Energy Economics, Winter Semester 2023-4

Lecture 7: Investment in Electricity Generation

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Table of Contents

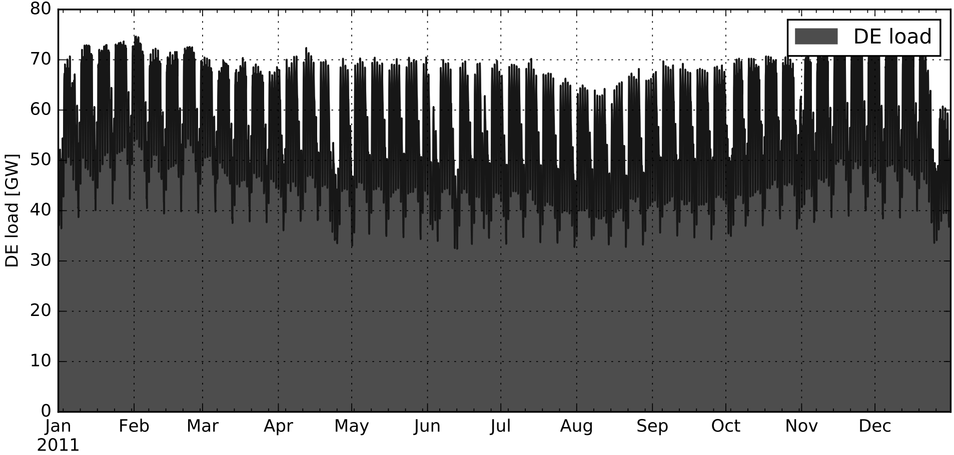
Introduction

Electricity investment: questions

- When should generation companies invest in new generation capacity?
- How do generators make back their fixed costs from the market?
- Which technologies should generation companies invest in?
- Which technologies should society invest in?
- What is the most efficient combination of technologies in the long-run?
- How does CO_2 pricing affect this picture?
- How do variable renewables fit into this picture?

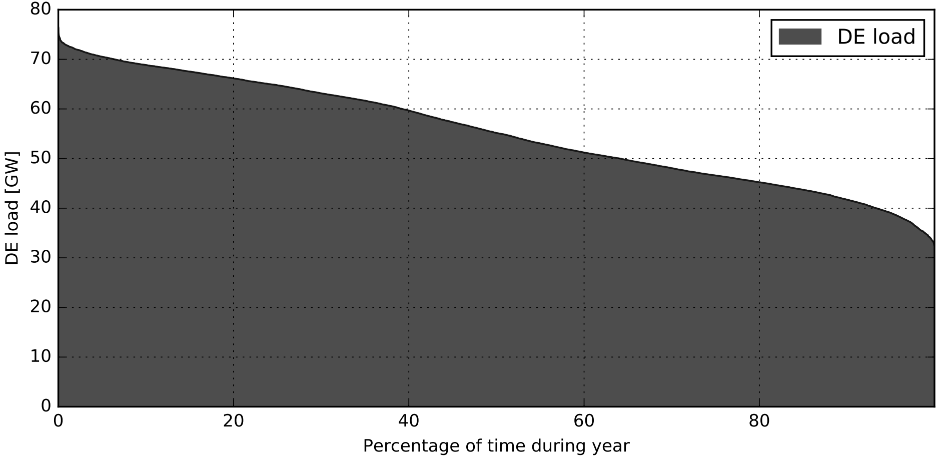
National yearly load curve

Recall the Germany load curve (around 500 TWh/a) plotted hourly through the year.



Load duration curve

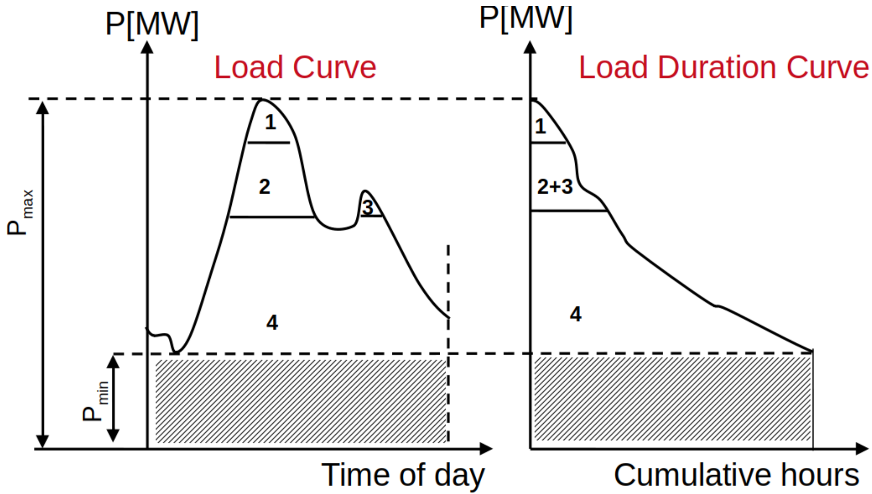
For some analysis it is useful to construct a **duration curve** by stacking the hourly values from highest to lowest. This gives us the **load duration curve**.



