System costs of large scale development of variable renewables generation: building an assessment methodology

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The NEA System Effect Study

In 2010 the NEA undertook an extensive study to assess the interactions between renewables, nuclear energy and the whole electricity system.

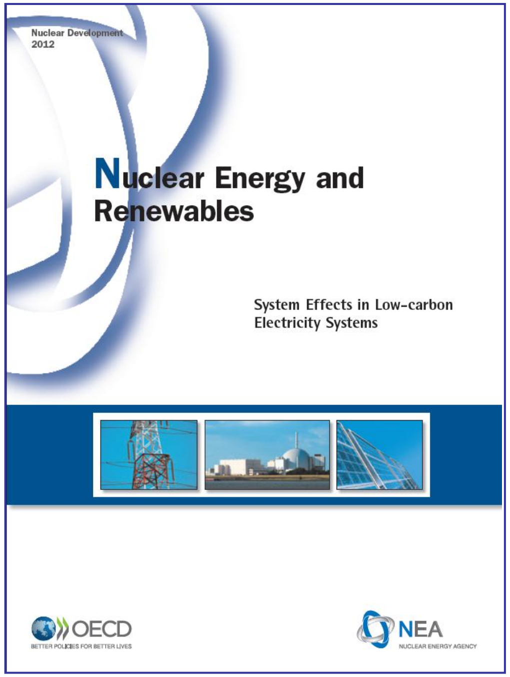
1) Estimation of system effects (and costs) of different generating technologies.
2) Impact of integrating significant amounts of **fluctuating** electricity at **low marginal cost** on the whole electricity system and on nuclear power.

Technical

- Transmission and distribution infrastructure.
- Challenge in short-term balancing and additional flexibility requirements from existing plants.
- Change in the traditional operation mode of power plants.

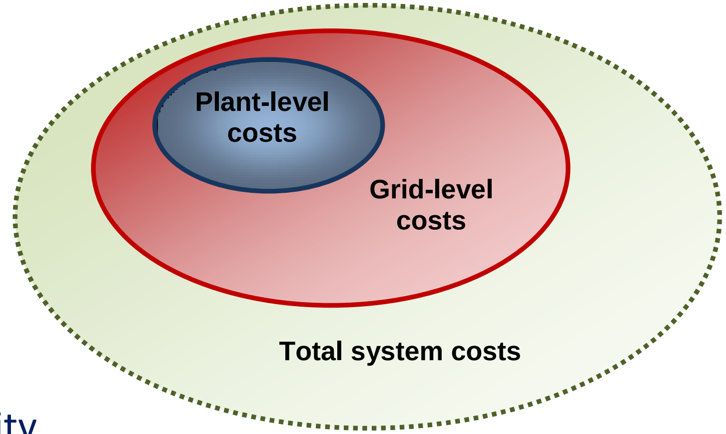
Economic

- Impact on electricity markets (lower prices, higher volatility).
- Investment issues in financing new capacity and adequacy concerns for the near future.
- Long-term impact on the "optimal" generation structure.
- Significant increase in total costs for electricity supply.



The System Effects Study - Introduction

"System costs are the total costs above plant-level costs to supply electricity at a given load and given level of security of supply."



- ***Plant-level costs***
- ***Grid-level system effects (technical externalities)***
  - Grid connection
  - Grid-extension and reinforcement
  - Short-term balancing costs
  - Long-term costs for maintaining adequate back-up capacity
- ***Impact on other electricity producers (pecuniary externalities)***
  - Reduced prices and load factors of conventional plants in the short-run
  - Re-configuration of the electricity system in the long-run
- ***Total system costs***
  - Take into account not only the costs but also the benefits of integrating new capacity (variable costs and fixed costs of new capacity that could be displaced).
  - Other externalities (environmental, security of supply, cost of accidents, …) not taken into account

Methodology and Challenges in defining and quantifying system costs

- Grid-level system costs are difficult to quantify (*externality*) and are a ***new area of study***.
  - There is not yet a common methodology used and accepted internationally.
  - Knowledge and understanding of the phenomena is still in progress.
  - Each study makes its own assumptions, specific objectives and has a different level of detail.
  - Strong difference between *short-term* and *long-term* effects and difficulties in seeing it recognised and acknowledged in the studies.
- Grid-level costs are country-specific, strongly inter-related and depend on penetration level. There are not clear cut categories, each one influencing the others:
  - *Larger balancing areas*: ↓ balancing costs, cheaper optimal generation mix, ↑ transmission costs.
  - *More flexible mix*: ↓ balancing costs, generally is more expensive.
- Modelling and quantitative estimation is challenging and there is no "all-inclusive" model.
- What we observe in electricity markets results from many factors, not only system effects.

However, a consensus is emerging for considering:

- Grid cost (including distribution and transmission).
- Balancing costs.
- Utilisation costs (*profile costs or back-up costs*) including adequacy.

The Short-run and the Long-run

Crucial importance of the time horizon, when assessing the **economical cost/benefits** and **impacts on existing generators** from introducing new capacity.

- **Long-term**
  - The analysis is situated in the future where all market players had the possibility to adapt to new market conditions.
  - In the **long-run**, the country electricity system is considered as a *green field*.
  - VaRen due to its low capacity credit requires dedicated back-up, which is not commercially sustainable on its own.
- **Short-term**
  - The introduction of new capacity occurs instantaneously and has not been anticipated by market players.
  - New capacity is simply added into a system already capable to satisfy a stable demand with a targeted level of reliability. ➡ No back-up costs for new VaRen capacity.
  - System costs depends on the speed of deployment + evolution of electricity demend.

➡ Issue for investors and researchers: when does short-run become long-run?

Methodology: residual load duration curves.

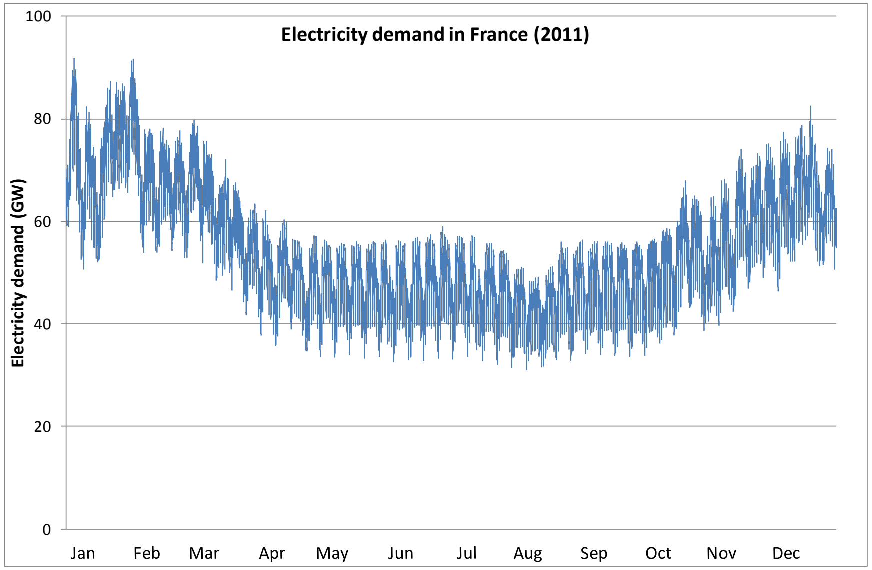
In the following, we look solely at the cost associated to the generation mix for providing the residual load *(cost of long-term dis-optimisation)*.

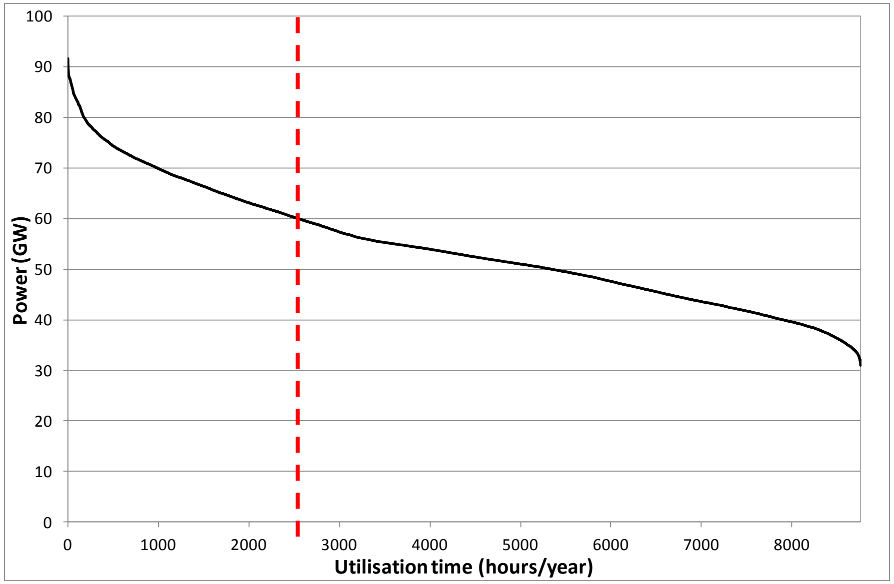
- Copper plate (no electrical grid costs)
- Residual load curve (no short-term balancing).
  Flexibility is not considered and thus not valued

The capacity credit is considered in the methodology (only partially), but could be treated correctly with this approach (***adequacy costs***).

