontrolled charging occurring on a daily pattern basis and the diurnal characteristic of controlled charging is depicted. Adjustment to high fluctuating RE feed-in still occurs but to a significantly lower degree.

Turning to the marginal values of BEV charging constraint equations, Figure B6 reveals a correlation between the marginal of the battery balance equation (in violet) with the power generation marginal. This correlation is higher for the case of lower flexibility indicating a more direct pass through of an increased electric driving demand or decrease of uncontrolled charging to total system costs at the respective cost of hourly power generation. BEV fleet batteries expand the availability of otherwise curtailed fluctuating RE to hours (and in S1 days) before and after low residual load situations occur. This can be seen in scenario S1, in which a load increase or charging decrease does not always lead to power system cost increases due to possible shifting of fluctuating RE feed-in as can be seen in the period between November 20th and December 14th in Figure B7. However, in these periods, controlled charging has a pivotal role in balancing wind feed-in as can be seen by the marginal value of the controlled charging variable in the same time frame.

The marginal value of the battery balance equation increases by the negative value of the marginal value of the constraint equation (*batLevMax* or *batLevMin*) at the last point in time where charging or discharging was constrained by SOC constraints (compare section **Error! Reference source not found.**). For S1, the marginal value of *batLevBal* shows a lower temporal dynamic and an overall lower absolute value which is exemplified in Figure B7, where over the course of three weeks, a RE fluctuation characteristic occurs that lies in the range of the BEV fleet load shifting potential. Thus, in this time, increasing electric driving demand doesn't affect total system costs.

In some times in S2, the marginal value of the battery level equation becomes negative, indicating a potential reduction in total system cost if exogenous discharging increases. As can be seen in Figure B7 at November, 19^{th}, this effect cannot be explained by either curtailment or the BEV fleet SOC being at its bounds. Supposedly, this is correlated with time intervals in which the relative BEV fleet SOC significantly increases, although this cannot be observed at November 20^{th}.

In general, the marginal value of controlled charging is drastically reduced in S2 in comparison with S1 indicating its decreased importance to overall system cost in S2. The higher importance to overall system cost can also be observed by the larger area under the duration curve of the marginal value of the controlled charging variable for S1 compared to the same area for S2 given in Figure B11.

Controlled charging has a more important role for the power system in the case of higher flexibility. This is due to a twofold effect of reduced flexibility from BEV load-shifting. For one, BEV charging load occurs more often in peak load situations as can be seen by increased peak load demand in S2 compared to S1 (see Table B1). Secondly, general balancing is strongly limited to approximately a day thus diminishing the balancing effect of the BEV fleet battery for wind power feed-in. More costly flexibility options such as curtailment and increased gas power plant capacities are necessary in S2. Through the investment need in especially gas power plants and their respective availability, marginal value of controlled charging is reduced.

Upper and lower bounds of the BEV fleet battery state-of-charge are less often important in S1. The effect is shown in the duration curve of the marginal values of the two battery limitation constraints for the full year in Figure B10. The main determinants for the difference between the SOC min and max profiles in CURRENT are the difference between parking time and necessary charging time as well as the users' option not to charge. This motivates increased charging powers resulting in shorter charging periods and incentivizing users to connect their cars to the grid over-sufficiently in order to increase connected parking periods.

Marginal values of the charging connection constraint (*maxCC*) are generally low and constraints occur in general not very often as shown in Table B1. In these hours, the full connected capacity is utilized for charging the BEV fleet, usually in hours of curtailment. In the case of a higher detail of modelling BEV users' connection behavior with a sufficiency-oriented BEV connection, this constraint gets more important in northern and less important in southern Germany. Increases in northern Germany can be explained by higher peaks in S2 and narrower SOC bands, necessitating steeper charging at times of low residual load. Decreasing number of hours in S2 in southern Germany occur because of increased utilization of other flexibility options such as gas power plants, imports and curtailment.