Duration curve for generation

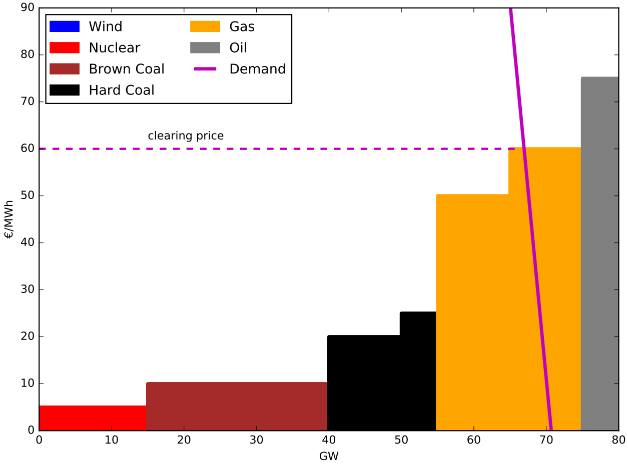
It can be useful to also see which technologies supply the load (here for a daily snapshot).

But how do we determine their capacities?



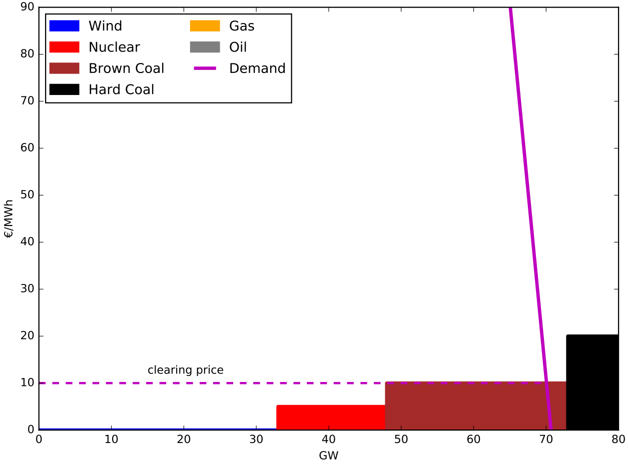
Merit order recap

- Recall that the **market price** is set by the intersection of the demand curve with the supply curve.
- The supply curve is constructed from the **merit order curve** by stacking up the marginal cost curves of the different plants.
- In hours with high demand and low wind and solar production prices are high...



Merit order recap

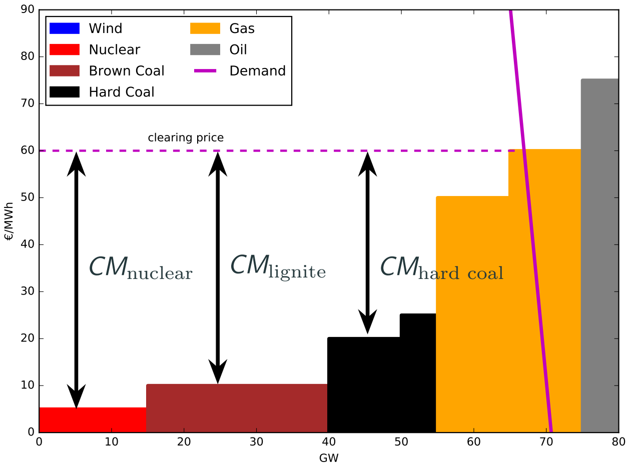
...whereas in hours with low demand or high wind and solar production prices are high.



