Complex Renewable Energy Networks
Summer Semester 2017, Lecture 9*

*Lecture based on a lecture given by Tom Brown in Aarhus

Dr. Alexander Kies

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Frankfurt Institute of Advanced Studies (FIAS), Goethe-Universität Frankfurt
FIAS Renewable Energy System and Network Analysis (FRESNA)

kies@fias.uni-frankfurt.de

FIAS Frankfurt Institute for Advanced Studies

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Temporal and Spatial Scales

Research questions

1. What infrastructure (wind, solar, hydro generators, heating units, storage and networks) does a highly renewable energy system require and where should it go?
2. Given a desired CO_2 reduction (e.g. 95% compared to 1990), what is the cost-optimal combination of infrastructure (including all capital and marginal costs)?
3. How best do we deal with the variability of wind and solar?
4. What is the trade-off between international transmission, storage and sector-coupling?

Need to capture spatial and temporal scope

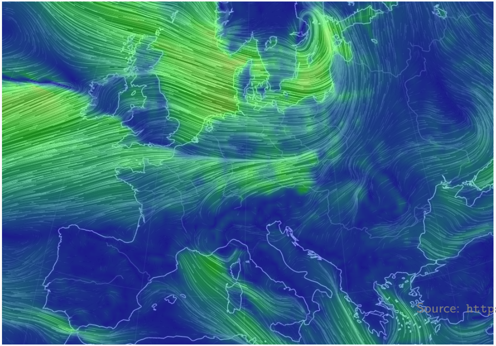
Wind and solar generation is variable in time and space at different scales:

Variation	Time scale	Space scale	Solution
Diurnal	1 day	Earth circumference	Grid over multiple longitudes, Short-term storage, Demand-Side-Management (DSM)
Synoptic	3-10 days	$\sim$600 km	Continental-scale grids, Long-term storage
Seasonal	1 year	$\pm 23.4^\circ$ latitude	Grid over multiple latitudes, Long-term storage

Short-term storage includes batteries, pumped hydro and thermal energy storage (TES); long-term storage includes chemical storage, hydro reservoirs and long-term TES.

Synoptic scales are key to cost-effectiveness in Europe

Given that wind is cheap and seasonally aligned with peak energy demand in Europe, cost-effective solutions tend to be dominated by wind. But wind has big synoptic-scale variations. These are caused by weather systems, which are bigger than countries and take days to pass, so you need either to integrate wind at the continental scale or use long-term storage.



Source: https://earth.nullschool.net/

Warm-Up: Electricity Sector

Linear optimisation of annual system costs

Given a desired CO_2 reduction, what is the most cost-effective energy system?

$$\text{Minimise}\begin{pmatrix}\text{Yearly system}\\ \text{costs}\end{pmatrix} = \sum_n \begin{pmatrix}\text{Annualised}\\ \text{capital costs}\end{pmatrix} + \sum_{n,t} (\text{Marginal costs})$$

subject to

- meeting energy demand at each node n (e.g. countries) and time t
- wind, solar, hydro (variable renewables) availability $\forall\, n, t$
- electricity transmission constraints between nodes
- (installed capacity) $\leq$ (geographical potential for renewables)
- CO_2 constraint (95% reduction compared to 1990)
- Flexibility from gas plants, battery storage, hydrogen storage, networks

Linear optimisation problem

Objective is the minimisation of total annual system costs, composed of capital costs c_* (investment costs) and operating costs o_* (fuel ,etc.):

$$\min f(\bar{P}_\ell, \bar{g}_{n,s}, g_{n,s,t}) = \sum_{\ell} c_l \bar{P}_\ell + \sum_{n,s} c_{n,s}\bar{g}_{n,s} + \sum_{n,s,t} w_t o_{n,s} g_{n,s,t}$$

We optimise for n nodes, representative times t and transmission lines l:

- the transmission capacity $\bar{P}_\ell$ of all the lines ℓ
- the generation and storage capacities $\bar{g}_{n,s}$ of all technologies (wind/solar/gas etc.) s at each node n
- the dispatch $g_{n,s,t}$ of each generator and storage unit at each point in time t

Model Inputs and Outputs

Inputs	Description
$d_{n,t}$	Demand (inelastic)
$\bar{g}_{n,s,t}$	Per unit availability for wind and solar
$\hat{g}_{n,s}$	Generator installable potentials
various	Existing hydro data
various	Grid topology
η_*	Storage efficiencies
$c_{n,s,t}$	Generator capital costs
$o_{n,s,t}$	Generator marginal costs
c_ℓ	Line costs

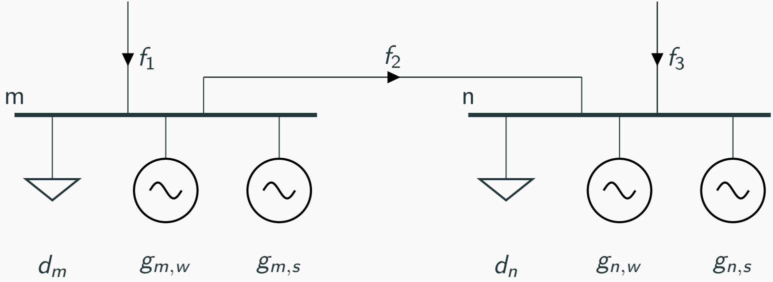
$\rightarrow$

Outputs	Description
$\bar{g}_{n,s}$	Generator capacities
$g_{n,s,t}$	Generator dispatch
$\bar{P}_\ell$	Line capacities
$f_{\ell,t}$	Line flows
λ_*, μ_*	Lagrange/KKT multipliers all constraints
f	Total system costs

