Nuclear Energy and Renewables: System Effects in Low-carbon Electricity Systems

Study methodology and key technical findings

Marco Cometto and Jan-Horst Keppler

OECD/NEA Nuclear Development Division

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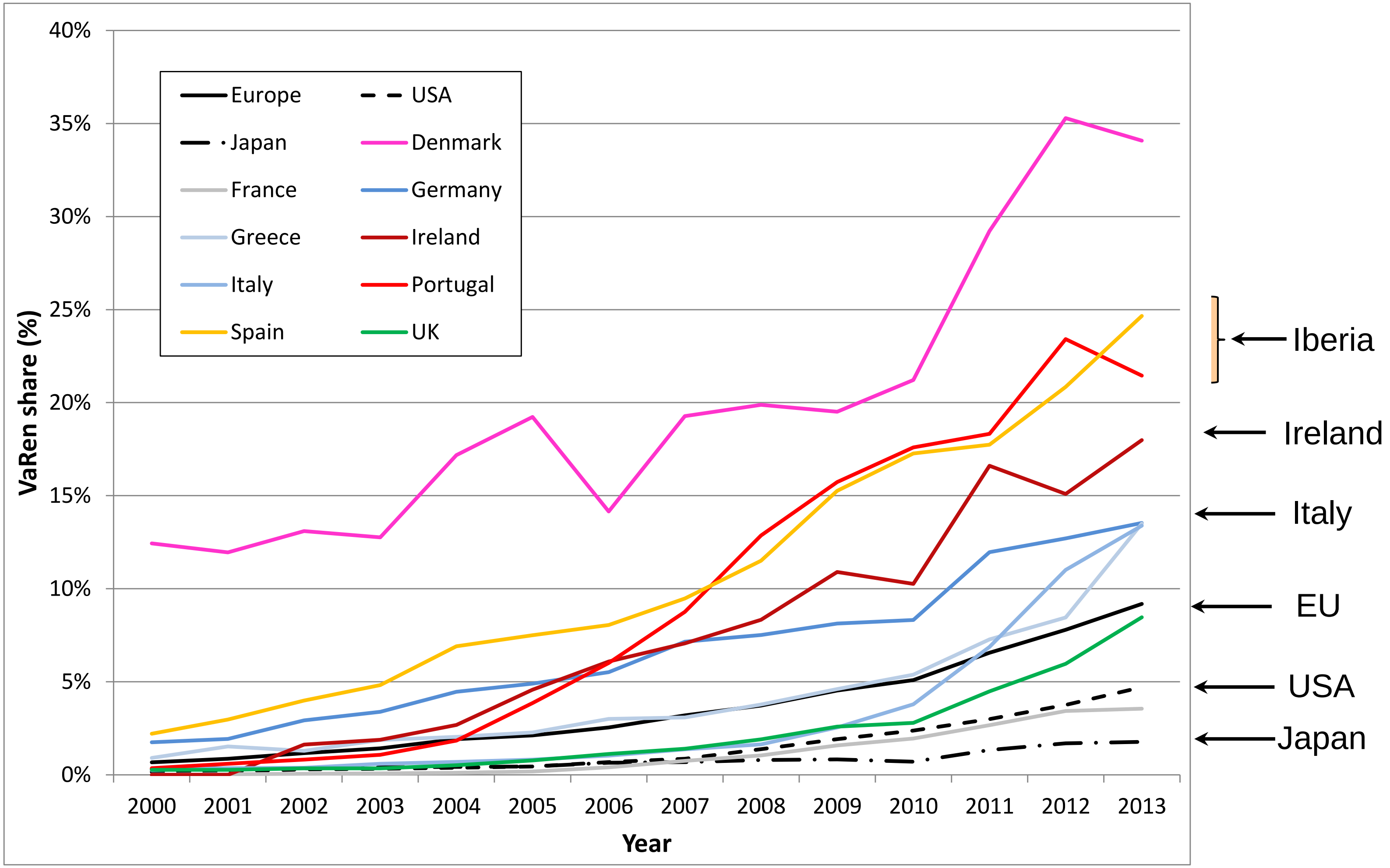
The System Effect Study - Background

Deployment of intermittent sources (solar and wind) in OECD countries



Source: IEA Electricity monthly reports

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.

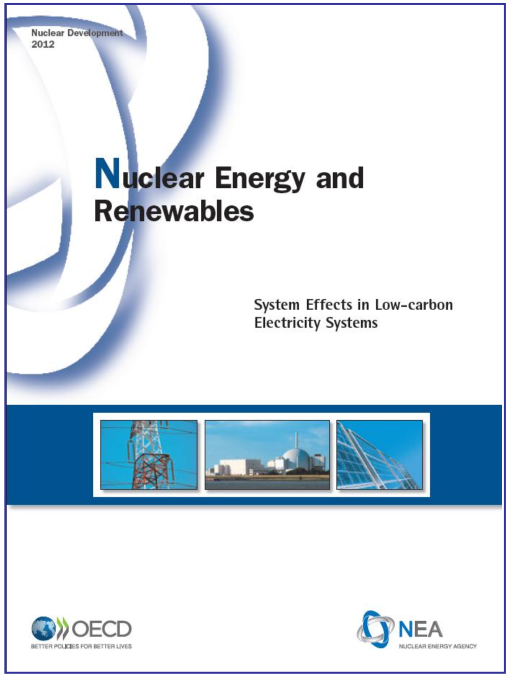
1) Estimation of system effects (and costs) of different generating technologies.
2) Impact of integrating significant amounts of **fluctuating** electricity at **low marginal cost** on the whole electricity system and on nuclear power.

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

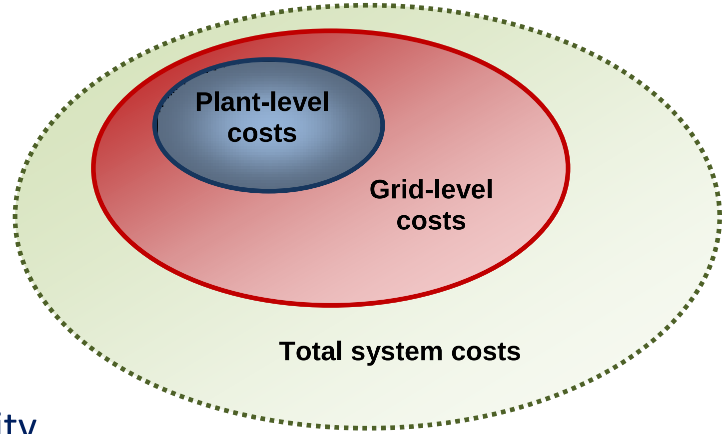
- Impact on electricity markets (lower prices, higher volatility).
- Investment issues in financing new capacity and adequacy concerns for the near future.
- Long-term impact on the "optimal" generation structure.
- Significant increase in total costs for electricity supply.



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 clear definition, nor 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.
    - Modelling and quantitative estimation is challenging and there is no "all-inclusive" model.
    - 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. Different cost categories influence each others:
    - *Larger balancing areas*: ↓ balancing costs, cheaper optimal generation mix;
    - *More flexible mix, storage* : ↓ balancing costs, generally is more expensive.
- What we observe in electricity markets results from many factors, not only system effects.
- System effects also create demand for new markets and services (capacity, flexibility…).

However, a consensus is emerging for considering as System Costs:

- **Grid cost (including distribution and transmission).**
- **Balancing costs.**
- **Utilisation costs (*profile costs or back-up costs*) including adequacy.**
- ***Still connection costs are substantial and should be considered.***

Estimates of system costs components: Grid-related costs

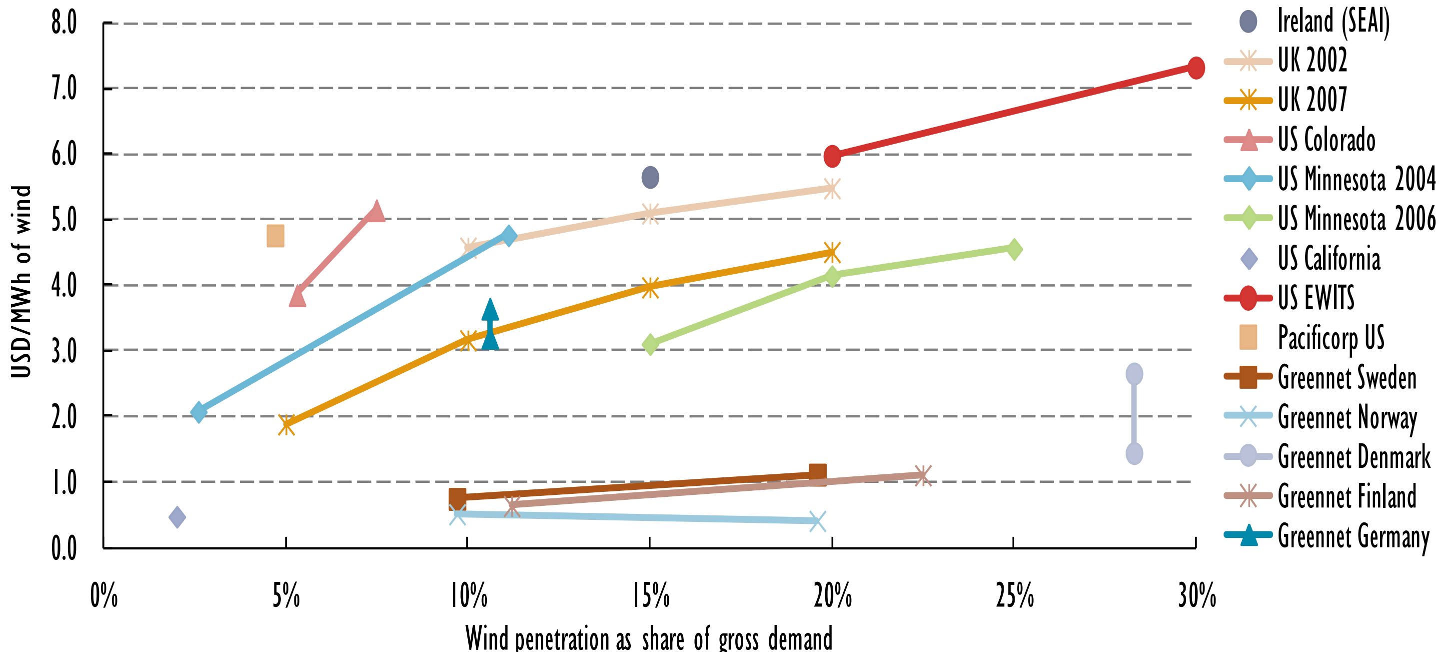
- T&D grid costs are related to geographic location of VRE output.
  - Increased investments in construction and reinforcement of transmission infrastructure.
  - Increase in transmission losses due to increased transport of electricity.
  - High penetration of distributed solar PV requires sizeable investments in the distribution network.
- ***Literature estimates*** vary strongly depending on location conditions and penetration level
  - USA (*EWITS*): 2-3 USD/MWh (46-92 USD/kW) at 6%-30% penetration.
  - EU (*European Wind Integration Study*): 1 to 5.4 USD/MWh at 10-13% penetration level.
  - Ireland: 2-10 EUR/MWh depending on penetration level.
  - Germany (*DENA I and II studies*): 2-22 USD/kW at 10%-30% penetration levels (different assumptions between DENA I and II studies).
  - Holttinen (2011): 2-7 EUR/MWh for penetration levels below 40% in Europe.
  - Sweden (Hirth): about 5 EUR/MWh
  - Solar PV (PV parity project): 1-3 Eur/MWh for transmission and 10 Eur/MWh for distribution grid.

- Grid-related costs are system specific, depend on technology and penetration level.
- Available estimates tend to lie in a range from few USD/MWh to 10 USD/MWh.

NB: Connection costs may be significant, especially if distant resources has to be connected to the grid. Not often considered in the literature of system costs.

Estimates of system costs components: Balancing costs

- Balancing costs are related to uncertainty of VRE output.
  - Changing power plant schedule more frequently and closer to real time.
  - Increasing ramping and cycling of conventional plants, and inefficiencies in plant scheduling.
  - Need for additional reserves in the system.
- ***Literature estimates*** for balancing coats (wind) range in 1-7 USD/MWh depending on penetration level and system context (lower for hydro-based than thermal-based systems).
- Increase in wear and tear on PP cycling has been estimated at less than 1 USD/MWh.



Source, Holltinen, 2013

Estimates of system costs components: Utilisation effects ("back-up" costs)

- Profile costs are related to the variability of VRE output.
  - Long-term impact on the cost for providing the residual system.
  - Takes into account also additional flexibility requirements on the system.
  - Impact associated to the low contribution to generation adequacy (low capacity credit).
- It represent the **opportunity cost** of having a cheaper generation mix for the residual system.
- Some authors established a link with the market price of electricity produced by VRE.
- Depend on:
  - The correlation between the VRE production and electricity demand.
  - Penetration level of VRE.
- Complex modelling is required, and results are sensitive to modelling assumptions.
  - Ability to correctly modelling and optimise storage capacity: ↓ profile costs.
  - Ability to correctly model impact of flexibility requirements: ↑ profile costs.
- Few estimates on the literature, but all tend to suggest that profile costs may be large at high penetration level (especially for solar PV).