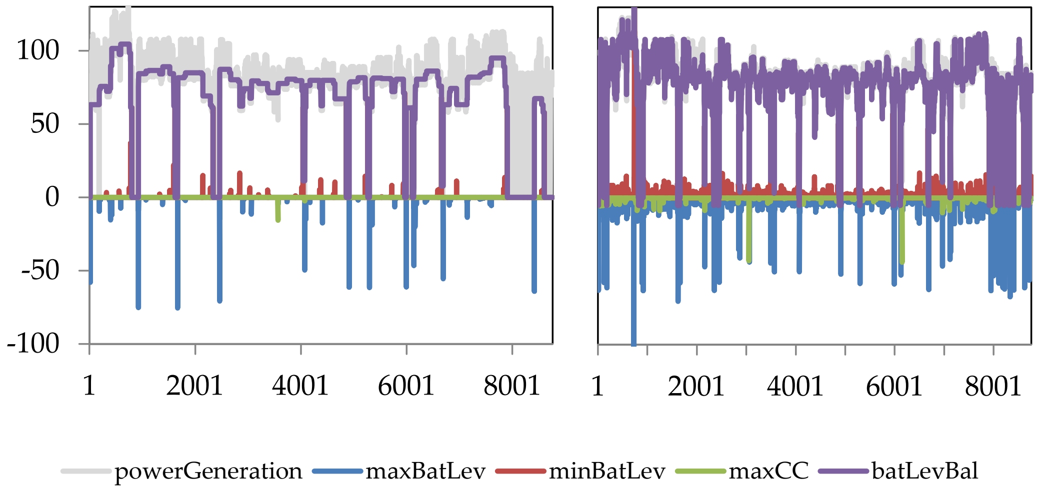

Figure B8. Marginal values of equations of the BEV modeling equations in REMix for the full year for scenario S1 (left) and S2 (right).