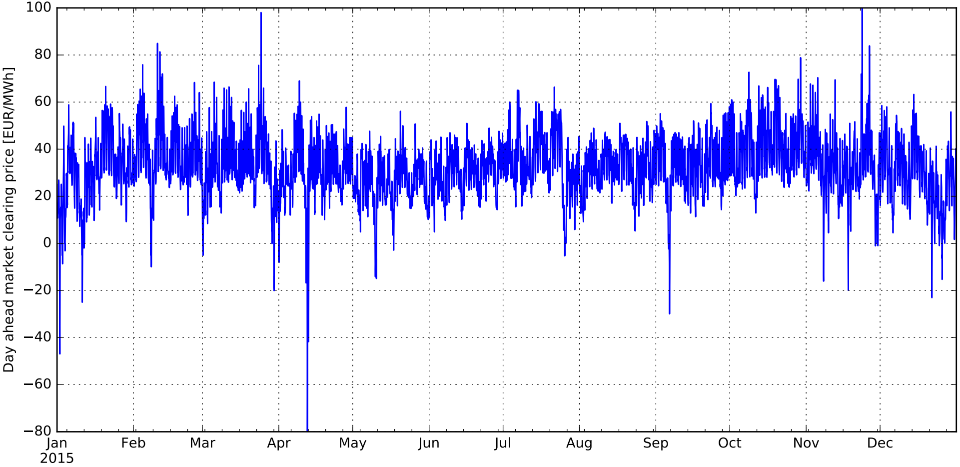
Contribution margin

Recall that the **contribution margin** is the selling price minus variable cost per unit, which is just price minus marginal cost for linear cost curves $CM = p - MC$, i.e. the contribution towards covering the fixed costs.

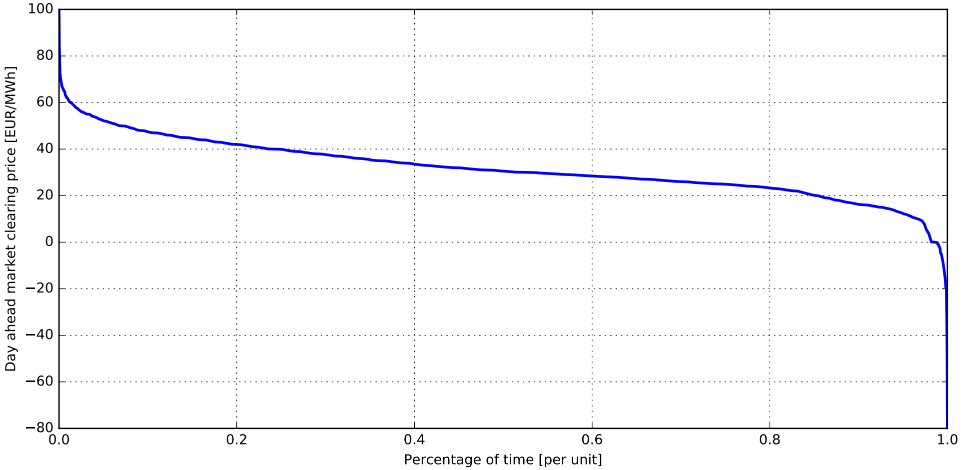
But what about the contribution margin in other hours?



Consider the hourly prices over the full year (here from 2015):

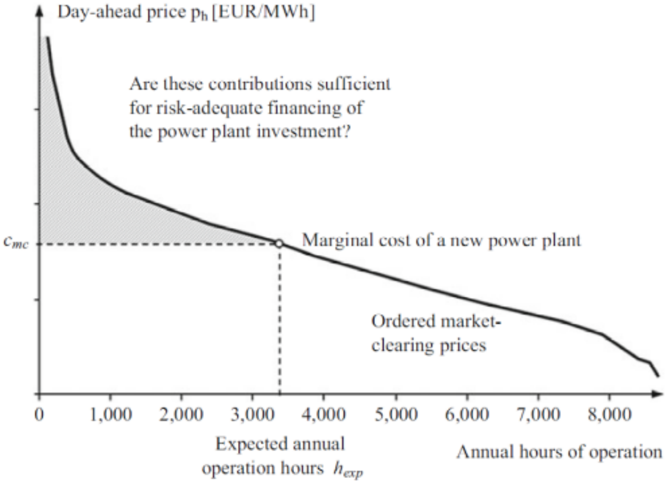


By ordering we get a duration curve, the **price duration curve**:



Price duration curve

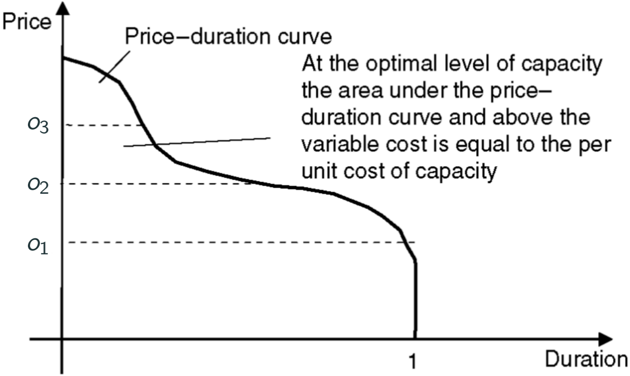
The price duration curve gives us the key link between variable costs, prices, capacity factor and the contribution margin.