NEA estimates (wind: 4-9 $/MWh, solar 13-26 $/MWh at 10-30% PL) using residual load duration curves.

IEA estimates (wind: 5-10 $/MWh, solar 4-15 $/MWh at 10-30% PL) using residual load duration curves.

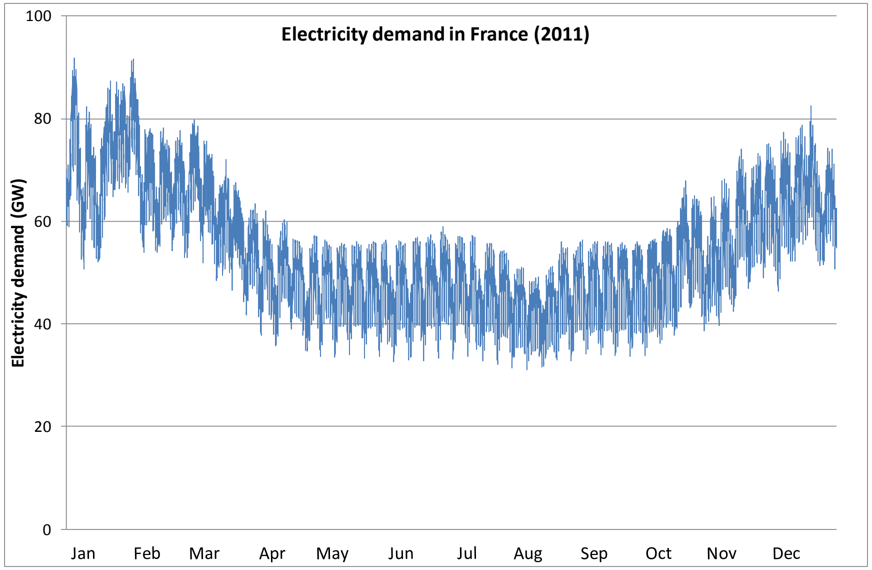
Estimates for the new EGC study are higher (Hirth) using dispatch & commitment model.

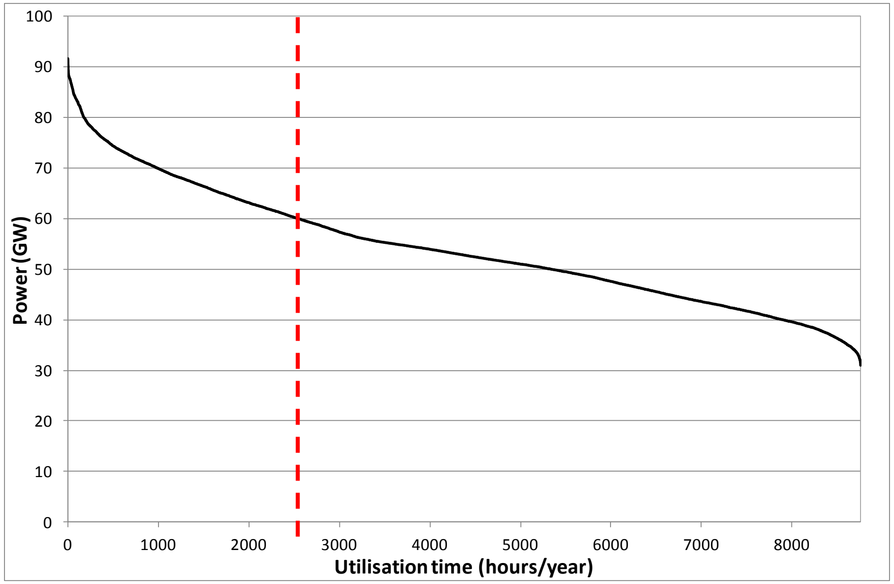
Methodology : residual load duration curves.

- How to calculate the long-term optimal mix (load duration curves)
- Extension to VaRen (residual load duration curves)

Methodology: Long-term optimal mix I

Yearly load duration curve

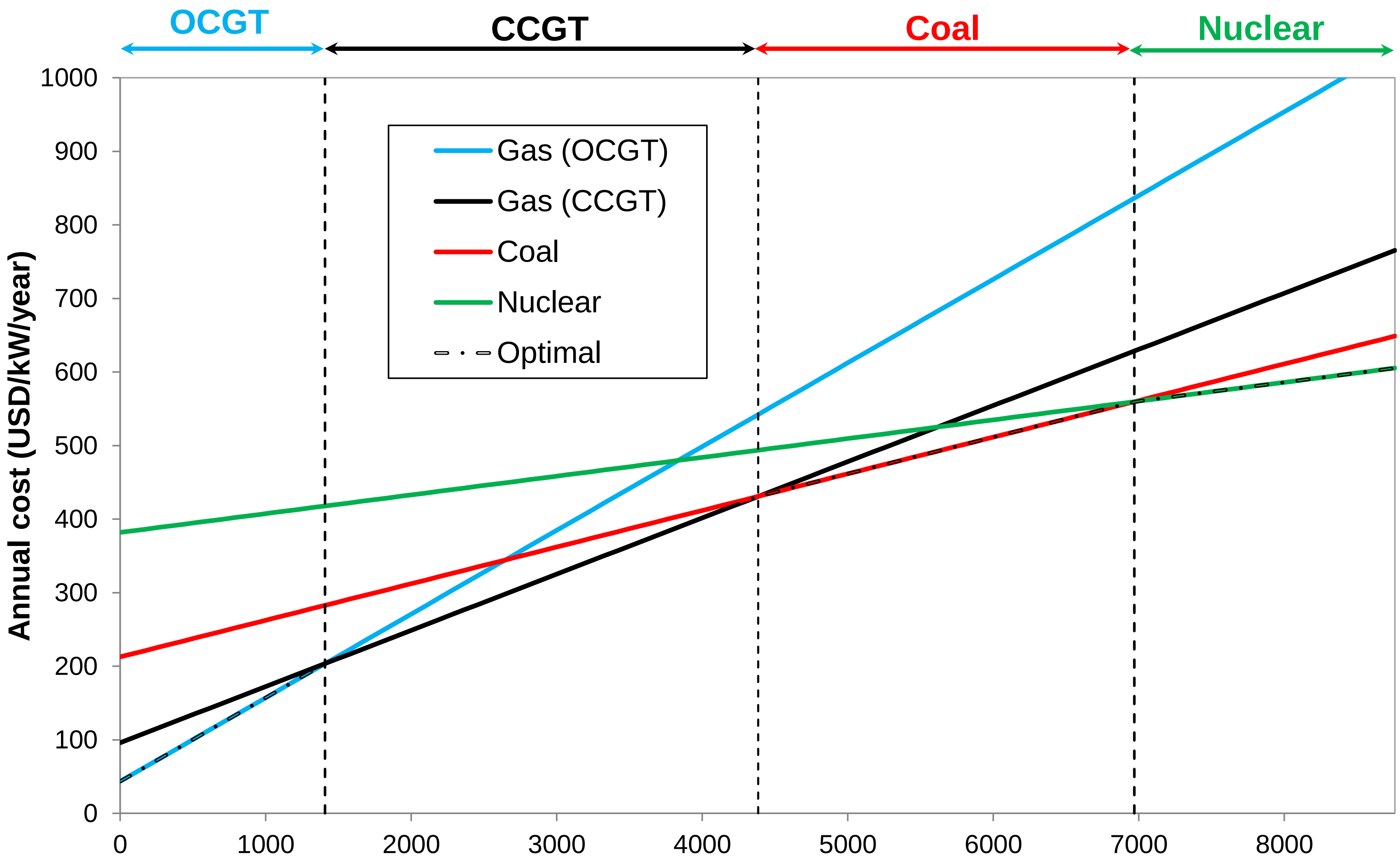




- Simply obtained by ordering demand from highest to lowest.
- The curve shows the number of hours that electricity demand is higher than a certain level.
- Electricity consumed is the integral of load duration curve.
- Load duration curve loses an important information: the time (and thus dynamics).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

Methodology: Long-term optimal mix II

Economics of different generation options

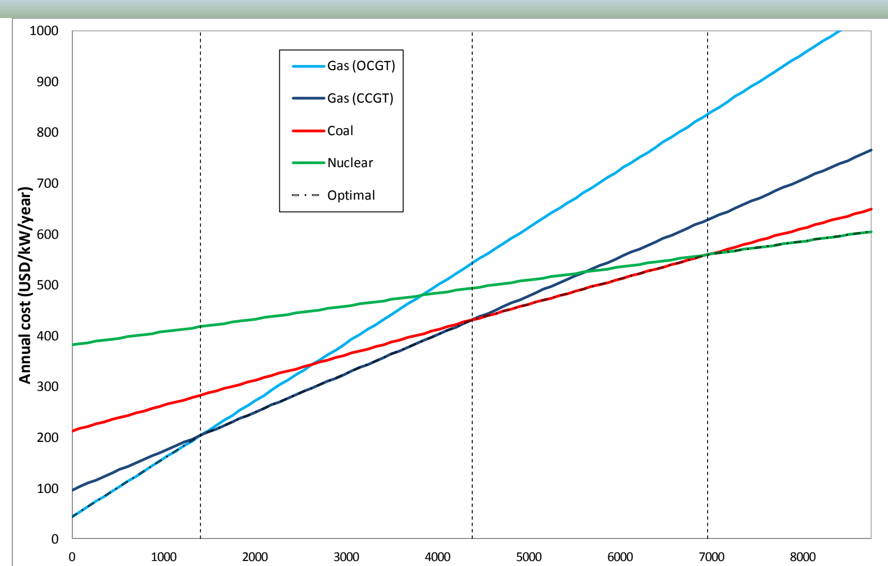


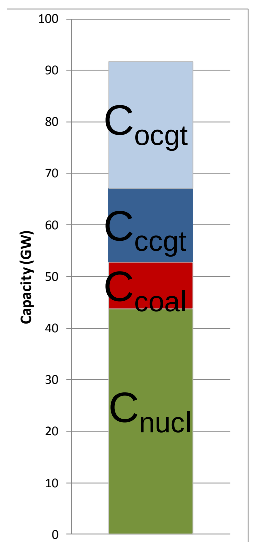
Methodology: Long-term optimal mix III

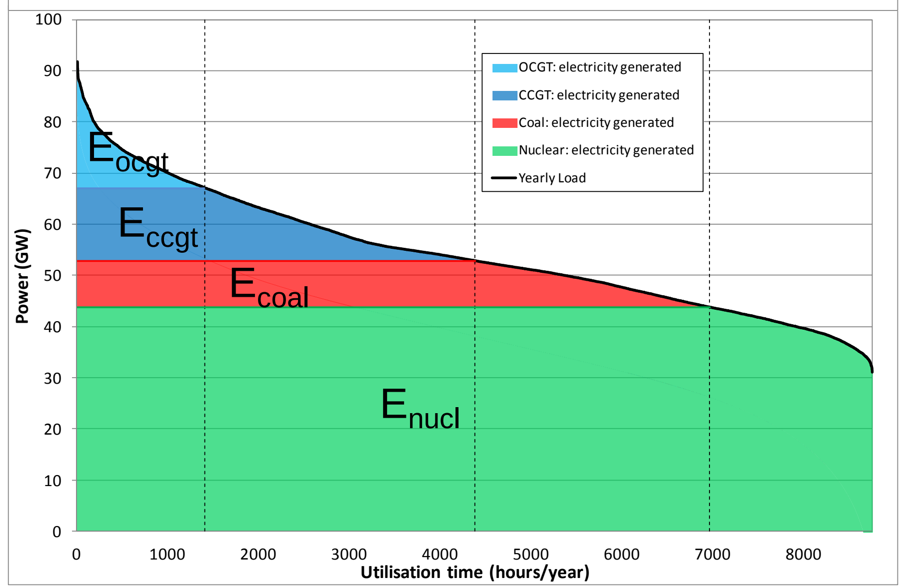
	Fixed costs USD/kW/year	Variable costs USD/MWh	LCOE USD/MWh
OCGT	43.5	113.8	118.7
CCGT	96.1	76.4	87.4
Coal	212.8	49.8	74.1
Nuclear	382.0	25.5	69.1

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

- 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.