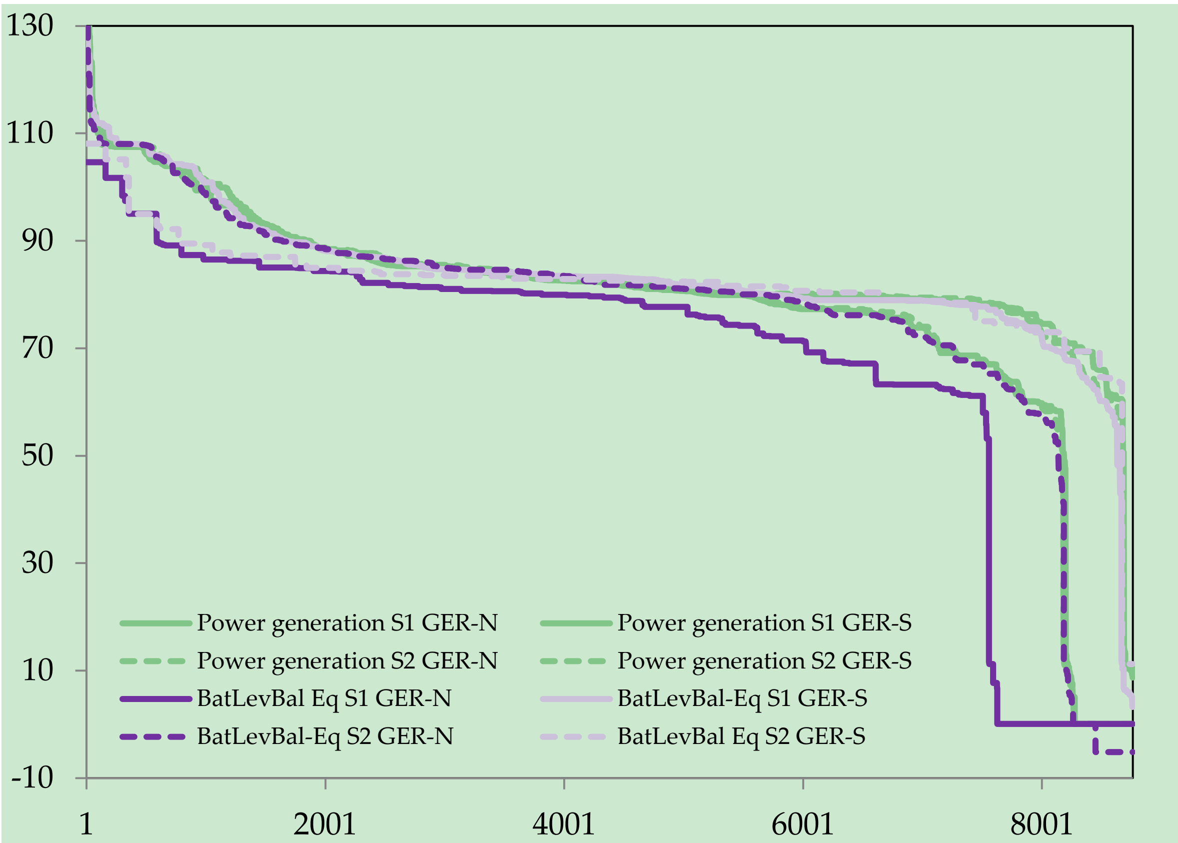

Figure B9. Duration curve of the marginal value of the battery balance equation (violet) compared to the load duration curve of the power generation marginal (grey). Solid lines show scenario S1 results and dashed lines scenario S2 results. Values for southern Germany are given in light violet.

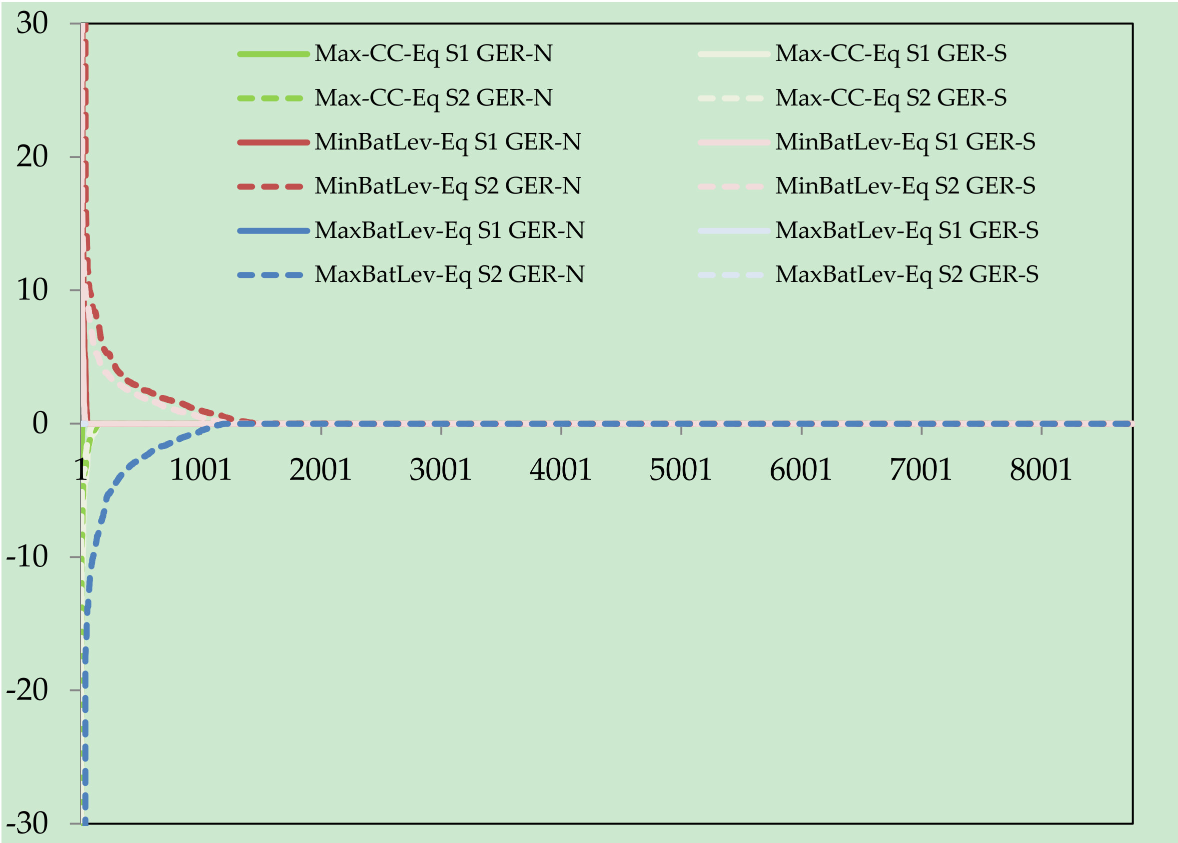

Figure B10. Duration curves of marginals of constraint equations. Max-CC: Equation constraining the power of controlled charging because of grid connection of EV fleet. MinBatLev: SOC min constraint. MaxBatLev: SOC max constraint. Curves are given solid for scenario S1 and dashed for scenario S2. Results for southern Germany are given in light colors.