Constraints 1/5: Nodal energy balance

Demand $d_{n,t}$ at each node n and time t is always met by generation/storage units $g_{n,s,t}$ at the node or from transmission flows $f_{\ell,t}$ on lines attached at the node (Kirchhoff's Current Law):

$$d_{n,t} = \sum_s g_{n,s,t} + \sum_{\ell \in n} f_{\ell,t} \qquad \leftrightarrow \qquad \lambda_{n,t}$$



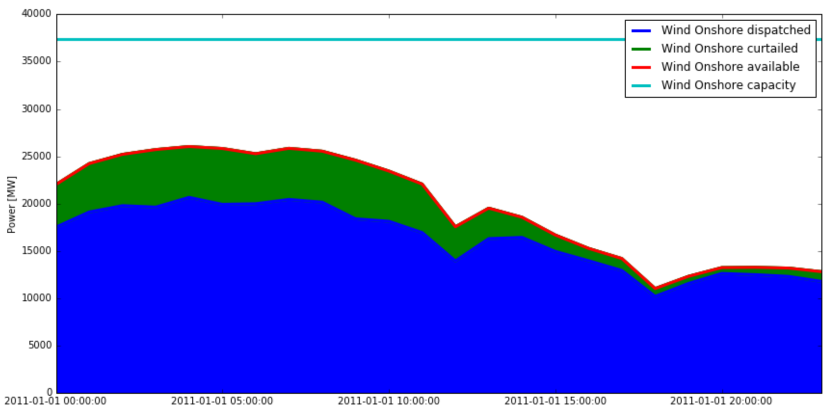
$d_m = g_{m,w} + g_{m,s} + f_1 - f_2$

$d_n = g_{n,w} + g_{n,s} + f_2 + f_3$

Constraints 2/5: Generation availability

Generator/storage dispatch $g_{n,s,t}$ cannot exceed availability $\bar{g}_{n,s,t} * \bar{g}_{n,s}$, made up of per unit availability $0 \leq \bar{g}_{n,s,t} \leq 1$ multiplied by the capacity $\bar{g}_{n,s}$. The capacity is bounded by the installable potential $\hat{g}_{n,s}$.

$$0 \leq g_{n,s,t} \leq \bar{g}_{n,s,t} * \bar{g}_{n,s} \leq \bar{g}_{n,s} \leq \hat{g}_{n,s}$$



Constraints 3/5: Storage consistency

Storage units such as batteries or hydrogen storage can work in both storage and dispatch mode. They have a limited energy capacity (state of charge).

$$soc_{n,t} = \eta_0 soc_{n,t-1} + \eta_1 g_{n,t,\text{store}} - \eta_2^{-1} g_{n,t,\text{dispatch}}$$

There are efficiency losses η; hydroelectric dams can also have a river inflow.

Constraints 4/5: Transmission Flows

The linearised power flows f_ℓ for each line $\ell \in \{1, \dots L\}$ in an AC network are determined by the reactances x_ℓ of the transmission lines and the net power injection at each node p_n for $n \in \{1, \dots N\}$.

The flows are related to the angles at the nodes:

$$f_\ell = \frac{\theta_i - \theta_j}{x_\ell} \tag{1}$$

In addition, the angle differences around each cycle must add to zero (Kirchoff's Voltage Law).

Transmission flows cannot exceed the thermal capacities of the transmission lines (otherwise they sag and hit buildings/trees):

$$|f_{\ell,t}| \leq \bar{P}_\ell$$

Since the impedances x_ℓ change as capacity $\bar{P}_\ell$ is added, we do multiple runs and iteratively update the x_ℓ after each run, rather than risking a non-linear (or MILP) optimisation.

Constraints 5/5: Global constraints on CO_2 and transmission volumes

CO_2 limits are respected, given emissions $e_{n,s}$ for each fuel source s:

$$\sum_{n,s,t} g_{n,s,t} e_{n,s} \leq \mathrm{CAP}_{\mathrm{CO_2}} \qquad \leftrightarrow \qquad \mu_{\mathrm{CO_2}}$$

We enforce a reduction of CO_2 emissions by 95% compared to 1990 levels, in line with German and EU targets for 2050.

Transmission volume limits are respected, given length d_l and capacity $\bar{P}_\ell$ of each line:

$$\sum_{\ell} d_\ell \bar{P}_\ell \leq \mathrm{CAP}_{\mathrm{trans}} \qquad \leftrightarrow \qquad \mu_{\mathrm{trans}}$$

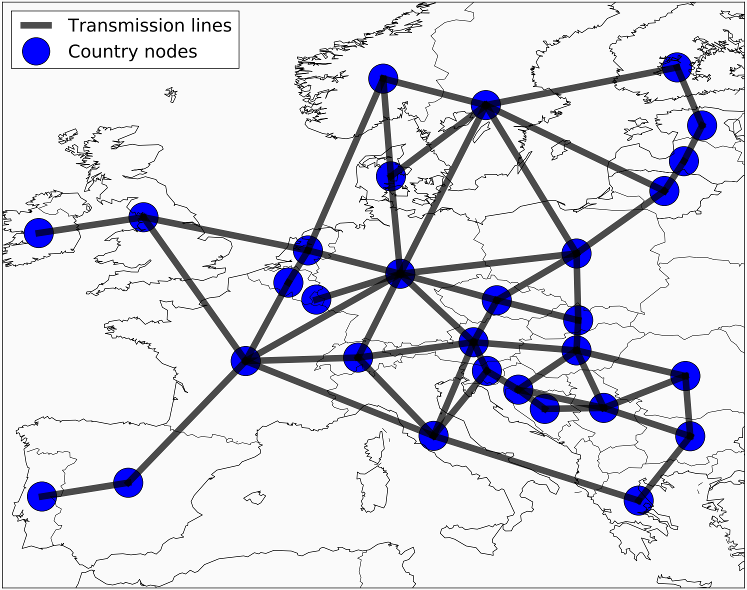
We successively change the transmission limit, to assess the costs of balancing power in time (i.e. storage) versus space (i.e. transmission networks).