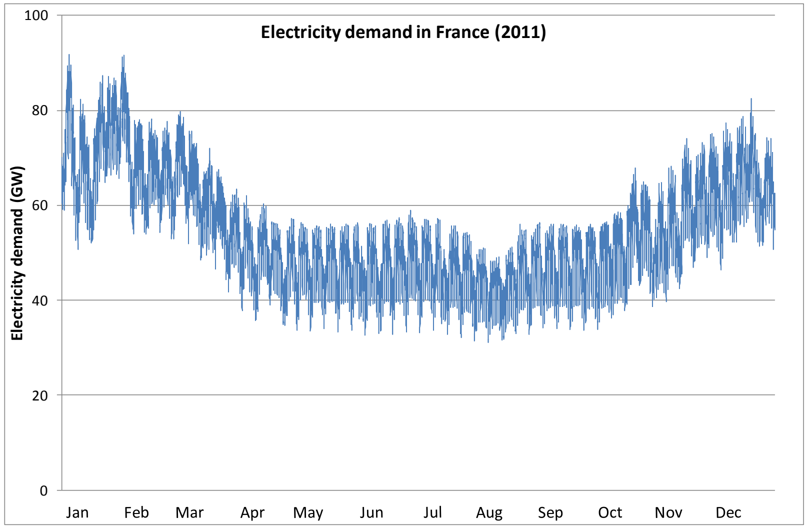






Methodology: calculating a residual load duration curve with VaRen (wind)

Residual load duration curve (wind at 30%)



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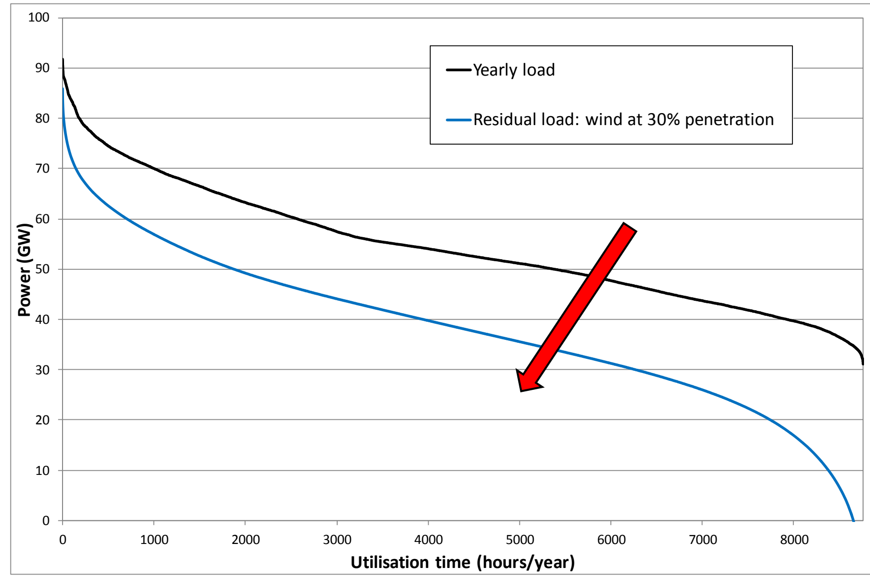
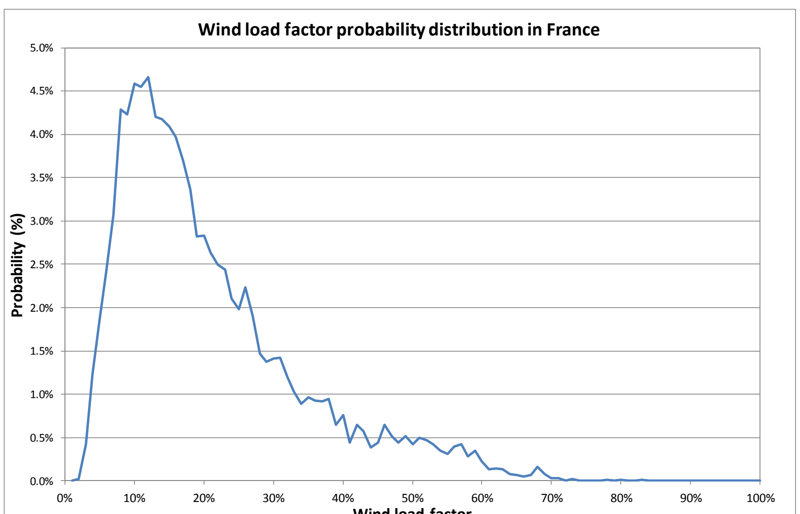


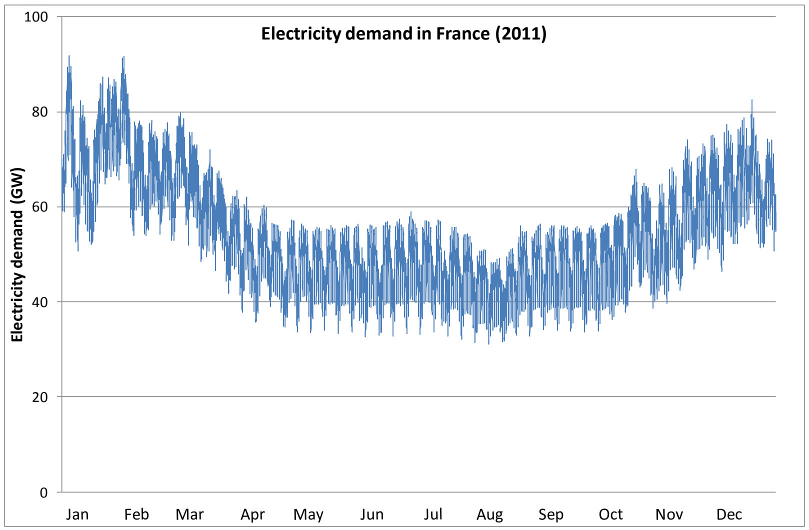


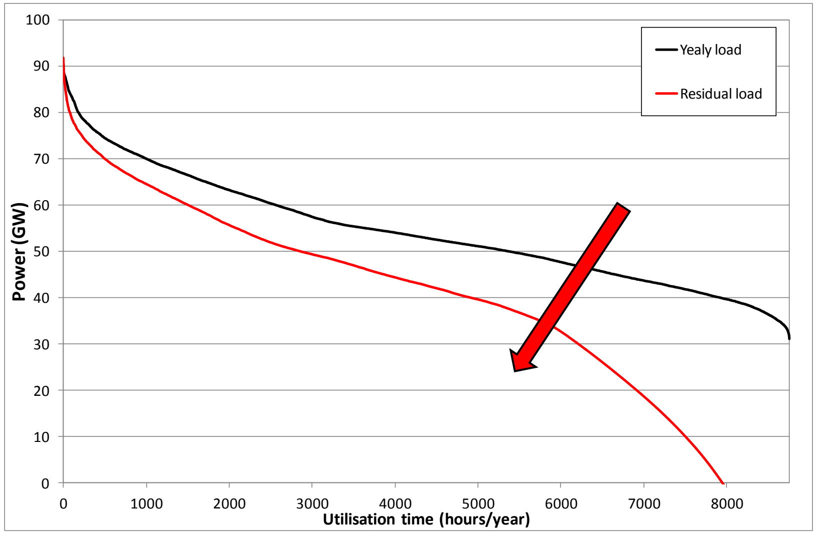
- Represents the load curve seen by the other dispatchable generators after the integration of low-marginal cost wind.
- Statistical analysis (Monte Carlo with 650 runs).
- Load factor probability derived from real RTE data.

  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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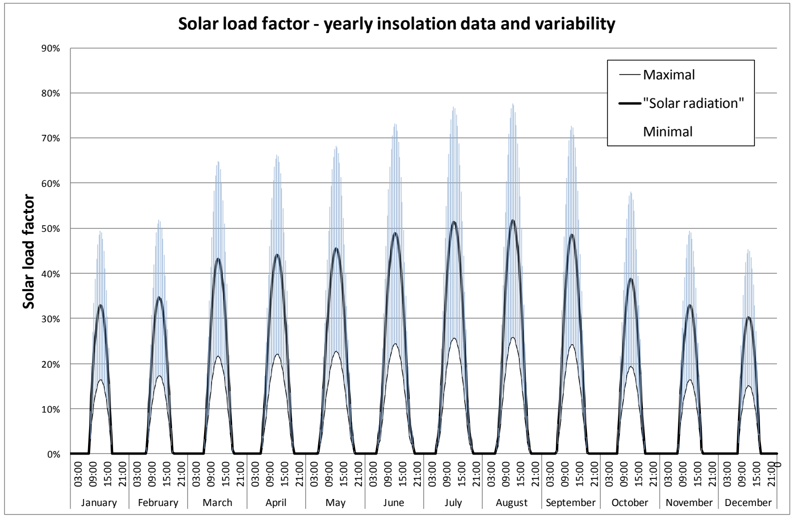


- Statistical analysis (Monte Carlo with 650 trials).
- Load factor probability:
  - Takes into account correlation solar/demand.
  - Educated guess (very smooth & “optimistic”).
- The non-parallel shift of the residual load duration curve is more pronounced than for wind.

Application of residual load duration curves: impacts of VaRen introduction.

- Effects on the generation structure: short-term and long-term
- Impacts on CO_2 emissions
- From adequacy concerns to the cost of back-up
- Cost of providing the residual load

The Short-run and the Long-run (I)

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

Two scenarios can be used to describe the time effects of the introduction of new generation capacity.

Short-term perspective

- The introduction of new capacity occurs instantaneously and has not been anticipated by market players.
- **In the short-term physical assets of the power system cannot be changed. Investment occurred are sunk.**
- VaRen deployment induce fuel, carbon and variable O&M cost savings. (value for the system)
- **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.**
- VaRen replace dispatchable technologies with higher marginal costs:
  - Reduction in generation by existing plants (lower load factors, *compression effect*)
  - Reduction in the electricity price level on wholesale power markets (*merit order effect)*
  - Declining profitability especially for peaking OCGT and CCGT; base-load is less affected

The Short-run and the Long-run (II)

Long-term perspective

- 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,* and the whole generation stock can be replaced and re-optimised.**
- VaRen can also induce investment and fixed O&M cost savings *(the system value of VaRen is higher than in the short-term).*
- VaRen due to its low capacity credit requires dedicated back-up, which is not commercially sustainable on its own.
- Structural change of the generation mix is observed:
  - Shift toward a more flexible generation system, with less base-load and more mid- and peak-load.
  - The per MWh cost for the residual load rises as technologies more expensive per MWh are used.

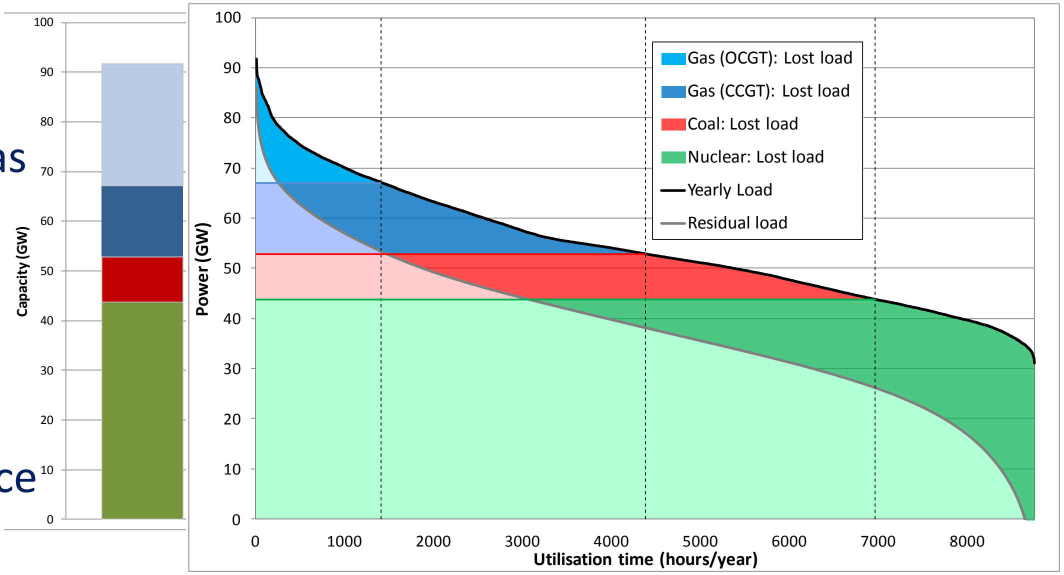
➡ Issue for investors and researchers: when does short-run become long-run?

Impacts of VaRen deployment depends on the degree of system adaptation and thus the *speed of their deployment* as well as on *evolution of electricity demand*.