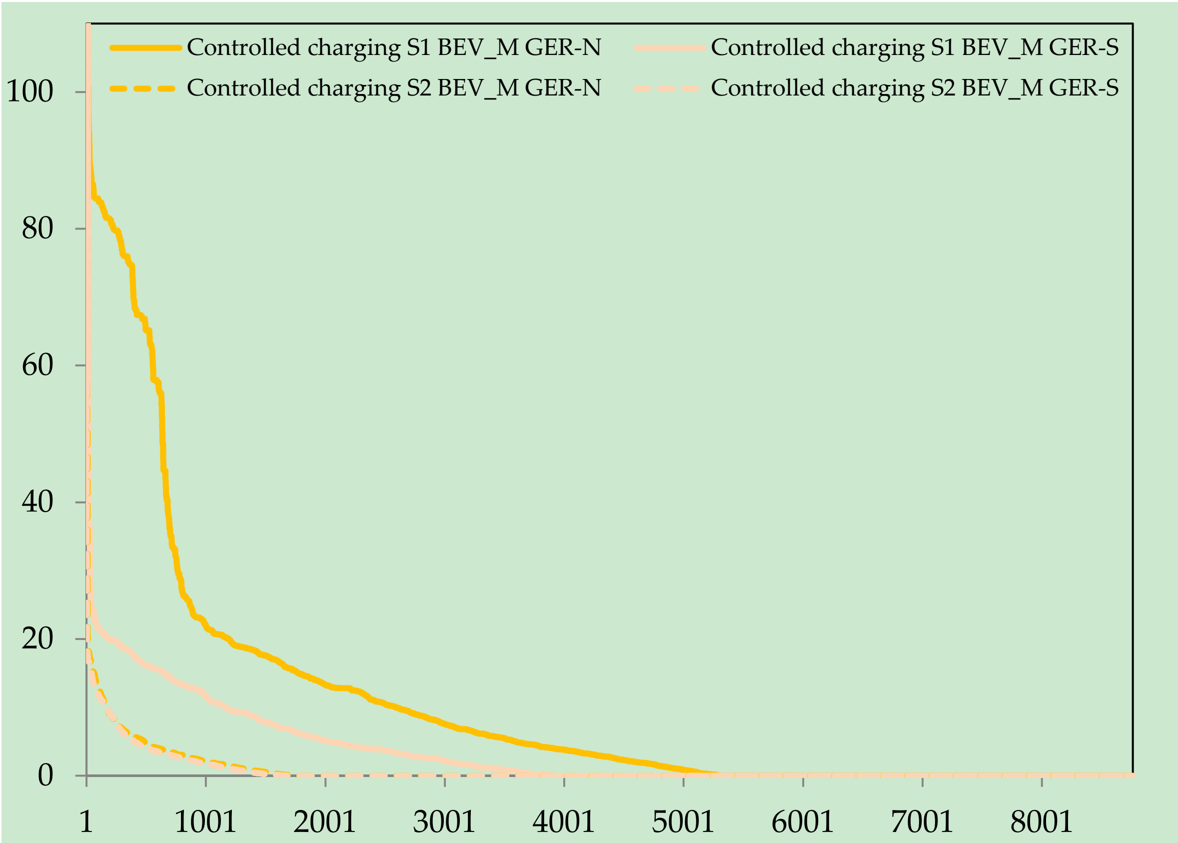

Figure B11. Duration curves of the marginal value of controlled charging for medium-sized BEV in Germany-North and -South.

Sensitivity Analysis

In the following, result tables of the annual energy system model results of the sensitivity scenarios b-m are given for GHG emission ambitions (scenarios b-d), weather and electric demand years (scenarios e-j), specific power plant technology investments (scenarios k and l) and controlled charging share (scenario m).