Source: Erdmann et al, 2017

Multiple price duration

The optimal mix of generation is where, for each generation type, the area under the price–duration curve and above the variable cost of that generation type is equal to the fixed cost of adding capacity of that generation type.



Source: Biggar and Hesamzadeh, 2014

Screening curves for conventional generation

Levelised Cost Of Energy (LCOE)

Recall that the **Levelised Cost Of Energy (LCOE)** in €/MWh was given by dividing the annualised cost (fixed and production-dependent variable costs) in €/a divided by the annual production Q in MWh/a

$$LCOE = \frac{1}{Q}\left(\frac{I_0}{PVF(r,T)} + B + oQ\right) = \frac{1}{Q}\left(I_0 \cdot a(r,T) + B\right) + o$$

where $PVF(r,T)$ is the present value factor for a given WACC r and lifetime T, its inverse $a(r,T)$ is the annnuity, B is the fixed operation and maintenance (FOM) cost and o is the marginal cost (e.g. fuel and variable O&M).

The production Q depends on the capacity of the generator G and the **capacity factor** $\theta \in [0,1]$ via

$$Q = \theta \cdot 8760\ \mathrm{h/a} \cdot G$$

(The capacity factor is related to the **full load hours** FLH by FLH $= \frac{Q}{G} = \theta \cdot 8760$ h/a.)

From LCOE to annual cost per unit capacity

For generation investment analysis it is useful to take the LCOE

$$LCOE = \frac{1}{Q}\left(I_0 \cdot a(r,T) + B\right) + o$$

and multiply by the full load hours $\mathrm{FLH} = \frac{Q}{G} = \theta \cdot 8760$ h/a to get the **annual cost per unit capacity** AC in €$\mathrm{MW}^{-1}\mathrm{a}^{-1}$

$$AC = \frac{Q}{G} * LCOE = \frac{1}{G}\left(I_0 \cdot a(r,T) + B\right) + o\frac{Q}{G} = i_0 \cdot a(r,T) + b + o \cdot \theta \cdot 8760$$

where $i_0 = \frac{I_0}{G}$ is the investment cost per capacity in €MW^{-1} and $b = \frac{B}{G}$ is the FOM cost per capacity per year in €$\mathrm{MW}^{-1}\mathrm{a}^{-1}$.

Parameters for different generation technologies

Here are some typical investment and operational parameters projected for 2020:

Source	Lifetime	Capital Cost	Fix O&M	Var O&M	η	Fuel Cost	Marg. Cost
	years	€kW^{-1}	€kW^{-1}a^{-1}	€MWh$_{\mathrm{el}}^{-1}$	[%]	€/MWh$_{\mathrm{th}}$	€/MWh$_{\mathrm{el}}$
Symbol	T	i_0	b				o
Hard Coal	40	1200	30	6	39	10	32
Gas OCGT	30	400	15	3	39	20	54
Gas CCGT	30	800	20	4	60	20	37
Nuclear	40-60	3000	0	6	33	3.3	16
Wind Onshore	25	1240	35	0		0	0
Solar PV	25	750	25	0		0	0

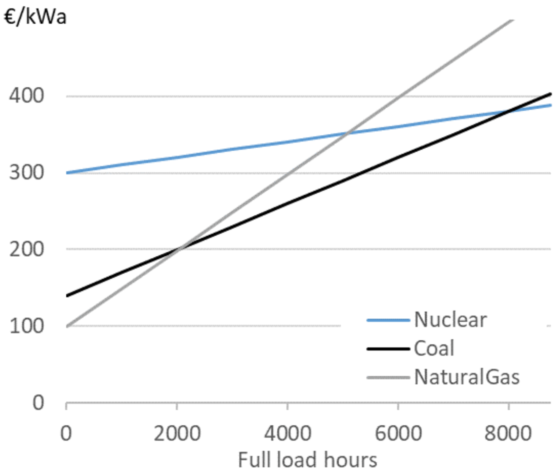
Source: DIW Data Documentation, 2013

Screening curve

A **screening curve** plots the annual cost per capacity AC in €$\text{kW}^{-1}\text{a}^{-1}$ of different technologies as a function of the FLH. Recalling that:

$$AC(FLH) = i_0 \cdot a(r, T) + b + o \cdot FLH$$

The y-axis-intercept is given by the fixed costs $i_0 \cdot a(r, T) + b$ while the slope is given by the variable cost o.
From the screening curve we can read off which generation technology is lowest cost for a given FLH; more expensive technologies for that FLH are **screened away**.