Methodology: Long-term optimal mix I

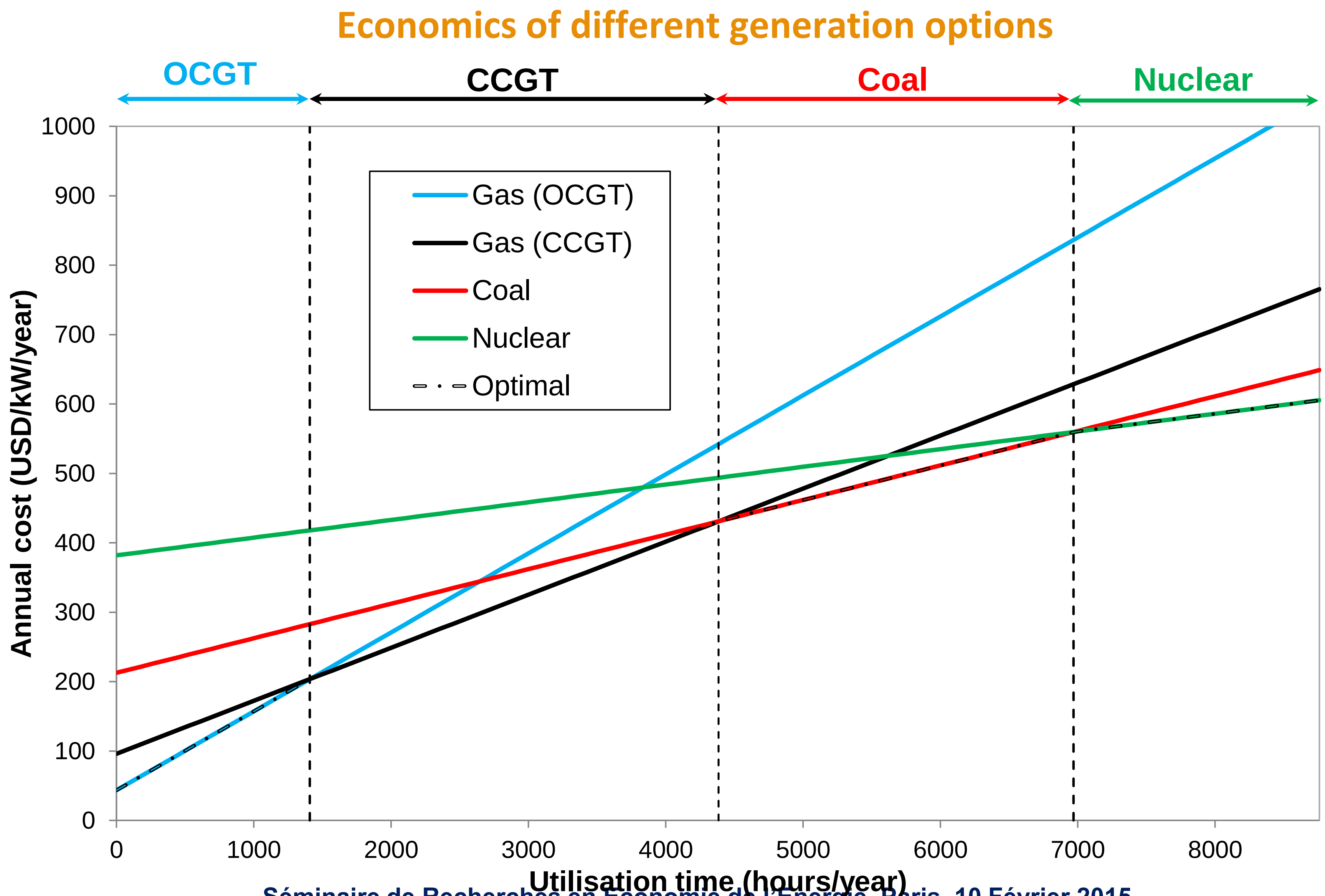
Yearly load duration curve





- Simply obtained by ordering demand from highest to lowest.
- The curve shows the number of hours that electricity demand is higher than a certain level.
- Electricity consumed is the integral of load duration curve.
- Load duration curve loses an important information: the time (and thus dynamics).
  All methods based on the residual load do not consider (and value) flexibility.

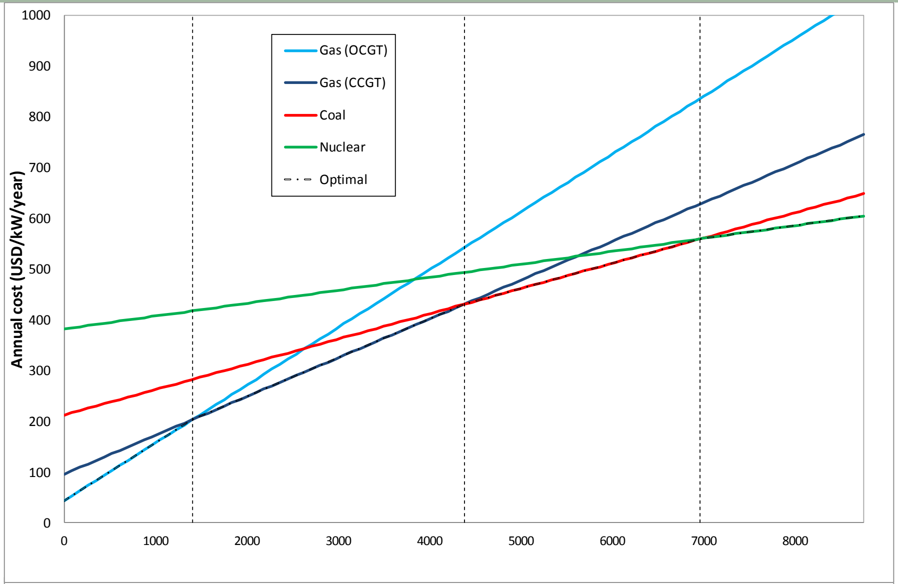
Methodology: Long-term optimal mix II



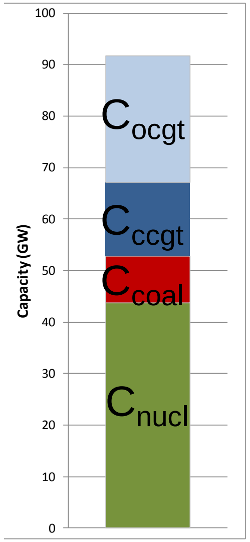
Methodology:
Long-term optimal mix III

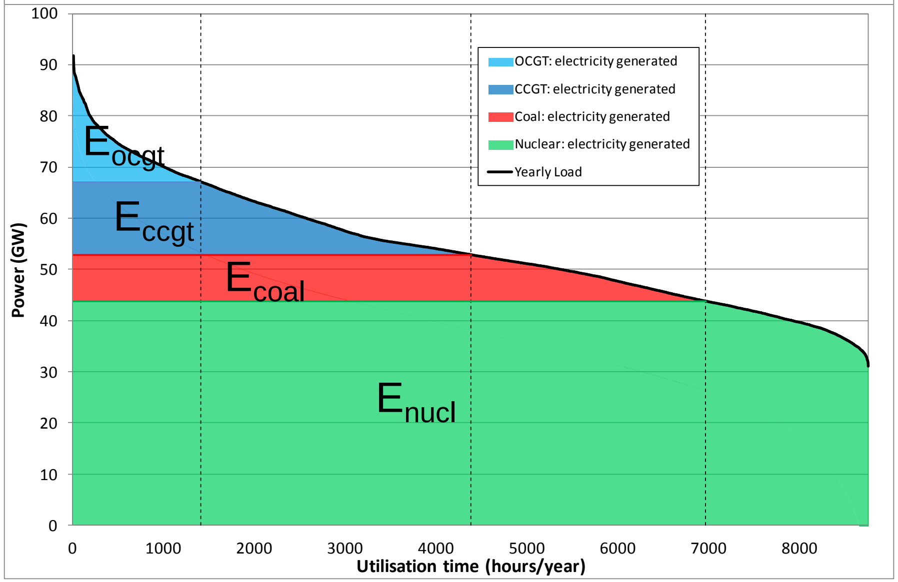
	Fixed costs USD/kW/year	Variable costs USD/MWh	LCOE USD/MWh
OCGT	43.5	113.8	118.7
CCGT	96.1	76.4	87.4
Coal	212.8	49.8	74.1
Nuclear	382.0	25.5	69.1

$$Gen_{Cost} = \sum_i (C_i \cdot FC_i + E_i \cdot VC_i)$$



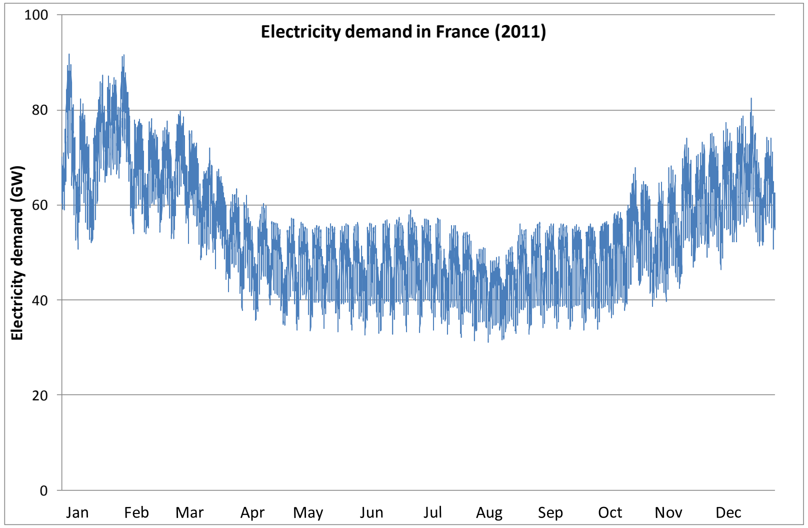
- The optimal generation mix obtained is the one that minimises the generation cost for meeting a given yearly load duration curve.
- The cost/MWh depends upon the shape of the load duration curve.
- Methodology developed for dispatchable generators but can be applied also to VaRen.
- Difficulty in modelling storage.





Methodology: calculating a residual load duration curve with VaRen (wind)

Residual load duration curve (wind at 30%)



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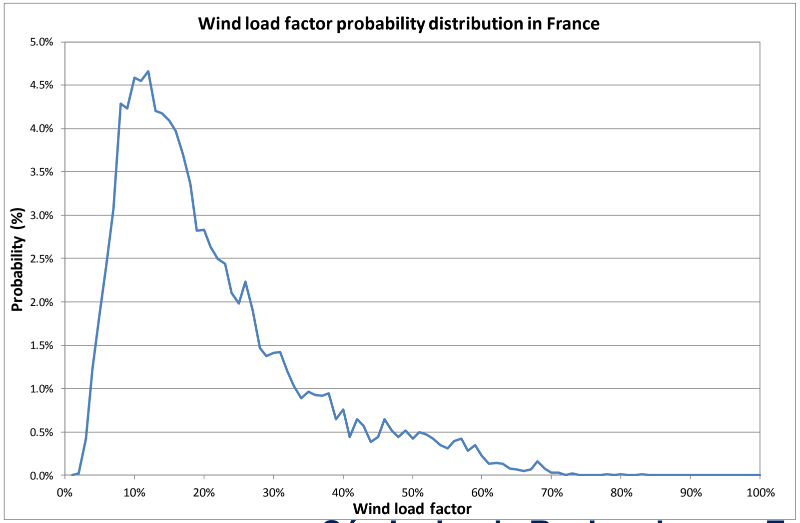
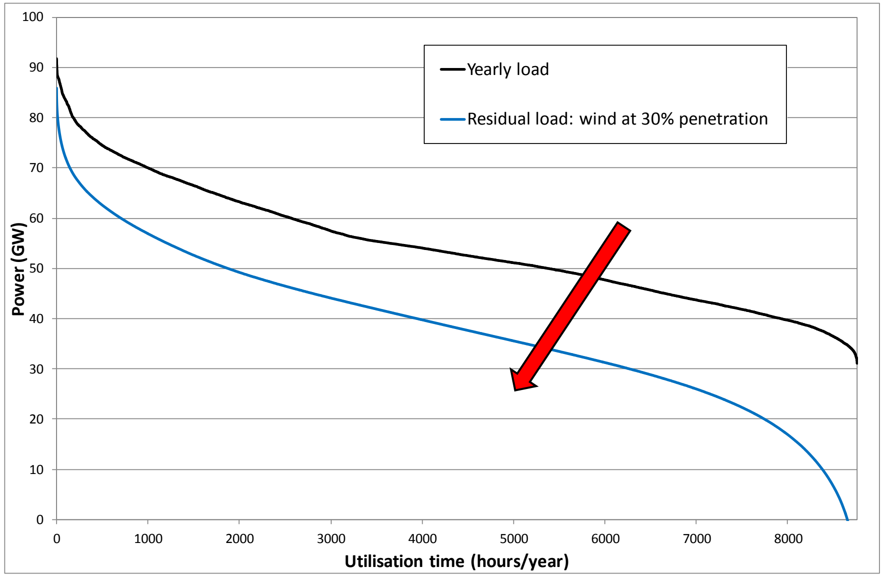