Table B1. Overview on scenario definitions and main annual results of the sensitivity analysis on the CO_2 emission limit and historic weather year used. Total system costs are given for the complete system boundary while all other values are given for Germany.

	Scenario definitions				**Results**												
Scenario	Annual electricity demand from BEV fleet in TWh	Controllable share in %	GHG limitation for G power system in Mt	Data year for load and VRE feed-in	Total system cost in Bn. €	Shifted load by German BEV fleets in TWh	Peak load in GW	Installed capacities of power plant park in GW	Installed RE capacities in GW	RE capacity additions in GW	Gas power plant capacity additions in GW	Annual power generation in TWh	Annual RE power generation in TWh	VRE share in total power generation in %	Annual RE curtailment in TWh	Imports to Germany in TWh	Exports from northern G to southern G in TWh
S0	0	-	122	2011	68.4	0	83.9	214	153	46.2	31.3	501	279	55.7	2.9	45.9	64.7
S1	27	66	122	2011	71.2	24.2	86.3	223	159	51.5	35.5	526	291	55.3	2.6	51.3	65.1
S2	27	30	122	2011	71.7	8.4	87.8	222	156	48.8	37.2	524	284	54.2	3.4	51.6	62.2

S1b	27	66	80	2011	71.4	24.6	87.4	222	166	59.0	26.4	453	309	68.2	4.9	124.0	77.6
S2b	27	30	80	2011	72.0	8.4	87.6	219	161	54.3	28.7	447	299	66.9	4.9	130.3	73.2
S1c	27	66	50	2011	72.1	24.9	89.3	237	187	79.6	21.3	431	331	76.8	6.3	147.1	77.3
S2c	27	30	50	2011	72.7	8.4	87.6	233	182	74.6	22.2	427	323	75.6	7.3	150.8	73.3
S1d	27	66	0	2011	79.4	24.2	87.4	304	274	167.1	0	497	494	99.4	5.5	105.8	89.3
S2d	27	30	0	2011	80.2	8.4	87.4	303	273	166.2	0	500	497	99.4	5.9	105.4	89.6
S1e	27	66	122	2006	72.2	23.6	90.8	211	155	47.8	27.0	510	268	53.9	1.4	54.9	65.7
S2e	27	30	122	2006	72.7	8.4	89.5	210	152	45.0	28.7	505	275	53.2	2.0	50.7	70.9
S1f	27	66	122	2007	67.9	23.4	87.6	225	165	57.6	31.2	541	309	59.4	6.7	70.2	34.4
S2f	27	30	122	2007	68.2	8.4	89.5	222	159	51.5	34.0	541	321	57.1	7.4	67.6	35.0
S1g	27	66	122	2008	68.8	23.0	91.8	213	160	52.6	24.2	535	290	56.5	4.8	68.5	40.3
S2g	27	30	122	2008	69.1	8.4	87.9	211	156	49.1	25.8	528	302	55.0	5.4	65.8	47.8
S1h	27	66	122	2009	74.8	24.3	88.0	226	165	57.8	32.0	519	273	54.8	2.2	60.1	56.4
S2h	27	30	122	2009	75.1	8.4	87.9	223	160	52.4	34.6	509	284	53.6	2.1	55.7	66.1
S1i	27	66	122	2010	77.4	23.2	94.2	226	169	61.6	28.4	516	275	54.8	2.4	54.9	58.4
S2i	27	30	122	2010	77.7	8.4	91.2	222	165	57.6	27.7	510	283	53.8	2.8	50.0	63.9
S1j	27	66	122	2012	74.4	24.0	88.4	224	164	57.3	30.9	525	291	55.0	4.8	54.9	50.7
S2j	27	30	122	2012	74.7	8.4	87.6	219	158	51.4	31.3	515	284	53.8	4.1	50.0	60.5

CAPEX sensitivity

Capital expenditure sensitivities are carried out taking into account two alternative data sources. The first are the IRENA projections for 2025 [14] but assuming respective values for 2030 assuming slower but effective political dynamics needed to leverage cost reduction potentials for the production of PV and wind power technology. This yields the values given in Table B assuming an average exchange rate of 0.9 2015 €/2015 USD. It represents the global weighted average of an optimistic cost reduction for PV and wind power technologies. The second set is based on an analysis by the Danish Energy Agency and Energinet [15] and better reflects European projections. All values in Table B are given rounded to 10 €/kW.