Costs and assumptions for the electricity sector (projections for 2030)

Quantity	Overnight Cost [€]	Unit	FOM [%/a]	Lifetime [a]
Wind onshore	1182	kW	3	20
Wind offshore	2506	kW	3	20
Solar PV	600	kW	4	20
Gas	400	kW	4	30
Battery storage	1275	kW	3	20
Hydrogen storage	2070	kW	1.7	20
Transmission line	400	MWkm	2	40

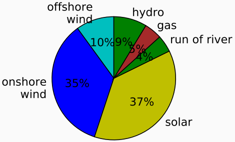
Interest rate of 7%, storage efficiency losses, only gas has CO_2 emissions, gas marginal costs. Batteries can store for 6 hours at maximal rating (efficiency 0.9×0.9), hydrogen storage for 168 hours (efficiency 0.75×0.58).

Europe: One node per country

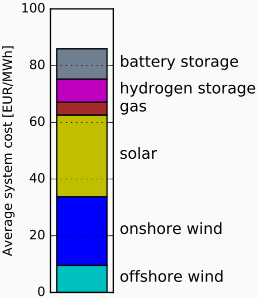


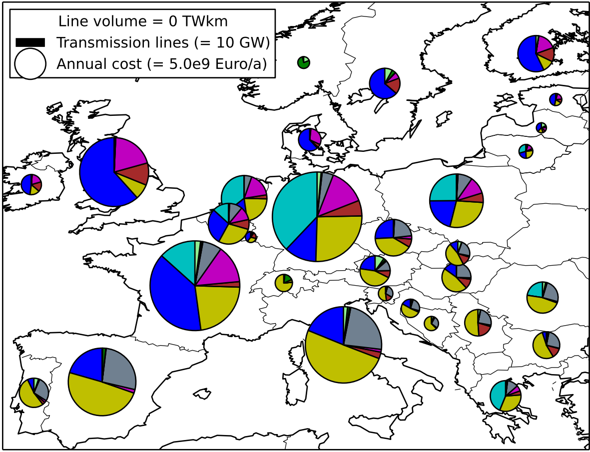
Costs: No interconnecting transmission allowed

Technology by energy:



Average cost €86/MWh:

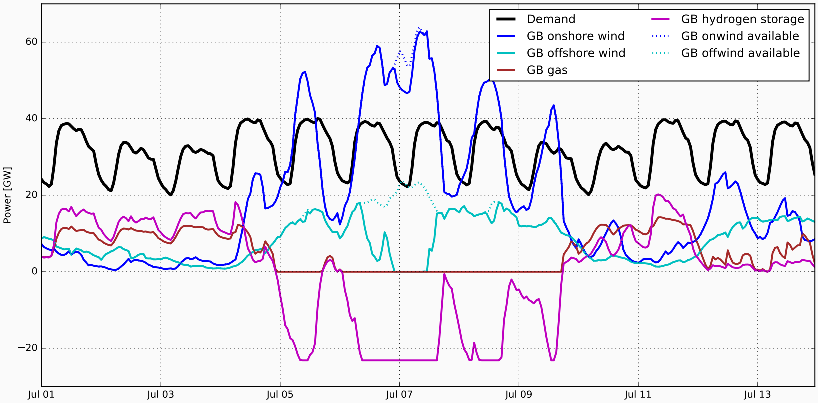




Countries must be self-sufficient at all times; lots of storage and some gas to deal with fluctuations of wind and solar.

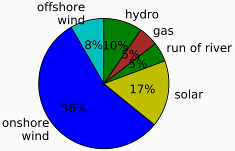
Dispatch with no interconnecting transmission

For Great Britain with no interconnecting transmission, excess wind is either stored as hydrogen or curtailed:

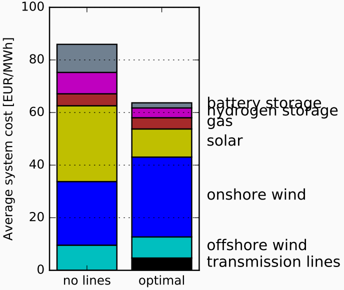


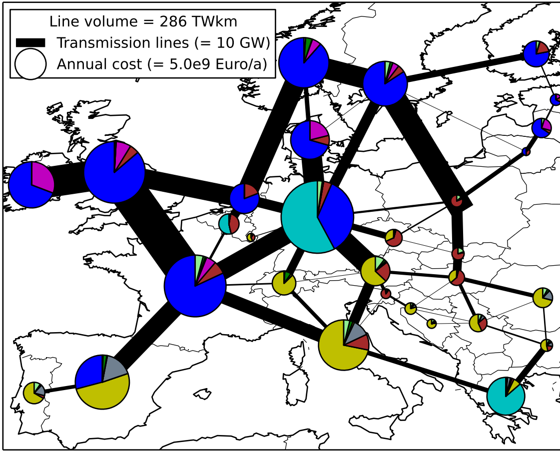
Costs: Cost-optimal expansion of interconnecting transmission

Technology by energy:



Average cost €64/MWh:

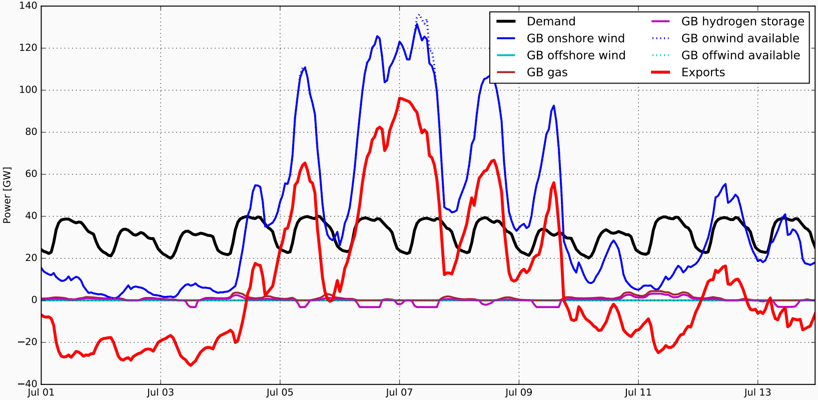




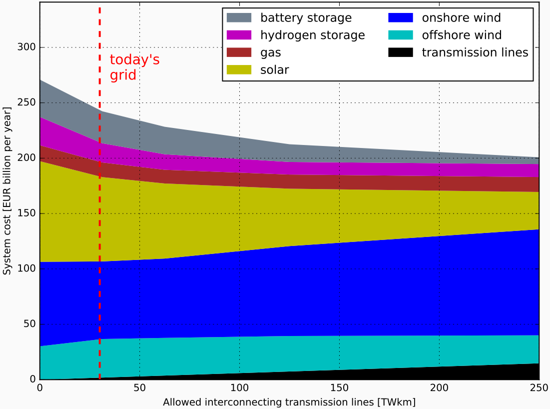
Large transmission expansion; onshore wind dominates. This optimal solution may run into public acceptance problems.

Dispatch with cost-optimal interconnecting transmission

Almost all excess wind can be now be exported:

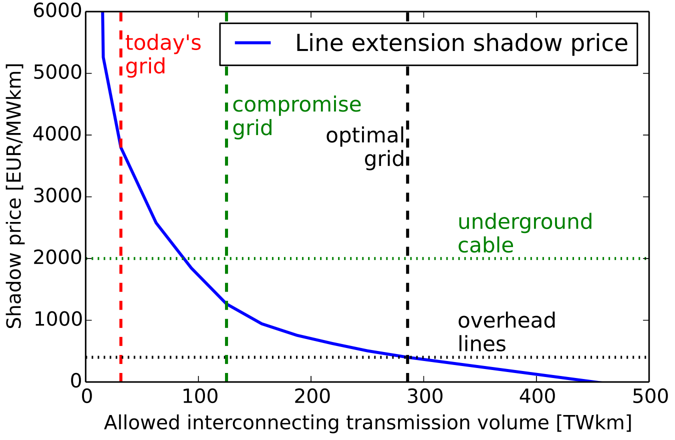


Electricity Only Costs Comparison



- Average total system costs can be as low as € 64/MWh
- Energy is dominated by wind (64% for the cost-optimal system), followed by hydro (15%) and solar (17%)
- Restricting transmission results in more storage to deal with variability, driving up the costs by up to 34%
- Many benefits already locked in at a few multiples of today's grid

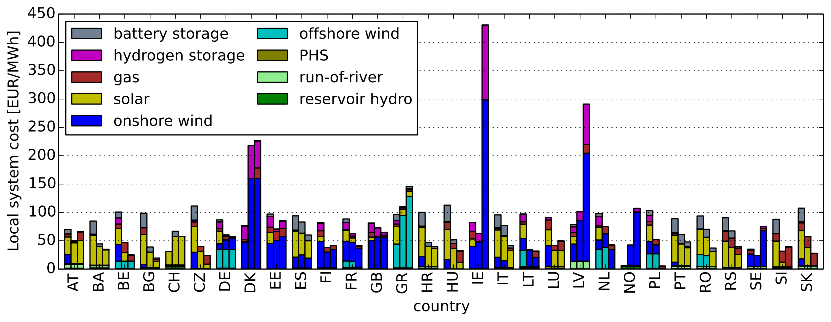
Grid expansion CAP shadow price as CAP relaxed



- With overhead lines the optimal system has around 7 times today's transmission volume
- With underground cables (5-8 times more expensive) the optimal system has around 3 times today's transmission volume

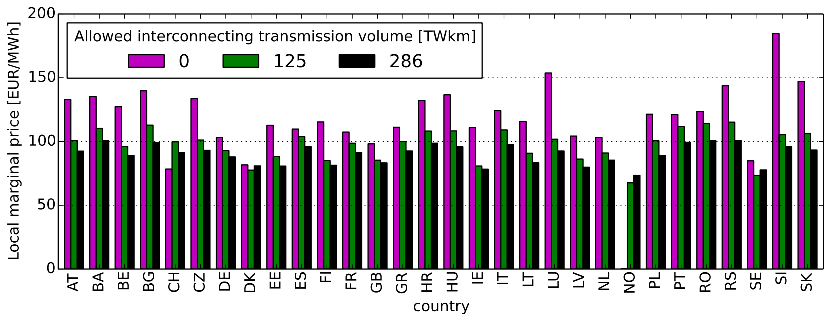
Distribution of costs

As transmission volumes increase, costs become more unequally distributed...

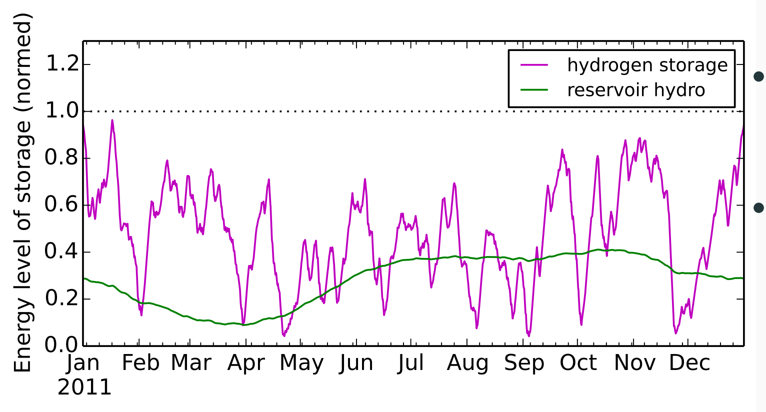


Distribution of prices

...while market prices converge.