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:

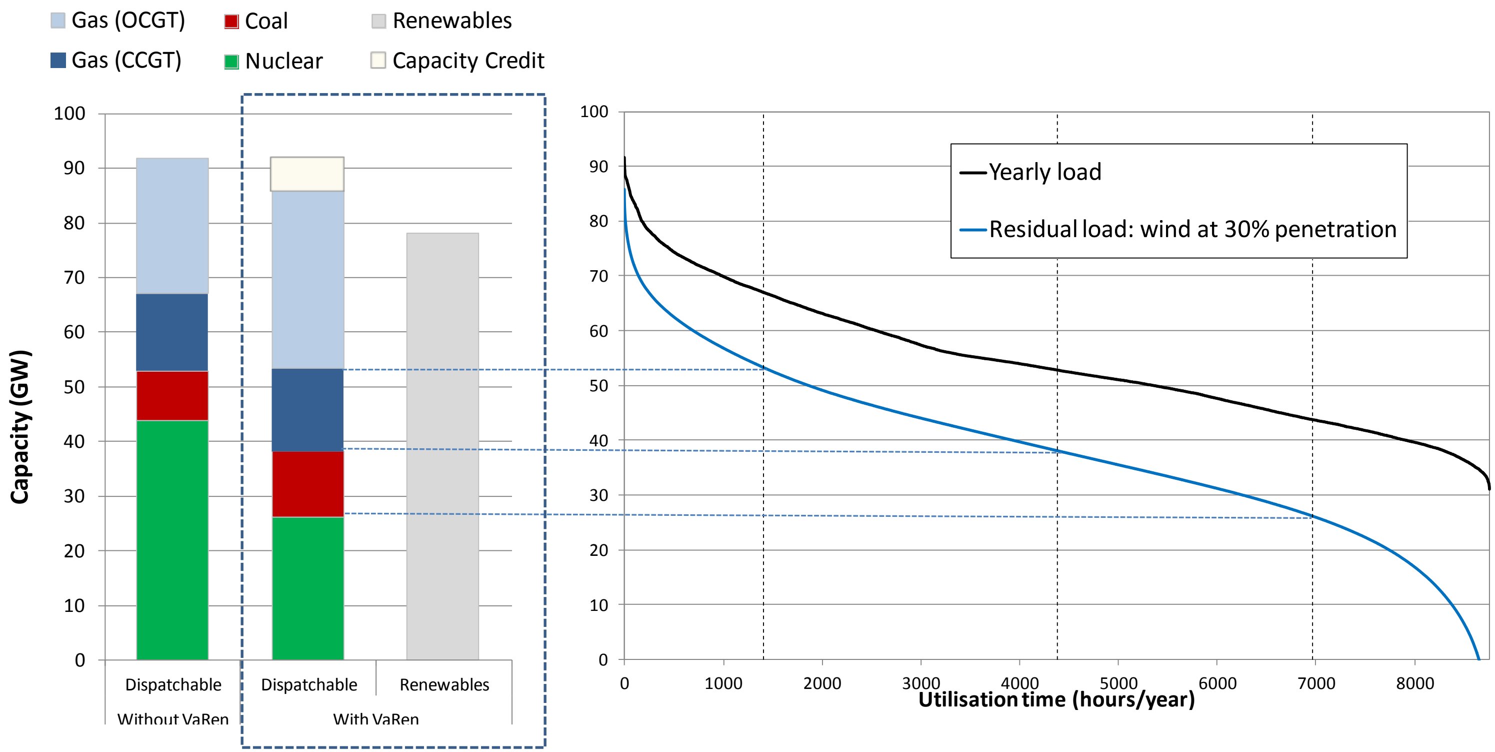
- Reductions in electricity produced by dispatchable power plants (lower load factors, *compression effect*).
- Reduction in the average electricity price on wholesale power markets (*merit order effect).*



		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.

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.

Impacts on CO_2 emissions and electricity price

In the ***short-run***, renewables replace technologies with higher marginal cost, i.e. fossil-fuelled plants emitting CO_2.

- Electricity market prices are significantly reduced (by 13-14% and 23-33%).
- Carbon emissions are considerably reduced (by 30% to 50%).

In the ***long-run***, low-marginal cost renewables replace base-load technology.

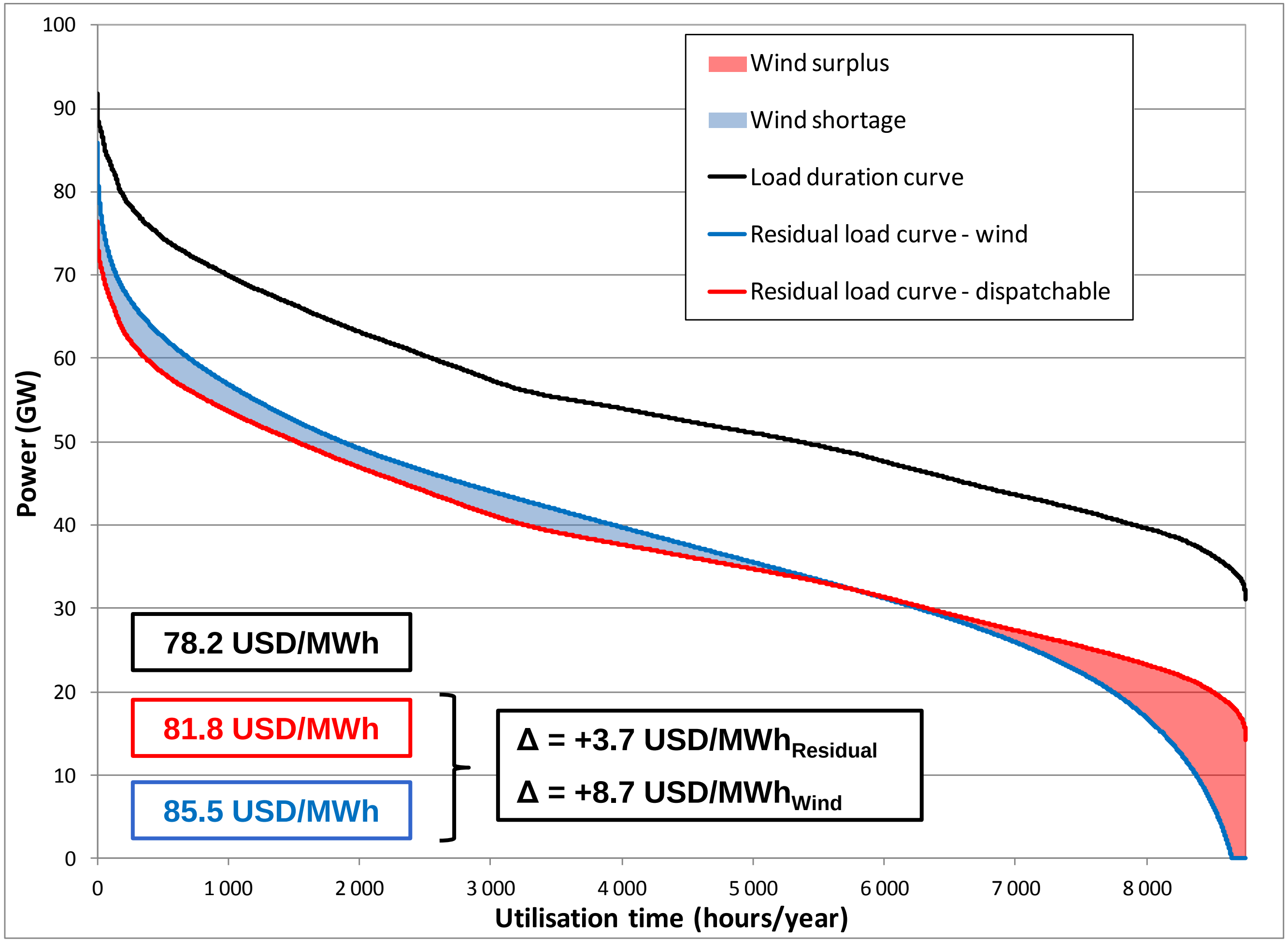
- No changes in electricity market prices at low penetration levels < 15-20%.
- The long-term effect on CO_2 emissions depends on the base-load technology displaced (nuclear or coal):
  - If there was no nuclear on the generating mix, renewables will reduce CO_2 emissions.
  - If nuclear was part of the generating mix, CO_2 emissions increase.

Short- and long-term CO_2 emissions *					
	Reference [Mio tonnes of CO_2]	***10% Penetration level***		***30% Penetration level***	
		Wind [%]	***Solar*** [%]	***Wind*** [%]	***Solar*** [%]
Short-term	59.3	-31%	-29%	-66%	-44%
Long-Term		2%	4%	26%	125%

* Based on a demand curve for France and optimised generation mix

Cost for providing the residual load (1)

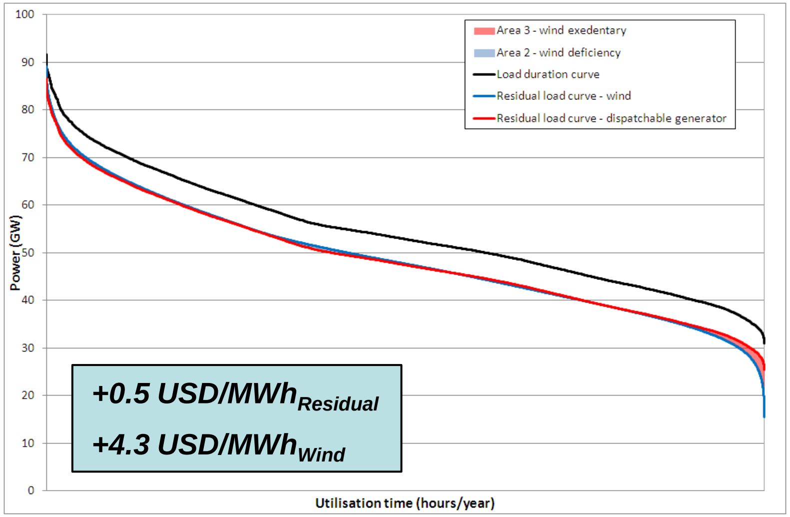
We compare two situations: the residual load duration curve for a 30% penetration of fluctuating wind (blue curve) and 30% penetration of a dispatchable technology (red curve).

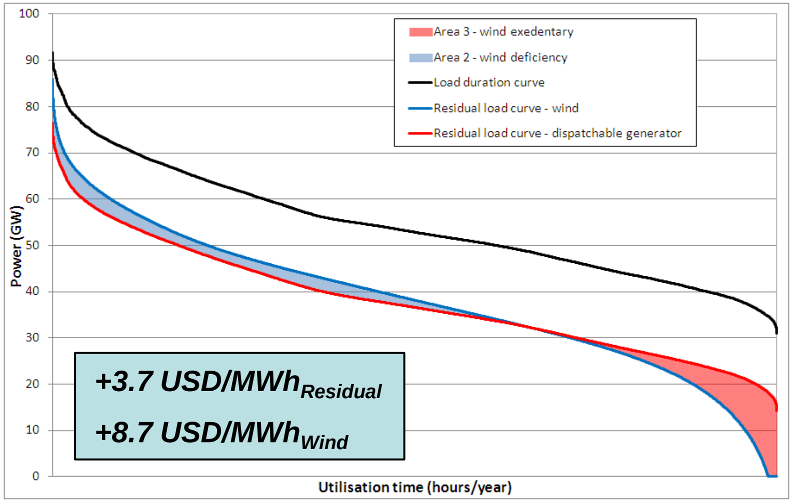


Cost for providing residual load (2)

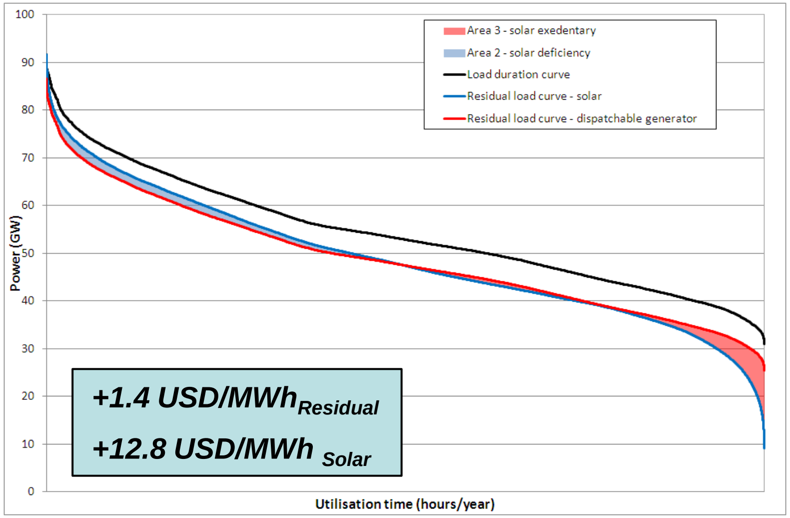
10% Penetration | 30% Penetration

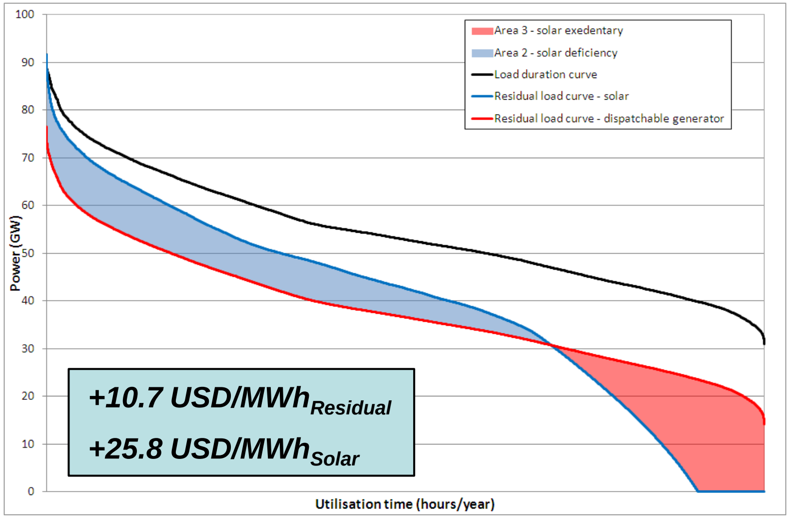
Wind





Solar



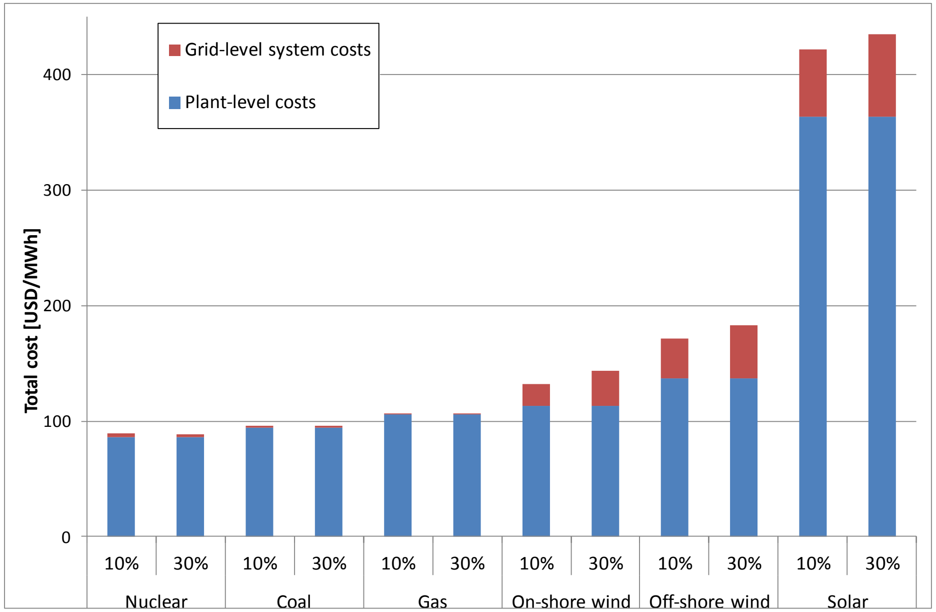


Synthesis of the results, key messages of the System Cost Study and overall conclusions.