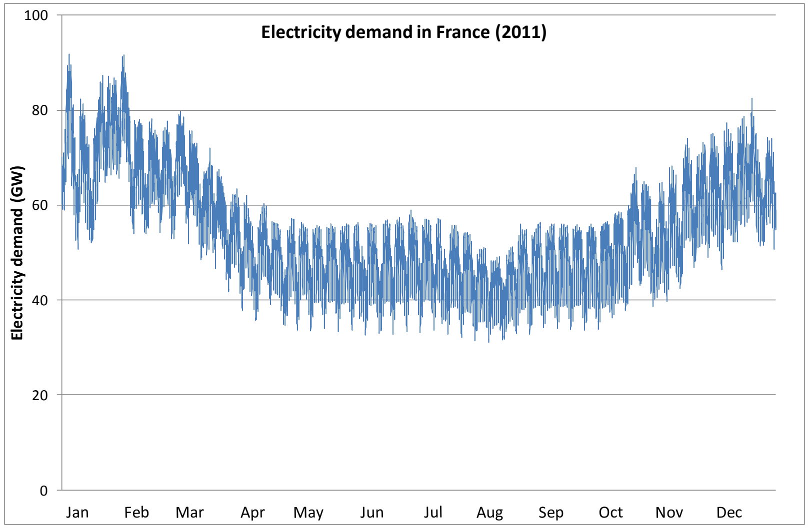


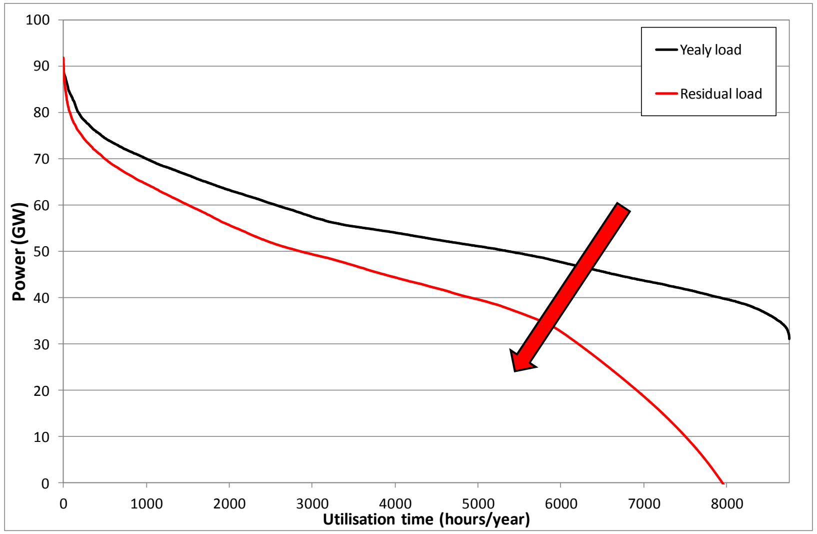
- Represents the load curve seen by the other dispatchable generators after the integration of low-marginal cost wind.
- Statistical analysis (Monte Carlo with 650 runs).
- Load factor probability derived from real RTE data.

  Does not take into account correlation wind/demand.
- Non-parallel shift of the residual load duration curve.

Methodology: calculating a residual load duration curve with VaRen (solar)

Residual load duration curve (solar at 30%)





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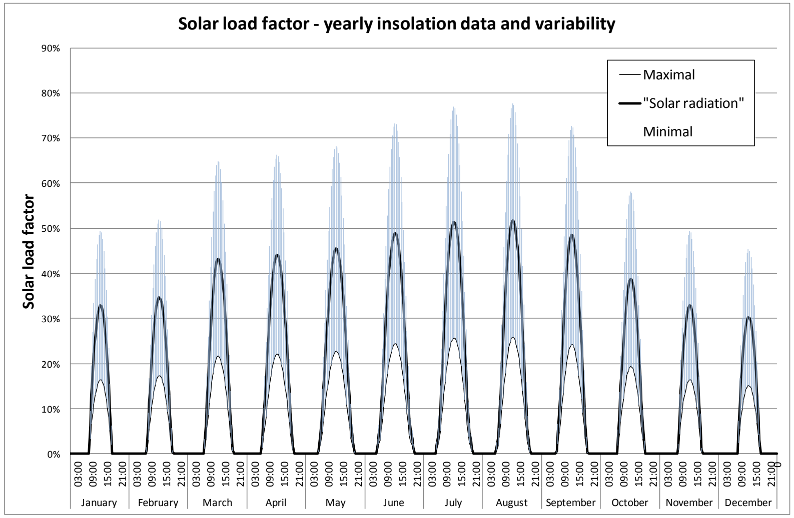
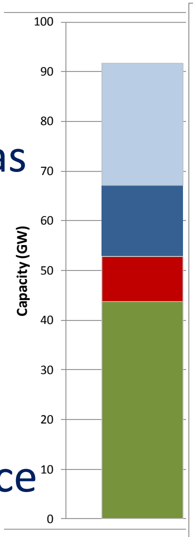


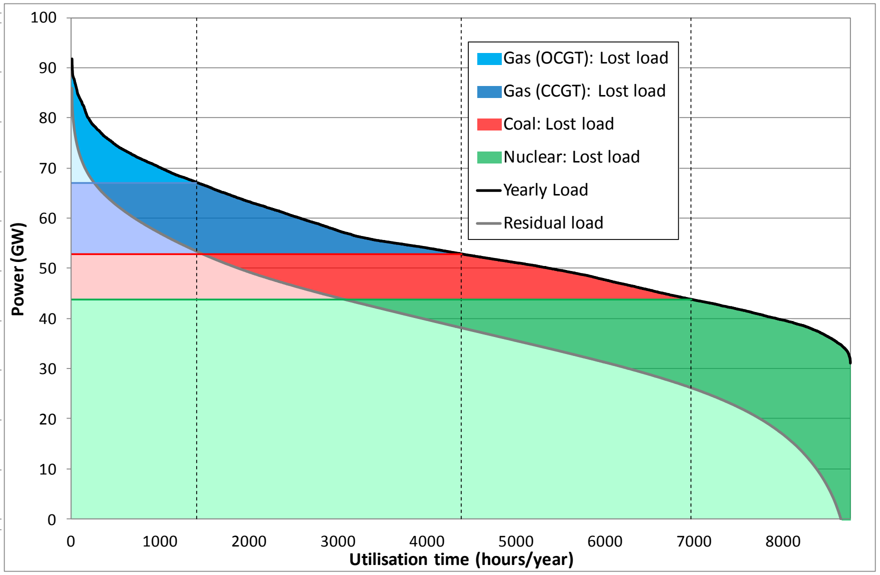
- Statistical analysis (Monte Carlo with 650 trials).
- Load factor probability:
  - Takes into account correlation solar/demand.
  - Educated guess (very smooth & "optimistic").
- The non-parallel shift of the residual load duration curve is more pronounced than for wind.

Short-run impacts

In the ***short-run***, renewables with zero marginal costs replace technologies with higher marginal costs, including nuclear as well as gas and coal plants. This means:

- Reductions in electricity produced by dispatchable power plants (lower load factors, *compression effect*).
- Reduction in the average electricity price on wholesale power markets (*merit order effect*).

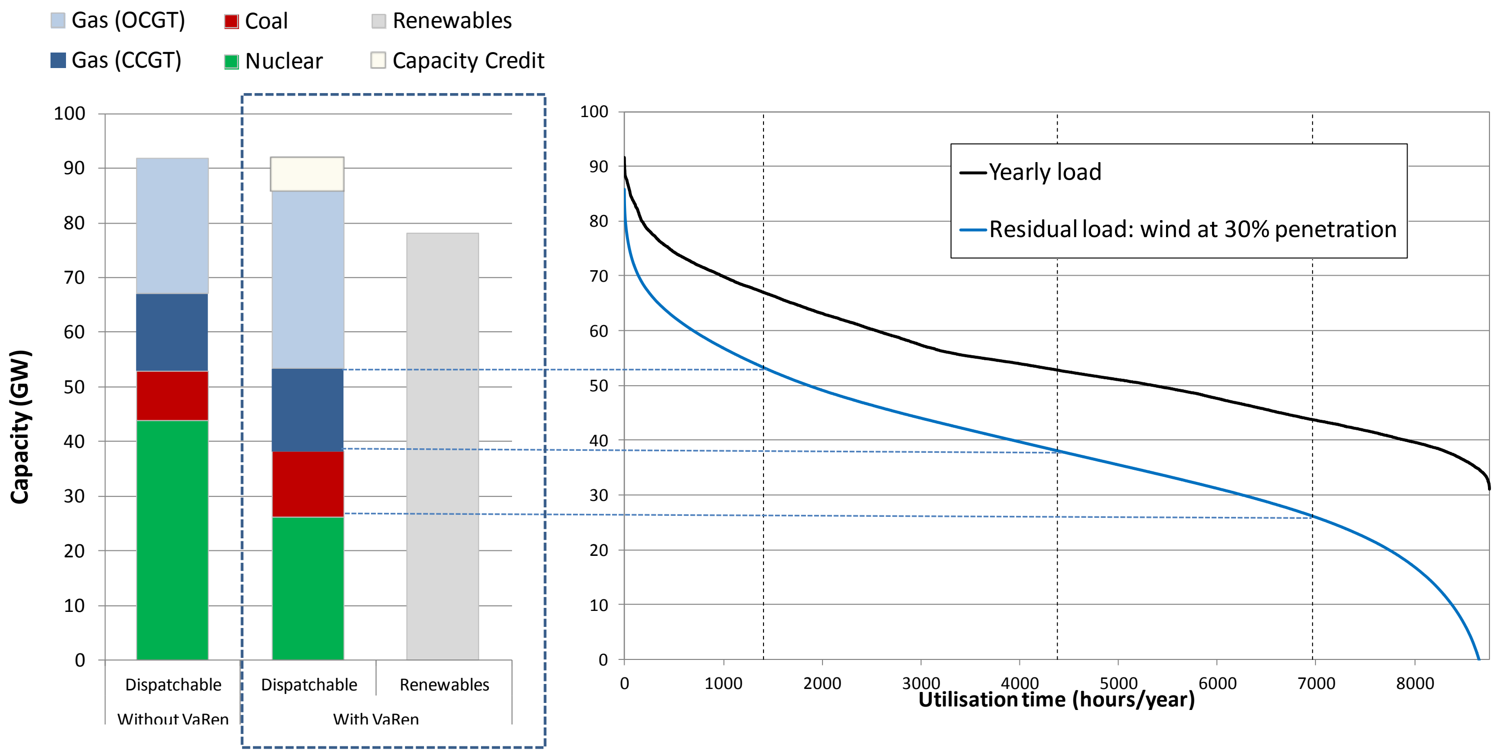




		10% Penetration level		*30% Penetration level*	
		Wind	***Solar***	***Wind***	***Solar***
Load losses	***Gas Turbine (OCGT)***	-54%	-40%	-87%	-51%
	Gas Turbine (CCGT)	-34%	-26%	-71%	-43%
	Coal	-27%	-28%	-62%	-44%
	Nuclear	-4%	-5%	-20%	-23%
Profitability losses	***Gas Turbine (OCGT)***	-54%	-40%	-87%	-51%
	Gas Turbine (CCGT)	-42%	-31%	-79%	-46%
	Coal	-35%	-30%	-69%	-46%
	Nuclear	-24%	-23%	-55%	-39%
Electricity price variation		-14%	-13%	-33%	-23%

- Together this means declining profitability especially for OCGT and CCGT (nuclear is less affected).
- No sufficient economical incentives to built new power plants.
- Security of supply risks as fossil plants close. *HIS CERA estimate 110 GW no longer cover AC and 23 GW will close until end 2014.*