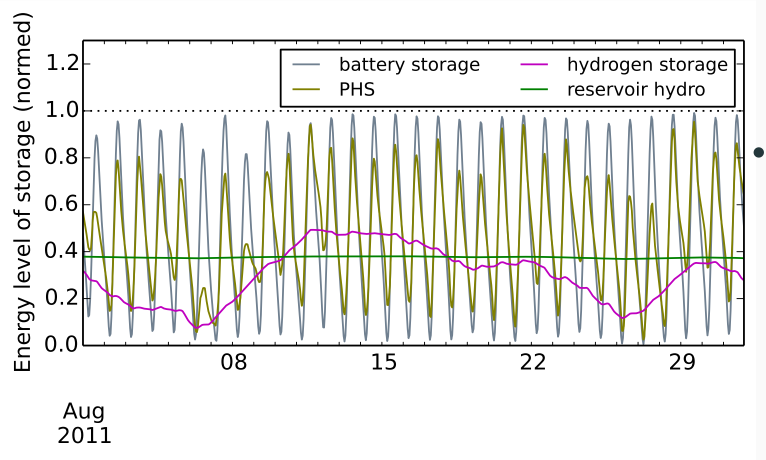


Different flexibility options have difference temporal scales



- Hydro reservoirs are seasonal
- Hydrogen storage is synoptic

Different flexibility options have difference temporal scales



- Pumped hydro and battery storage are daily

Coupling Electricity to Heating and Transport

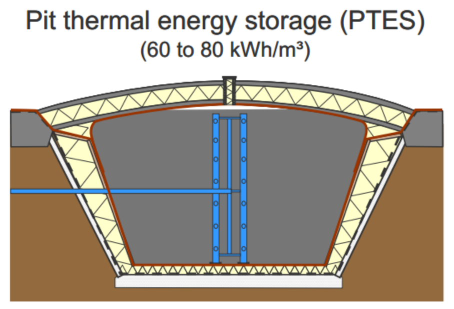
Sector Coupling

Idea: Couple the electricity sector to heating and mobility.

This enables decarbonisation of these sectors and offers more flexibility to the power system.

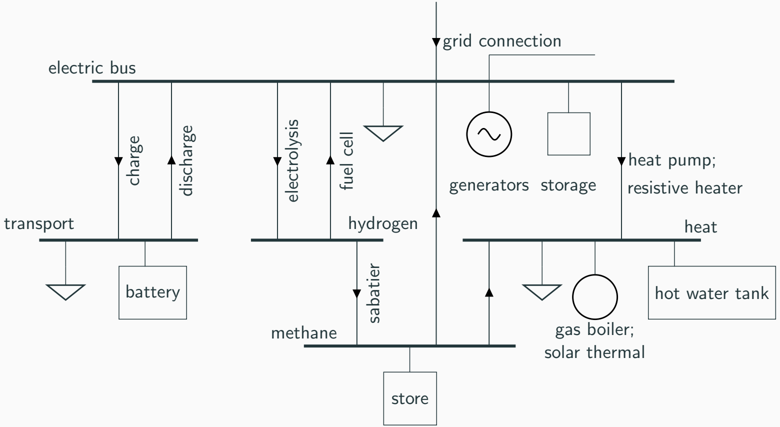
Battery electric vehicles can change their charging pattern to benefit the system and even feed back into the grid if necessary

Heat is much easier and cheaper to store than electricity, even over many months

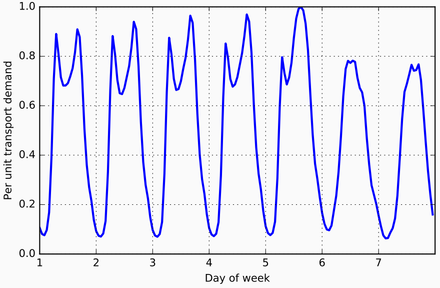


Sector coupling: A new source of flexibility

Couple the electricity sector (electric demand, generators, electricity storage, grid) to electrified transport and low-T heating demand (model covers 75% of final energy consumption in 2014). Also allow production of synthetic hydrogen and methane.



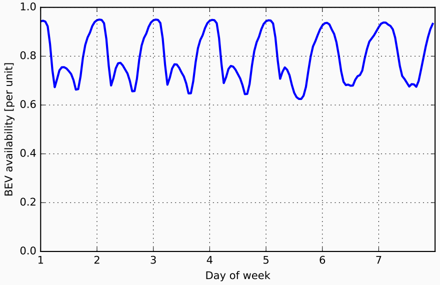
Transport sector: Electrification of Transport



Weekly profile for the transport demand based on statistics provided by the BASt.

- All road and rail transport in each country is electrified, where it is not already electrified
- Because of higher efficiency of electric motors, final energy consumption 3.5 times lower at 1014 TWh_{el}/a for the 30 countries than today
- In model can replace Electric Vehicles (EVs) with Fuel Cell Vehicles (FCVs) consuming hydrogen. Advantage: hydrogen cheap to store. Disadvantage: efficiency of fuel cell only 60%, compared to 90% for battery.

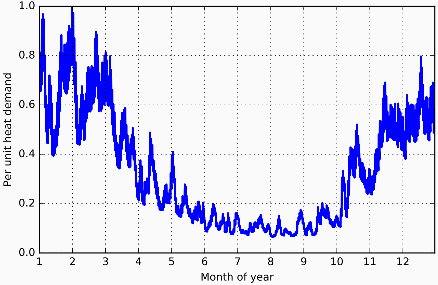
Transport sector: Battery Electric Vehicles



Availability (i.e. fraction of vehicles plugged in) of Battery Electric Vehicles (BEV).
BEV production costs 10-20% more expensive than Diesel in 2030, but lower fuel costs.