System Effects of Different Technologies: Estimating Grid-level Costs

System Costs at the Grid Level (average of 6 countries - USD/MWh)												
	System Costs at the Grid Level [USD/MWh]											
Technology	*Nuclear*		*Coal*		*Gas*		*On-shore wind*		*Off-shore wind*		*Solar*	
Penetration level	*10%*	*30%*	*10%*	*30%*	*10%*	*30%*	*10%*	*30%*	*10%*	*30%*	*10%*	*30%*
Back-up Costs (Adequacy)	0.00	0.00	0.05	0.05	0.00	0.00	6.03	7.38	5.71	7.67	15.88	18.04
Balancing Costs	0.53	0.35	0.00	0.00	0.00	0.00	4.19	8.34	4.19	8.34	4.19	8.34
Grid Connection	1.71	1.71	0.94	0.94	0.51	0.51	6.24	6.24	18.68	18.68	13.71	13.71
Grid Reinforcement and Extension	0.00	0.00	0.00	0.00	0.00	0.00	2.23	6.28	1.51	3.82	4.46	13.55
Total Grid-Level System Costs	***2.24***	***2.05***	***0.99***	***0.99***	***0.51***	***0.51***	***18.69***	***28.24***	***30.11***	***38.51***	***38.25***	***53.64***

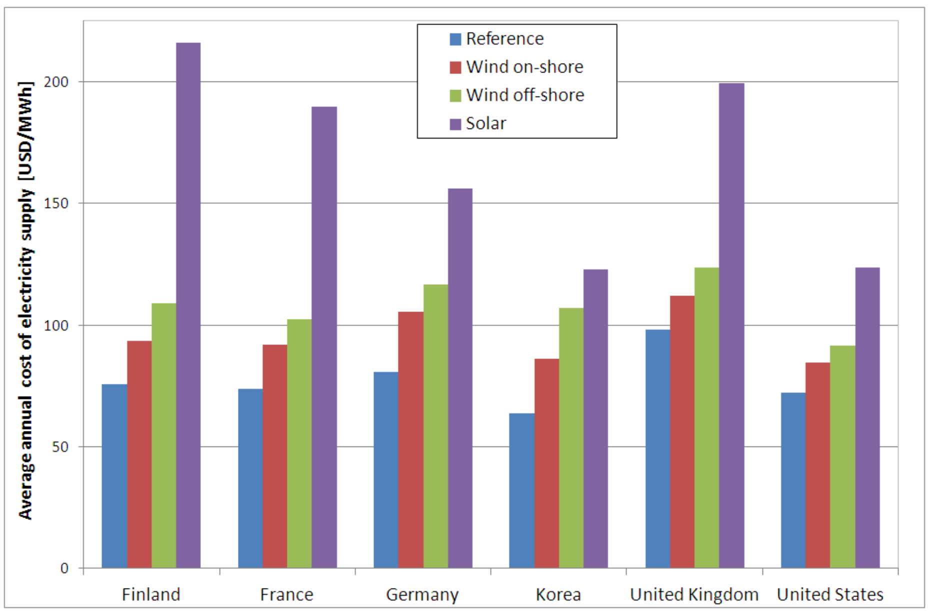
- Six countries, Finland, France, Germany, Korea, United Kingdom and USA analysed.
- Grid-level costs for variable renewables at least one level of magnitude higher than for dispatchable technologies.
  - Grid-level costs depend strongly on country, context and penetration level.
  - Grid-level costs are in the range of 15-80 USD/MWh for renewables (wind-on shore lowest, solar highest).
  - Average grid-level costs in Europe about 50% of plant-level costs of base-load technology (33% in USA).
  - Nuclear grid-level costs 1-3 USD/MWh.
  - Coal and gas 0.5-1.5 USD/MWh.



The "Total" Costs of Electricity Supply for Different Renewables Scenarios

- Comparing "total" annual supply costs of a reference scenario with only dispatchable technologies with six renewable scenarios (wind On, wind Off, solar at 10% and 30%).
  - Takes into account also fixed and variable cost savings of displaced conventional PPs.

		Total cost of electricity supply [USD/MWh]						
		Ref.	***10% penetration level***			***30% penetration level***		
		Conv. Mix	*Wind on-shore*	*Wind off-shore*	*Solar*	*Wind on-shore*	*Wind off-shore*	*Solar*
Germany	***Total cost of electricity supply***	80.7	86.6	91.3	101.2	105.5	116.9	156.2
	Increase in plant-level cost	-	3.9	7.8	16.9	11.6	23.3	50.6
	Grid-level system costs	-	1.9	2.8	3.6	13.2	12.9	24.9
	Cost increase	-	5.8	10.6	20.4	24.8	36.2	75.4
UK	***Total cost of electricity supply***	98.3	101.7	105.6	130.6	111.9	123.6	199.4
	Increase in plant-level cost	-	1.5	3.9	26.5	4.5	11.7	79.6
	Grid-level system costs	-	1.9	3.4	5.8	9.1	13.6	21.5
	Cost increase	-	3.4	7.3	32.3	13.6	25.3	101.1
USA	***Total cost of electricity supply***	72.4	76.1	78.0	88.2	84.6	91.5	123.7
	Increase in plant-level cost	-	2.1	4.2	14.3	6.2	12.5	42.8
	Grid-level system costs	-	1.6	1.4	1.5	6.0	6.5	8.5
	Cost increase	-	3.7	5.6	15.7	12.2	19.1	51.2



- Total costs of renewables scenarios are large, especially at 30% penetration levels:
  - Plant-level cost of renewables still significantly higher than that of dispatchable technologies.
  - Grid-level system costs alone are large, representing about ⅓ of the cost increase.

New Markets for New Challenges

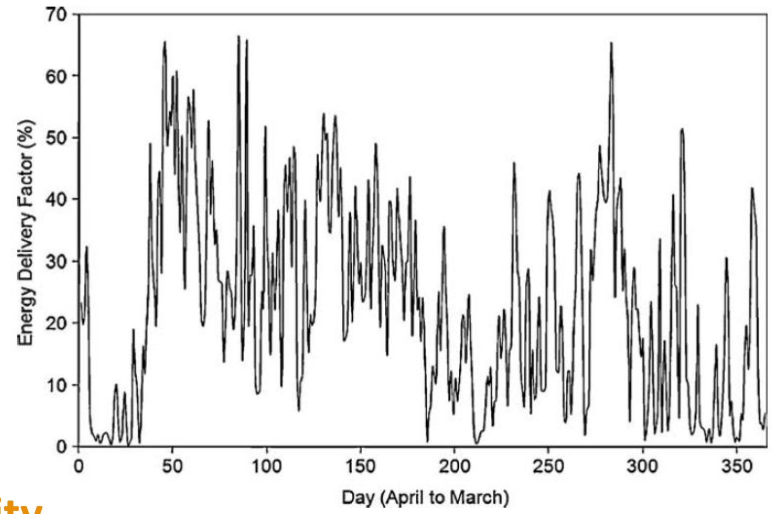
The integration of large amounts of variable generation and the dislocation it creates in electricity markets requires institutional and regulatory responses in at least three areas:

A. Markets for short-term flexibility provision

For greater flexibility to guarantee continuous matching of demand and supply exist in principle four options that should compete on cost:

1. Dispatchable back-up capacity and load-following.
2. Electricity storage.
3. Interconnections and market integration.
4. Demand side management.

So far dispatchable back-up remains cheapest.



B. Mechanisms for the long-term provision of capacity

There will always be moments when the wind does not blow or the sun does not shine. Capacity mechanisms (payments to dispatchable producers or markets with supply obligations for all providers) can assure profitability even with reduced load factors and lower prices.

C. A Review of Support Mechanisms for Renewable Energies

Subsidising output through feed-in tariffs (FITs) in Europe or production tax credits (PTCs) in the United States incentivises production when electricity is not needed (*negative prices).*
Feed-in premiums, capacity support or best a substantial carbon tax would be preferable.

Key Messages

Lessons Learnt

The integration of large shares of intermittent renewable electricity is an important challenge for the electricity systems of OECD countries and for dispatchable generators such as nuclear.

- Grid-level system costs for variable renewables are large but depend on country, context and technology (Wind On < Wind Off < Solar PV).
- System effects of nuclear power exist but are modest compared to those of variable renewables.
- Grid-level and total system cost increase *over-proportionally* with the share of variable renewables.
- Lower load factors and lower prices affect the economics of dispatchable generators: difficulties in financing capacity to provide short-term flexibility and long-term adequacy need to be addressed.

Policy Conclusions

1. **Account for system costs and ensure their correct allocation.**
2. **New regulatory frameworks are needed to minimise and internalise system effects.**
   (1) Capacity payments or markets with capacity obligations, (2) Oblige operators to feed stable hourly bands of capacity into the grid, (3) Allocate costs of grid connection and extension to generators,
   (4) Offer long-term contracts to dispatchable base-load capacity.
3. **A Review of Support Mechanisms for Renewable Energies.**
   Subsidising output through feed-in tariffs (FITs) in Europe or production tax credits in the US incentivises production when electricity is not needed (including *negative prices).* A substantial carbon tax would be optimal and less distortive solution. Second best options are feed-in premiums or support to investment.
4. **Develop flexibility resources to enable the co-existence of nuclear and VaRen.**

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

Why 1 kWh generated by fluctuating sources has a lower value for the system than 1 kWh generated by dispatchable power plants

Introduction

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

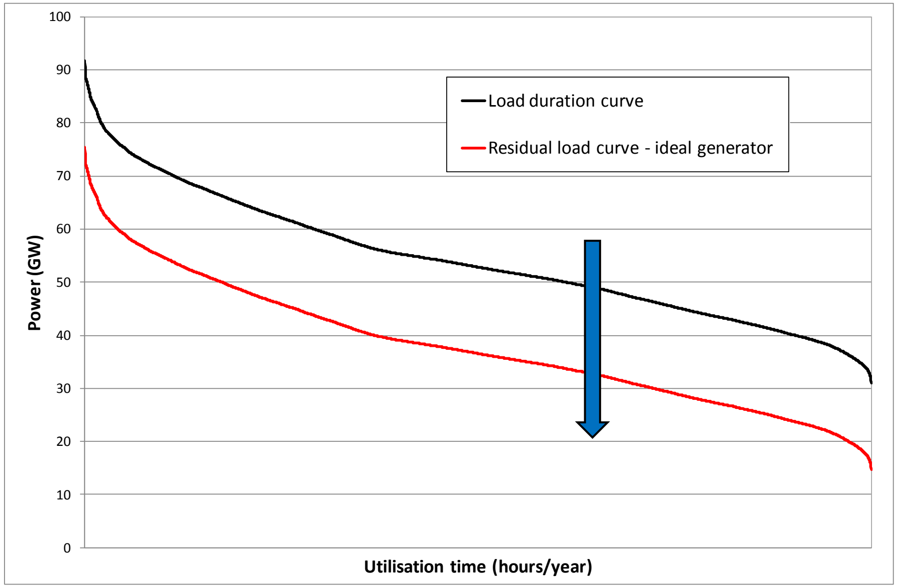
- In absence of large amount of storage, the value of electricity is not homogeneous over time, but depends on ***when*** (and ***where***) it is produced.
- Fluctuating generation does not have the same “value” or utility for the system as dispatchable generation.
- The “value” of fluctuating generation 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 using residual duration curves to overcome these drawbacks and into account **when** the electricity is generated.