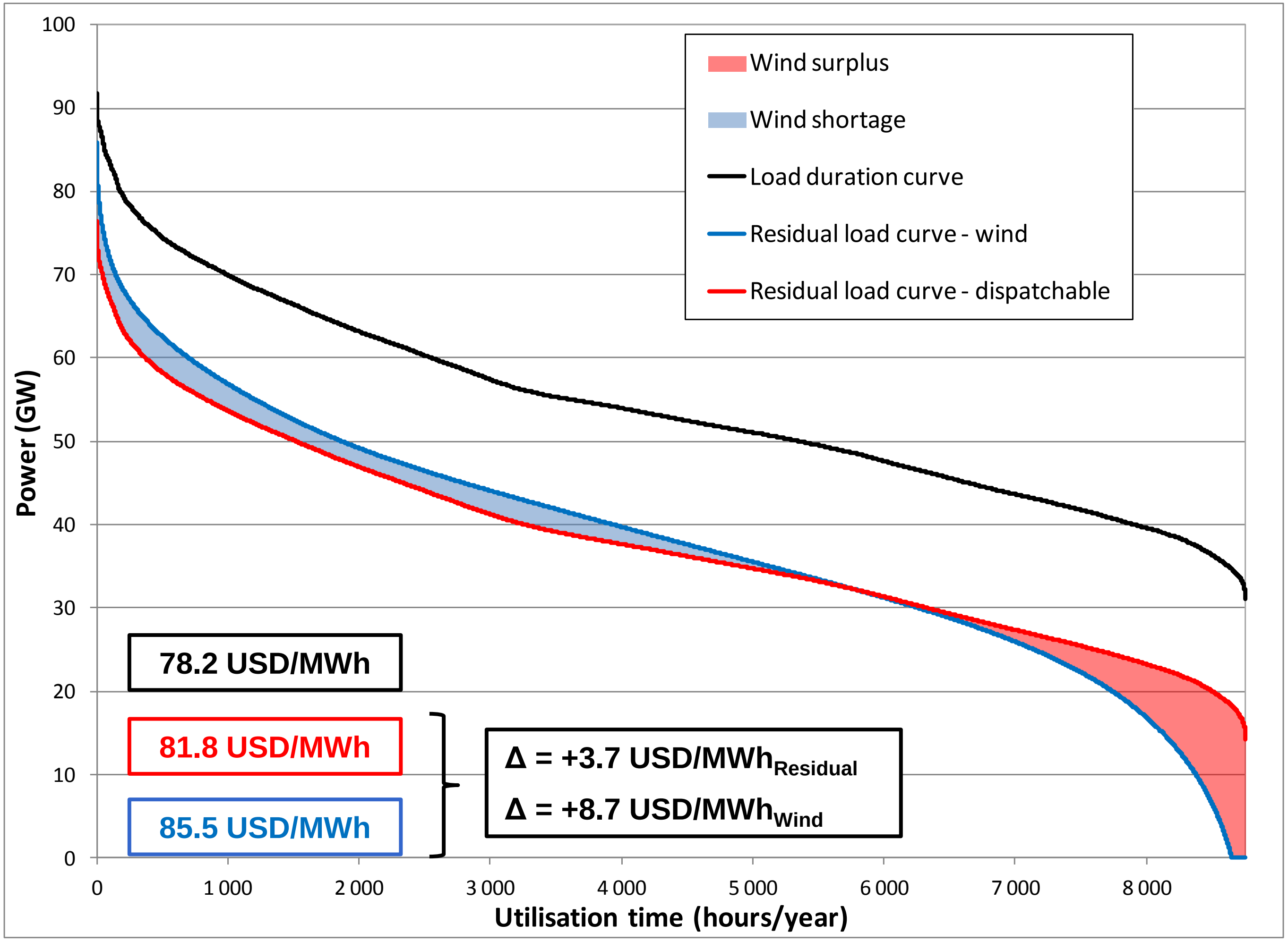
Long-run impacts on the optimal generation mix



- New investment in the presence of renewable production will change generation structure.
- Renewables will displace base-load on more than a one-to-one basis, especially at high penetration levels: base-load is replaced by wind **and** gas/coal (**more carbon intensive)**.
- The cost for residual dispatchable load will rise as technologies more expensive per MWh are used.
- No change in electricity prices for introducing VaRen at low penetration levels.
- These effects (and costs) increase with the penetration level.

Cost for providing the residual load (1)

We compare two situations: the residual load duration curve for a 30% penetration of fluctuating wind (blue curve) and 30% penetration of a dispatchable technology (red curve).

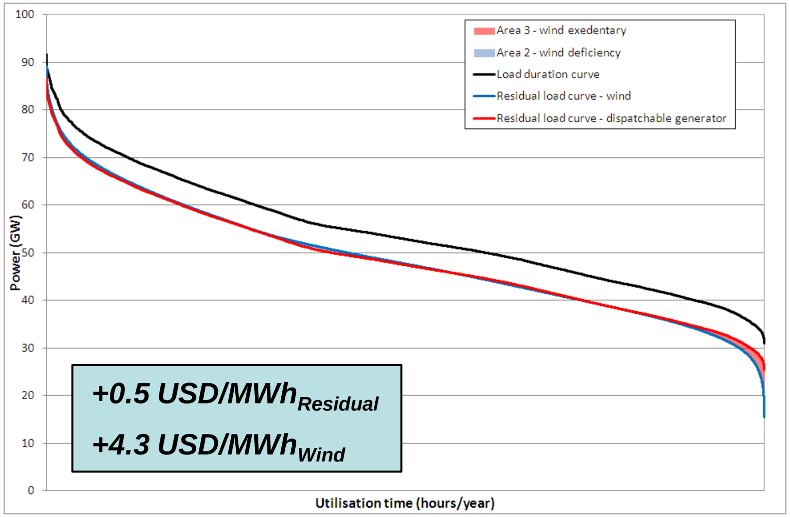


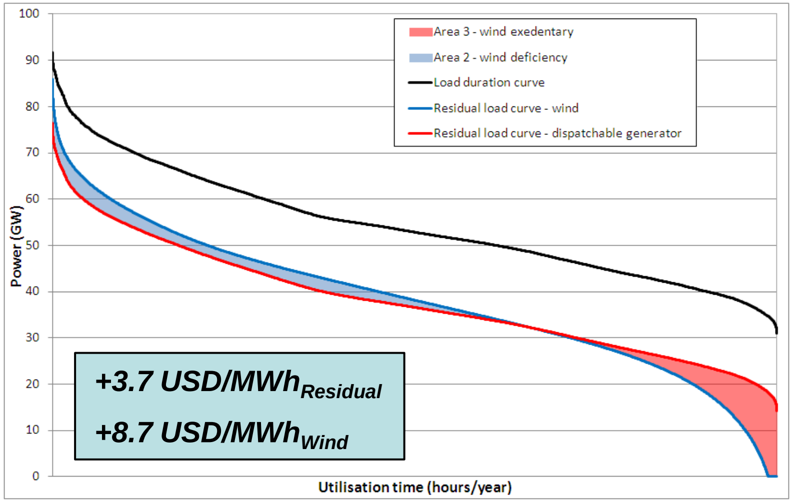
Cost for providing residual load (2)

10% Penetration

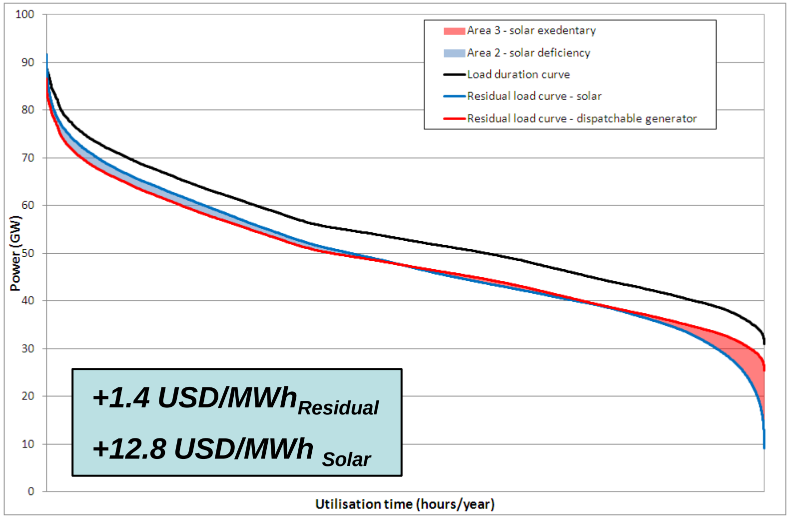
30% Penetration

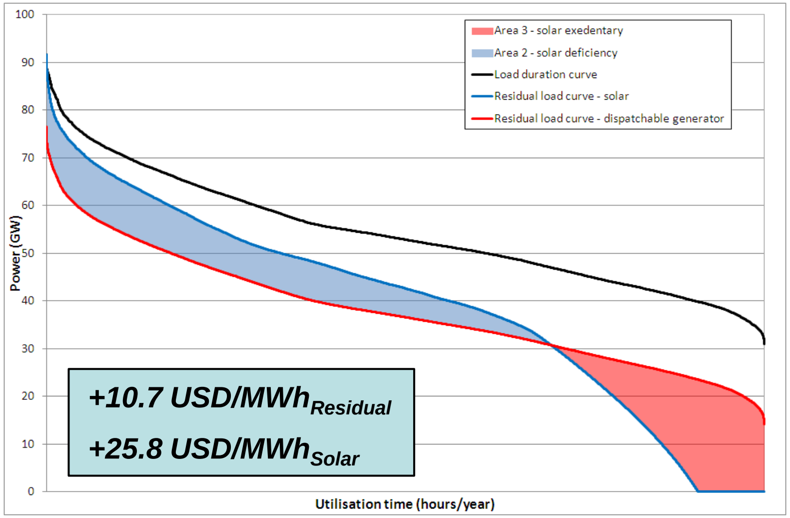
Wind





Solar





Capacity credit and adequacy costs

(Generation) Adequacy is *"the ability of an electric power system to satisfy demand at all times (peak), taking into account the fluctuations of demand and supply, reasonably expected outages of system components, projected retiring of generating facilities, etc".*

C**apacity credit** is *"the amount of additional peak load that can be served due to the addition of a power plant, while maintaining the existing levels of reliability".*

Capacity credit of variable renewables
- is lower than that of dispatchable.
- decreases with penetration level.

Short-term (a plant is added to a system that already meets adequacy goals).

The new power plant only increases (or does not decrease) the system adequacy.

→ Adequacy needs and costs are zero in a short-term perspective.

Long term (a plant is added to satisfy new demand **instead** of another plant).