- Assumed that all passenger cars are Battery Electric Vehicles (BEVs), each with 50 kWh battery available (rest as buffer) and 11 kW charging power
- Assumed that all BEVs have time-dependent availability, averaging 80%, maximum 95%
- No changes in consumer behaviour assumed (e.g. car-sharing), but even with 50% reduction in BEVs, the results are barely effected
- BEVs are treated as exogenous (capital costs NOT included in calculation)

Heating sector: Many Options with Thermal Energy Storage (TES)



Heat demand profile from 2011 in all 30 countries using population-weighted average daily T in each country, degree-day approx. and scaled to Eurostat total heating demand.

- All space and water heating in the residential and services sectors is considered, with no additional efficiency measures - total heating demand is 3231 TWh_{th}/a.
- Heating demand can be met by resistive heaters, gas boilers, solar thermal, Combined-Heat-and-Power (CHP) units and heat pumps, which have an average Coefficient of Performance of just under 3. No industrial waste heat.
- Thermal Energy Storage is available to the system as hot water tanks.

Centralised District Heating versus Decentralised Heating

We model both fully decentralised heating and cases where up to 60% of heat demand is met with district heating in northern countries.

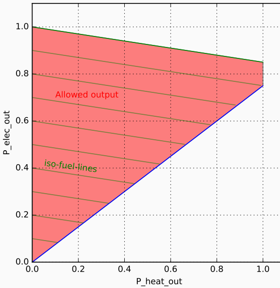
Decentral heating can be supplied by:

- Gas boilers
- Resistive heaters
- Small CHPs
- Small solar thermal
- Water tanks with short time constant $\tau = 3$ days
- Heat pumps

Central heating can be supplied via district heating networks by:

- Gas boilers
- Resistive heaters
- Large CHPs
- Large solar thermal
- Water tanks with long time constant $\tau = 180$ days

CHP feasible dispatch:



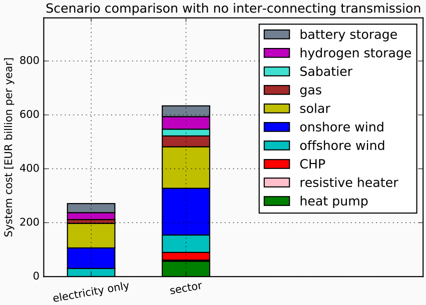
Cost and other assumptions

Quantity	Cost [€]	Unit	FOM [%/a]	Lifetime [a]
Sabatier	1100	kW_{gas}	2	20
Heat pump	1050	kW_{th}	1.5	20
Resistive heater	100	kW_{th}	2	20
Gas boiler	300	kW_{th}	1	20
Decentral solar thermal	270	kW_{th}	1.3	20
Central solar thermal	140	kW_{th}	1.4	20
Decentral CHP	1400	kW_{el}	3	25
Central CHP	650	kW_{el}	3	25
Central water tanks	20	m^3	1	40
District heating	400	kW_{th}	1	50

Costs oriented towards Henning & Palzer (2014, Fraunhofer ISE)

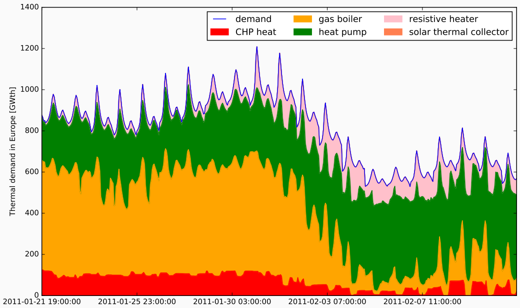
1. **electricity only**: no sector coupling
2. **sector**: sector coupling to heating and transport with no use of sector flexibility
3. **sector BEV**: sector coupling; BEV can shift their charging time
4. **sector BEV V2G**: sector coupling; BEV can in addition feed back into the grid (V2G)
5. **sector FC50**: sector coupling; 50% of BEV replaced by FCV
6. **sector FC100**: sector coupling; 100% of BEV replaced by FCV
7. **sector TES**: sector coupling with short-term Thermal Energy Storage (TES) $\tau = 3$ days
8. **sector central**: sector coupling with 60% district heating in North and long-term TES
9. **sector all flex**: sector coupling with all flexibility options
10. **sector all flex central**: sector coupling with all flexibility options and 60% district heating

From electricity to sector coupling



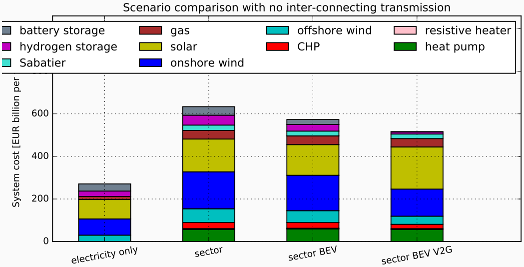
- With sector coupling costs are over twice as much because of higher energy demand, heating units and strong seasonality of heating demand.
- Decentralised heating demand peak (1260 GW_{th}) met by heat pumps (500 GW_{th}), gas boilers (750 GW_{th}), resistive heaters (360 GW_{th}) and CHP (165 GW_{th}).
- No additional flexibility activated.
- 800 TWh_{th}/a of natural gas used (limited by CO2 cap); 725 TWh_{th}/a of hydrogen produced; 530 TWh_{th}/a of syngas produced, i.e. 40% of methane used is synthetic

Heat coverage for decentralised heating



- Over the year heat pumps (green) provide most of the heat energy, as in the second week shown here
- However when demand is high, heat pump COP is low and there is no wind or sun, gas boilers must step in (orange), as in first week shown here, to cover most of the heat demand

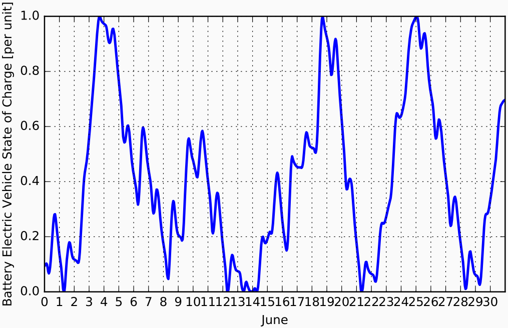
Using Electric Vehicle flexibility



With V2G total solar capacity jumps from 1,764 GW to 2,426 GW.