Table B2. Specific CAPEX sensitivity assumptions based on [14,15].

		PV	Wind onshore	Wind offshore
Scenario assumptions	**€ / kW**	860	1100	1800
CAPEX sensitivity set 1 [14]	***USD / kW***	*790*	*1370*	*3950*
	€ / kW	710	1230	3560
CAPEX sensitivity set 2 [15]	**€ / kW**	660[1]	1040	1800[2]

[1] PV specific installation costs assumed to be the average of small (870 €/kW), medium (800 €/kW) and large scale plants with large scale plants being made up half of tracking (310 €/kW) and half of non-tracking (300 €/kW) systems

[2] Offshore wind plants assumed to be half near shore (1660 €/kW) and half offshore (1930 €/kW)

Table B3. Overview on scenario definitions and main annual results of the sensitivity analysis on specific capital expenditure assumptions for fluctuating RE technologies. Total system costs are given for the complete system boundary while all other values are given for Germany.

	Results

Scenario	Annual electricity demand from BEV fleet in TWh	Controllable share in %	CAPEX PV in k€/MW	CAPEX wind onshore in k€/MW	CAPEX wind offshore in k€/MW	Total system cost in Bn. €	Shifted load by German BEV fleets in TWh	Peak load in GW	Installed capacities of power plant park in GW	Installed RE capacities in GW	Fluctuating RE capacity additions in GW	Gas power plant capacity additions in GW	Annual power generation in TWh	Annual fluctuating RE power generation in TWh	Fluctuating RE share in total power generation in %	Annual RE curtailment in TWh	Imports to Germany in TWh	Exports from northern to southern G in TWh
S0	0	-	857	1100	1800	68.4	0	83.9	214	153	46.2	31.3	501	279	55.7	2.9	45.9	64.7
S1	27	66	857	1100	1800	71.2	24.2	86.3	223	159	51.5	35.5	526	291	55.3	2.6	51.3	65.1
S2	27	30	857	1100	1800	71.7	8.4	87.8	222	156	48.8	37.2	524	284	54.2	3.4	51.6	62.2
S1k	27	66	711	1233	3555	73.1	23.6	88.3	263	203	136.4	30.4	539	302	56.0	0.4	38.6	25.6
S2k	27	30	711	1233	3555	73.5	8.4	89.7	250	189	122.0	31.8	536	321	59.9	0.7	36.2	23.1
S1l	27	66	660	1040	1800	57.9	24.1	87.4	248	195	115.6	23.9	537	407	75.8	10.7	40.1	112.3
S2l	27	30	660	1040	1800	58.5	8.4	87.5	248	192	113.7	26.2	538	401	74.5	13.5	39.3	109.9

S1m with 30% load flexibility

An additional model run tests the exogenous assumption of S1 of 66% of the electric demand being flexible. In scenario S1m, this share is reduced to CURRENT's share of flexible charging of 30%.

Table B4. Sensitivity scenario results of scenario S1m in comparison with all reference and baseline scenarios S0-S2. Total system costs are given for the complete system boundary while all other values are given for Germany.

Scenario	Annual electricity demand from BEV fleet in TWh	Controllable share in %	Total system cost in Bn. €	Shifted load by German BEV fleets in TWh	Peak load in GW	Installed capacities of power plant park in GW	Installed RE capacities in GW	RE capacity additions in GW	Gas power plant capacity additions in GW	Annual power generation in TWh	Annual RE power generation in TWh	Fluctuating RE share in total power generation in %	Annual RE curtailment in TWh	Imports to Germany in TWh	Exports from northern G to southern G in TWh
S0	0	-	68.4	0	83.9	214	153	46.2	31.3	501	279	55.7	2.9	45.9	64.7
S1a	*27*	*0*	*71.7*	*0*	*91.1*	*224*	*156*	*49.0*	*39.0*	*525*	*284*	*54.1*	*3.6*	*50.3*	*62.9*
S1	27	66	71.2	24.2	86.3	223	159	51.5	35.5	526	291	55.3	2.6	51.3	65.1
S2a	*27*	*30*	*71.7*	*0*	*93.5*	*223*	*156*	*48.8*	*37.9*	*524*	*284*	*54.2*	*3.5*	*51.6*	*62.4*
S2	27	30	71.7	8.4	87.8	222	156	48.8	37.2	524	284	54.2	3.4	51.6	62.2
S1m	27	30	71.4	18.9	90.0	225	158	51.1	37.9	527	289	54.8	3.0	48.4	63.4