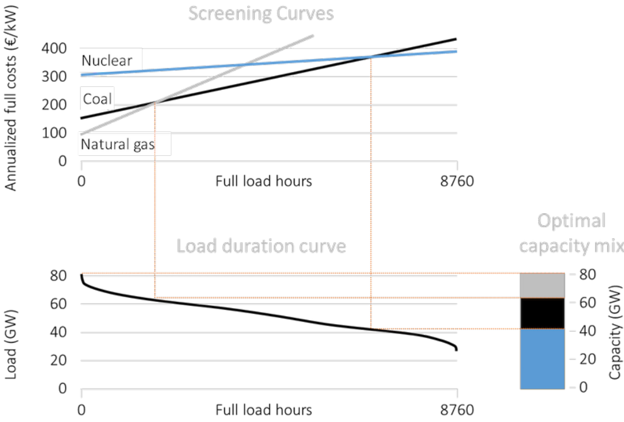


Source: Open Electricity Economics

Screening curve analysis

To determine the optimal capacity mix we must:

- determine the crossing points in the screen curve, so we know for each FLH range what technology is cheapest
- map the FLH ranges from the screening curve to the FLH ranges in the load duration curve
- read off the generation capacities from the y-axis of the load duration curve



Source: Open Electricity Economics

Power plants in the merit order

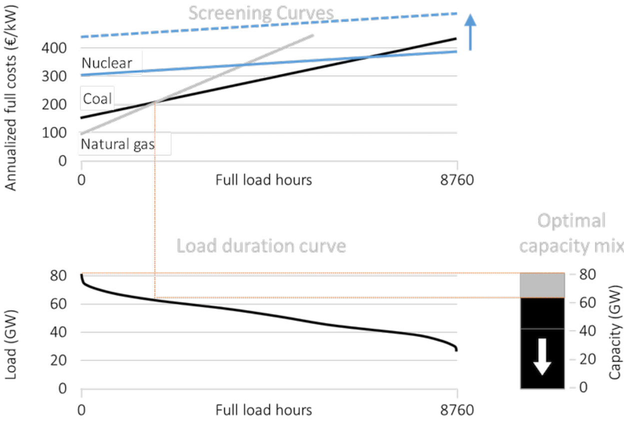
Different technologies have a different role in the merit order and screening curve analysis.

power plant type	FLH [h/a]	operation features	fixed costs	variable costs	examples
baseload	7000+	continuous	high	low	nuclear, lignite
intermediate	4000-5000	during peak hours (wd 8-8)	medium	medium	hard coal
peaker	<1500	peak demand	low	high	gas, pumped-hydro storage
load shedding	1-5	yearly peak	none	v. high	load shedding

What happens if fixed costs change?

Suppose nuclear fixed costs change, e.g. because of increased safety requirements.

- Now the y-axis-intercept of nuclear is so high that there is no FLH for which nuclear is cheaper than the other technologies.
- Nuclear is **screened** away and doesn't appear on the optimal mix.

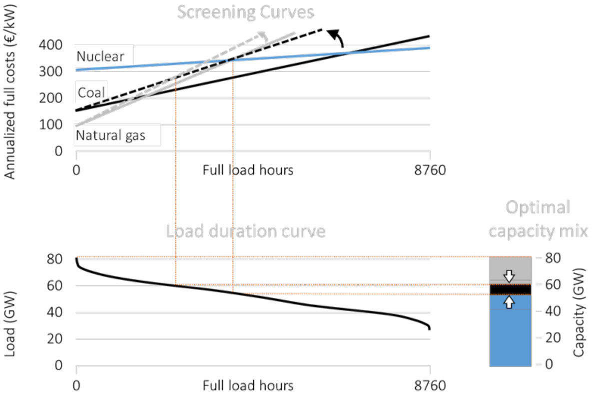


Source: Open Electricity Economics

What happens if the CO_2 price increases?

Now suppose the CO_2 price is increased.

- This increases the variable cost of each technology depending on its specific emissions (tCO_2/MWh_{el}).
- The slope for coal increases much more strongly than natural gas.
- As a result, coal is squeezed out of the optimal mix.
- The long-run effect of a CO_2 price is not just to decrease coal generation, but coal capacity too.



Source: Open Electricity Economics

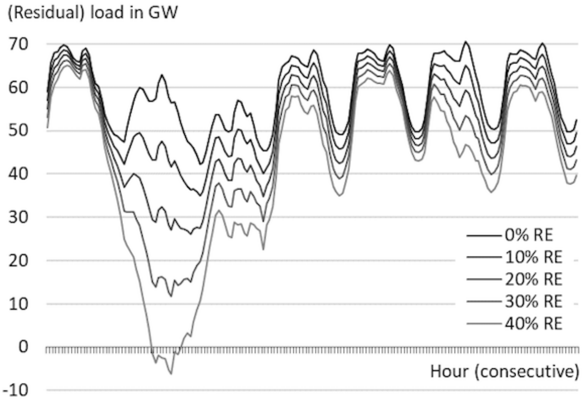
Effect of variable renewables

Integrating variable renewables into the screening curve analysis

Renewables cannot be dispatched at any time, so do not fit into the screening curve analysis.