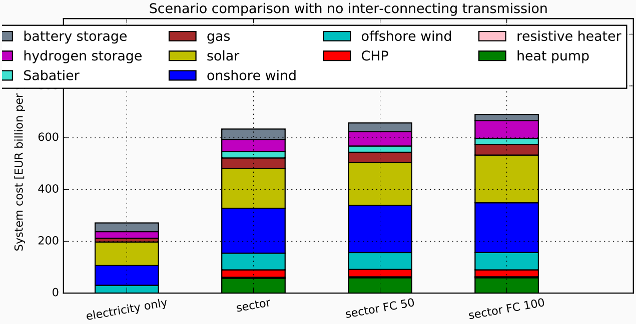
- Shifting the charging time to benefit the system reduces system costs by 10%.
- This Demand-Side Management reduced the need for stationary storage by half.
- Allowing BEVs to feed back into the grid (V2G) reduces costs by a further 10%.
- This eliminates the need for batteries and allows much more solar to be integrated.

Battery Electric Vehicle state of charge



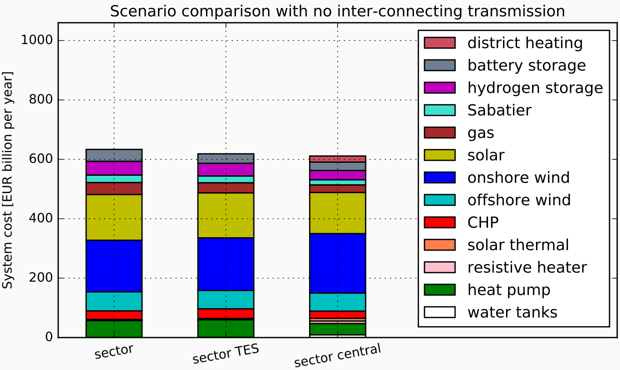
- Aggregated Battery Electric Vehicl state of charge in Germany shows very little day-to-day cycling which would degrade the battery, even with V2G and lots of solar
- Bigger longer-term synoptic variations driven by wind
- NB: This shows only the SOC available to the V2G (50 kWh per vehicle); there is also a buffer that is not available to V2G
- Only 0.1% change in total costs if V2G capacity reduced by 50%

Using Fuel Cells instead of Electric Vehicles



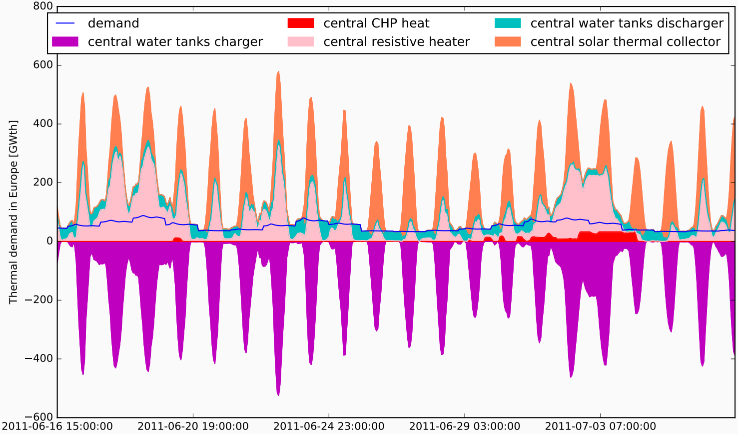
- The lower efficiency of fuel cells (60%) means more energy has to be generated, leading to higher overall costs.
- These higher costs are NOT compensated by the extra flexibility of cheap hydrogen storage.
- FCEVs are also more expensive than BEVs, then comes the hydrogen infrastructure costs...

Using heating sector flexibility



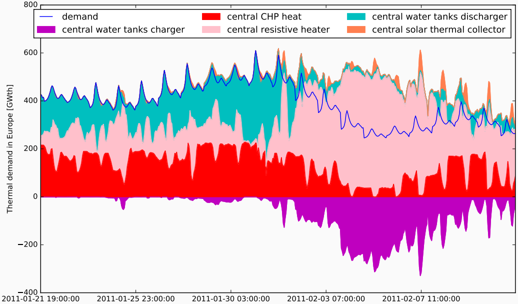
- Allowing short-term Thermal Energy Storage (TES) ($\tau = 3$ days) has only a 2% effect on the costs.
- Using 60% centralised heating enables the use of long-term TES ($\tau = 180$ days). In this case solar thermal is built to fill the TES in the summer. The cost decrease is mostly compensated by the cost

Centralised heating: charging TES with solar thermal in summer



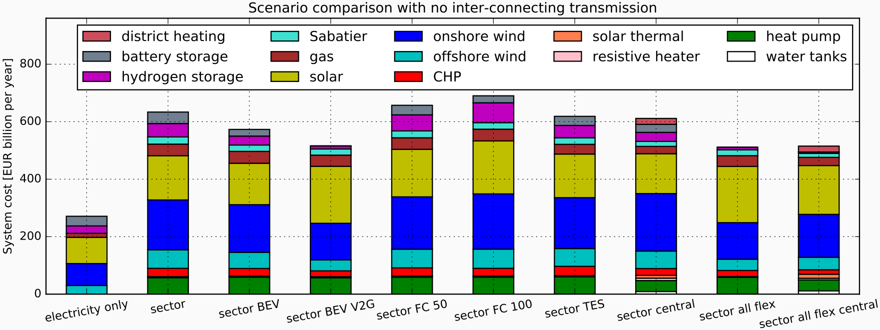
In summer solar thermal collectors (orange) and resistive heaters (pink) fill up the long-term centralised thermal energy storage (purple).