A simple example for a flat band

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.

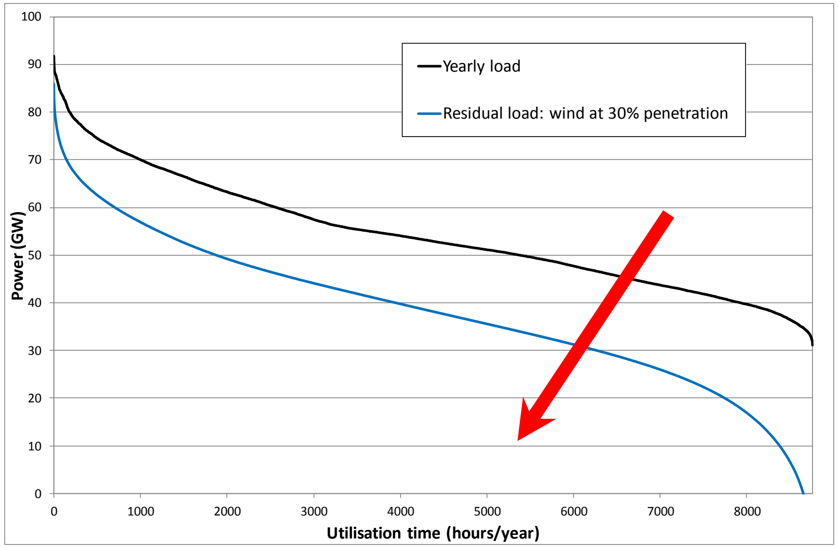
	Total cost [Bil. USD]	***Specific cost*** [USD/MWh]
Original load curve	37.18	78.20
Residual curve	27.32	81.96
Value of flat band	9.86	69.11

- 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)

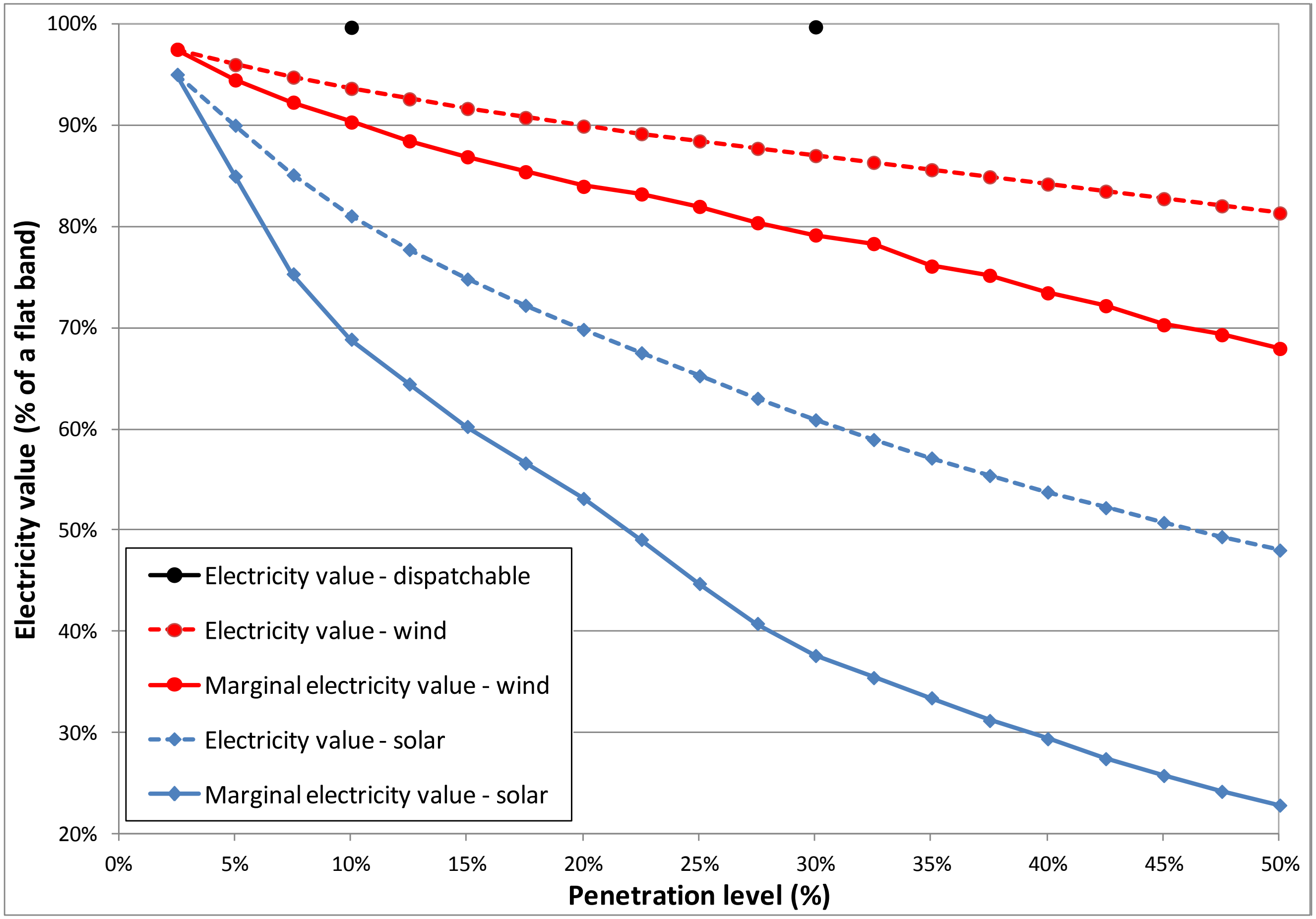
	Total cost [Bil. USD]	***Specific cost*** [USD/MWh]
Original load curve	37.18	78.20
Residual curve	27.32	81.96
Value of flat band	9.86	69.11

- 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*.

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

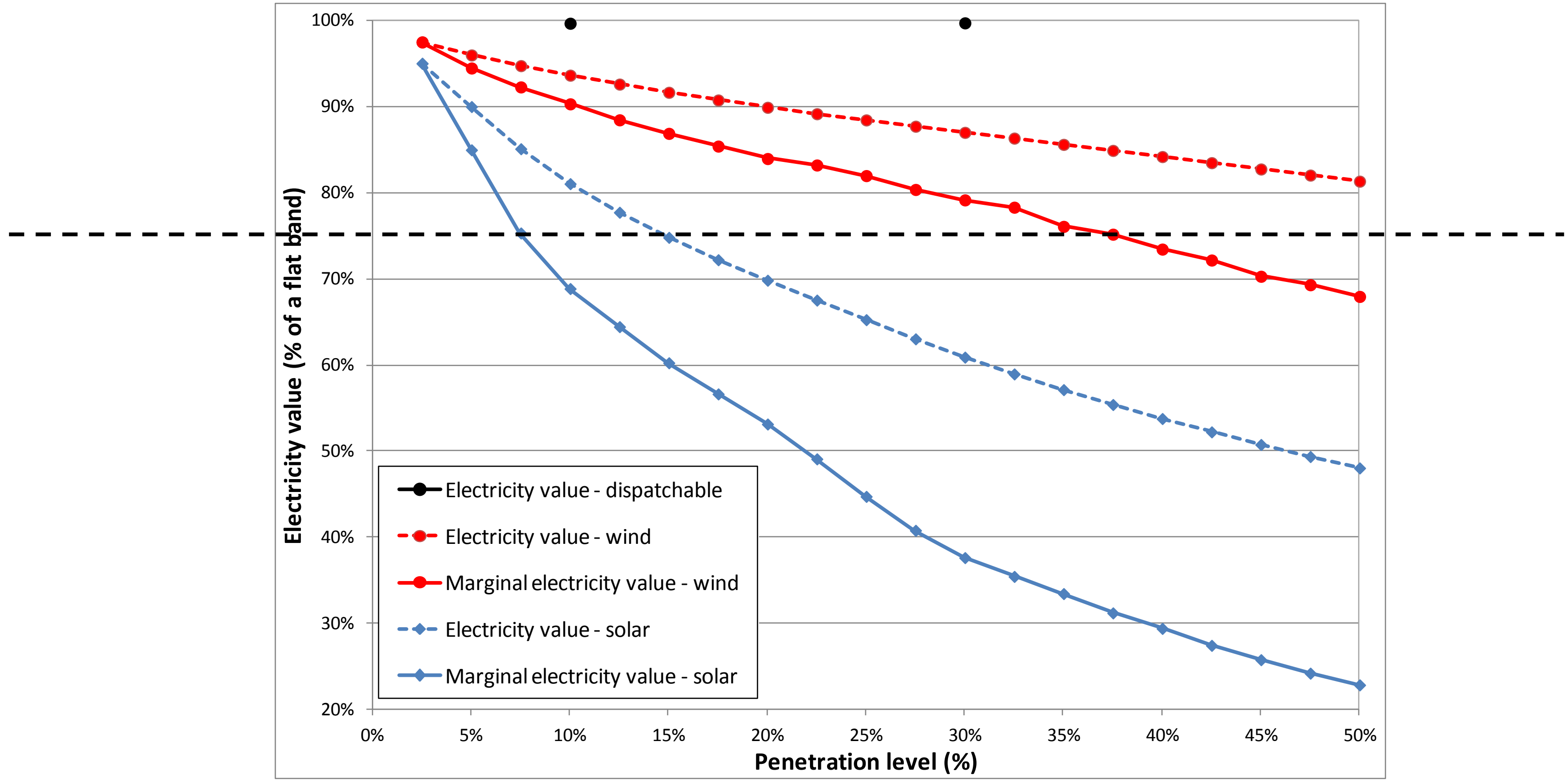
We can look at the impact of the variability from a different perspective:

- 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%).

Value factor and correlation with demand

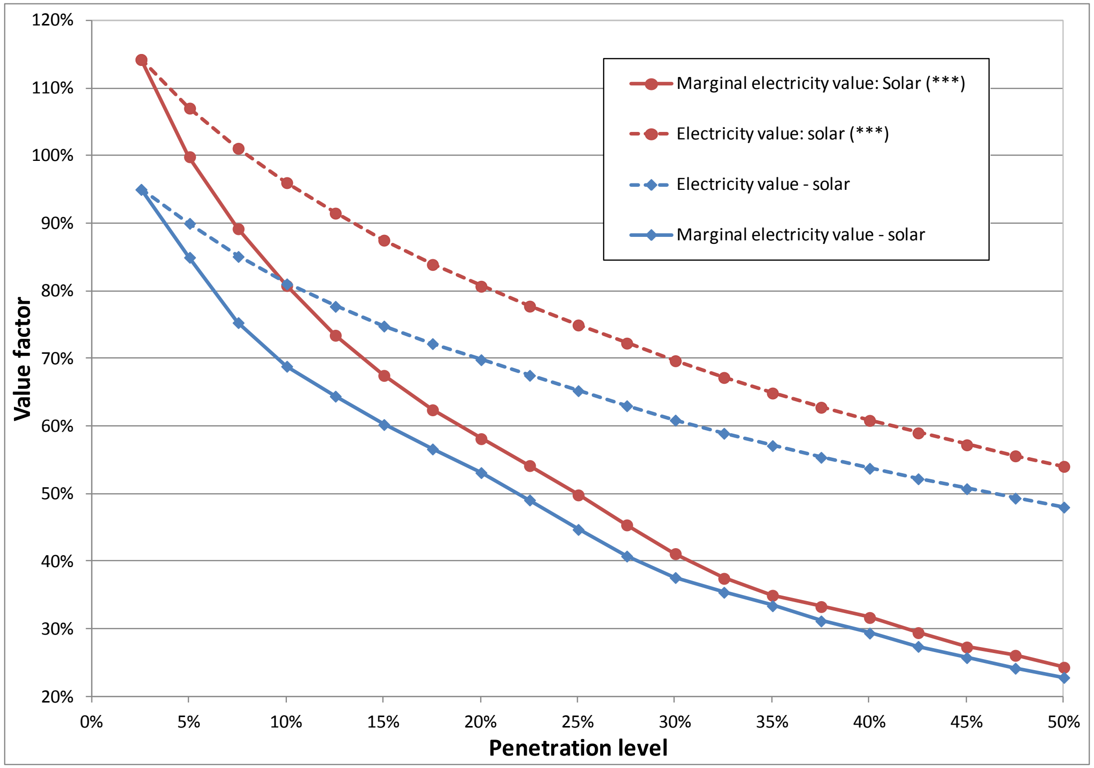
Data on load curves and VaRen correlations have been derived from RTE data (France) and are valid only for France.