The re-ordering of time for the duration curve doesn't take account when wind and solar are available.

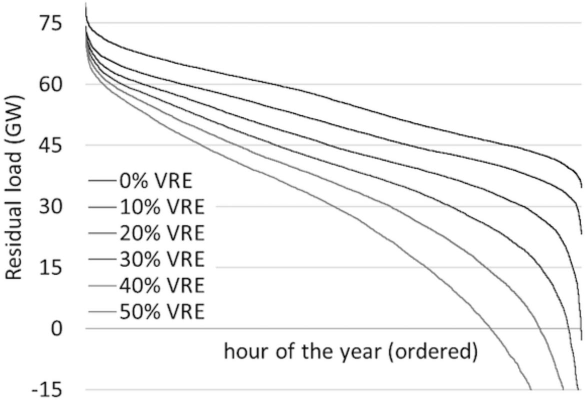
However, once we know the renewable capacity, we can fix it and examine how the rest of the system adapts to the **residual load**, load minus wind and solar.



Source: Open Electricity Economics

Residual load duration curve

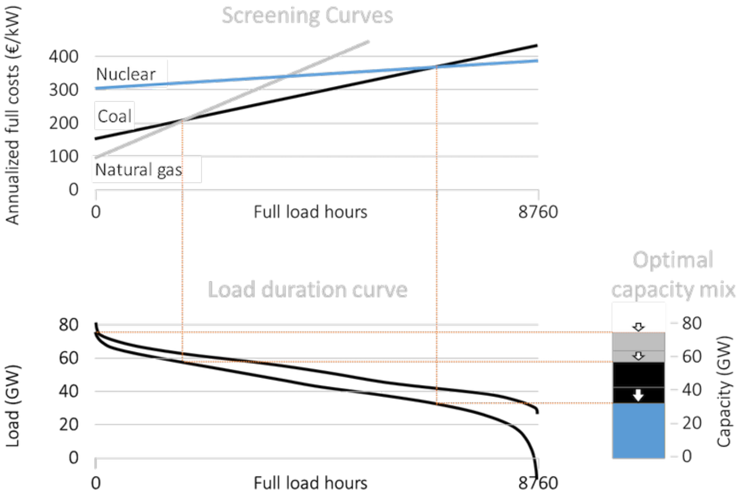
From the residual load we can build the **residual load duration curve** (RLDC).



Source: **Open Electricity Economics**

Integrating variable renewables into the screening curve analysis

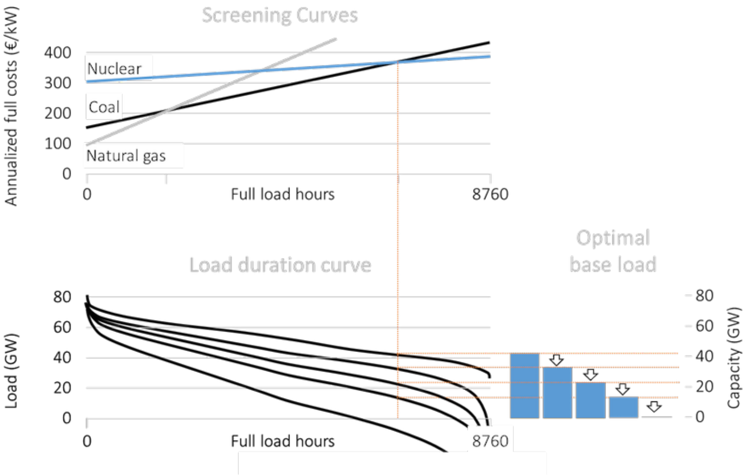
The shape of the residual load curve now alters the optimal technology mix, leading to less of all technologies.