Centralised heating: discharging TES in winter

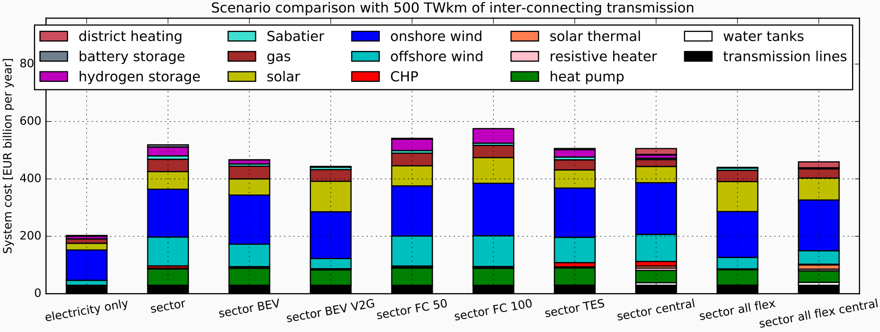


In winter, demand is met by a combination of CHP (red), resistive heating (pink) and the discharge from the long-term centralised TES (cyan).

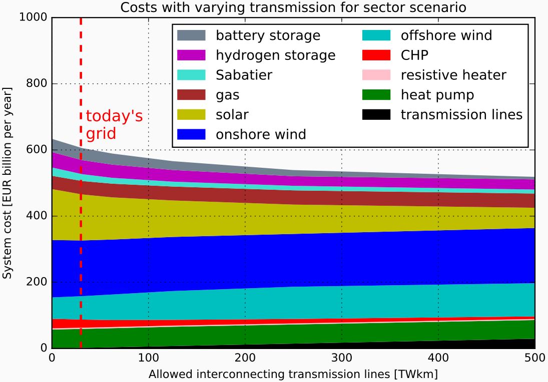
Scenario comparison with no inter-connecting transmission



Scenario comparison with optimal inter-connecting transmission

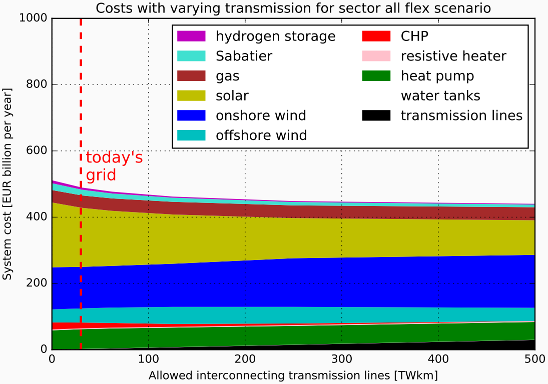


Sector Coupling with No Extra Flexibility



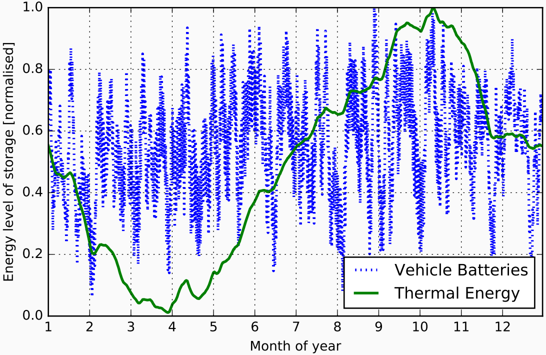
- Solution with no inter-connecting transmission costs 33% more than optimal transmission
- Gas boilers replace CHPs as transmission inceases, since transmission reduces need for gas for balancing in electricity sector
- Need stationary batteries and hydrogen storage to balance RES variability
- Transmission allows cheaper wind to substitute for solar power

Sector Coupling with All Extra Flexibilty (V2G and TES)



- The benefits of inter-connecting transmission are now much weaker: it reduces costs by only 16%
- Even with no transmission, the system is cheaper than all levels of transmission for sector-coupling with no sector flexibility
- System costs are comparable to today's (with same cost assumptions, today's system comes out around € 377 billion per year, excluding 'externalities')

Storage energy levels: different time scales



The different scales on which storage flexibility work can be seen clearly when examining the state of charge.

- Long-Term Thermal Energy Storage (TES) has a dominant seasonal pattern, charging in summer and discharging in winter.
- Battery Electric Vehicles (BEV) with Vehicle-To-Grid (V2G) show large fluctuations on daily and synoptic scales.

Unfinished results

- In the above results, solar thermal collectors were assumed to be flat. They were only built in district heating networks, where their energy can be stored in LTES and used in winter.
  If you tilt them 45 degrees to the South, they are also built in decentralised scenarios.
- Autonomous car sharing $\Rightarrow$ times with zero BEV availability.
- Thermo-chemical storage allows long-term storage, decentrally (e.g. $CaCl_2$, CaO, silica gel).
- Sensitivity to heating sector efficiency.
- Demand from industry, aviation, shipping.
- Better base scenario: disallowing methanation (hydrogen $\rightarrow$ methane) causes costs to rise.

Conclusions

Conclusions

- This is no single solution for highly renewable systems, but a family of solutions with different costs and compromises
- Generation costs always dominate total costs, but the grid can cause higher generation costs if expansion is restricted
- Cost-optimal grid expansion favours wind over solar
- Much of the need for stationary storage can be eliminated by sector-coupling: in particular the use of flexible charging from (and discharging into) the grid by battery electric vehicles can reduce system costs by up to 20%, and enable more solar integration
- With sector coupling, grid expansion becomes less important
- Understanding the need for flexibility at different temporal and spatial scales is key to mastering the complex interactions in the energy system