Relative sensitivity

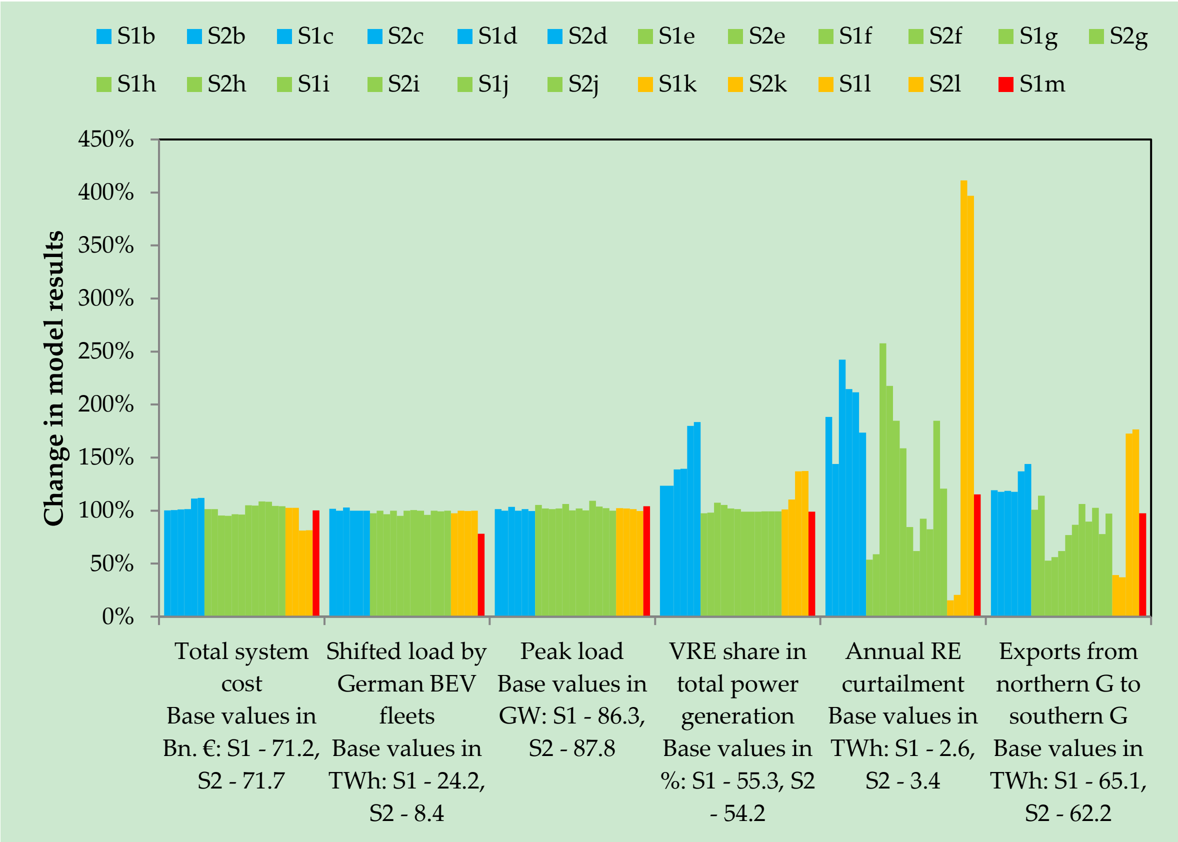

Figure B12. Relative sensitivity of annual energy system model results analyzed in Section 3.2. Each result value (of S1x, S2x) is divided by result values of baseline (S1, S2) values respectively. Blue bars show the results for the model runs with lower CO_2 limit, green those with different weather years, yellow those with different fluctuating RE specific investment assumptions and red that with lower BEV charge control availability

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