- 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

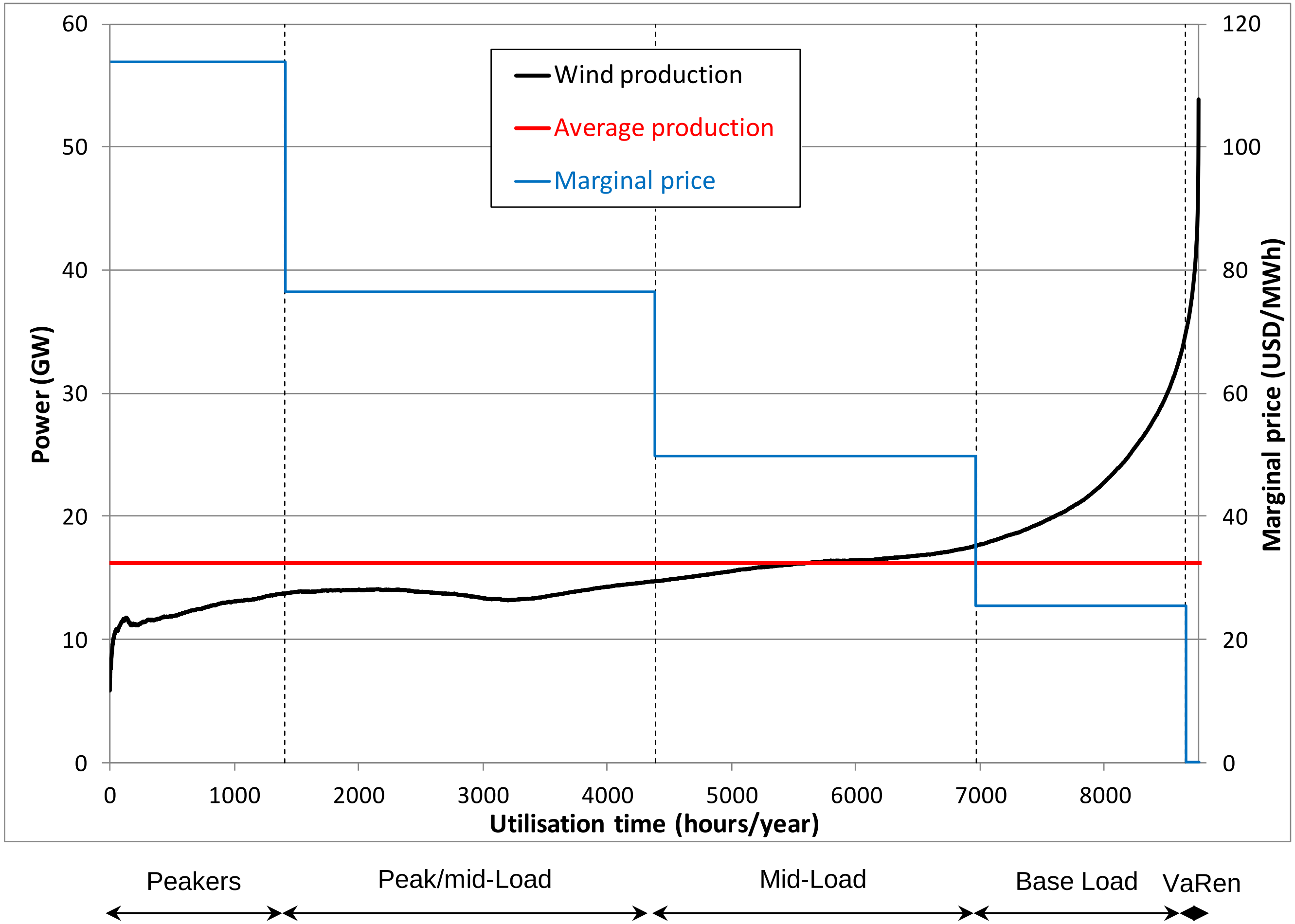
- Storage will reduce the cost of residual load for both the scenario with VaRen and the reference.
- The presence of significant amount of storage will increase the value factor of VaRen.
- Different systems (depending on Ren type and penetration level) will call for an “optimal” level of storage.
- 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.

The market value of variable renewables: A graphic explanation

Simple graphic explanation of these phenomena.

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



Summary

- ***Methodology***
  - Relatively simple, robust and intuitive.
  - Needs reliable data on renewable production profiles and correlations (with demand and with other variable renewables) to derive correctly residual load duration curves.
  - Difficult to model storage capacity in a satisfactory way.

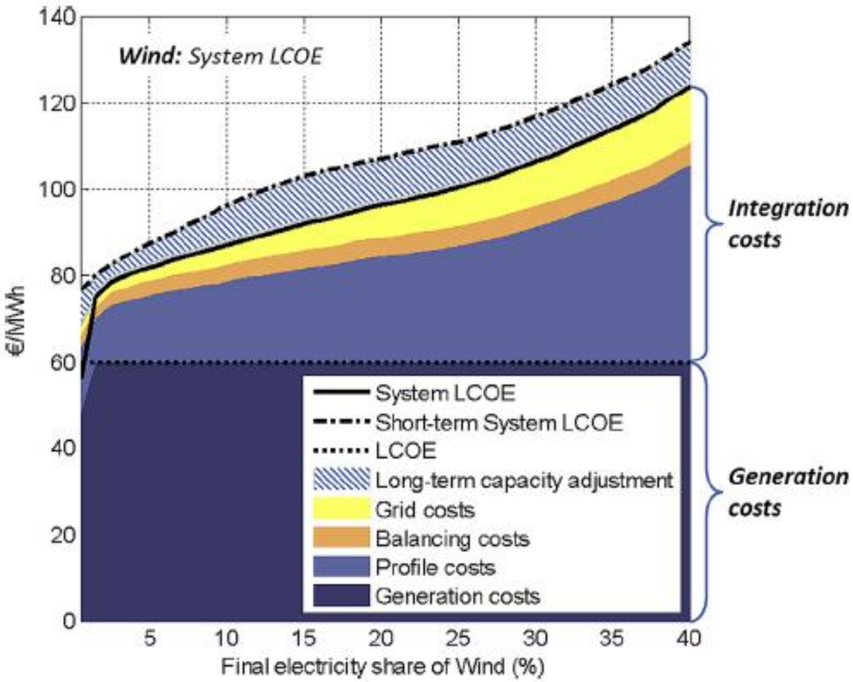
- ***Results***
  - The value factor drops significantly for fluctuating sources with penetration level.
  - Important implications if VaRen have to be financed in a competitive market environment.
  - Marginal value factor should be used in system planning.
  - Storage availability would reduce integration cost and hence improve the value factor of VaRen ….but at what cost?

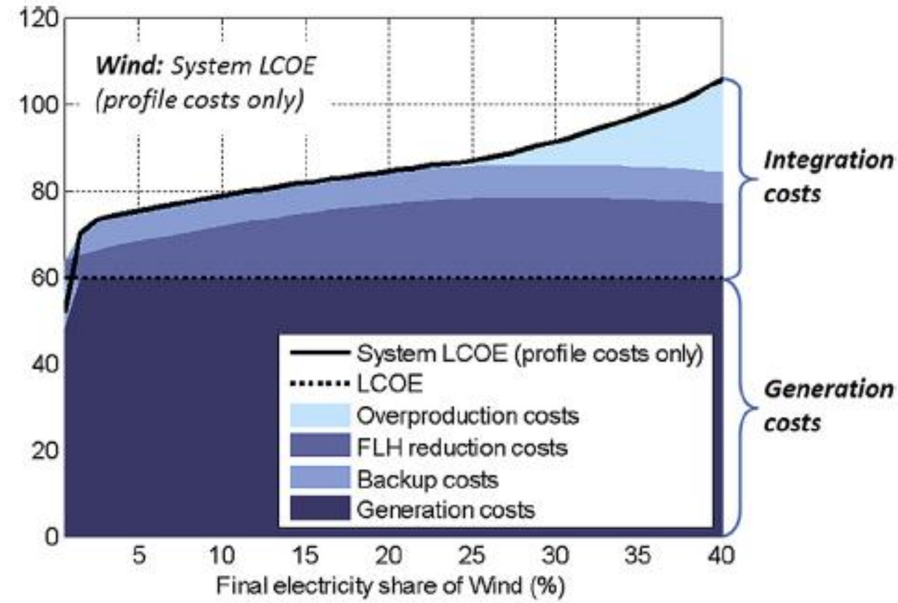
- ***Potential applications***
  - To LCOE calculations (correcting the electricity produced by the value factor).

    - but this introduces additional complications
  - Concept of grid-parity.

A comparison with other studies on profile costs (Hirth)

An expression of integration costs*





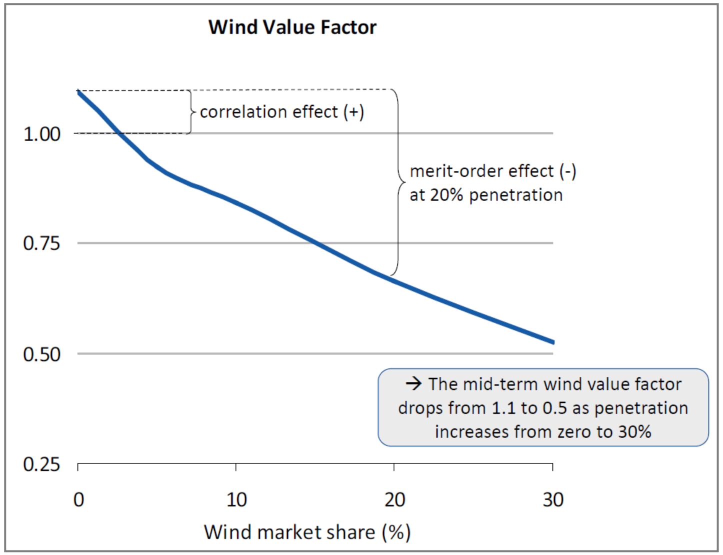
- Profile costs are divided into 3 components
  - Overproduction (cost of curtailing VaRen).
  - Backup requirements due to the lower capacity credit.
  - Full Load Hour reduction costs.
- Grid costs and balancing costs are summed to obtain integration costs.
- Consideration of long-term/short term capacity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

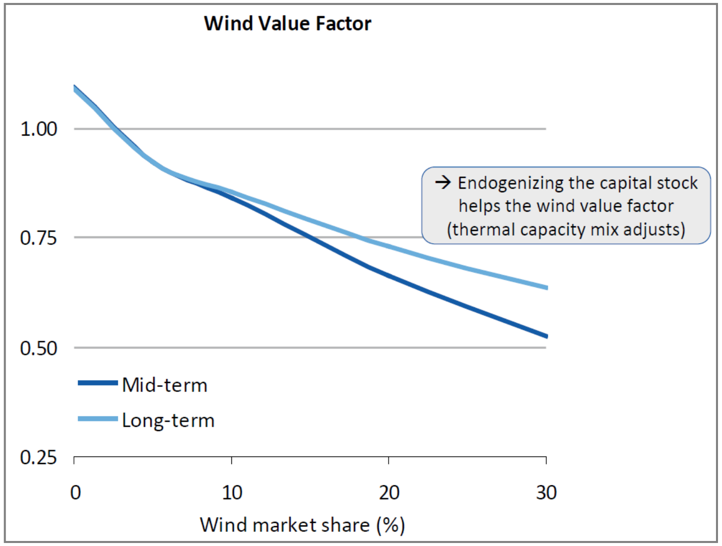
* F. Ueckerdt, L. Hirth, G. Luderer, O. Edenhofer,: *"System LCOE: What are the costs of variable renewables?"* Energy 63 (2013) pp 61-75

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

Market value and System cost approach are "equivalent"

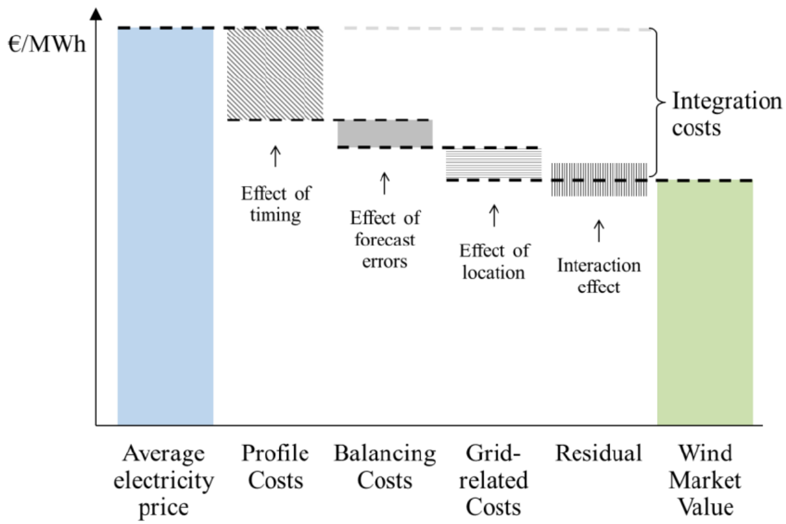


Figure 4: We decompose integration costs into three components, balancing, grid-related, file costs. They correspond to the three characteristics of VRE uncertainty, locational spe ity, and temporal variability.