Source: **Open Electricity Economics**

Integrating variable renewables into the screening curve analysis

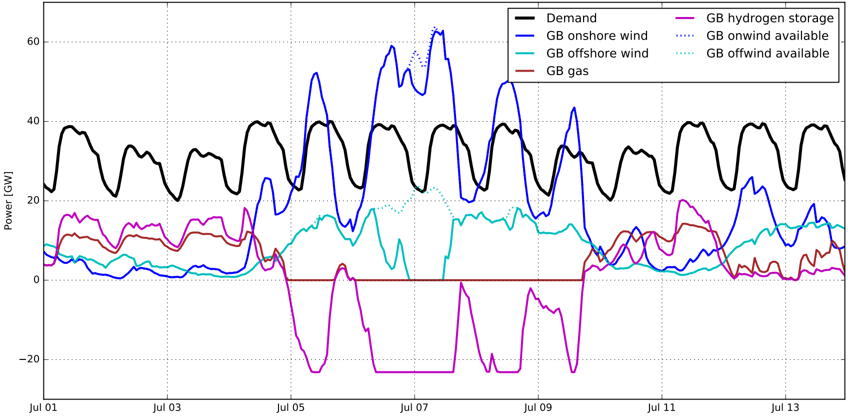
For high shares of wind and solar, particularly baseload technologies are pushed out of the system.



Source: Open Electricity Economics

Need for hourly system analysis

In order to assess the need for variable renewables, dispatchable generation and storage, you need an **optimisation model** that can see the consecutive hours of demand, wind and solar. In this example of a low-CO_2 UK power system, excess wind is either stored as hydrogen or curtailed. Interested in more? Come to **Energy Systems** course in Summer Semester!



Scarcity pricing and missing money problem

How do peaking plants recover their costs?

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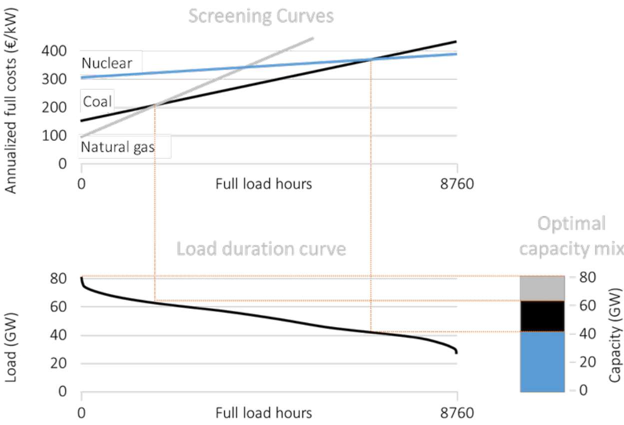
If there is enough capacity to cover all demand situations, then the highest price in the system will be set by the variable cost of the peaking plant, e.g. natural gas.

But how do peakers recover their fixed costs?

This is the **missing money problem**.

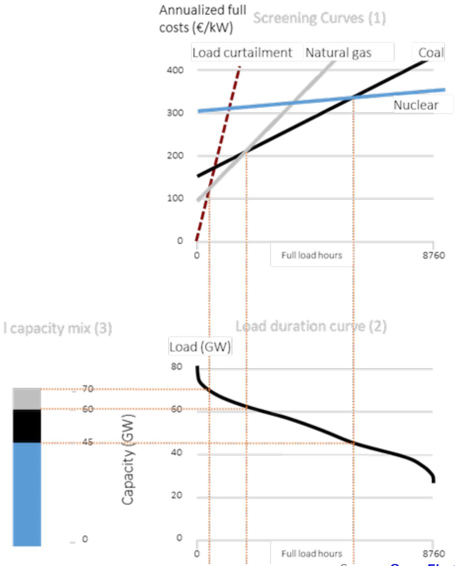


Source: Open Electricity Economics

Load shedding

A solution is to allow some demand not to be met, i.e. **load-shedding** costed at the **value of lost load** (VOLL) which is typically very high (thousands of €/MWh).

During these hours the price jumps to the VOLL, so that even the peakers recover their money.



Source: Open Electricity Economics

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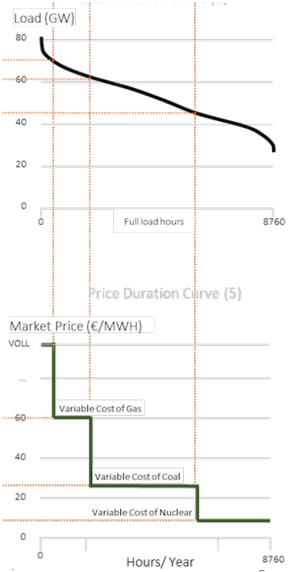


Source: Open Electricity Economics

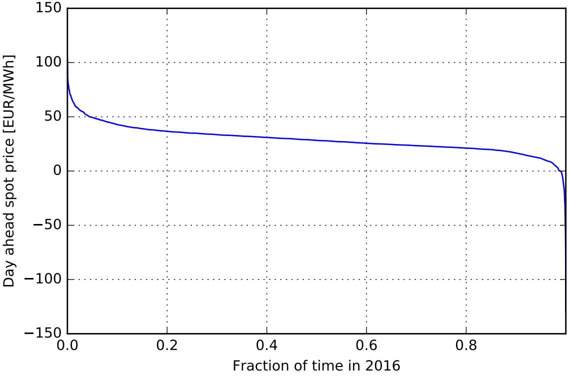
Episodes of High Prices are an Essential Part of an Energy-Only Market

In an energy-only market (in which generators are only compensated for the energy they produce), the wholesale spot price must at times be higher than the variable cost of the highest-variable-cost generating unit in the market. Episodes of high prices and/ or price spikes are not in themselves evidence of market power or evidence of market failure.