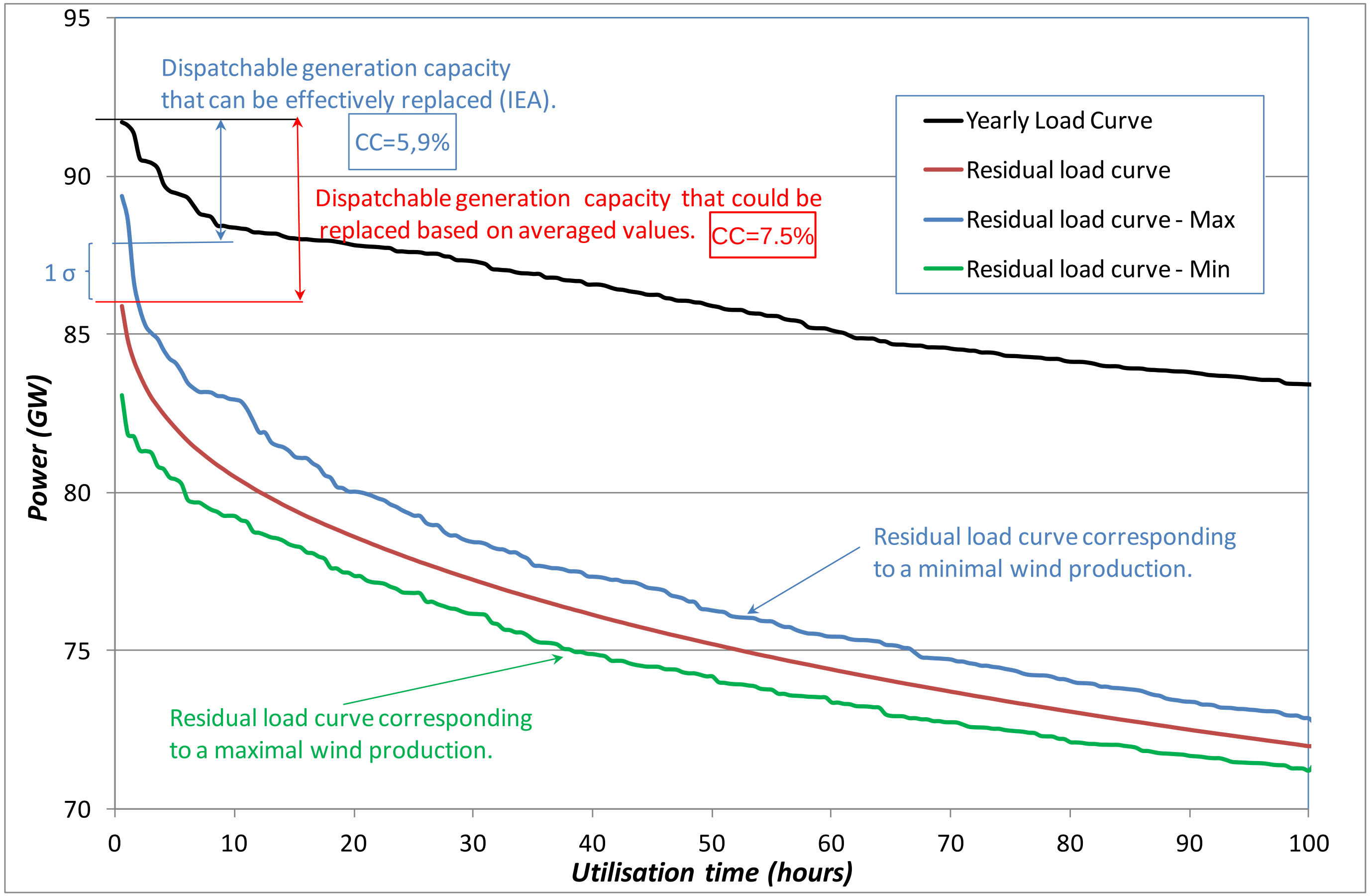
The two plants have to provide the same service in term of
- Electricity produced.
- Contribution to adequacy.

→ Additional capacity must be built in addition to VaRen to ensure the same adequacy level of a dispatchable power plant.

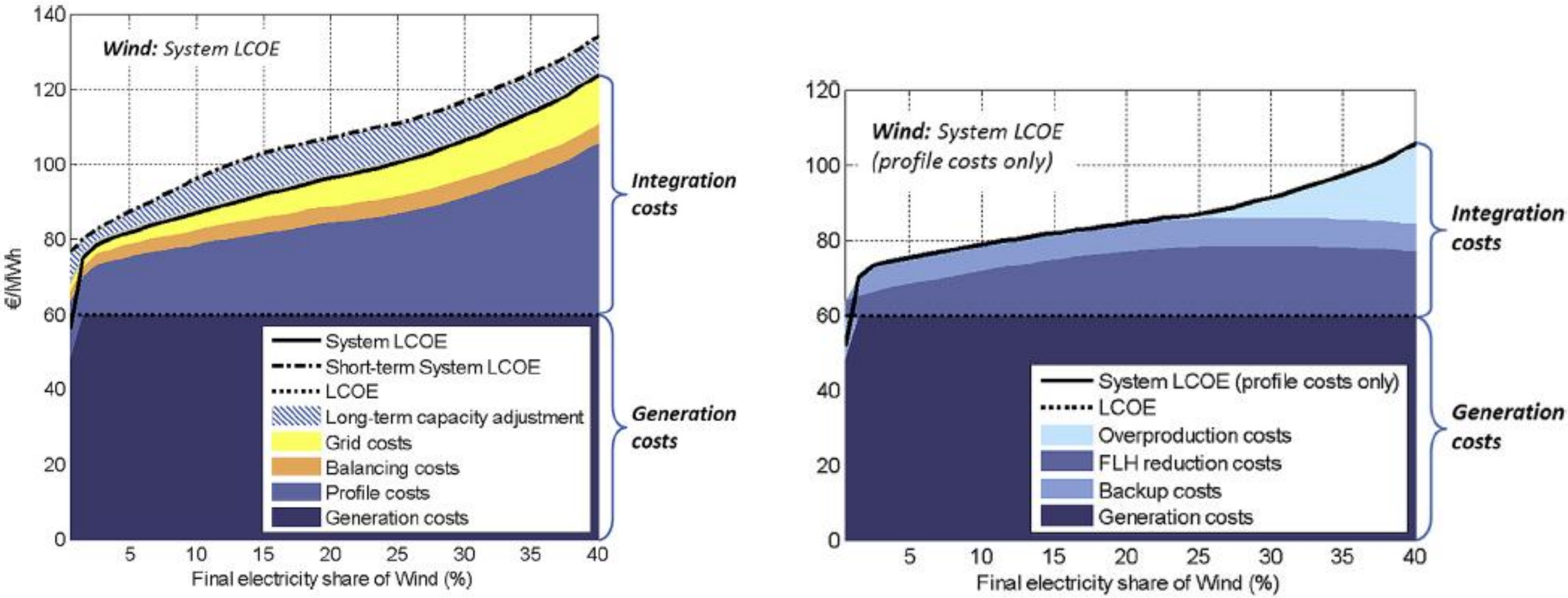
Methodology: estimates of capacity credit using residual load duration curves

- Capacity credit is calculated using complex probabilistic techniques (LOLP) and requires a sophisticated modeling of the whole electricity system.

Residual load duration curves allow for simple and reasonably reliable estimation of the capacity credit (*only generation*).



An expression of integration costs*



- Profile costs are divided into 3 components
  - overproduction (cost of curtailing VaRen).
  - backup requirements due to the lower capacity credit.
  - Full Load Hour reduction costs.
- Grid costs and balancing costs are summed to obtain integration costs.
- Consideration of long-term/short term capacity adjustments.
- Integration costs (function of penetration level) are added to generation costs (LCOE)

* F. Ueckerdt, L. Hirth, G. Luderer, O. Edenhofer,: *"System LCOE: What are the costs of variable renewables?"* Energy 63 (2013) pp 61-75

A different approach of considering system costs: a measure of the economical value of fluctuating renewables

Séminaire de Recherches en Economie de l'Energie, Paris, 10 Février 2015

Introduction

A different approach consist in weighting the generation costs of Variable Renewables with the ***(marginal) value*** of the electricity produced.

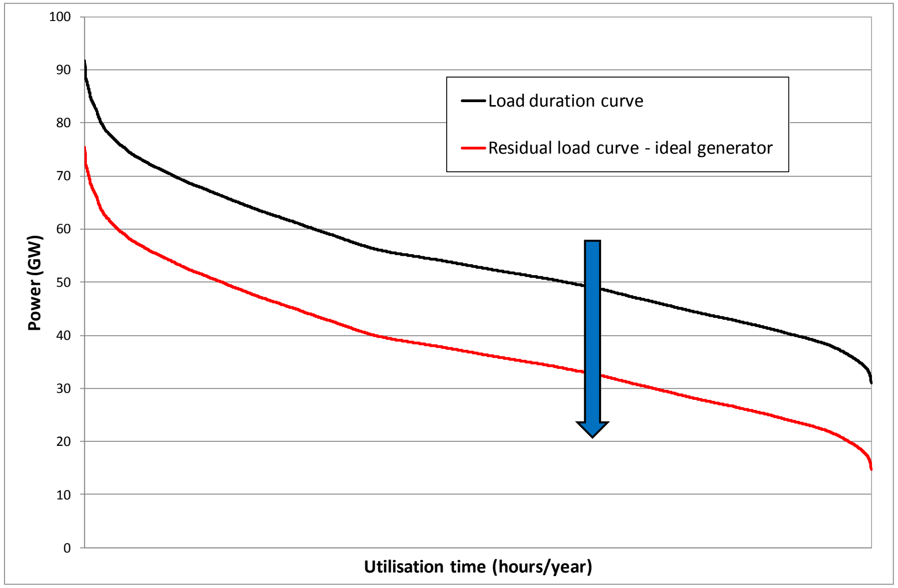
- In absence of large amount of storage, the value of electricity is not homogeneous over time, but depends on ***when*** (and ***where***) it is produced.
- Fluctuating generation does not have the same “value” or utility for the system as dispatchable generation.
- The “value” of fluctuating generation sources for the electrical system decreases significantly with penetration level.

The two approaches are complementary and in my view equivalent. They should lead to the same economic choices.

We developed a simple method based on residual duration curves to derive the value of electricity produced (which takes into account **when** the electricity is generated).

A simple example for an "ideal" generator

A generator providing a flat power band (30% of the electricity)



Results

- A parallel shift on the load curve.
- No changes in the capacities and electricity production of medium- and peak-load technologies.
- The flat power band replaces base-load technology.

- The value of the electricity produced by the ideal generator is calculated as the difference between the cost of supplying the original load duration and the residual curve.

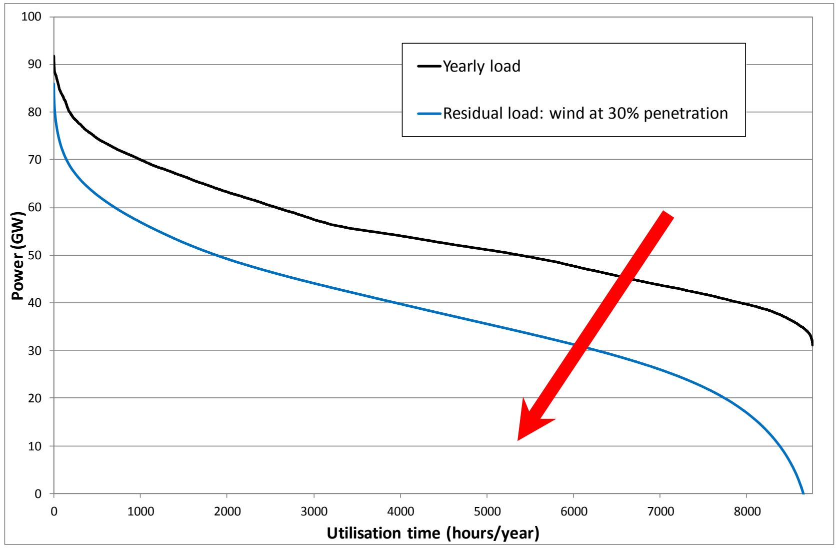
	Total cost [Bil. USD]	***Specific cost*** [USD/MWh]
Original load curve	37.18	78.20
Residual curve	27.32	81.96
Value of flat band	9.86	69.11

- The total cost of residual load is reduced
- The specific cost increases

- The value of the flat band for the system is equal to the cost of base-load technology ***(Expected)***.