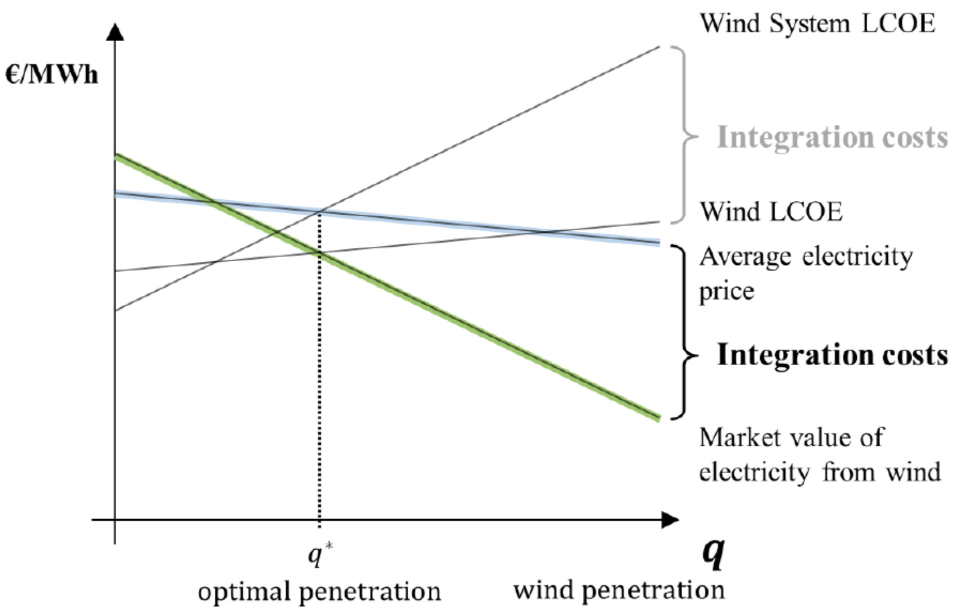


Figure 2: Integration costs can be accounted for by reducing the market value of VRE compared to the average electricity price (value perspective). Alternatively, they can be accounted for by adding them to the generation costs of VRE leading to system LCOE (cost perspective). The welfare-optimal deployment q^* is defined by the intersection of market value and LCOE, and, equivalently, by the intersection of system LCOE with the average electricity price.

F. Ueckerdt, L. Hirth, O. Edenhofer:

"Integration costs revisited. An economic framework for wind and solar variability". Renewable Energy 74 (2015) 925-939

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

The new EGC study and the nuclear new built study will be available shortly on the NEA website.

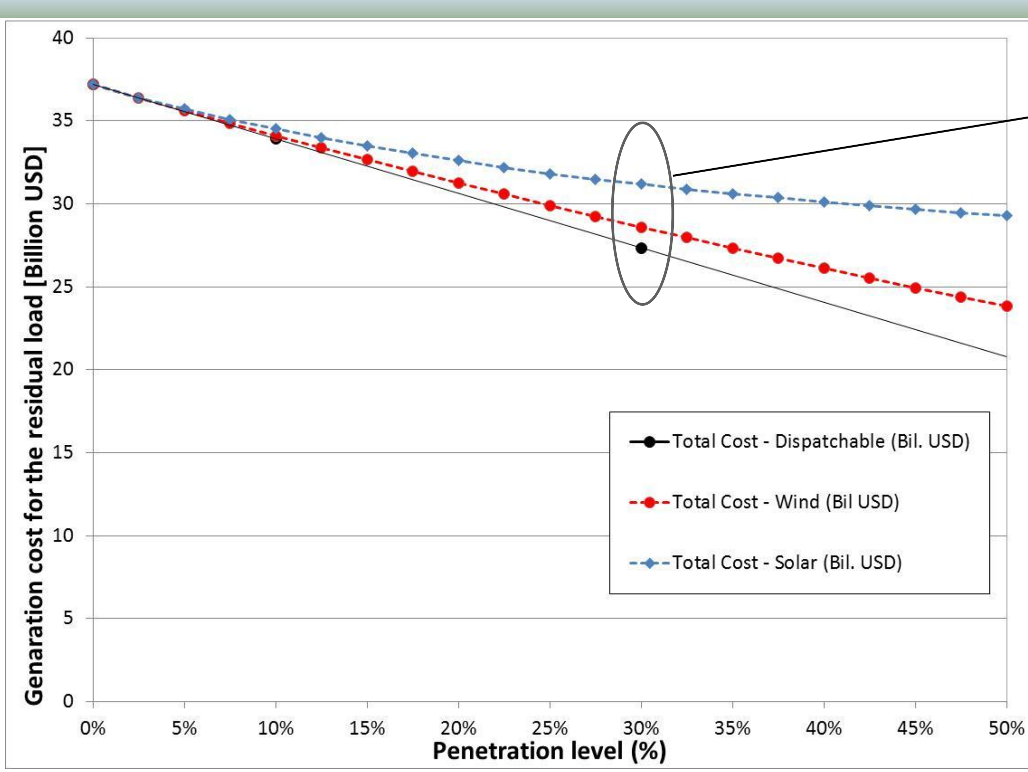
Contacts: Marco Cometto and Jan-Horst Keppler

Marco.Cometto@oecd.org
Jan-Horst.Keppler@oecd.org

Reserve slides

Capacity credit

Generation Cost for providing Residual Load



Penetration Level			Wind	Solar
	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.

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

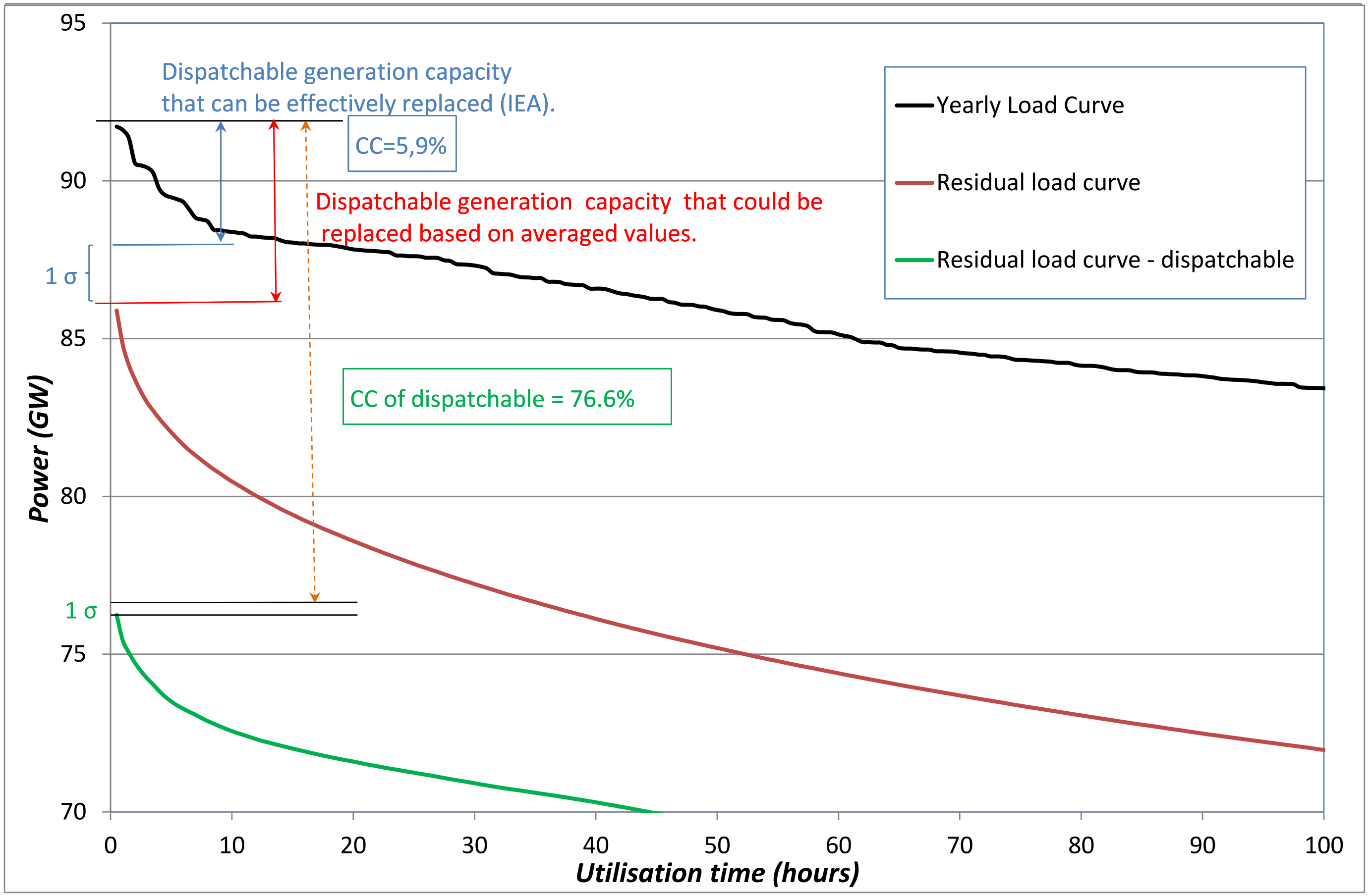
- Electricity produced.
- Contribution to adequacy.

→ 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

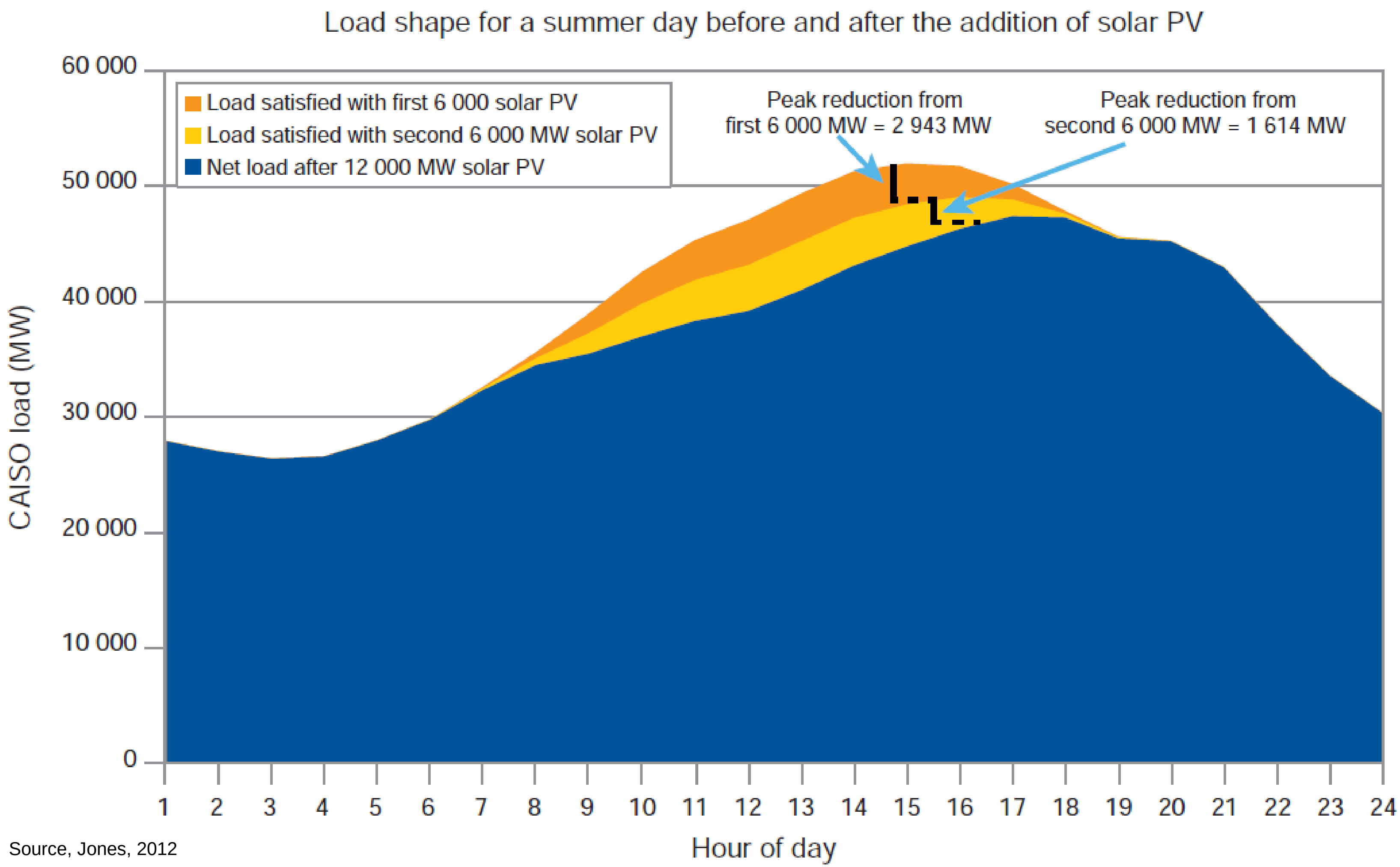
- Capacity credit is calculated using complex probabilistic techniques (LOLP) and requires a sophisticated modeling of the whole electricity system.

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



Decreasing capacity credit of VRE: an example

The declining contribution of increasing solar PV to system capacity in the CAISO system



Source, Jones, 2012