However, there may be political or administrative restrictions on prices going to very high levels (i.e. consumer protection, concerns about market abuse).

Today's market does not have episodes of very high prices

This makes it hard for e.g. gas generators to make back their costs. Day ahead spot market prices in 2016 in Germany-Austria bidding zone:



Gas generators can bid into other markets, such as the intra-day or reserve power markets, or provide redispatch services.

Market prices from highly renewable simulations

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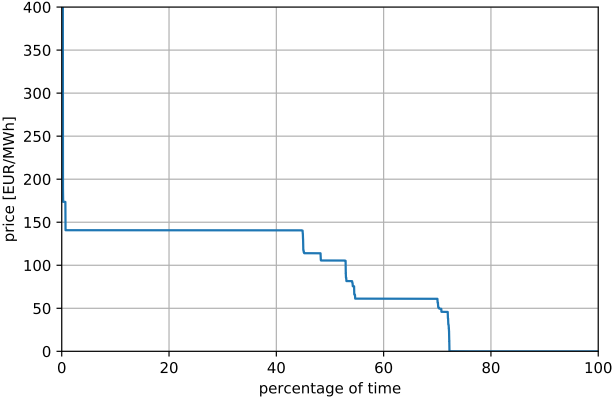
In our simulations for high renewable penetrations (taken from **this paper**), the theory does however work:

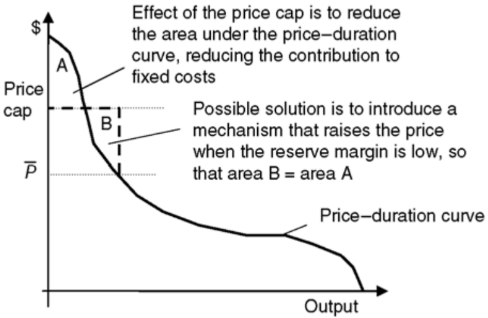


Prices are zero around a quarter of the time, but spike above 10,000 €/MWh in some hours.

Price cap

Some markets implement a maximum market price cap (MPC), which may be below the Value of Lost Load (VoLL) (V for the inelastic case).

In the Eastern Australian National Electricity Market (NEM), a MPC of A$15,000/MWh (€ 9,300/MWh) for the 2020-2021 financial year is set, corresponding to the price automatically triggered when AEMO directs network service providers to interrupt customer supply in order to keep supply and demand in the system in balance.



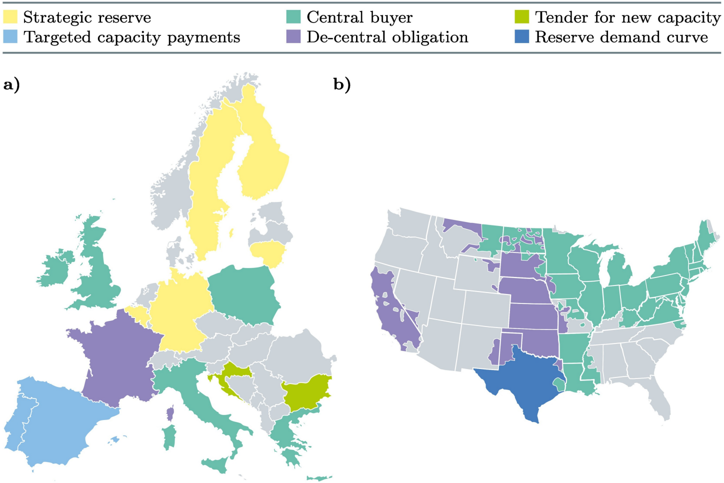
The Electric Reliability Council of Texas (ERCOT) has an energy only market with an MPC of $9000/MWh.

MPC can introduce distortions which make it difficult for some generators to recover costs.

Source: Biggar and Hesamzadeh, 2014

Capacity Remuneration Mechanisms vary widely

Capacity Remuneration Mechanisms (CRM) in 2019 in Europe and the US:



Source: Bublitz et al, 2019