The 30% wind penetration case

A wind providing fluctuating power (at 30% penetration level)



Results

- Non-parallel shift on the load curve.
- Significant changes in the composition of the generating mix (proportionally more peak- and medium-load capacity).
- The wind production replaces base-load technology on more than one-to-one basis.

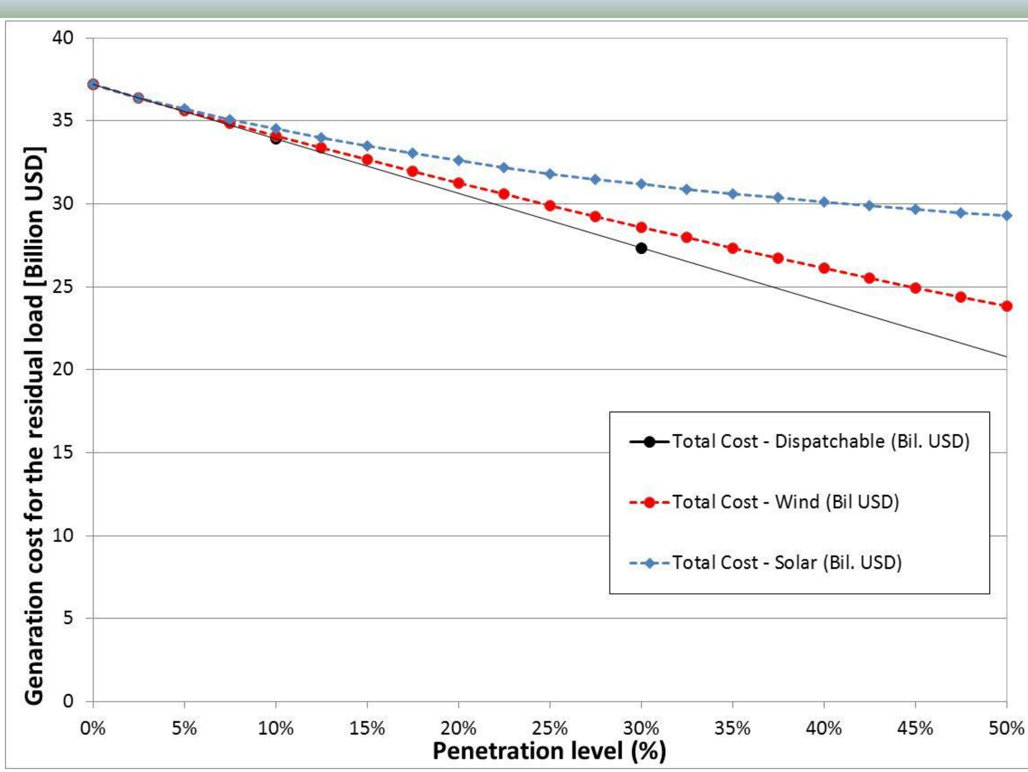
	Total cost [Bil. USD]	***Specific cost*** [USD/MWh]
Original load curve	37.18	78.20
Residual curve	28.60	85.79
Value of wind at 30% PL	8.58	60.16

Previous case (flat power band)

	Total cost [Bil. USD]	***Specific cost*** [USD/MWh]
Original load curve	37.18	78.20
Residual curve	27.32	81.96
Value of flat band	9.86	69.11

- The total cost for the residual load is higher → ***the value of wind production is lower***.
- We define the **value factor (or utility factor)** as the "*value of a fluctuating technology relative to that of a flat power band*".
- Value factor depends on *technology, penetration level and country*.

Generation Cost for providing Residual Load



			Wind	Solar
Penetration Level	10%	Extra cost [Mio USD]	197.6	612.6
		Cost increase [%]	0.6%	1.8%
	20%	Extra cost [Mio USD]	644.3	1964.9
		Cost increase [%]	1.9%	5.9%
	30%	Extra cost [Mio USD]	1253.2	3828.1
		Cost increase [%]	4.4%	10.0%
	40%	Extra cost [Mio USD]	2046.0	6044.2
		Cost increase [%]	7.8%	12.7%

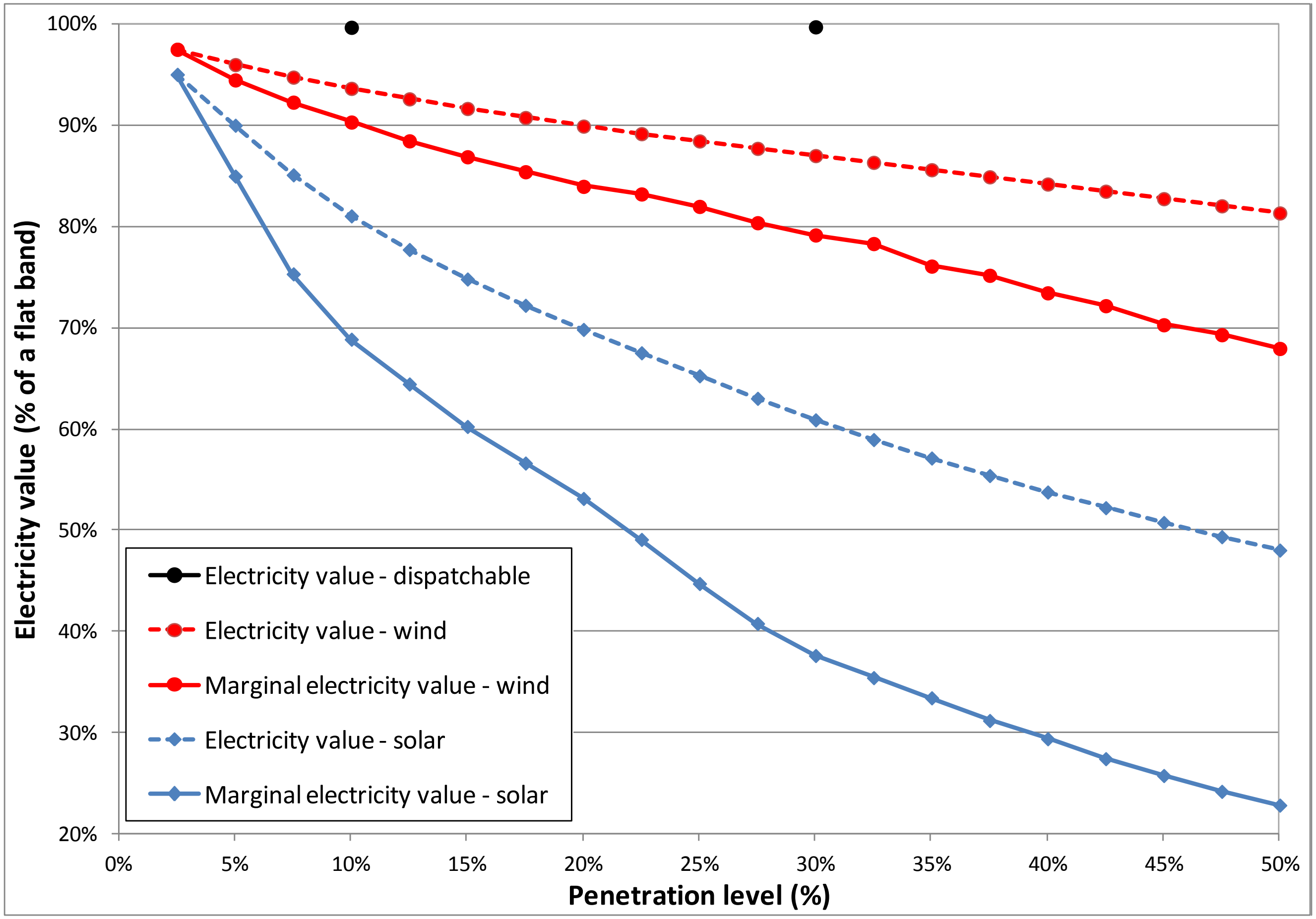
* Yearly generation cost in excess to the reference case (without VaRen)

- The auto-correlation of VaREN production reduces the effective contribution of variable resources to covering electricity demand.
- Cost of the residual load does not decreases linearly with penetration level. New VaRen additions bring lesser and lesser value to the system.
- The additional cost for providing the residual load increases significantly with penetration level, up to several Billion USD per year.

Value of a variable generation source from the view-point of the system

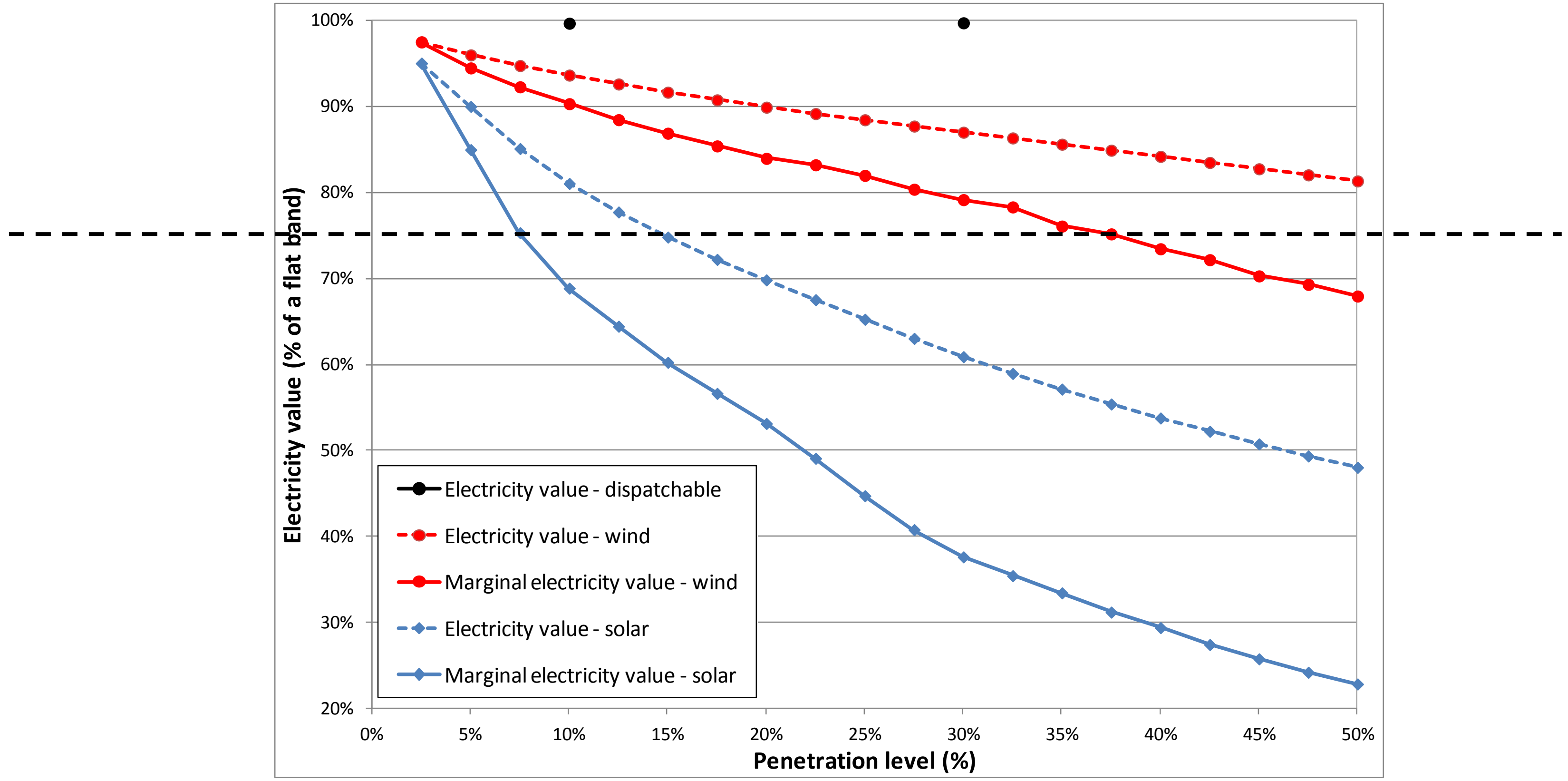
We can look at the impact of the variability from a different perspective:

- Cost for the whole electrical system
- Value of an intermittent generation source (as seen by the system)



The marginal value should be taken into account in investment decision making !

How to use it?

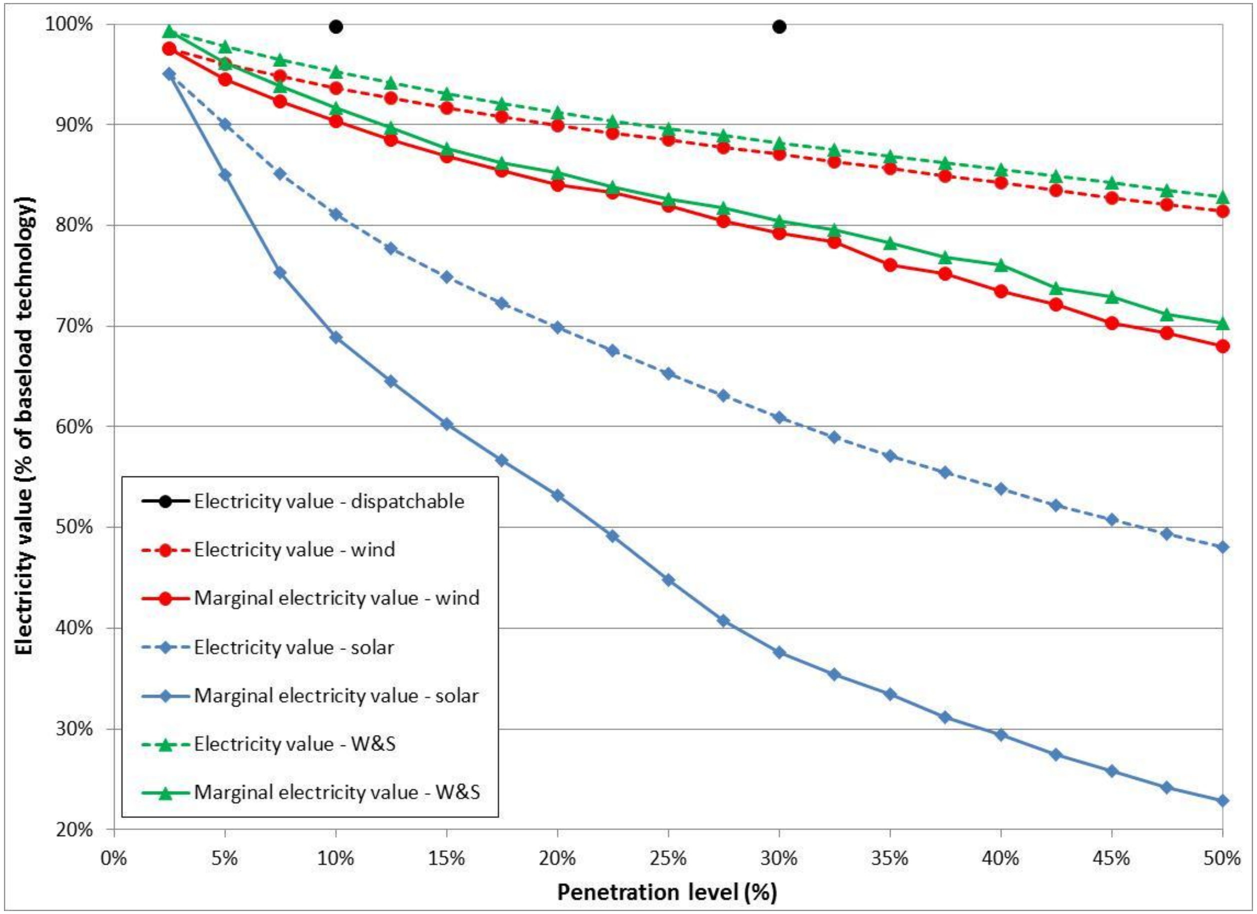


- What is the optimal amount of solar/wind in a system as a function of his levelised cost (relative to the base-load technology).

If the solar would be 25% cheaper than base-load ➡ the ***economic*** optimal penetration level would be 5% (for wind it would be 37.5%).

The effects of diversification: Combination of solar PV and wind

- A combination of wind and solar increases the value of combined output (*but not too much*).
- Calculations have been done assuming 70% wind and 30% solar .
- At each penetration level it is possible to calculate the optimal share of the 2 technologies.



Value factor and correlation with demand

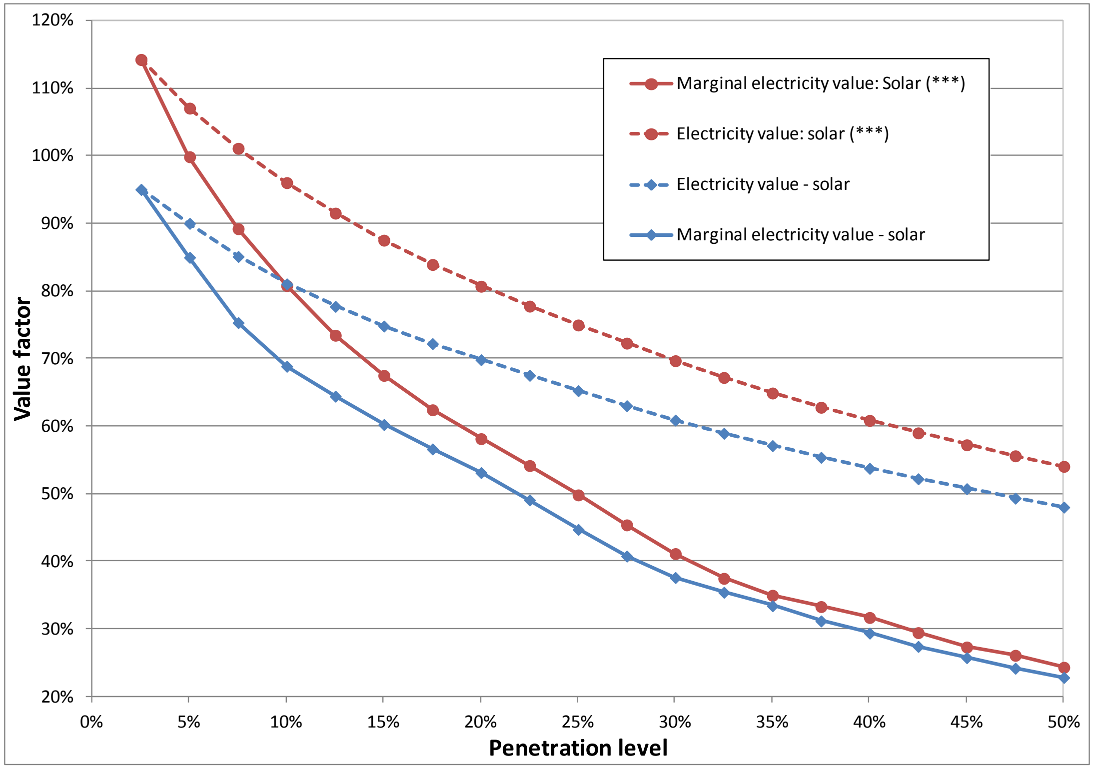
Data on load curves and VaRen correlations have been derived from RTE data (France) and are valid only for France.

- France peak production occurs in the evening at winter -> poorly correlated with **solar** output.
- Simulation for **wind** does not take into account correlation between wind production and electricity demand *(but it could be done)*.

"California Dreaming": what if solar PV output would be better correlated with demand?

- We created an *ad-hoc* (*unrealistic*) model in which we have forced a better correlation between solar production and daily/seasonal demand.
- It has simply the purpose to show what could be the solar utility value in a country in which solar output is better correlated with demand.

What if solar would be better correlated with demand



Ad-hoc model

Real data for France.

The value factor for solar can be higher than that of dispatchble plants.

- Solar could be economically competitive (and deployed) even if more expensive than base-load.

The value factor of solar decreases significantly with penetration level

- Even in optimal locations the value of solar is rather low when penetration level reaches 10-15% (*in absence of storage*).

Current Limits of Technical Analysis : Storage modelling

The model developed does not take into account storage capacity (nor dynamics of the system)

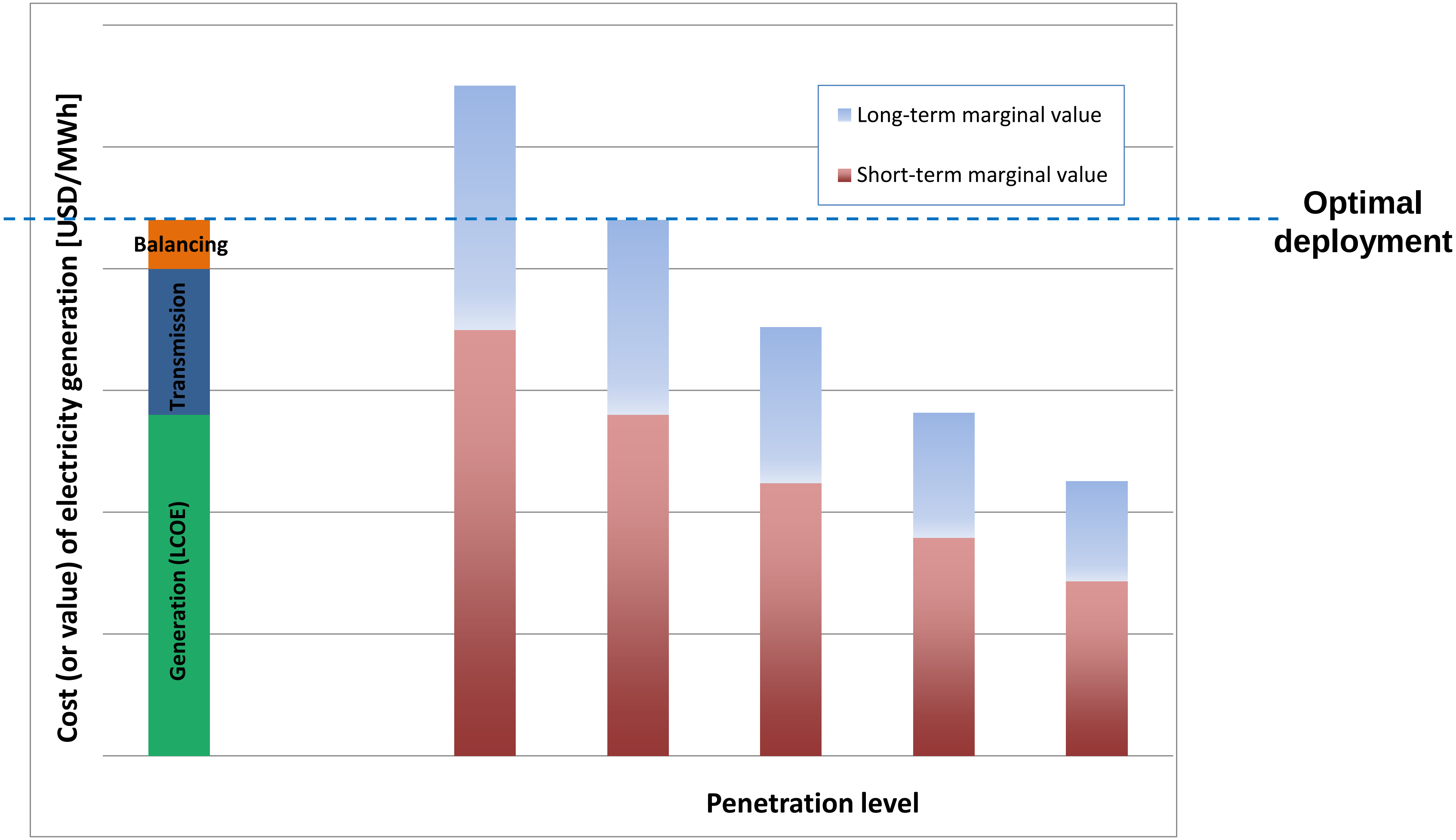
- Difficult to correctly model storage using a ”load duration” approach.
- It can be done in a simplified way.

Few qualitative comments

- Storage will reduce the cost of residual load for both the scenario with VaRen and the reference.
- The presence of significant amount of storage will increase the value factor of VaRen.
- Different systems (depending on Ren type and penetration level) will call for an “optimal” level of storage.
- Increasing VaRen penetration level ➡ increase optimal storage level.
  - The associated cost for storage should be taken into account in the analysis.
- Taking into account the dynamics of the system will reduce the value of VaRen (at high PL).

Cost of providing the residual load is a key driver for VaRen integration cost and should be better understood and modelled.

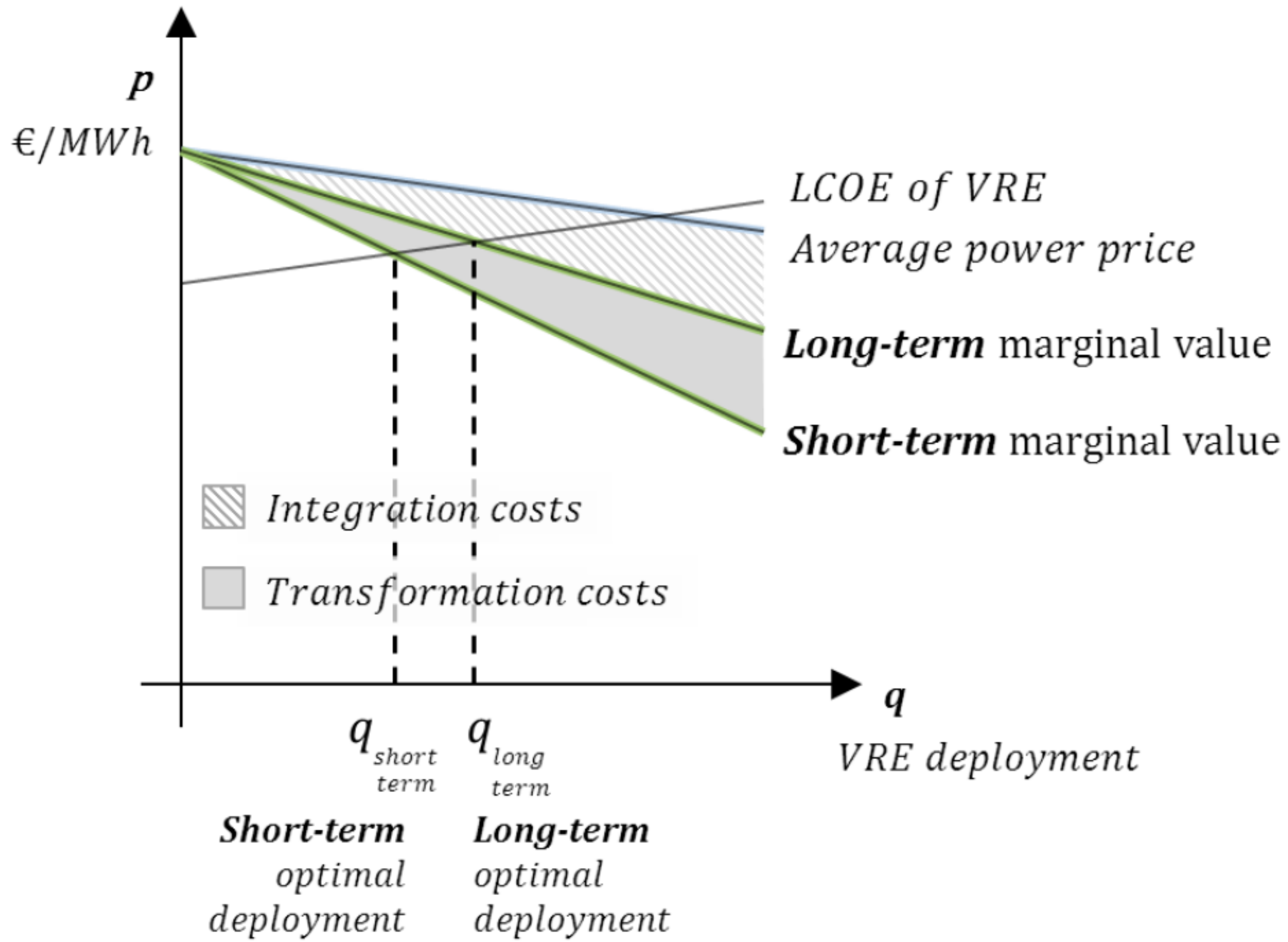
A qualitative representation of the marginal value approach (1)



Short-term value: fuel and carbon cost savings + variable O&M.

Long-term value: investment costs, fuel and O&M cost savings.

A qualitative representation of the marginal value approach* (2)



* F. Ueckerdt, S. Mueller, L. Hirth, M. Nicolosi:
"Integration costs and marginal value. Connecting two perspectives on the economics of variable renewables"

Thank you for your attention

Additional information and Contacts:

On NEA reports and activities

http://www.oecd-nea.org

http://www.oecd-nea.org/ndd/reports/

On the system cost study

The full report and the ES of the System Cost study are available on-line

http://www.oecd-nea.org/ndd/pubs/2012/7056-system-effects.pdf

http://www.oecd-nea.org/ndd/reports/2012/system-effects-exec-sum.pdf

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Reserve slides

An analytical decomposition ....

The total cost of a system can be expressed as the sum of 3 components:

$$C_{Tot}(\propto_{Win}) = C\ Gen_{Win}(\propto_{Win}) + C\ Gen_{Res}(\propto_{Win}) + C_{Sys}(\propto_{Win})$$

Integration costs can be defined as the difference between a system with and without renawables:

$$\Delta C(\propto_{Win}) = C_{Tot}(\propto_{Win}) - C_{Tot}(0)$$

Specific Integration costs (cost per unit of electricity produced by renewables) can be expressed as the sum of 3 terms:

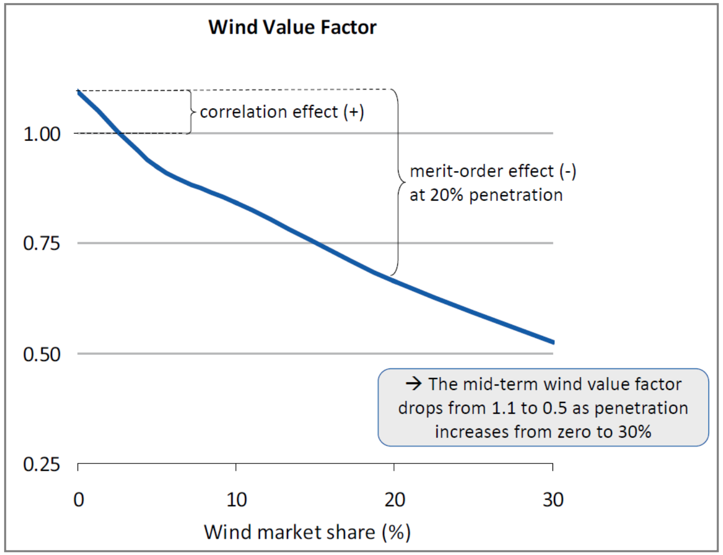
$$\frac{\Delta C(\propto_{Win})}{\propto_{Win} \cdot E_{Tot}} = \underbrace{[c\ Gen_{Win}(\propto_{Win}) - c\ Gen_{BL}(\alpha)]}_{1} + \underbrace{\frac{(1 - \propto_{Win})}{\propto_{Win}} \cdot [c\ Gen_{Res}(\propto_{Win}) - c\ Gen^{*}_{Res}(\alpha)]}_{2} + \underbrace{\frac{\Delta C_{Sys}(\propto_{Win}, 0)}{\propto_{Win} \cdot E_{Tot}}}_{3}$$

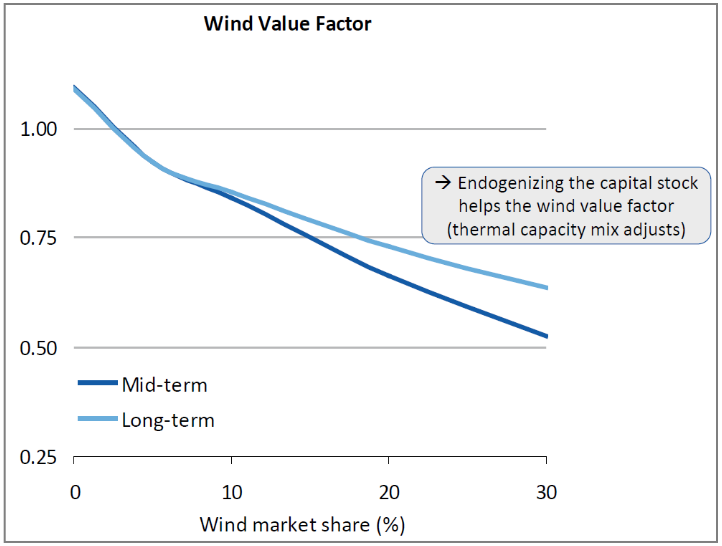
1. **Difference in generation cost (LCOE) with respect to base-load technology**
2. **Difference in the cost for providing the residual load**
3. **Other integration costs (grid costs and balancing)**

Another approach: the market value of variable renewables

From Lion Hirt: "The market value of variable renewables", IAEE Conf., Venise, 11 Sept 2012

Similar approach looking at the market value of wind and solar for the European North-West interconnected power system.





Conclusions

- Wind value factor decreases with wind penetration (as expected)
- It drops from 1.1 at zero market share to about 0.5 at 30% (*merit-order* effect)
- Solar value factor drops even quicker to 0.5 at only 15% market share
- Existing capital stock interacts with VaRen: systems with much base load capacity feature steeper drop
- Long-term value factors are higher – almost 15 percentage points at 30% market share

The market value of variable renewables: a graphical explanation

Simple graphic explanation of these phenomena.

Power produced by the technology vs. electricity price on the market